Summary of Data from DOE-Subsidized Field Trial #1 of Downhole Oil/Water Separator Technology

Texaco Well Bilbrey 30-Federal No.5
Lea County, New Mexico

Prepared for:

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Chapter 1 - Introduction

The U.S. Department of Energy's (DOE's) National Petroleum Technology Office (NPTO) is interested in new oil and gas technologies that can produce oil and gas at a lower cost or that can provide additional environmental protection at a reasonable cost. Several years ago, DOE became aware of a new technology for produced water management known as a downhole oil/water separator, or DOWS. A DOWS system separates oil from water at the bottom of a well and injects the water directly to a disposal zone without lifting it to the surface. DOWS technology offered three potential advantages over traditional pumping systems. First, DOWS were reported to reduce the volume of produced water brought to the surface. Second, the volume of oil produced often increased. Third, because large volumes of produced water were not being lifted to the surface past drinking water zones and subsequently reinjected downward past the same drinking water zones, there was less opportunity for contamination of those zones.

DOE provided funding to Argonne National Laboratory to conduct an independent investigation of the technical feasibility, legality, and economic viability of DOWS technology. Argonne, in conjunction with two other partners (CH2M-Hill and the Nebraska Oil and Gas Conservation Commission), issued a final report in January 1999 (Veil et al. 1999). The report provides a considerable general information about DOWS, but most operators were not willing to share the detailed day-by-day operating data on their systems. To obtain more data to share with other interested operators and to better understand how DOWS work, DOE made additional funding available to Argonne to collect detailed operating data from up to six field trials of new DOWS installations. Argonne has advertised the availability of these funds for several years. This data summary report describes the first field trial conducted under this program.

Chapter 2 - Description of DOWS

What is a DOWS and How Does It Work?

DOWS technology reduces the quantity of produced water that is handled at the surface by separating it from the oil downhole and simultaneously injecting it underground. The two primary components of a DOWS system are an oil/water separation system and at least one pump to lift oil to the surface and inject the water. Two basic types of DOWS have been developed – one type using hydrocyclones to mechanically separate oil and water and one relying on gravity separation that takes place in the well bore.

Hydrocyclones use centrifugal force to separate fluids of different specific gravity without any moving parts. A mixture of oil and water enters the hydrocyclone at a high velocity from the side of a conical chamber. The subsequent swirling action causes the heavier water to move to the outside of the chamber and exit through one end, while the lighter oil remains in the interior of the chamber and exits through a second opening. The water fraction is then injected, and the oil fraction is pumped to the surface. Hydrocyclone-type DOWS have been designed with electric submersible pumps, progressing cavity pumps, and rod pumps. Most of the development work on this type of DOWS was done through several joint industry projects by a Canadian organization, CFER-Technologies.

Gravity separator-type DOWS are designed to allow the oil droplets that enter a well bore through the perforations to rise and form a discrete oil layer in the well. A gravity separator tool has two intakes, one in the oil layer and the other in the water layer. The gravity separator-type DOWS use rod pumps. As the sucker rods move up and down, the oil is lifted to the surface and the water is injected. The most common gravity separator-type DOWS is the dual-action pumping system (DAPS) developed by Texaco. Over the past year, Texaco developed an improved version that develops greater injection pressure, the triple-action pumping system (TAPS) (Wacker et al. 1999). A diagram of a TAPS is shown as Figure 1. The field trial described in this report is the first installation of a TAPS.

The TAPS achieves greater injection pressure than the DAPS by adding a third, bottom injection plunger that has smaller surface area than the middle plunger. This small bottom plunger is connected to the middle plunger with larger surface area. The fluid column exerts pressure on the middle plunger, which in turn exerts pressure on the bottom plunger through the connecting rod. The injection pressure produced by the bottom is increased by the ratio of the surface areas of the middle and bottom plungers. As the pressure produced by the lower plunger increases, the volume of fluid that can be pumped decreases.

Why Should Operators Install DOWS?

The costs of lifting, treating, and disposing of produced water are important components of operating expenses. DOWS can save operators money by reducing produced water management costs. In all of the 29 DOWS installations examined by Veil et al. (1999) that had both pre- and post-installation data, DOWS reduced the volume of water brought to the surface. The percent reduction ranged from 14% to 97%, with most of those installations exceeding 75% reduction in water brought to the surface.

In over half of the North American wells in which DOWS have been installed, the oil production rates increased following the installation. The percent increase in oil production rates ranged from 11% to over 1,100%, although a few wells lost oil production (Veil et al.

1999). In some cases where surface processing or disposal capacity is a limiting factor for further production within a field, the use of DOWS to dispose of some of the produced water may allow additional production in that field.

DOWS provide a positive but unquantifiable environmental benefit through minimization of the opportunity for contamination of underground sources of drinking water through leaks in tubing and casing during the injection process. Likewise, DOWS minimize spillage of produced water onto the soil at the surface because less produced water is handled at the surface.

Economic Considerations

Nearly all of the DOWS installations to date have been made as retrofits to existing wells with standard pumps. Conversion of a well from a regular pump to a DOWS is a relatively expensive undertaking. Total costs include the cost of the DOWS tool itself and well workover expenses. Veil et al. (1999) provide some information on costs, but many of the operators polled by the authors did not provide any detailed cost information.

Costs for the hydrocyclone-type DOWS are high. For example, the cost of an electric submersible pump-type DOWS system is approximately double to triple the cost of replacing a conventional electrical submersible pump and is often in the range of $90,000 - $250,000. In addition, the associated well workover costs can often exceed $100,000. Costs are somewhat lower for the gravity separator-type DOWS, ranging from $15,000 - $25,000. The cost of one complete gravity separator-type DOWS installation was $140,000 Canadian (Veil et al.1999).

Summary Statistics on North American Installations of DOWS

As of 1999, fewer than 50 DOWS had been installed in the world. Veil et al. (1999) provide information on the geology and performance of 37 of those installations. Some of the key findings are summarized below:

- More than half of the installations have been hydrocyclone-type DOWS (21 compared with 16 gravity separator-type DOWS).

- Twenty-seven installations have been in Canada and 10 have been in the United States.

- Of the 37 DOWS trials described, 27 have been in four producing areas – southeast Saskatchewan, east-central Alberta, the central Alberta reef trends, and East Texas.

- Seventeen installations were in 5.5-inch casing, 14 were in 7-inch casing, 1 was in 8.625-inch casing, and 5 were unspecified.

- Twenty of the DOWS installations have been in wells located in carbonate formations and 16 in wells located in sandstone formations. One trial did not specify the lithology. DOWS appeared to work better in carbonate formations, showing an average increase in oil production of 47% (compared with an average of 17% for sandstone formations) and an average decrease in water brought to the surface of 88% (compared with 78% for sandstone formations).

- The rate of oil production increased in 19 of the trials, decreased in 12, stayed the same in 2, and was unspecified in 4. The top three performing hydrocyclone-type wells showed oil production increases ranging from 457% to 1,162%, while one well lost all oil production. The top performing well improved from 13 to 164 barrels per day (bbl/d). The top three gravity separator-type wells showed oil production increases ranging from 106% to 233%, while one well lost all oil production. The top performing well in this group improved from 3 to 10 bbl/d.

- All 29 trials for which both pre-installation and post-installation water production data were provided showed a decrease in water brought to the surface. The decrease ranged from 14% to 97%, with 22 of 29 trials exceeding 75% reduction.

What Problems Have Been Experienced

Although most of the DOWS installed to date have worked well, some of the installations have experienced problems. The problems can be broken down into several major categories, as noted below:

- Some installations were poorly chosen or designed. Some operators didn't want to risk damaging good performing wells with a new device and selected less than optimal candidate wells. Particularly in the earliest installations, many of the design flaws had not been worked out. Subsequent models avoided some of these flaws.

- Some installations did not allow a suitable difference in depth between the producing and the injection interval. If isolation between the intervals is not sufficient, the injectate can migrate into the producing zone and then short-circuit into the producing perforations. The result will be recycling of the produced water, with oil production rates dropping to nearly zero.

- Two installations suffered from low injectivity of the receiving zone; in both cases, incompatible fluids contacted sensitive reservoir sands, which plugged part of the permeability.

- Several installations suffered from corrosion or scaling. This problem may be a result of incompatible chemistry between the producing and injection formations.

- Several other installations had problems with excessive sand collection that either clogged or eroded the DOWS.

Chapter 3 - Description of Bilbrey 30-Federal No.5 Well

Location

The Bilbrey 30-Federal No.5 well is located in Section 30, Township 21-S, Range 32-E of Lea County, New Mexico. This location is approximately 32.5 miles west of Eunice in the southeastern corner of New Mexico. This region produces oil and gas from the Lost Tank Delaware field. The API well number is 30-025-33647. The surface elevation at the wellhead is about 3,680 feet above sea level.

Well Construction Details

The well was spudded on November 30, 1996, and completed on February 20, 1997. The well was plugged back at a depth of 7,250 feet.

The well has three strings of casing plus tubing. The casing consists of 11-3/4 inch casing from the surface to a depth of 805 feet, 8-5/8 inch casing from the surface to a depth of 4,380 feet, and 5-1/2 inch casing from the surface to a depth of 8,850 feet. The tubing string of 2-7/8 inch diameter runs from the surface to a depth of 7,015 feet.

The well was initially completed with production perforations in several formations: (1) 8,394 to 8,418 feet (Lower Brushy Canyon formation); (2) 7,314 to 7,319 feet (Brushy Canyon formation); and (3) 7,113 to 7,125 feet (Brushy Canyon formation). Production from these formations proved to be uneconomical. In April 1997, additional perforations were made at the following shallower depths: (1) 6,797 to 6,806 feet (Lower Cherry Canyon formation); (2) 6,819 to 6,822 feet (Lower Cherry Canyon formation); (3) 6,855 to 6,863 feet (Lower Cherry Canyon formation); and (4) 4,654 to 4,680 feet (Bell Canyon formation).

Production from the second set of perforations also produced excessive water such that the well was not economical to produce. Texaco decided to convert this producing well into a dual completion well, by which the same well would produce oil and gas from one formation and inject most of the produced water into a second formation. Texaco selected this well for its first trial of the TAPS technology. All production perforations except those from 4,654 to 4,680 feet were plugged. New injection perforations were made at depths from 5,160 to 5,210 feet in the Bell Canyon formation. A packer was set at a depth of about 4,870 feet to isolate the production fluids from the injected fluids. The well was recompleted, and the TAPS unit was installed in January 1999.

Characteristics of the Production and Injection Formations

To ensure that transfer of water from the producing formation to the injection formation did not cause excessive scaling or corrosion, Texaco monitored chemical and physical properties of both formations. Tables 1 and 2 show this information.

