ROCKY MOUNTAIN OILFIELD TESTING CENTER

PROJECT TEST RESULTS

CHEMICAL & MICROBIAL PARAFFIN CONTROL PROJECT

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RMOTC Test Report

Paraffin Control Project

BDM Oklahoma/NIPER
220 N. Virginia
Bartlesville, OK 4003
918-336-2400, FAX 918-337-4365

Leo Giangiacomo, Project Manager
Rocky Mountain Oilfield Testing Center
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Abstract

This report summarizes the field performance results of a comparison of chemical and microbial paraffin control systems. The two systems were selected from laboratory screening work. Well selection was based on production rates, produced fluids, and prior paraffin treatments. The treatments were performed on similar groups of wells over the same period of time, using quantities and techniques recommended by the supplier specifically for the wells to be treated. The tests were conducted by the U. S. Department of Energy's Rocky Mountain Oilfield Testing Center at Naval Petroleum Reserve #3 in Natrona County, Wyoming.

The chemical system was applied to three stripper wells. The treatments utilized paraffin solvent and diesel and were pumped down the casing annulus of the wells. Initially, a smaller treatment was performed to clean up the wellbore and tubulars. Shortly thereafter a larger treatment was performed to clean up the perforations and near-wellbore area.

The microbial system was applied to four stripper wells. A dry medium containing microbes was mixed with produced water and pumped down the casing annulus. The wells were treated monthly for three months.

Production was monitored closely on all the treated wells prior to the treatment and for eight months thereafter. The study makes recommendations for choosing wells for paraffin treatments and for treating wells with microbial systems. It concluded that solvent treatments were capable of yielding larger production increases, but microbial treatments were cheaper and capable of yielding better returns on investment.

Introduction

Problem Statement

Paraffin is an organic compound commonly found in crude oil. As described by Misra, et al[1] , it consists of various forms and combinations of aliphatic hydrocarbons, aromatic hydrocarbons, napthenes, resins, and asphaltenes. These different forms and combinations give paraffin its melting point, boiling point, solubility, pour point and cloud point properties.

Paraffin crystallization and deposition is responsible for a myriad of problems in the oilfield. These problems range from clogging reservoir flow paths and causing premature abandonment of reserves, to increasing maintenance costs of pumps, rods, tubing, flowlines, separators and creating tank bottoms in the surface facilities. Crystallization is caused by decreases in pressure and temperature that occur throughout the production process. The temperature at which paraffin begins to precipitate is the cloud point[2] . The cloud point is a good indication of the potential paraffin problem associated with a given crude oil, however the measurement of cloud point is often difficult and impractical.

As reported by Brown, et a1[3], two mechanisms for paraffin deposition are proposed. Shear dispersion describes the relationship between deposition rate and shear rate. Deposition rates decrease with higher shear rates. Molecular diffusion describes the process by which the radial temperature gradient in the tubulars causes a concentration gradient of dissolved paraffin components in the liquid phase, which causes paraffin to diffuse to the pipe wall, where it is assumed to deposit.

An effective paraffin control program prevents paraffin from:

reducing reservoir productivity, plugging perforations,
plugging downhole pump intakes, plugging tubing,
increasing stress and wear on rods, causing holes in tubing,
plugging flowlines,
causing flowline leaks, causing separation problems, and generating tank bottoms.

Conventional paraffin control programs use chemical, thermal and mechanical methods to control paraffin problems. In some cases, excellent results have been achieved with these methods. In every case, the control program adds significantly to the cost of oil production.

The chemicals generally fall into four groups, including solvents, inhibitors, dispersants, and surfactants[4] . Solvents are used to dissolve existing deposits. Certain solvents can cause problems with refining the produced crude oils. Diesel and xylene mixtures have been found to be very effective. Many proprietary formulations are also available for dissolving paraffin deposits. Paraffin inhibitors are used to inhibit paraffin deposition on tubulars by altering their crystal growth. Dispersants break up the paraffin deposits into smaller pieces that can be moved by the oil stream. Surfactants solubilize the paraffin in oil.

Thermal methods usually involve hot-oiling the well tubulars and flowlines on a regular basis. This sometimes results in formation damage from concentrating heavier ends of the oil and paraffin, which can no longer be mobilized by the heat available through hot oiling[5]. Electrically heated tubing strings have also been used in limited applications with success. Even exothermic chemical reactions in combination with inhibitors have been utilized to control paraffin problems[6].

Mechanical methods commonly employ scrapers conveyed by wireline, sucker rods, and work strings. This is generally done on a regular schedule. The loosened paraffin deposits are then carried to the surface along with the flow of well fluids.

Even though literature references to microbial degradation of oil date back to 1972[7], microbes have only recently become noticed for their ability to control paraffin problems. Since it is a relatively new method for paraffin control, many operators are still unsure about its technical and economic benefits. Some reports of successful application of microbial paraffin control have been published [8,9] . However, no literature has been found to compare its performance in the field to industry-accepted chemical systems.

Solution Statement

A valid comparison between chemical and n-dcrobial paraffin treatments should be a useful tool for aiding operators in making economic and operational decisions on treating their wells. In order to get a valid comparison between the abilities of chemical solvents and microbes to manage paraffin problems in production wells, it is necessary to select appropriate paraffin control systems based on laboratory studies.

A careful well selection is then required to ensure that the systems are being tested in equivalent situations. Multiple wells can be used to lend statistical strength to the data. The selected wells were in the same reservoir in the same field. The treatments were designed by the vendors to be the most cost-effective treatment considering all the data on the wells to be treated. The treatments were conducted during the same time frame to equalize any changes in reservoir conditions.

Laboratory Summary

The laboratory analysis of chemical systems for paraffin control is presented by Fan and Llave[10]. Their studies at the National Institute for Petroleum and Energy Research (NIPER) evaluated the performance of three commercial solvents and a toluene/xylene mixture on Polywax 500. Results of two other commercial solvents were not available at the time the field test was planned, and fimding for the project was discontinued before they could be included in the field testing.

The best performing commercial solvent of those tested under the laboratory conditions is reported by Fan and Llave to be a multiple aromatic hydrocarbon solvent known commercially as Waxsol. King and Cotney[11] describe the production of this solvent as a process where condensate feedstocks are blended and processed through a patented fractionation process. The light volatile ends of hexane and lower order alkanes which cause asphaltene precipitation are removed. This leaves a fluid compatible with the reservoir fluids and rock matrix. The complex aromatic content keeps paraffins in solution to sub-zero temperatures. **Table 1** shows some of the physical properties of this solvent.

Other factors Fan and Llave identified as aiding wax dissolution in their study were increased temperature and mechanical agitation. All of the tested solvents showed significant increases in their ability to dissolve paraffin deposits when their temperature was elevated and when the solvent was kept moving.

A single supplier submitted samples to NIPER for microbial screening. The supplier donated dry medium consisting of two different consortia, one to target paraffin, scale, and interfacial tension reduction, and the other to target asphaltenes. The microbial blends are proprietary, so the specific species, combinations, cell counts, and nutrients making up the blend are unavailable. It is known that they are naturally-occurring, non-pathogenic, and non-genetically engineered bacteria.

Bacteria have limitations on the environment in which they can be effective. Pelger[9] suggests that a temperature range from 34°F to 208°F is necessary for their survival, while they are most effective between 90°F and 150°F. Chloride content needs to be below 15%. The hydrogen sulfide concentration need to be less than 1,000 parts per million (ppm) in fluid and 20,000 ppin in gas. In addition, the bacteria need a continuous water phase in which to habitate. This generally means that some water production is necessary.

