TEAGUE-BLINEBRY IMPROVED OIL RECOVERY FEASIBILITY STUDY

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Abstract

A project to review previous work, perform additional laboratory tests, and identify pay from well logs in the Teague-Blinebry field was performed at the Petroleum Recovery Research Center at New Mexico Tech. Recovered core from one well and well logs from across the field were evaluated. Laboratory tests included:

1. Mineralogy, fracture systems, and oil stains have been described for 251 ft of recovered core.
2. Slabbed core scanning minipermeametry on 79 samples, air perms on both ends of twelve plugs, brine perms on two samples, and water and CO2 floods on two samples.
3. Minimum miscibility pressure is the higher of 1000 psig or the system bubble point pressure.
4. Wettability index is –0.608.

Core permeability measurements identified very low matrix permeability in the Blinebry dolomite. Regions of conductive vugs and fractures were detected. Tests indicate that even apparently filled fractures play a significant role in fluid movement. This observation is supported by effective permeability results derived from step rate tests to be 1.15 md; well above the average matrix permeability.

Density/neutron and induction or laterologs were used to identify pay in 18 wells with modern log suites. In order to include a greater number of wells, a procedure was adopted in which field average parameters were used with 57 sonic porosity logs from the older wells lacking density/neutron data. Net pay and original oil in place were calculated for 65 wells. Targets for potential water or CO2 flood development are identified as the upper one-third of the Blinebry.

Introduction

The Blinebry formation in the Teague Field is located in southwestern New Mexico in Lea County. The first Lamunyon property wells were put on primary production in 1938. The field is in the final stage of a 20 acre infill-drilling program. Ultimate primary recovery is expected to be less than 10% of the original oil in place. The purpose of this study was to examine the possibility of profitably increasing the oil production by the injection of water and/or CO_2. An earlier study had indicated that, because of low permeability and mixed or strongly oil wet conditions, a water flood was not expected to produce significant oil and CO_2 was a possible flooding agent, but expected to be marginally profitable. This study revisits earlier work to obtain a better handle on the reservoir characteristic, determine the original oil in place, and run tests on core samples to determine the feasibility of water and CO_2 injection on a core level. Future studies could model the primary production and then predict if any injection process would be profitable.

Results and Discussion

Core Description

Core taken from the Teague-Blinebry Lamunyon 50 well in 1989 was examined at the PRRC. Core was recovered from 5280.0 ft to 5399.0 ft and from 5455.0 ft to 5587.0 ft. Every segment of the core was examined and segments with clear fracture traces on the top or bottom were measured to obtain strike angle.

Examination of the core reveals a dolomite composition, with zones of fractures that are partially to completely filled by anhydrite. There are also conspicuous nodules of anhydrite, stylolites, a few fossils, and some zones of visible small-scale vugs. There are subtle changes in texture along the core but the composition is primarily dolomite. There are a few zones that show a shaly material, but they do not correlate to the gamma ray measurements made earlier on the core (ref Core Lab). These are thought to be dark organic-rich deposits due to storm surge events.

Fractures over the entire core interval were found to be approximately twice as abundant on the NW-SE trend than the NE-SW trend. Zonation by narrow depth intervals failed to reveal any clear trend. It is not known how the fracture distribution effects fluid flow in the Blinebry formation. Further examination of fracture filling minerals by thin section, study of fracture history, and additional laboratory fracture testing are required to make this determination.

Thin sections taken from 12 depths showed the matrix is composed of dolomite, which ranges in texture from microcrystalline to pelloidal. Quartz is present as silt in some samples. Porosity varies but tends to be less than ten percent. Anhydrite is the most common pore and fracture filling material.

Core Air Permeability

Intervals along the core were selected for minipermeameter analysis based on the following criteria: presence of oil and permeability according to Core Labs special core analysis, visual indications of high perm zones and fractures, and proximity to well-bore perforations. Seventy-nine intervals were investigated between 5278.3 ft and 5580.3 ft. Core plugs to be used in core flooding were selected from 12 depths.

Scanning minipermeameter measurements were performed on the slabbed core by centering the instrument's scan pattern on the depth. The typical scan pattern used was a 3.0 in. by 1.0 in. rectangle with increments of 0.25 in. and 0.5 in. respectively. The 3.0 in. side was aligned with the axis of the core. This scan pattern yields a data set of 39 measurement points. The minipermeameter probe tip has an interior diameter of 0.25 in. and an outside diameter of 0.375 in.

