Gel Polymer Treatments in Kansas Arbuckle Wells

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Bottom Line

Recent success in applying gel polymer treatments in Kansas Arbuckle producing wells has created a "boom" of activity. All of the approximately 300 wells treated since 2001 have responded favorably to the treatments to one degree or another. All of the wells have responded with significant reduction in water production and many have also responded with an increase in oil production. In many instances these treatments are paying out in weeks to months. Even though the mechanisms of why these treatments have been so successful are not well understood and is still being studied, it has not slowed down operator's enthusiasm in applying this technology.

Introduction

In the Arbuckle formation in Kansas, water production can be excessive due to channeling in this water-drive reservoir. High water production restricts oil production and increases operating costs, often leading to leases and/or wells becoming prematurely uneconomic to produce. Gel polymer treatments have a long history in the mid-continent for blocking these channels. Recent treatments in Kansas Arbuckle producing wells are proving to be more effective in controlling water production and increasing oil production than past treatments.

Overview

Comparing recent treatments to earlier ones indicate several differences. The majority of the recent successful treatments are using the MARCIT^{SM} technology where the polymer and crosslinker are mixed on the surface as opposed to previous systems that mixed chemicals in the reservoir and much larger volumes of gel are being used. Recent treatment volumes range from 1,500 to 5,000 barrels versus the few hundred barrels historically used. MARCIT^{SM} is the acronym for **MAR**athon **C**onformance **I**mprovement **T**reatment. This polymer gel system was developed in the mid-1980s by Marathon Oil Company and licensed to various service companies in the early 1990s. The MARCIT^{SM} technology consists of mixing dry polymer, Cr(III)carboxylate/acrylamide in water and crosslinking it with chromium triacetate at the surface. Gel Technologies Corporation and TIORCO (**T**he **I**mproved **O**il **R**ecovery **Co**mpany), Inc. are the two service companies applying the MARCIT^{SM} technology in Kansas.

In January 2003 another service company (Polymer Services, LLC) started conducting treatments using a Chevron/Phillips Chemical Company technology referred to as the PROD^{SM} system. This system also uses the chromium III crosslinking system with chromium propionate as the crosslinker and is applied similarly as the MARCIT^{SM} system. Forty-two producing oil wells were treated with this system from January through July of 2003.

Since 2001, over 30 operators have treated approximately 300 central Kansas Arbuckle producing wells with MARCIT^{SM} and PROD^{SM} gel polymer systems. To one degree or another, the wells have successfully responded to the treatments. For some wells, oil production has increased from approximately 5 BOPD to over 200 BOPD for several days after the treatments (+/- 14 days) and has stabilized at between 10 and 30 BOPD for six months or longer. For the same wells, water production has dropped from over 1500 BWPD in many cases to between 100 and 200 BWPD and has remained at the lower volumes for a year or longer. Other wells have not responded as favorably, but have still seen an increase in oil production and a decrease in water production. In some cases no significant oil benefits are seen, but water production is still reduced. Operators indicate that the $20,000 to $50,000 gel treatments in most instances pay out in weeks to months.

Kansas Arbuckle Formation - (from Franseen, et al., 2003)

> Since the 1910's, several billion barrels of oil have been produced from the Central Kansas Uplift (CKU), primarily from carbonate reservoirs within the Arbuckle and Lansing-Kansas City groups (Figure 1). The majority of Arbuckle reservoirs of central Kansas were drilled prior to 1955 and constitute a series of giant and near giant oil fields. The significance of the Arbuckle to Kansas production and reserves is highlighted by the estimate that Arbuckle reservoirs have produced about 2.19 billion barrels of oil (BBO) representing approximately 36% of the 6.1 BBO of total Kansas oil production to date. Arbuckle reservoirs produce from 31 counties statewide with a significant portion of the total production coming from the 10 counties in the CKU region. Table 1 lists the 21 most productive Arbuckle fields and the cumulative oil production attributed to each. These fields represent approximately 56% of all Arbuckle production with nineteen of the fields lying on the CKU and the remaining two on the Nemaha Uplift in Butler and Cowley counties. Although the Arbuckle has been a prolific producing interval since 1917, annual production peaked in the early 1950's at more than 68 million barrels and has declined to approximately 12 million barrels per year in 2002. Today, stripper production dominates Arbuckle production with over 90% of wells producing less than 5 barrels of oil per day and is very sensitive to commodity prices.
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> The long production history and exploration/exploitation strategies have led to some commonly held perceptions about Arbuckle reservoir properties. These include: 1) Arbuckle reservoirs are fracture-controlled karstic reservoirs with porosity and permeability influenced by basement structural patterns and subaerial exposure. The weathering and secondary solution of the upper Arbuckle beds, due to subaerial exposure, is thought to have significantly enhanced porosity and permeability and created petroleum reservoirs in these strata. 2) The Arbuckle is composed predominantly of shallow-shelf dolomites. The process of dolomitization enhanced porosity. 3) Most of the oil and gas zones in the Arbuckle are contained in the top 25 ft, some are 25-50 ft within the Arbuckle and Arbuckle wells are characterized by high initial potential, steep decline rates, and production of large quantities of oil at high water/oil ratios. Thus, Arbuckle

reservoirs typically have been visualized as an oil column on top of a strong aquifer. This conceptual model of the Arbuckle reservoir resulted in drilling and completion practices in which wells were drilled into the top of the Arbuckle with relatively shallow penetration (less than 10 ft.) and completed open hole. The geology of the Arbuckle is not well understood due to these drilling and completion practices along with the limited number of cores that have been taken.

Basic Information Pertaining to Water Shut-off Treatments Using Gelled Polymers

The majority of polymer treatments to control water production in producing wells are performed in fractured carbonate/dolomite formations associated with a natural water drive, such as the Arbuckle formation in Kansas. Gelled polymers are created when dry polymer is mixed in water and crosslinked with a metal ion (usually chromium triacetate or aluminum citrate). Gelation is controllable, ranging from a few hours to weeks. Slower gelation time allows for more volume and deeper placement. Different polymer systems are available from different service providers.

Service company experience seems to be the dominant factor in estimating how a particular formation in a given area will respond to gelant injection. The service provider must be prepared to alter the original design based on the ability of a formation to accept a viscous fluid. A formation injectivity test is important in determining any changes in the original design.

