ARTIFICIAL LIFT PRACTICES IN A HOSTILE ENVIROMENT – POSTLE FIELD CO_2 FLOOD

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ABSTRACT
When evaluating artificial lift in a CO_2 flood, certain factors must be taken into special consideration. This statement is especially true if the reservoir is a sandstone without H_2S. Such conditions exist at Postle Field in the panhandle of Oklahoma, making it a field of unique nature. Under normal considerations, when CO_2 is injected, it mixes with water and produces a weak carbonic acid. If the reservoir is a carbonate, the rock will buffer the acid. If H_2S gas is present, it also offers benefit and provides further buffer to the acid. At Postle Field, however, neither is present. This field produces out of the Upper Morrow Sandstone which contains no carbonic cementation. In addition, it is an extremely corrosive field, which makes artificial lift very complex and dangerous. Postle Field has a robust number of wells that have either been lost or in danger of being lost, due to problems created by corrosion. This paper will discuss what is taken into consideration when designing artificial lift for the corrosive nature of Postle Field.

INTRODUCTION

Postle History

Postle is located in the panhandle of Oklahoma in Texas County. The field was originally discovered in 1958 and operated by Mobil. The field has been produced from continuously since the initial discovery. The waterflood was initiated in 1966. In 1970, Postle reached its peak production of 24,957 BOPD. By the end of the waterflood the production rate had decreased to 1,647 BOPD. In 1995, the first phases of the CO_2 flood were implemented. In 2000, the Mobil operated CO_2 flood reached its highest production of 7,551 BOPD. Four years later, the field had declined down to a rate of 3,795 BOPD. At this time Postle was sold to Celero Energy; who sold the field to Whiting Petroleum shortly afterwards in 2005. Whiting has drilled over 100 wells and executed numerous workovers since 2005 to optimize the field. Whiting has also implemented first-class reservoir management to achieve phenomenal production response. In 2009, Postle was presented with the Oil and Gas Investor's Best Field Rejuvenation 2008 award. In March of 2010, the Postle CO_2 flood reached another milestone; an average production of 10,064 BOPD for the month. This was an increase of 265% from where it was when ExxonMobil sold the field.

Reservoir Overview

Postle produces out of the Upper Morrow Sandstone at a depth of 6,100 feet. The average thickness of the net pay is 28 feet. The average porosity is 16%, ranging between 11% and 23%. The average permeability is 20-112 mD, ranging anywhere from 1to over 2000 mD. The initial oil saturation of the reservoir was 65-85% and the reservoir temperature is 140°F. The initial pressure of the reservoir was 1,630 psi. The current reservoir pressure ranges from zero to 4,500 psi. The minimum miscibility pressure (MMP) is 2,100 psi. The oil gravity ranges from 40-44°API. The Postle area is 26,000 acres, with most wells on 40 acre spacing. Cumulative oil production to date is 118 MMBO of the estimated 300 MMBO of OOIP (39.3%).

Basics of CO_2 Flooding

Why inject CO_2? CO_2 is miscible with oil while in a supercritical state, meaning the oil will dissolve in the CO_2. In layman's terms, the CO_2 acts as a soap, and cleans the rock of the oil. The oil then becomes mobile and is able to be pushed through the reservoir into the production equipment and to the surface. Proper pressures must be achieved while injecting to attain the supercritical state. At Postle WAG (water alternating gas) injection is used. Water is used to alternate with the CO_2 to create a more uniform flow through the reservoir. It is key not to forget that the reservoir pressure must be maintained above the MMP while injecting water as well. When the CO_2 moves through the reservoir it is constantly mixing with reservoir water and injected water. When CO_2 is mixed with water, carbonic acid is formed.

Corrosion

The drawback to CO_2 flooding is the corrosion caused by carbonic acid. In a carbonate reservoir the lime buffers the acid. H_2S can also be an additional buffer to the acid. In the Postle Upper Morrow Sandstone neither is present. Because of these conditions, Postle has earned a reputation of being one of the most corrosive CO_2 floods. During the beginning phases of CO_2 flooding the corrosive nature of the field was greatly underestimated. Non stainless steel and non-coated metals would not last more that six weeks after CO_2 breakthrough occurred. (Examples of corrosion at Postle can be seen in figures 1-1 through 1-4). Sometimes assumptions were made during the beginning stages of the CO_2 flood come back to haunt us today. Countless rod pumps, ESPs, packers, and tubing joints have been lost down hole, and limit what we can do while optimizing a well. Severe casing corrosion has caused thousands of feet of liner material to be run as well. Liner sizes in mature wells range from 2-7/8" to 4-1/2". In newer wells, liner sizes are 4-1/2" and 5-1/2". These restrictions in hole diameter make it very difficult to run needed equipment. To make matters worse, the combination of losing equipment down hole and small hole diameter make it difficult to fish lost equipment out. Due to the conditions at Postle the number one rule is; if the well will flow, let it flow.

ROD PUMPING

Artificial lift by means of rod pump is not favored in areas that are still actively injecting large volumes of CO_2. Rod pumps are primarily used in areas that inject little to no CO_2, or where it is assumed CO_2 will never travel through the reservoir in large volumes. If CO_2 breakthrough occurs in these areas at large volumes, and is not caught soon enough rods will corrode and part in a very short time. Well testing and communication with lease operators becomes crucial in this situation. Painting the rods can delay the effects of carbonic acid. This is an inexpensive and simple application that can save large amounts of time and money. Although, there are occasions where it is impossible to either prevent or delay the corrosion.