Two trends are evident in the permeameter data. The first are data sets with a normal distribution. These results were associated with intervals with a standard deviation that was less than the average permeability. These do not show significant fractures or large vugs. The second trend is with a standard deviation that exceeds the average value of permeability for the interval. These intervals have fractures and/or small-scale vuggy porosity. Near-probe effects due to high conductivity features (fractures or vugs) which cross the seal at the probe tip dominate the instrument response in these intervals. These permeability values are considered to be artificially high. These will be discussed further in a later section on fracture conductivity. Figure 1 illustrates the trends in the minipermeameter data. All of the measurements reflecting the characteristics of the matrix dolomite are characterized by permeabilities rarely exceeding 1 md, and it should be understood that the radius and depth of investigation at the probe tip is severely constrained under these circumstances. Permeability values less than 0.05 md are at the instruments lower limit of detection.

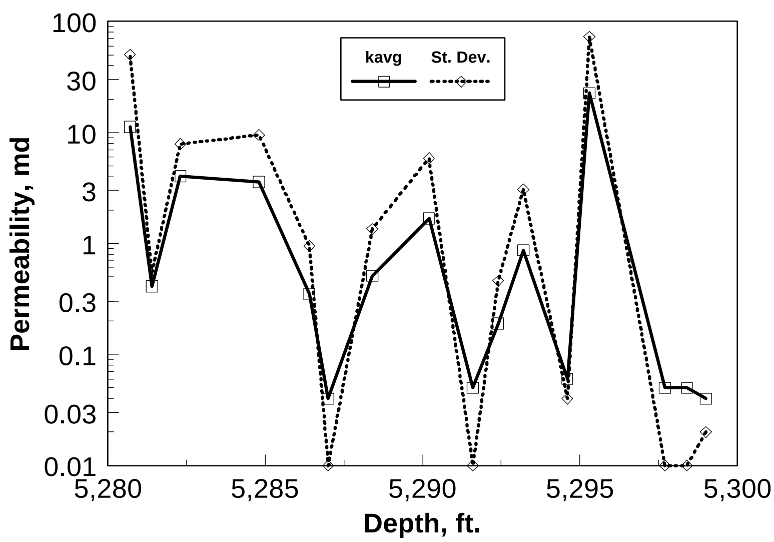

Figure 1. Average permeability and standard deviation for Lamunyon 50 over a 20 ft interval

Core Plug Brine Permeability

Brine permeability tests were conducted on eight core plug samples from Lamunyon 50. The core plugs were 1.5 in. diameter and approximately 2.25 in. long. The tests were conducted in a Hassler type core holder with 1500 psi confining pressure. A high-pressure syringe pump was used to flow brine through the sample at a known rate. The brine composition was based on well water analysis reports for Lamunyon 50, with a total dissolved solids (TDS) of 86,820 ppm. Before the permeability measurements were taken, the samples were dried in a vacuum oven and dry weight was recorded. Wet weight was recorded immediately after the sample was removed from the core holder. Calculated permeability and porosity are found in Table 1. Permeability measurements on the order of 0.001 md are estimates due to the extremely long time (days) necessary to reach saturation and steady state differential pressure (dP) measurements.

Depth	Q [cc/hr]	dP [psid]	L [cm]	k [md]	Porosity [%]	Pore vol [cc]
5304	97.6	18.6	5.93	11.2	15.7	10.57
5308	35.1	100	5.84	0.74	12.4	8.24
5319	0.8	133	5.38	0.012	7.8	4.76
5326	0.6	114	6.55	0.012	6.9	5.11
5370	0.08	>181	5.33	<0.0009	2.5	1.49
5465	0.2	>250	4.19	<0.0012	0.4	0.17
5555	2	103	5.36	0.038	5.7	3.43
5575	0.2	>250	4.19	<0.0012	1.3	0.59

Table 1. Core Plug Brine Permeability

Core Flooding

Brine permeability measurements suggested that core plug samples 5304 (upper Blinebry) and 5555 (lower Blinebry) could be successfully flooded. Samples were installed into a core holder with 3000 psi confining pressure. The core holder and high pressure syringe pump were located in an air bath controlling at 100 ^oF. The system plumbing was designed to minimize volume and eliminate possible storage of oil, which could strongly effect the effluent measurements. The sample outlet side was maintained at 1500 psi with a backpressure regulator. An upstream backpressure regulator was installed down stream of the injection pump so that the CO_2 mass flow rate could be easily controlled.

