# WATER SHUTOFF CANDIDATE SELECTION METHOD IN THE GRAYBURG FORMATION IN WORLD FIELD – CROCKETT COUNTY, TEXAS

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ABSTRACT

Excess water production is a wide-spread and costly issue in the oil and gas industry. Polymer gel water shutoff treatments provide a valuable means of decreasing water production and reducing operating costs; however, successful treatments are dependent upon selecting viable candidate wells. The industry has long sought a reliable means of identifying wells to target with polymer gel treatments. Most studies on this problem have looked into a potential link between formation permeability and the success of treatments. This paper explores a new method: a correlation which uses the porosity and height of the treated zone to evaluate the viability of polymer-based water shutoffs.

This study proposes a selection method for water shutoff candidates in a dolomitized, oolitic highly-permeable carbonate reservoir in the Grayburg formation. Wells completed in this field often have issues with a high water-oil ratio (WOR), creating a need for water shutoff. The candidate selection method took shape while reviewing the data of several recent treatments in the field. The selection method is based on the formation porosity and height ($\phi H$) of the treated interval. It is proposed that a $\phi H$ value within a given range is indicative of a potentially-successful treatment.

Once the initial idea was defined, the results of the first wells were compared to the proposed correlation. Using the function to identify candidates, additional wells were selected and treated. Results of these wells are presented in the paper and support the proposed model. For additional confirmation, the method was applied to the data for a series of wells treated with polymer gel in the same formation and field in 1997-8. The results of this study are also presented.

## EXCESS WATER PRODUCTION

Excess water production can be divided into two categories; 1) Water that has to be produced in order for oil or gas to be produced; and 2) Water that, when it is produced, does not bring any additional oil or gas as it moves from the reservoir to the surface. This “bad” water, when shut off or reduced, reduces the hydrostatic head so that additional oil can be produced, reduces lease operating expense because it does not need to be treated and disposed, and reduces energy expenditures because it does not need to be lifted to the surface.

There are various ways to shut off or reduce the flow of this produced water depending on whether the fluid flow is in void space, like fractures, faults or vugs, or in the matrix of reservoir rock. The solution will also depend on if the flow problem is near wellbore or deeper within the reservoir. Solutions include everything from mechanical devices to chemicals, depending on the specific situation. Determining which solution is correct is wholly dependent on correctly defining the nature of the problem.

A good candidate well most often is one that has a water cut in excess of 90%, has sufficient remaining oil-in-place to be economic, is producing at high drawdown pressures or with high fluid levels and has been a good producer in the past. For wells such as these, chemical solutions are most often recommended. The most common and most useful of these are polymer gels. Chrome carboxylate acrylamide polymer (CCAP) gels are formulated by crosslinking an aqueous solution of polyacrylamide polymer with chromic tri-acetate to form a “flowing” gel. The gels are a single fluid system that is crosslinked “on-the-fly” as the solution is pumped into the well.

## THE WORLD FIELD

The World Field is located with a cluster of fields in the southern part of the Midland Basin and alongside or just north of the Ozona Arch (Figure 1). It is one of the earliest field discoveries in the Permian Basin, first found in 1925 and originally designated the Powell Field (later designated the World-Powell Field, and finally, the World Field). The primary producing zone is the Grayburg reservoir, which is composed of a series of high-energy dolomitized ooid shoals and associated subtidal facies, as are typical of Grayburg formation fields on the Ozona Arch. The Grayburg is normally less than 250 feet thick; the pervasively dolomitized carbonate interval extends downward an additional 100 feet into the Upper San Andres.[1]

While there are multiple oil-bearing zones in the World Field (see Figure 2), most wells are completed open-hole with only the top portion of the Grayburg exposed to avoid unnecessary production of water. Newer wells have been cased and perforated, but this change does not appear to affect the water production either positively or negatively. Typical water cuts are 98-99% and fluid levels range from 90 to 2100 feet above the pump.