An example of such a complication involving rod pumping is as follows. A well in a very young and active area of the CO_2 flood was drilled in June 2007. A rod pump was initially installed. The well produced anywhere from 0 to 10 MCFPD of CO_2 for 16 months. On the 17^{th} month the well produced 35 MCFPD of CO_2. One month later the rods parted at only 50 MCFPD of CO_2 being produced, a relatively low volume of CO_2 at Postle (see attached production plot, figure 2-1). An extensive fishing job commenced at this point. (Pictures of equipment that were fished are attached, figures 2-2 through 2-5). Because of high costs and little progress, the work came to a halt. Over 450 feet of rods, tubing, and the tubing anchor left down hole. We decided to set a packer above the lost equipment to let the CO_2, over time, eat away the equipment left down-hole. This was not successful. The perforations were completely plugged off due to the combination of equipment left down hole and the large amounts of calcium carbonate used to maintain well control while working on the well. Eight months later a new plan was devised. The fishing/milling commenced in late 2009, and lasted a month-and-a-half. The job was successful. Although the well was not completely lost, nine months of oil production was. At the time the pump failed, the well produced 40 BOPD and trending rapidly upward. Assuming the well would have maintained at least a production rate of 40 BOPD, 11,000 BO were lost during the nine months the well was down.

Other limitations to rod pumping are the restrictions in casing size. As stated before, there are many small liners at Postle, especially in older wells that require lift. Currently mature wells that were once flowing are starting to decline. We cannot run a large enough pump in the small liners to get the fluid low enough to prevent corrosion on the casing. To overcome this operational concern we are running a larger pump that sets above the liner in seven inch casing, with fiberglass tailpipe down to below the perforations. By doing this we will be able to lower the fluid level and prevent most gas-locking.

Today pumping units are only used in mature areas where small volumes of CO_2 are produced. There are some areas that are mature and still produce very large volumes of CO_2, but little oil. An economical and safe way needs to be proven to lift more oil out of these wells. We are currently evaluating using gas separators with our pumping units. The major disadvantage to this is that the outside of our tubing will not be protected from corrosive fluids in the annulus. Currently, tests are taking place with tubing that has an anti-corrosive coating applied to the inside and outside of the tubular. Such tests are being administered in wells that are flowing. Due to the fact that our flowing wells only have a packer, if the tubing corrodes and parts it will be easier to fish the equipment out. Although the outside of the tubing will not be exposed to the corrosive fluids, the inside will be. Because it is the same coating on both sides, this test will be sufficient. Although rod pumping might not consistently prove the most convenient of methods, due to areas becoming more mature rod pumping is becoming an increasing necessity at the Postle. Wells must be individually evaluated to decide what application will not only work, but be safe in the sense of not potentially losing the well to a failed fishing excavation.

ELECTRICAL SUBMERSIBLE PUMPS

ESPs are primarily used at Postle in wells where CO_2 has not yet broken through. Before CO_2 can be injected, the reservoir pressure must be increased if proper pressure maintenance was not executed during the waterflood; and/or if the reservoir pressure is below the MMP. This requires large amounts of water prior to the injection of CO_2. For the CO_2 to be able to be processed, the water must be moved. ESPs are superior to rod pumping in this application. ESPs move more volume, so they are able to process the reservoir faster. Once the CO_2 shows up in the production, the ESP is pulled and the well is converted to flow.

There are four units at Postle. When Whiting acquired the field, two units had been exposed to CO_2. One unit had been partially exposed to CO_2, while the fourth unit had never been injected with CO_2. ESPs were run in almost every producing well as CO_2 was first being injected into this unit. Two design errors were committed, costing us valuable time and money. Many wells used bare 2-7/8" tubing and the pumps were generally sized too large. The pumps were sized for a pump intake pressure (PIP) of 600-800 psi. This is not only well below the supercritical state of CO_2, but CO_2 is also a gas at this pressure. The efficiency of the ESPs became greatly hindered by this. When the CO_2 is in a gaseous form it also causes more corrosion, because it causes more surface area to be exposed to carbonic acid for a longer period of time. In most fields this might not serve as a considerable issue. We currently size the pumps for a PIP at 1450 psi. By increasing the PIP, the pump is not only more efficient, but the CO_2 is more efficient in the reservoir near the wellbore. This application was used on a well that produced with an ESP at very low pressures, sometimes too low for the well to even enter our production facilities (see attached production plot, figure 3-1). A variable speed drive (VSD) was put on location, and the pump was slowed down to the slowest possible speed. As can be seen by the attached production plot, when the VSD was slowed down enough to increase the PIP above 1400 psi; the total fluid production decreased but more oil was produced. This was cheaper and inexpensive than trading out the pump for a smaller one. Another way to increase the PIP and protect the tubing from corrosion is to run 2-3/8" internal plastic coated (IPC) tubing opposed to bare 2-7/8" tubing. This also provides further benefit; when the well is converted to flow the IPC tubing will be used when the packer is installed. When bare tubing was run, the entire tubing string had to be traded out when the packer was installed.