Brine composition was the same as used for the brine permeability measurements. The samples were prepared by flowing Blinebry separator oil through the system at control pressure and temperature. Between 100 and 150 cc of oil was injected through the sample over a 24 hour period to ensure that oil saturation had been reached. Further aging was accomplished with the core shut in overnight while the system plumbing was cleaned to remove extraneous oil.

The sample was water flooded until oil production ceased. Then the sample was CO_2 flooded until oil production ceased. To prepare for the repeat run, the sample was slowly blown down to ambient pressure, then oil saturated as described above. The core flooding results are presented in Figures 2 through 4. Flood A for sample 5555 is not presented because the initial oil saturation is suspect, but Flood A did produce oil with CO_2.

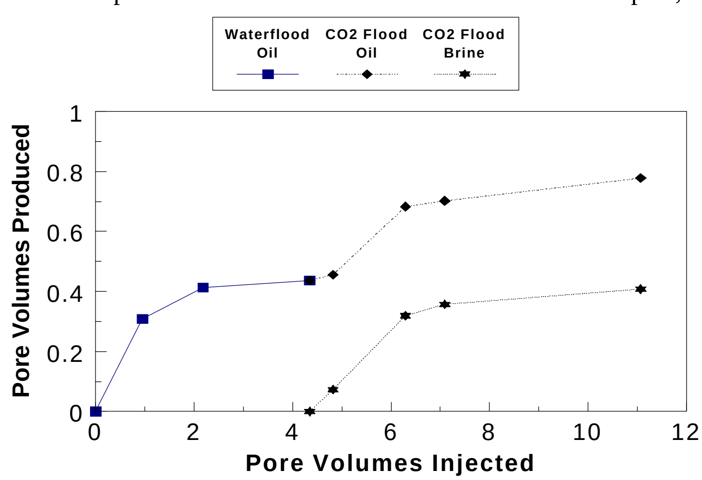

Figure 2. Core Plug 5304 Flood A

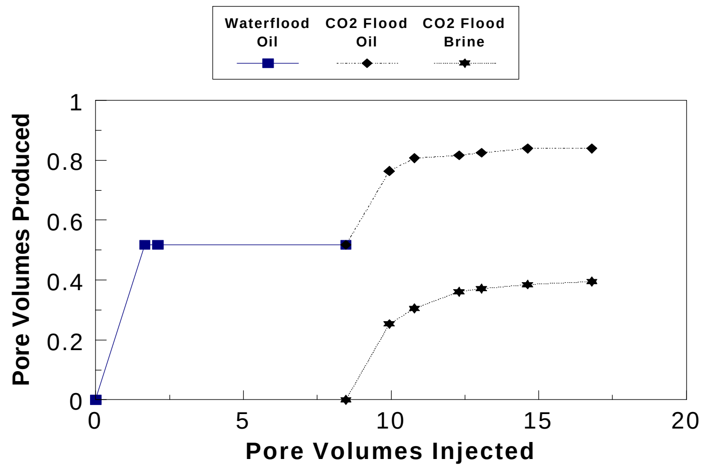

Figure 3. Core Plug 5304 Flood B

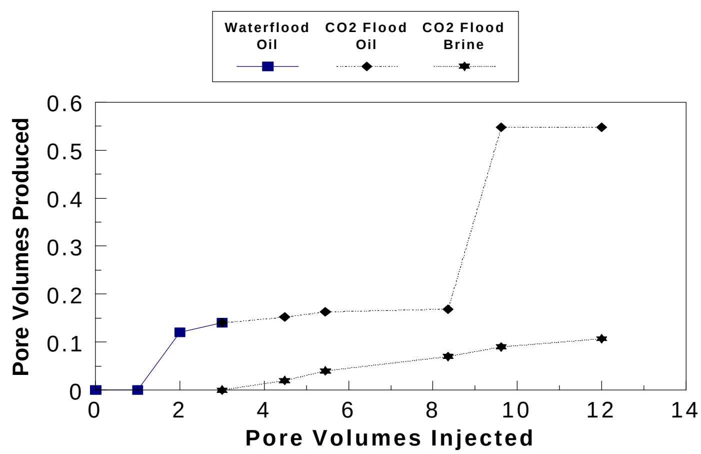

Figure 4. Core Plug 5555 Flood B

Fracture Conductivity

The PRRC scanning air minipermeameter is designed to make permeability measurements on a flat sample on a programmable grid. The instrument may also be used to make single point measurements. This feature is utilized in a new measurement technique pioneered at PRRC. Several core segments exhibiting fracture traces on a slabbed or sliced surface were selected for study. Polycarbonate strips were made with 0.125 in. diameter ports spaced 0.375 in. on centers, see Figure 5. The ports follow the trace of the fracture. The strip is sealed to the surface of the core with silicone RTV and allowed to cure. Measurements are made at each port by manually positioning the sample on the minipermeameter table. Ports not at the measurement point are sealed during the measurement.