In many instances creating a pressure response during treatment is the single most important indicator of a potentially successful water control project. A slow, steady pressure increase over a period of time during pumping will tell the operator one of two things: 1) the formation is reaching fill-up of polymer into the problem zone, or 2) the reservoir temperature is causing the polymer to crosslink and build viscosity. In the Arbuckle formation in Kansas, in many instances, it is difficult to determine when a pressure response is occurring as the surface treating pressure is a vacuum throughout most, if not all, of the treatment.

Pressure response is a product of polymer volume, injection rate and gel strength. Altering any or all of these factors can improve the success of the treatment if reservoir resistance is not seen as the gelant is being pumped. Increasing polymer volume is typically the first step many service companies recommend if the Hall plot indicates only a slight increase of pressure near the end of the treatment. The advantage of pumping a larger volume is that greater in-depth reservoir penetration can improve the longevity and effectiveness of the treatment. The disadvantage of more volume is increased treatment costs due to longer pump times and additional chemicals. However, in most instances, the incremental per barrel cost of the extra volume is relatively low since many of the costs associated with conducting the treatment (well preparation, service company equipment, etc.) are already spent.

Usually injection rates are increased at the beginning of the treatment in order to determine how easily the formation can accept a viscous fluid. Recent research and field experience have shown that higher pump rates can improve the effectiveness of treatments in carbonates that exhibit secondary permeability and porosity features. Increasing the injection rate also reduces the service company's field time, which translates into a cost reduction for the operator.

Increasing gel strength or gel viscosity is the third method for achieving a pressure response. This method is typically used at the midpoint of a treatment when the Hall plot shows no increase in slope or after several treatments in a particular field indicate the need for such action. Improving gel strength can be done by accelerating the crosslinking, increasing the polymer loading (concentration) of the gelant, or using a higher molecular-weight polyacrylamide.

Acceleration of the crosslinker in Marathon's MARCIT^{sm} is accomplished by adding chrome chloride to the chromic triacetate. Mature gels can be formed in approximately 4-6 hours at a temperature of 90^{o} F with the accelerated crosslinker, as compared to the normal time of 16-18 hours. The advantage of this technique is that treatment volume may be significantly decreased in heterogeneous carbonates while the gel is placed into the highest permeability features of the formation. The disadvantage is that higher temperature reservoirs may cause the gel to prematurely set in or near the wellbore.

Increasing polymer loading will also improve gel strength. A 4,000 ppm gel contains 1.4 pounds of polymer per barrel of mix water. Increasing the concentration to 5,500 ppm will add 0.52 pounds per barrel, which is a nominal change in chemical cost. The advantage of high polymer loading is having a stronger gel that crosslinks in a shorter time.

Molecular weight also plays an important part in gel strength. Most treatments utilize polyacrylamides that have a molecular weight of 4-8 million. This medium molecular-weight polymer can be used for both high permeability matrix and smaller fracture systems. Service companies can also supply higher molecular-weight products that are designed for use in high conductive secondary features. Gels formed with this polymer will enter only the highest permeability sections of the reservoir where the water problem exists. The disadvantage of high molecular-weight gels is that in-depth reservoir penetration and subsequent water diversion may be reduced.

Candidate Well Selection

Best candidates are shut-in wells or wells producing at or near their economic limit. These wells benefit most from a successful treatment and little is at risk if the treatment fails, other than the treatment cost. However, with the documented success of these gel treatments in the Arbuckle formation in Kansas, many operators are treating wells that are producing economically. Other selection criteria include high water disposal and/or lifting costs, significant remaining mobile oil in place, high water-oil ratio, high producing fluid level, high initial productivity, wells associated with active natural water drive, structural position and high permeability contrast between oil and water-saturated rock (i.e., vuggy and/or fractured reservoir). Successful treatments have been conducted in both cased and open hole completions.

Treatment Sizing

Only empirical methods exist at this time for sizing treatments. Experience in a particular formation is most beneficial. However, in many instances larger volume treatments appear to decrease water production for longer periods of time and recover more incremental oil. Some rules-of -thumb being used in the Arbuckle formation in Kansas include two times the well's daily production rate as the minimum polymer volume or using the daily production capacity of the well at maximum drawdown (i.e., what the well would be capable of producing if it were pumped off) as the treatment volume. In lower fluid level wells the daily production rate is sometimes used as the minimum polymer volume.

Preparation Prior to Pumping

It is important to ensure the wellbore is clean. Acid is important to remove near wellbore obstructions that can reduce polymer injectivity. Most operators acidize the well prior to the gel treatment. In the past typically 350-500 gal of 15% acid was used prior to the treatment. However, recent trends indicate larger volumes of acid are being used, 1000-1500 gal. The acid is being pumped away and displaced with water ahead of the gel treatment. Data obtained during the acid stimulation is important in making any treatment design changes. In many instances, low acid injectivity is a good indicator of a potential polymer treatment failure. It is also recommended to establish a maximum treating pressure; run a step rate test to determine parting pressure, if necessary. Select an acceptable source of water to blend and pump the treatment. Gels can be formed using a wide range of waters, from fresh to formation brines. Have the service provider test the water's compatibility to form the desired gels. Select a polymer-compatible biocide for the mix water (typically 5-10 gallons per 500 barrels of mix water). Set tubing and packer to isolate the zone to be treated.

Placing the Treatment

Use stages of increasing polymer concentration. Inject the treatment at a rate similar to the normal producing rate, one of the service companies recommend an optimal rate of 1 bbl/minute (BPM) which is equivalent to 1440 barrels per day. Some rules-of-thumb are 0.25 to 0.5 BPM for tighter formations and 1.0 to 1.5 for more permeable formations. Keep treatment pressure below reservoir parting/fracture pressure. Changing conditions during treatment may warrant design changes during pumping. It is common practice to perform shut-in pressure tests throughout the treatment if there is a pressure response. Offset producing wells should be monitored for polymer entry. Over displace the treatment with water or oil. In some instances, a rapid pressure response early in the treatment is a danger sign the treatment may not be successful.

For high fluid level wells in the Arbuckle, the optimal polymer volume has been 3500 to 4000 barrels of polymer. The polymer is pumped in increasing stages of concentration. Typical stages start out at 4,000 ppm, increase to 5,500 ppm, 6,500 ppm and end with 8,000 ppm. High molecular weight polymer is used in the 8,000 ppm stage.