ESPs that were not operated ideally at Postle lead to long and expensive work. Pumps that were not sized correctly had to be pulled the instant CO_2 hit the producing well due to failures caused by corrosion. Some were lost down hole, and were unable to be fished. Usually some small amount of CO_2 moves faster through the reservoir, ahead of the main CO_2 bank. When this happened the ESPs still had to be pulled due to corrosion, but were not yet ready to flow. An ESP would have to be ran back in, which allowed us to correct our mistakes. When we started to operate the ESPs properly, we got better production responses, and had a much lower failure rate.

Looking towards the future of Postle, we will have to lift mature wells economically. Because ESPs are very expensive to maintain, we currently do not run them in mature wells until absolutely necessary. Mature wells usually produce lower volumes of oil, have a very high gas-liquid-ratio (GLR), and have small liners. Under the previous operator, encapsulated ESPs were run. An encapsulated ESP is a pump that hangs in a large piece of tubing that is connected to a permanent packer. All fluid flows through the packer, and is forced into the ESP. The annulus is filled with packer fluid. These cut down on corrosion significantly. The only drawback was that if the equipment failed or parted, it led to an expensive workover. With improved metallurgies over the years, this application is being revisited. Another application for ESPs being brought back into play is gas separators. They were once used at Postle, but quickly abandoned. Every gas separator that was installed at Postle failed when the separator body either before or while the sub was pulled out. The manufacturers claim they have made improvements in the metallurgies of the separators. Soon, one will be installed in a mature producing well as a test.

"POOR-BOY" GAS LIFT

Our poor-boy gas lift is the pride and joy of Postle. The poor-boy gas lift is a stainless steel capillary string (3/8"-3/4") with a check valve ran to a depth of 4,500 feet in the IPC tubing. A CO_2 supply is run to the wellhead from the closest supply line or injector, usually ¼ mile away (see attached picture of assembly at the wellhead, figure 4-1 & 4-2). Anywhere from 100 to 300 MCFPD is injected through the capillary string, which helps lift fluid to the surface. The average gas lift uses 120 MCFPD at Postle. This is an inexpensive and low risk way to lift fluid to the surface. There is no corrosion involved with this process. The gas used is instantly produced, recycled and reinjected throughout the field. Therefore, no CO_2 is wasted.

The guidelines while evaluating a well for gas lift is to only install them on wells that produce less than 250 MCFPD and the fluid level must be within 1,000 feet of the surface. It has been observed that wells that already produce 250 MCFPD of gas will not benefit from the additional 120 MCFPD. The exception is if a well produces a very large volume of water, then a larger capillary string is run. It has been attempted to find a more definitive GLR guideline for running a gas lift. This has not been successful. Wells that have almost identical production plots do not react the same way to gas lifts. Surrounding injection plays a major role into the reasoning why a well will act the way it does, making it very difficult to estimate the way a well will respond to gas lift.

Gas lift is used on some wells prior to CO_2 breakthrough. An example of this application is as follows. A well was already flowing a high rate of oil and water, but no CO_2. Because the well was flowing large volumes, we knew the CO_2 bank was close. A gas lift was installed, and oil production increased by 50% instantly and leveled out to a 30% increase. The gas lift aided the well by lifting more water, allowing the CO_2 to breakthrough (see attached production plot, figure 4-3).

Another advantageous use for gas lift is when there is "trash" in the hole. There are many wells with lost equipment in them. Also, most older wells have already been sidetracked; although this is mainly due to bad casing. At this point, economical options are slim to none. In the rod pumping example mentioned earlier, we tried to flow the well with equipment down hole and were unable to. Most wells are able to flow with lost equipment in the hole. Over time these wells will decline and need artificial lift but we are often unable to pump above the lost equipment. There is too high of a risk of pieces breaking off the lost equipment and creating operational concerns with a pump. Instead, we are able to run a capillary string to just above where the lost equipment sets. We were able to do this in a well that had dramatically declined after the equipment had been lost some years ago. Even though the well slowly started to incline, due to injection changes in surrounding wells, we were able to increase the rate even more with a gas lift (see attached production plot, figure 4-4). An increase of 15 BOPD occurred that we would not have been able to achieve otherwise. This method allows us to work around problems without extensive workovers, sidetracks, or replacing a well.

When a well produces too low of a volume for an ESP we prefer to run a gas lift instead of a rod pump. Gas lifts, in some cases, are able to achieve the same results as a pumping unit. Since the installation and operating expenses are very inexpensive with no risk, gas lift is the obvious choice. If the gas lift does not work, the supply line will be there permanently for future optimization if needed. The production in some wells varies drastically over time, based on the surrounding injectors WAG cycles. Instead of running and pulling artificial lift equipment every three months, a capillary string can be left in the tubing and the CO_2 supply be open or closed when needed. Pumpers are able to watch the tubing pressures of these wells, and when the tubing pressure drops, they open the CO_2 to the capillary string. This enables a well to maintain a consistent production rate with no new equipment needed, additional cost, or down time. As stated before, there is no clear cut method for predicting gas lift response. There have been several wells that appeared as if like gas lift would have aided tremendously, and nothing happened. Generally speaking, installing successful gas lifts is trial by error.

