FINAL TECHNICAL PROGRESS REPORT FOR THE PERIOD ENDING March 7, 2010

TITLE: FIELD DEMONSTRATION OF CARBON DIOXIDE MISCIBLE FLOODING IN THE LANSING-KANSAS CITY FORMATION, CENTRAL KANSAS

DOE Contract No. DE-AC26-00BC15124

Contractor: University of Kansas Center for Research, Inc.
2385 Irving Hill Road
Lawrence, KS 66044

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ABSTRACT:

A pilot carbon dioxide miscible flood was initiated in the Lansing Kansas City C formation in the Hall Gurney Field, Russell County, Kansas. The reservoir zone is an oomoldic carbonate located at a depth of about 2900 feet. The pilot consists of one carbon dioxide injection well and three production wells. Continuous carbon dioxide injection began on December 2, 2003. By the end of June 2005, 16.19 MM lb of carbon dioxide was injected into the pilot area. Injection was converted to water on June 21, 2005 to reduce operating costs to a breakeven level with the expectation that sufficient carbon dioxide was injected to displace the oil bank to the production wells by water injection. By March 7,2010, 8,736 bbl of oil were produced from the pilot. Production from wells to the northwest of the pilot region indicates that oil displaced from carbon dioxide injection was produced from Colliver A7, Colliver A3, Colliver A14 and Graham A4 located on adjacent leases. About 19,166 bbl of incremental oil were estimated to have been produced from these wells as of March 7, 2010. There is evidence of a directional permeability trend toward the NW through the pilot region. The majority of the injected carbon dioxide remains in the pilot region, which has been maintained at a pressure at or above the minimum miscibility pressure. Estimated oil recovery attributed to the CO2 flood is 27,902 bbl which is equivalent to a gross CO2 utilization of 4.8 MCF/bbl. The pilot project is not economic.

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INTRODUCTION

Objectives - The objective of this Class II Revisited project was to demonstrate the viability of carbon dioxide miscible flooding in the Lansing-Kansas City formation on the Central Kansas Uplift and to obtain data concerning reservoir properties, flood performance, operating costs and methods to aid operators in future floods. The project addressed the producibility problem that these Class II shallow-shelf carbonate reservoirs have been depleted by effective waterflooding leaving significant trapped oil reserves. The objective was addressed by performing a CO_2 miscible flood in a 10-acre (4.05 ha) pilot in a representative oomoldic limestone reservoir in the Hall-Gurney Field, Russell County, Kansas. At the demonstration site, the Kansas team characterized the reservoir geologic and engineering properties, modeled the flood using reservoir simulation, designed and constructed facilities and remediated existing wells, implemented the planned flood, and monitored the flood process. The results of this project were disseminated through various technology transfer activities.

Project Task Overview -

Activities in Budget Period 1 (03/00-2/04) involved reservoir characterization, modeling, and assessment:

- Task 1.1- Acquisition and consolidation of data into a web-based accessible database
- Task 1.2 - Geologic, petrophysical, and engineering reservoir characterization at the proposed demonstration site to understand the reservoir system
- Task 1.3 - Develop descriptive and numerical models of the reservoir
- Task 1.4 - Multiphase numerical flow simulation of oil recovery and prediction of the optimum location for a new injector well based on the numerical reservoir model
- Task 2.1 - Drilling, sponge coring, logging and testing a new CO2 injection well to obtain better reservoir data
- Task 2.2 - Measurement of residual oil and advanced rock properties for improved reservoir characterization and to address decisions concerning the resource base
- Task 2.3 – Remediate and test wells and patterns, re-pressure pilot area by water injection and evaluate inter-well properties, perform initial CO2 injection to test for premature breakthrough
- Task 3.1 - Advanced flow simulation based on the data provided by the improved characterization
- Task 3.2 - Assessment of the condition of existing wellbores, and evaluation of the economics of carbon dioxide flooding based on the improved reservoir characterization, advanced flow simulation, and engineering analyses
- Task 4.1 – Review of Budget Period 1 activities and assessment of flood implementation

Activities in Budget Period 2 (2/04-12/08) involve implementation and monitoring of the flood:

- Task 5.4 - Implement CO_2 flood operations
- Task 5.5 - Analyze CO_2 flooding progress - carbon dioxide injection will be terminated at the end of Budget Period 2 and the project will be converted to continuous water injection.
- A no cost extension of Budget Period 2 to June 30, 2009 was approved to continue development of the reservoir model

Activities in Budget Period 3 (1/09-03/10) will involve post-CO2 flood monitoring:

- Task 6.1 – Collection and analysis of post-CO2 production and injection data

Activities that occur over all budget periods include:

- Task 7.0 – Management of geologic, engineering, and operations activities
- Task 8.0 – Technology transfer and fulfillment of reporting requirements

EXECUTIVE SUMMARY:

The project involved injection of CO_2 from an ethanol plant into the Lansing Kansas City C formation in the Hall Gurney field near Russell, KS. The oil reservoir is a thin, oomoldic carbonate zone located at a depth of about 2900 feet. The reservoir zone was waterflooded previously and was abandoned by about 1990. The pilot consisted of one CO_2 injection well and two production wells on about 10 acre spacing. Water injection wells were used to confine the CO_2 to the pilot area.

The project was carried out in three phases: Phase 1) Reservoir characterization and economic analysis, Phase 2) Implementation and Phase 3) Post CO_2 flood monitoring. Phase 1 began on March 8, 2000 and was completed on March 6, 2004. Phase 2 began on March 7, 2004 and was completed on December 31, 2008. Phase 3 began on January 1, 2009 and was completed on March 7, 2010.

Continuous injection of CO_2 into the Lansing Kansas City C formation in Hall Gurney field near Russell, KS, began on December 2, 2003. CO_2 was trucked from the ethanol plant operated by US Energy Partners by EPCO, where it was unloaded into a portable storage tank on the lease. CO_2 was injected as a compressed fluid using an injection skid provided by FLOCO2. By the end of June 2005, about 16.92 million pounds of CO_2 had been injected. The average rate of CO_2 injection during January-June 2005 was about 245 MCFD. Injection was converted to water on June 21, 2005, in an effort to reduce operating costs to a breakeven level with the expectation that sufficient CO_2 was injected to displace the oil bank to the production wells by water injection. The amount of gas produced was about 5 percent of the injected CO_2.

Production from the pilot lease (8,736 bbl) was less than anticipated and was slower to build than expected. In August 2006, wells on the adjacent leases (Colliver A and Graham) north of the pilot area were opened in the C zone and produced substantial amounts of oil attributed to the CO_2 flood. As of March 7, 2010 about 19,166 bbl of incremental oil were estimated to be produced from these wells since the beginning of the CO_2 project. Incremental oil from the CO_2 pilot area and the Graham and Colliver A leases attributed to CO_2 injection is about 27,902 bbl which is equivalent to gross CO_2 ratio of 4.8 MCF/bbl. The pilot project was not economic.

TASK 1.1 ACQUISITION AND CONSOLIDATION OF DATA INTO A WEB-BASED ACCESSIBLE DATABASE

A web-based database was created which contains all reports, core analyses and presentations concerning the CO2 project. This database is accessible through the following URL: http://www.kgs.ku.edu/CO2/index.html .

TASK 1.2 RESERVOIR CHARACTERIZATION

1.2.1 Geologic Characterization - The Lansing-Kansas City 'C' zone reservoir was characterized geologically in the Colliver-Carter area using available cuttings and wireline logs. There was limited core data from wells in the pilot area. Based on correlation with outcrop Lansing-Kansas City and log signatures, the Lansing-Kansas City section comprises a succession of alternating marine limestones and shallow marine to nonmarine shales deposited during the Upper Pennsylvanian Series. Seas episodically covered Kansas and the Midcontinent leading to the accumulation of limestones and shales. The extreme fluctuations in sea level lead to the advance and retreat of multiple shorelines, locally characterized by high-energy conditions, much like portions of the present day Bahama Platform. The shoal water limestones of the Lansing-Kansas City were locally oolitic grainstones, a common lithology that serves as the main petroleum reservoir in these rocks in Kansas. The ooids are typically distributed as bars, spillover lobes, deltas, and beaches exhibiting potentially complex sets of lobes, pods, and lenses of oolite deposited during a particular cycle and sea level conditions. Geometries of beds within oolitic grainstones can include cross stratification, large foresets, and cut-and-fill structure.

Based on thin section analysis, original primary porosity was interparticle and could range up to 40 percent of the volume of the rock. This pore space was modified by early post-depositional processes including alteration by rainwater (meteoric) and shallow groundwater moving through the rock leading to both dissolution of ooids and cementation of original interparticle porosity. Most Pennsylvanian ooids were originally aragonite and tended to dissolve and recrystalize after coming into contact with percolating fresh rainwater or shallow groundwater. While Lansing-Kansas City oolitic grainstones were formed by the deposition of ooids, oomoldic grainstones in the Lansing-Kansas City of Hall-Gurney Field and the demonstration site are dominated by molds of ooids. These oomoldic pores are the dominant porosity found in oolitic grainstones of the Pennsylvanian in the Midcontinent. The geometries of the permeable (effective) reservoir rock vary considerably as a function of: 1) sedimentation of the oolites and 2) post depositional alteration including dissolution, cementation, and structural deformation.

At the demonstration site the reservoir facies was an oomoldic limestone. Figure 1.2.1 illustrates a typical Lansing 'C' zone oomoldic limestone in both direct image and under plane light in thin section with blue-dye epoxy filling pores. Scanned images of cuttings will be placed on the web site in the next quarter.

Mercury capillary pressure was measured on eight samples including oomoldic limestones distributed across the Central Kansas Uplift and a core chip from the Colliver #12. Selected samples spanned nearly the complete range in porosity (16.8%-24.9%) and permeability (0.68md – 91.9md) exhibited by the reservoir quality Lansing-Kansas City oomoldic limestones from the

Central Kansas Uplift available in the study set.

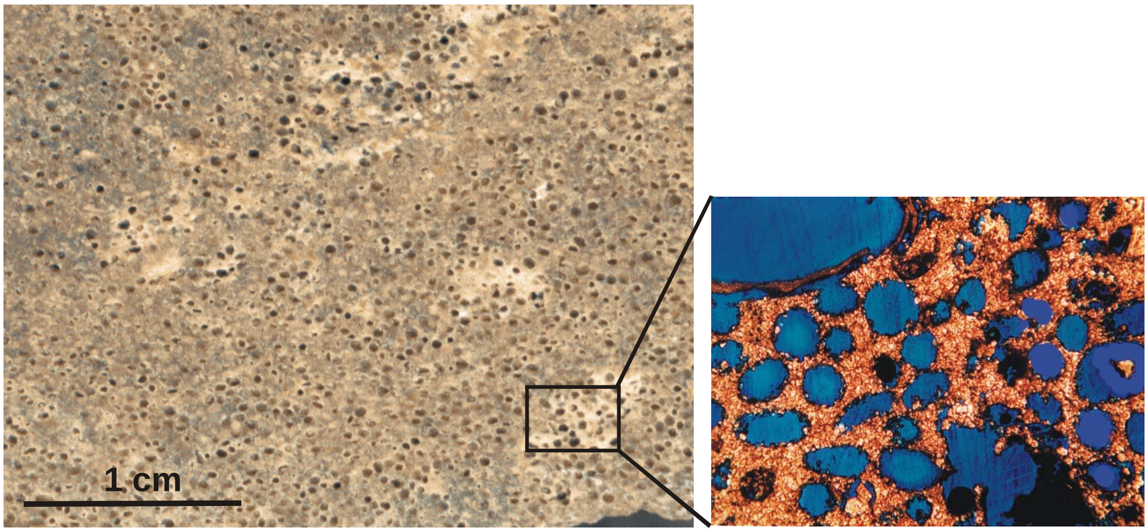


Figure 1.2.1 Lansing-Kansas City oomoldic limestone and plane light thin section showing blue-dye epoxy-filled pore space.

Examination of wireline log gamma ray and unscaled neutron porosity depth profiles indicates that the Lansing 'C' zone at the demonstration site consists of either three transgressive-regressive cycles or three stacked beds. For maximum numerical simulation accuracy the C zone was divided into six layers, termed C1 through C6 as described below.

Core Petrophysics - Preliminary routine and special core analysis on oomoldic limestones from the Central Kansas Uplift was completed and the data analyzed. Full diameter porosity and permeability data for the Colliver #1, measured by Phillips Oil Company in 1936, were found in the well files. These full-diameter permeabilities are some of the highest values reported or measured to date though they fall below the maximum permeability versus porosity trend for Central Kansas Uplift oomoldic limestones as shown below on Figure 1.2.2. Core chips were also obtained for the Colliver #12. Porosity and grain density were measured on trimmed chips, generally measuring approximately 2-6 cm^3, after these measurements the chips were embedded in epoxy with two end faces exposed for permeability testing. Full diameter and chip permeability versus porosity trends are shown on Figure 1.2.2. Differences between chip and whole core permeabilities may reflect such factors as microfracturing, vuggy porosity channels, differences in oomoldic limestone properties, or other parameters. These differences will be resolved using data obtained on the new injector well core under Task 2.

Air-brine capillary pressure measurements were performed on a range of Lansing-Kansas City oomoldic limestone samples to obtain a trend to predict initial water saturation in the reservoir. Capillary data indicate very low irreducible water saturations for oil column heights greater than 180 feet above free water level. Analysis of the Hall-Gurney structure near the Colliver and Carter leases indicates that the reservoir lies approximately 45-55 feet above free water level (Figure 1.2.3) which exhibit higher saturations.

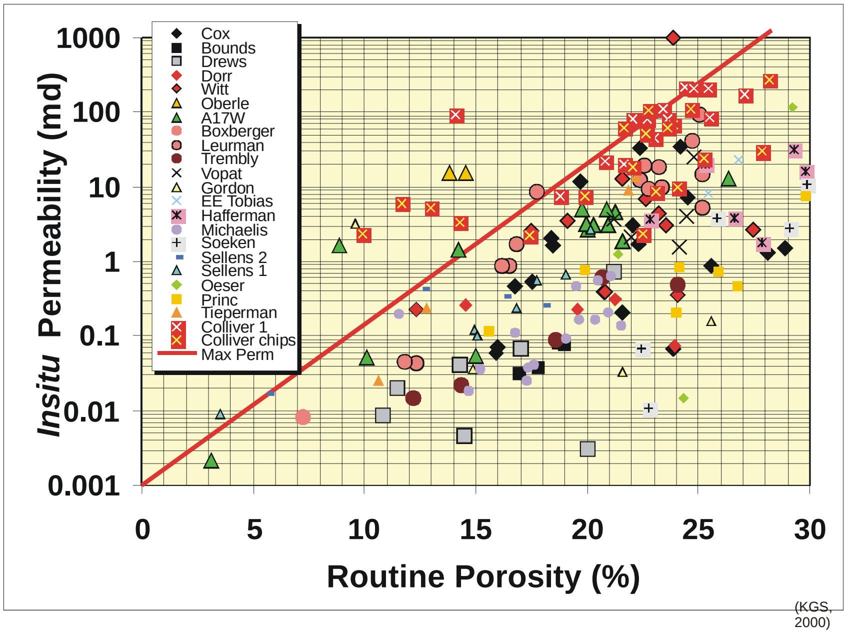


Figure 1.2.2. In situ Klinkenberg permeability versus routine porosity for Lansing-Kansas City oomoldic limestone cores obtained from wells in reservoirs lying along the Central Kansas Uplift. Estimated maximum permeability for unfractured and non-vuggy rocks is shown as red trendline. While scatter for total population is high, individual wells exhibit significantly less scatter.

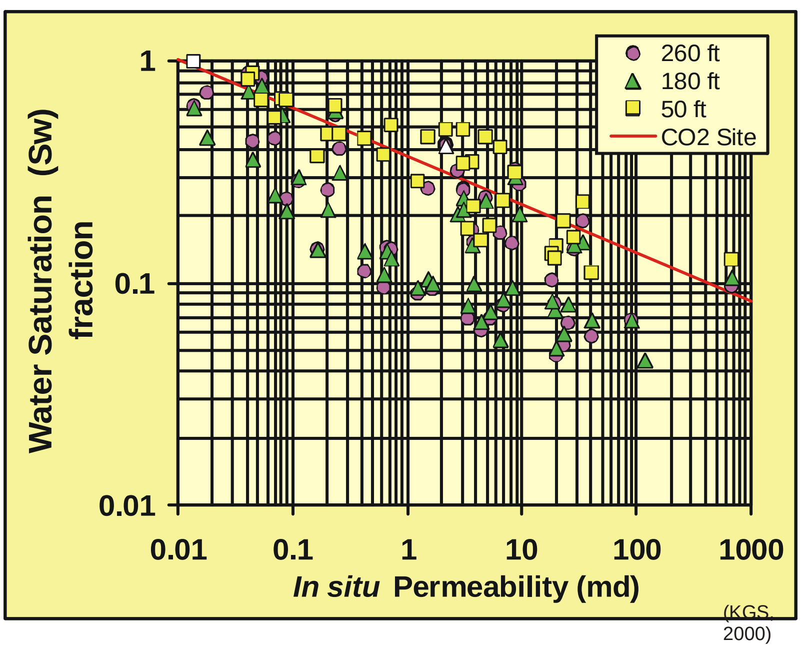


Figure 1.2.3. Water saturation at various oil column heights above free water level versus permeability for Lansing-Kansas City oomoldic limestones.

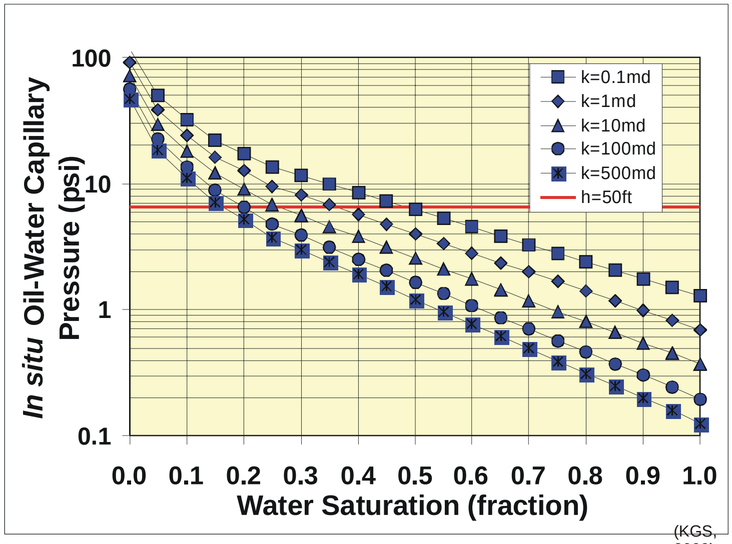


Figure 1.2.4. Generalized capillary pressure curves for oomoldic limestones constructed using formulas. Curvature below 15% Sw was induced by adjustment multiplier and is not predicted by the equations.

Examination of the capillary pressure curves for the eight samples reveals that many samples exhibit a near log-linear trend between wetting phase saturation (assumed to be water in the reservoir) and oil-brine height above free water level. This would also translate to a log-linear relationship between wetting-phase saturation and reservoir oil-brine capillary pressure. Comparison between samples of different permeability indicates that capillary pressures decrease with increasing permeability at any given saturation. This is a typical trend for most rocks. Analyzing the relationship between the change in capillary pressure and permeability, an equation was constructed that provides approximate capillary pressure curves for any given permeability (Fig. 1.2.4). This equation takes the form:

$$Pc = 10^{(A\ Sw\ +\ B)}\ (\rho_{water}-\rho_{oil})$$

Where Pc is reservoir oil-brine capillary pressure (psia), Sw is water saturation (fraction), ρ_{water} and ρ_{oil} are water and oil density (g/cc), and A and B are constants that vary with permeability. These constants can be predicted from permeability using:

$A = -0.1663 \log_{10}$*Permeability* (md) –1.5186
$B = 0.1088 \log_{10}$*Permeability* (md) +2.2476

These equations provided generalized capillary pressure curves that approximate the general relationships shown by the samples studied.

Thin sections were prepared for twenty cuttings and core chips from the Colliver lease. These are all oomoldic limestones but exhibit a range of pore types including isolated oomolds, connected oomolds, vuggy, microcrystalline, fractured, interparticle, and exhibit macroporous cement.

Because core was not available from the Colliver or Carter leases or from more permeable Lansing-Kansas City oomoldic limestone, imbibition water-oil relative permeability curves were obtained from data provided by McCoy Petroleum measured on oomoldic limestone from the Marmaton Formation , Amazon Ditch East Field, Six-M Farms "A" No. 3-22, Finney County, KS. These limestones exhibited properties very similar to the Lansing 'C' zone with porosity of 24-25% and permeability of 20-28 md. These data were used for initial relative permeability curves for the numerical simulator.

Log Petrophysics - Wireline logs for 41 wells in the area of the pilot were obtained, digitized and analyzed. The majority of these logs were older gamma ray – neutron logs with no resistivity logs but these appear to provide adequate porosity evaluation within $\pm$2 porosity percent. To convert neutron response to porosity the logs were calibrated using the standard log-linear relationship:

$$\text{Porosity (\%)} = 10^{(A*\text{Neutron} + B)}$$

Where A is the slope of the correlation between $\log_{10}$Porosity and neutron response and B is the intercept. These constants were derived using a log-linear straight-line relationship between the two points: 40% porosity-minimum Neutron response, 1% porosity-maximum neutron response. Using this correlation neutron log response was converted into porosity.

1.2.2 Fluid Characterization – Oil from the Letsch #7, one mile east of the Colliver lease was analyzed for minimum miscibility pressure prior to start of the DOE contract. . Interfacial tension was measured on a Letsch #10 oil sample and found to be 28.6 dyne/cm at 25^{o}C. Oil chemical composition was measured by Core Laboratories on the Letsch #7 oil sample and used to adjust reservoir PVT properties in the VIP reservoir simulator..

1.2.3 Engineering Characterization – Preliminary reservoir simulation results indicated the presence of a low permeability region between the Colliver and Carter leases, based on flood response. This may indicate the possibility of shingling of oolite pods or bed sets. Initial estimates of permeability did not result in simulated production rates that were consistent with known injection/production data. Consequently, permeability-height, *kh*, were calculated based on known production/injection rates in 1980, wireline interpreted reservoir thickness, an assumed water relative permeability of 20% at residual oil saturation, and other basic properties assumptions were estimated from 1980 production and injection rates (Figure 1.2.5). These estimates were used to modify the assigned permeabilities for each well that were based on calculated permeabilities predicted from wireline log porosities

Because gas was not sold off-site, gas production rates were not recorded for most of the primary production period for the Lansing-Kansas City. Therefore no quantitative data are available for initial gas in solution. In general Lansing-Kansas City oils are undersaturated but gas-in-solution varies with location. Based on the report that engines driving pumps were run using lease gas through much of primary production, an estimate was made of the minimum gas required to operate the wells. This estimate indicated approximately 65-80 standard cubic feet per barrel. This value for gas-in-solution provided appropriate production response including sufficient drive to sustain known primary production and pressure decline.