Figure 6 contains an example with each point an average of three measurements. The measurements showed near zero variance, which is an indication of an excellent probe-to-surface seal. After all ports had been measured, a ten-point average of the core matrix permeability was made adjacent to the polycarbonate strip. Small fractures or vugs were carefully avoided in these matrix measurements. The average matrix permeability and standard deviation are listed at the bottom of the fracture measurements.

In a homogeneous isotropic medium, the flowlines from the probe tip would extend symmetrically radially and into the material. The Lamunyon 50 cores deviate significantly from this model. Due to the very low permeability of these dolomites, a more correct description of the flowlines would be primarily radial, entering only shallowly into the rock, and reemerging adjacent to the external edge of the probe tip. This is the case for the matrix measurements. The very large contrast between the fracture and matrix permeability effectively prevents flow into the matrix so that the flow is constrained to the fracture system. The polycarbonate strip eliminates any possibility that the flowline can emerge a short distance from the probe tip. Fracture structure and degree of mineralization determine the actual flow path. The practical upper limit of the instrument response is 500 md, thus a measurement of 500 md is actually 500 md or greater.

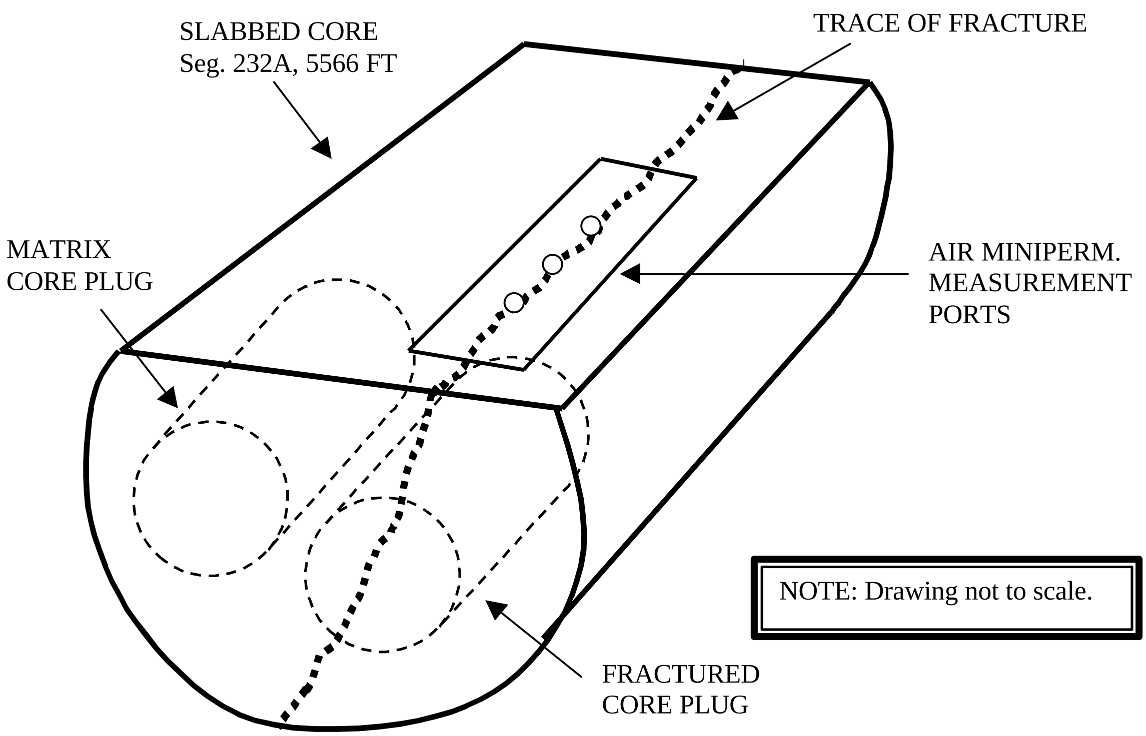

Figure 5. Fractured Core Measurement

Core Segment 232A, 5566 ft

PORT	kavg[md]
1	120.4
2	181.71
3	202.74
4	304.56
5	373.27
6	500
7	500
8	26.04

Matrix: k=3.28 +/- 3.165 md

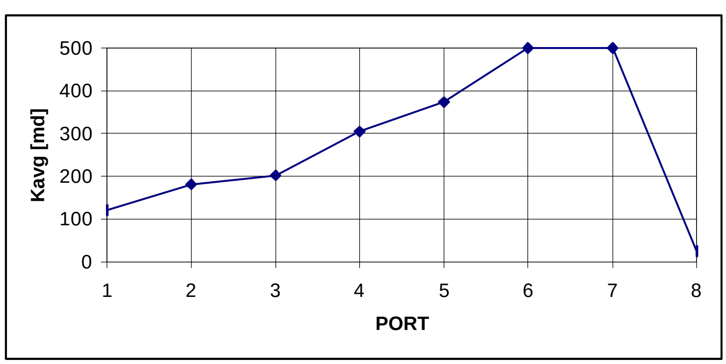

Figure 6. Fracture Permeability Measurement

To further characterize the fractures in the middle Blinebry the sample from 5566 ft was selected for further study. This fractured sample was previously studied using the minipermeameter. Two core plugs were taken from this sample; one approximately centered on the fracture and the other representative of the unfractured matrix, see Figure 5.

The fractured core plug fell into two pieces when removed from the core drill. It was realigned and secured with vinyl tape around the circumference. The core plug was installed in a Hassler type core holder and injected with distilled water until saturated. Steady state differential pressure was used to calculate permeability. It was interesting to find that even though the fractured core permeability was less than 1 md, 0.53 md, it is nearly 200 times more permeable (0.530 md vs 0.003 md) than the matrix core.

Wettability