The New Mexico Oil Control Division authorizes a standardized injection pressure of 0.2 pounds per square inch (psi) per foot of depth. In the case of this well, the maximum injection pressure would be just above 1,000 psi. If an operator wants to inject at higher pressures, the Oil Control Division requires the operators to conduct a step rate injection test to determine the pressure at which the injection formation begins to fracture. Texaco conducted a step rate injection test in January 1999. The test showed that even at a pressure of more than 1,550 psi, the receiving formation did not fracture. The data from the test are shown in Table 3 and Figure 2.

Features of the Well That Made It a Good DOWS Candidate

Wacker et al. (1999) offer several reasons why Texaco selected the Bilbrey 30-Federal No.5 well as the candidate for the first TAPS trial. First, the well was relatively new so that the casing could withstand the high injection pressure. Second, the well had already been completed to a greater depth so that no additional drilling was necessary to reach an injection zone. Because the well had been completed to a greater depth, the rods and pumping unit were oversized compared with rods and pumps normally used at shallower depths. Third, the well had its own dedicated tanks and a pump controller. Finally, there were no other partners to convince that a trial was worthwhile.

Chapter 4 - Well Performance before TAPS Installation

The well operated from February 1997 until December 1998 before being fitted with the TAPS unit in January 1999. As part of the contract between Argonne and Texaco to purchase DOWS operating data, production data were provided for the 6 months prior to installation of the TAPS. Table 4 contains daily measurements on oil production, water production, and gas production to the surface from July 1, 1998, to December 31, 1998. The average daily production for that period was 27 bbl/d oil, 173 bbl/d water, 200 bbl/d total produced fluids, and 2.5 thousand cubic feet/day (mcf/d) gas. This production represents an oil cut of 15.8%.

Figure 3 plots the data from Table 4. Linear trend lines are drawn for the water and oil to the surface data. The volume of water brought to the surface increased steadily from about 170 bbl/d to 180 bbl/d, while the volume of oil brought to the surface decreased steadily from about 40 bbl/d to 20 bbl/d during the 6-month period. Neither trend is desirable for sustained economical performance of the well. These trends mirror those that occur naturally throughout the life of most wells. However, the rate of oil decline and water increase are generally much slower than the rates demonstrated in this well.

Gas production fluctuated within a narrow range (1-5 mcf/d). Gas production was reported to only one significant figure, thereby making it difficult to see daily variation.

Chapter 5 - Well Performance Following TAPS Installation

The TAPS unit was placed into service on January 19, 1999. Texaco provided daily information on oil, water, and gas brought to the surface; the amount of water injected; the amount of water returned to the wellbore; and the net water at the surface through August 30, 1999. Texaco also provided a few daily injection pressure measurements. Table 5 contains these data.

Oil and Water Production

Long-Term Average Performance: Texaco management allowed installation of the TAPS with a plan of working up to maximum capacity over a period of time rather than immediately moving to full capacity (Wacker et al. 1999). The long-term performance of the well for Case 1 (all days beginning with TAPS installation through August 30) and Case 2 (all days excluding those in which both oil and water production to the surface is zero [assumes that the TAPS was not operating on those days]) is as follows:

- The average oil production was 6.7 bbl/d (Case 1) and 7.3 bbl/d (Case 2).

- The average water production to the surface was 77 bbl/d (Case 1) and 84 bbl/d (Case 2).

- The average injected water volume was 84 bbl/d (Case 1) and 91 bbl/d (Case 2).

- The average net water to the surface (water produced to the surface minus the water injected or reintroduced to the well) was 42 bbl/d (Case 1) and 45 bbl/d (Case 2).

Oil Production: The oil production, water production, and net water production data are plotted in Figure 4. Oil production declined from 17 bbl/d before TAPS installation to 7 bbl/d (59% decrease) during the trial. Some of the oil decline is a result of Texaco's decision to operate the pumps at moderate levels to gain familiarity with the new TAPS.

The oil produced to the surface, the overall oil cut (the proportion of oil in the total fluid volume), and the oil cut of the surface-produced fluids are plotted in Figure 5. The daily volume of oil produced to the surface was erratic. For the first 3 months of the trial, the daily oil production declined from an average of about 15bbl/d to an average of about 7 bbl/d. Following nearly a month of no oil production, the TAPS performed better for 2 months, producing an average of nearly 10 bbl/d. However, for the last month of the data records in this trial, the oil production declined to an average of about 5 bbl/day.

The two oil cut values followed a similar trend. The overall oil cut was fairly high for the first three months of the trial (5.5% average) but dropped for the last 3 months of the trial to 2.9% average. Likewise the oil cut of the surface-produced fluids dropped from 14.2% average to 6.6% average during the same period.

Water Production: The water produced to the surface remained relatively constant throughout most of the trial (about 70 bbl/d average) except during June, when it increased significantly. Net water production to the surface declined from 190 bbl/d before TAPS installation to 42 bbl/d (78% decrease) during the trial. During some periods, particularly from January to mid-February, part of March, and most of June, the volume of water brought to the surface was the same as the net water volume at the surface, indicating that no water was returned to the well on those days. The TAPS was taken out of service for repairs during several periods. These problems are discussed in the next chapter.

From mid-February to mid-March, during April and May, and during July and August, however, little or no produced water had to be trucked away from this well because all water was either injected by the TAPS or reintroduced to the well annulus. On some days, the well experienced a net loss of water at the surface as more water was reintroduced from the aboveground water storage tanks than was produced to the surface. The ability to operate without having to haul water offsite is a significant accomplishment. The approach used to achieve zero discharge can be transferred to other wells.

Total Fluid Production: The total fluids produced by the well fluctuated significantly as shown in Figure 6. For the first 3 months of the trial, the average was similar to that of the pre-installation period (about 200 bbl/d).   During May, total fluid production rose to an average of about 270 bbl/d, then declined during June to about 200 bbl/d. During the last 2 months of the trial, the total fluid production averaged about 240 bbl/d.

Pump Data

Texaco provided extensive data on the pumping system. The data from March 2 to August 31 are presented in Table 6. Key features of those data are given below.

Pump Load: The daily high pump load ranged from 13,417 to 19,773 pounds. The daily low pump load ranged from 7,261 to 10,069 pounds. The daily high pump load gradually increased over time, while the daily low pump load remained relatively constant.

Run Time: On most of the days on which the pump ran at all, it ran for more than 20 hours. On many days, the pump ran for all 24 hours.

Load on Standing Valve Check: This test was performed to see if the standing valve was leaking. The load was measured intermittently and varied from 10,100 to 11,829 pounds. All values recorded after June 7 were greater than or equal to 11,382 pounds, whereas all values recorded before that date were lower than or equal to 11,350 pounds.

Estimated Injection Pump Volume: From March through April, the injection pump ran between 41% and 63% of its volume. From May through the end of the trial, the injection pump volume was increased to 70% to 75%.

Fluid Level Above Pump: The height of fluid accumulated above the pump gives an indication of the pump's ability to keep up with the volume of fluid entering the well from the formation. The data for the first several months of the trial show that a large amount of fluids accumulated above the pump, suggesting that the pump was not able to pump the full volume of fluids entering the well. The values ranged from 815 to 2,781 feet. Unfortunately, this parameter was not measured consistently during the later months of the trial. The only reported measurement after June 7 was made on August 10. It shows that only 4 feet of fluid had accumulated above the pump, indicating that the pump's output was nearly equal to the volume of fluids entering the well.

Calculated Formation and Surface Pressures: The calculated formation pressure ranged from 2,232 to 1,465 psi. The surface pressure ranged from -295 to - 1,062 psi. Both sets of pressures declined throughout the trial.

Pump Intake Pressure: Pump intake pressure data were available only from March to early June. The pressure ranged from 315 to 864 psi. The data follow no obvious trend.

Chapter 6 - Discussion

Wacker et al. (1999) offer a good discussion of the TAPS trial by the persons who actually did the field work on the trial. Key findings of that article and other observations by the author are described in this chapter.

TAPS Technology

Texaco had previous experience with a similar gravity separator-type of DOWS, the DAPS, but was concerned that the DAPS could not produce sufficient injection pressure to inject water into tight formations. By adding a third stage to the pumping system, the TAPS solved that problem. The TAPS was able to inject successfully during this trial. Wacker et al. (1999) note that balancing the size of the three pumps in the TAPS is critical to making the system work as planned.

Produced Water Management

The cost of trucking produced water away from the well for disposal was prohibitive for cost-effective well operation. Even a well-operated DAPS or TAPS produces about one quarter of the water to the surface. Texaco wanted to find a method to dispose of the water produced to the surface downhole to avoid trucking costs. Texaco decided to remove produced water from the surface production tanks and let it siphon down the well annulus. That approach proved successful. On many days, no net produced water accumulated at the surface. On some days, more water than was produced that day was siphoned down the annulus, for a net negative water production. By lengthening the stroke of the pumping unit, Texaco was able to inject the extra volume of produced water reintroduced into the well by the siphon tube.

In previous applications, corrosion proved to be a problem. Wacker et al. (1999) report that to control corrosion, Texaco continuously added an oil-dispersible, water-soluble chemical to the water stream going through the siphon tube. This solution provided satisfactory performance.

Operational Problems

Wacker et al. (1999) report that on two occasions, oil production dropped to zero. Following the first incident, the TAPS unit was removed from the well and inspected. The system had indications of sucker rod wear, and the lower valve assembly had split. The sucker rods (the metal rods leading from the surface pump jack to the DOWS unit) are normally sized to account for stress in the upward direction (elongation). A DOWS unit also applies stress in the downward direction during the injection phase. To avoid buckling of the rods and inducing premature rod failure, Texaco added sinker bars (weights to counteract the buckling stress). The valve assembly was replaced and the TAPS was reinstalled.

The system worked satisfactorily for several weeks, but then failed again. Upon inspecting the pump, Texaco noted that the valve assembly had split in the same location. This time, the operator added a stronger valve assembly, and reinstalled the TAPS. It worked fine for the remainder of the trial.

A second problem was caused by trapped gas within the injection pump system. Initially, trapped gas prevented the pump from completing its full range of motion. Although Wacker et al.

(1999) report that Texaco solved that problem by modifying the TAPS, they provide no description of the actual steps or actions that were followed.

Spread of DOWS Technology

DOWS technology was introduced to the industry in the early 1990s. Most of the early work was done by individual companies or a consortium of companies that elected not to share the resulting data with groups outside of the consortium. DOE anticipated that there would be great interest in DOWS technology and funded the feasibility evaluation study (Veil et al. 1999). DOE sponsored several workshops on DOWS and encouraged Argonne to make presentations at technical conferences and publish papers on DOWS to transfer the technology to many more potential users. DOE further provided funding to partially pay for up to six field trials of DOWS technology to obtain detailed operating data.