The compatibility of the bacteria with reservoir conditions was tested at NIPER. The dry microbe media was mixed in fluid samples from the selected wells and incubated for 6 days at the reservoir temperature of 125°F. The two consortia were cultured separately, and both showed good to excellent counts of aerobic and anaerobic populations. Total evolved gas was good from the samples from wells 88AX3 and 22AX2 1, but poor from the Well 18AX34 sample. The lab studies showed that the indigenous bacteria and the specific microbial blends were compatible. No evidence of toxicity to microbes was encountered. The tests showed that a viable microbe population could be established at reservoir conditions.

Field Testing

Reservoir Description

The Second Wall Creek Reservoir in the Teapot Dome Field at Naval Petroleum Reserve #3 was selected as the site for the test. Although the Shannon, Steele, and Niobrara Reservoirs were also considered, they did not provide as good of a combination of reservoir conditions, well selection, and production rates and conditions.

This reservoir depth is from 2,850 to 3,100 feet below surface. Reservoir temperature is near 125'F. The Second Wall Creek oil has an API gravity of 361. Paraffin content was measured at 10% by volume. The oil has a sulfur content of 0. 16%.

Reservoir pressure is currently near 200 psi, although the initial pressure was close to 1,100 psi in 1922. The reservoir had been produced by solution gas and gas cap expansion drive, was waterflooded, and then pressure depleted again after injection ceased in June 1992.

Rock properties vary widely in this naturally fractured reservoir. Porosity averages from 13.5 to 16%. Permeabilities vary from 0. 1 to 600 millidarcies (md), with an average near 60 md. Both permeability and porosity are usually highest near the top of the sand, decreasing to near zero at the base of the sand. The depositional environment is a near-shore bar that has been bioturbated. Much of the Dorositv has been infilled with secondary calcite deposits.

Wells are drilled on 40-acre spacing, with some infill. drilling on 10-acre spacing. Completions generally require a hydraulic fracture treatment to be economic. Production wells are rod pumped, with the pump set within the 20 to 60 feet of perforated interval.

These wells have a history of paraffin problems, usually manifested as flowline plugging, rod parts and problems when pulling rod strings. Paraffin control practices in the past have ranged from weekly hot oiling with asphaltic based crude to periodic in-depth solvent and crystal modifier treatments. Although various degrees of success were experienced with the treatments, oil price drops forced budget cuts, and regular paraffin control activities were phased out in the late 1980's.

Well Selection

In previous paraffin teStS8, it was concluded that periodic in-depth solvent treatments were successftil in cleaning up parafrin deposits in the reservoir and maintaining reservoir flow. Wells that had been treated with these large solvent treatments in the past were found to be poor candidates for observing increases in production due to subsequent paraffin cleanup treatments. Therefore it was important for a candidate well to not only have a history of paraffin deposition, but also a minimal paraffin treatment history.

The completion and production characteristics of the well were also thought to be important. Many of the wells produce gas from the gas cap. The cool, expanding gas has an effect on paraffin deposition that would be different than that in wells producing with a high water cut and no gas. The size of the hydraulic fracture and the perforation density also affect the paraffin deposition characteristics.

Considering these criteria, the selection process began. All active Second Wall Creek production wells were reviewed. The well files were searched for completion design and evidence of paraffin deposits on the rods and pump during pulling operations. From this screening, a group of 23 candidate wells in the SecondVall Creek was selected. This group had perforation densities of I or 2 shots per foot. Fracture treatments from 12,000 to 29,000 lbs of sand had been done on these wells during their initial completion. All of the wells had at least 15 years of production history.

Well Grouping

A point system was developed to aid in the grouping of the wells. Points were assigned to wells in water-oil ratio (WOR), gas-oil ratio (GOR), and prior treatment history categories. The points for each category for all wells in the group were then totaled and compared. Wells were juggled to get the grouping totals to be as close as possible for each group-

The production data from December 1995 to May 1996 was used as the basis for the calculation of GOR and the WOR. Wells with no recordable gas production were given one point. Wells with a GOR between I and 25 Thousand standard cubic feet (MCF)/stock tank barrel (STB) were given two points. Wells with a GOR between 25 and 75 MCF/STB were given three points. Wells with a GOR between 75 and 150 MCF/STB were given four points and above 150 MCF/STB were given five points.

Similarly, the wells' WOR was used to assign points. Wells with 0 to 5 barrels of water (BW)/barrel of oil (BO) were given one point. Wells with 5 to 15 BW/BO were given two points. Wells with 15 to 35 BW/BO were given three points. Wells with 35 to 75 BW/BO were given four points. Wells with more than 75 BW/BO were given five points.

A scoring system for the type of prior paraffin treatment was developed. Large treatments, where in-situ heat, crystal modifiers, and solvents were used, were given three points. Large treatments where a crystal modifier and solvent was used, but no in-situ heat was generated, were assigned two points. Treatments where only solvents were used were assigned a single point. No points were given for hot oil treatments, since they were designed to be a wellbore cleanup treatment only and the treatment record were poor.

The size of the previous paraffin treatments was considered by assigning a multiplication factor based on the size of the treatment. A treatment volume of 0 to 20 bbls was assigned a factor of 1. A treatment volume of 20.1 to 40 bbIs was assigned a factor of 2, while a treatment volume larger than 40 bbls was assigned a factor of 3. The points assigned for the type of treatment were then multiplied by the points assigned to the size of the treatment to arrive at the total score for treatment history. Only treatments done since 1985 were considered since these were available on a computer database.

Initially, two chemical and two microbial systems were to be tested. Each system was to be tested on three wells. Therefore 12 wells were selected and divided into four groups of three wells each. This was done in such a way that the total points for each category for each group were equivalent. The groups are shown in **Table 2.**

Just prior to doing the test, a well in Group IV assigned to the microbial system was found to have a hole in the casing allowing sour oil and water from the Shannon formation to enter the wen. Since the 112S could threaten the performance of the microbes, an alternate well, 28AX34, was selected. The irdcrobial supplier decided to treat 88AX3 free of charge to see the effect. Therefore this group has four wells. The points for 88AX3 were not considered in the group totals.

Treatment Procedures

Chemical System

After the wells had been selected and grouped, baseline well tests were obtained prior to the treatments. The chemical system was shipped to the field site, and stored in a 2,000 gallon (gal) tank. The treatment procedure was developed by the supplier. Since the depths and mechanical configurations were similar for the three wells, the same volumes were used for each well. The treatment procedure involved two phases.

In Phase 1, the wellbore and tubulars are cleaned. In Phase II, the solvent is displaced into the formation with diesel to clean the near-wellbore area. A Phase III treatment for routine maintenance was also recommended by the supplier, but was not ftmded.

As summarized in **Table 3,** on September 5, 1996, wells 85AX20, 34AX34, and 85AX3 were given the Phase I treatment. The wells were pumped off, with a fluid level near the top of the perforations. A volume of 150 gallons of Waxsol was pumped down the casing annulus and flushed with 150 gallons of clean diesel. The treatment was pumped with no surface pressure. The tubing was then connected to the annulus and the well left circulating for 24 hours. The well was then replumbed to pump down the flowline. Since it was not possible to directly measure the well's production, the wells were tested periodically (usually for 24 hours twice per week) through a test separator. This did not allow the treatment fluid to be subtracted from the incremental production. Daily production for the well was interpolated based on the actual test data.