## METHOD

The hypothesis proposes that a treated interval with a $\phi H$ of 12 or higher is the optimum value for successful water shutoff treatments. This theory is based on observations made during and after treatments in the World field in the Grayburg formation. In order to test this theory, it is necessary first to define a “successful” treatment. The two goals of the treatment are first: to decrease water production; and second: to increase oil production—both to the greatest extent possible. These goals have their bases in economics, which will be discussed in greater detail below; however, for analytical purposes, the success of a treatment will be defined on a barrel—rather than dollar—basis. When comparing two treatments to each other, the more successful treatment is the one with a greater amount of water production decreased and oil production increased. In order to allow for more uniform comparison of the treatments, these numbers will be changed to a percentage basis: the percentage that water production decreased and the percentage that oil production increased. For example, for the wells examined in this study, the pre-treatment water production ranges from 400 BWPD to 4,000 BWPD. Where a 200 BPD decrease in water production on the former well would be a great success, it would be less impressive viewed in terms of the latter well.

A total of 46 wells and their associated treatments are examined in this study: 11 that were treated in recent months and 35 that were treated in the late 1990s. The focus on analyzing the results of the treatments is placed on comparing daily water and oil production before and after the treatments took place. The pre-treatment production rates for all wells were taken within a few days prior to the treatment. For the 1990s set of treatments, the post-treatment production rates used in this study are approximately six months after the treatment took place. As some of the newly-treated wells were completed very recently, the post-treatment production rates for the recent treatments were taken one month after completion of the treatment. It is additionally worth noting that while the recent treatments took $\phi H$ into account for both candidate selection and treatment design, the late 1990s treatments did not. Because of these differences, as well as the amount of time between the two sets of treatments, the results for the two sets of treatments are presented separately.

## RESULTS

Figure 3 below shows results for the recent set of treatments in the World field. This chart and all others which follow are designed to show beneficial results as more positive along the y axis. This means that oil is presented on an "oil increased" basis, whereas water is presented on a "water decreased" basis. The vertical black line represents a $\phi H$ value of 12, where the hypothesis states the most successful treatments should take place. These data offer some support for the theory, showing in particular a cluster of high oil increase near the $\phi H$ of 12 mark. The water, though, shows no real trend. Additionally, while there are a few instances of high oil increase near $\phi H$ of 12, there are also instances of poor oil increase and even oil decrease in the same range (though the decreases in oil production are due to a switch from ESP to rod pump on the wells).

Figure 4 presents the same metrics as Figure 1, with data for the late 1990s set of treatments. As with the recent treatments, there are spikes in oil increase near $\phi H$ of 12; however, neither oil nor water show a definitive trend supporting the hypothesis.

While the data lacks definitive support for a particular range of $\phi H$ values leading to more successful treatments, there is some evidence to show the usefulness of considering $\phi H$ when selecting candidates and in designing treatments. Intuitively, a higher value of $\phi H$ means more void space to be filled and the potential for needing a greater treatment volume. This being the case, a greater treatment volume for an interval with a given value of $\phi H$ would lead to a generally more successful treatment. Another way of viewing this is as a comparison between the volume of a treatment and the $\phi H$ of the interval into which it was placed. This can be achieved by creating a ratio: dividing the volume of a treatment by its corresponding value of $\phi H$. One would expect that for increasing values of this ratio (greater treatment volume as compared to $\phi H$), a more successful treatment would be achieved.

For the purposes of this study, this ratio will be referred to simply as R and be defined as shown below.

$$R = \frac{Volume\ of\ Treatment\ (Bbls)}{\phi H}$$

The theory is that higher values of R will generally produce more successful treatments. Figure 5 shows the results of the recent set of treatments, as a function of R. The resulting trends, while not particularly strong, show both greater oil increase and water decrease with increasing R. These trends support the theory surrounding R and by extension support the value of taking $\phi H$ into account when designing water shutoff treatments.

Similarly, Figure 6 shows the results of the late 1990s treatments as a function of R. Again, the trends are not strong, but they do show a general increase in success of treatments as R is increased.