The timing of the release of Veil et al. (1999) and the availability of cost-sharing funds for the field trials could not have come at a more inopportune time. In early 1999, the oil and gas industry faced it lowest oil prices in decades. Many independent operators, a prime target audience for DOWS, shut in wells or went out of business. They were not inclined to spend their limited capital on new, somewhat experimental technology. Worldwide DOWS sales were virtually nonexistent for most of 1999. As oil prices have risen in 2000, companies are still somewhat reluctant to expend capital on technologies such as DOWS.

The data presented in this report come from the first and, to date, the only DOE-sponsored field trial. Although DOWS technology appears to be sound, it has not yet caught on widely in the oil patch.

Chapter 7 – Conclusions

This field trial, with over 8 months of operating history, demonstrated that Texaco's TAPS operated successfully to reduce the amount of produced water lifted to the surface. The addition of a third pumping stage allowed injection of produced water into a tight formation. The ability to inject at high pressures enhances the potential for DOWS to be used in water flooding situations. By using a separate siphon tube for disposal of the remaining volume of water lifted to the surface, the operators were able to eliminate the need to haul produced water offsite.

The oil production following TAPS installation was not as great as before TAPS installation and decreased during the period of the trial. To some extent, the reduction in performance was a function of the Texaco engineers' choice of pumping rates as they experimented with the new TAPS tool.

The TAPS experienced several problems that were subsequently corrected. The design has applicability for other installations, but due to market considerations, has not yet been tried again.

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Table 1 - Water Analysis of Producing and Injection Formations

Parameter	Producing Formation	Injection Formation
Specific gravity	1.131	1.094
Total dissolved solids (mg/L)	183,977	131,033
pH	5.75	4.82
Ionic strength	3.557	2.615
Calcium (mg/L)	10,400	9,116
Magnesium (mg/L)	1,944	2,107
Sodium (mg/L)	57,856	38,299
Iron (mg/L)	7.38	78
Barium (mg/L)	no value reported	23.93
Strontium (mg/L)	no value reported	502
Manganese (mg/L)	2.72	14.03
Bicarbonate (mg/L)	37	61
Hydroxide (mg/L)	0	0
Sulfate (mg/L)	1,750	450
Chloride (mg/L)	112,000	81,000
Carbon dioxide gas (ppm)	185	20
Hydrogen sulfide gas (ppm)	0	0

Table 2 - Scale Index (Note: Positive values indicate a tendency for scale formation)

Temperature (°C)	Producing Formation $CaCO_3$ Index	Producing Formation $CaSO_4$ Index	Injection Formation $CaCO_3$ Index	Injection Formation $CaSO_4$ Index
30	-0.79	12.74	-1.91	-16.23
40	-0.53	12.74	-1.70	-16.23
50	-0.22	12.78	-1.42	-15.76
60	0.14	12.70	-1.13	-15.43
70	0.53	12.67	-0.80	-15.35
80	0.96	12.52	-0.42	-15.52

Table 3 - Data from Step Rate Injection Test

Step No.	Time	Surface Tubing Pressure (psig)	Cumulative Volume Injected (bbl)	Injection Rate (bbl/d)	Friction Head Loss (psi)	Corrected Tubing Pressure (psi)	Injection Rate (gpm)
	12:35						
	12:40	42.4	2.4	691.2	8.463	33.9	20.16
	12:45	43.7	4.6	633.6	7.205	36.5	18.48
1	12:50	51.1	6.8	627.8	7.084	44	18.31
	12:55	291.1	11.4	1330.6	28.426	262.7	38.81
	1:00	294.9	16.2	1382.4	30.509	264.4	40.32
2	1:05	287.4	21.4	1505.8	35.738	251.7	43.92
	1:10	417	29	2189.9	71.456	345.5	63.87
	1:15	419.5	36.7	2217.6	73.137	346.4	64.68
3	1:20	441.9	45.1	2422.1	86.1	355.8	70.64
	1:25	516.7	54.7	2761.9	109.773	406.9	80.56
	1:30	513	64.7	2880	118.613	394.4	84
4	1:35	515.5	75	2966.4	125.279	390.2	86.52
	1:40	642.6	88	3744	192.72	449.9	109.2
	1:45	630.1	100.9	3715.2	189.986	440.1	108.36
5	1:50	661.2	113.8	3715.2	189.986	471.2	108.36
	1:55	697.4	128.5	4233.6	241.918	455.5	123.48
	2:00	718.5	142.8	4118.4	229.881	488.6	120.12
6	2:05	743.4	157.9	4348.8	254.237	489.2	126.84
	2:10	849.3	175.5	5068.8	337.543	511.8	147.84
	2:15	844.2	192.9	5011.2	330.481	513.7	146.16
7	2:20	852.9	210	4924.8	320.017	532.9	143.64
	2:25	971.3	230	5760	427.599	543.7	168
	2:30	961.3	249.8	5702.4	419.722	541.6	166.32
8	2:35	993.6	270.4	5932.8	451.633	542	173.04
	2:40	1120.9	292.3	6307.2	505.769	615.1	183.96
	2:45	1112.2	315.9	6796.8	580.789	531.4	198.24
9	2:50	1142.1	337.3	6163.2	484.614	657.5	179.76
	2:55	1279.4	362.5	7257.6	655.725	623.7	211.68
	3:00		400.1				
10	3:05	1349.2	400.1			1349.2	
	3:10	1424.1	428.2	8092.8	802.117	622	236.04
	3:15	1415.3	455.5	7862.4	760.382	654.9	229.32
11	3:20	1447.8	483.5	8064	796.844	651	235.2
	3:25	1562.6	514	8784	933.438	629.2	256.2
	3:30	1533.8	542.9	8323.2	844.874	688.9	242.76
12	3:35	1558.7	572.8	8611.2	899.751	658.9	251.16
Falloff	3:37	795.2				795.2	
	3:38	680.5				680.5	
	3:39	598.3				598.3	
	3:40	580.9				580.9	
	3:45	501.1				501.1	
	3:50	441.2				441.2	

Table 4 - Well Performance Data Before TAPS Installation

Date	Oil to Surface (bbl)	Water to Surface (bbl)	Gas to Surface (mcf)	Total Fluids Produced (bbl)
7/1/98	37	140	4	177
7/2/98	40	170	3	210
7/3/98	37	170	3	207
7/4/98	40	170	3	210
7/5/98	37	170	3	207
7/6/98	40	180	3	220
7/7/98	33	140	3	173
7/8/98	0	50	1	50
7/9/98	0	0	0	0
7/10/98	0	0	0	0
7/11/98	37	220	2	257
7/12/98	47	250	5	297
7/13/98	43	250	5	293
7/14/98	47	230	4	277
7/15/98	37	190	4	227
7/16/98	43	220	4	263
7/17/98	40	200	4	240
7/18/98	43	180	3	223
7/19/98	40	200	4	240
7/20/98	37	180	4	217
7/21/98	43	200	4	243
7/22/98	6	0	2	6
7/23/98	53	190	2	243
7/24/98	40	220	4	260
7/25/98	40	210	3	250
7/26/98	36	200	3	236
7/27/98	40	190	3	230
7/28/98	40	190	3	230
7/29/98	30	180	3	210
7/30/98	40	180	3	220
7/31/98	30	170	3	200
8/1/98	24	180	3	204
8/2/98	40	200	3	240
8/3/98	40	180	3	220
8/4/98	30	160	3	190
8/5/98	37	200	3	237
8/6/98	40	170	3	210
8/7/98	37	180	3	217
8/8/98	33	190	3	223
8/9/98	33	130	3	163
8/10/98	37	240	2	277
8/11/98	33	152	3	185
8/12/98	27	170	3	197
8/13/98	40	204	3	244
8/14/98	27	170	3	197
8/15/98	33	170	3	203
8/16/98	33	190	3	223
8/17/98	33	180	3	213
8/18/98	30	170	3	200

Table 4 - Well Performance Data Before TAPS Installation

Date	Oil to Surface (bbl)	Water to Surface (bbl)	Gas to Surface (mcf)	Total Fluids Produced (bbl)
8/19/98	33	200	3	233
8/20/98	33	180	3	213
8/21/98	33	145	3	178
8/22/98	33	200	3	233
8/23/98	33	110	2	143
8/24/98	30	180	2	210
8/25/98	33	173	2	206
8/26/98	27	170	2	197
8/27/98	31	190	2	221
8/28/98	30	195	2	225
8/29/98	30	170	2	200
8/30/98	27	150	2	177
8/31/98	33	150	2	183
9/1/98	45	111	1	156
9/2/98	30	189	1	219
9/3/98	36	151	1	187
9/4/98	33	73	1	106
9/5/98	33	198	1	231
9/6/98	33	167	1	200
9/7/98	30	153	1	183
9/8/98	8	74	1	82
9/9/98	0	5	1	5
9/10/98	22	213	3	235
9/11/98	30	182	5	212
9/12/98	36	200	3	236
9/13/98	28	144	3	172
9/14/98	28	175	3	203
9/15/98	33	179	3	212
9/16/98	28	184	3	212
9/17/98	33	226	3	259
9/18/98	33	195	3	228
9/19/98	30	182	3	212
9/20/98	33	189	3	222
9/21/98	22	132	3	154
9/22/98	27	179	3	206
9/23/98	25	165	3	190
9/24/98	27	187	3	214
9/25/98	30	179	3	209
9/26/98	33	178	3	211
9/27/98	30	154	3	184
9/28/98	30	173	3	203
9/29/98	30	174	3	204
9/30/98	25	167	3	192
10/1/98	33	187	3	220
10/2/98	30	170	3	200
10/3/98	25	138	3	163
10/4/98	30	195	3	225
10/5/98	28	176	4	204
10/6/98	28	158	3	186

Table 4 - Well Performance Data Before TAPS Installation

Date	Oil to Surface (bbl)	Water to Surface (bbl)	Gas to Surface (mcf)	Total Fluids Produced (bbl)
10/7/98	22	157	3	179
10/8/98	28	186	3	214
10/9/98	30	176	3	206
10/10/98	28	179	3	207
10/11/98	28	165	3	193
10/12/98	28	184	3	212
10/13/98	25	163	3	188
10/14/98	25	158	3	183
10/15/98	30	146	3	176
10/16/98	25	196	3	221
10/17/98	28	183	3	211
10/18/98	28	175	2	203
10/19/98	25	176	2	201
10/20/98	22	178	2	200
10/21/98	14	156	2	170
10/22/98	28	194	2	222
10/23/98	28	185	2	213
10/24/98	25	193	2	218
10/25/98	25	175	2	200
10/26/98	28	201	2	229
10/27/98	22	165	2	187
10/28/98	25	160	2	185
10/29/98	28	193	3	221
10/30/98	22	167	2	189
10/31/98	25	186	3	211
11/1/98	22	180	2	202
11/2/98	28	210	2	238
11/3/98	22	152	2	174
11/4/98	22	228	2	250
11/5/98	27	212	2	239
11/6/98	30	149	2	179
11/7/98	27	187	1	214
11/8/98	22	241	3	263
11/9/98	25	186	2	211
11/10/98	22	174	2	196
11/11/98	22	135	2	157
11/12/98	25	201	2	226
11/13/98	19	154	2	173
11/14/98	22	173	2	195
11/15/98	25	203	3	228
11/16/98	22	173	3	195
11/17/98	22	158	2	180
11/18/98	22	138	2	160
11/19/98	22	247	2	269
11/20/98	22	158	2	180
11/21/98	22	166	2	188
11/22/98	28	183	2	211
11/23/98	19	194	2	213
11/24/98	19	275	2	294