On September 17, 1996, wells 34AX34 and 85AX3 were given the Phase II treatment. Well 85AX20 was not treated that day because the Waxsol storage tank had a hole in the bottom and leaked approximately 500 gallons into the soil. A replacement volume had to be ordered and shipped. The Phase 11 treatment was not done on 85AX20 until October 9, 1996. For Phase II treatments, the wells were shut in. The 500 gallons of Waxsol was pumped down the annulus. This was flushed by 1,500 gallons of diesel. The treatments were pumped with no surface pressure. The wells were then shut in for 24 hours and returned to production.

Microbial System

The bacteria arrived in a dry medium. Twenty pounds of dry medium was mixed with 10 barrels of 120117 produced water (3,000 ppm total dissolved solids) and pumped down the casing annulus of 18AX34, 88AX3, 22AX21, and 28AX34 on September 5, 1996. The wells were shut in for 24 hours and then put on production. As in the chemical treatments, direct production measurements were not available, and production volumes were interpolated from test data.

As summarized in **Table 4,** the treatments were repeated on September 30, and October 29, 1996 using the same procedure, except that the water volume was increased to 20 bbIs per well. The supplier recommended treatment for at least six months, but finiding for the project was cut after three treatments.

Comparison of Treatments

The chen-dcal treatments involved a larger volume of fluid. Seven barrels were pumped in the wellbore treatment, but 48 barrels were required in the squeeze treatment. This effort required more pump truck time, since the truck only has a capacity of 30 bbls. The solvent and diesel fuel were hazardous and required personal protective equipment for handling. An inadvertent spill of 500 gallons from a hole in the bottom of the storage tank required 370 cubic yards (cu yds) contaminated soil to be dug up and land farmed at a cost of over $8,995. This cost was not included in the treatment cost or economics, but illustrates the risks associated with using hazardous chemicals.

The microbial treatments required only 10 to 20 bbls of fluid to be pumped. The dry media had to be rolled over in the pump truck with the produced water for adequate mixing. However it was not hazardous, and no special handling was required. Since monthly treatments are required, additional pump truck time was incurred for the third treatment.

Similar attention was required from the pumper for both treatments. The solvent wellbore cleanup treatments required slightly more effort to prepare the well for circulation and then return it to the flowline.

The chemical treatment was more expensive than the microbial treatment. **Tables 5 and 6** show the details of the treatment costs. The chemical treatments cost $5,048 per well, while the microbial treatment cost was $1,032 per well, including materials, pumping services, and pumper labor.

Production Results

Calculation of Incremental Oil Production

The incremental oil production is based on well tests since there is no way to collect individual well production. The well tests gathered during a month were arithmetically averaged and multiplied by the days in a month to compute the well's total production for the month. The wells were tested for a 24 hour period from 2 to 10 times per month depending on the availability of the test separator for that well. These production numbers were fitted with an exponential decline to project a baseline following the treatments. The difference between the well's actual production and the calculated baseline was assumed to be the incremental production.

Chemical Treatments

Well 85AX3 had a 35 bbI solvent/crystal modifier paraffin treatment in 1989. The production response for the current treatment in Figure 1 shows sharp production increases in both oil and water from the wellbore cleanup and the squeeze treatment. Prior production was approximately 1.7 barrels of oil per day (BOPD). Following the wellbore cleanup, production rates increased to 2.2 BOPD. Four days after the squeeze treatment, production rates of 9.1 BOPD were measured. This was probably still a result of recovering the 48 bbIs of diesel and solvent pumped during the treatment. By November, production rates dropped to 1.0 BOPD, but by January, they were back up to 2.0 BOPD. By the end of April, production rates returned to baseline levels. The erratic behavior in the test data is attributed to periodic plugging of the fracture, perforations and pump intake by mobilized paraffin particles. As shown in Table 7, after eight months an incremental 65 barrels of oil were produced.

Well 85AX20 has a high water cut, but had no prior paraffin treatments. **Figure 2** shows a delayed response to the wellbore solvent treatment, producing about 3.2 BOPD before and after the treatment until September 25 when production jumped to 9 BOPD. The squeeze treatment did not show any significant short term results, however a slowly increasing trend in production continues into April 1997, when production rates of 9 BOPD can be observed. Incremental production through April is estimated at 302 BO.

Well 34AX34 had no history of paraffin treatments. It produces a significant volume of gas, and had a significant decline rate in oil production as shown in **Figure 3.** Oil production prior to the treatment averaged 1.0 BOPD. Following the wellbore cleanup, production increased to 1.5 BOPD. The squeeze treatment boosted production slightly to 5.0 BOPD. It quickly stabilized near 2 BOPD through October. However it started a slow increase through March 1997 to 4.0 BOPD. It has since resumed its previous decline rate and produced about 3.0 BOPD at the end of April 1997. Incremental oil production is estimated at 513 BO.

The responses in the wells treated with solvent varied widely. The well with the previous treatment had the poorest response. The well with the associated gas production had the best response. The cooling effect associated with the expansion of produced gas will increase the rate of paraffin deposition. This seems to indicate that the wells with the worst paraffin damage produced the best response to the treatment. As a group, the wells showed a 74% increase in production over their previously established decline in the eight months following the treatment.

Microhial Treatments

Well 18AX34 has had two previous 20 bbls solvent treatments and a 30 bbls solvent/crystal modifier treatment between 1988 and 1991. As shown in **Figure 4,** production prior to treatment averaged 2.2 BOPD. Following the initial microbial treatment, production dropped sharply for 5 days. Production then returned to near normal rates until the next treatment. Again, production dropped to near 1.0 BOPD following the treatment, and recovered before the next treatment. The third treatment caused little decline in production, and quickly recovered to rates clearly higher than the established decline. For the next five months, production remained above the previously established decline, netting an incremental production of 10 1 bbls.

Well 88AX3 has no history of solvent treatments. A hole in the casing was discovered prior to treatment. The hole allowed fluids from the sour Shannon formation to enter the wellbore. Gas produced from the casing annulus has an H_2S concentration of 10 ppm. Production prior to treatment averaged 1.2 BOPD. During the treatment period and for a month after, production dropped to 0.5 BOPD. Production then started an upward trend. However in February, the well was shut-in due to uneconomic production rates. The well was produced for 2 days at the end of February, and then for 2 days in April. Although 23 bbls of incremental oil a
credited to this well, the results are inconclusive.

Well 22AX21 produces with a 97% water cut as shown in **Figure 6.** It has no history of previous paraffin control treatments. Production averaged 7 BOPD prior to the microbial treatment. After the first two treatments, production increased briefly to 8.5 BOPD, then returned quickly to previous levels. After the second treatment, the decline quickened and the third treatment resulted in a significant drop in production. The decline continued to 4.5 BOPD after two months. It then started to return to pre-treatment levels and remained there. The increases in production after the first two treatments indicate that positive microbial action was occurring. However, there must have been particles carried into the perforations which plugged them off, causing the three months of decreased production. This well would probably have benefited from continued or more frequent treatment. There was a 67 BO incremental loss as a result of the treatment.