Gas lifts play an integral role in the operations at Postle. They offer tremendous benefit with no failure. The only disadvantage to them is they can create paraffin build up because of the rapid cooling caused by the CO_2. To counteract this, we have installed solar powered injection pumps that inject two GPD of paraffin inhibitor into the capillary string. We have yet to encounter difficulties with this. When evaluating wells for artificial lift at Postle, initially gas lift is tried, unless the well already produces a significant volume of gas. If gas lift does not cause a positive response, we then evaluate the well for either a rod pump or ESP. It has proven to be a valuable method that North Ward Estes CO_2 flood, Whiting's other EOR project, has adopted the process. Gas lift is an ideal tool for a CO_2 flood since the gas is readily available.

CONCLUSIONS

Implementing artificial lift is not as simplistic a task at Postle as it is in other areas. We are limited to what we can do without the risk of severely damaging wellbores. With the combination of knowledge from the foreman that have been at Postle from the beginning of the CO_2 flood, and the engineers that have experience at several other CO_2 floods; we have been able to adapt to our environment by combining old and new ideas. This combination has led to a production response at Postle field that no one ever predicted. We are using lessons learned at Postle to implement in other areas we are beginning to optimize in this same field and in another EOR unit recently purchased in Texas County Oklahoma by whiting.

ACKNOWLEDGEMENTS

Firstly, I would like to thank Whiting Petroleum for allowing me to write this paper. I would also like to thank Bob Boomer, Robert McNaughton, Scott Wehner and Gary Wright for guidance and encouragement throughout the writing process.

Figure 1-1: Example of bare steel tubing after six weeks

Figure 1-2: Hole in IPC tubing. A regular occurrence at Postle.

Figure 1-3: Corrosion on ESP motor after six months of CO_2 exposure. Manufacturer claimed this was the first time they had ever seen corrosion this bad on a motor. A band can be seen in this picture that is welded across the housing, this prevents threads from backing off, but makes it very hard to fish.

Figure 1-4: More corrosion on the same ESP.

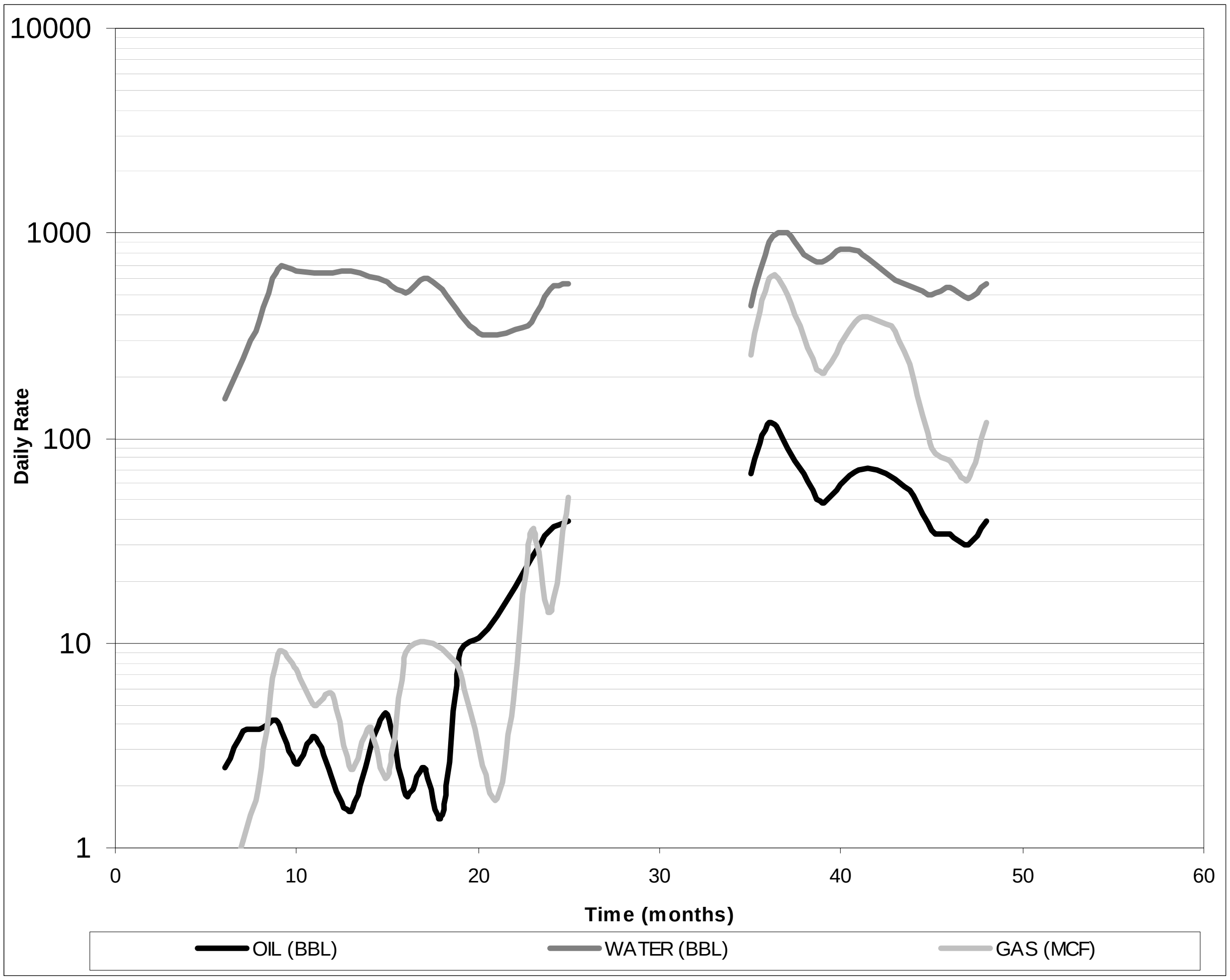

Figure 2-1: Example of rod pump failure. Pump failed on month 25, and well was unable to produce until month 35.