Table 4 - Well Performance Data Before TAPS Installation

Date	Oil to Surface (bbl)	Water to Surface (bbl)	Gas to Surface (mcf)	Total Fluids Produced (bbl)
11/25/98	22	121	2	143
11/26/98	22	173	3	195
11/27/98	25	206	2	231
11/28/98	22	180	3	202
11/29/98	22	163	3	185
11/30/98	22	213	3	235
12/1/98	19	206	2	225
12/2/98	22	148	3	170
12/3/98	22	287	2	309
12/4/98	19	156	2	175
12/5/98	22	189	2	211
12/6/98	22	121	2	143
12/7/98	19	176	2	195
12/8/98	16	163	2	179
12/9/98	22	176	2	198
12/10/98	19	190	2	209
12/11/98	22	182	3	204
12/12/98	19	165	2	184
12/13/98	19	188	3	207
12/14/98	22	158	3	180
12/15/98	0	0	0	0
12/16/98	0	0	0	0
12/17/98	0	0	0	0
12/18/98	36	171	2	207
12/19/98	28	251	2	279
12/20/98	28	202	3	230
12/21/98	25	240	2	265
12/22/98	16	194	2	210
12/23/98	19	180	2	199
12/24/98	22	207	3	229
12/25/98	22	205	3	227
12/26/98	22	197	2	219
12/27/98	22	238	3	260
12/28/98	17	168	2	185
12/29/98	19	178	3	197
12/30/98	13	176	2	189
12/31/98	13	190	2	203

Table 5 - Well Performance Data Following TAPS Installation

Date	Oil to Surface (bbl)	Overall Oil Cut (%)	Oil Cut of Fluids to Surface (%)	Water to Surface (bbl)	Injected Water - Calculated (bbl)	Water Returned to Wellbore (bbl)	Net Water at Surface (bbl)	Total Water Produced (bbl)	Total Fluids Produced (bbl)	Gas to Surface (mcf)	Injection Pressure (psig)
1/20/1999	3	1.7	5.2	55	116		55	171	174	0	
1/21/1999	3	1.9	4.7	61	98		61	159	162	0	
1/22/1999	0	0.0	0.0	63	113		63	176	176	0	
1/23/1999	0	0.0	0.0	58	97		58	155	155	0	
1/24/1999	0	0.0	0.0	52	93		52	145	145	0	
1/25/1999	0	0.0	0.0	58	98		58	156	156	0	
1/26/1999	0	0.0	0.0	56	96		56	152	152	0	
1/27/1999	0	0.0	0.0	56	95		56	151	151	0	
1/28/1999	0	0.0	0.0	53	85		53	138	138	0	
1/29/1999	0	0.0	0.0	55	95		55	150	150	0	
1/30/1999	6	4.5	18.2	27	100		27	127	133	0	
1/31/1999	8	6.0	21.1	30	95		30	125	133	0	
2/1/1999	11	7.2	19.0	47	95		47	142	153	0	
2/2/1999	33	18.9	41.3	47	95		47	142	175	0	
2/3/1999	11	8.0	26.2	31	96		31	127	138	0	
2/4/1999	11	7.7	21.2	41	90		41	131	142	0	
2/5/1999	14	9.5	28.0	36	97		36	133	147	0	
2/6/1999	8	5.8	19.5	33	96		33	129	137	0	
2/7/1999	11	19.0	19.0	47			47	47	58	0	
2/8/1999	11	7.5	21.2	41	94		41	135	146	0	
2/9/1999	11	5.2	22.0	39	163		39	202	213	0	
2/10/1999	14	6.7	21.2	52	143		52	195	209	0	
2/11/1999	19	9.3	29.2	46	139		46	185	204	0	
2/12/1999	14	6.7	18.2	63	131		63	194	208	0	
2/13/1999	14	16.7	16.7	70			70	70	84	0	
2/14/1999	14	7.6	21.9	50	120		50	170	184	0	
2/15/1999	17	8.7	22.7	58	120		58	178	195	0	
2/16/1999	17	9.0	24.6	52	120		52	172	189	0	
2/17/1999	14	7.6	21.9	50	120		50	170	184	0	
2/18/1999	17	8.6	21.8	61	120		61	181	198	0	
2/19/1999	14	7.7	23.0	47	120		47	167	181	0	
2/20/1999	14	7.3	19.4	58	120		58	178	192	0	
2/21/1999	11	5.7	15.1	62	120		62	182	193	0	
2/22/1999	6	2.9	16.2	31	167		31	198	204	0	
2/23/1999	6	3.0	16.7	30	167		30	197	203	0	
2/24/1999	8	3.3	11.1	64	167		64	231	239	0	
2/25/1999	11	4.5	14.5	65	167		65	232	243	0	
2/26/1999	11	4.5	14.5	65	167		65	232	243	0	
2/27/1999	11	4.5	13.9	68	167		68	235	246	0	
2/28/1999	8	3.4	11.3	63	167		63	230	238	0	
3/1/1999	8	3.8	17.4	38	167		38	205	213	0	
3/2/1999	11	5.0	15.1	62	147	70	-8	209	220	0	NA
3/3/1999	11	4.9	13.4	71	142	70	1	213	224	0	NA

Table 5 - Well Performance Data Following TAPS Installation

Date	Oil to Surface (bbl)	Overall Oil Cut (%)	Oil Cut of Fluids to Surface (%)	Water to Surface (bbl)	Injected Water - Calculated (bbl)	Water Returned to Wellbore (bbl)	Net Water at Surface (bbl)	Total Water Produced (bbl)	Total Fluids Produced (bbl)	Gas to Surface (mcf)	Injection Pressure (psig)
3/4/1999	8	3.8	11.8	60	140	70	-10	200	208	0	NA
3/5/1999	14	6.1	16.3	72	142	70	2	214	228	0	NA
3/6/1999	11	5.0	14.5	65	142	70	-5	207	218	0	NA
3/7/1999	11	5.3	14.5	65	132	70	-5	197	208	0	NA
3/8/1999	8	3.9	10.8	66	133	70	-4	199	207	0	NA
3/9/1999	8	4.1	12.5	56	133	70	-14	189	197	0	-474
3/10/1999	11	5.2	14.1	67	135	70	-3	202	213	0	NA
3/11/1999	14	6.3	16.3	72	135	72	0	207	221	0	NA
3/12/1999	11	3.5	13.3	72	231	64	8	303	314	0	NA
3/13/1999	6	2.1	9.4	58	225	52	6	283	289	0	NA
3/14/1999	11	5.3	15.5	60	135	54	6	195	206	0	NA
3/15/1999	14	5.9	17.1	68	155	65	3	223	237	0	NA
3/16/1999	11	6.5	20.4	43	115	54	-11	158	169	0	-567
3/17/1999	5	2.6	6.7	70	119	64	6	189	194	0	NA
3/18/1999	6	2.8	7.4	75	135	67	8	210	216	0	NA
3/19/1999	6	2.9	8.7	63	135	60	3	198	204	0	-778
3/20/1999	5	2.3	6.2	76	135	73	3	211	216	0	NA
3/21/1999	8	3.8	10.4	69	135	69	0	204	212	0	NA
3/22/1999	11	5.1	13.9	68	135	71	-3	203	214	0	-618
3/23/1999	3	1.5	4.2	68	131	71	-3	199	202	0	-295
3/24/1999	6	2.9	8.1	68	135	63	5	203	209	0	NA
3/25/1999	8	5.0	11.6	61	90	64	-3	151	159	0	NA
3/26/1999	6	2.9	8.1	68	135	62	6	203	209	0	NA
3/27/1999	6	2.8	7.7	72	135	72	0	207	213	0	NA
3/28/1999	3	1.4	4.2	69	135	69	0	204	207	0	NA
3/29/1999	5	2.3	6.2	76	135	73	3	211	216	0	NA
3/30/1999	6	2.8	7.8	71	135	71	0	206	212	0	NA
3/31/1999	6	2.7	7.1	78	135	78	0	213	219	0	NA
4/1/1999	8	3.8	10.3	70	135	67	3	205	213	0	-384
4/2/1999	0	0.0	0.0	63	120	0	63	183	183	1	NA
4/3/1999	11	5.5	14.3	66	123	0	66	189	200	1	NA
4/4/1999	14	7.5	21.9	50	123	0	50	173	187	1	-796
4/5/1999	11	5.9	17.2	53	123	0	53	176	187	1	-651
4/6/1999	11	5.9	16.7	55	120	0	55	175	186	1	NA
4/7/1999	6	3.2	8.7	63	118	0	63	181	187	1	NA
4/8/1999	8	4.4	11.8	60	115	0	60	175	183	0	NA
4/9/1999	8	4.1	10.0	72	115	0	72	187	195	0	NA
4/10/1999	8	4.5	12.1	58	113	0	58	171	179	0	NA
4/11/1999	6	3.2	8.3	66	113	0	66	179	185	0	NA
4/12/1999	8	4.3	10.8	66	111	0	66	177	185	0	-609
4/13/1999	6	3.3	8.3	66	111	0	66	177	183	0	NA
4/14/1999	6	3.1	7.2	77	108	0	77	185	191	0	NA
4/15/1999	6	3.3	8.3	66	108	0	66	174	180	0	NA