A wettabilty test was performed on one core plug from depth 5308 ft. Brine based on the Lamunyon 50 water analysis and reservoir crude oil from the field were used in the test. The core was saturated with brine, then brought to irreducible water saturation by injecting oil. After aging in oil the core was placed in a brine filled imbibition cell at 100^{o}F. Recovered oil is defined as "***A***". Brine was then injected to achieve irreducible oil saturation, and the oil recovered is defined as "***B***"**.** The core was then placed in an oil filled imbibition cell at 100 F. Recovered brine is defined as "***C***". Oil was then injected and the brine recovered is defined as "***D***".

The wettability index to water is ***Iw = A/(A+B)*****, [0.15/3.50].** The wettability index to oil is ***Io = C/(C+D)*****, [1.40/2.15]**. The relative wettability index is ***WI = Iw – Io*****, -0.608**. This relative wettability index demonstrates that the core sample is strongly oil wet. This result compares well to the Core Laboratory data where the relative wettability index was found to be **–0.653**.

MMP Determination

Four slim tube experiments were run with the Blinebry separator oil. The slim tube used had an inside diameter of 0.25 in., length of 40 ft, and is packed with 170 to 200 mesh glass beads. Using both CO_2 breakthrough and final oil recovery suggest the minimum miscibility pressure (MMP) of the separator oil is about 1000 psig. The live oil is expected to have a similar MMP unless the bubblepoint of the oil is above 1000 psig. If the bubblepoint of the live oil is above 1000 psig, then the bubblepoint pressure is considered to be the MMP for CO_2 injection.

Well Log Analysis

A variety of Teague field well logs were available in the Log ASCII Standard (LAS) format. A review of the available curve sets suggested that the data should be divided into two groups: density/neutron (D/N) wells and sonic wells. A few wells had both D/N and sonic logs. Multiple companies recorded the D/N logs over several years. Therefore it was necessary to develop an interpretation procedure that was customized to each well. In a few cases it was not possible to derive a satisfactory porosity from the D/N logs, probably due to improper instrument calibration at the time of logging. In these cases a company generated porosity curve was digitized at PRRC and substituted in the analysis. The D/N logs were used to generate crossplot porosity, water saturation, pay thickness, and original oil in place.

Several well logging companies obtained the sonic logs over a 30-year interval. In order to compensate for instrumental inconsistencies a sonic log calibration procedure was developed and applied during the porosity calculation. Field average water saturation was applied to the pay intervals to calculate original oil in place from the sonic porosity.

The Blinebry formation interval was located in each logged well and then applied to the log analysis. The average value of the top of the pay interval is about 5270 ft. The average value of the bottom of the pay interval is about 5970 ft.