The rationale for using lower concentration gels to begin the treatment are to test the injectivity of the viscous fluid into the reservoir and the gel on the leading edge of the treatment will occupy rock furthest from the wellbore where it will be exposed to much lower differential pressure, therefore higher concentration gels are not needed deep into the reservoir. Rationales for higher concentration gels at the end of the treatment are this gel will occupy the area nearest the wellbore where it will be exposed to higher differential pressure and these stronger gels will hold the treatment in place.

Post Treatment Procedure

Most operators are over displacing the treatment with 80-150 barrels of water and/or lease crude. The well is shut-in for a minimum of 4 to 14 days to allow time for the gels to form. It is then swab tested for one day or until little or no polymer is observed in the returns. The well is reactivated based on the swab test results. It is recommended to monitor production rates for at least 30 days, if not longer.

Re-Treatments

Some wells have been treated multiple times with polymer. It is believed that the gels have not chemically degraded, but that the water eventually finds another fracture or vugular system to travel through. These re-treatments are typically lower volume. Most of the re-treatments noted an earlier pressure response due to the existing gel. In many instances initial production responses were equivalent to the first treatment. It is felt in many instances the re-treatments are more economical than adding larger artificial lift equipment.

Potential Problems

Corrosion and separation (tank battery upsets) are the most common problems associated with producing well polymer treatments. Accelerated corrosion can occur as a result of polymer production. The use of uncrosslinked polymer as flush can make this problem worse. Polymer also coats rods and tubing, which prevents contact by corrosion inhibitors. It is recommended to use a separate work string for pumping the polymer treatment as a best practice. Corrosion treating recommendations are to: 1) batch treat rather than continuous (twice per month if over 500 barrels of fluid per day), 2) circulate a “bio-dispersant” prior to batch treatment (quaternary amines are most common), 3) continue the above program only as long as polymer production continues.

Most battery upsets can be avoided by swabbing to a frac tank after the treatment to make sure the well has “cleaned-up” prior to switching production to the tank battery. Visual inspection of the produced fluid is usually an adequate quality control method.

Online Database

The Tertiary Oil Recovery Project (TORP) at the University of Kansas has a long history of research and field applications related to gelled polymers. TORP is working with service companies and oil operators to develop a database on the treatments conducted to date and investigating areas where university engineers and scientists can be of assistance in better defining where and how to apply this technology. Questions looking to be answered include better defining candidate well selection, treatment volumes and modeling what actually occurs during and after the treatments.

As part of this effort, TORP working in conjunction with the North Midcontinent region of the Petroleum Technology Transfer Council (PTTC) has developed a website containing information on these gel polymer treatments. The website address is www.nmcpttc.org/gel/index.html. The website contains: 1) names, locations, and well data of treated wells, 2) size of pre-treatment acid job, 3) treating report from vendor, 4) before and after water and oil production plots, 5) before and after fluid levels when available, 6) before and after artificial lift equipment when available, 7) build-up and bottom-hole pressure data when available, 8) miscellaneous reports, and 9) contact information and links to other relevant sights. Some of the operators supplying data choose to keep well names and locations confidential.

The website currently contains detailed information on 37 treatments. The website will soon be expanded to include information on 92 treatments, along with economic analysis of the treatments. Plans are to continue to expand the data on the website to include as many wells as data can be acquired for and to link the production data to State production records to continually update production plots where applicable.

Example Wells from Database

Three example wells will be discussed in this section. Wells were selected to illustrate the range of how different wells have responded to gel polymer treatments. Information discussed on these example wells is the type of data available on a larger number of wells in the online database.

Example of a Nice Initial Response with Above Average Incremental Oil Recovery

The Johnson B #3A is located in the SE SW SW of Section 29-T11S-R18W in Ellis County, Kansas. This well is in the Bemis-Shutts Field. Casing is set at 3718 ft. and perforated from 3526-3533 and 3576-3580. It was treated in August of 2001 by TIORCO using the MARCIT^{SM} system. The pre-polymer acid job was 250 gal followed by 1621 barrels of polymer. The treatment consisted of 118 bbls at 3500 ppm, 1001 bbls at 4000 ppm and 502 bbls at 5000 ppm. The treatment was overflushed with 80 bbls of oil. The maximum surface treating pressure was 51 psi and 97% (1578 bbls) of the treatment was at a vacuum at the surface. The average injection rate was 1025 bbls per day.

Prior to the treatment this well was producing 2 BOPD and 677 BWPD with a producing fluid level of 834 ft. above the perforations. The well was shut-in for 10 days following the treatment and returned to production. The initial production following the treatment was 116 BOPD and 62 BWPD. One month later the well was producing 43 BOPD and 130 BWPD. Six months following the treatment it was producing 14.5 BOPD and 147 BWPD. The producing fluid level following the treatment was approximately 200 ft. above the perforations. This well has produced approximately 8532 bbls of incremental oil to date as a result of the treatment. There were no artificial lift equipment changes on this well. Figure 2 is a plot illustrating production from this well.

Example of Average Response

The Peavey A-6 is located in the NW SW of Section 13-T11S-R18W in Ellis County, Kansas. This well is in the Bemis-Shutts Field. Casing is set at 3342 ft. and it is an open-hole completion from 3342-3346. It was treated in August of 2001 by TIORCO using the MARCIT^{SM} system. The pre-treatment acid job was 250 gal followed by 3806 barrels of polymer. The treatment consisted of 897 bbls at 3500ppm, 1251 bbls at 4000 ppm, 1254 bbls at 5000 ppm and 404 bbls at 6000 ppm. The treatment was overflushed with 80 bbls of oil. The maximum surface treating pressure was 446 psi and 64% (2433 bbls) of the treatment was on a vacuum at the surface. The average injection rate was 1050 bbls per day.

Prior to the treatment this well was producing 11 BOPD and 1056 BWPD, the producing fluid level was not reported. The well was shut in for 7 days and returned to production. The initial production following the treatment was 22 BOPD and 162 BWPD. One month later the well was producing 27 BOPD and 153 BWPD. Six months following the treatment it was producing 21 BOPD and 192 BWPD. The producing fluid level following the treatment was approximately 1253 ft. above the perforations. This well produced approximately 4952 bbls of incremental oil as a result of the treatment. The artificial lift changes were the pumping unit was speeded up and a larger bottom-hole pump was installed early in 2002. Figure 3 is a plot illustrating production from this well.