From examining the results of both sets of treatments—recent and late 1990s—it is clear that no definitive support has been found for the hypothesis that a reservoir interval with a $\phi H$ value of 12 can be treated for water shutoff more effectively than intervals with other values of $\phi H$. This may be at least partially due to the high heterogeneity of the Grayburg formation, which makes trends more difficult to observe. There is additionally no evidence in support of a different specific value of $\phi H$ having use as a candidate selection method.

The results, however, do show that $\phi H$ has value in treatment design. In combination with other design criteria, it offers ideas on how much volume is needed for a successful treatment. By the same token, it has potential applicability in candidate selection, where extreme values may indicate that an interval is too loose or too tight to be treated successfully.

## ECONOMICS

As mentioned earlier, the goals of the treatment—both decreasing water production and increasing oil production—are based in economics. In compiling the data for this study, a unique opportunity presented itself to look at the economics of the studied treatments.

For the recent treatments, data is limited by the amount of time passed since the treatments took place; however, all 11 of the more recently-treated wells have at least one month of post-treatment production data. Table 1 below shows the results of these 11 wells: the change in both oil and water production per day, the treatment cost, and the values associated with each change in production. Two of the wells exhibited a decrease in oil production after treatment. As mentioned previously, this change is due to a switch from ESP to rod pump on these wells, causing a decrease in total fluid production—both water and oil. Cost savings are based on an estimated cost of $0.09 per barrel of water produced. Increased revenue is estimated using an oil price of $30 per barrel.

Using these daily values as an average across the first 30 days of production, the total payback in 30 days is $192,480—over 20% of the total treatment cost.

Along with direct revenue generation and the water disposal savings, there are several other economic benefits to the treatments. Decreased water production yields less electrical and operating costs. In cases where the wells were previously on ESP, most saw water production decreased significantly enough to switch to a smaller, less expensive ESP—or even from an ESP to a rod pump. These changes lead to less workover and repair costs, by decreasing the total number of ESPs in the field. When accounting for all of these factors, the treatments are estimated to pay out in a year or less.

## CONCLUSIONS

- Formation porosity and height of treated interval ($\phi H$) can be useful in candidate selection, when used alongside traditional selection methods
- The $\phi H$ value of a target interval can be used in determining treatment volumes for polymer gel water shutoff
- There is no conclusive evidence to support a specific range of $\phi H$ values corresponding to the most successful treatments
- The high heterogeneity of the Grayburg formation may be a contributing factor to the lack of definitive trends in the data
- Polymer gel water shutoff treatments have proven to be a successful means of improving the economics of wells in the World Field