Interpretation Parameters

Log interpretations were performed using GeoGraphix Prizm log interpretation software. This software requires several parameters to perform environmental corrections and calculate derivative curves. Previous work by Core Laboratories on the Lamunyon 50 core was reviewed to determine values for the Archie parameters (m and n) and acoustic transit time (DT). A report dated April 27, 1990 averages four points along the core to obtain values of m=1.73 and n=1.57. A report dated July 6, 1990 gives values of m=2.09 and n=1.87 at a single point.

The values m=1.73 and n=1.57 were applied to the log analysis. This produced water saturation values that are considered to be artificially low (Sw=10%). Consultation with the client field geologist suggested that the default values m=2 and n=2 should be applied to the Teague-Blinebry field, since this approach had been successful in the Permian Basin in previous log analysis. This assumption gave more realistic water saturation values.

In order to derive porosity from the sonic logs a matrix transit time is needed. Acoustic velocity measurements made by Core Laboratories on the Lamunyon 50 core were the basis for determining the matrix transit time. The core porosity values are total porosity indications as determined by the helium method at Core Laboratories. The matrix transit time was obtained from the empirical transit time to porosity transform PHI=0.67((DT-DTma)/DT), hence DTma=DT-DT(PHI/0.67). The Core Laboratories data and calculated DTma values are presented in Table 2. The average DTma value for these samples is 45.17 usec/ft. DTma=45.0 usec/ft was used in the sonic log analysis because this value is a better mean between the upper and lower Blinebry characteristics.

Table 2. Acoustic Data

Depth[ft]	P-wave velocity [ft/sec]	DT [usec/ft]	Core PHI [%]	DTma [usec/ft]
5303	17449	57.31	14.4	45.0
5307	16713	59.83	16.0	45.5
5320	17862	55.98	12.4	45.6
5556	20181	49.55	6.7	44.6

Water analysis reports were available for many wells. The water analysis reports were produced by several different companies and span the years from 1978 to 1997. In addition, Arch Petroleum supplied caught-water samples for several wells. These samples were measured at PRRC using a TDS meter calibrated specifically for Blinebry type brines. TDS determination varied from 36 kppm to 136 kppm.

It is thought that the water samples poorly represent the Blinebry formation water. The well water composition can be strongly influenced by well treatment chemicals and contributions from adjacent formations. The best estimate for Blinebry formation water TDS is 46 kppm. This salinity corresponds to a Rw value of 0.1 Ohm-m at 110^{o}F.

Density/Neutron Interpretation

In order to use the Schlumberger crossplot functions for compensated neutron logs (CNL) that are built into the software, several environmental corrections need to be backed out of the neutron log. This is accomplished by applying functions for borehole size, salinity, mud weight, temperature, mud cake, and pressure. This yields a neutron porosity curve in limestone porosity units that can be entered into the crossplot function.

In most cases the well log contained a density porosity curve. The crossplot function supported by Prizm requires a bulk density curve. Bulk density curves were calculated from the density porosity curves. If a bulk density curve was recorded in the log, this curve was used directly.

Although all the neutron logs were of the CNL type, these logs were either part of a formation density (FDC) or litho-density (LDT) tool package. The logs were recorded over a several year time span during which the technology applied in the field was changing from FDC to LDT. Different companies also recorded the logs. Therefore it was necessary to examine each log in detail to determine which tool (FDC or LDT) had actually been used. Because of these idiosyncrasies the density/neutron interpretation was customized to each well.

Crossplot Porosity

The software used supports both FDC and LDT crossplot porosity (PHIA) functions. The density and neutron measurements respond to both primary and secondary porosity. PHIA crossplot porosity is the best estimator of true porosity available in this study.

Water Saturation and Bulk Volume Water

Water saturation (SwA) is derived from the crossplot porosity PHIA and the true resistivity of the formation (Rt). The Blinebry reservoir is characterized by intervals of very high resistivity where the dual laterolog traces may exceed the maximum scale value and only the deep laterolog trace is recorded on the backup curve. This causes gaps in the Rt data because Rt is a function of shallow and deep laterolog and the micro SFL log. To overcome this problem a test was performed to determine if the Rt value was significantly different from the deep laterolog (LLD) value. LLD was found to be a very good estimate of the Rt. This is consistent with very shallow invasion by the drilling fluid and the extreme low permeability found from core analysis.