Estimated Peremability for Colliver-Carter Wells based in Injection/Production in 1980								
Viscosity of water,cp		0.77		k_{rw} @ S_{iw}	0.2			
B_w, RB/STB		1.0079		p_e, psi	600			
r_w, ft		0.359		p_w, psi	30			
Production Wells	**h, ft**	**r_d, ft**	**q_w, B/D**	**k_w, darcy**	**k, darcy**	**kh, darcy ft**		
Colliver 1	14	664	151	0.015	0.077	1.083		
Colliver 3	11	652	91	0.012	0.059	0.651		
Colliver 5	15.5	678	137	0.013	0.064	0.986		
Colliver 6	12.5	554	115	0.013	0.064	0.805		
Colliver 7	11	1071	614	0.085	0.426	4.685		
Colliver 9	13	901	92	0.011	0.053	0.687		
Colliver 12	15	593	128	0.012	0.060	0.905		
Colliver 13	13	571	71	0.008	0.038	0.499		
Colliver 14	15	470	219	0.020	0.100	1.499		
Total-Colliver			1618					
Carter 2	12	455	14	0.002	0.008	0.095		
Carter 3	17.5	362	101	0.008	0.038	0.666		
Carter 5	17.5	441	56	0.004	0.022	0.380		
Carter 11	14	145	39	0.003	0.016	0.223		
Carter 12	11.5	212	33	0.003	0.017	0.201		
Total-Carter			243					
Total-Colliver and Carter			1861					
Injection Wells	**h, ft**	**r_e,ft**	**i_w, B/D**	**p_{wh},psi**	**p_{bh},psi @2880 ft**	**k_w darcy**	**k,darcy**	**kh, darcy ft**
Colliver 2	17	716.56	417	1100	2433.44	0.0111	0.0553	0.9396
Colliver 4	17	963.19	290	1150	2483.44	0.0078	0.0389	0.6608
Colliver 8	9.5	1196.23	274	250	1583.44	0.0259	0.1293	1.2286
Colliver 10	15	1143.23	119	415	1748.44	0.0061	0.0303	0.4544
Colliver 18	12	667.02	230	1280	2613.44	0.0078	0.0390	0.4674
Colliver 19	12	518.15	349	1275	2608.44	0.0115	0.0573	0.6872
Colliver 20	12	381.77	185	1275	2608.44	0.0058	0.0291	0.3490
Total Colliver			1864					
Carter 4	12	349.07	182	1430	2763.44	0.0052	0.0262	0.3146
Carter 10	12	530.82	288	1140	2473.44	0.0102	0.0508	0.6100

Figure 1.2.5: Estimates of Colliver and Carter Permeabilities Based on Well Data

TASK 1.3 RESERVOIR MODEL

A qualitative and quantitative preliminary reservoir model was constructed for the Colliver and Carter leases. The Lansing 'C' interval has been characterized as being composed of three stacked units between which the vertical communication is uncertain (Figure 1.3.1)

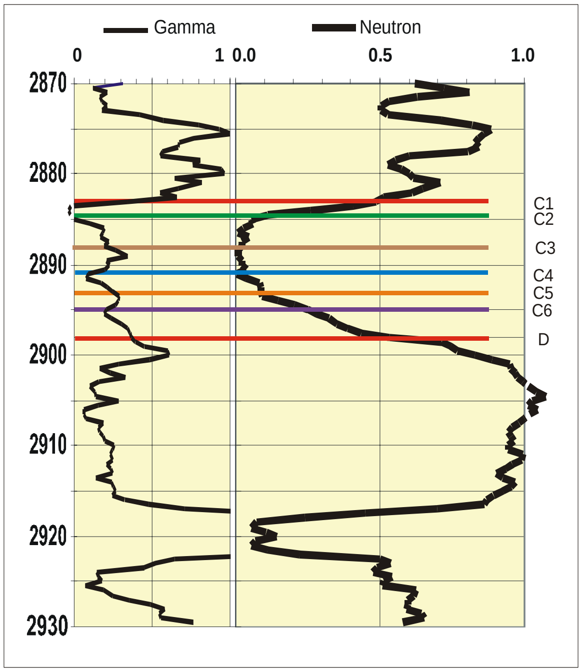


Figure 1.3.1. Colliver #18 normalized gamma ray-unscaled neutron log showing six C zone layers and three cycles. The Colliver #18 exhibits some of the best porosity compared to all wells in both leases.

Because permeability changes by a factor of 2 for every 1 porosity unit change, each of the three layers was divided into an upper and lower layer to minimize permeability variance within a layer and error associated with layer averaging. Overall, the C zone deceases in porosity and permeability from top to bottom. The six layers have been termed C1 through C6. This division allows more accurate delineation of saturations and flooding behavior in each layer.

Average Layer Properties

C1: 8 md, 18.8%
C2: 150 md, 25.8%
C3: 40 md, 22.0%
C4: 6 md, 19.4%
C5: 2 md, 14.7%
C6: 0.3 md, 12.0%

Porosity and calculated permeability were mapped for each layer for the Colliver and Carter leases. An example of the porosity distribution is shown in Figure 1.3.2.

14S-13W Russell Co., Kansas

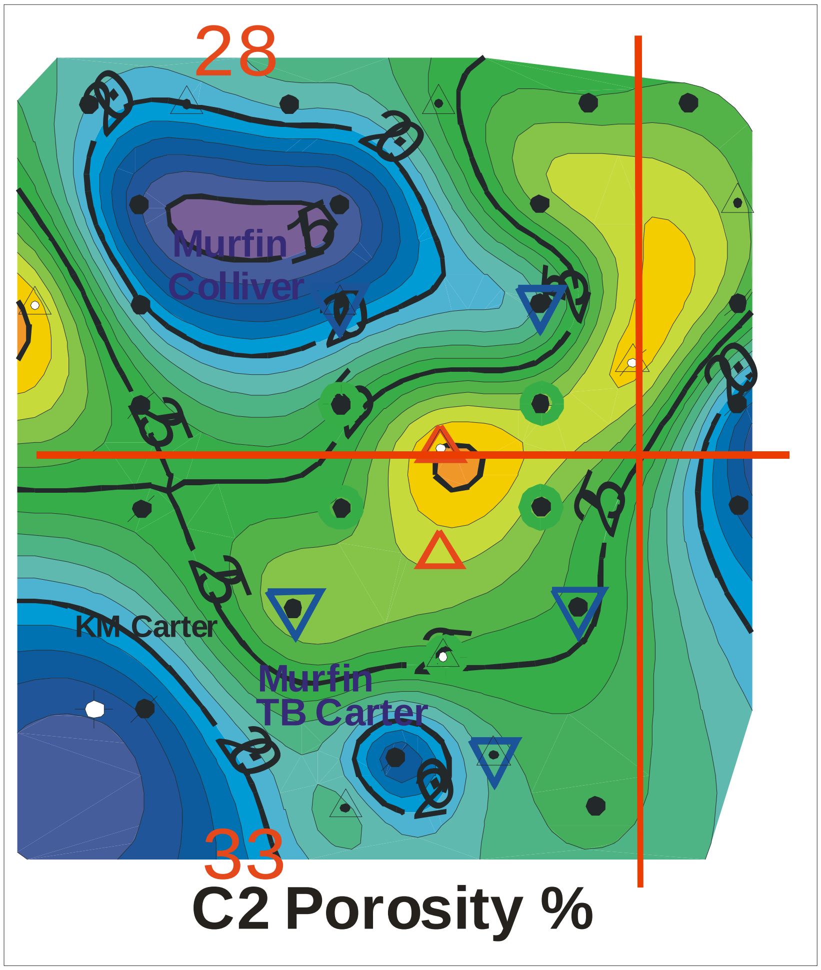


Figure 1.3.2. Example of porosity distribution in layer C2 for Colliver and Carter leases.

Properties of the preliminary quantitative reservoir model were modified to provide an optimum match between numerical simulator predicted production rates and cumulative production and reported values. Since permeability was correlated with porosity, and capillary pressures and relative permeability were correlated with permeability, changes in model reservoir porosity resulted in changes in model reservoir permeability, relative permeability, and initial water saturation. Permeabilities were predicted using two equations:

Porosity > 21%: $\quad$ $\textit{Permeability (md)} = 28.8 * \textit{Porosity (\%)} - 584.4$

Porosity < 21%: $\quad$ $\textit{Permeability (md)} = 10^{(0.207 * \textit{Porosity (\%)} - 3.05)}$

The high porosity equation was used because existing full-diameter core analysis data from the Colliver #1 well do not exhibit log-linear increase in permeability with increasing porosity at higher porosities.

Initial water saturations were predicted for each layer using the generalized capillary pressure curves presented in previous quarterly report. A single average saturation was assigned to each layer for the Colliver and Carter leases respectively. Although permeability differences between gridcells would indicate that water saturations and relative permeabilities should also vary between gridcells, the use of a single relative permeability curve for each layer (effectively a pseudo-relative permeability curve) required the use of pseudo-water saturations to avoid calculation of incorrect effective oil and water permeabilities in each gridcell.

Since relative permeability end point saturations change with permeability (e.g., “irreducible” water saturation changes with permeability), the relative permeability curves also change with absolute permeability. Starting relative permeability curves for each layer were predicted from the absolute permeability values for each layer (Figure 1.3.3).

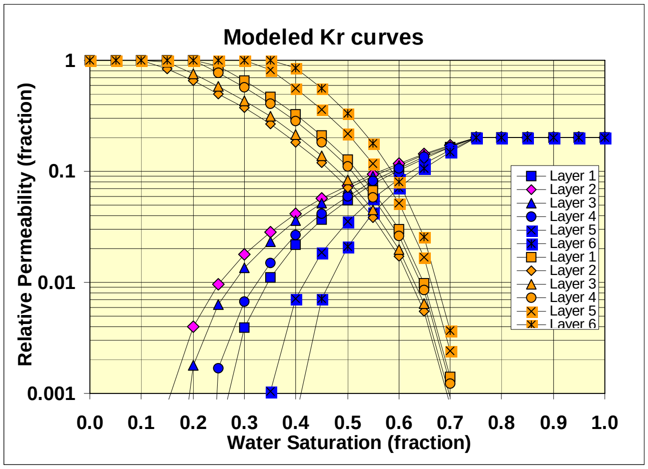


Figure 1.3.3:. Initial oil and water relative permeability curves for Layers C1-C6.

TASK 1.4 RESERVOIR SIMULATION (PHASE I)

Compiled lease production histories were used to construct a recurrent database for input into the VIP reservoir model. Oil composition and other data obtained from Letsch #7 were used to adjust PVT properties in the VIP numerical simulator. Simulation of primary production and waterflooding was performed on a Landmark Graphics ***VIP98 Plus*** reservoir simulator installed in a Silicon Graphics Octane MXE workstation. The pilot area was simulated using the six layer geomodel, with 48x46 gridcells in each layer, and with grid cells 110ftx110ft. History matching simulations were performed to match estimated primary and secondary production history using black oil simulation (Figure 1.4.1).

Simulations of the entire flood area were performed to determine surrounding water injection requirements for pressuring up the flood area to minimum miscible pressure (MMP) and maintaining pressures during flooding. Evaluation of pressuring the pilot area was simulated using a single layer model, injection into the five containment wells and the two CO2 injectors at 350 BWPD, initial BHP of 500#. About 165 days were required to pressure up the entire flood area to 1800 psi in the center of the pattern, 1500 psi in the pattern, and 1200 psi one-half mile from the pattern. Confinement and pressure maintenance was evaluated with wells outside the pattern allowed to produce. These results indicated that pressure control should not be a problem.

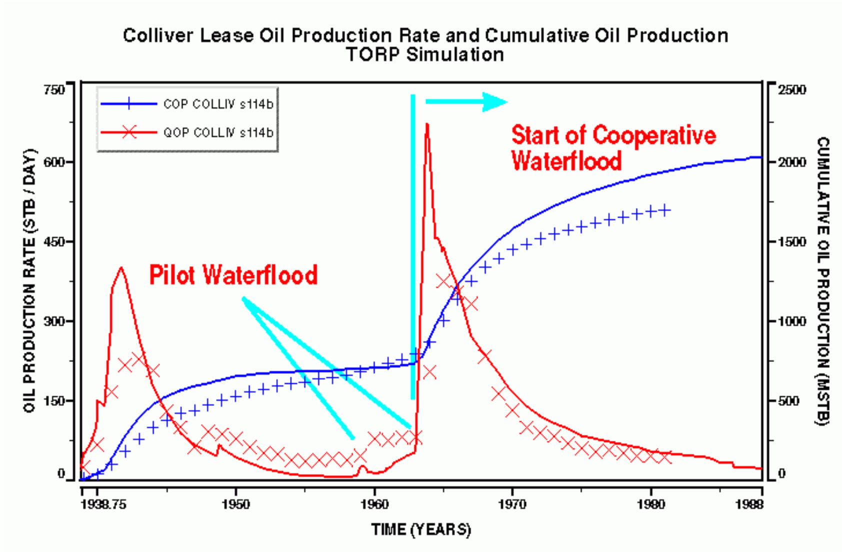


Figure 1.4.1:. History match of primary and secondary production history for Colliver lease.

Initial simulation of CO_2 flooding was done using the compositional version of VIP. Numerical simulations successfully matched the flood behavior in slimtube experiments conducted previously using LKC crude oil.. For CO_2 flooding a six pseudo-component fully compositional model was run in the pilot area. Multiple CO_2 flood simulations were performed to identify the best location of the new injection well. Figure 1.4.2 illustrates an example of a simulation showing the CO_2 oil bank (blue).

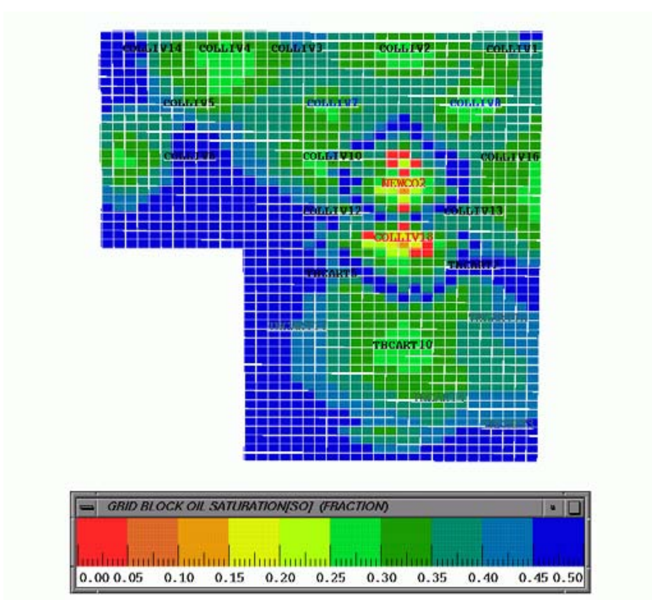


Figure 1.4.2: Simulation of CO_2 injection into two injection wells located on the Carter-Colliver Leases showing creation of an oil bank. The color scale is based on oil saturation with warm colors representing low oil saturation and cool colors high oil saturation.

TASK 2.1 DRILL, CORE, LOG AND TEST NEW CO2 INJECTION WELL

2.1.1 Drilling, Coring and Completion of CO2I-1

CO2 I#1 Carter-Colliver well (API# 15-167-23179), located in the S/2 SE/4 of Section 28-14S-13W, Russell County, Kansas began on September 23, 2000 and was completed on October 2, 2000 (Figure 2.1.1). Eight and five-eighths inch surface casing was set at 1435 feet (437.4 m) with 650 sacks of cement, a 7-7/8 inch (0.2 m) hole was drilled to a total depth of 3115 feet (949.45 m) and 5.5-inch (0.14 m) production casing was set at 3114 feet (949.15 m), one foot (0.3 m) off bottom, with 360 sacks of cement. Drilling operations were trouble free and the maximum hole deviation was ¾ degrees from vertical. Total cost for drilling and completion was initially estimated to be $146,050. Actual costs were $165,505. A low water loss polymer and starch mud system resulted in excellent hole conditions throughout the operation.

Five cores were taken including three conventional cores at depths of 2871-2894 (875.1-882.1 m; L-KC ‘B’ and ‘C’ zones), 2949-54 (898.86-900.38 m; L-KC ‘G’ zone), and 2954-2981 (900.38-908.6 m; L-KC ‘G’ zone) and two pressure cores at depths of 2894-2904 (882.1-885.14 m; L-KC ‘C’ zone) and 2904-2914 (885.14-888.19 m; L-KC ‘C’ and ‘D’ zones). Schlumberger’s Platform Express logging suite was run at total depth, including Compensated Neutron Litho Density, Array Induction Linear Correlation, and Microlog. In addition, a Borehole Compensated Sonic log was run. Schlumberger’s Repeat Formation Tester tool was run following the electric logging operation on sixteen intervals to obtain pressure data.

Though recovery of material cored using the high-pressure core barrel was good, a significant portion of material recovered from the good quality reservoir interval was deconsolidated and was primarily carbonate “dust.” Given the unconsolidated nature of the core, the core is believed to have been extensively flushed.

The geologic report log for the Lansing-Kansas City interval is presented at:
http://www.kgs.ku.edu/CO2/CO2Data/Misc/CO2I-1gr.html.
Wireline logs in the ‘C’ zone can be viewed at:
http://www.kgs.ku.edu/CO2/CO2Data/1516723179.html
And complete LAS format logs can be viewed and downloaded from:
http://polaris.kgs.ku.edu/pls/abyss/qualified.well_page.DisplayWell?f_kid=1020066130

Figure 2.1.1. NW view of Murfin Carter Colliver #1 CO2 I in background and the Colliver #13 producing well, in the SE corner of the flood pattern, in the foreground.

Testing on the Carter-Colliver CO2 I#1 indicated lower permeabilities than predicted and indicated by the core. Based on these results it was decided to: 1) Acid stimulate Carter-Colliver CO2 I#1, 2) Perform a build-up test, and 3) Perform fall-off test at a later date when facilities are in place. The goals of this work were to 1) Clean-up near-wellbore damage for entire L-KC 'C' interval without unduly affecting native reservoir properties, 2) Measure reservoir permeability-height and wellbore skin, 3) Avoid fracturing the reservoir during treatment and testing so that testing can reveal if native fractures exist, and 4) Prepare the well for its future role as an injector. Important considerations included: 1) Treat entire reservoir interval, 2) Break-down each set of perforations, 3) Recommend >150 gallons acid/ft, 4) Block perforations by rock salt or balls or use PPI tool, and 5) Avoid fracturing the reservoir since we want to determine presence of fractures.

Carter-Colliver CO2 I#1 was treated with 400 gallons (1.5 m^3) 15% HCl acid on July 13, 2001 and another 1000 gallons (4.5 m^3) on July 16, 2001. The well responded to the stimulation with a pre-stimulation swab rate of +/- 2.5 bph (barrels per hour; $1.1*10^{-4}$ m^3/s) and a swab rate after the second acid job of 18 bph ($7.9*10^{-4}$ m^3/s). Treating pressures did not exceed 200 psig (1.38 MPa) at the surface. An attempt was made to use the PPI tool to breakdown individual perfs but the tool failed to work and was pulled out of the hole. The well was treated using a packer.

The well was produced until August 30 when the well was shut in for a build-up test.
Prior to the build-up test the well was producing at 2.88 BOPD (barrels oil per day, 0.46 m^3/d) and 69.12 BWPD (11 m^3/d). The response curve for the build-up test (Figure 2.1.2) did not conform easily to models available in standard commercial well test analysis software.

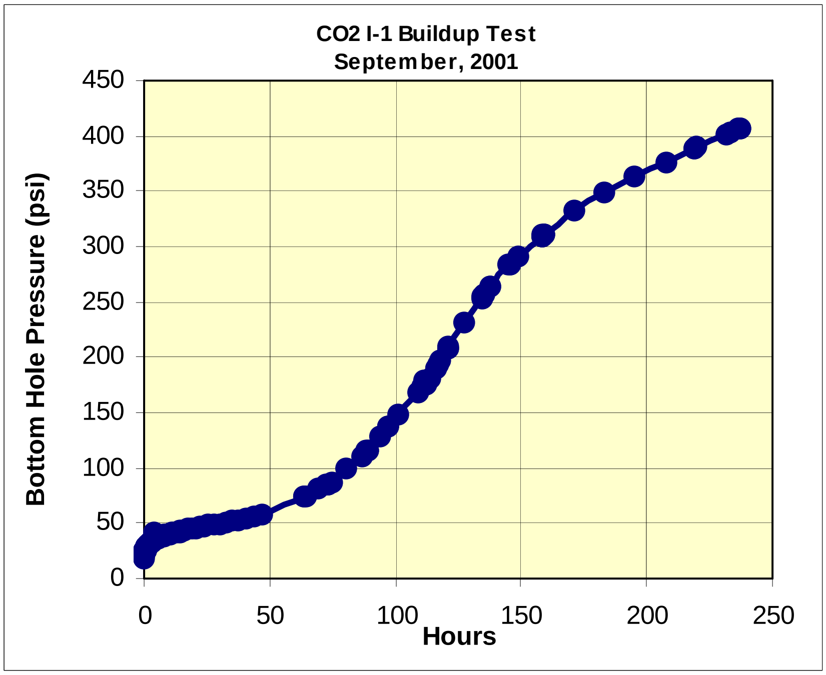


Figure 2.1.2. Pressure build-up test results for Carter-Colliver CO2 I#1 well.

2.1.2 Injection Water Filtration

A study was completed to evaluate the possible influence of precipitate fines on plugging of the formation, pore capillary pressure data were analyzed for principal pore throat size. Several core flood tests were performed with brine filtered to <25 *u*m (micron) and to <6 μm. Principal pore throat diameter was calculated from mercury intrusion capillary pressure analysis data using the Washburn equation. The relationship between permeability and pore throat diameters for the Lansing-Kansas City (L-KC) is generally consistent with that exhibited by other sandstones and carbonates (Figure 2.1.3). This correlation indicated that the injection brine must be filtered to < ~3-5 μm and <15 µm to prevent plugging of rocks with permeability as low as 1 md (millidarcy; 0.001 μm^2) and 10 md (0.01 μm^2), respectively. If it is assumed that these particles can bridge pore throats with as few as three grains then the brine must be filtered to <1 µm and <5 µm for 1 md and 10 md rock, respectively.