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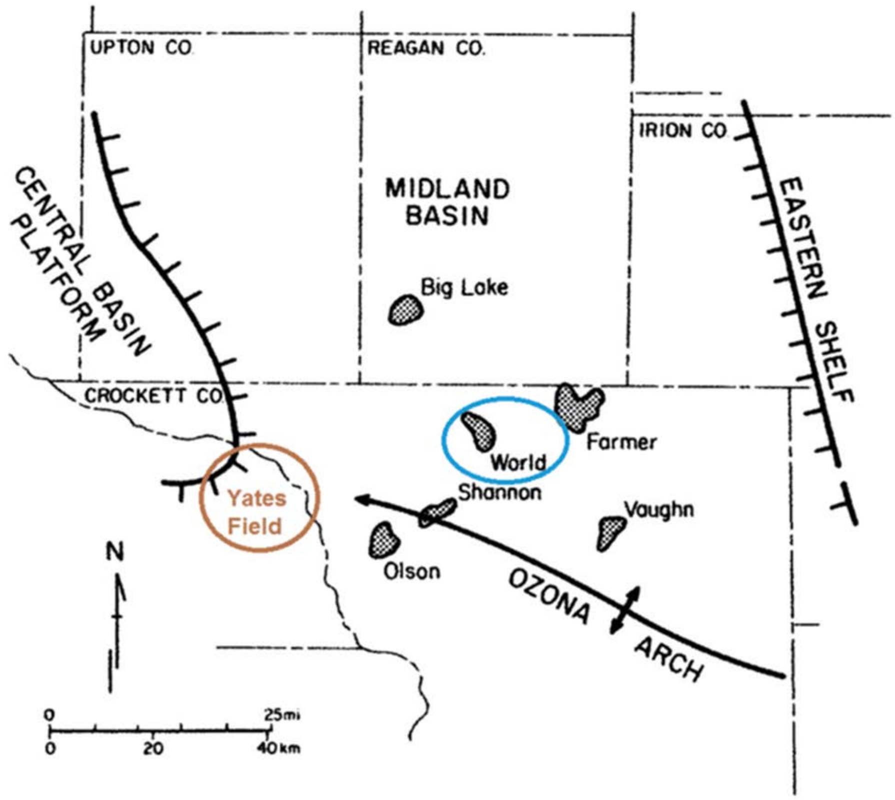
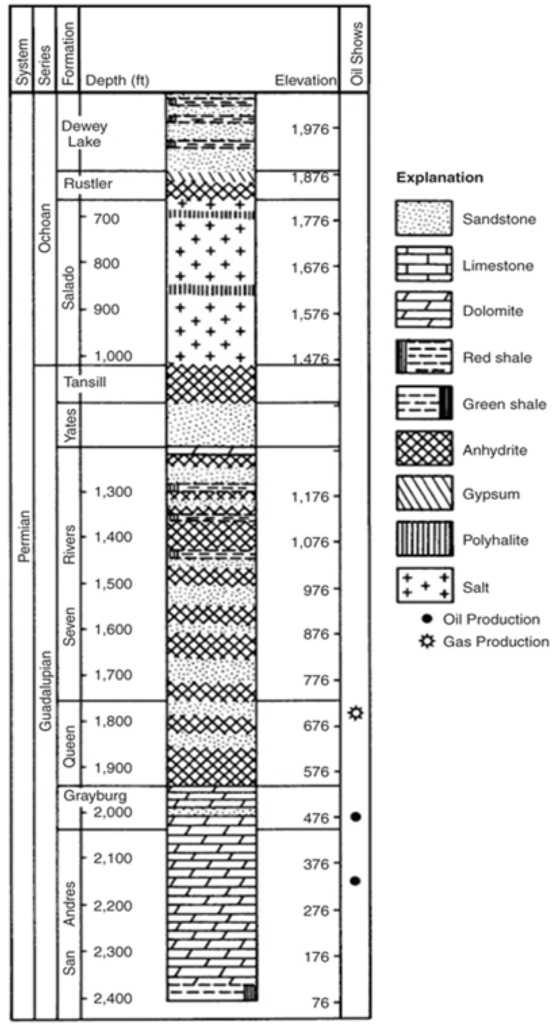



a. Figure 1: World Field[2]




b. Figure 2: World Field Stratigraphic Column[2]