The Archie empirical relationship $SwA=(a*Rw/(LLD*PHIA^{m}))^{1/n}$ is used to obtain water saturation. The parameters a, m, and n used were previously discussed. SwA values can range from zero to 1, but normally are found between 0.15 and 1. Bulk volume water (BVW) is simply SwA multiplied by PHIA.

Sonic Log Calibration

The sonic logs proved less difficult to interpret because the data is less complex and there had been no significant technological changes over the time span represented in the field well logs. The sonic logging tool should be calibrated at the time of well logging; however, this is not always properly done. In this case a small error will be added to the interval transit time recorded on the sonic log. This timing error can be either positive or negative.

Fifty-seven wells were logged with the sonic tool and 33 required calibration. Again the core well, Lamunyon 50, was used to develop the procedure for this calibration. Utilizing core data and calculated PHIA, it was determined that the sonic calibration would be executed by determining a deltacal value from two depths. The interval 5520 to 5530 ft is thought to have a true porosity of 1.0%. The interval 5880 to 5890 ft is thought to have a true porosity near 0%. If it was possible to correlate both regions to the other wells, an average calibration factor was determined. The sonic calibration was utilized in a modified Wyllie time average calculation, where sonic porosity PHIS=((DT-deltacal)-DTma)/(DTfld-DTma).

Cutoff Criteria and Pay

In order to determine pay intervals a series of cutoff criteria was developed. The first criteria (D/N PAY) requires PHIA to be greater than 5% and simultaneously BVW to be less than 5%. The second criterion (PHIA PAY) simply requires that PHIA be greater than 5%. This pay interval was calculated as a quality control check to see how much pay was excluded in D/N PAY by the BVW requirement. The third criterion requires PHIS calculated with the calibrated sonic log to be greater than 5%.

Pay and OOIP

For each well a text file of pay as a function of depth was generated from each pay report. Pay versus depth is necessary to identify correlatable pay zones within the Blinebry formation and will serve as the basis for CO_2 flood design in this field. A set of Prizm generated correlation logs was also developed.

Original oil in place (OOIP) was calculated for the wells with D/N logs. OOIP was generated using the function BBL=(7758/Bo)*acres*PAY*PHIA*(1-SwA), where Bo=1.2 and acres=20. Two wells were excluded from the calculation of the field average parameters because they have anomalous values. Lamunyon 49 has an unusually low water saturation and excessive pay thickness. Lamunyon 68 has a high water saturation and low pay thickness.

Although only porosities could be generated for the 57 sonic log wells, it is highly desirable to use the sonic wells to characterize the field due to their extensive distribution throughout the field compared to the 18 D/N wells. Therefore it was decided to use the pay thickness from the sonic logs in combination with the average barrels per acre-foot from the D/N wells to calculate OOIP. As a quality check, OOIP was also calculated using sonic pay thickness, well average sonic porosity, and the D/N field average SwA. These two methods compare to within 3% for the 57 wells. The average pay thickness per well is very similar to the D/N result (149 ft vs 147 ft). Also, both OOIP calculations mentioned above and the sonic well average are close to the D/N well average (915,291 bbl and 941,693 bbl vs 925,030 bbl respectively).

This OOIP data set and the pay versus depth data are the basis for further work toward design of a CO_2 flood. Maps of net pay derived from the D/N and sonic logs were generated. The map distribution of net pay includes a central dome and a south dome separated by a structural saddle. These features correlate generally to the structure of the Blinebry formation.

Target Zone for Future Studies

It was noted from the logs that features in the upper Blinebry (5200 to 5500 ft) are continuous across the field, while the features below 5500 ft do not correlate well. These continuous zones represent a potential flow path for displacing fluids from well to well. Also, although the upper Blinebry comprises only 40% of the potential pay zone, it contains about 70% of the net pay. These factors combined make the upper Blinebry the focus of any future study. As an example see Figure 7 for Lamunyon 50 showing cumulative oil in place versus depth.