The concentration and size of particulates in the injection brine is strongly influenced by such variables as chemistry of the brines being mixed for injection, relative abundance of sulfur reducing bacteria, the nature of the tubulars, exposure to oxygen, residence time and mixing in tanks, and other environmental variables. Because of the complex influence of these variables, accurate analysis of the concentration and size of particulates is best done in the field.

Injection brine used at the Colliver lease was collected and brought back to the Kansas Geological Survey for to provide an <u>approximate</u> test of the influence of fines on permeability. The brine was exposed to the air and contained fine black FeS and FeS_2 particulates. Two subsamples of brine were created, one filtered to <25 µm and the second filtered to <6 µm. These were used in flow through tests on two Carter-Colliver CO2 I#1 core plugs. Flow through testing of water filtered to <25µm was conducted on the Carter-Colliver CO2 I#1 sample 2894.5 ft (porosity = 33.6%, *in situ* Klinkenberg permeability = 30.2 md (0.03 μm^2), starting water saturation = 76.6% at residual oil saturation of 24.4%). After an initial increase in water effective permeability due to slight oil displacement, introduction of 25 μm filtered brine resulted in a continuous decrease in effective brine permeability (Figure 2.1.4) through the termination of the test.

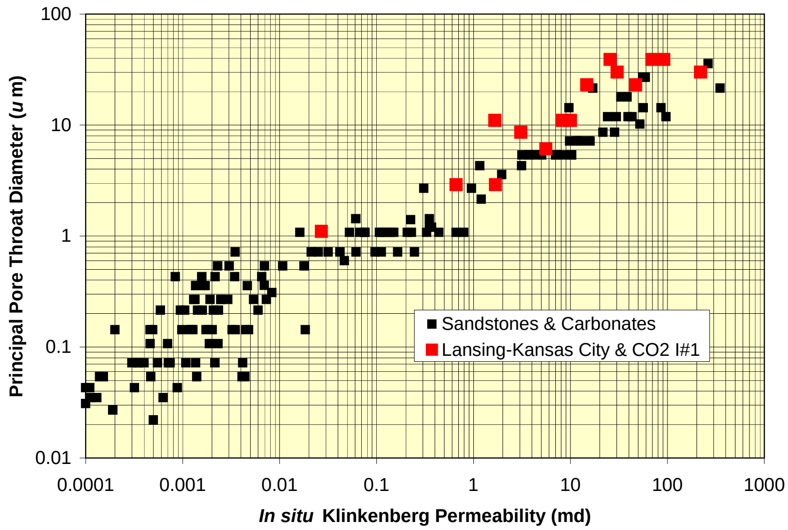


Figure 2.1.3. Cross-plot of principal pore throat diameter and permeability for Lansing-Kansas City oomoldic limestones and other carbonate and sandstone rocks. Pore throat diameters provide information on brine filtration requirements.

Similar testing on the Carter-Colliver CO2 I#1 sample 2893.1 ft (porosity = 27.5%, *in situ* Klinkenberg permeability = 46.9 md, starting water saturation = 81.4% at residual oil saturation of 18.6%) using <6 μm brine resulted in a decrease in effective water permeability of 39% after 566 pore volumes throughput. These results would indicate that fines in the filtered field brines are plugging the L-KC oomoldic limestone pore throats.

If unfiltered or partially filtered brines were used during the original waterflood it is possible that plugging occurred and that injection water was progressively forced into lower permeability rock as the higher permeability rock was plugged. Plugging may also have resulted in the use of higher injection pressures and successive fracturing of the formation as the exposed surface was plugged. For short-term injection testing, series cartridge filters were employed to filter injected brine to <25 μm. Injection into the Colliver #7 and #10 using this filtering system was used to evaluate the impact using 25 µm-filtered brine. Evaluation of the viability of using 1 µm and 5 µm cartridge filters or using different filtering system was conducted.

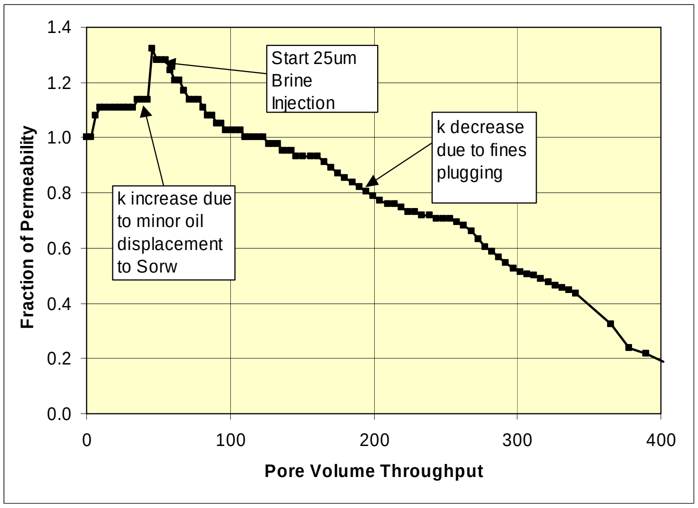


Figure 2.1.4. Influence of brine filtered to < 25µm on effective brine permeability as a function of the pore volume of brine throughput for Colliver-Carter CO2I#1 sample 2894.5 ft (882 m), oomoldic limestone.

2.1.3 Formation Pressures

Original plans were to perform drill stem testing of the reservoir interval. The pressure cores obtained from the reservoir interval exhibited severe damage either as the result of the use of the pressure-coring tool or as a result of significant reservoir rock fragility. Because of possible significant rock fragility, drill stem testing was not performed so as not to potentially damage the formation. Rather than drill stem test, Schlumberger's Repeat Formation Tester tool was run following the electric logging operation on sixteen intervals to obtain pressure data. Data for these tests are presented in Table 2.1.1. Differences in pressure between the Lansing-Kansas City 'C" zone (~800 psi, 5.9 MPa) and overlying formations (~1250 psi, 8.6 MPa) indicated that these intervals were not in communication which would indicate that wellbore integrity issues and potential loss of fluids into shallower intervals should not present a problem for the demonstration project.

Table 2.1.1 Repeat formation tests on Carter-Colliver #!-CO2I

Client:	MURFIN DRILLING CO., INC.	Tool:	RFT-B
Field:	HALL-GURNEY	Probe Type:	Standard packer
Well:	CARTER-COLLIVER #1-C02 I	Gauge:	SGP
Run date:	1-OCT-2000	Gauge Resolution:	0.040 psi

Test	File	Depth FT	TVD FT	Drawdown Mobility MD/CP	Mud Pressure Before PSIG	After PSIG	Last read build-up Pres PSIG	Formation Pressure PSIG	Test Type	Zone	
2	26	2970.52	2970.52	0.93	1446.12	1442.26	500.21	500.21	Normal Pretest	L-KC "G" Zone	
3	27	2963.46	2963.46	0.30	1438.69	1436.48	497.44	497.44	Normal Pretest	L-KC "G" Zone	
4	28	2935.45	2935.45	3.11	1423.27	1421.38	441.56	441.56	Normal Pretest	L-KC "E" Zone	
5	30	2902.02	2902.02		1405.41	1404.00	19.13	19.13	Dry Test		
6	31	2901.49	2901.49	0.04	1404.89	1402.96	837.79	837.79	Normal Pretest	L-KC "C" Zone	
7	32	2897.98	2897.98	2.36	1402.53	1400.67	807.30	807.30	Normal Pretest	L-KC "C" Zone	Fluid Samp
8	33	2894.99	2894.99	1.92	1400.82	1398.81	800.7	800.7	Normal Pretest	L-KC "C" Zone	Fluid Samp
9	34	2813.49	2813.49	0.17	1362.88	1359.57	818.26	818.26	Normal Pretest	L-KC Toronto	
10	35	2762.50	2762.50		1337.95	1336.55			Lost Seal		
11	36	2759.48	2759.48	0.14	1335.84	1333.76	1258.81	1258.81	Normal Pretest	Plattsmouth	
12	37	2747.98	2747.98		1330.01	1327.93	1.76	1.76	Dry Test		
13	38	2742.01	2742.01	0.07	1326.66	1325.13	1245.85	1245.85	Normal Pretest	Plattsmouth	
14	39	2593.01	2593.01	0.06	1257.50	1253.28	1262.13	1262.13	Normal Pretest	Topeka	
15	40	2558.46	2558.46		1238.72	1237.36	-5.92	-5.92	Dry Test		
16	41	2559.02	2559.02		1238.45	1238.57			Lost Seal		
17	42	2561.45	2561.45		1239.91	1238.19	-4.50	-4.50	Dry Test		

TASK 2.2 PRODUCIBILITY CHARACTERIZATION USING NEW CORE

2.2.1 Residual Oil Saturation

Core analysis of residual oil saturation to waterflood indicates that mean residual oil saturation for “C” zone oomoldic limestones measured to date in the Carter-Colliver #1 CO2 I is 27.4% with a minimum and maximum of 14.3% and 36.9%, respectively (Figure 2.2.1). These core flood values are consistent with the routine core saturation and the log-measured saturations but are not consistent with the high-pressure core oil saturations.

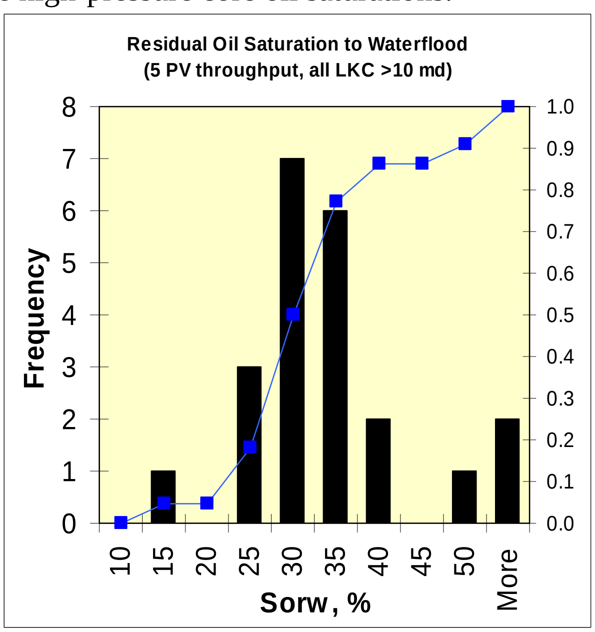


Figure 2.2.1. Histogram of residual oil saturation to waterflood for coreplugs from the Carter-Colliver #1 CO2 I oomoldic limestone “C” zone.

2.2.2 Routine and Special Core Analysis

Permeabilities decrease with increasing depth below the top of the "C" zone and exhibited properties similar to initial reservoir simulations. Core obtained using the pressure core barrel exhibited significant damage and may have affected the representativeness of data obtained on these cores. Oil saturations measured in the routine core, taken in the top 2 feet (0.61 m) of the "C" zone exhibit an average oil saturation of 28%. The high pressure core, taken over the remainder of the "C" zone exhibit an average oil saturation of 10%. This low saturation is believed to be the result of extension flushing of the crushed and unconsolidated core.

The second high-pressure core recovered from the "C" zone interval 2904-2914 ft (885.14-888.19 m) in the Carter-Colliver #1 CO2 I well is well-consolidated and exhibits decreasing porosity with increasing depth from 16% to 1% and permeabilities from 0.73 md to <0.01 md ($7.3*10^{-5}$ to $1*10^{-6}$ *u*m^2). These data indicate that model layers 5 and 6 are thicker and exhibit slightly poorer reservoir properties than predicted. The trend of decreasing permeability with increasing depth below the top of the "C" zone extends into the interval of the second core (Figure 2.2.2).

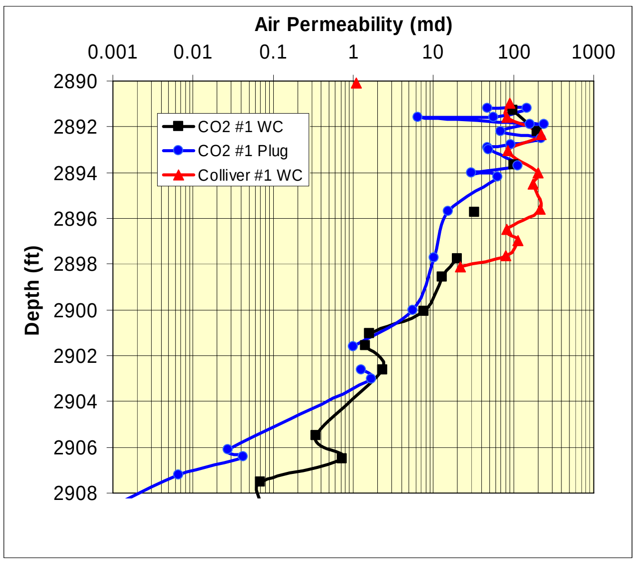


Figure 2.2.2. Permeability versus depth for Murfin Carter-Colliver #1 CO2 I well and the Collvier #1 well. (1md = $9.87*10^{-4}$ *u*m^2, 1 ft = 0.3048 m)

"Irreducible" water saturations (*Swi*) measured at an air-brine pressure equivalent to a hydrocarbon column height of 50 ft (15 m) above free water level, exhibit a trend similar to that of other L-KC oomoldic limestones (Figure 2.2.3) except that cores with permeability greater than 50 md exhibit Swi values as much as 25% greater than the predicted by the general L-KC trends. This represents a limited sample set in the upper-most portion of the core and must be evaluated further.

Mercury capillary pressure intrusion measurements to 10,000 psi (1,000 kPa) provided capillary pressure curves for selected samples ranging in permeability from 0.027 md to 220 md ($2.6*10^{-6}$ to $2.2*10^{-2}$ *u*m^2). Saturation versus capillary pressure curves for these cores are consistent with capillary pressure curves measured on other Central Kansas Uplift oomoldic limestones and with the generalized model curves constructed for the reservoir simulation geomodel (Figure 2.2.4).

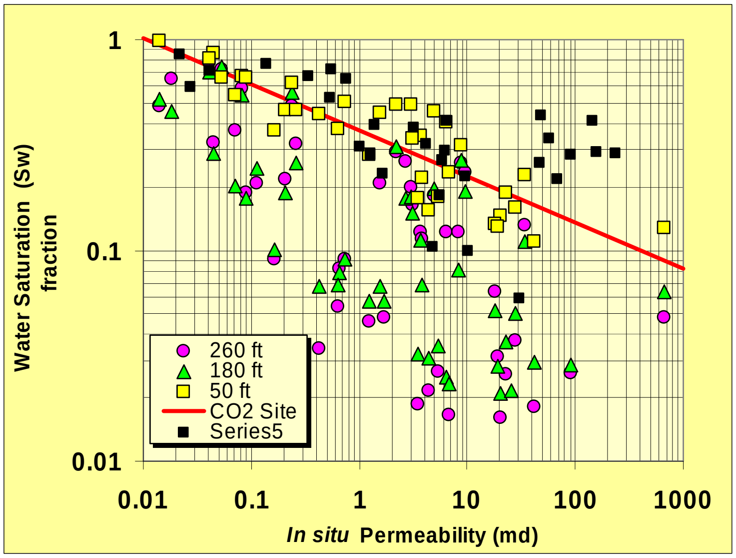


Figure 2.2.3. Water saturation versus permeability for L-KC oomoldic rocks and from the Carter-Colliver #1 CO2 I (black squares). High permeability samples exhibit anomalously high Swi values and indicated further testing was warranted. (1md = 9.87*10^{-4} *um*^{2}, 1 ft = 0.3048 m).

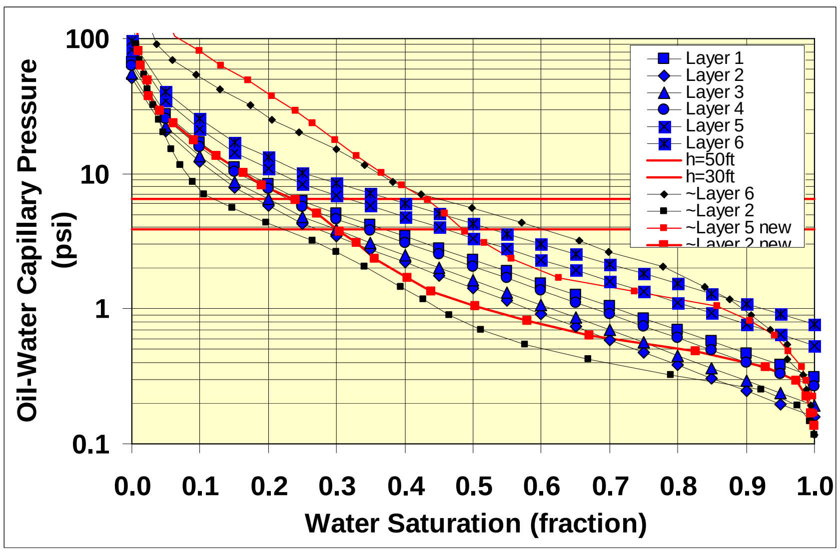


Figure 2.2.4. Capillary pressure curves for high and low permeability samples from the Carter-Colliver #1 CO2 I "C" zone (black and red symbols) compared with the generalized model curves developed for the reservoir simulation geomodel (blue curves).

Archie cementation exponents, *m*, for Wireline log analysis are significantly greater than the conventional value of 2.0. Cementation exponent values for "C" zone oomoldic limestones ranged from 2.2 to 3.6. Values increase with increasing porosity (Figure 2.2.5) and with increasing proximity to the top of the "C" zone.

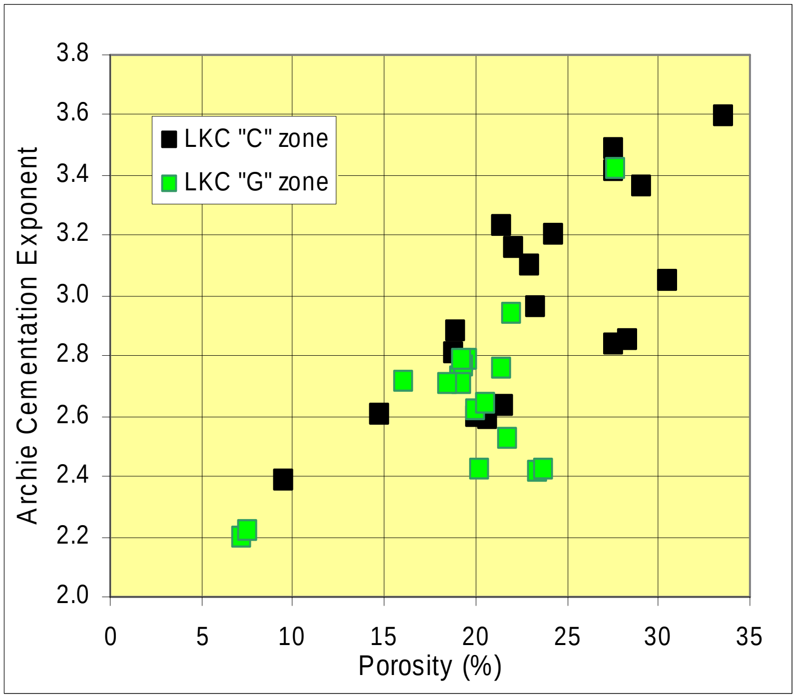


Figure 2.2.5. Cross-plot of Archie cementation exponents versus porosity showing increase in *m* with increasing porosity.

2.2.3 Geologic Characterization

Wireline Log Analysis

To obtain information concerning subsurface rock types, porosity, and fluid saturations Schlumberger's Platform Express logging suite was run from casing to total depth. Logs included in this suite include Caliper, Gamma Ray, Compensated Neutron Litho-Density, Array Induction Linear Correlation, and Microlog. In addition, a Borehole Compensated Sonic log was run. Initial analysis of logs for this interval indicate that remaining oil saturations are near 30-40% (Figure 2.2.6). Saturations of 30%-40% are sufficient for a meaningful test of CO_2 flooding.

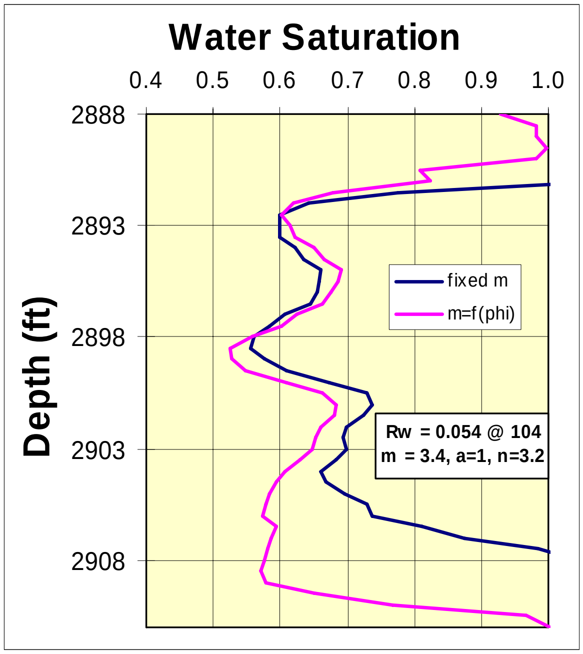


Figure 2.2.6. Calculated water saturations in Lansing-Kansas City "C" zone using Wireline log deep induction response and Archie parameters that are both fixed at values measured in the Laboratory or vary with porosity. Water saturations in "C" zone range from 30-40% and are sufficiently high to justify implementation of CO_2 enhanced recovery operations.

The "C" zone is composed of coarse grained oomoldic grainstone exhibits a slight decrease in oomold size and deceasing packing with increasing depth below the top of the zone. Minor isopachous rim cementation and micritized ooid cortices are also present. Based on thin-section analysis, the L-KC in this region underwent similar diagenesis to that described by LeBeau (1997) and Byrnes and others (2000) (Figure 2.2.7).