Table 5 - Well Performance Data Following TAPS Installation

Date	Oil to Surface (bbl)	Overall Oil Cut (%)	Oil Cut of Fluids to Surface (%)	Water to Surface (bbl)	Injected Water - Calculated (bbl)	Water Returned to Wellbore (bbl)	Net Water at Surface (bbl)	Total Water Produced (bbl)	Total Fluids Produced (bbl)	Gas to Surface (mcf)	Injection Pressure (psig)
4/16/1999	6	3.2	7.5	74	106	0	74	180	186	0	NA
4/17/1999	3	1.7	4.0	72	106	0	72	178	181	0	NA
4/18/1999	3	1.7	4.0	72	106	0	72	178	181	0	NA
4/19/1999	6	3.3	7.7	72	106	0	72	178	184	0	-775
4/20/1999	3	1.7	4.2	69	101	0	69	170	173	0	NA
4/21/1999	22	25.9	25.9	63	0	74	-11	63	85	1	NA
4/22/1999	3	3.2	3.2	91	0	80	11	91	94	0	NA
4/23/1999	8	8.6	8.6	85	0	82	3	85	93	0	NA
4/24/1999	0	0.0	0.0	95	0	78	17	95	95	0	NA
4/25/1999	0	0.0	0.0	89	0	75	14	89	89	0	NA
4/26/1999	0	0.0	0.0	91	0	77	14	91	91	0	NA
4/27/1999	0	0.0	0.0	44	0	83	-39	44	44	0	NA
4/28/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
4/29/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
4/30/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/1/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/2/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/3/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/4/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/5/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/6/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/7/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/8/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/9/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/10/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/11/1999	0	0.0	0.0	8	0	85	-77	8	8	0	NA
5/12/1999	0	0.0	0.0	7	0	86	-79	7	7	0	NA
5/13/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
5/14/1999	0	0.0	0.0	52	154	0	52	206	206	0	NA
5/15/1999	0	0.0	0.0	55	132	0	55	187	187	0	NA
5/16/1999	0	0.0	0.0	6	57	0	6	63	63	0	NA
5/17/1999	0	0.0	0.0	14	24	14	0	38	38	0	NA
5/18/1999	0	0.0	0.0	59	79	87	-28	138	138	0	NA
5/19/1999	0	0.0	0.0	85	154	79	6	239	239	0	NA
5/20/1999	0	0.0	0.0	83	161	83	0	244	244	0	NA
5/21/1999	11	3.8	10.4	95	184	92	3	279	290	0	NA
5/22/1999	5	1.9	6.0	78	184	78	0	262	267	0	NA
5/23/1999	8	2.9	8.8	83	184	83	0	267	275	0	NA
5/24/1999	6	2.2	6.8	82	183	82	0	265	271	0	-563
5/25/1999	8	2.9	8.4	87	183	84	3	270	278	0	NA
5/26/1999	5	2.0	6.3	75	174	53	22	249	254	0	NA
5/27/1999	6	2.3	6.1	93	164	60	33	257	263	0	NA
5/28/1999	11	4.2	12.9	74	177	60	14	251	262	1	NA

Table 5 - Well Performance Data Following TAPS Installation

Date	Oil to Surface (bbl)	Overall Oil Cut (%)	Oil Cut of Fluids to Surface (%)	Water to Surface (bbl)	Injected Water - Calculated (bbl)	Water Returned to Wellbore (bbl)	Net Water at Surface (bbl)	Total Water Produced (bbl)	Total Fluids Produced (bbl)	Gas to Surface (mcf)	Injection Pressure (psig)
5/29/1999	8	3.6	16.3	41	171	71	-30	212	220	1	NA
5/30/1999	5	2.7	5.7	83	95	69	14	178	183	0	NA
5/31/1999	11	4.0	12.5	77	184	74	3	261	272	1	NA
6/1/1999	8	2.9	9.1	80	184	80	0	264	272	1	NA
6/2/1999	8	3.0	9.5	76	184	0	76	260	268	0	NA
6/3/1999	12	4.5	14.1	73	183	67	6	256	268	1	NA
6/4/1999	11	4.1	12.6	76	184	65	11	260	271	1	NA
6/5/1999	8	3.0	9.3	78	184	64	14	262	270	0	NA
6/6/1999	8	3.0	10.1	71	184	55	16	255	263	1	NA
6/7/1999	11	4.1	12.6	76	184	65	11	260	271	1	-420
6/8/1999	11	4.1	12.6	76	184	62	14	260	271	1	NA
6/9/1999	11	4.2	14.5	65	184	7	58	249	260	0	NA
6/10/1999	11	4.3	14.1	67	180	75	-8	247	258	1	NA
6/11/1999	8	2.9	9.2	79	184	71	8	263	271	0	-1062
6/12/1999	11	4.1	12.8	75	184	64	11	259	270	0	NA
6/13/1999	8	3.0	9.3	78	184	75	3	262	270	0	NA
6/14/1999	8	3.0	10.1	71	184	63	8	255	263	0	NA
6/15/1999	6	2.3	7.8	71	184	79	-8	255	261	0	NA
6/16/1999	6	2.3	7.8	71	184	71	0	255	261	0	NA
6/17/1999	6	2.3	7.8	71	184	71	0	255	261	1	NA
6/18/1999	14	4.8	13.2	92	184	95	-3	276	290	0	-892
6/19/1999	11	4.1	13.1	73	184	73	0	257	268	0	NA
6/20/1999	11	4.2	14.1	67	184	64	3	251	262	0	NA
6/21/1999	0	0.0	0.0	56	184	48	8	240	240	0	NA
6/22/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
6/23/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
6/24/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
6/25/1999	11	4.1	4.1	256	0	0	256	256	267	0	NA
6/26/1999	8	2.7	2.7	284	0	0	284	284	292	1	NA
6/27/1999	14	4.7	4.7	286	0	0	286	286	300	2	NA
6/28/1999	17	5.9	5.9	273	0	0	273	273	290	2	NA
6/29/1999	19	6.0	6.0	299	0	0	299	299	318	2	NA
6/30/1999	11	5.1	5.1	206	0	0	206	206	217	2	NA
7/1/1999	11	4.6	4.6	228	0	0	228	228	239	1	NA
7/2/1999	8	3.1	3.1	248	0	0	248	248	256	1	NA
7/3/1999	11	5.7	5.7	182	0	0	182	182	193	1	NA
7/4/1999	8	3.5	3.5	221	0	0	221	221	229	1	NA
7/5/1999	8	3.8	3.8	204	0	0	204	204	212	1	NA
7/6/1999	8	3.9	3.9	195	0	0	195	195	203	1	NA
7/7/1999	8	4.0	4.0	193	0	0	193	193	201	1	NA
7/8/1999	11	5.0	5.0	209	0	0	209	209	220	1	NA
7/9/1999	8	4.4	4.4	173	0	0	173	173	181	1	NA
7/10/1999	8	4.1	4.1	188	0	0	188	188	196	1	NA

Table 5 - Well Performance Data Following TAPS Installation

Date	Oil to Surface (bbl)	Overall Oil Cut (%)	Oil Cut of Fluids to Surface (%)	Water to Surface (bbl)	Injected Water - Calculated (bbl)	Water Returned to Wellbore (bbl)	Net Water at Surface (bbl)	Total Water Produced (bbl)	Total Fluids Produced (bbl)	Gas to Surface (mcf)	Injection Pressure (psig)
7/11/1999	8	4.1	4.1	187	0	0	187	187	195	0	NA
7/12/1999	8	4.0	4.0	193	0	0	193	193	201	1	NA
7/13/1999	8	4.3	4.3	179	0	0	179	179	187	1	NA
7/14/1999	8	4.0	4.0	190	0	0	190	190	198	1	NA
7/15/1999	8	3.8	3.8	202	0	0	202	202	210	1	NA
7/16/1999	8	4.1	4.1	185	0	0	185	185	193	0	NA
7/17/1999	8	4.1	4.1	187	0	0	187	187	195	1	NA
7/18/1999	8	4.3	4.3	179	0	0	179	179	187	1	NA
7/19/1999	8	3.7	3.7	208	0	0	208	208	216	1	NA
7/20/1999	8	4.1	4.1	187	0	0	187	187	195	1	NA
7/21/1999	3	4.3	4.3	66	0	0	66	66	69	0	NA
7/22/1999	0	0.0	0.0	0	0	0	0	0	0	0	NA
7/23/1999	3	2.3	4.5	64	65	86	-22	129	132	0	NA
7/24/1999	6	2.5	7.9	70	167	89	-19	237	243	0	-961
7/25/1999	8	3.2	10.3	70	172	78	-8	242	250	1	NA
7/26/1999	6	2.4	7.8	71	172	74	-3	243	249	0	NA
7/27/1999	8	3.3	10.8	66	172	72	-6	238	246	0	-825
7/28/1999	0	0.0	0.0	27	153	63	-36	180	180	0	NA
7/29/1999	3	1.7	4.2	69	107	36	33	176	179	0	NA
7/30/1999	5	2.1	7.0	66	171	74	-8	237	242	1	NA
7/31/1999	6	2.4	7.6	73	171	79	-6	244	250	1	NA
8/1/1999	3	1.3	4.5	64	171	69	-5	235	238	1	NA
8/2/1999	5	2.1	6.7	70	165	70	0	235	240	1	NA
8/3/1999	6	2.6	7.3	76	147	54	22	223	229	0	NA
8/4/1999	5	1.9	5.6	85	171	58	27	256	261	1	NA
8/5/1999	6	2.2	6.1	92	172	59	33	264	270	1	NA
8/6/1999	5	1.9	5.4	88	172	77	11	260	265	0	NA
8/7/1999	8	3.0	8.2	89	172	67	22	261	269	1	NA
8/8/1999	8	3.1	9.0	81	165	59	22	246	254	1	-947
8/9/1999	3	1.3	4.0	72	159	64	8	231	234	2	NA
8/10/1999	6	2.5	7.1	78	158	64	14	236	242	2	-1019
8/11/1999	5	2.0	5.6	85	158	68	17	243	248	1	NA
8/12/1999	3	1.3	4.5	63	158	57	6	221	224	1	NA
8/13/1999	8	3.3	9.8	74	163	74	0	237	245	0	NA
8/14/1999	6	2.4	7.0	80	161	75	5	241	247	1	NA
8/15/1999	5	2.1	7.0	66	163	69	-3	229	234	0	NA
8/16/1999	3	1.3	4.0	72	158	66	6	230	233	1	NA
8/17/1999	3	1.3	4.0	72	158	67	5	230	233	1	NA
8/18/1999	3	1.3	4.2	69	154	66	3	223	226	1	NA
8/19/1999	3	1.2	3.3	89	168	103	-14	257	260	0	NA
8/20/1999	2	0.8	2.4	81	165	78	3	246	248	0	NA
8/21/1999	6	2.6	8.0	69	152	66	3	221	227	1	-972
8/22/1999	3	1.4	4.5	64	151	64	0	215	218	1	NA