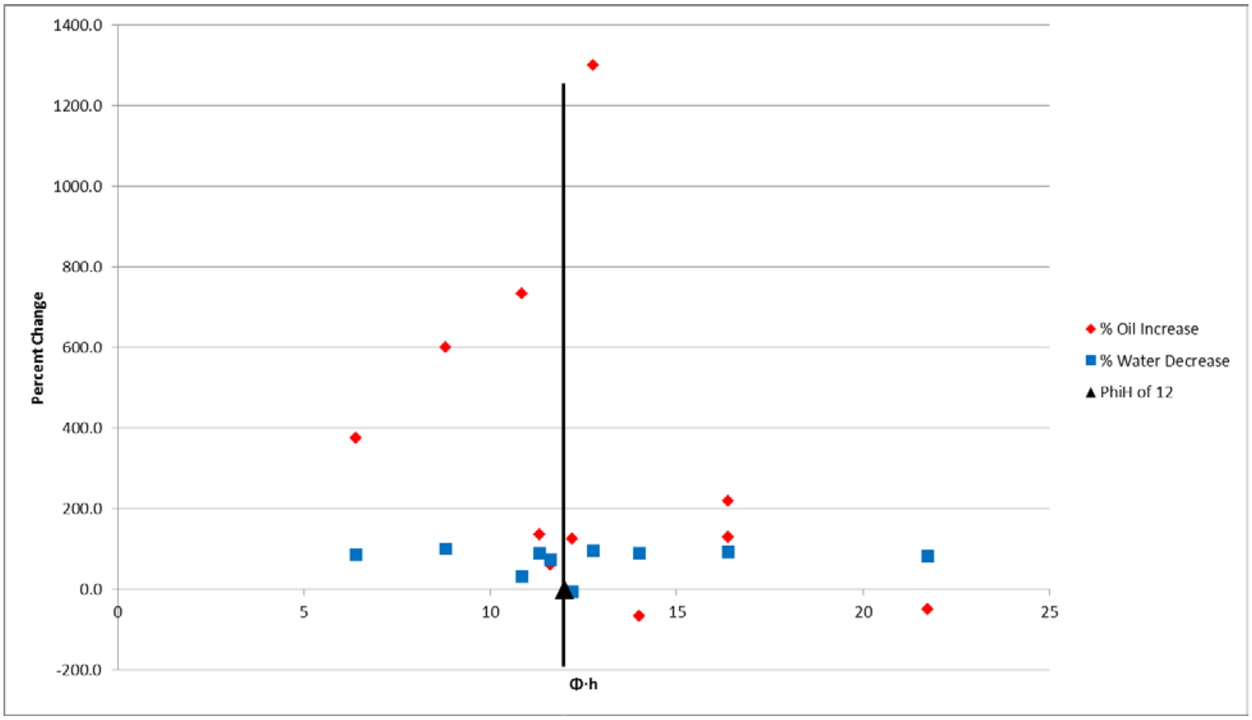



Figure 3: Percentage Change of Daily Oil and Water Production vs. $\phi H$ – Recent Treatments