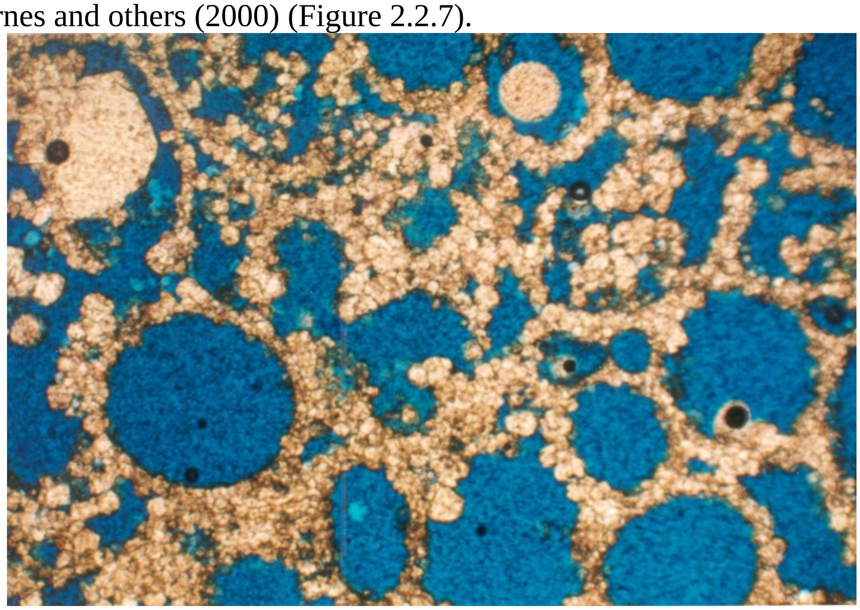


Figure 2.2.7. Plane light thin section of L-KC "C" zone 2903 ft (884.8 m) showing blue-dye impregnated oomoldic porosity and recrystallized limestone matrix framework. Crushing of matrix is evident.

TASK 3.1 RESERVOIR SIMULATION

3.1.1 History Match of Primary and Secondary Recovery-Colliver Lease

The reservoir model described in Task 1.4 was modified to reflect the rock and reservoir properties measured in the Carter-Colliver #1 CO2 I core and well. Primary changes involved: 1) an increase in "irreducible" water saturation for layers C2 and C3 to 23% from 11% and 14%, respectively, 2) modification of layer permeabilities within approximately a factor of 2, and 3) an increase in model porosities by approximately 2 porosity percent.

Although the history match improved, it was necessary to refine the model to provide a better history match in the region of the Colliver #7 well and the western Colliver lease. The new model (Model # S171) history match for the Colliver lease provides a closer match of the estimated lease oil production history and rates than previous models (Figure 3.1.1). As with the previous models, differences between model and estimated rates of production during the pilot waterflood from 1958 to late 1962 are believed to result from either: 1) a different contribution of oil from the L-KC "G" zone than estimated, or 2) reservoir properties in the pilot flood area, and particularly around the Colliver #7 well, that are significantly different than other areas of the lease. Model refinements improved the history match but predicted recovery was still highly sensitive to uncertainty in reservoir properties in the western Colliver lease region in the region around the Colliver #7 well.

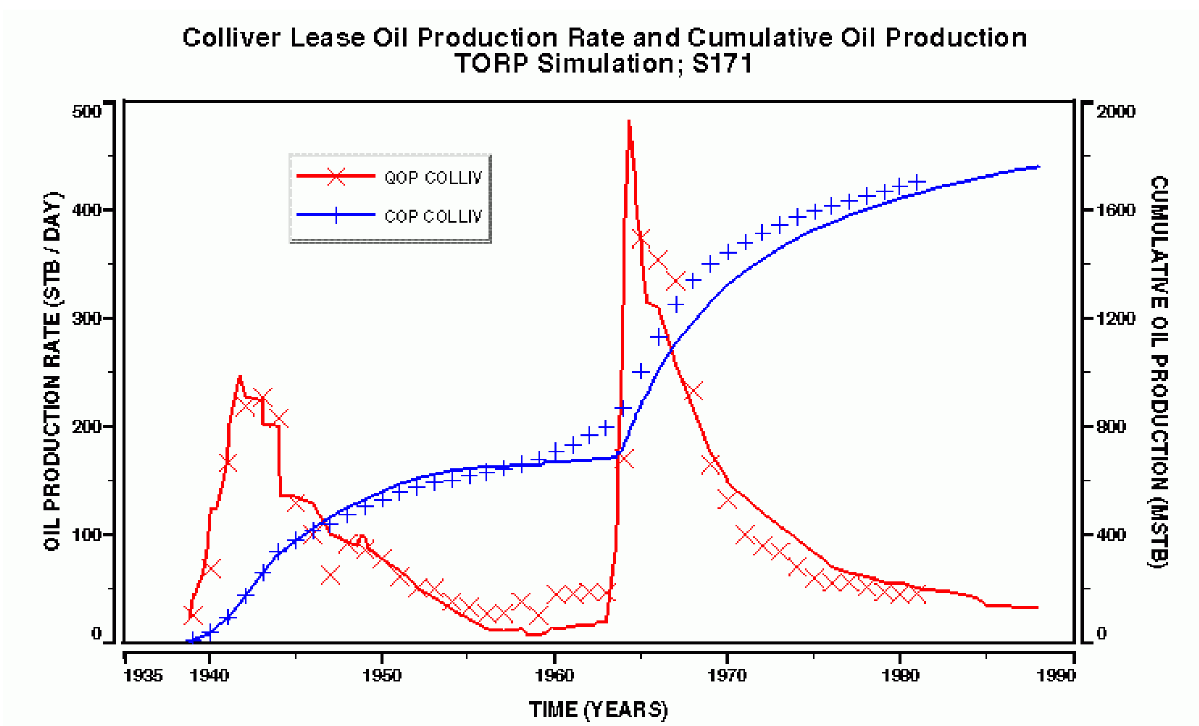


Figure 3.1.1: Comparison of model and estimated Colliver lease oil production rates and cumulative production for TORP simulation model S171.

3.1.2 Simulation of Carbon Dioxide Flooding

The revised reservoir model was used to predict oil recovery using a CO2 WAG (Water-Alternating - Gas) flood. Oil recovery was predicted for 10-acre, 40-acre, and 60-acre flood patterns (Figure 3.1.2). For these patterns oil recovery within the 5-year period of the DOE demonstration was predicted to be 21,000BO, 70,000 BO, and 105,000 BO (BO-barrels of oil) for each of the patterns respectively.

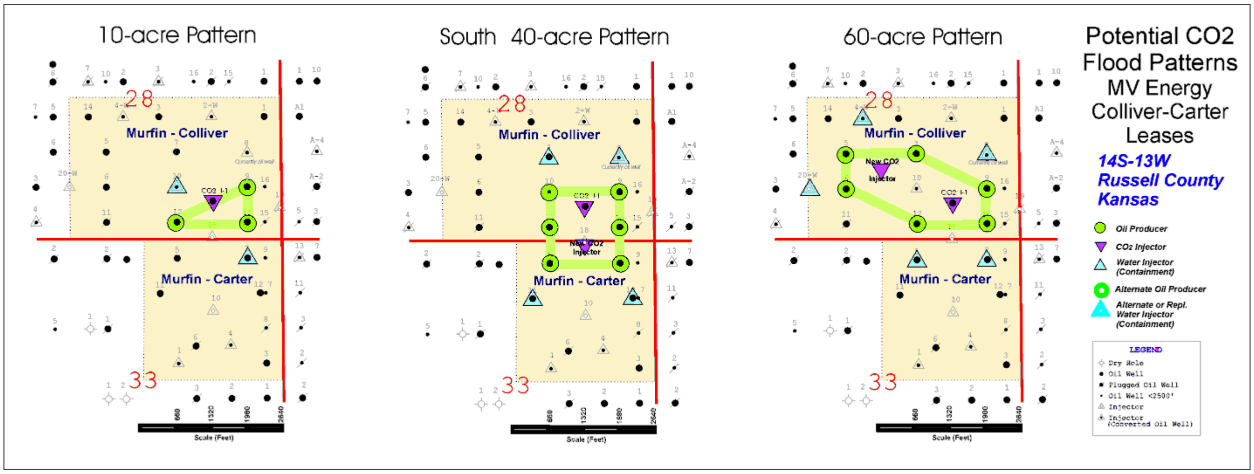


Figure 3.1.2: Flood patterns evaluated for CO2 flood recovery using the TORP reservoir simulation model.

Reservoir simulator model #S171 was used to model oil saturation distribution in the Colliver lease at the end of waterflood as input for simulation of carbon dioxide flooding.. Previous analysis indicated that the 60-acre pattern(Figure 3.1.3) provided an economically viable pilot. *VIP* compositional simulation run #T61 for a CO_2 WAG (Water-Alternating Gas) flood predicts that oil recovery from the 60-acre pilot area (Figure 3.1.4) is approximately 116,000 bbls (18,400 m^3) within the DOE demonstration period. This recovery was compared with general volumetric recovery efficiency models based on West Texas floods. Oil recoveries using general West Texas models are estimated to be approximately 95,000-97,000 bbls (15,100-15,400 m^3). Estimated CO2 volumes injected range from 765 MMcf to 843 MMcf (million cubic feet, 21.6–23.8*10^6 m^3).

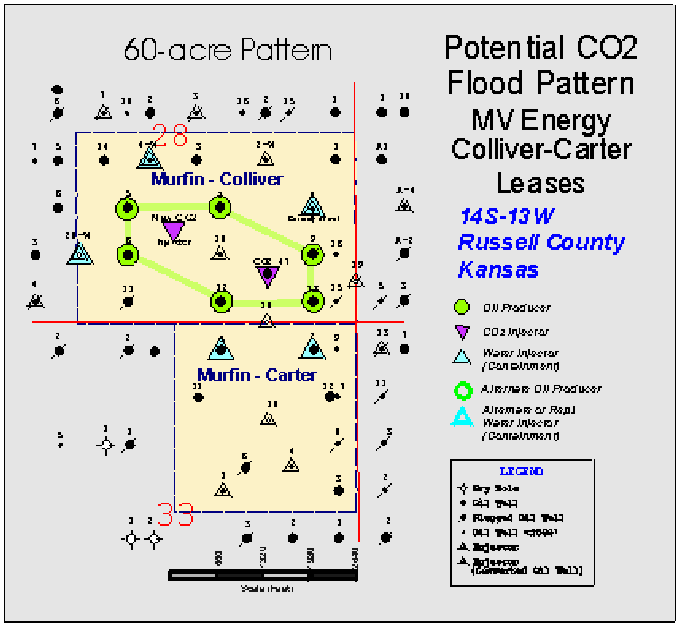


Figure 3.1.3: 60-acre (24.3 ha) CO_2 flood pattern for demonstration site.

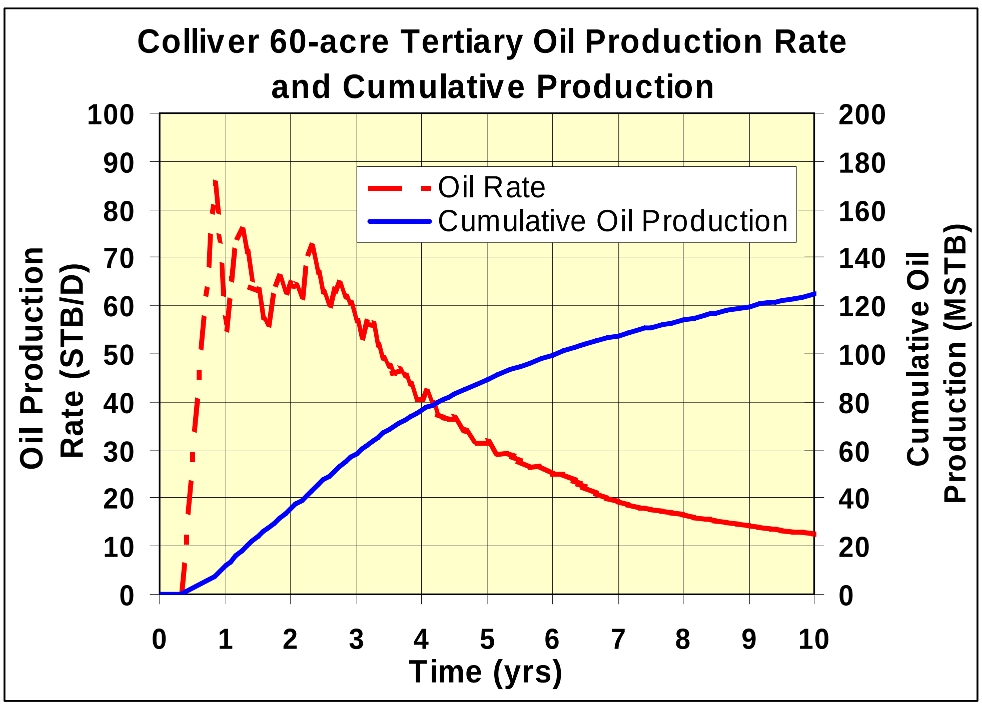


Figure 3.1.4: Simulation Run T61 prediction of oil recovery for 60-acre (24.3 ha) pattern.

3.1.3 Simulation of Pressure Maintenance Using Confinement Wells

It was necessary to maintain pressures above the minimum miscibility pressure(~1,250 psi, 8.6 Mpa) to mobilize oil in the pilot pattern. Preliminary studies of lease repressurization and CO2 flood confinement indicated that repressurization should require less than three months and that fewer wells may be required for pressure control and containment.

Water injection wells cost approximately $40,000-$50,000 for rework and $800/month ($9,600/year) in operating expense during the flood. For a 7-year pilot the total cost of a containment well can be ~$117,000. Even if some oil is lost because of lack of containment, the lost oil revenue may not warrant the use of all containment wells. If not all injectors are needed then the project can realize a cost saving.

Simulations were performed to study the effect of confinement wells on the 60-acre (24.3 ha) pattern and on a smaller 20-acre pattern. The simulations were performed using only water injection. Because water has a significantly higher viscosity than CO2 (~0.7 centipoise compared with ~0.04 centipoise), water injection represents a limiting or “worst-case” scenario for pressure distribution created by injection. Pressure distributions were obtained with fewer or no containment wells.

Figures 3.1.5 and 3.1.6 illustrate the pressure distribution for the 60-acre (24.3 ha) pattern with the injection wells held at a constant bottom hole pressure (BHP) of 2,000 psi (13.8 MPa). Figure 3.1.5 illustrates pressure distribution in the period before the pattern producers are turned on and have a BHP equal to the reservoir (BHP = ~800 psi, 5.5 MPa). Figure 3.1.6 illustrates pressure distribution during the semi-steady state period later in the flood when the BHP of all producers is held at a constant pressure of 600 psi (4.1 MPa). These figures illustrate that containment wells are not necessary for pressure buildup to MMP conditions. During flood operations pressures at the outer edge of the flood drop below MMP without surrounding containment injectors. With injection of low viscosity CO2, pressures at the outer edge increase to near MMP.

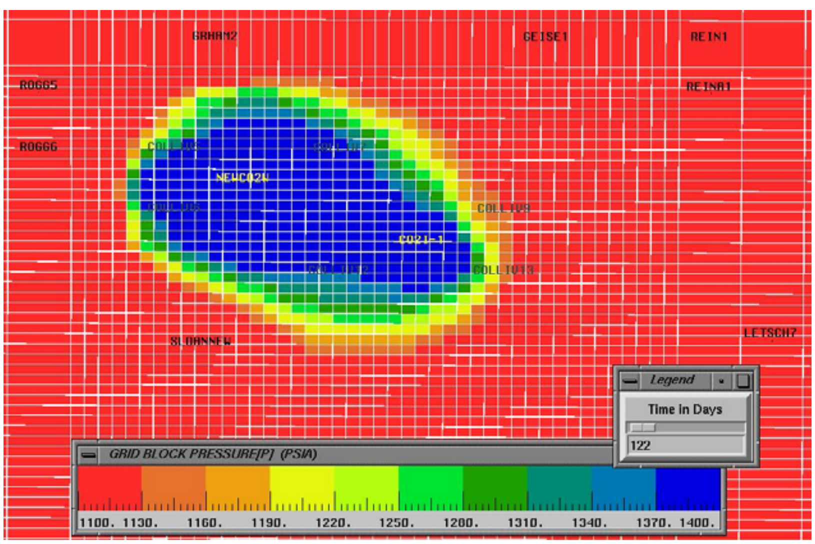


Figure 3.1.5: Pressure distribution for 60-acre pattern with no containment wells active. Injection well BHP= 2,000 psi, 13.8 MPa) producing wells are inactive during this pressure buildup phase. Note red indicates pressures of 1,130 psi (7.8 MPa) or less.

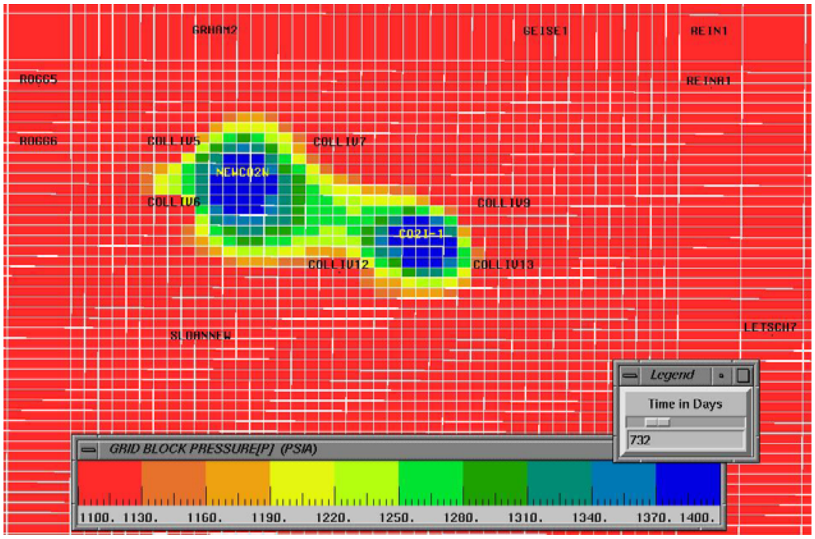


Figure 3.1.6: Pressure distribution during flood operations with producers at 600 psi BHP (4.1 MPa) and with only water injection. Note red indicates pressures of 1,130 psi (7.8 MPa) or less.

From well testing, the Carter-Colliver CO2 I#1 well appears to exhibit lower permeability (~800 md-ft; 0.24 μm^2-m) than the area surrounding the New CO2 I well to the northwest. Simulation of a 20-acre pattern using only the Carter-Colliver CO2I#1 well as an injector, without a second injector, exhibits a smaller region with pressure above MMP than the two-injector pattern because of the limited injectivity in the CO2 I#1 well (Figures 3.1.7 and Figure 3.1.8). In this simulation the Carter-Colliver CO2I#1 injection well BHP was 2,000 psi (13.8 MPa). In Figure 3.1.6 the producing wells

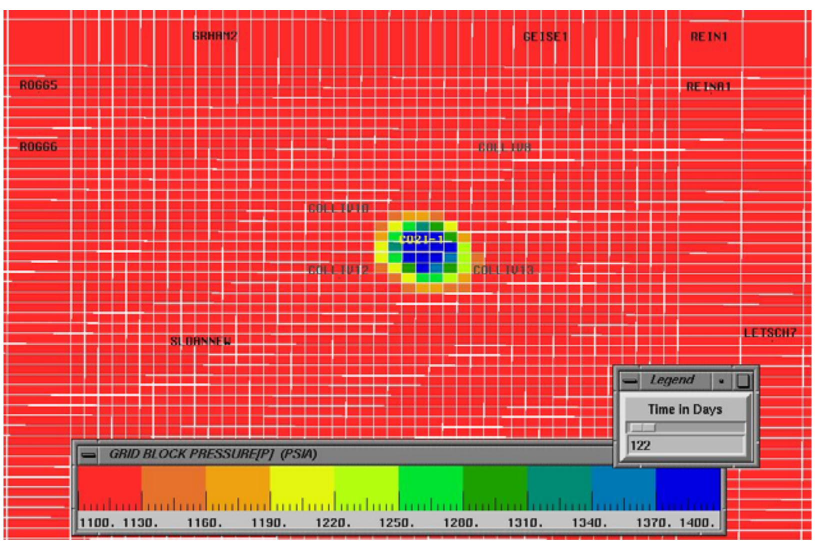


Figure 3.1.7: Pressure distribution around Carter-Colliver CO2 I#1 using only water injection in the pressure-up period before the producing wells are turned on. Note red indicates pressures of 1,130 psi (7.8 MPa) or less.

(Colliver #10, #12, #13, and #8) were not on and had a bottom hole pressure of ~800 psi (5.5 MPa), equal to the reservoir pressure. In Figure 3.1.8 the producing wells were on and maintained a BHP of 600 psi (4.1 MPa). As with the larger pattern, injection of low-viscosity CO2 would enlarge the area of high pressure. The exact size and distribution of pressure is still not well delineated until data are obtained from well testing and interference testing.

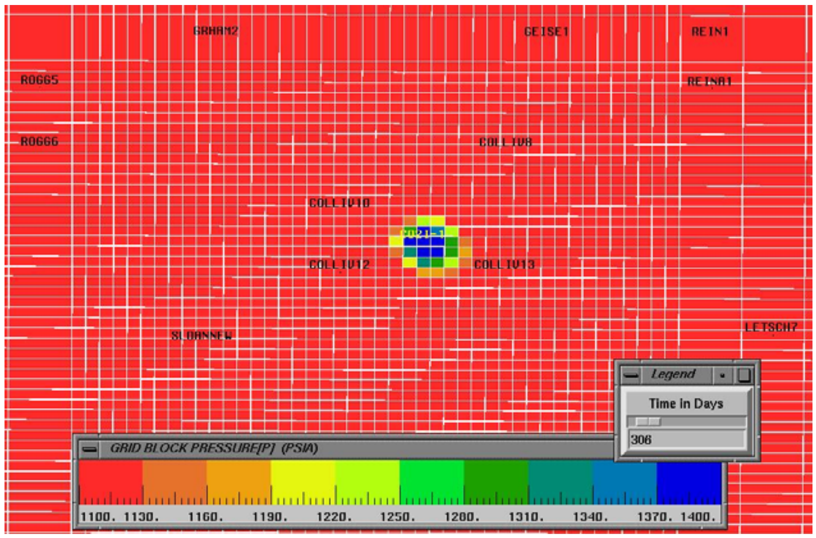


Figure 3.1.8: Pressure distribution of 30-acre flood pattern with Colliver #10, #12, #13, and #8 BHP equal to 600 psi (4.1 MPa). Note red indicates pressures of 1,130 psi (7.8 MPa) or less.

3.1.4 Influence of the Number of Layers

The reservoir simulation model was constructed with six (6) layers representing the subdivision of three flood cycles into an upper and lower layer. In the model, average layer thicknesses range from 1.5 to 3.7 ft (0.45-1.1 m). Because of the higher mobility ratio of CO2:oil compared to water:oil, the vertical distribution of horizontal permeability exerts greater influence on flood performance and on CO2 breakthrough. Vertical permeability distribution for the flood pattern area was not well defined. The only available data was the core analysis from the Carter-Colliver CO2 I#1 well and core analysis data measured in 1936 on the Colliver #1 in the northeast corner of the lease. The lateral distribution of permeability between wells was not known.