Well 28AX34 production is shown in **Figure 7.** Its pretreatment production was I BOPD. A period of decreased production followed each treatment. Each was less severe than the last. Following the second treatment, production started increasing above baseline. After the third treatment, production increased to 3 BOPD. Some decreased production was experienced for three months after that, but then the well started to show a dramatic increase with rates as high as 7 BOPD. Cumulative incremental oil after eight months was 350 BO.

The responses to the wells treated with bacteria had several distinct characteristics. The treatments usually did not have a quick positive production response. The response was usually negative at first, then gradually increased with time. This effect is attributed to the continued slow action of the bacteria on the paraffin deposits. It appears that large particles are mobilized and tend to cause plugging problems. Over time, these plugs are remediated by the microbes, but the action is very different from that of the chemical treatments. The beneficial effect of these microbial treatments needs to be measured over a longer period of time than what we are used to giving chemical treatments. As a group, these wells experienced an average increase in production of 16% over an eight month period.

Maintenance Results

The maintenance records for the wells involved in the study were researched. No conclusive information could be obtained from the records regarding the effect of the paraffin treatments. The average time between jobs was usually several years, and did not have a regular frequency. It was noted that 18AX34 and 85AX20 had been pulled for a pump change and a hole in the tubing respectively, during the study period. The discovery of these problems during the study period may have been due to the extra attention paid to the wells during this time.

Economics

Treatment costs are shown in Tables 5 and 6. The cost to do the chemical treatments described previously was $5,048 per well. This includes the solvent, diesel, pump truck, and pumper labor. The cost for doing the microbial treatments was $1,032 per well. This included the three treatments and the pump truck and pumper labor to perform the treatments. The microbial treatments are much cheaper than the chemical treatments.

The incremental production is shown for each well and each month in **Tables 7 and 8.** The chemical treatments netted 880 barrels of incremental oil in the eight months following the treatment. This is an average of 293 BO per well. The microbial treatments netted 407 bbIs of incremental oil, or 102 BO per well. The chemical treatments were successful in obtaining more incremental production than the microbial treatments.

The revenues are calculated on the incremental production assuming a net oil price of $15 per barrel. **Table 9** summarizes the treatment economics for the chemical and microbial systems. The chemical treatments produced a incremental revenue of $13,200, or $4,400 per well, while the microbial treatments produced only $6,105, or $1,526 per well.

When the cost of the treatments is considered, the net benefit of the chemical treatments is $398, or $133 per well. The unusual transportation charge is not included in this calculation. The microbial treatments had a net benefit of $1,977, or $494 per well. The ratio of net benefit to cost was 0.03 for the chemical treatment and 0.48 for the microbial treatment. The microbial treatments were able to yield a better return on cost than the chemical treatments.

Conclusions

1. The best candidate wells for paraffin treatments are those with physical evidence of paraffin deposition that have never been treated with a large solvent treatment. Wells with the smallest solvent treatments and the longest elapsed time since the treatment would be the next best candidates for an economically successful treatment. Wells with higher GOR's performed better in this study.
2. As paraffin particles move through the production system, they cause plugging. This effect is often manifested by erratic production decline curves. Wells exhibiting this behavior without other explanations are often good candidates for treatments. This plugging problem is aggravated by the slow action of microbial treatments, and often production decreases are observed for several months after the treatments are started. This effect is most pronounced in wells that later are the best successes.
3. Microbial treatments are easier to perform than chemical treatments. Less fluid volume is required, and the fluids a non-hazardous. However more of the microbial treatments a required.
4. The microbial treatments are much cheaper than the chemical treatments, with an average cost of $1,032 per well for the three months of treatments done for this test.
5. The chemical treatments were successful in obtaining more incremental production than the microbial treatments. The incremental production was also obtained quicker than with the microbial treatments. Over 8 months this test achieved a 74% increase over baseline production. The wells treated with microbes achieved only a 16% increase.
6. The microbial treatments were able to yield a better return on cost than the chemical treatments. In this test, a 48% return on investment was achieved in 8 months.

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SI Metric Conversion Factors

acres x 4.047 E-03 = kM^2
°API + 131.5 =141.5/specific gravity
bbIs x 1.589 873 E-01 = m^3
cuydsx7.6455 E-01 = m^3
°F (OF-32)/1.8=°C
ft x 3.048 E-01 = m
gals x 3.785 412 E-03 = m^3
lbs x 4.5359 E-01 = kg
MCF x 2.832 E+01 = m^3
md x 9.87 E-04 = mm^2
psi x 6.895 E+00 = kPa

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Table 2. Well Grouping Point Assignments			
Well	**Treatment**	**GOR**	**WOR**
	Group I		
85-AX-20	0	1	3
34-AX-34	0	5	1
85-AX-3	4	1	2
Total	**4**	**7**	**6**
	Group II		
32-A-34	4	4	1
61-A-3	3	1	2
84-A-20	0	1	4
Total	**7**	**6**	**7**
	Group III		
15-AX-11	6	4	1
16-1-AX-21	0	1	3
32-AX-10	0	1	3
Total	**6**	**6**	**7**
	Group IV		
18-AX-34	5	5	1
88-AX-3	(0)	(1)	(2)
22-AX-21	0	1	5
28-AX-34	0	2	1
Total	**5**	**8**	**7**

Table 1. Physical Properties of Chemical System	
Aromatics	59% (liquid volume)
Flashpoint (pmcc)	63°F
Flashpoint (coc)	66°F
Density	6.7 lb/gal @60°F
API Gravity	45°
Cloud Point	-8°F
Pour Point	-76°F
Vapor Pressure	< 0.5 psi @ 100°F

Table 3. Chemical Treatment Schedule	
5 Sept 96	Treat 85AX20, 34AX34, and 85AX3 with 150 gals Waxsol and 150 gals diesel. Circulate for 24 hours
6 Sept 96	Return wells to production
17 Sept 96	Treat 34AX34, and 85AX3 with 500 gals Waxsol and 1500 gals diesel. Shut-in for 24 hours
18 Sept 96	Return 34AX34 and 85AX3 to production
9 Oct 96	Treat 85AX20 with 500 gals Waxsol, 1500 gals diesel. Shut-in for 24 hours
10 Oct 96	Return 85AX20 to production.

Table 4. Microbial Treatment Schedule	
5 Sept 96	Treat 18AX34, 88AX3, 22AX21, and 28AX34 with 10 bbls bacteria solution. Shut in 24 hrs.
6 Sept 96	Return wells to production.
30 Sept 96	Treat 18AX34, 88AX3, 22AX21, and 28AX34 with 10 bbls bacteria solution. Shut in 24 hrs.
31 Sept 96	Return wells to production.
29 Oct 96	Treat 18AX34, 88AX3, 22AX21, and 28AX34 with 10 bbls bacteria solution. Shut in 24 hrs.
30 Oct 96	Return wells to production.