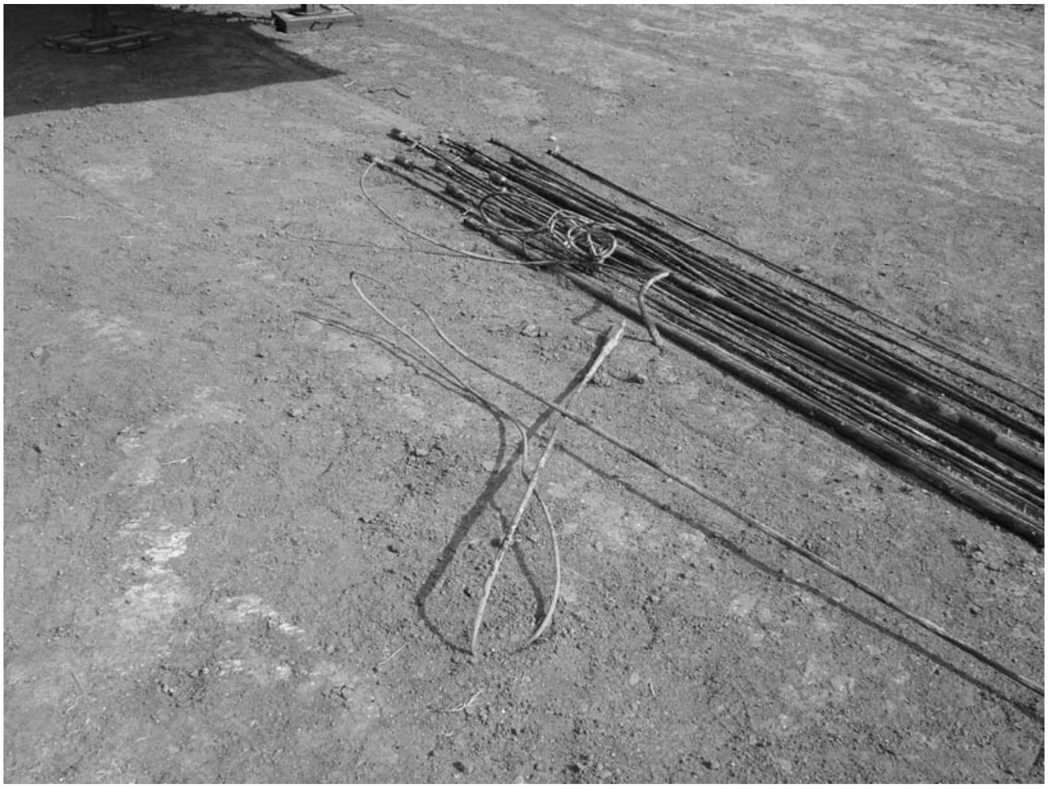

Figure 2-2: ¾” rods and 1” sinker bars. The ¾” rods were stretched to a 3/8” diameter.