Example of Poorer Response
The Colahan A #41 is located in the C W/2 NE of Section 24-T11S-R17W in Ellis County, Kansas. This well is in the Bemis-Shutts Field. Casing is set at 3389 ft. and perforated from 3386-3389 and also has open-hole from 3389-3390.5. It was treated in August of 2001 by TIORCO using the MARCIT^{SM} system. The pre-treatment acid job was 500 gal followed by 2988 barrels of polymer. The treatment consisted of 897 bbls at 3500 ppm, 1394 at 4000ppm, 602 at 5000 ppm and 95 bbls at 6000 ppm. The treatment was overflushed with 80 barrels of oil. The maximum surface treating pressure was 923 psi and 8% (245 bbls) of the treatment was on a vacuum at the surface. The average injection rate was 850 bbls per day.

Prior to the treatment this well was producing 3 BOPD and 500 BWPD with a producing fluid level of 2016 ft above the perforations. The well was shut-in for 7 days and returned to production. The initial production following the treatment was 34 BOPD and 52 BWPD. One month later the well was producing 21 BOPD and 46 BWPD. Six months following the treatment it was producing 10 BOPD and 48 BWPD. The producing fluid level following the treatment was approximately 100 ft. above the perforations. This well produced approximately 1474 bbls of incremental oil as a result of this treatment. The artificial lift change was a larger bottom-hole pump was installed in December 2001. Figure 4 is a plot illustrating production from this well.

TORP Efforts
In addition to participating in developing the database and website on these gel polymer treatments, TORP has also conducted pre and post build-up tests on wells using their computerized echometer, participated with operators and service companies in collecting bottom-hole pressure data during treatments and has began efforts to computer model what occurs during the treatments.

Transient test analysis (build-up tests) measures formation kh (permeability), skin damage and the flow regime. The flow regime can be linear as flow through fractures or radial as flow through matrix rock. It is hoped by analyzing and comparing these tests that insight might be gained on the size required for pre-treatment acid volumes, candidate well selection, sizing the polymer treatment and how the reservoir permeability and fluid flow is affected by the treatments. This data will be used to help develop the computer model.

Since many of the treatments see little or no pressure at the surface, it was thought it could be useful to collect bottom-hole pressure data during treatments. The pressure response related to pumping this viscous fluid into the reservoir could provide insights into the gel/rock interface, which could help in sizing treatments and setting maximum treating pressures. It could also assist in determining a friction coefficient for pumping gel down tubing and with the computer modeling.

This data is available on the TORP/PTTC gel polymer website on the wells for which it has been collected. Figures 5 through 7 show the bottom-hole pressure data that was collected during the treatment of the Hall B #4 located in the NW/4 of Section 26-T11S-R17W in Ellis County, Kansas and produces from the Bemis-Shutts Field.

Individual Well Economics
Economics for these polymer treatments vary from well to well depending on the pre-treatment acid volume, polymer volume, tank rental, pumping time, rig time, post treatment oil and water production rates, disposal costs, electrical costs, artificial lift equipment changes, etc.

Operators have indicated the cost for doing the polymer treatments are approximately $10 to $15 per barrel for the volume of the polymer treatment. Typical ranges are $40,000 to $55,000 for ± 4,000 bbl treatments and $20,000 to $30,000 for ± 1,500 bbl treatments. These costs include all expenses associated with conducting the treatment and returning the well to production.

Payout on the treatments is also variable. Major factors are oil production rates, oil price, lifting costs and water disposal costs. Some of the treatments that have sustained high initial oil rates have paid out in several weeks, where other treatments may take longer or may never pay out based on incremental oil recovery. In most cases wells that exhibit average performance after the treatments are paying out in 3 to 6 months. This is based on ± 18 BOPD incremental oil recovery for 6 months, $22/bbl oil price and $45,000 job cost (this is based on only incremental oil recovery, water reduction savings are not considered).

Also the methods used to evaluate the treatments affect payout and economics. Initially in most instances, the water shut-off treatments using gelled polymers were just that, treatments conducted to reduce the amount of water production. Wells had become marginal to uneconomic due the amount of water that had to be handled. Well economics could be improved by reducing water production. Therefore, any oil recovered at a water-oil ratio lower than prior to the treatment was considered incremental recovery. The increased oil production rates and recovery of additional oil reserves was considered to be a fortunate by-product. Now operators are conducting the treatments with the expectation of improving oil recovery and in most instances are disappointed if that does not happen. Some operators have indicated that in their circumstances they could not economically justify the treatments if incremental oil recovery did not occur. Also, operators are now treating wells that are economic, in hopes of improving economics and adding reserves. Operators have reported adding oil reserves for $2 to $5 per barrel from polymer treatments.

Estimate of State-Wide Economics
Based on the average from wells currently in the database, the average size treatment volume is 2,637 barrels of polymer, the average cumulative incremental oil recovery per well to date is 5,469 barrels (based on oil recovery rates above pre-treatment rates), and the average cumulative reduction in water production per well to date is 377,073 barrels. Applying these averages to the estimated 300 wells that have been treated since 2001 equates to 791,100 bbls of polymer has been used to recover 1,640,700 of incremental oil to date (many wells are still recovering incremental oil) and reduced water production by 113,121,900 bbls to date. Using $15 per barrel of polymer as a treatment cost, oil reserves have been added State-wide for $7.23 per barrel to date.

Assuming $28 per bbl for the price of oil, $15 per barrel of polymer as a treatment cost, $10 per barrel of oil as an operating expense, $0.05 per barrel of water as a disposal fee and the treatment was conducted 18 months ago, the average payout is 6.1 months. Payout using the above assumptions based on only incremental oil production (excluding savings from reduced water production) is 7.2 months.

At $28 per barrel of oil an additional $45,939,600 has been added to the State economy from incremental oil production since 2001.

Conclusions

The application of technologies in mature producing basins can result in improving marginal well economics, thus prolonging their life. Improving economics is accomplished by reducing lifting costs, recovering additional reserves, or a combination of both. The application of gel polymer treatments on Arbuckle wells in Kansas is a good example of revitalizing mature marginal production through technology application.