Table 5. Chemical Treatment Cost	
1,950 gals Waxsol	$7,312.50
Delivery Charges	$2,343.00
5,000 gals diesel	$4,421.20
Tank Rental	$150.00
Pump Truck 9/5	$200.00
Pump Truck 9/17	$200.00
Pump Truck 10/9	$100.00
Pumper Labor 9/5	$209.16
Pumper Labor 9/17	$139.44
Pumper Labor 10/9	$69.72
Total Cost	**$15,145.02**
Total Cost per Well	**$5,048.34**
Total Wellbore Cleanup Cost	$3,414.20
Wellbore Cleanup Cost per Well	$1,138.07
Total Squeeze Treatment Cost	$11,730.82
Squeeze Treatment Cost per Well	$3,910.27

Table 6. Microbial Treatment Cost	
Bacteria Treatments, 3 wells (1 free) 9/5	$990.00
Bacteria Treatments, 3 wells (1 free) 9/30	$990.00
Bacteria Treatments, 3 wells (1 free) 10/29	$990.00
Pump Truck 9/5	$200.00
Pump Truck 9/30	$200.00
Pump Truck 10/29	$200.00
Pumper Labor 9/5	$185.92
Pumper Labor 9/30	$185.92
Pumper Labor 10/29	$185.92
Total Cost	**$4,127.76**
Total Cost per Well	**$1,031.94**

Table 7. Incremental Chemical Treatment Production				
Month	**85AX20**	**34AX34**	**85AX3**	**Total**
Sept 96	81	48	49	178
Oct 96	49	37	2	87
Nov 96	18	47	-10	56
Dec 96	1	70	-9	62
Jan 97	-6	77	22	93
Feb 97	23	84	14	122
Mar 97	53	90	6	149
Apr 97	83	60	-10	133
Total	**302**	**513**	**65**	**880**

Table 8. Incremental Microbial Treatment Production					
M/Yr	**18A34**	**88AX3**	**22AX21**	**28AX34**	**Total**
9/96	30	-6	10	0	33
10/96	-12	-5	-22	29	-10
11/96	-15	-23	-44	26	-57
12/96	8	43	-45	8	14
1/97	29	14	16	12	72
2/97	29	0	8	64	100
3/97	29	0	8	115	152
4/97	4	0	1	97	103
Total	**101**	**23**	**-68**	**350**	**407**

Table 9. Net Economic Benefits Comparison		
	Chemical	**Microbial**
Total Incremental Oil	880 bbls	407 bbls
Revenue	$13,200	$6,105
Cost	$15,145	$4,128
Cost (less Transportation)	$12,802	$4,128
Net Benefit	($1,945)	$1,977
Net Benefit (less Transportation)	$398	$1,977
Net Benefit per Well (less transportation)	$133	$494
Benefit/Cost Ratio	0.03	0.48