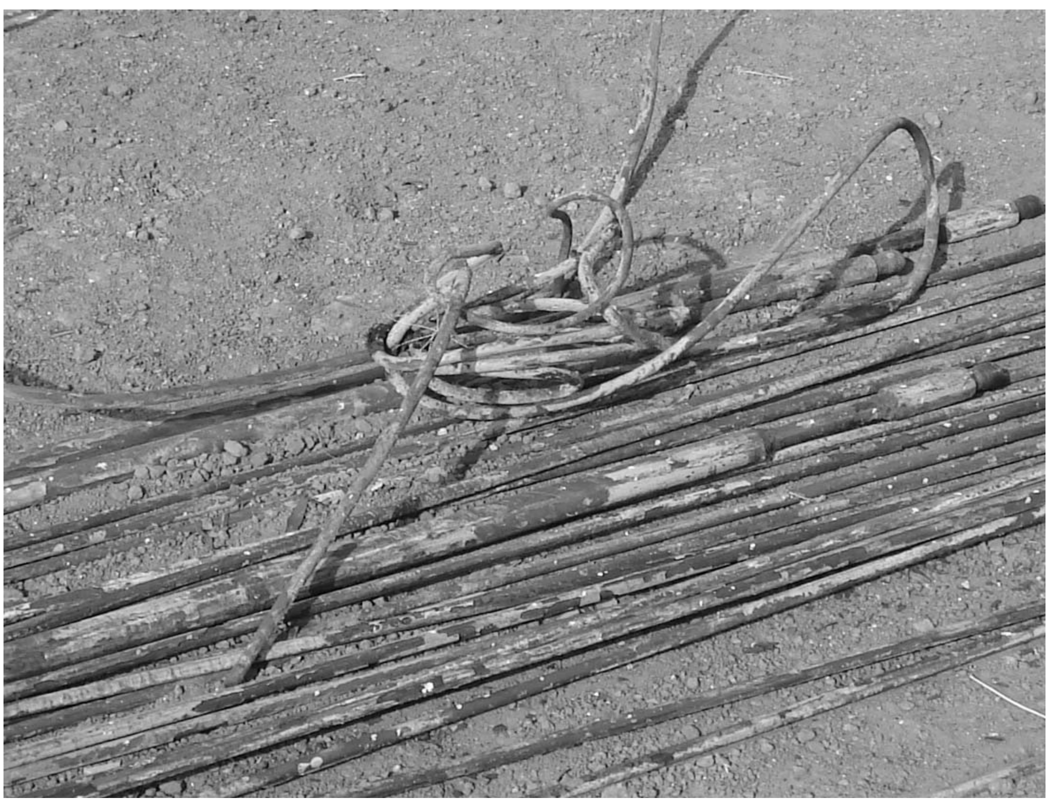

Figure 2-3: Rods that were tied into a knot by wash pipe

Figure 2-4: ¾" steel rod with severe corrosion and pitting

Figure 2-5: Corroded 2-7/8" collar. Paper thin wall with pits and holes.

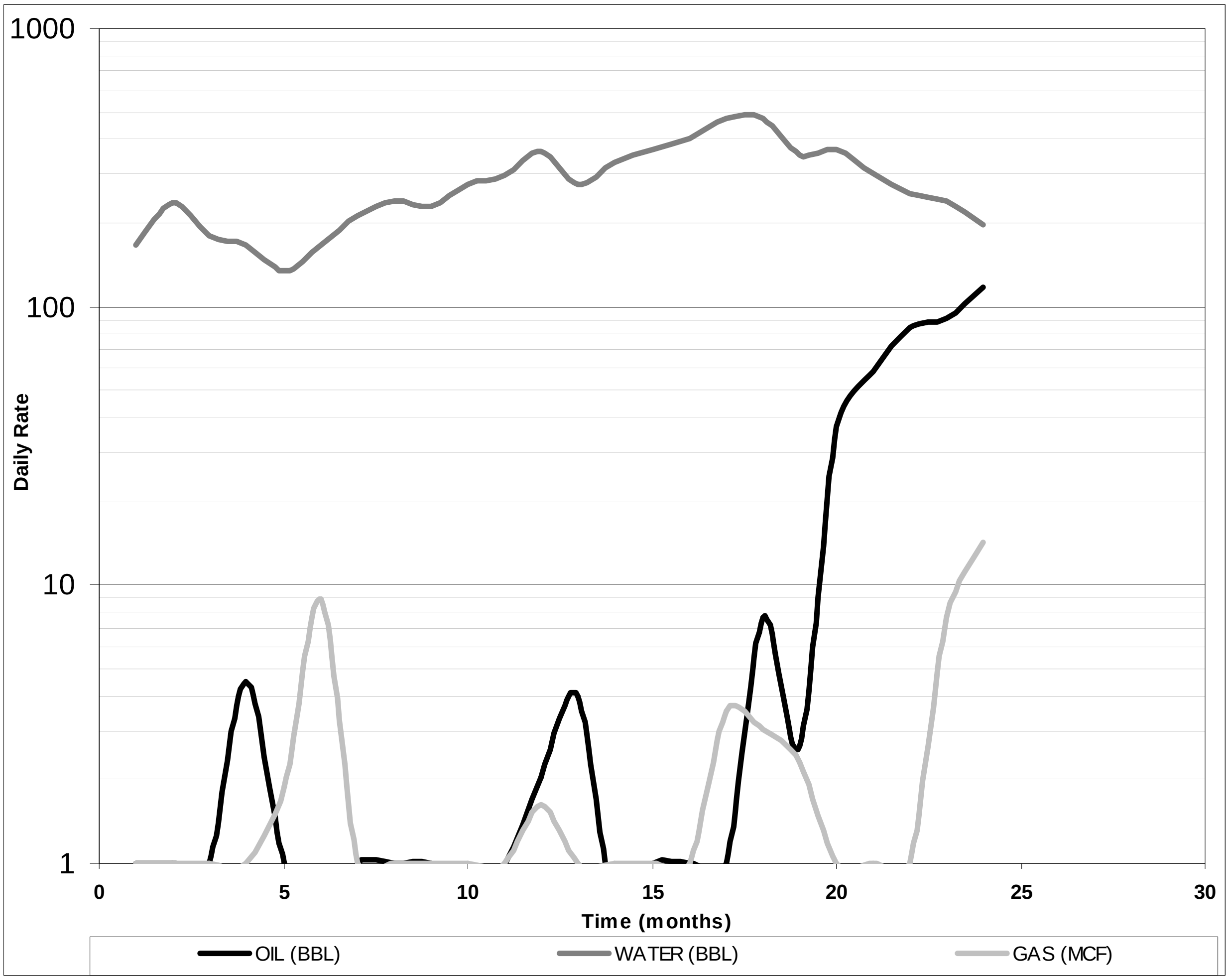

Figure 3-1: ESP example. VSD was slowed down to slowest possible speed at the 15th month. This increased the PIP to above 1450 psi. Shortly afterwards, classic CO_2 response occurred. Water production went down, and oil & gas production went up.