Simulations were performed to compare flood performance for models ranging from 6 layers to 20 layers to investigate the possible influence of thin, high permeability layers on CO2 flood performance. A model for investigating the influence of layering in the region of the CO2 #1 was constructed. Using permeability and porosity data from the Colliver #1 and the Carter-Colliver CO2 I#1 wells analysis of the permeability data indicated that permeability is both a function of porosity and is a function of depth below the unconformity surface at the top of the Lansing-Kansas City C zone. A multivariate equation was developed that predicted permeability in the CO2 I #1 well:

$\log_{10}\boldsymbol{k}$ = -0.18 Depth + 0.0036 Porosity + 2.23

Where k = permeability (md), depth = depth below top of L-KC C zone (ft), and porosity is in percent (%). This equation gives significant weight to depth and is not considered applicable to all L-KC reservoirs but does provide good prediction in this well.

Wireline log porosities, which correlate with core porosities, were estimated at intervals of one-half foot. Permeabilities were predicted from the log porosities for every half-foot. Porosity and permeability were successively averaged to scale half-foot data to coarser layers for a 40, 20, 10, 6, and 3-layer models. Permeabilities for each of these models are compared in Figure 3.1.9. For each of these models the total and layer-specific average porosity (ϕ), permeability ($\boldsymbol{k}$), porosity-height (ϕ-*h*), and permeability-height ($\boldsymbol{k}$-*h*) were the same. The models assigned relative permeabilities to each layer based on the layer absolute permeability.

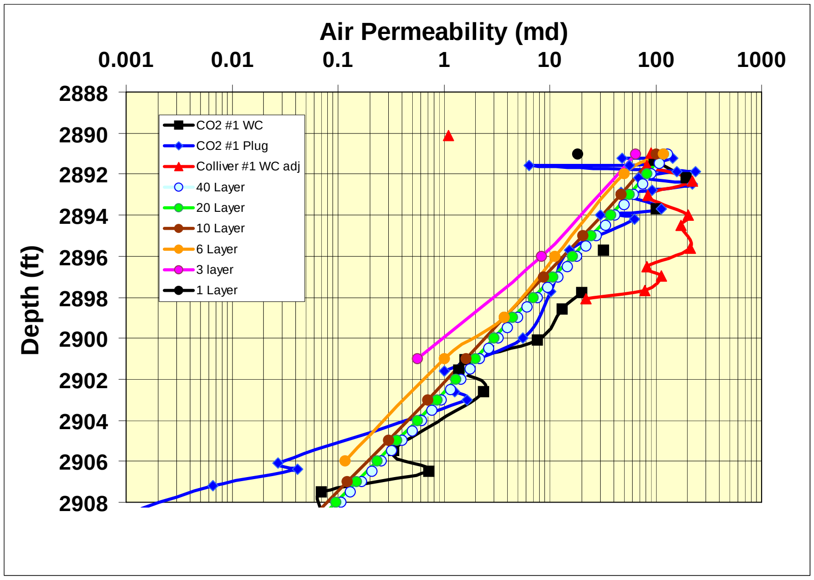


Figure 3.1.9: Comparison of permeability distribution for layer models and measured data.

The effect of subdividing the Colliver Carter "C" zone into thinner layers was studied by simulating carbon dioxide miscible flooding in a ¼ 5-spot with an area of 5 acres (2 ha). The dimensions of the ¼ 5-spot were 660 ft (201 m) in the east-west direction and 330 ft (100 m) in the north-south direction (area of exactly 5 acres). There was no flow across the pattern boundaries. The reservoir interval simulated was 20 feet (6.1 m) thick. The reservoir model was subdivided into 3, 6, 10, 20 and 40 layers. Each layer was 0.5 ft (0.15 m) thick in the 40 layer model, 1 foot thick in the 20 layer model and 2 feet thick in the 10 layer model. A 6 layer model corresponding to that used in earlier simulations was assigned thickness of 1 ft, 4 ft, 3 ft, 2 ft, 5 ft, and 5 ft (0.3, 1.2, 0.9, 0.6, 1.5, an 1.5 m) for layers 1 to 6 respectively. Thicknesses of individual layers in the 3 layer model were respectively; 5 ft, 5 ft, and 10 ft (1.5, 1.5, 3.0 m) respectively.

Permeabilities were constant in each layer. The ratio of vertical to horizontal permeability was

0.05. Residual oil saturations were assigned to each layer based on the present simulation model. The hydrocarbon pore volume (HCPV) and original oil in place (OOIP) of the model at connate water saturation were ~122.03 MRB (thousand reservoir barrels; $19.4*10^3$ m^3). The oil at the beginning of carbon dioxide flooding was 65.4 MRB ($10.4*10^3$ m^3) so that primary and secondary recovery was 54 %. Average residual oil saturation was 46%. The bottom hole pressure of the producer was set at 1,000 psia (6.9 MPa) with the following injection sequence: 5 months of CO_2 slug, WAG ratio of 1:1, 10 cycles of WAG injection, and a 3 % HCPV slug size (3,661 RB; 582 m^3).

Comparison of flood results (Figure 3.1.10) shows the recovery decreasing with increasing number of layers. A detailed analysis of production from individual layers indicates that the top three zones corresponding to about 8 feet of reservoir are the most productive (i.e., zones correspond to existing 'C' layers 1,2, and 3, respectively). The thickness of Zone 1 is 1 foot (0.3 m) , Zone 2 is 4 feet (1.2 m) , and Zone 3 is 3 feet (0.9 m).

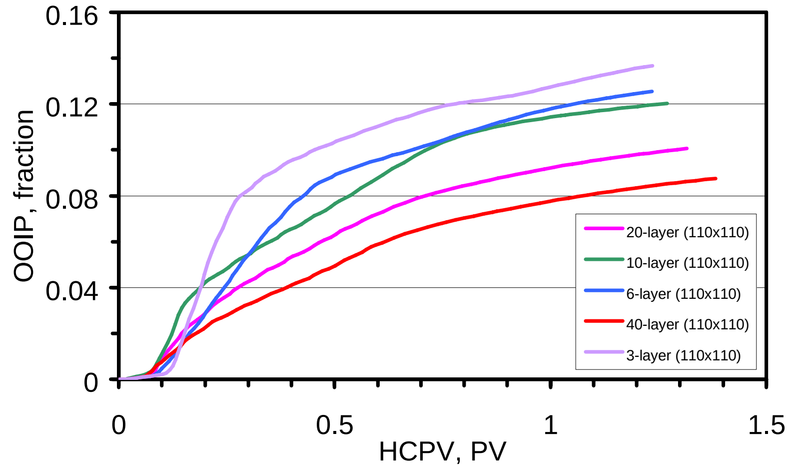


Figure 3.1.10: Comparison of oil recovery for different layer models showing decreasing recovery with increasing number of layers.

The effect of vertical permeability on oil recovery from these three zones was investigated by varying the vertical permeability from 0% of the horizontal permeability to 50% of the horizontal permeability. Figure 3.1.11 summarizes oil recovery (% residual oil saturation for each zone) at 1 HCPV of fluid injected into the reservoir. Simulation results indicate that recovery decreases when vertical permeability is greater than zero. This is believed to be due to cross-flow and CO2 migration to the top of the interval due to gravity segregation.

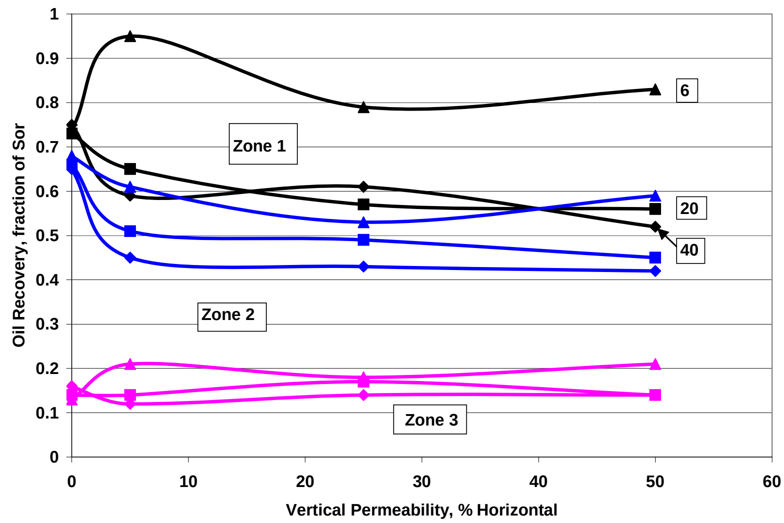


Figure 3.1.11: Influence of vertical permeability on oil recovery.

3.1.5 Influence of Gridcell Size on Model Recovery

The *VIP* reservoir simulation model, utilized for predicting CO_2 oil recovery, was continuously refined to provide better prediction of the CO_2 flood process. The influence of gridcell size/layering/vertical permeability on predicted recovery was further investigated.

Simulation was also performed on modifications of the 60-acre (24.3 ha), two-injector pattern to evaluate oil recovery using other large-scale patterns. Simulations indicated that several 73-acre (29.5 ha) patterns with a single injector located near the Colliver #7 could provide improved economics without increasing the amount of CO_2 injected.

The principal reservoir simulation model for the pilot used gridcells of approximately 110 ft x 110 ft (33.5 m x 33.5 m) in the x and y directions and 1 ft (0.30 m) in the vertical direction. This represented a minimum of six gridcells between wells in the x and y directions. *VIP* simulations to investigate the influence of gridcell size on oil recovery were performed on a vertical 2-D model. The 2D-20 layer model was used with a 7% pre-slug injection of CO_2 followed by 3% HCPV 1:1 water-alternating-gas (WAG) slug pattern. Total CO_2 injected was ~37% of hydrocarbon pore volume (HCPV). The simulator compositional module binary interaction parameter (BIP) was set to 0.08.

Permeability distributions in the model representing the distribution measured on core shown in Figure 3.1.9. Simulations with gridcell x-dimensions of 10 ft, 20 ft, 41ft, 62 ft, 81 ft, and 106 ft were investigated. Simulation results (Figure 3.1.12) indicate that when vertical permeability is 5% of horizontal permeability (Kv =5%) oil recovery (expressed as percent of original oil in place, OOIP) increases with decreasing gridcell size but when vertical permeability is zero (Kv = 0%) oil recovery decreases.

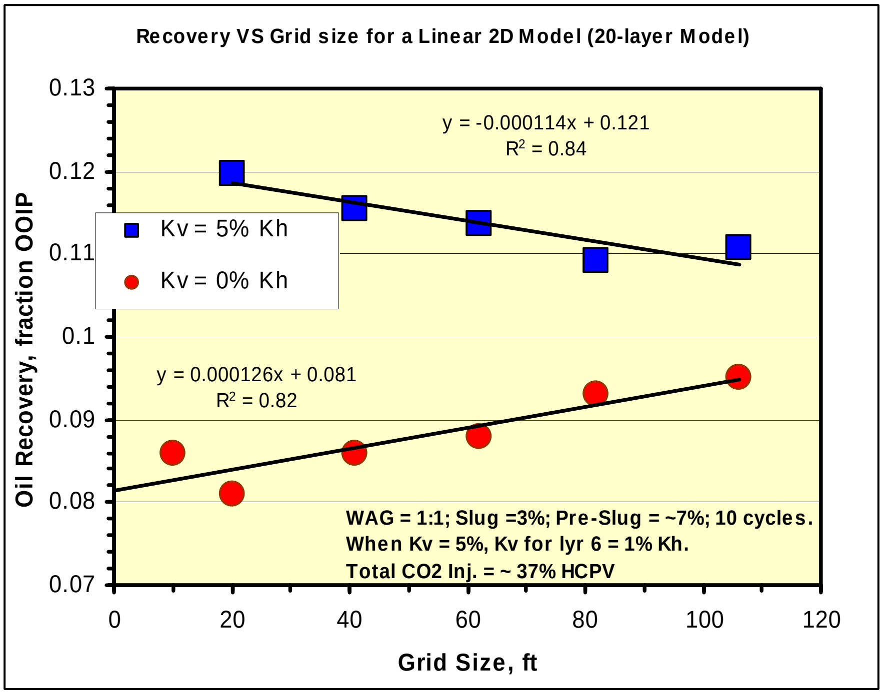


Figure 3.1.12: Simulation model-predicted oil recovery versus gridcell size for model with no vertical permeability between layers and model with vertical permeability = 5% of horizontal permeability (1 ft = 0.305 m).

Analysis indicated that oil recovery was reduced by gas cross-flow between layers enhanced by gravity segregation as grid cell length was reduced (Figure 3.1.13). When even minor vertical permeability was present, vertical migration of CO_2 to the upper-most layers results in reduced oil recovery. This increased the importance of bedding architecture. Present understanding of reservoir bedding architecture indicated that either one of two flooding cycles may be present in the pilot area. The basal portion of these flooding cycles is prone to comprise mudstone and wackestone and have low vertical permeability. The possible presence of vertical permeability barriers (allowing isolated processing of the middle flood cycle), and the role of small-scale bedding architecture such as cross-bedding or stylolites would act to limit gravity override.

There are many unknowns concerning lateral heterogeneity within the flood cycles such as shingling, weathering, and other diagenetic processes that might result in minimizing gravity override and promote more uniform sweep efficiency. The role that bedding architecture plays in improving vertical conformance was difficult to further quantify with available data but was addressed by analyzing pilot flood response.

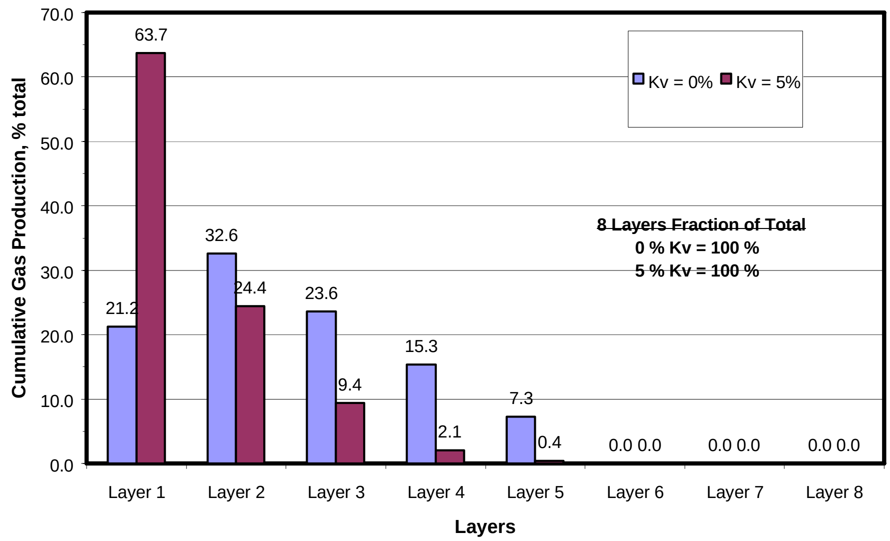


Figure 3.1.13: Model-predicted cumulative CO_2 gas produced by layer showing high gas volumes in upper layer (Layer 1) due to vertical gas migration.

3.1.6 73-Acre Single-Injector Pattern

The proposed pilot design under review by the USDOE during this stage of project evaluation used two CO_2 injectors, six producers, and five water-injection containment wells(Figure 3.1.2). Simulations were performed to investigate the optimum location for the second CO_2 injection well and the possibility of limiting injection to just the new well. Based on available well data the proposed second CO2 injection well could be located between the Colliver #7 and Colliver #10 wells, where data indicate injectivity is high. For an injector in this location with the injection rates possible for this location the Carter-Colliver CO2 I#1 well could be used as a producer.

Single-injector patterns (Figure 3.1.14- B002 pattern) decrease injection and production capital and operating costs while providing for flooding of a 73-acre (29.5 ha) area. Oil recovery from single-injector, 73-acre patterns was analyzed by the Tertiary Oil Recovery Project using the *VIP* reservoir simulation model and by Transpetco Engineering, Inc. using displacement calculations and fractional pattern modeling using general Colliver properties and assuming a 20% Process Pore Volume (PPV) CO2 slug size, 40% PPV total slug, and PPV rates ranging from 7.2-9.9% for the B00 pattern and 6.3-8.67% PPV for the B002 pattern.

Using the above methods for predicting oil recovery the B002 pattern was predicted to recover between 71,200 and 83,800 stock tank barrels (STB; 11,310-13,320 m^3) over a period of 10 years (with >80% in first 7 years). High-side potential exceeded 89,000 STB (14,140 m^3) assuming effective flooding of the middle flood cycle, and low-side potential approached 58,000 STB (9,220 m^3) assuming that the high permeability intervals have been efficiently waterflooded and exhibit residual oil saturations near 17%.

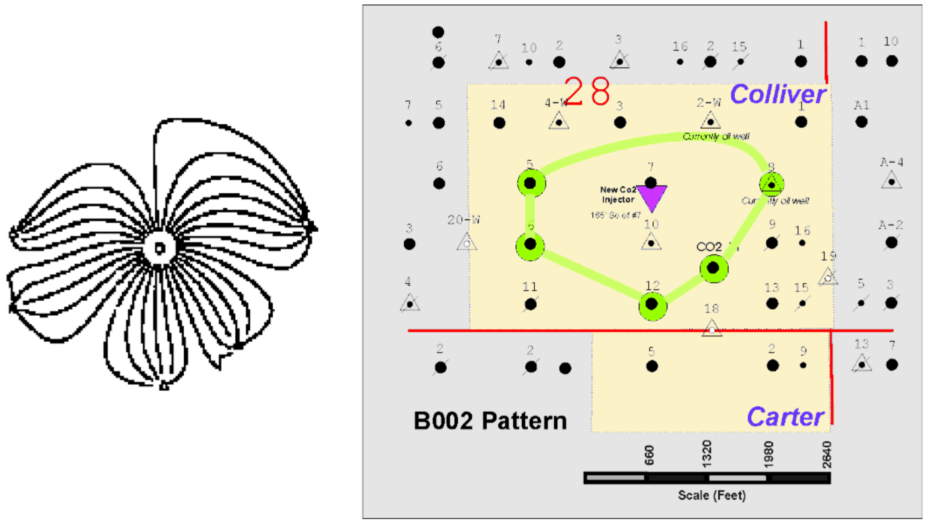


Figure 3.1.14: Example pattern (B002) for single-injector, 73-acre (29.5 ha) pattern.

Oil recovery estimates for the timetable of the project were strongly influenced by: 1) assumed residual oil saturation to waterflood; vertical distribution of horizontal permeability (permeability differences between upper, middle, and lower C flood cycles); the lateral distribution of permeability; and the presence or absence of vertical permeability barriers (flood cycle bounding bioclastic-rich layers); and the process rate. Without vertical permeability barriers between depositional flood cycles or shingling of ooid shoal deposits, gravity override of CO_2 acts to decrease oil recovery. The density ratio of ρ_{CO2}/ρ_{oil} = 0.6-0.8 (varying with pressure and oil density) for this pilot compared to density ratios in West Texas CO_2 floods that are often near $\rho_{CO2}/\rho_{oil} = 0.9$.

3.1.7 Correlation of Phase Behavior in Reservoir Models

Reservoir simulations of the carbon dioxide flood to this point in the project were done using the compositional version of VIP. A critical element in the compositional simulation of carbon dioxide flooding was tuning the binary interaction parameters in the phase behavior model to experimental data. Experimental data for phase behavior between CO2 and LKC crude oil were not available. Preliminary calculations used empirical correlations to estimate binary interaction parameters. Results from these calculations indicated that the residual oil saturation to carbon dioxide flooding varied over a wide range of values depending upon the values of the binary interaction parameters. Residual oil saturations as low as 0.05 saturation units were predicted with corresponding high oil recoveries.

The budget for the project did not include the cost of carbon dioxide-crude oil phase behavior data. One oil sample was sent to Core Laboratories to obtain oil formation volume factors and carbon dioxide solubility for two pressures at the estimated reservoir temperature of 105˚F. These data are presented in Table 3.1. The data point at 1325.98 psig was described as having some uncertainty. The amount of carbon dioxide dissolved in the crude oil was estimated at several pressures. These data are presented in Table 3.2 as mole fraction carbon dioxide as a function of saturation pressure. The data are also presented in Figure 3.1.15.

Table 3.1 Swelling Factors for the Dissolution of Carbon Dioxide into LKC Crude Oil from CO2#I-1 at 105˚F(Core Laboratory RFL 2002-071)

p [bar]	p(psi)	x_{CO2}	Sw
54.74	793.99	0.484	1.191
91.42	1325.98	0.729	1.583

Table 3.2: Solubility of Carbon Dioxide in LKC Crude Oil at 105˚F from Core Laboratory Visual Observations.

p [bar]	p(psi)	x_{CO2}
29.44	427	0.276
33.03	479	0.303
36.89	535	0.335
39.09	567	0.352
41.71	605	0.374
43.37	629	0.390
46.95	681	0.419
53.09	770	0.469
54.74	794	0.484
59.78	867	0.524
67.71	982	0.579
73.57	1067	0.622
80.19	1163	0.670
82.53	1197	0.687
85.15	1235	0.706
88.46	1283	0.724
91.42	1326	0.729

The swelling behavior of CO_2-LKC oil was examined by simulating a swelling test using the parameters developed by fitting the PVT data for Letch #7 using the Peng-Robinson EOS in *VIP*. In these simulations, the bubble point pressure was determined for a specified mole fraction of CO2 dissolved in oil and swelling factors were computed at each pressure. Results were compared with generalized correlations proposed by Simon and Graue[1] shown in Figure 3.1.16 (Figure 8.39 from Whitson and Brule[2])

Figure 3.1.17 presents the swelling factor as a function of mole fraction of CO_2 in the mixture. The solid blue diamonds represent data calculated by VIP program with binary interaction parameter (BIP) of CO_2 and three heavy pseudo-components set at 0.12. The red open circles represent data from the correlation in Figure 3.1.16 with molar volume of oil at 225 cc/g-mole. The molar volume of Letsch oil was 228 cc/g-mole. The calculated swelling factors are in good agreement with the correlation data up to CO_2 mole fraction of 0.65.