Figure 1. 85AX3 Production Performance

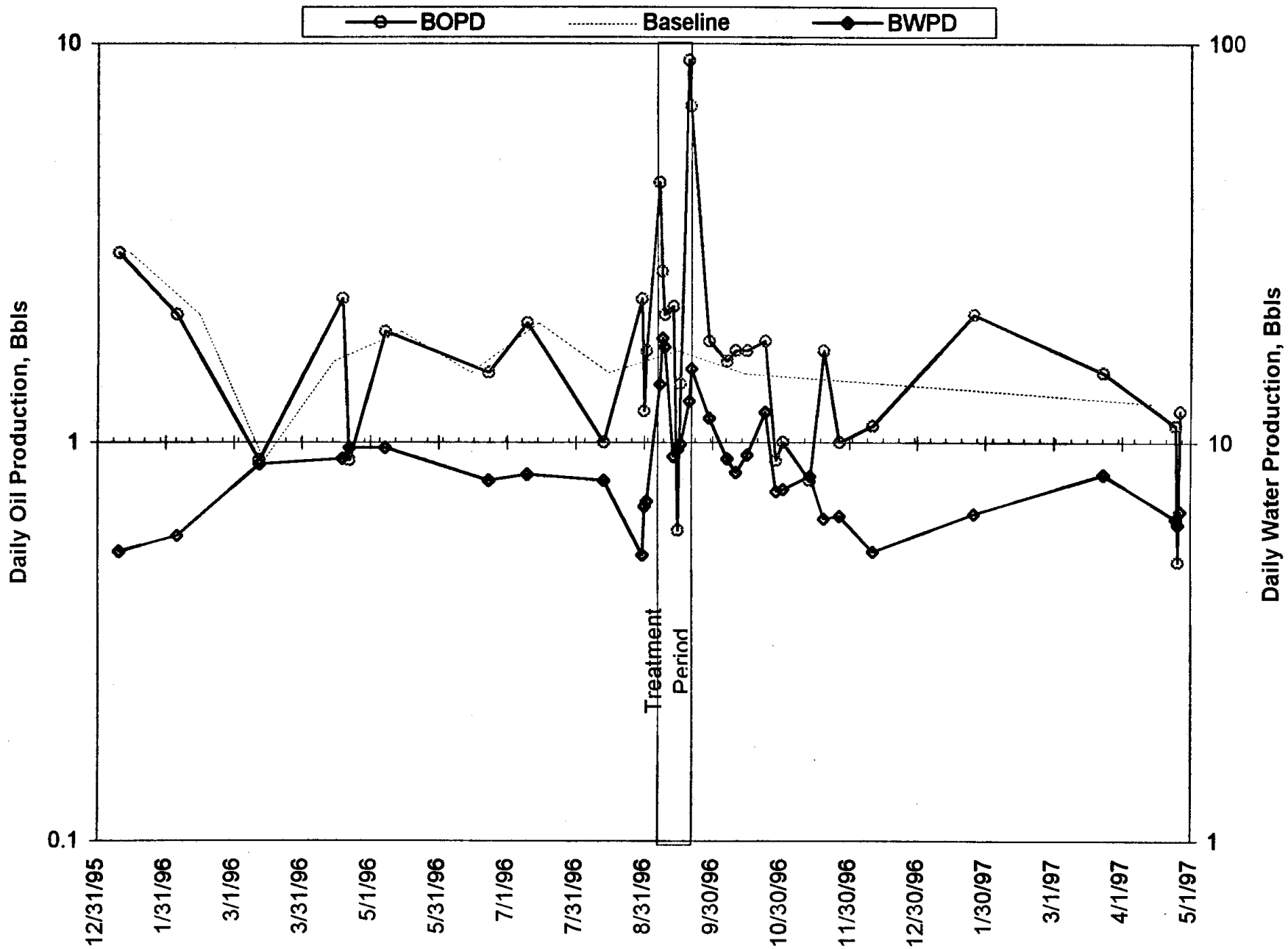

Figure 2. 85AX20 Production Performance

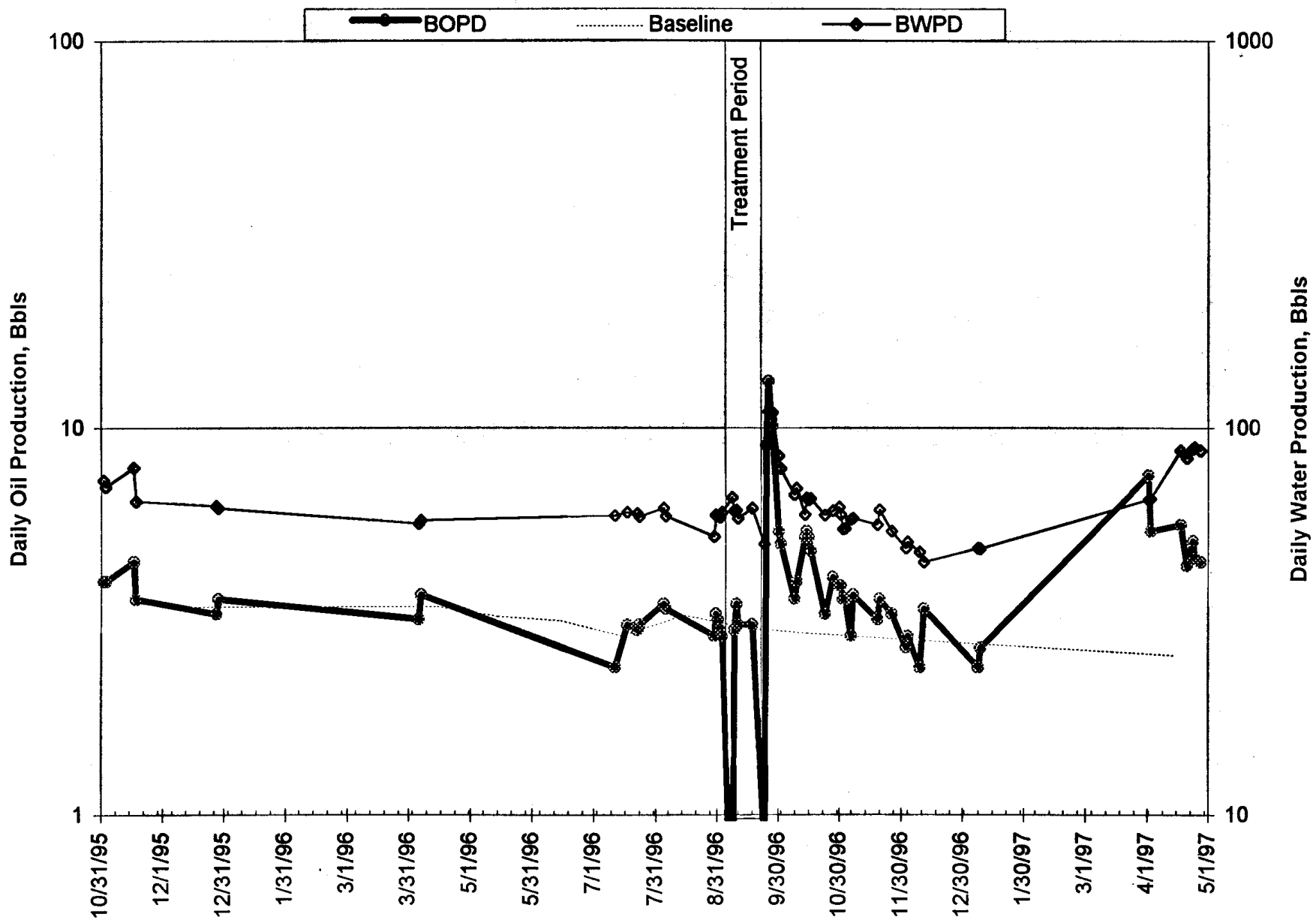

Figure 3. 34AX34 Production Performance