Table 5 - Well Performance Data Following TAPS Installation

Date	Oil to Surface (bbl)	Overall Oil Cut (%)	Oil Cut of Fluids to Surface (%)	Water to Surface (bbl)	Injected Water - Calculated (bbl)	Water Returned to Wellbore (bbl)	Net Water at Surface (bbl)	Total Water Produced (bbl)	Total Fluids Produced (bbl)	Gas to Surface (mcf)	Injection Pressure (psig)
8/23/1999	3	1.4	4.3	67	151	64	3	218	221	0	NA
8/24/1999	11	4.5	13.9	68	163	62	6	231	242	1	NA
8/25/1999	3	1.4	4.6	62	155	59	3	217	220	0	NA
8/26/1999	2	0.9	2.7	72	155	66	6	227	229	1	NA
8/27/1999	3	1.4	4.5	63	155	60	3	218	221	1	NA
8/28/1999	3	1.3	3.8	76	154	71	5	230	233	0	NA
8/29/1999	0	0.0	0.0	76	153	70	6	229	229	1	NA
8/30/1999	0	0.0	0.0	76	153	70	6	229	229	0	NA

Table 6 - Pump Data Following TAPS Installation

Date	Daily High Pump Load (lb)	Daily Low Pump Load (lb)	Run Time (hours)	Load on Standing Valve Check (lb)	Estimated Injection Pump Volume (%)	Fluid Level Above Pump (feet)	Calculated Formation Injection Pressure (psi)	Calculated Surface Injection Pressure (psi)	Pump Intake Pressure (psi)
3/2/99	15,841	8,304	24.0		60%	1,152			
3/3/99			24.0		58%	1,225			
3/4/99			24.0		57%	1,060			
3/5/99	16,026	8,424	24.0		58%	1,205			
3/6/99	16,008	8,725	24.0		58%				
3/7/99	15,933	8,716	23.5		55%				
3/8/99	16,116	8,350	24.0		54%				
3/9/99	15,919	8,578	24.0	10,100	54%	1,282	2053	-474	459
3/10/99	15,877	8,643	24.0		55%				
3/11/99	15,823	8,862	24.0		55%				
3/12/99	16,117	8,479	24.0		55%				
3/13/99	15,825	8,871	24.0		55%				
3/14/99	15,490	8,962	24.0		55%				
3/15/99			24.0		63%	1,424			498
3/16/99	16,105	9,355	21.1	10,300	53%	967	1960	-567	331
3/17/99	16,242	8,982	22.0		53%	1,046			358
3/18/99	16,174	9,109	24.0		55%				
3/19/99	16,411	8,808	24.0	10,150	55%		1749	-778	864
3/20/99	16,204	8,862	24.0		55%				
3/21/99	16,170	9,000	24.0		55%				
3/22/99	16,202	8,817	24.0	10,960	55%		1909	-618	
3/23/99	16,294	8,899	23.3	10,100	55%	932	2232	-295	337
3/24/99	16,212	8,881	24.0		55%				
3/25/99	16,008	9,118	16.0		55%				
3/26/99	16,317	9,256	24.0		55%				
3/27/99	16,155	9,082	24.0		55%				
3/28/99	16,336	9,036	24.0		55%				
3/29/99	16,204	8,899	24.0		55%				
3/30/99	16,299	8,899	24.0		55%				
3/31/99	16,237	8,799	24.0		55%				
4/1/99			24.0	10,100	55%	1,029	2143	-384	373
4/2/99	16,642	9,219	23.5		50%				

Table 6 - Pump Data Following TAPS Installation

Date	Daily High Pump Load (lb)	Daily Low Pump Load (lb)	Run Time (hours)	Load on Standing Valve Check (lb)	Estimated Injection Pump Volume (%)	Fluid Level Above Pump (feet)	Calculated Formation Injection Pressure (psi)	Calculated Surface Injection Pressure (psi)	Pump Intake Pressure (psi)
4/3/99	16,828	9,393	24.0		50%				
4/4/99	16,776	9,595	24.0	11,133	50%		1731	-796	
4/5/99	16,738	9,757	24.0	10,960	50%		1876	-651	402
4/6/99	16,642	9,595	24.0		49%				
4/7/99	16,734	9,768	24.0		48%				
4/8/99	16,593	9,764	24.0		47%				
4/9/99	16,774	9,841	24.0		47%				
4/10/99	16,828	9,934	24.0		46%				
4/11/99	16,282	9,283	24.0		46%				
4/12/99	16,537	9,841	24.0	11,000	45%	1,640	1918	-609	566
4/13/99	16,864	9,933	24.0		45%				
4/14/99	16,920	10,006	24.0		44%				
4/15/99	16,537	9,841	24.0		44%				
4/16/99	17,137	10,069	24.0		43%	2,781			698
4/17/99	17,103	10,060	24.0		43%				
4/18/99	17,083	9,969	24.0		43%				
4/19/99	17,047	9,886	24.0	11,350	43%		1752	-775	
4/20/99	17,083	9,850	24.0		41%				716
4/21/99	16,222	9,319	24.0						
4/22/99	15,909	8,853	24.0						
4/23/99	16,189	8,871	24.0						
4/24/99	15,789	8,817	24.0						
4/25/99	15,697	8,670	24.0						
4/26/99	15,585	8,652	24.0						
4/27/99	15,436	8,514	16.8						
4/28/99	15,436	8,514	0.0						
4/29/99			0.0						
4/30/99									
5/1/99									
5/2/99			0.0						
5/3/99			0.0						
5/4/99			0.0						

Table 6 - Pump Data Following TAPS Installation

Date	Daily High Pump Load (lb)	Daily Low Pump Load (lb)	Run Time (hours)	Load on Standing Valve Check (lb)	Estimated Injection Pump Volume (%)	Fluid Level Above Pump (feet)	Calculated Formation Injection Pressure (psi)	Calculated Surface Injection Pressure (psi)	Pump Intake Pressure (psi)
5/5/99			0.0						
5/6/99			0.0						
5/7/99			0.0						
5/8/99			0.0						
5/9/99			0.0						
5/10/99			0.0						
5/11/99	13,417	7,675	8.2						
5/12/99	15,051	7,324	23.8						
5/13/99	13,971	7,261	24.0						
5/14/99	17,140	8,175	20.0		75%	1,612			557
5/15/99	18,768	8,038	17.2		75%				
5/16/99	14,264	6,882	7.5		75%				
5/17/99	15,802	8,232	3.1		75%	1,845			645
5/18/99	15,673	8,194	10.3		75%	2,222			760
5/19/99	16,152	8,314	20.0		75%	1,633			560
5/20/99	16,551	8,349	21.0		75%	1,457			500
5/21/99	17,286	8,140	24.0		75%				
5/22/99	16,975	8,551	24.0		75%				
5/23/99	17,304	8,460	24.0		75%				
5/24/99	17,250	8,515	23.9	10,500	75%	1,212	1964	-563	357
5/25/99	17,340	8,634	23.9		75%				
5/26/99	17,341	8,487	22.7		75%				
5/27/99	17,415	8,605	21.4		75%				
5/28/99	17,506	8,614	23.1		75%				
5/29/99	14,524	7,690	22.3		75%				
5/30/99	16,552	8,148	12.4		75%				
5/31/99	16,647	8,185	24.0		75%				
6/1/99	18,054	8,661	24.0		75%				
6/2/99	17,140	8,406	24.0		75%				
6/3/99	17,980	8,752	23.9		75%				
6/4/99	17,890	8,799	24.0		75%				
6/5/99	17,980	8,761	24.0		75%				

Table 6 - Pump Data Following TAPS Installation

Date	Daily High Pump Load (lb)	Daily Low Pump Load (lb)	Run Time (hours)	Load on Standing Valve Check (lb)	Estimated Injection Pump Volume (%)	Fluid Level Above Pump (feet)	Calculated Formation Injection Pressure (psi)	Calculated Surface Injection Pressure (psi)	Pump Intake Pressure (psi)
6/6/99	17,451	8,560	24.0		75%				
6/7/99	17,065	8,460	24.0	10,200	75%	815	2107	-420	315
6/8/99	17,890	8,506	24.0		75%				
6/9/99	17,632	8,661	24.0		75%				
6/10/99	18,091	8,790	23.5		75%				
6/11/99	18,019	8,917	24.0	11,829	75%		1465	-1062	
6/12/99	18,073	8,935	24.0		75%				
6/13/99	17,964	9,036	24.0		75%				
6/14/99	18,091	9,027	24.0		75%				
6/15/99	18,037	8,899	24.0		75%				
6/16/99	18,037	8,899	24.0		75%				
6/17/99	18,073	8,935	24.0		75%				
6/18/99	17,964	8,716	24.0	11,458	75%		1635	-892	
6/19/99	17,826	8,817	24.0		75%				
6/20/99	17,400	8,023	24.0		75%				
6/21/99	16,834	7,851	24.0		75%				
6/22/99	0	0	0.0		0%				
6/23/99	0	0	0.0		0%				
6/24/99	0		0.0		0%				
6/25/99			9.3						
6/26/99			24.0						
6/27/99			24.0						
6/28/99			24.0						
6/29/99			22.3						
6/30/99			19.7						
7/1/99			18.4						
7/2/99			17.9						
7/3/99			17.5						
7/4/99			17.3						
7/5/99			17.0						
7/6/99			16.7						
7/7/99			16.4						

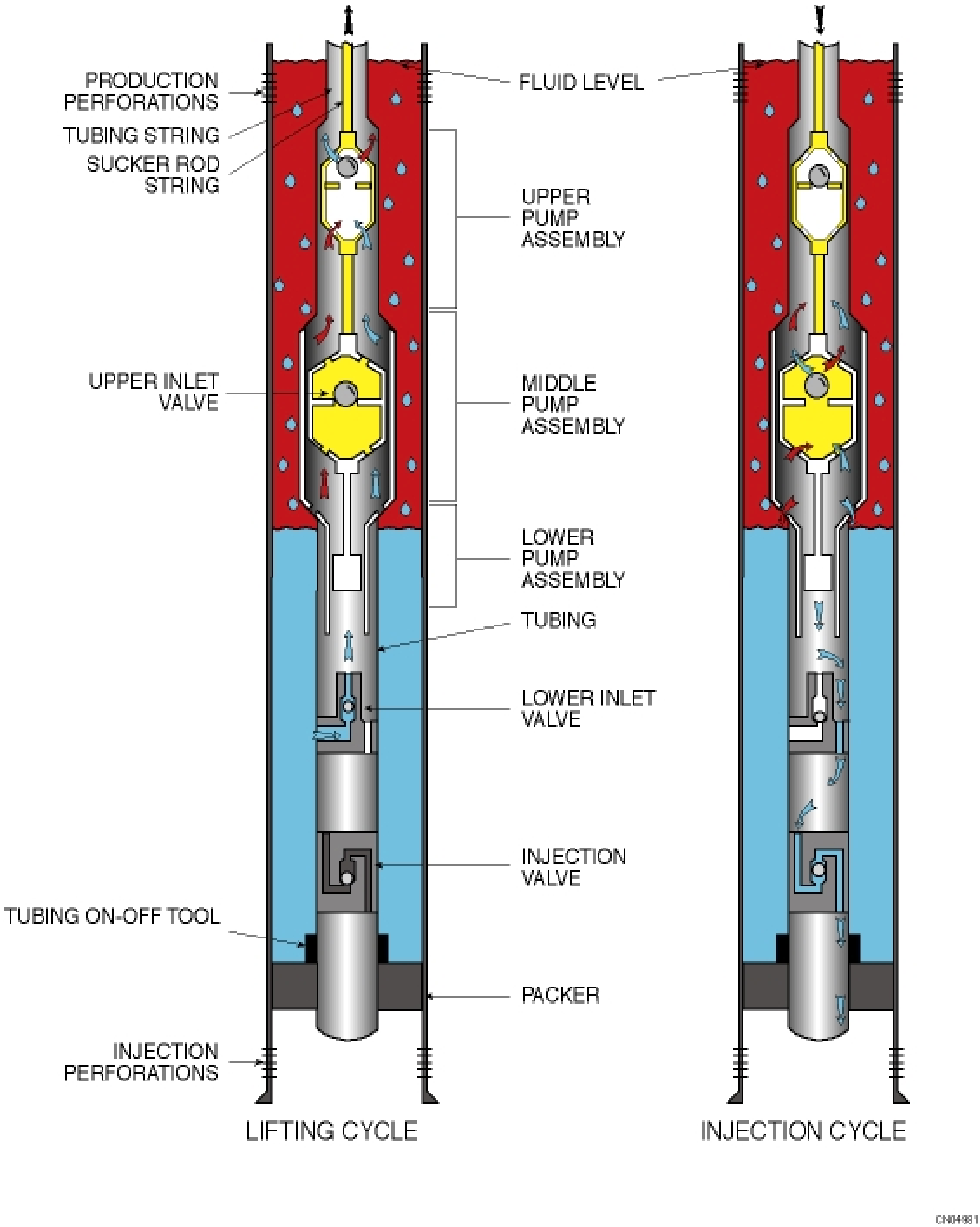
Table 6 - Pump Data Following TAPS Installation