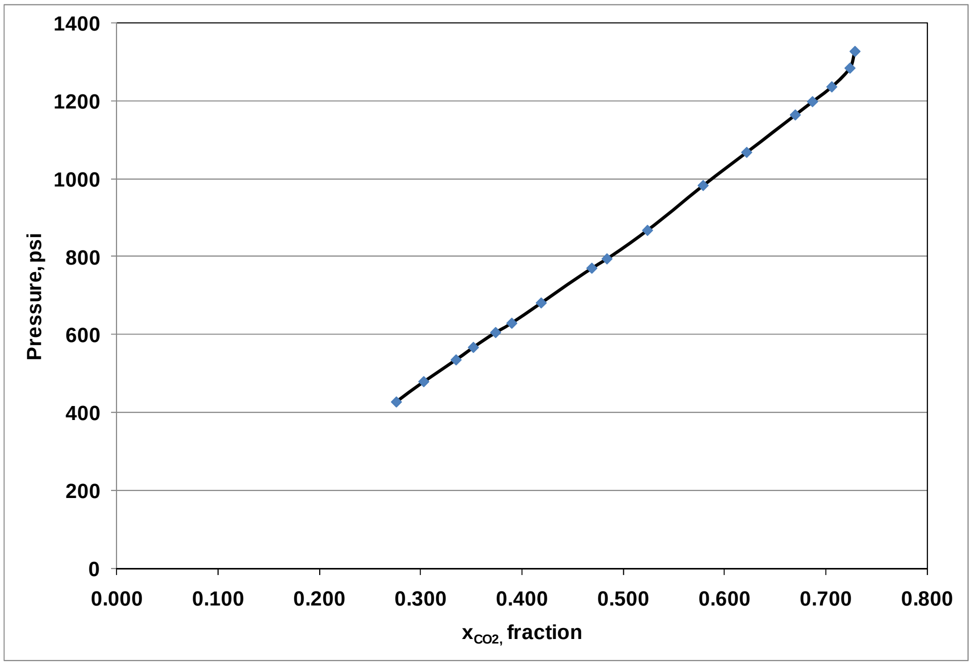


Figure 3.1.15: Saturation pressure versus mole fraction carbon dioxide in oil phase for Letsch No. 7 at 105ºF.

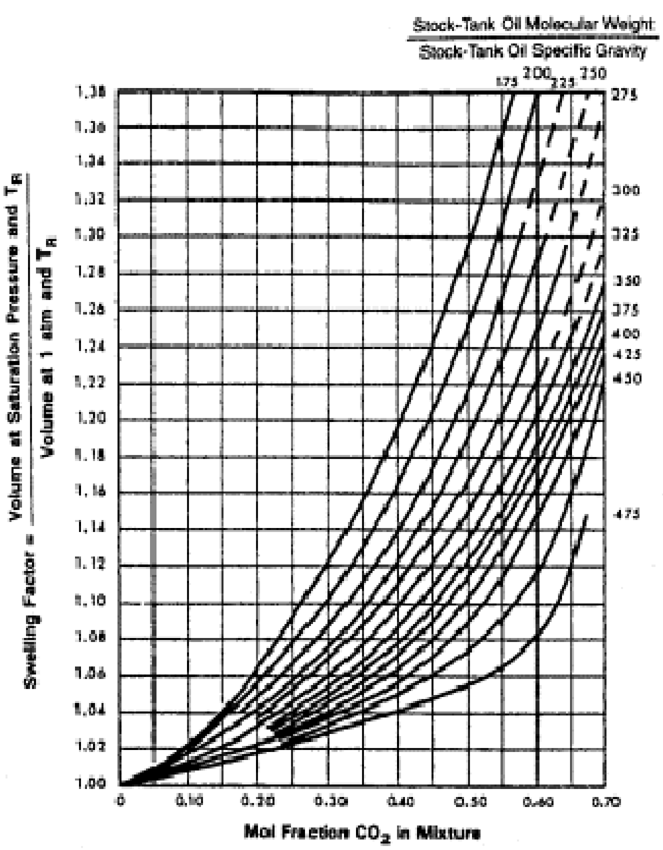


Figure 3.1.16: Correlation for swelling of a dead stock-tank oil when saturated with CO_2 (Figure 8.39 Whitson and Brule[2] after Simon and Graue[1]).

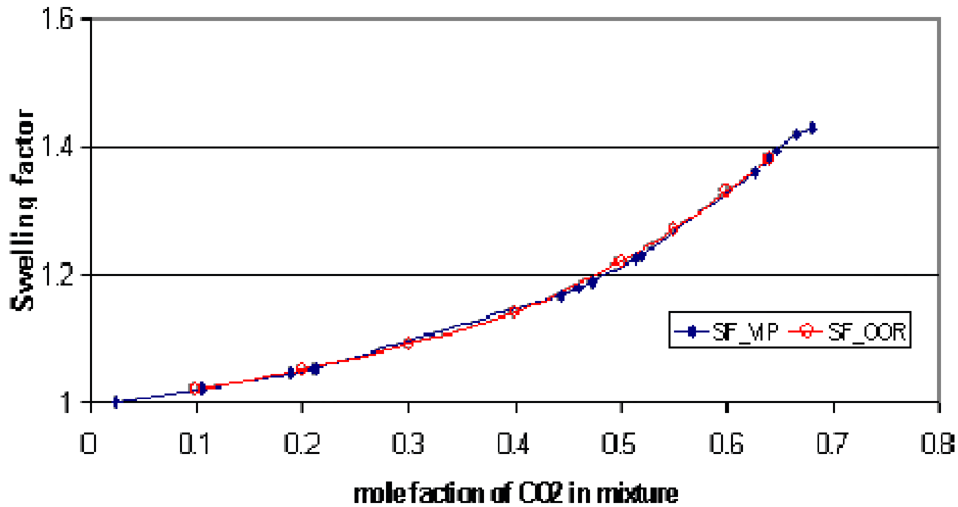


Figure 3.1.17: Swelling factor as function of mole fraction of CO_2 in CO_2-Letsch oil mixture using correlation in Figure 3.1.16.

Figure 3.1.18 shows the effect of the BIP value on swelling factor for the Letsch EOS parameters. In the range of mole fractions from 0-0.65, the calculated swelling factors do not depend on the value of BIP. Swelling factors greater than ~1.4 could be obtained only by using a BIP value of 0.08. The composition of this liquid phase, if it exists, is ~78 mole % carbon dioxide. Thus, it was not possible to match the second swelling data point from Core Laboratory measurements without using a small value of BIP to predict the existence of a carbon dioxide rich liquid phase that has a swelling factor or 1.8 The limited amount of experimental data created uncertainty in the appropriate value of the BIP for the data.

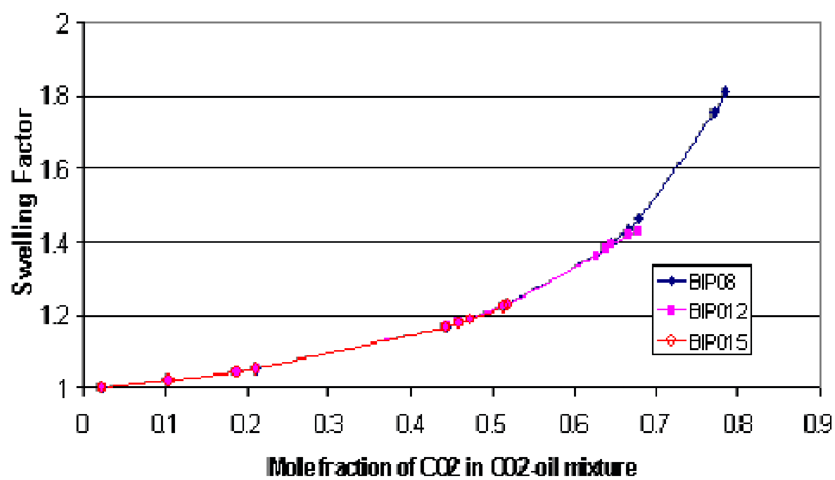


Figure 3.1.18: Effect of BIP on swelling factor

The effect of BIP on saturation pressure is presented in Figure 3.1.19. Although it was possible to match the simulated saturation pressure with Core Laboratory data specifically at a pressure of 1325 psi with BIP =0.08, there was an inconsistency between swelling factor correlations in the literature and the data point measured on the CO2#I-1 oil. This inconsistency could not be resolved with the data available. Consequently, composition simulation was replaced by the Todd and Longstaff model[3] which did not require binary interaction parameters for computation of residual saturations. Residual oil saturations to carbon dioxide flooding in the Todd and Longstaff model were set as input parameters. This model was used extensively in simulating carbon dioxide floods in West Texas.

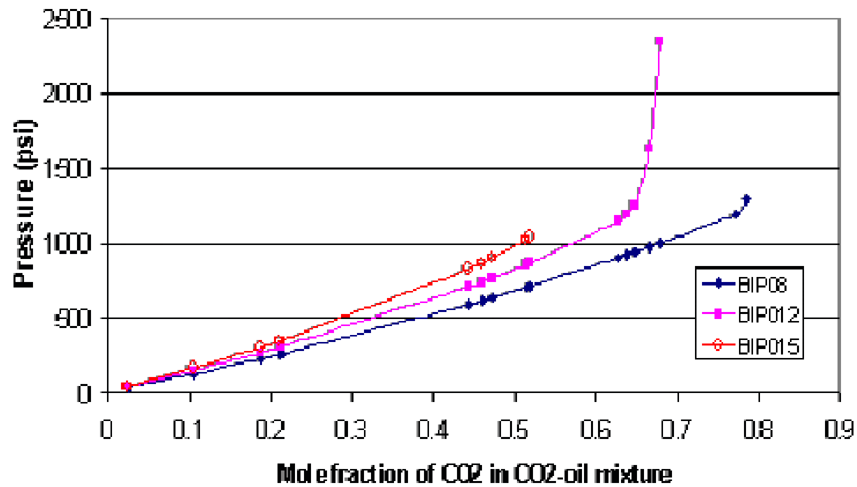


Figure 3.1.19: Effect of BIP on saturation pressure

3.1.8 10-Acre Pilot Pattern

The decision to reduce the size of the pilot area described in Section 3.2 led to the development of the pattern described in Figure 3.1.20.

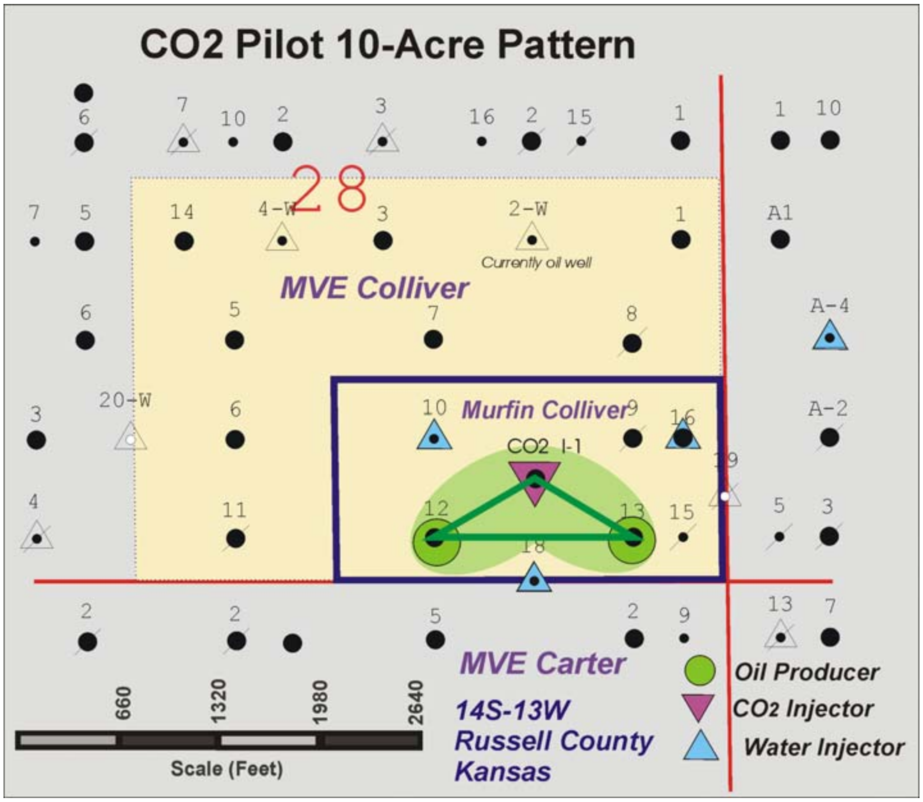


Figure 3.1.20. CO2 pilot comprising the CO2I#1 CO2 injection well, two containment wells (CO2#10, CO2#18), two producing wells (CO2#12, CO2#13) and an observation well (CO2#16).

A new geomodel of the pattern area was developed based on the "C" interval core from the CO2 #16 and wireline logs from the #12, #13, and #16. Using the new logs, old unscaled neutron logs in the pattern area were rescaled to provide consistent porosity values. Rescaling increased interpreted porosities from previous analysis (Figure 3.1.21). The new porosities were used in the ***Petra*** mapping software package to construct new porosity maps for six layers in the LKC "C" interval. This model was used to estimate the pattern pore volumes that can be processed provided #12 and #13 are used as producing wells.

Low permeabilities in and around #16 described in Section 5.1 were not predicted. Existing models were modified to be consistent with the present understanding of this portion of the pattern. Reservoir simulation models were constructed using the Computer Modeling Group ***CMG–IMEX*** reservoir simulator using the Todd and Longstaff model for carbon dioxide flooding as discussed previously.

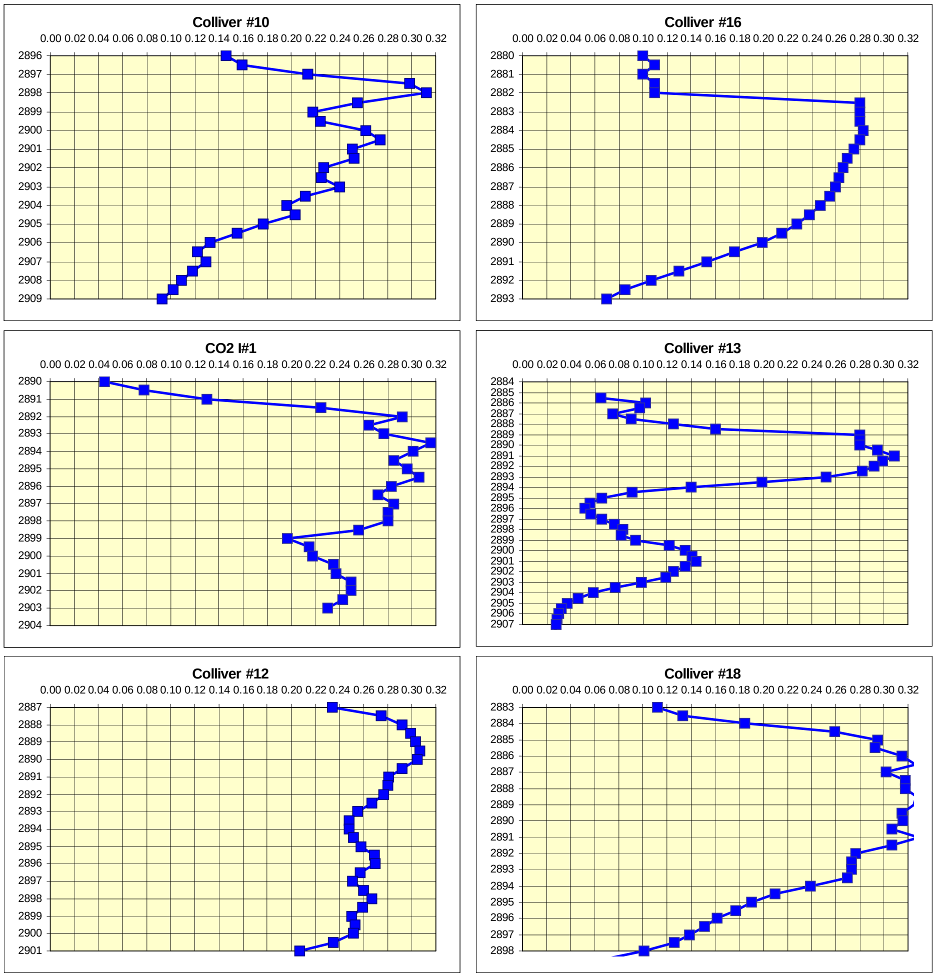


Figure3.1.21. Wireline log porosity profiles for wells in CO2 Pilot pattern. CO2 Project #18 neutron porosity was rescaled from previous analyses to match new well log responses.

These new reservoir properties and the well test data indicated greater permeability architectural complexity than previously modeled, a not uncommon situation. The process pore volume rate between the CO2I#1 and the CO2#16 was sufficiently low that without stimulation of the CO2#16 the PPV was too low to properly process the region within the demonstration time period. The flood was planned to produce only from the CO2#12 and CO2#13 and to monitor the CO2#16 (Figure 3.1.20). It was planned to observe CO2#16 during the flood to determine there was any indications of the movement of an oil bank.

Model-generated streamlines for the 2-producing well pattern indicated that this pattern would provide 80-85% containment (Figure 3.1.22) and recover about 18,000-21,000 BO (2,880-3,360 m^3). Several models were constructed to simulate different alternate working hypotheses for reservoir permeability architecture.

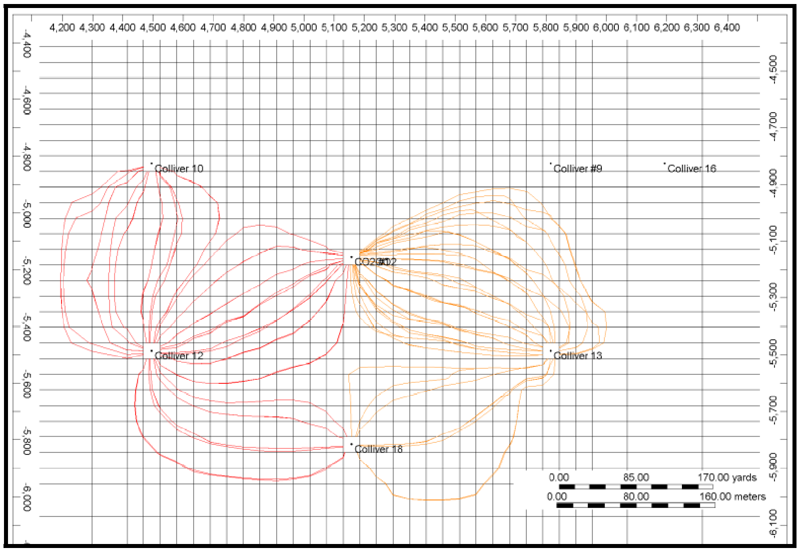


Figure 3.1.22. Flowlines generated by computer model of pilot area using permeability distributions shown in Table 3.3.

Table 3.3 summarizes permeabilities at and near wellbores for leading 2-layer models and/or reservoir properties calculated from various tests interpreted by the Tertiary Oil Recovery Project (TORP) and at Transpetco Engineering (TPE; consulting for Kinder-Morgan CO2 Company). The table also shows predicted permeabilities based on porosity-permeability transforms.

Table 3.3. Summary of Lansing-Kansas City 'C' zone permeability in and near wells in pilot pattern measured from core and interpreted from well tests and used in reservoir simulations

Well	Core Perm Avg (md)	Log ↗only Perm Avg (md)	TPEC Perm Avg (md)	core Layer 1 Perm (md)	log ↗only Layer 1 Perm (md)	TORP Layer 1 Perm (md)	TPEC Layer 1 Perm (md)	core Layer 2 Perm (md)	log ↗only Layer 2 Perm (md)	TORP Layer 2 Perm (md)	TPEC Layer 2 Perm (md)
CO2 I#1	88	72	85	115	94	117	134	20	47	117	35
Colliver 10		33	48		55	117	80		14	17	15
Colliver 12		66	60		95	117f	100		37	50	19
Colliver 13		62	79		44	10	38		81	117	120
Colliver 16	25	36	26	10	58	10	17	37	26	20	34
Colliver 18		133	30		172	53f	50		108	117	10
Main Reservoir			112			117	188			117	36
W of #13			72				64				80
E of #13			110				80				140

f-indicates fracture or enhanced permeability channel may influence CO2#12-CO2#18 connection

Simulations were conducted using the revised properties to investigate the conductivity between CO2I#1 and CO2#13. Conductivity test results between CO2I#1 and CO2#13 are interpreted to indicate the presence of a lower permeability region or barrier between the two wells that restricts but did not stop flow. Based on the differences in permeability between the upper and middle intervals in the two wells, the permeability distribution between these wells was interpreted to consist of an uppermost interval decreases in permeability from the CO2I#1 towards the CO2#13 and the middle interval increases in permeability. A lower permeability barrier between the upper and middle intervals, possibly reflecting a low-permeability bedset contact, could decrease composite permeability and explain the lower conductivity between

CO2I#1 and CO2#13 compared to between the CO2I#1 and CO2#12. Figure 3.1.23 represents one possible model describing the transition in permeability between CO2#I-1 and CO2#13.

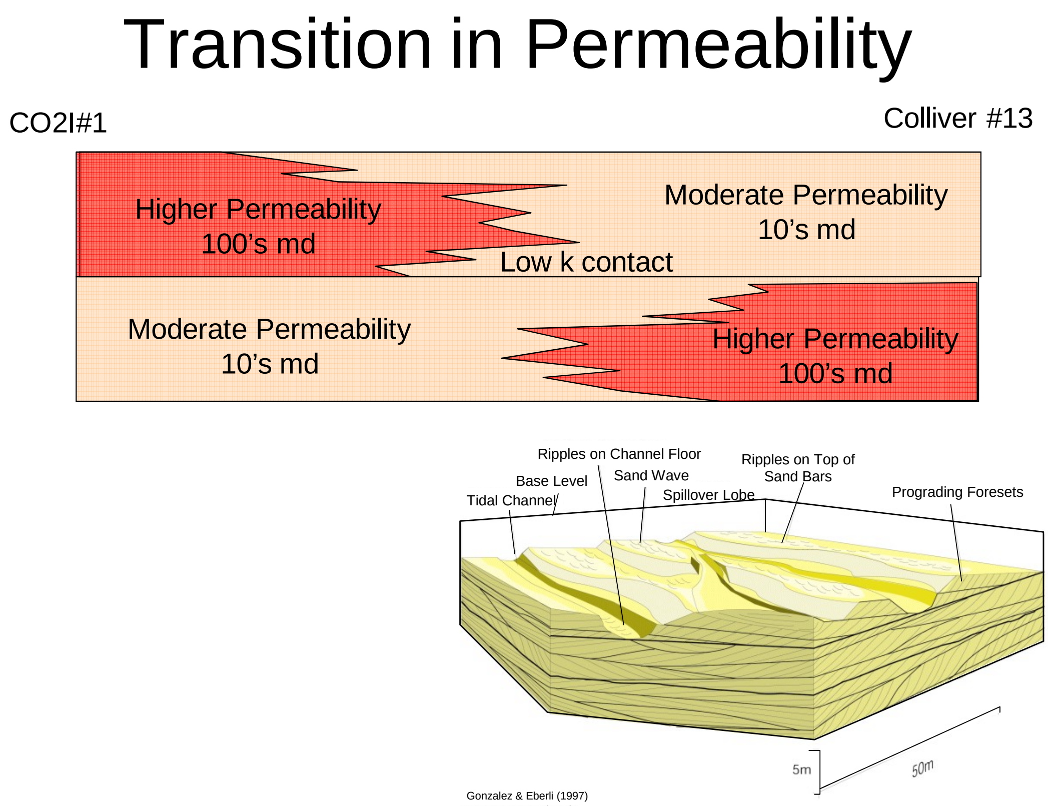


Figure 3.1.23: Model representing the transition in permeability between CO2#I-1 and Colliver #13(CO2#13).