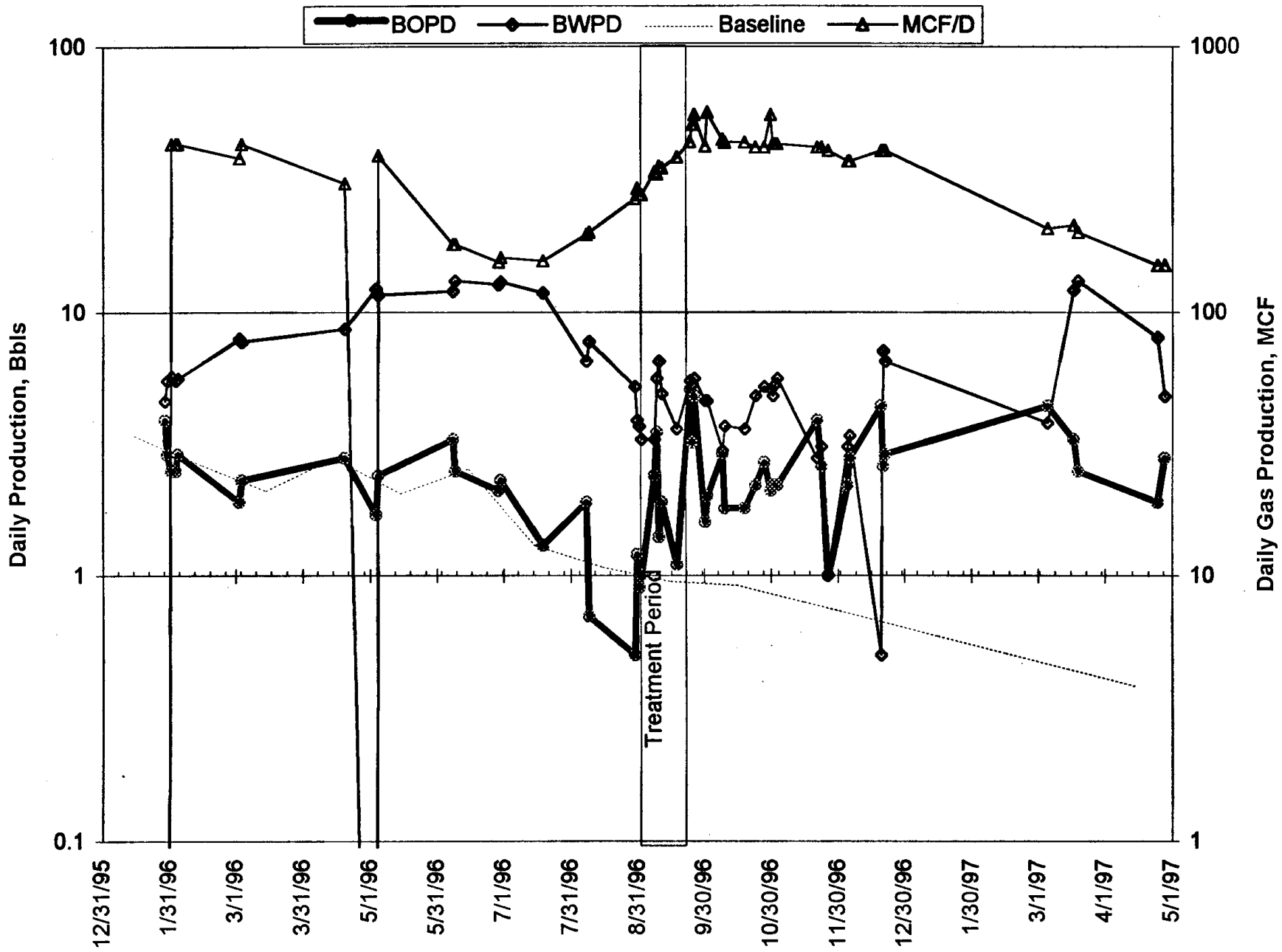

Figure 4. 18AX34 Production Performance

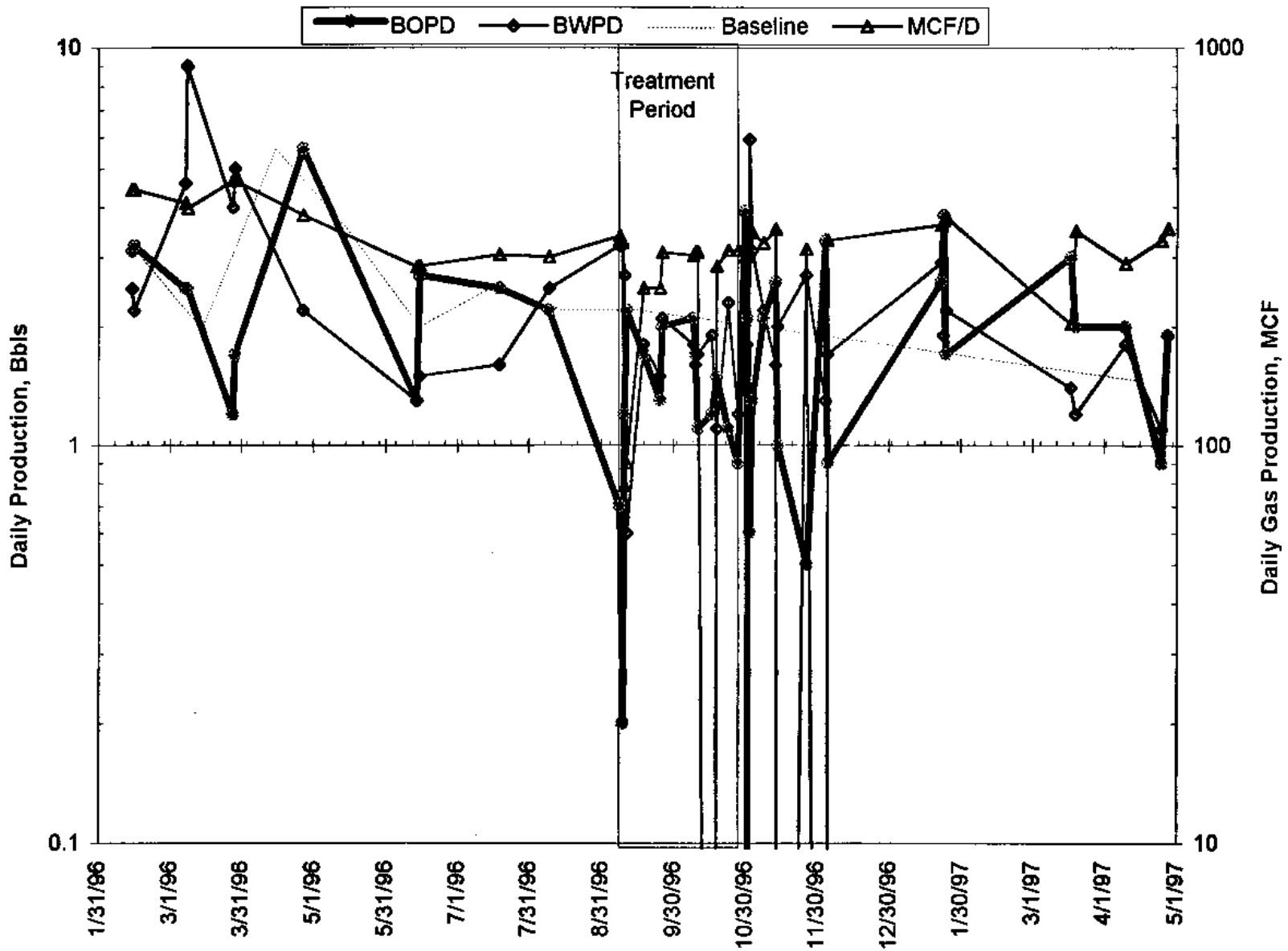

Figure 5. 88AX3 Production Performance