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Field Name	Cumulative Oil (bbl)	Active Wells	Twn Rng	County	Approx. Depth (ft)
CHASE-SILICA	307,571,872	876	18S-10W	BARTON/RICE/STAFFORD	3,328
TRAPP	300,087,115	726	15S-14W	BARTON/RUSSELL	3,252
El DORADO	299,365,153	618	25S-5E	BUTLER	2,550
BEMIS-SHUTTS	248,694,147	2,150	10S-16W	ELLIS/ROOKS	2,967
HALL-GURNEY	152,414,246	1,107	14S-13W	BARTON/RUSSELL	3,192
KRAFT-PRUSA	130,826,618	700	15S-10W	BARTON/ELLSWORTH/RUSSELL	2,885
GORHAM	94,783,868	369	14S-15W	RUSSELL	3,289
GENESEO-EDWARDS	85,900,491	190	18S-8W	ELLSWORTH/RICE	3,278
FAIRPORT	58,735,912	388	12S-15W	ELLIS/RUSSELL	3,350
BLOOMER	55,787,569	244	17S-10W	BARTON/ELLSWORTH/RICE	3,200
STOLTENBERG	52,996,954	470	15S-19W	BARTON/ELLSWORTH	3,333
RAY	48,122,148	159	5S-20W	GRAHAM, NORTON, PHILLIPS, ROOKS	3,540
AUGUSTA	47,773,725	111	28S-4E	BUTLER	2,600
MOREL	46,765,270	444	9S-21W	GRAHAM	3,718
MARCOTTE	41,659,245	221	9S-19W	ROOKS	3,752
VOSHELL	36,066,429	22	20S-3W	MCPHERSON	3,400
IUKA-CARMI	34,128,807	226	27S-13W	PRATT	4,354
COOPER	25,486,646	112	9S-20W	GRAHAM/ROOKS	3,216
RUSSELL	23,243,643	53	13S-14W	RUSSELL	3,280
GATES	21,519,184	125	21S-12W	STAFFORD	3,679
TRICO	20,959,428	144	10S-20W	ELLIS/GRAHAM/ROOKS/TREGO	3,651
RICHARDSON	19,843,416	75	22S-11W	STAFFORD	3,537
OXFORD	18,196,474	26	32S-2E	SUMNER	2,890
BARRY	17,812,734	132	8S-19W	ROOKS	3,430
MUELLER	15,950,997	105	21S-12W	STAFFORD	3,594
OTIS-ALBERT	15,278,960	22	18S-16W	BARTON	3,703
OGALLAH	14,805,787	37	12S-21W	TREGO	3,961
GREENWICH	14,165,749	20	26S-2E	SEDGWICK	3,321
BOYD	14,055,036	54	17S-13W	BARTON	3,438
MAX	13,344,772	63	21S-11W	STAFFORD	3,570
LORRAINE	12,666,332	26	17S-9W	ELLSWORTH	3,200
TOBIAS	12,521,480		20S-9W	RICE	3,218
SOLOMON	12,083,711	86	11S-19W	ELLIS	3,629
IRVIN	11,812,943	76	13S-19W	ELLIS	3,860
NORTON	11,692,977	88	3S-23W	NORTON	3,778
DOPITA	11,321,826	131	8S-17W	ROOKS	3,409
HITTLE	10,542,917	240	31S-4E	COWLEY	3,280
NORTHHAMPTON	10,113,608	51	9S-20W	ROOKS	3,803
DRACH	10,016,115	23	22S-13W	STAFFORD	3,690
TOTAL	2,379,114,304	10,710		NOTE: Many fields produce from multiple horizons and not all production is Arbuckle	

Table 1: Twenty-one major Arbuckle fields in Kansas. (from Franseen, et al., 2003)

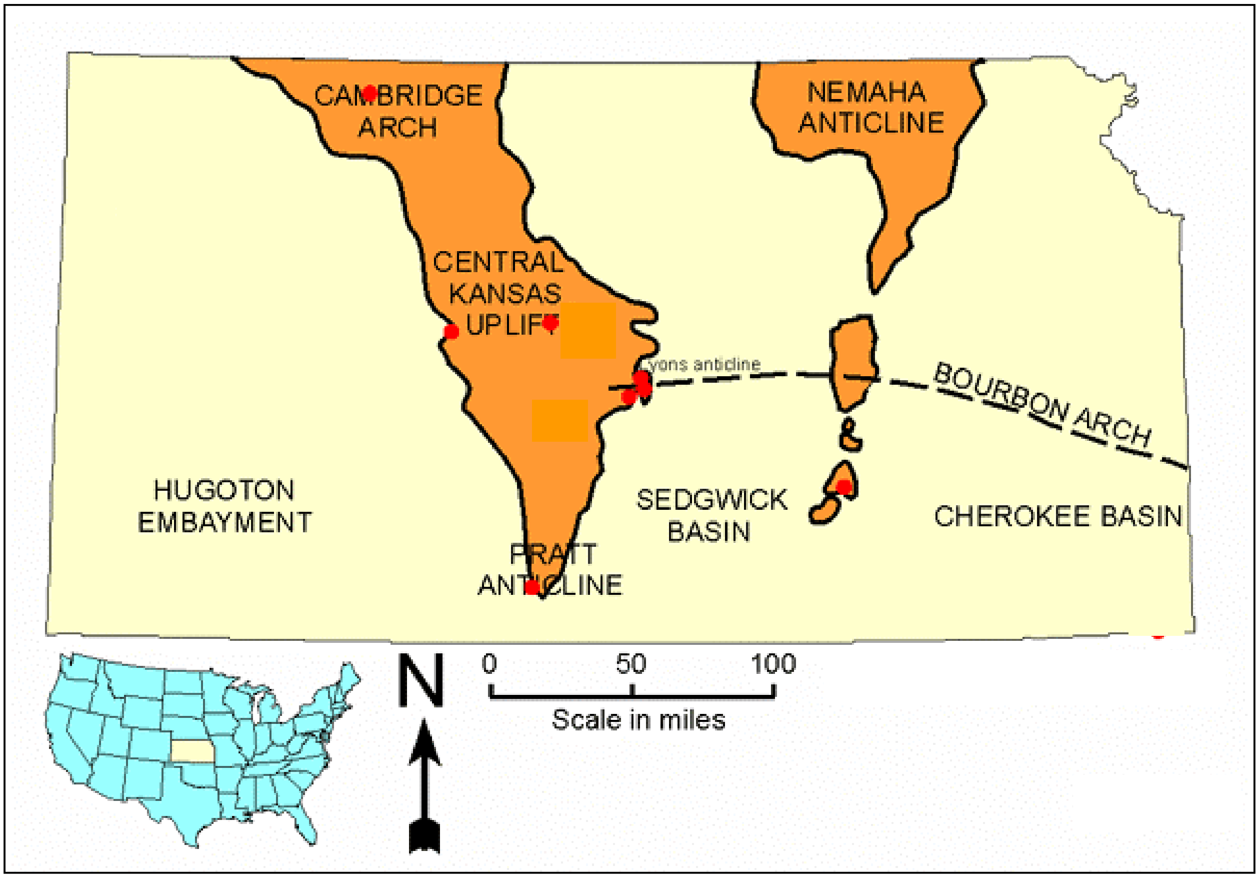

Figure 1: Map of Kansas showing major structural elements (from Franseen, et al., 2003)