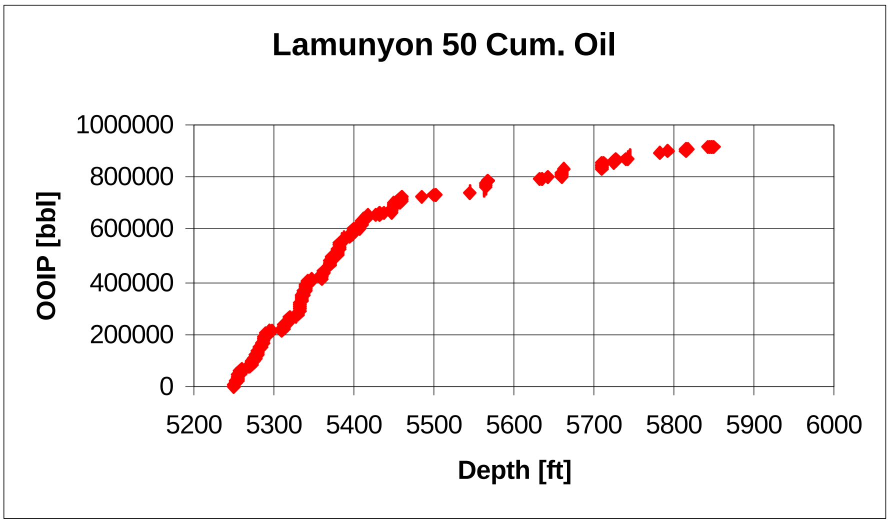

Figure 7. Typical Net Pay Distribution in the Blinebry Formation

Effective Permeability

Results from a step rate test on Lamunyon 62 and net pay results determine the effective permeability to be (163.91 md-ft)/(143 ft) = 1.15 md. A 1989 test on Lamunyon 50 and a given viscosity of 1.49 cp provide two estimates for total fluid mobility that can be used to solve for effective permeability. By the Horner radial flow analysis, effective permeability is (1.27 md/cp)*(1.49 cp) = 1.89 md. By the derivative type curve analysis, effective permeability is (1.40 md/cp)*(1.49 cp) = 2.09 md. These values that range from 1.15 to 2.09 md are well above the average matrix permeabilities, indicating an effective permeability contribution from a fracture system.

Production Effects From Infill Drilling

Oil production data was examined for four areas of the field. In each case at least one new infill well was included and several nearby wells that had pre-1995 production data. Only oil production from 1995 through 1997 was included. No significant oil production changes were seen that could clearly be attributed to production from the infill wells. Stimulation effects due to well treatment that may be present in the older well data complicate interpretation. Another factor that must be considered is the long time-scale masking effect of the low permeability reservoir.

Conclusions

1. Air permeabilities were determined on seventy-nine intervals using the PRRC scanning minipermeameter. Two types of permeability regions were identified. The first or normal region has consistently low permeabilities of less than 1 md with a standard deviation that is less than the average permeability. The second type contained fractures and/or vugs that gave poor results with a standard deviation larger than the average permeability that was usually greater than 1 md.
2. Twelve core plugs had air permeabilities determined at both ends using the scanning minipermeameter. Eight were selected for brine permeability tests; two were selected for water and CO_2 displacement tests. The two core displacement tests show that oil can be displaced in a core from both water and CO_2 injection. The pressure drop across the core was always less with CO_2 and in each tested case CO_2 followed water injection to residual oil. In each case CO_2 produced a significant amount of oil after waterflood. In the field, it appears that CO_2 could be injected without a prior waterflood.
3. It was found that even in the well-mineralized fractures, the permeability was generally much greater than the surrounding matrix. Two flow tests using adjacent core plugs found the brine permeability to be 0.53 md in a region with a visual fracture and 0.003 md in a region without a visual fracture.
4. A core was determined to be strongly oilwet and compared well to an earlier test by Core Labs with wettability indices of –0.608 and –0.653, respectively.
5. Tests determined the MMP to be the higher of 1000 psig or the system bubblepoint pressure.
6. The upper Blinebry has significantly more continuous features and net pay than the lower Blinebry, and is a prime target for future studies.
7. From net pay and results of a step rate test on Lamunyon 62 well, the effective permeability of Lamunyon 62 was determined to be 1.15 md. This compares well with earlier work. This is much greater than the matrix permeability; typically around 0.1 md; indicating some type of fracture system.
8. The examination of production data on wells near a new infill well is not conclusive. Most wells show no change in production that is clearly due to the infill well. This would indicate that new oil that would not otherwise be produced has been tapped. A few wells show a production change that may be related to the infill well. These may indicate interwell communication through a fracture system.

Acknowledgements

The authors acknowledge the support of Arch Petroleum (now POGO Producing Company) especially Glenn Curry (geologist) and Rick Vanderslice (engineer), The Department of Energy (contract DE-FG22-97BC-15047), and the State of New Mexico. The authors also acknowledge the contributions of PRRC personnel: David Schecter, Martha Cather, Boyun Guo, Cletus Scharle, Yan Fidra, and Mike Jaramillo.