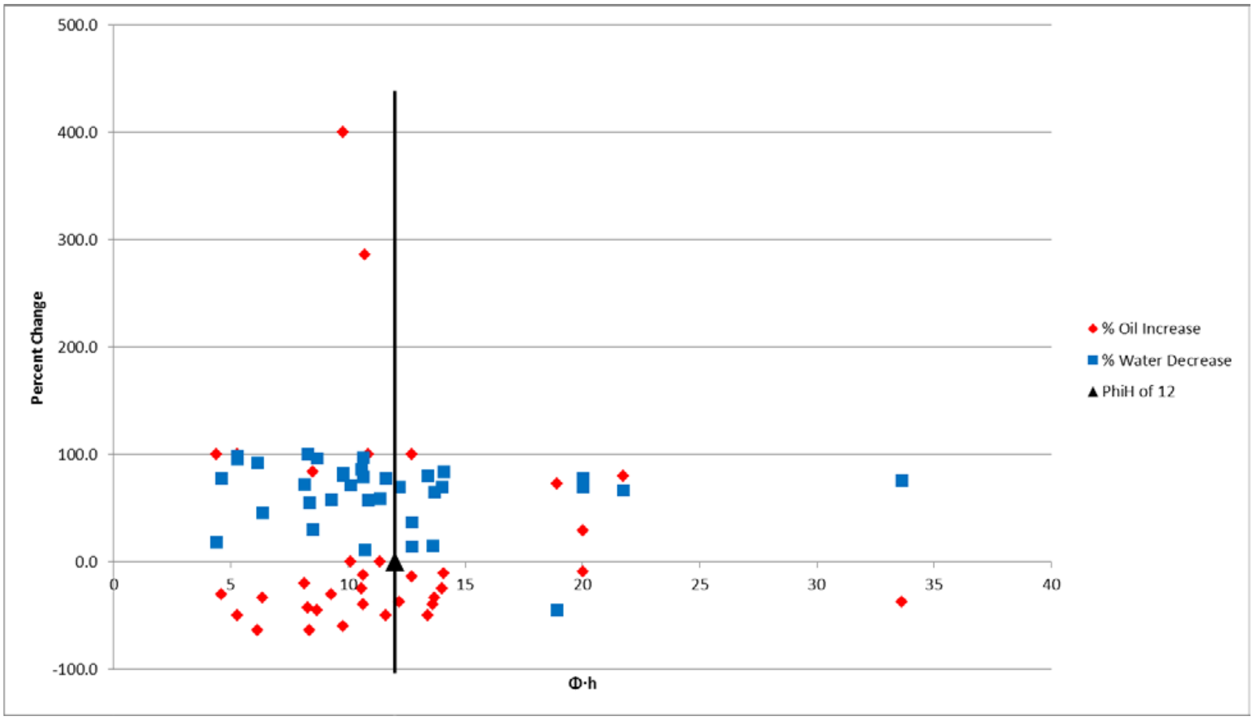



Figure 4: Percentage Change of Daily Oil and Water Production vs. $\phi H$ – 1990s Treatments

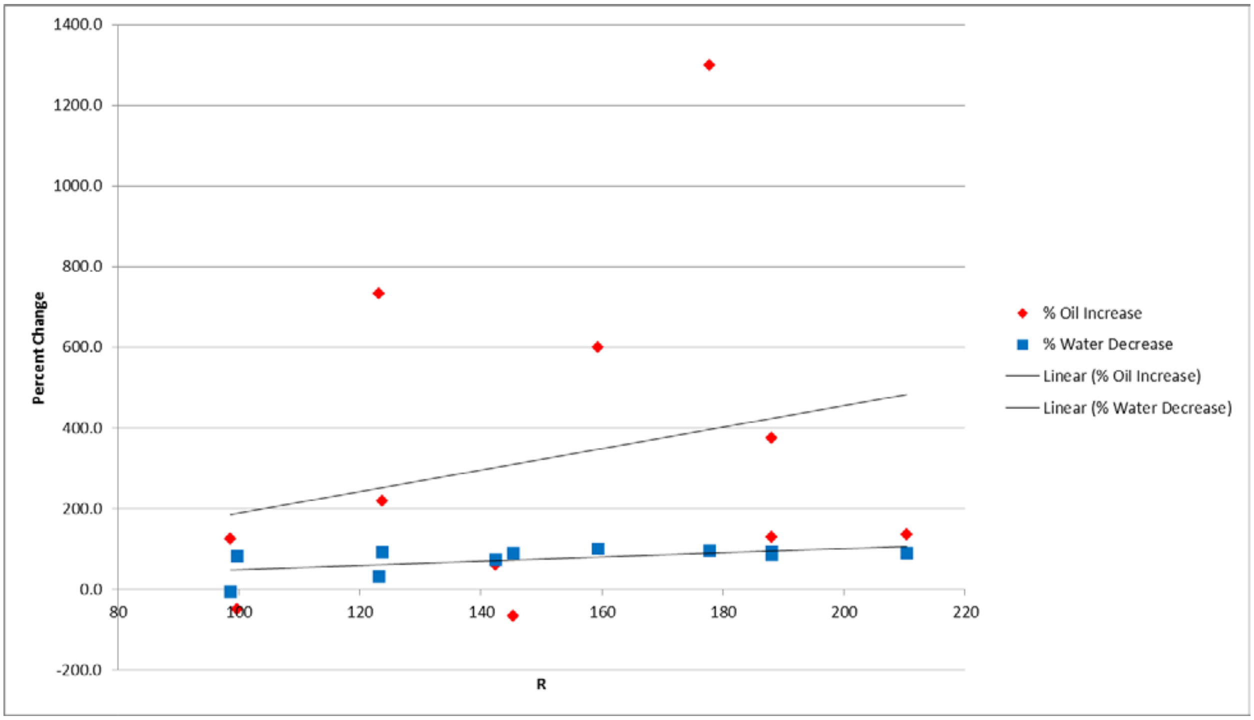



Figure 5: Percentage Change of Daily Oil and Water Production vs. R – Recent Treatments