Figure 4-1: “Poor-Boy” Gas Lift assembly at the wellhead. 3/8” stainless steel capillary string is connected to a CO_2 supply line from the nearest injector. Gas lift has been able to replace many pumping units at Postle.

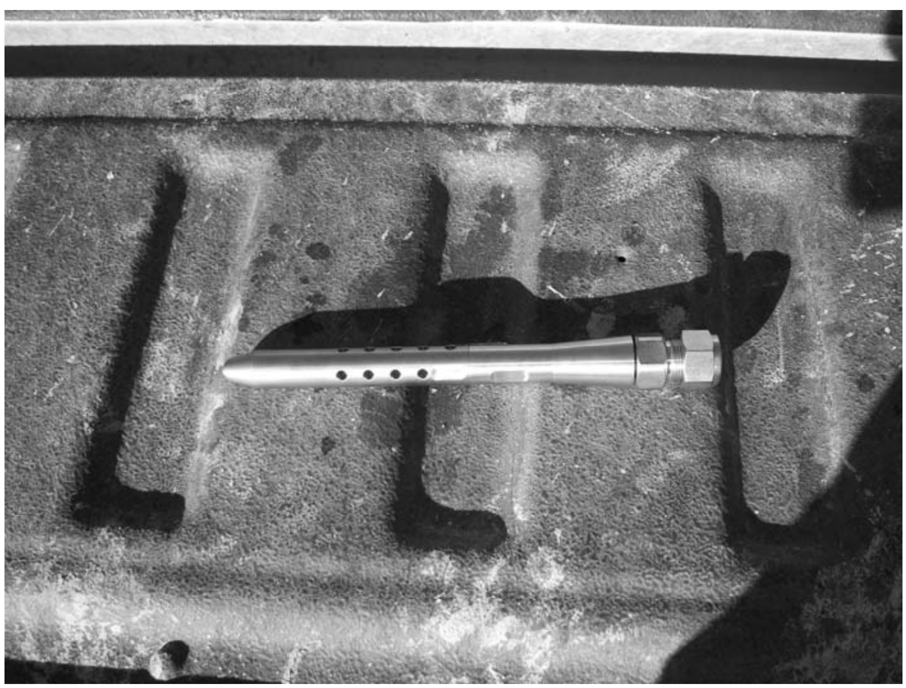

Figure 4-2: Check valve that is installed at the end of the capillary string 4500 feet down in the tubing