Date	Daily High Pump Load (lb)	Daily Low Pump Load (lb)	Run Time (hours)	Load on Standing Valve Check (lb)	Estimated Injection Pump Volume (%)	Fluid Level Above Pump (feet)	Calculated Formation Injection Pressure (psi)	Calculated Surface Injection Pressure (psi)	Pump Intake Pressure (psi)
7/8/99			16.2						
7/9/99			16.1						
7/10/99			16.1						
7/11/99			15.5						
7/12/99			15.5						
7/13/99			15.2						
7/14/99			16.1						
7/15/99			15.7						
7/16/99			15.5						
7/17/99			15.4						
7/18/99			15.7						
7/19/99			15.7						
7/20/99			15.9						
7/21/99			14.2						
7/22/99			0.0						
7/23/99	17,967	8,664	9.1		70%				
7/24/99	17,419	8,728	23.3	11,674	70%		1566	-961	
7/25/99	17,674	8,746	24.0		70%				
7/26/99	17,820	8,910	24.0		70%				
7/27/99	17,694	8,983	24.0	11,382	70%		1702	-825	
7/28/99	17,202	8,947	21.3		70%				
7/29/99	17,436	8,782	15.0		70%				
7/30/99	17,500	8,800	23.9		70%				
7/31/99	17,493	9,046	23.8		70%				
8/1/99	17,602	9,066	23.8		70%				
8/2/99	17,875	8,938	23.0		70%				
8/3/99	18,786	8,491	20.5		70%				
8/4/99	19,389	8,527	23.9		70%				
8/5/99	19,333	8,635	24.0		70%				
8/6/99	19,534	8,719	24.0		70%				
8/7/99	19,771	8,683	24.0		70%				
8/8/99	19,534	8,655	23.1	11,630	70%		1580	-947	

Table 6 - Pump Data Following TAPS Installation

Date	Daily High Pump Load (lb)	Daily Low Pump Load (lb)	Run Time (hours)	Load on Standing Valve Check (lb)	Estimated Injection Pump Volume (%)	Fluid Level Above Pump (feet)	Calculated Formation Injection Pressure (psi)	Calculated Surface Injection Pressure (psi)	Pump Intake Pressure (psi)
8/9/99	19,588	8,856	22.2		70%				
8/10/99	19,461	8,773	22.1	11,790	70%	4	1508	-1019	
8/11/99	19,843	8,610	22.1		70%				
8/12/99	19,773	8,365	22.1		70%				
8/13/99	19,588	8,710	22.7		70%				
8/14/99	19,500	8,856	22.5		70%				
8/15/99	19,350	8,784	22.7		70%				
8/16/99	19,168	9,084	22.1		70%				
8/17/99	19,315	8,920	22.0		70%				
8/18/99	19,278	8,920	21.5		70%				
8/19/99	19,279	9,030	23.4		70%				
8/20/99	19,278	9,019	23.0		70%				
8/21/99	19,315	8,920	21.2	11,692	70%		1555	-972	
8/22/99	19,332	8,865	21.1		70%				
8/23/99	19,315	8,875	21.1		70%				
8/24/99	19,371	8,802	21.3		70%				
8/25/99	19,186	8,974	21.7		70%				
8/26/99	19,098	9,093	21.6		70%				
8/27/99	19,134	9,098	21.6		70%				
8/28/99	19,098	9,093	21.5		70%				
8/29/99	18,897	9,102	21.3		70%				
8/30/99	18,897	9,102	21.3		70%				

Figure 1 - Diagram of TAPS



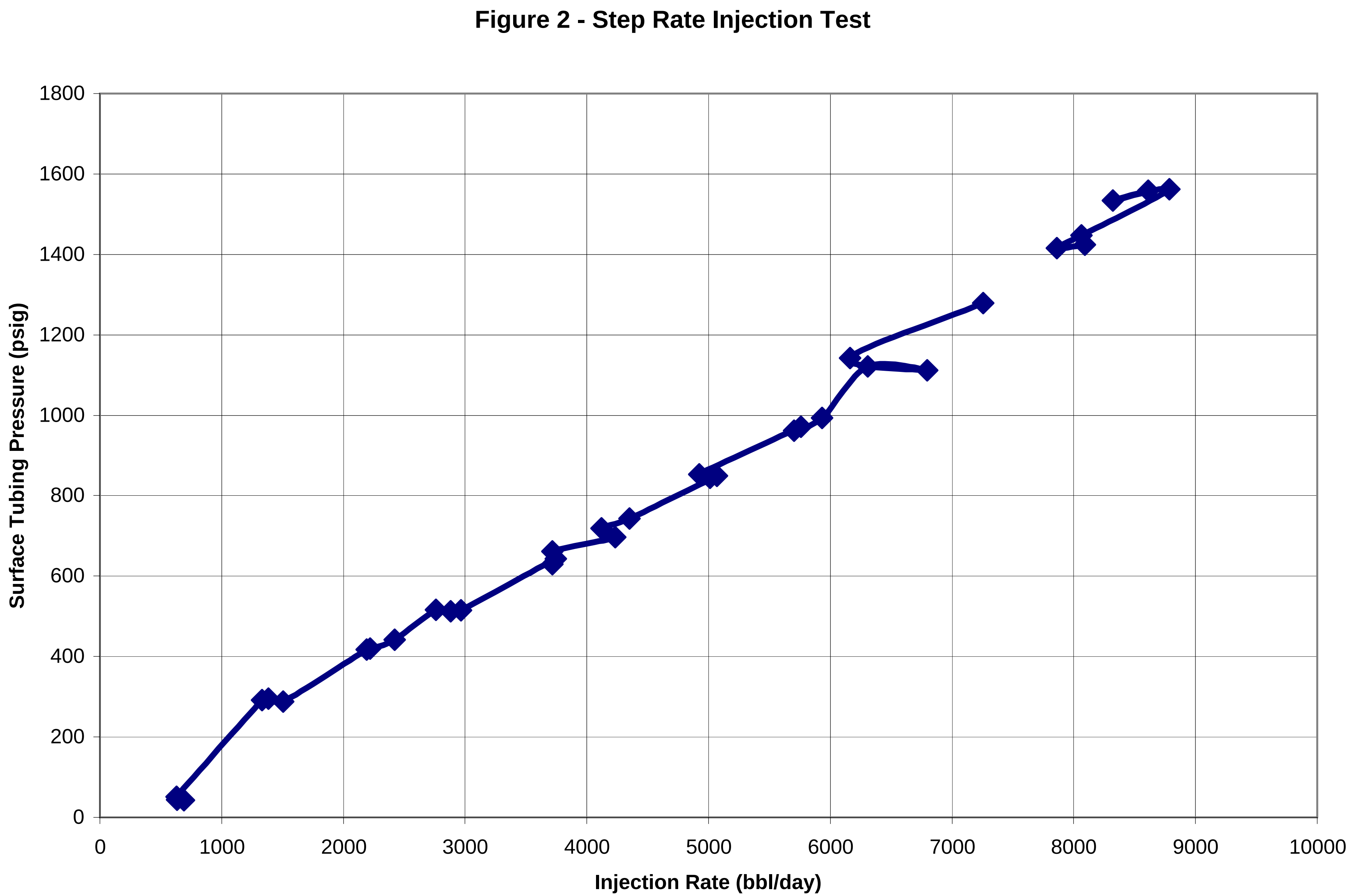
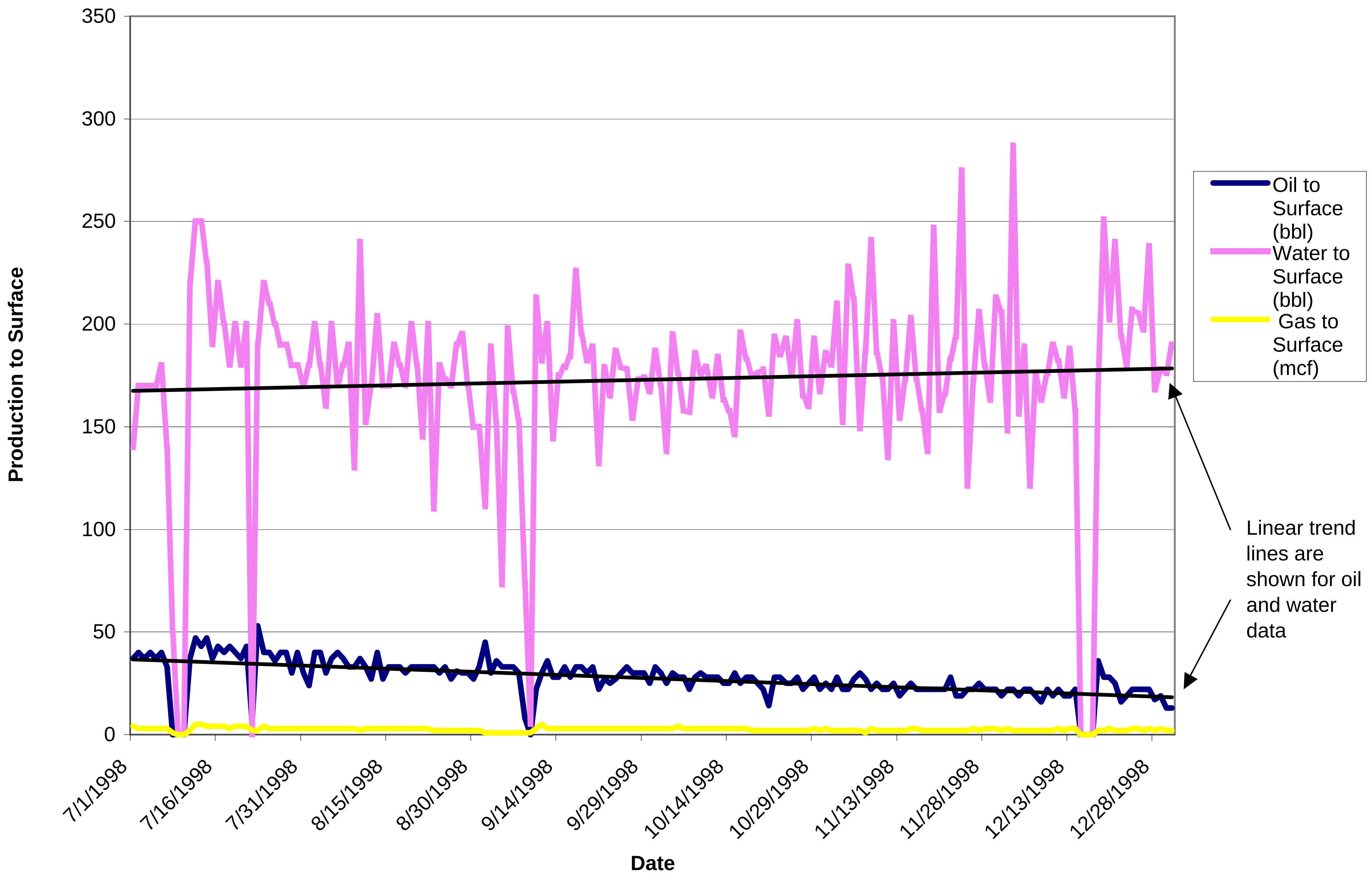