3.1.9 Advanced Phase Behavior Data

Experimental Swelling and Viscosity Data

In January 2009, a high pressure PVT cell was developed in the Tertiary Oil Recovery Laboratories. This laboratory was funded by TORP and was not part of the CO2 Project. Phase behavior experiments were conducted using LKC crude oil at 98˚F. The reservoir temperature of 98˚F was measured in CO2#16, replacing the initial estimate of 105˚F. Details of the experimental equipment and procedures are presented in reference 4. Viscosities of stock tank oil and carbon dioxide saturated oil were also determined.

The PVT cell permitted visual observation of the phases as carbon dioxide pressure was increased as shown in Figure 3.1.24. The amount of carbon dioxide dissolved in the liquid phase was determined by material balance assuming that the extraction of hydrocarbon into the vapor phase was negligible up to the point where the swelling factor decreased as carbon dioxide pressure increased.

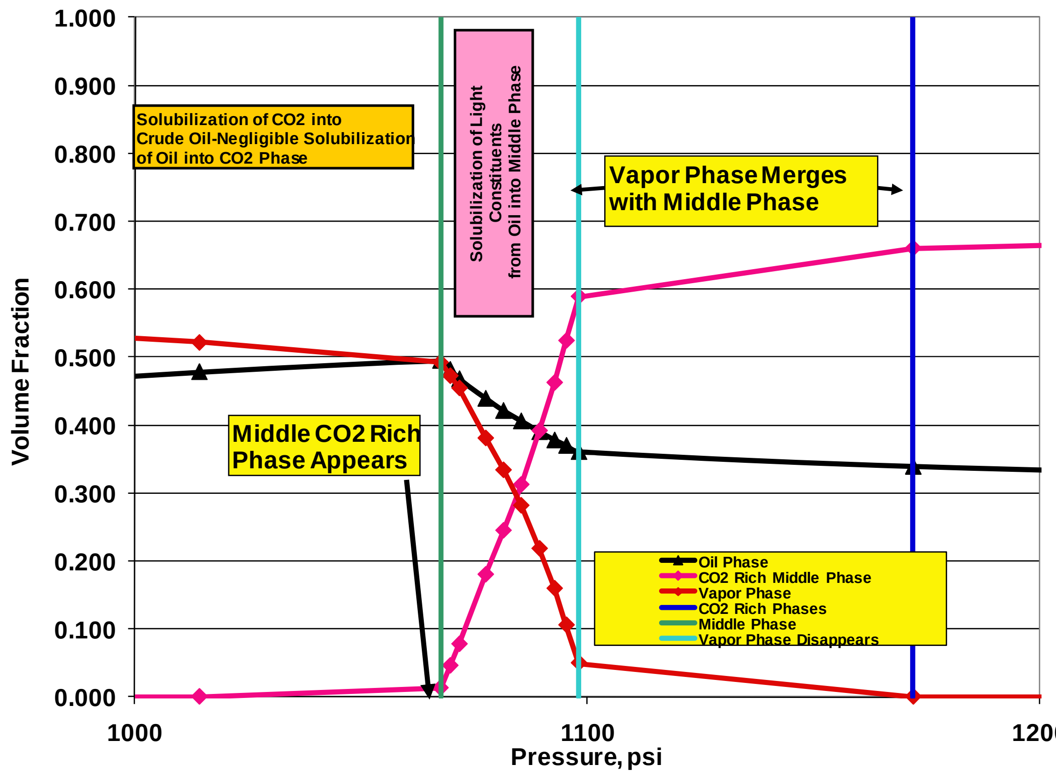


Figure 3.1.24: Phase behavior of CO2-LKC crude oil at 98ºF

The third phase appeared at a pressure of 1067.5 psi and disappeared at about 1102.psi. During this pressure transition, the volume fraction of the liquid phase decreased from 0.5 to 0.35 which is interpreted to be extraction of both carbon dioxide and hydrocarbon to form a CO2 rich middle phase.

The lower liquid phase appears to be saturated with carbon dioxide at 1067 psi where the mole fraction of carbon dioxide was estimated to be 0.702. Oil extracted from the oil phase appears to be primarily located in the middle phase which contained primarily carbon dioxide as indicated by slight coloration. The upper phase remained colorless and was believed to contain little oil. Middle and upper phases merge at a pressure of 1102 psi leaving an oil rich lower phase and a carbon dioxide rich upper phase. The phase behavior observed is not predictable from commercial reservoir simulation models.

Figure 3.1.25 shows the variation of the swelling factor of the oil rich liquid phase with pressure. Maximum swelling factor was about 1.4 and occurred at the pressure where the third phase appeared. Figure 3.1.26 shows the solubility of carbon dioxide in the oil rich liquid for the pressures less than 1067 psi. Maximum carbon dioxide solubility was about 1253 SCF/bbl. Viscosity data were also obtained for oil saturated with carbon dioxide at 98˚F over a range of pressures. The data are shown in Figure 3.1.27. There is a small change in viscosity of the oil phase with pressure above about 1000 psig. This suggests that the composition of the oil phase may be relatively constant above this pressure.

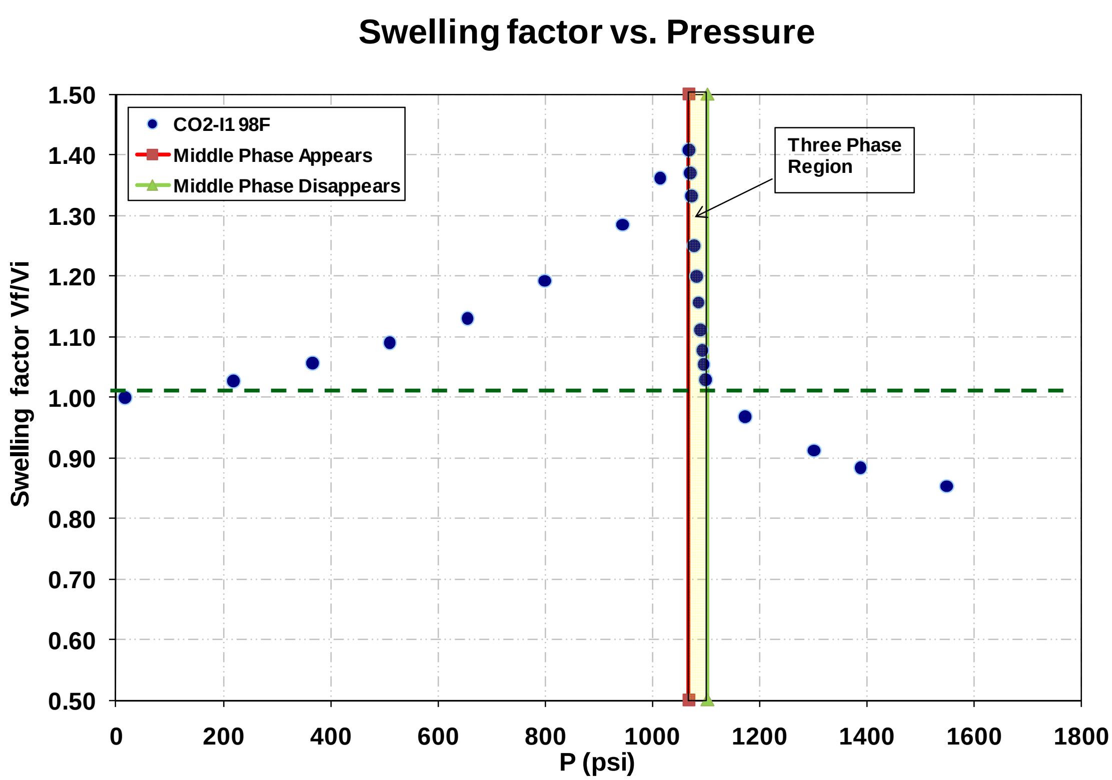


Figure 3.1.25: Variation of swelling factor with pressure for the solubilization of carbon dioxide in LKC crude oil at 98ºF.

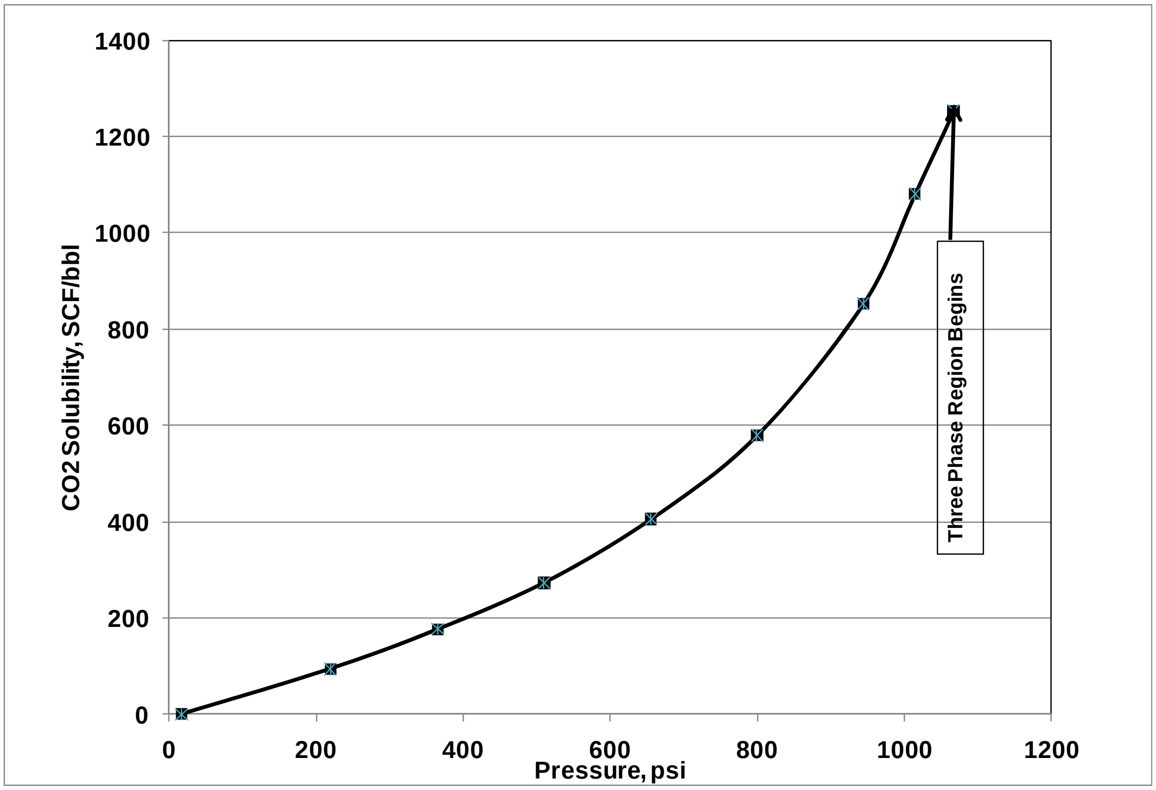


Figure 3.1.26: shows the solubility of carbon dioxide in LKC crude oil at 98˚F.

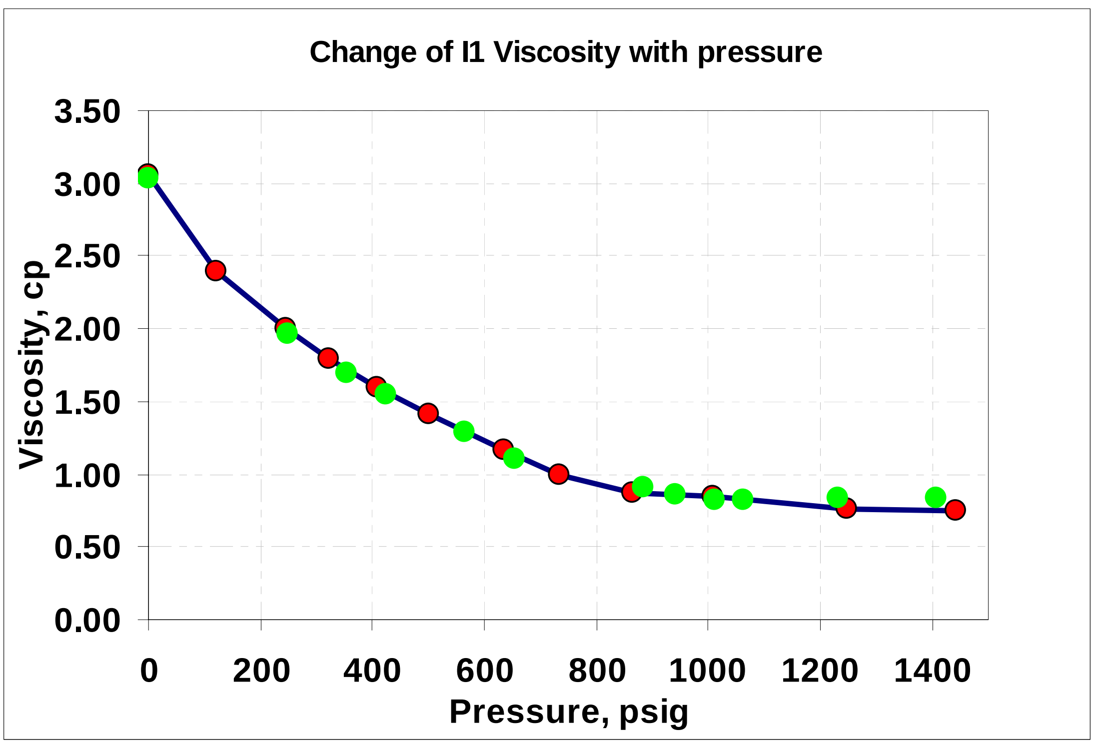


Figure 3.1.27: Change in viscosity of LKC crude oil saturated with carbon dioxide with pressure at 98˚F.

TASK 3.2 ECONOMIC AND RECOVERY ANALYSIS OF PILOT

3.2.1 Regional Assessment of LKC-Arbuckle Resource. Shortly after the proposal was selected by the USDOE, Shell CO2 Company, Ltd sold all assets to Kinder-Morgan CO2. Kinder-Morgan requested an economic study of the regional resource integrated with the economics of a pipeline from Guymon, Oklahoma and the economics of CO2 flooding Central Kansas Uplift leases. Kinder-Morgan indicated that an economic pipeline would require a resource base of approximately ~200 million barrels of primary and secondary recovery. Lease economics indicate that at $1.00/mcf CO2 cost, $20/bbl oil price, and estimated capital costs of $1MM/lease (Dubois and others, 2000), a viable CO2 flood candidate site must have produced greater than 8MBO/acre.

Regional assessment of L-KC and Arbuckle potential was performed on a section and lease-basis assuming values for the average lease size. Analysis of the Lansing-Kansas City indicated that for these economics the L-KC did not have sufficient resource base to support a pipeline alone but the Arbuckle did have sufficient resource (Table 3.4). Based on this assessment, Kinder-Morgan CO2 Company indicated the resource base of the Arbuckle needed to be proven.

Table 3.4. Cumulative Oil Production for L-KC and Arbuckle Based on DOR Database and Calculated assuming Section and Lease Basis

Calculated MBO/acre	L-KC Cumulative Production (bbls) from 10 County Region by Section	L-KC Cumulative Production (bbls) from 10 County Region by Lease	Arbuckle Cumulative Production (bbls) from 10 County Region by Section	Arbuckle Cumulative Production (bbls) from 10 County Region by Lease	Mississippian Cumulative Production (bbls) from 10 County Region by Lease
>10	49,270,125	118,729,970	242,713,940	335,957,840	27,107,353
9	61,811,405	135,266,247	260,253,625	393,422,559	28,659,833
8	77,838,373	152,823,438	303,246,717	454,630,672	30,037,051
7	92,081,810	177,008,452	415,783,953	521,019,943	33,611,084
6	120,379,742	203,041,866	502,774,338	610,869,878	37,816,051
5	134,642,276	230,641,508	619,055,065	712,170,200	48,535,274

note: Lease basis calculated assuming Lease cum/160acres (APB 11/21/00)

An Arbuckle resource assessment was initiated to justify Kinder-Morgan participation in the project. The assessment included preliminary mapping of Arbuckle reservoir pressure and oil production distribution, generic reservoir geomodel construction, reservoir simulation to determine the feasibility of CO2 flooding the Arbuckle, calculation of the influence of dissolved natural gas in oil on Arbuckle minimum miscibility pressure values, and initial research into identifying Arbuckle fracture pressure gradients.

Preliminary analysis of drillstem tests (DST) in the Arbuckle indicated that the Arbuckle may be divided into three classes of reservoir based on bottom hole pressures (BHP) measured after significant lease production. Low BHPs are interpreted to result from poor connection of the producing Arbuckle interval with the underlying aquifer. Intermediate and high BHPs are interpreted to indicate moderate and good connection with the underlying aquifer. Mapping of reservoir pressures shows that different portions of major Arbuckle fields exhibit different connection to the underlying aquifer, as shown for example in the Bemis South field in Figure 3.2.1.

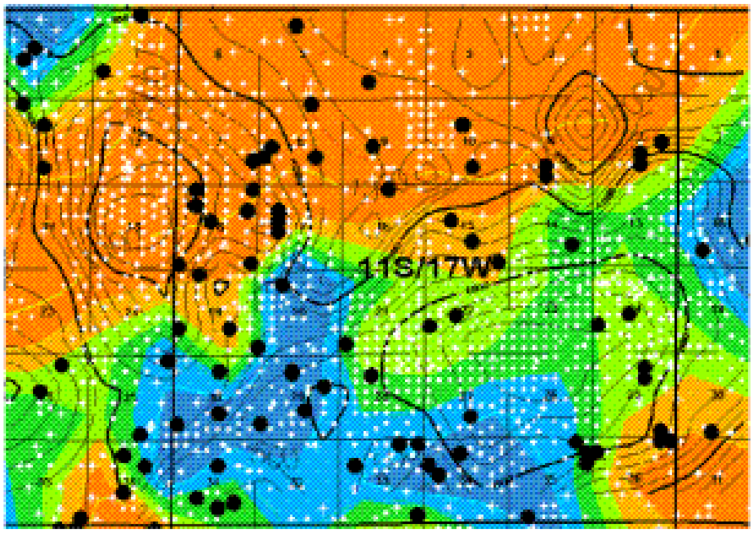


Figure 3.2.1: Drillstem test pressure regions in Bemis South showing low (<500 psi, blue), intermediate (green), and high (>1100 psi, orange) pressure regions.

Logs for the Bemis-Shutts were analyzed and integrated with core petrophysics (Byrnes and others, 1999) to construct generalized layered reservoir models for the three classes of Arbuckle reservoir in the Bemis South field. Reservoir flow simulations on these generalized models indicate that it is possible to pressurize the Arbuckle productive intervals to pressures greater than minimum miscibility pressure for Arbuckle oil (Figure 3.2.2)

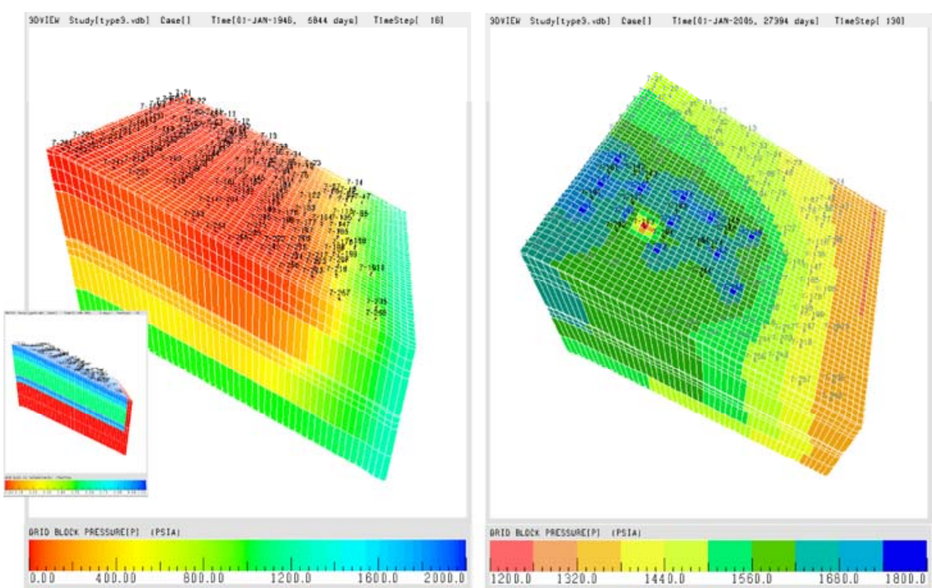


Figure 3.2.2: Reservoir simulation of present pressure and post-injection pressure in generalized isolated Arbuckle reservoir showing ability to reach MMP pressures in Arbuckle.

In the 10-county central Kansas area, a number of Arbuckle reservoirs were identified which are isolated from the underlying aquifer. These reservoirs are believed to be capable of being pressured up to MMP. Cumulative production from these reservoirs was approximately 150-186 million barrels (MMBO; 23.8-29.6 $*10^6 m^3$). Approximately 150-186 billion cubic feet (BCF, 4.2-5.3$*10^9 m^3$) of CO2 would be required if 25% of the oil was recovered at a net CO2 requirement of 4MCF/bbl.

Total regional Arbuckle production for leases estimated to produce over 10,000-8,000 bbls/acre was 337-454 MMBO (53.6-72.2 $*10^6 m^3$), respectively. Approximately 75-112 MMBO (11.9-17.8$*10^6 m^3$) were in areas where connection to the aquifer was not determined but would likely be floodable based on regional distribution. About 112-140 MMBO (17.8-22.3$*10^6$ m^3) were produced from high-pressure reservoirs that are well connected to the aquifer and may not be suitable for CO2 miscible flooding.

The data and results indicated that a significant fraction of the Arbuckle may be a viable resource for CO2 enhanced oil recovery. Lansing-Kansas City (LKC) leases which have produced >10,0000-8,000 bbl/acre are estimated to have produced from 70-120 MMBO (11.1-19.1$*10^6$ m^3), where the range expresses differences due to the method for assessing production. The combined CO2 demand for the Arbuckle (225-298 BCF; 6.4-8.4$*10^9$ m^3) and the L-KC (70-120 BCF; 2.0-3.4 $*10^9$ m^3) indicate there is sufficient resource to require at least 295-320 BCF (8.3-9.1 $*10^9$ m^3) of CO2 which would support an 8- to 10-inch pipeline.