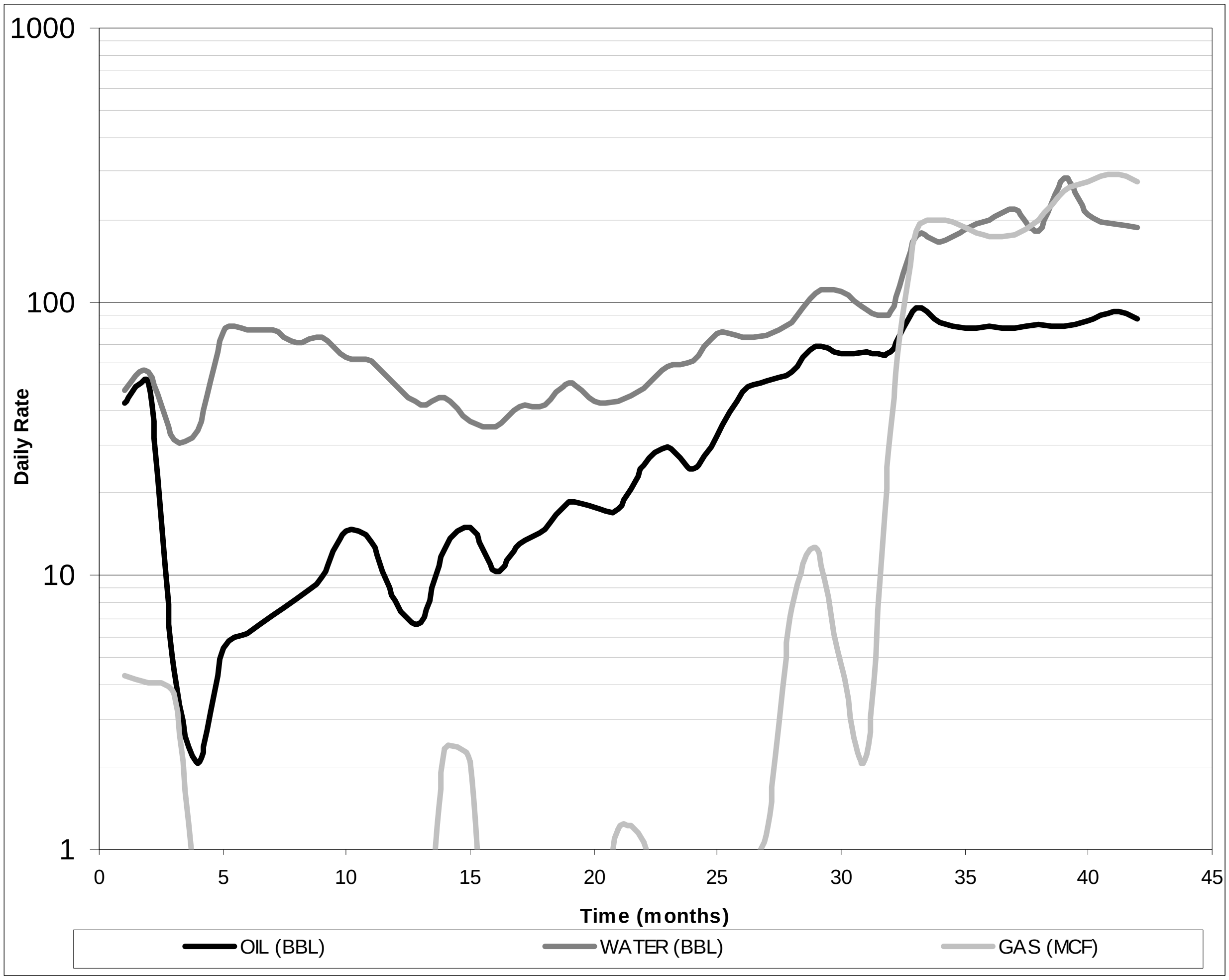

Figure 4-3: Example of gas lift used in a well prior to CO_2 breakthrough. The gas lift was installed at the 34th month. The gas lift was able to increase the water production to allow the CO_2 to breakthrough. With the CO_2 came an additional 30 BOPD.

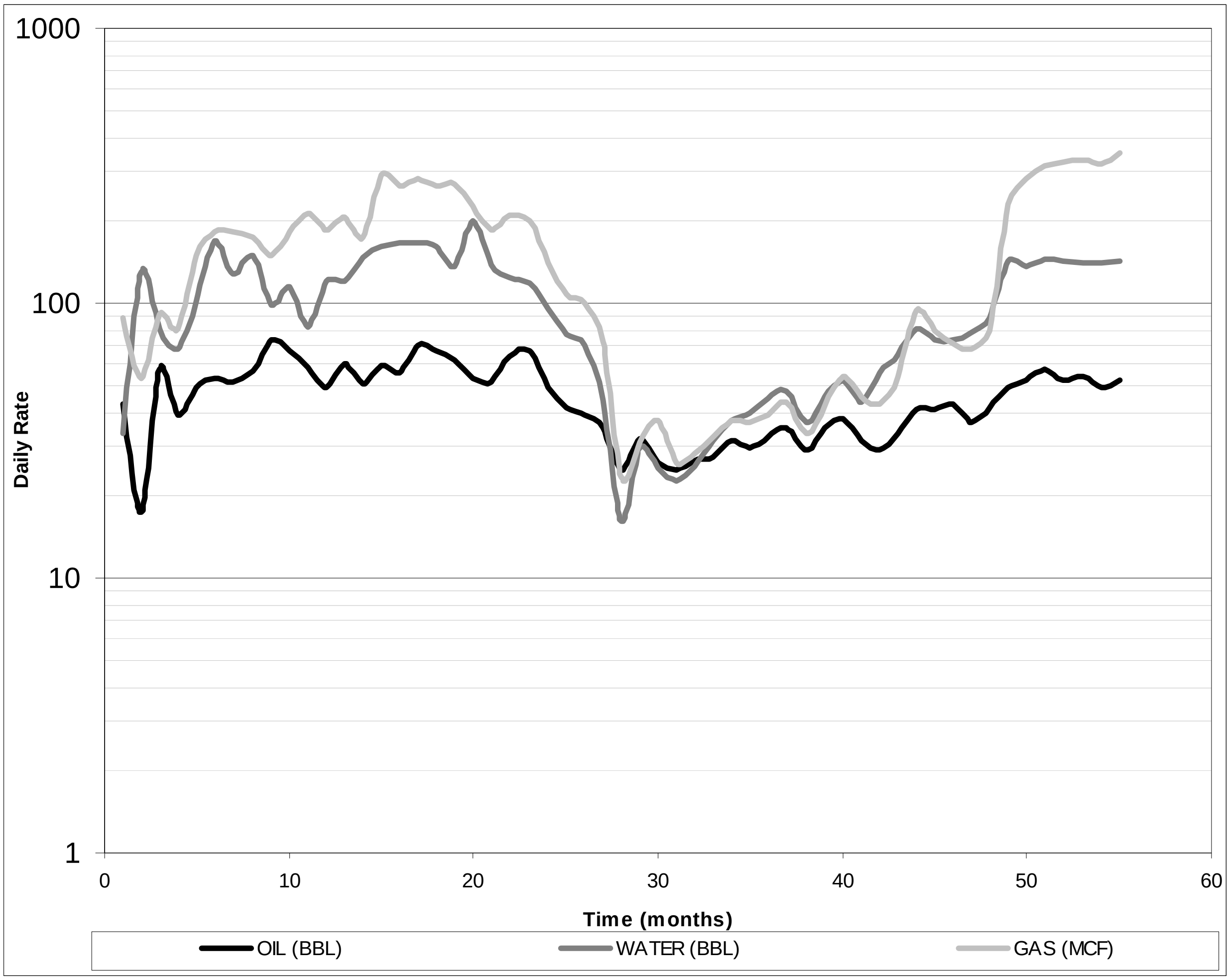

Figure 4-4: Example of gas lift used in a well with lost equipment in the wellbore. The gas lift was installed at the 48th month. An increase of 15 BOPD occurred.