Figure 2 - Step Rate Injection Test
Surface Tubing Pressure (psig)
0
200
400
600
800
1000
1200
1400
1600
1800
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
Injection Rate (bbl/day)

Figure 3 - Well Performance Before TAPS Installation



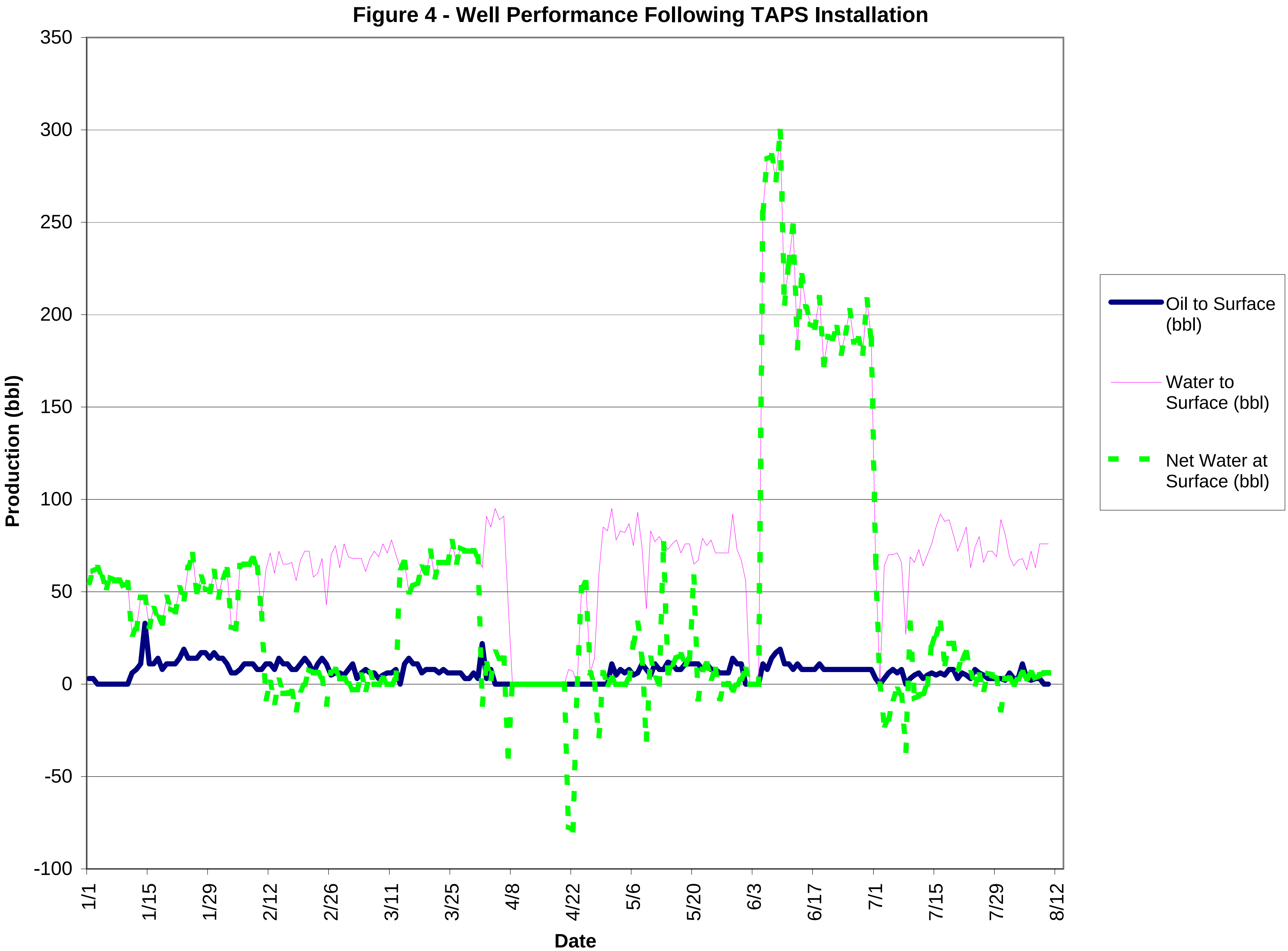


Figure 4 - Well Performance Following TAPS Installation
Production (bbl)
350
300
250
200
150
100
50
0
-50
-100
1/1
1/15
1/29
2/12
2/26
3/11
3/25
4/8
4/22
5/6
5/20
6/3
6/17
7/1
7/15
7/29
8/12
Date
Oil to Surface (bbl)
Water to Surface (bbl)
Net Water at Surface (bbl)

Figure 5 - Oil Production Following TAPS Installation

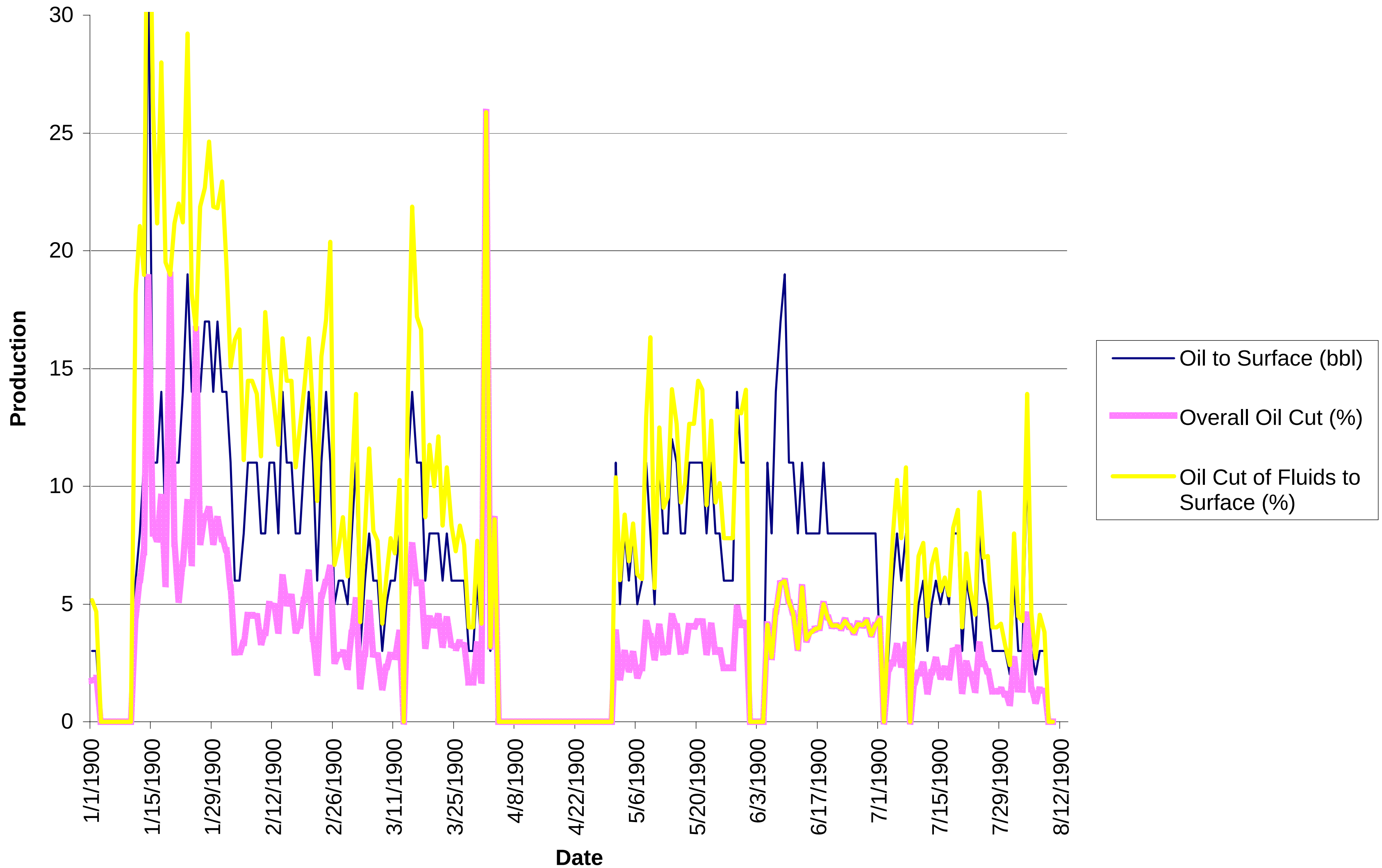


Figure 6 - Total Fluid Production Following TAPS Installation