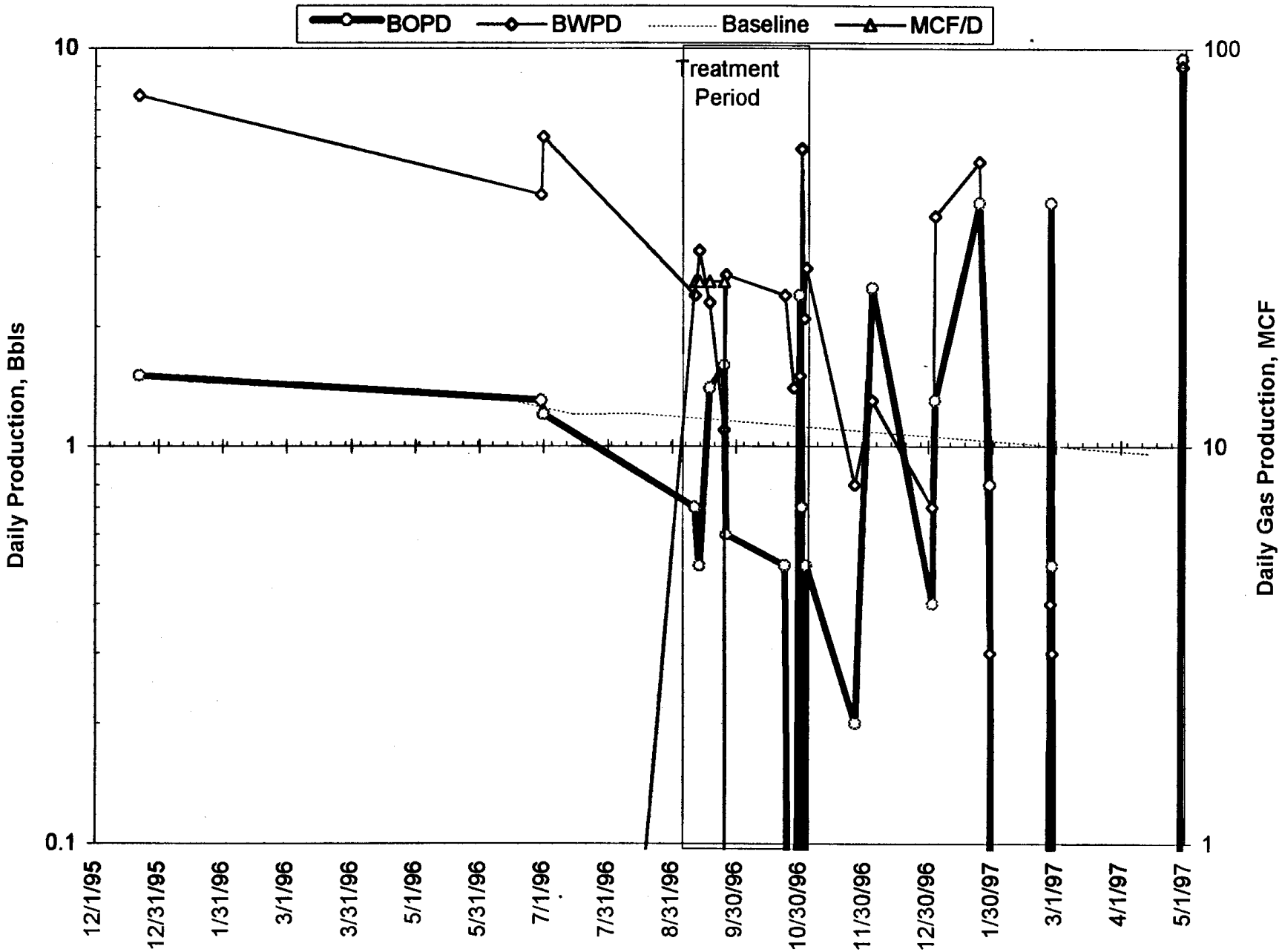

Figure 6. 22AX21 Production Performance

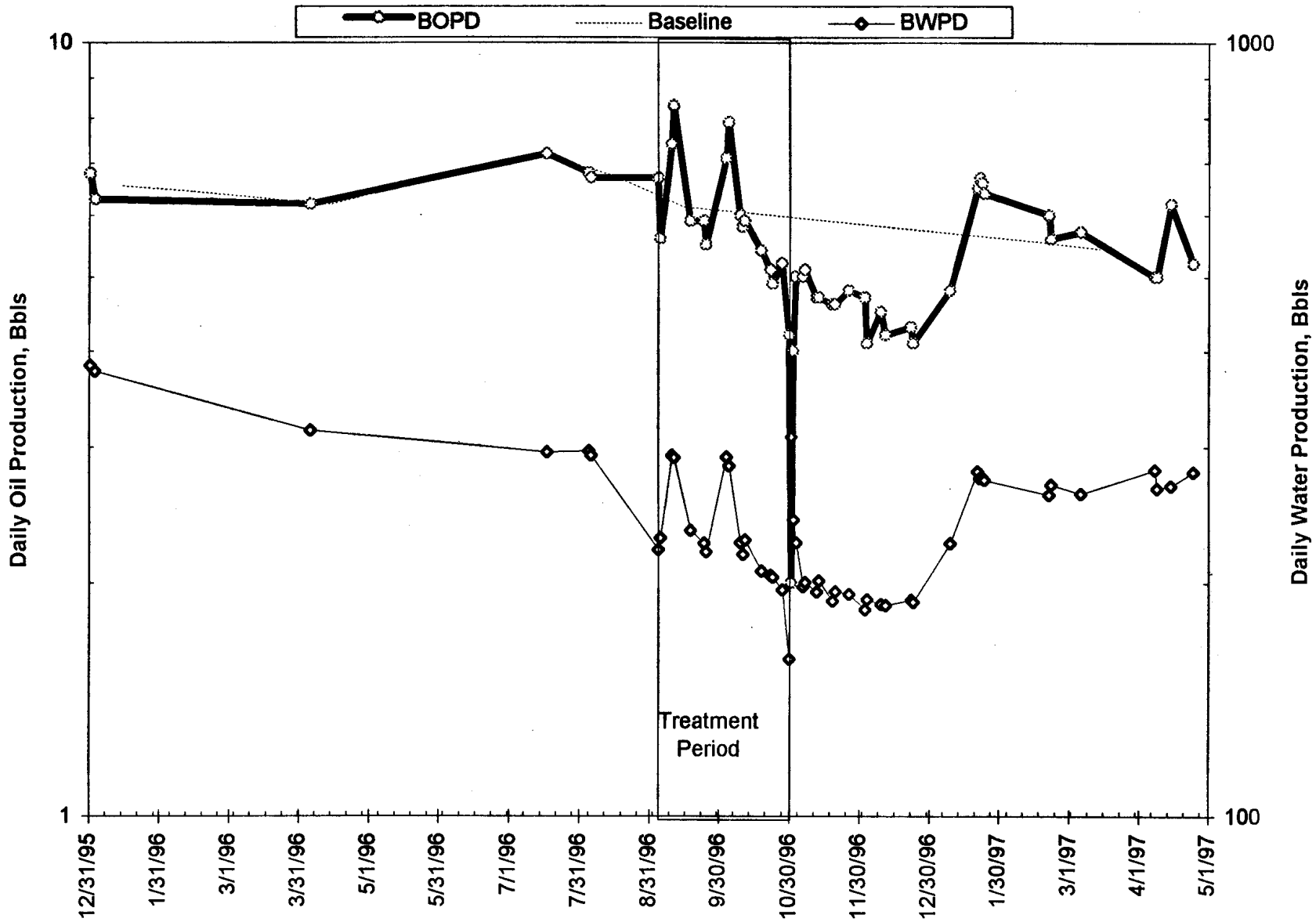
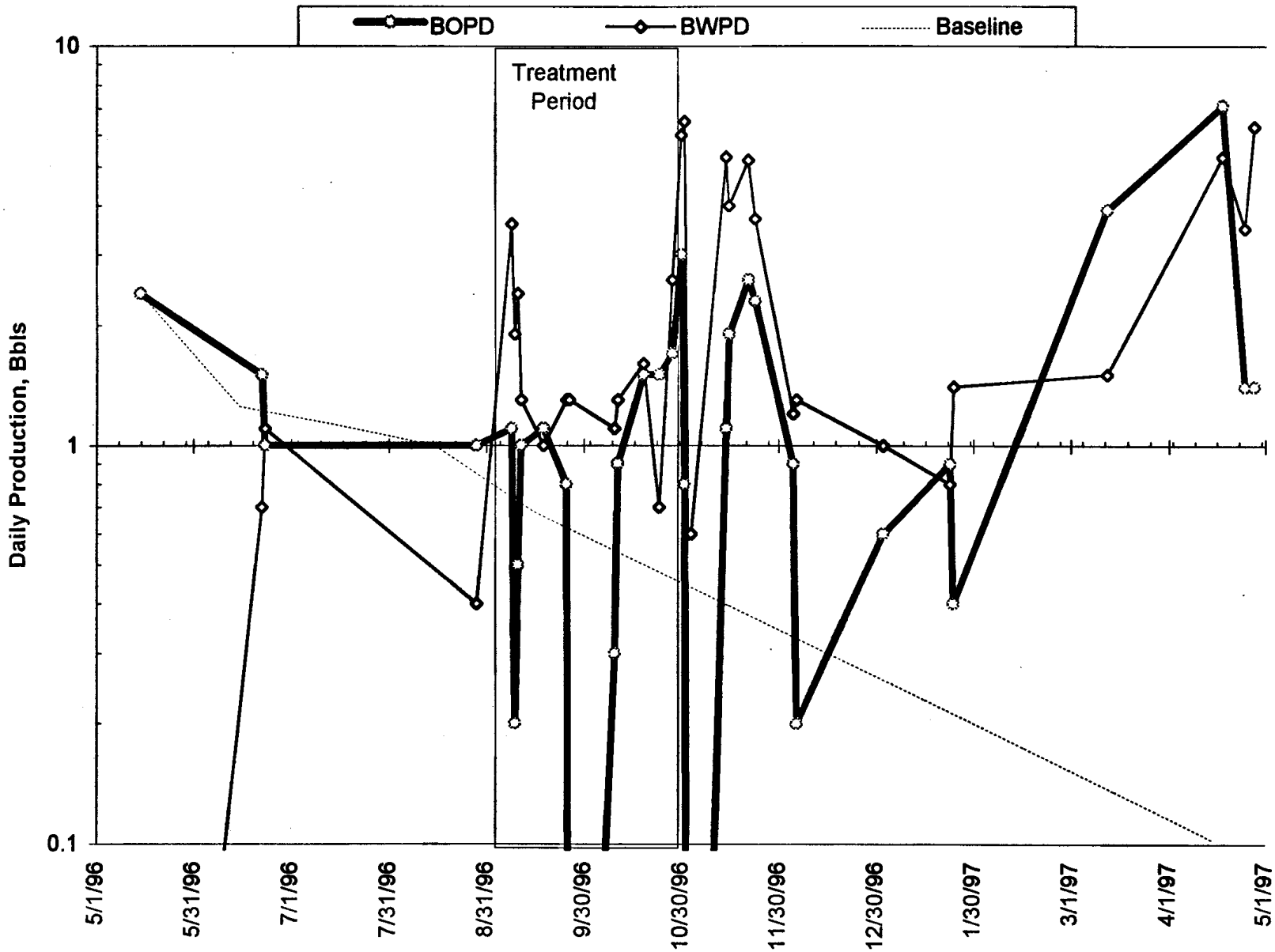
Figure 7. 28AX34 Production Performance