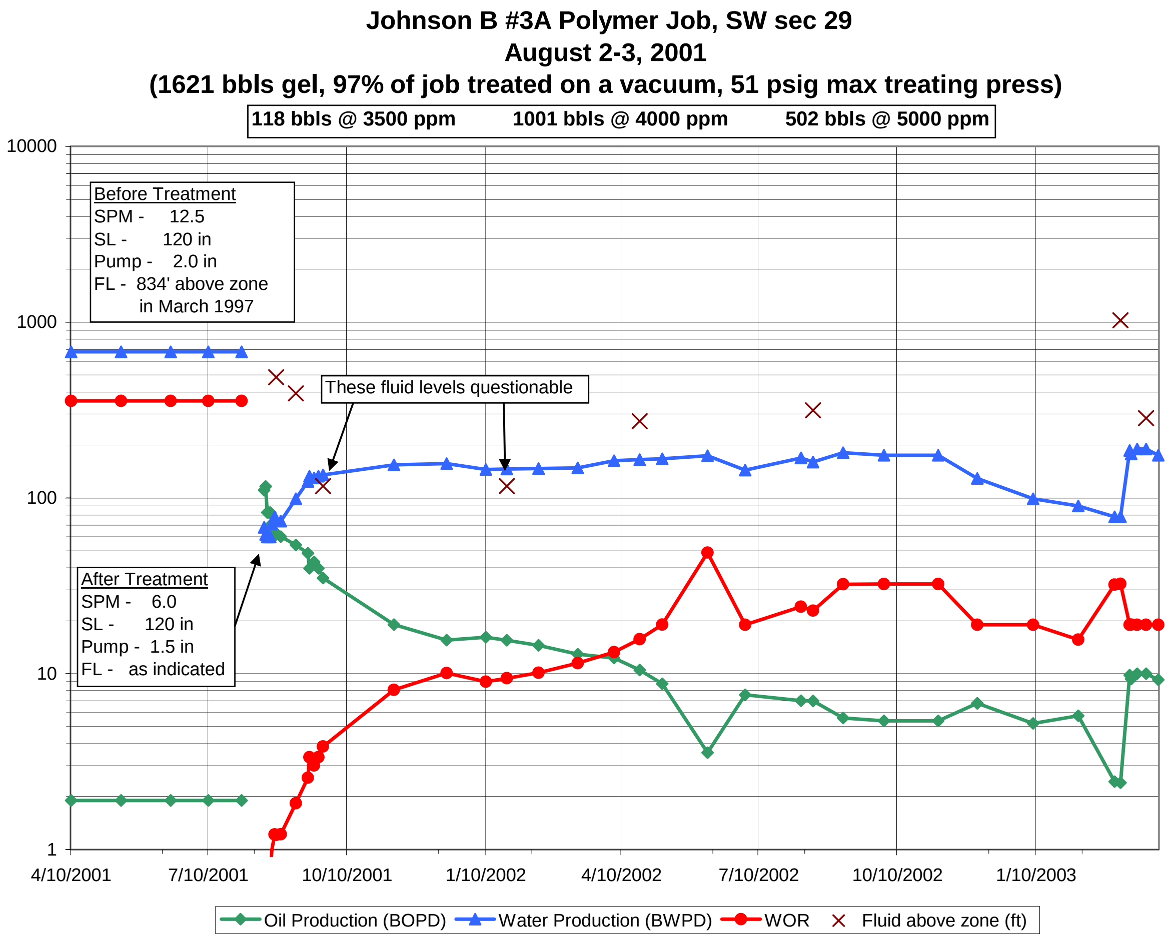

Figure 2: Example of a Nice Initial Response with Above Average Incremental Oil Recovery