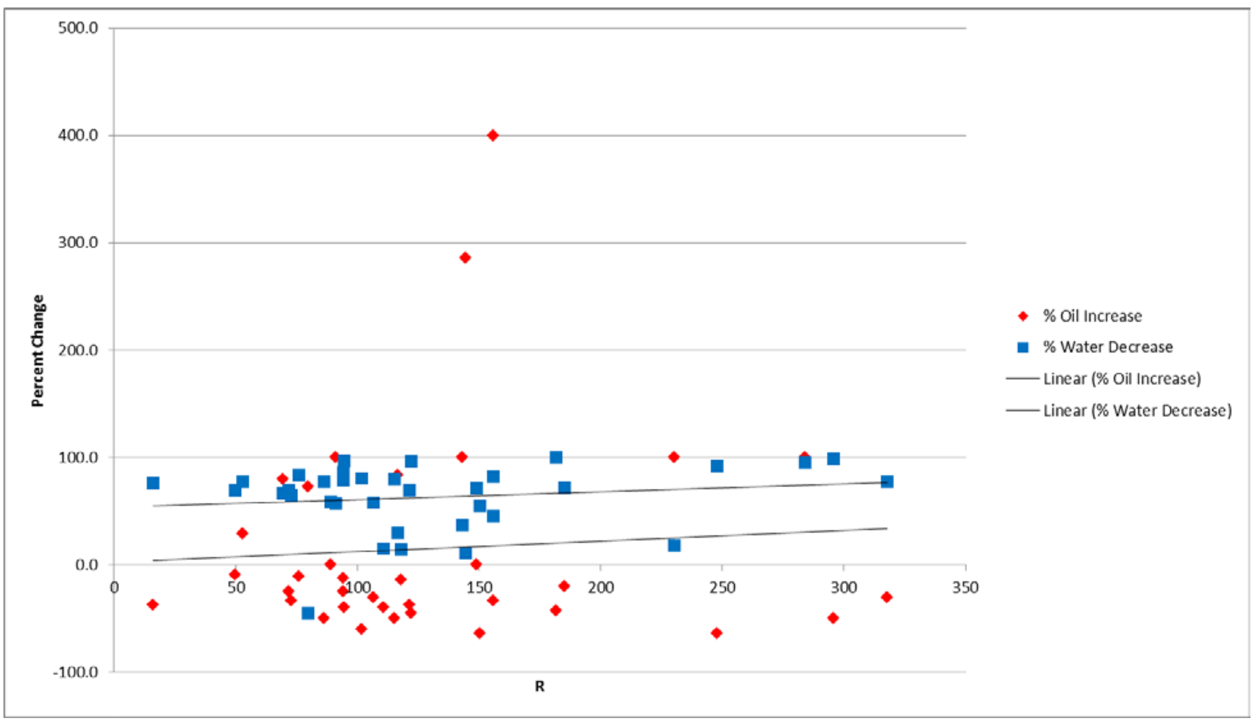



Figure 6: Percentage Change of Daily Oil and Water Production vs. R – 1990s Treatments

Table 1: 30-Day Production Data – Recent Treatments

| Well | ΔBOPD | ΔBWPD | Treatment Cost | Cost Savings/Day | Increased Revenue/Day |
|---|---|---|---|---|---|
| 1 | 5 | 20 | $44,764 | -$1.80 | 150 |
| 2 | 48 | -1396 | $58,032 | $125.64 | 1440 |
| 3 | 30 | -598 | $44,947 | $53.82 | 900 |
| 4 | 18 | -1972 | $121,005 | $177.48 | 540 |
| 5 | 35 | -2093 | $102,190 | $188.37 | 1050 |
| 6 | 15 | -3616 | $92,500 | $325.44 | 450 |
| 7 | 13 | -576 | $70,977 | $51.84 | 390 |
| 8 | 22 | -129 | $58,328 | $11.61 | 660 |
| 9 | 3 | -303 | $58,739 | $27.27 | 90 |
| 10 | -5 | -784 | $92,586 | $70.56 | -150 |
| 11 | -8 | -1180 | $85,545 | $106.20 | -240 |
| **Total** | **176** | **-12,627** | **$829,613** | **$1,136** | **$5,280** |