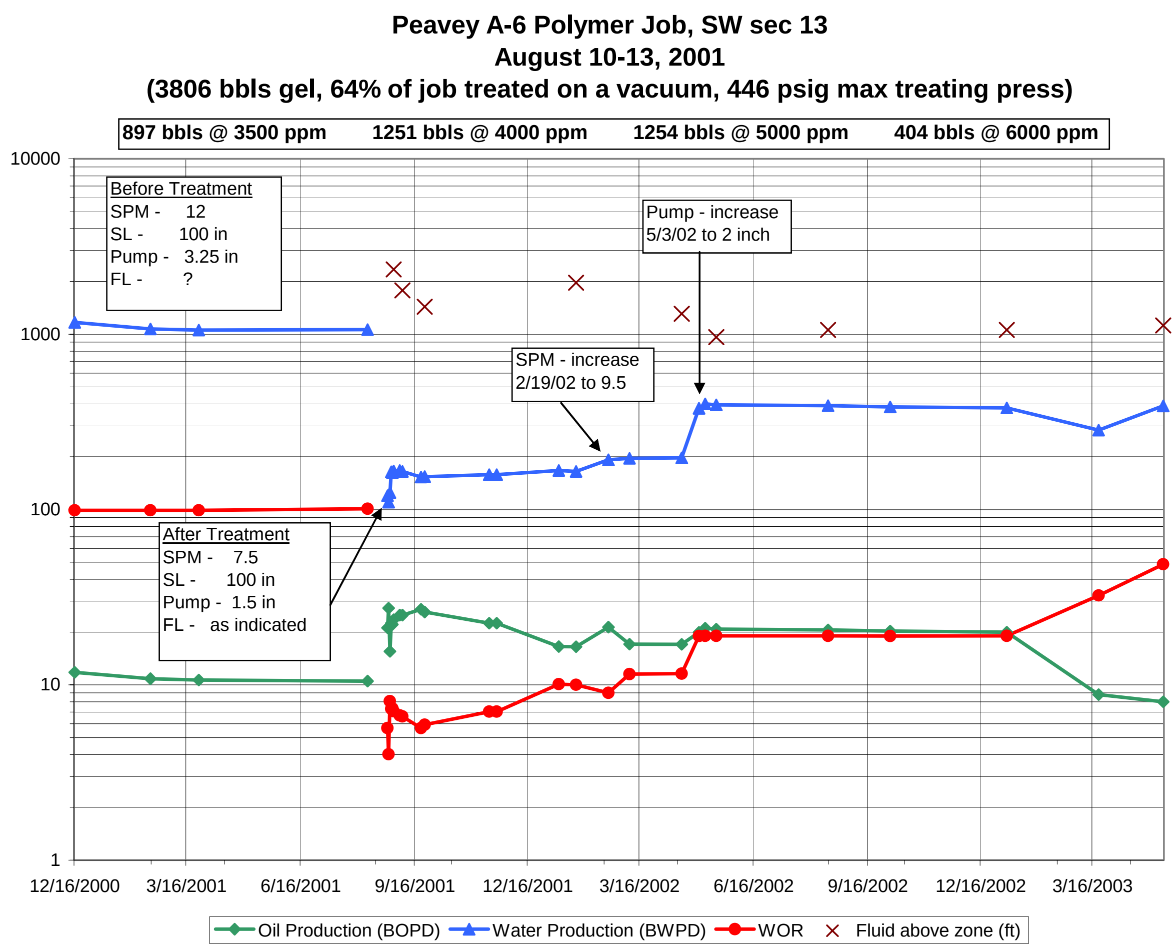

Figure 3: Example of Average Response

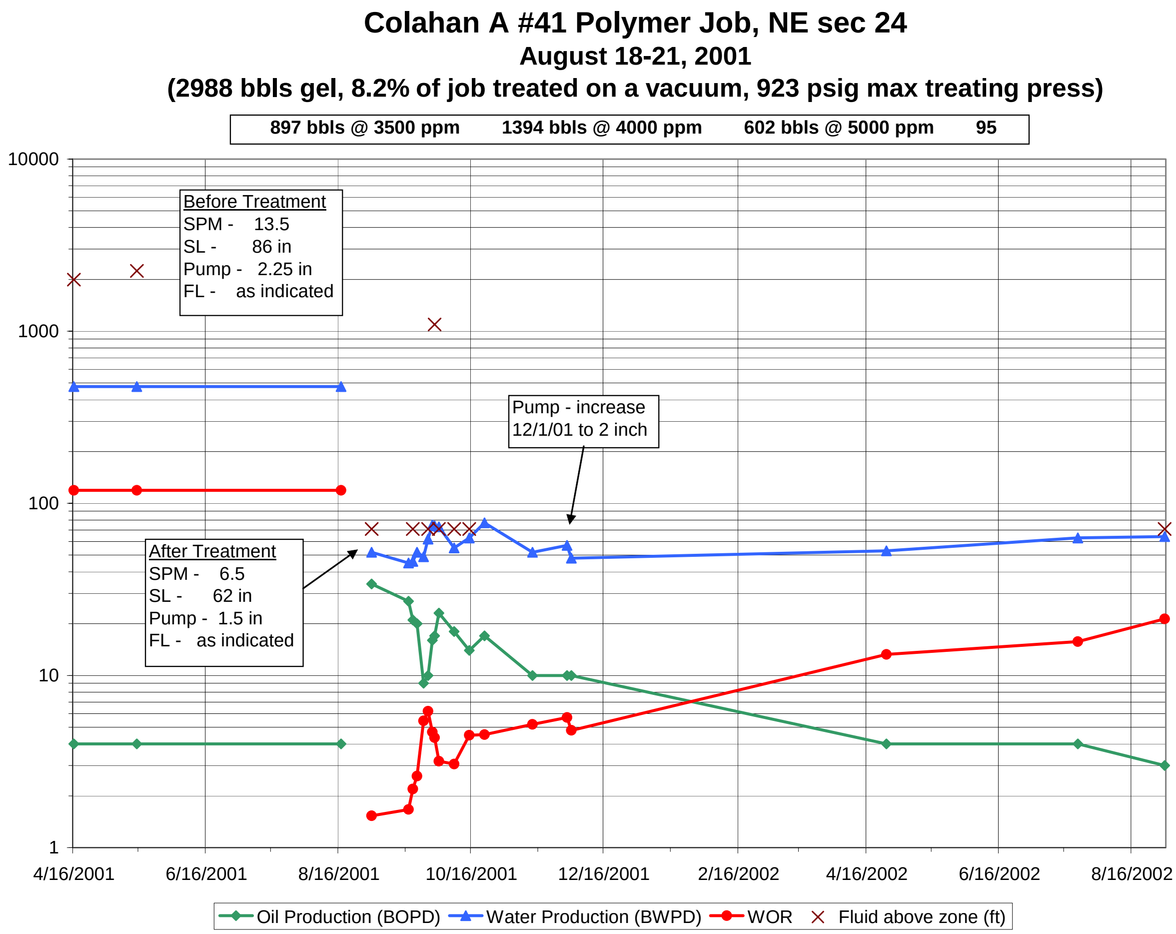

Figure 4: Example of Poorer Response

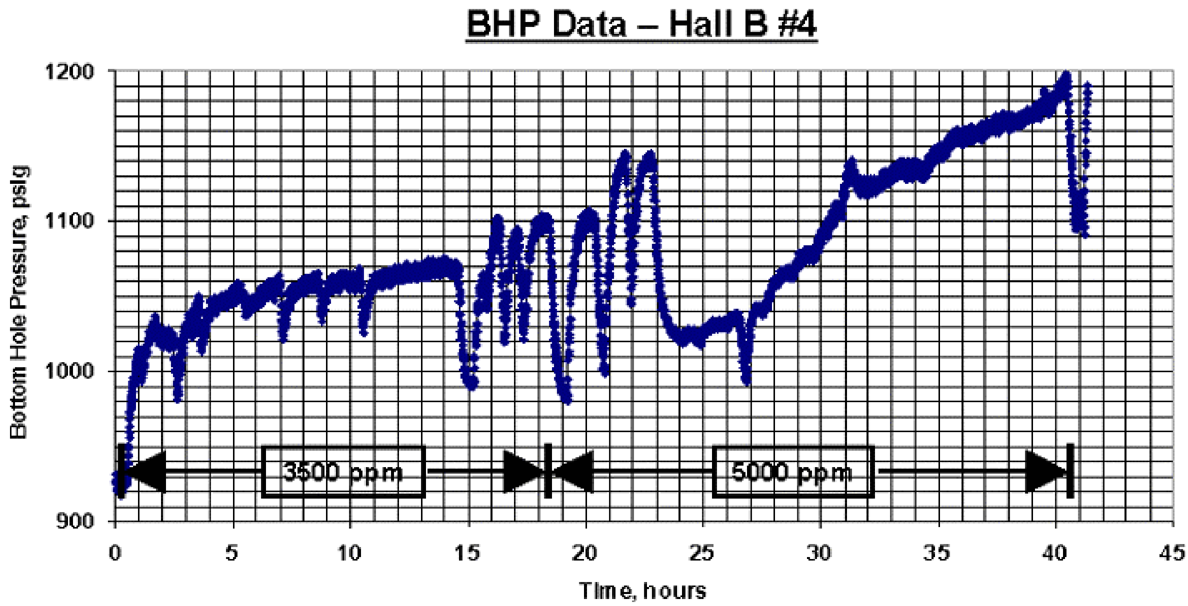

Figure 5: Bottom-hole pressure data that was collected during the treatment of the Hall B #4.

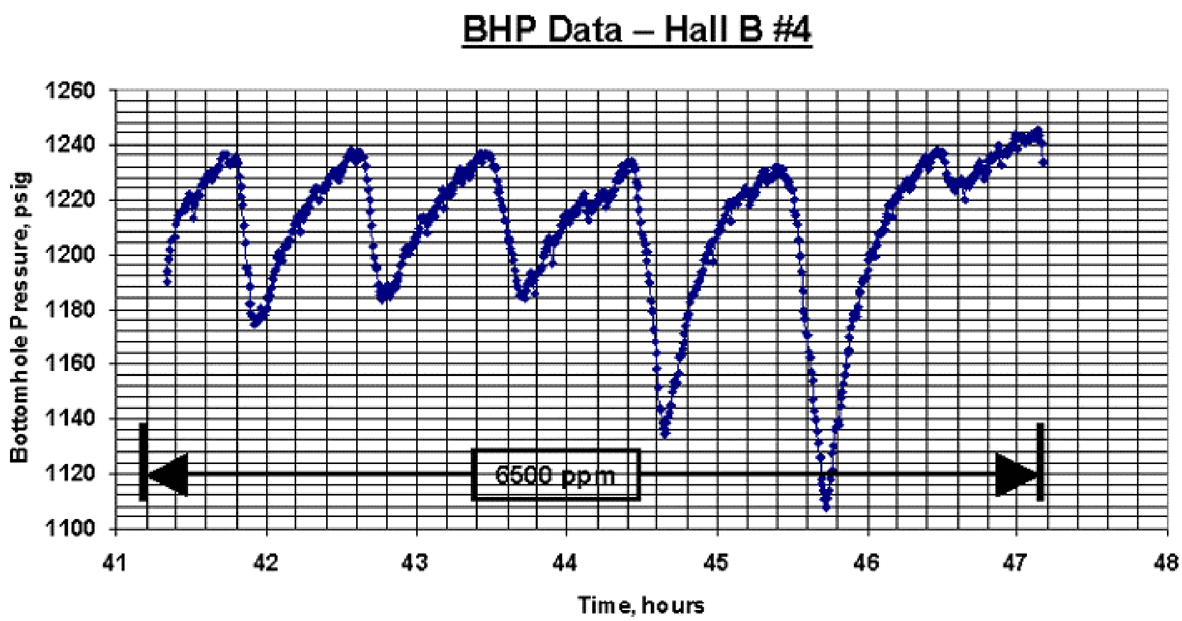

Figure 6: Bottom-hole pressure data that was collected during the treatment of the Hall B #4.

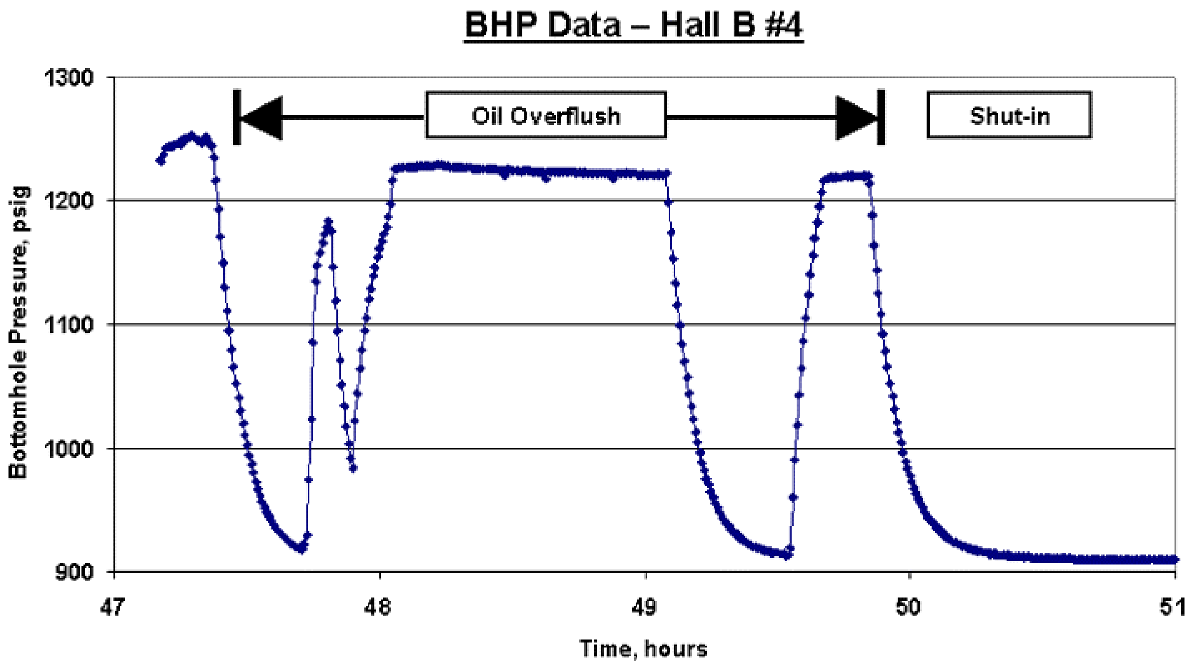

Figure 7: Bottom-hole pressure data that was collected during the treatment of the Hall B #4.