3.2.2 Economic and recovery of Proposed Colliver Pilot: In October 2000, the municipal power plant at Russell, KS exploded. This plant was replaced by a cogeneration plant coupling power generation with an ethanol plant operated by ICM Inc. The ethanol plant produced high purity CO2. Discussions were initiated with ICM Inc. to explore the possibility of obtaining CO2 from the ethanol plant for the pilot project replacing the trucking of CO2 from the pipeline terminus in Guymon, Oklahoma. Economic analyses of the potential pilot patterns were based on the assumption that CO2 would be available from the Russell ethanol plant at the equivalent cost of trucking from Guymon.

Analysis of potential pilot locations on the Colliver lease were completed based on oil recovery projected from the reservoir model. Results indicated that a pilot pattern of 60-acres (24.3 ha) was necessary to generate revenues and CO_2 usage needed for the demonstration to be economically viable for MV Energy LLC and ICM Inc. Smaller patterns had too high a lease capital cost for the oil income returned and require less CO2, limiting the income to ICM Inc. to offset CO_2 capture and delivery capital and operating expenses.

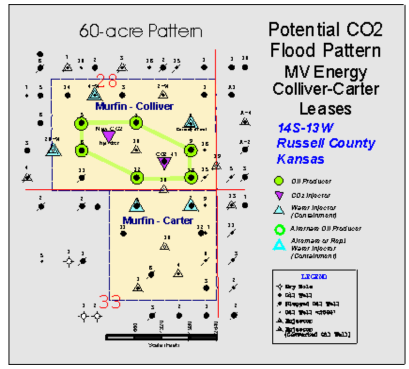
Based on the simulator-predicted recoveries and updated estimates of well remediation costs and other capital and lease operating expenses, the 10-acre pattern flood provided a –27% internal rate of return (IRR) for MV Energy LLC, the 40-acre pattern provided a 0% IRR, and the 60-acre provided a 13% IRR. Predicted recovery for the 60-acre pattern was highly sensitive to model properties near the Colliver #7 well. This well exhibited anomalously high production for predicted reservoir properties based on wireline logs. In addition, to match the estimated production history, model permeabilities in the region near the Colliver #7 were as high as 1.2 darcy (0.1 um^2). The uncertainty of properties near the Colliver #7 and the sensitivity of the economics to those properties resulted in too much uncertainty in economic forecasting. The model, existing, data, and the allocation of oil production from the “C” and “G” zones were re-evaluated to reduce uncertainty.

Economics for a 60-acre (24.3 ha) pattern are presented in Tables 2.3.2 through 2.3.3. Table 2.3.2

shows a summary of the original project economics and revised project economics for a 60-acre (24.3 ha) pattern. Modifications to the original project plan require increased financial commitment by MV Energy LLC, the U.S. Department of Energy, and a new partner, ICM Incorporated, and decreased commitment by Kinder-Morgan CO_2 Company LLP in the present L-KC demonstration. All modified activities and tasks would maintain the existing required industry match of 55% in Budget Period 1, 65% in Budget Period 2, and 90% in Budget Period 3. Carbon dioxide supplied by the ICM ethanol facility would be valued such that the total cost of CO_2 delivered to the demonstration site would not exceed the $3.00/Mcf ($0.106/m^3) cost of supplying CO_2 from Guymon, OK. Total cost of the modified project was $7,469,292 compared with $5,388,064 in the original project.

Table 3.5- Budget Summary for Revised Kansas CO2 Flood Project

	Original Project	Modified Project
Flood Performance		
Acres	40	60
Total CO2 Injected (mcf)	843	850
WAG Years	3.7	6
Post CO2 WF years (DOE)	1	1
Post CO2 WF years (post DOE)		1
Oil Produced (Commercial Life)	75,300	96,700
Capital		
Drill & Equip #1 CO2 I &Plug Line Well (Task	236180	$341,750
Rework and upgrade wells (old Task 5.1 /Tas	$474,500	$706,244
Drill & Equip CO2 I-2 (Task 2.1)	$0	$175,000
Surface facilities (Task 5.3)	$322,575	$308,315
Drill and Equip Water Supply Well (Task 2.3)	$35,000	$35,000
Subtotal	$1,068,255	$1,566,309
Flood Operations		
Repressure Reservoir (Task 2.3&Task 5.2)	$16,377	$31,487
CO2 Slug, WAG + Admin (Task 5.4)	$734,231	$1,188,570
Post waterflood (Task 5.4)	$100,858	$129,484
CO2 Purchased by operator (Task 5.4)	$0	$212,500
Subtotal	$851,466	$1,562,041
CO2 Supply		
Compressors or Liquifaction Equipment Lease		$547,600
8 mile pipeline		$530,000
CO2 compression (fuel & ops)		$484,500
Value of CO2 contributed	$1,608,900	$775,400
Recycled CO2	$414,045	$0
Subtotal	$2,022,945	$2,337,500
Research, Data, Tech Transfer, Admin.		
KU Research, Data Collection & Tech Transf	$1,446,018	$1,829,887
Outside Consulting & Adm.	0	$173,477
Subtotal	$1,446,018	$2,003,363
PROJECT TOTAL EXPENSES	**$5,388,684**	**$7,469,213**
Revenue Sources		
DOE ($Cap $LOE)	$676,261	$1,176,405
DOE ($CO2)	$708,031	$892,500
DOE (Research, Data, Tech Transfer)	$507,802	$655,959
Murfin ($Cap $LOE)	$830,259	$1,840,639
Murfin (net $CO2)	$0	$138,125
Kinder-Morgan In-kind CO2	$268,150	$476,000
Kinder-Morgan Cash	$1,359,858	$46,657
ICM ($Cap $Lease $Ops)	$0	$457,100
ICM In-kind CO2	$0	$511,900
KUCR In-kind	$938,323	$1,173,927
State Of KS DOC	$100,000	$100,000
PROJECT TOTAL REVENUES	**$5,388,684**	**$7,469,213**
DOE Total	$1,892,094	$2,724,865
DOE Incremental over Original Project	$0	$832,771



MURFIN COST ESTIMATES & VARIABLES	
Capital Costs	
Characterization activities	$105,570
BP-1 Rework and upgrade wells	$529,635
BP-1 WIW Surface Facilities	$94,645
Drill & Equip CO2 I-2	$175,000
BP-2 Prepare wells	$81,964
BP-2 WI Surface Facilities	$308,315
Drill and Equip Water Supply Well	$35,000
	$1,330,129
Lease Operations	
CO2 Oil	1,200
Post CO2 Oil	1,200
Water Inj	800
CO2 Injector	1,200
WSW	1,000
CO2 Purchase	$0.25
Lost Oil Revenue	($50,000)
Oil Price	$20.00
EOR Tax Credit	10%
ICM COST ESTIMATES AND Variables	
Pipeline	$530,000
(Not budgetted)chase Compression	*$350,000*
Dehydration	$30,000
Install Compress & Dehy	$100,000
Compressor lease costs/yr	$69,600
Power	$0.18
Compress ops	$0.26
Pipeline ops	$0.13
	$0.57
MV Purchase Price CO2 from ICM	$0.25
EOR Tax Credit	0%
CO2 Required MMCF	850
FACTOR	**100.0%**
Kinder-Morgan	
Spot Value at Bravo Dome	$0.60
Relative Value for 800/900 mmcf	$0.56

TABLE 3.6 - GENERAL ECONOMICS FOR MV ENERGY

(These calculations use average numbers and may differ slightly from budget worksheets) DATE 05/01

Color Code	Input Cell	
	Input elsewhere	
	Calculated	mportant

60-Acre Pattern

Colliver-Carter CO2 Pilot

Date: DATE: 05/01 — $20.00 per Barrel

Working Interest	100.00%	Probability:	100%	100%	Model Output
N.R.I.	87.50%		0%	82%	Model Output
			0%	111%	Model Output
Price:	$ 20.00				
Tax Rate:	0.00%	Year 1-3	0.00%		

Year	Prod	Price	Net Oper Revenues	Sev & Adv Taxes	Net Well Oper Expenses	CO2 Costs	Pre-Op Cap Costs	Surf Fac Cap Costs	EOR Tax Credit	Cash Flow BFIT	PVP @ 10%	PV Factor 10%
Initial	Pre-flood repressuring				18,688		445,613	219,655	68,396	(665,560)	(665,560)	1.00000
1	2,562	$20.00	44,839	0	145,600	37,153		0	18,275	(119,639)	(108,762)	0.90909
2	10,698	$20.00	187,223	0	145,600	20,234		0	16,583	37,973	31,383	0.82645
3	23,006	$20.00	402,605	0	145,600	20,061		0	16,566	253,510	190,465	0.75131
4	23,201	$20.00	406,018	0	145,600	20,061		0	16,566	256,923	175,481	0.68301
5	16,428	$20.00	287,493	0	145,600	20,061		0	16,566	138,398	85,934	0.62092
6	10,863	$20.00	190,103	0	145,600	20,556		0	16,616	40,562	22,896	0.56447
7	6,506	$20.00	113,848	0	84,326	0		0	8,433	37,954	19,476	0.51316
8	3,422	$20.00	59,879	0	93,696	0		0	9,370	(24,448)	(11,405)	0.46651
9	0	$20.00	0	0	0	0		0	0	0	0	0.42410
10	0	$20.00	0	0	0	0		0	0	0	0	0.38554
	96,686		1,692,006	0	1,070,310	138,125	445,613	219,655		(44,327)	(260,093)	

Capital Cost/NetBbl	$ 7.08	I.R.R.	-1.55%
Operations/Net Bbl	$11.39	Profit	(44,327)
CO2 Cost/Net Bbl	$1.47	Profit/Capital	-7%
Total/Net Bbl	$19.93	Net Ult. Reserves	84,600

Possible Outcome		Probability	Cash Flow BFIT	Risk-weighted Cash Flow	PVP @ 10%
100%	Model Output	100.00%	(44,327)	(44,327)	(260,093)
60-Acre CO2 Demo					
Flander's Mid PPV					
82%	Model Output	0.00%	(348,888)	0	(466,636)
60-Acre CO2 Demo					
Flander's Mid PPV					
111%	Model Output	0.00%	141,794	0	(133,872)
60-Acre CO2 Demo					
Flander's Mid PPV					
Expected Value		100.00%		(44,327)	

Oil Production (Flander's)		
	% of Projected	
Optimistic	82%	
Pessimistic	111%	
Risk Wieghting	1	1 = No
		2 = Yes
	Risk	% Prod
Scenario 1	60%	100%
Scenario 2	20%	82%
Scenario 3	20%	111%

		Capital		DOE	Operator	DOE	Operator	
CO2 costs $/mcf	$0.25	BP-1characterization	$105,570	45%	55%	$47,507	$58,064	
EOR Tax Credit	10%	BP-1 Rework and upgrade wel	$529,636	45%	55%	$238,336	$291,300	
		BP-1 WI Surface Fac	$94,645	45%	55%	$42,590	$52,055	
Lost Oil Revenue	($50,000)	Drill & Equip CO2 I-2	$175,000	45%	55%	$78,750	$96,250	
(from plugged zones)		Drill and Equip Water SW	$35,000	45%	55%	$15,750	$19,250	
		BP-2 Rework and upgrade wel	$81,964	35%	65%	$28,687	$53,277	
		BP-2 All Other Surface Fac	$308,315	35%	65%	$107,910	$200,405	
			$1,330,130			$559,531	$770,599	$1,330,130
		Lease Operating Expense						
$LOE	Avg Monthly/Well	BP-1	$16,250	45%	55%	$7,313	$8,938	
CO2 Oil	1,600 6 mos represssure	BP-2	$1,359,000	35%	65%	$475,650	$883,350	
Post CO2 Oil	1,200 6 years wag	BP-3	$93,696	10%	90%	$9,370	$84,326	
Water Inj	800 1 year DOE post WF		$1,452,696			$492,332	$976,614	
CO2 Injector	1,200							
WSW	1,000		CO2 Purchase	35%	65%	$74,375	$138,125	

3	Months repressure BP-1
3	Months repressure BP-2

Wells in Pattern 2 shut down when uneconomic

CO2 Inj convert to WIW in WF

# Wells	BP-1	BP2 WAG							BP3 Post WF	Post DOE
Year	Repressure	Repressure	1	2	3	4	5	6	7	8
CO2 Oil	0	0	6	6	6	6	6	6	0	0
Post CO2 Oil	0	0	0	0	0	0	0	0	3	3
Water Inj	5	5	5	5	5	5	5	5	5	5
CO2 Inj	0	0	2	2	2	2	2	2	0	0
WSW	1	1	1	1	1	1	1	1	0	0
Mngmnt (mor	417	0	1,667	1,667	1,667	1,667	1,667	1,667	208	208
	16,250	15,000	224,000	224,000	224,000	224,000	224,000	224,000	93,696	93,696
		31,250						1,344,000	93,696	93,696

Year	Oil Prod
1	2,562
2	10,698
3	23,006
4	23,201
5	16,428
6	10,863
7	6,506
8	3,422
9	1,555
10	556
	98,797

DATE: 05/01

Table 3.7 General CO2 Supply Economics for Miscible flood project

(These calculations use average numbers and may differ slightly from budget worksheets)

60-Acre Demonstration

Color Code	
Input Cell	
(for most)	Input elsewhere
	Calculated important

Assume ICM recovers 35% DOE match on capital, operations and CO2 in-kind contribution

ICM delivers CO2 to site at injection pressure for pilot project
ICM is able to sell commercial CO2 after pilot

Max Rate (mcfpd) 626 (Calculate)

	RATE		Tons/day
Injection Rate-Pilot Period, mcfd	378	mcfpd	22
Injection Rate-Commercial Period, mcfd	1000	mcfpd	58

Original operating expense from FloCO2 = $0.1805/mcf
Original power costs, $0.26/mcf from ICM

Purchase or Lease Compression

Purchase Compression	$0
Dehydration	$30,000
Instal Compression & Dehydration	$100,000
Compressor annual lease costs	$69,600
Power Costs, $/mcf	$0.18
Compressor Ops $/mcf	$0.26
Pipeline Ops $/mcf	$0.13
Total operating Costs, $/mcf	$0.57

Kinder-Morgan CO2 $/mcf	$0.560
EOR Tax Credit	0%
CO2 Revenue ($/mcf)	
MV Energy Purchase	$0.250
Commercial sales	$1.00

3" Pipeline	$530,000
2" Pipeline	$500,000
ICM invest in larger diameter	$30,000

CO2 usage for pilot 60Acre Pattern	CO2	% of projected	Projected
Year 1	228,634	100.0%	228,634
2	124,515		124,515
3	123,450		123,450
4	123,450		123,450
5	123,450		123,450
6	126,501		126,501
7	0	Avg Rate	0
CO2 total mcf	850,000	378	(Calculate)
Value of CO2	$0.912		
DOE Match	35%		
Price for purchase of CO2 from ICM	$0.250	$431 per ton	
CO2Income	$212,500		
CO2$ Target	$3.000		

RISK WEIGHTED ECONOMICS for ICM

Year	Pipeline Investment	Compressor Investment	Compressor Lease Option	Operating Costs	Income (DOE match $Cap & CO2)	Income (DOE match $LEASE & $OPER)	Investment Tax Credit (Applied in next year)	Kinder-Morgan CO2 Contribution	Income from CO2 Sales	Net Cash Flow BFIT	Cum Net Cash Flow BFIT		Scenario 1 Success Net Cash Flow BFIT	Scenario 2 Failure Net Cash Flow BFIT	Risk Weighted Net Cash Flow BFIT
												Success Rate	50%	50%	
0	(530,000)	(130,000)			231,000	0	0			-429,000	-429,000		-214,500	-214,500	-429,000
1			(69,600)	(130,321)	72,980	69,972	0	128,035	57,159	128,225	-300,775		64,113	64,113	128,226
2			(69,600)	(70,974)	39,745	49,201	0	69,728	31,129	49,229	-251,546		24,615	24,615	49,230
3			(69,600)	(70,367)	39,405	48,988	0	69,132	30,863	48,421	-203,125		24,211	24,211	48,422
4			(69,600)	(70,367)	39,405	48,988	0	69,132	30,863	48,421	-154,704		24,211	24,211	48,422
5			(69,600)	(70,367)	39,405	48,988	0	69,132	30,863	48,421	-106,283		24,211	24,211	48,422
6			(69,600)	(72,106)	40,379	40,607	0	70,941	31,626	60,736	-55,547		26,368	26,368	60,736
7			0	0	0	0	0	0	0	0	-55,547		0	0	0
Buy-out compression*		(260,000)		(208,050)	0	0	0	0	365,000	-93,050	-296,175		-46,525		-46,525
	Buy-out lease on 1 MMCFD compression for $260,000			(208,050)	0	0	0	0	365,000	156,950	-139,225		78,475		78,475
				(208,050)	0	0	0	0	365,000	156,950	17,725		78,475		78,475
				(208,050)	0	0	0	0	365,000	156,950	174,675		78,475		78,475
				(208,050)	0	0	0	0	365,000	156,950	331,625		78,475		78,475
				(208,050)	0	0	0	0	365,000	156,950	488,575		78,475		78,475
				(208,050)	0	0	0	0	365,000	156,950	645,525		78,475		78,475
								476,000	Total	793,103		Total	396,554	-27,771	398,793
									IRR	15%		IRR	15%	-4%	10%

ICM Revenues	"Cost"/mcf			Net ICM Costs		
DOE match $CO2	$0.91	271,320		In-kind $CO2	503,880	
DOE match $CAP		231,000		$Cap	429,000	
DOE match $Lease		146,160		$Lease	271,440	
DOE match $OPER		169,576	818,056	$Oper	314,926	
Investment Tax Credit Net CapLease 0%		0		K-M CO2	(476,000)	539,366 (Out of pocket)
CO2 Sales during pilot ($/mcf) 0.25		212,502		Less CO2 Sales	212,502	
		1,030,558			1,255,748	
ICM Loss if project fails at end of (1)	($55,547)	(Less salvage-DOE share of salvage)				

Potential ICM Loss

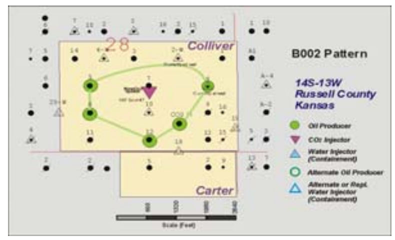
Total cost$	-1,562,102	-539,366	Out of pocket
DOE Income	818,053	271,319	DOE CO2 match
K-M CO2	476,000		
CO2Income	$212,500	$212,500	
Investtax credit	0	0	Inst tax credit
	($55,549)	($55,547)	

CO2 Costs to manifold	
$Capital	660,000
Compression	484,502
Equip Lease	417,600
CO2 value	775,200
CO2 Sales	$212,500
	$2,549,802
Per mcf	$3.00
Per ton	$51.69
CO2 Compress &Transport	$1.838
Total CO2 Value	$1.162
	$3.00

Approximate economics were calculated for a variety of flood patterns, assumed reservoir properties, process rates, and operation plans in an effort to improve the economics of the pilot as well as to reduce the capital investment. Example economics for the B002 73-acre single-injector pattern project a potential profit ranging from -$138,000 to $80,000, depending highly on process rate and the price of oil. Table 3.8 illustrates B002 pattern economics for a high process rate and a $20/barrel oil price.

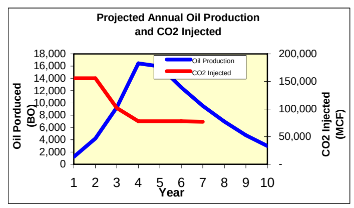
Table 3.8: Hall-Gurney Pilot CO2 Flood-Colliver-Carter BOO2 73-acre Pattern

Hall-Gurney Pilot CO2 Flood
Colliver-Carter BOO2 73-acre Pattern
Location: Sec 28-14S-13W, Russell County, Kansas



Data Input Variables

Economic Measures			Major Input Parameters		
ROR (Mid Yr Discount)	**3.17%**		Oil Price	**$20.00**	per BBL
NPV (Mid Yr Discount)	($135,527)		Purhased CO2 Cost	**$0.00**	per MCF
ROR (End Yr Discount)	2.84%		Recycle CO2 Cost	**$0.35**	per MCF
NPV (End Yr Discount)	($154,893)				
			Discount Rate	**10.0%**	
Profit (BFIT)	$80,662				
Profit/Capital	16%		Working Interest	100.0%	
Net Ultimate Rec **(BO)**	**73,317**		Net Revenue Interest	87.5%	
			Severance Tax	0.0%	
Cost/Net BBL Capital	$6.00		Ad Valorem Tax	0.0%	
LOE	$10.70		EOR Tax Credit	10.0%	
Purchased CO2	$0.00				
Recycle CO2	$0.00		LOE Cost Factor	100.0%	FO
Total Cost/Net BBL	**$16.70**		Capital Cost Factor	100.0%	FC
			Oil Price Escalator	0.0%	per year
Gross CO2 Utilization	**8.6**		LOE Escalator	0.0%	per year
Net CO2 Utilization	**8.6**		CO2 Cost Escalator	0.0%	per year



Capital Costs

	Est. Item Cost	Factored (x FC) Item Cost	DOE	Operator	DOE	Operator	EOR Tax Credit
BP-1 Loss carried forward	$105,692	$105,692	45%	55%	$47,561	$58,131	
Rework and upgrade wells	$292,188	$292,188	45%	55%	$131,485	$160,703	
Drill & Equip CO2 I-2	$175,000	$175,000	45%	55%	$78,750	$96,250	$9,625
Drill and Equip Water SW	$35,000	$35,000	45%	55%	$15,750	$19,250	
Surface facilities	$238,136	$238,136	35%	65%	$83,348	$154,789	$15,479
total before DOE cost share and EOR credit		$846,016		*before EOR credit*	$356,894	$489,123	$25,104
Operator Capital Expnses (excludes BP1 Loss)						**$430,992**	

EOR tax credit applied to CO2 injectors and their lines, and surface facilities

Lease Operating Expense Costs

	Est. Unit $/mo	Factored (x FO) Unit $/mo
CO2 Oil Well	1,400	1,400
Post CO2 Oil	1,100	1,100
Water Injectin Well	800	800
CO2 Injection Well	1,200	1,200
Water Supply Well	800	800
Flood Mgmt ($/pattern)	417	417
Repressure Phase	6	Months

Lease Operating Expense Calculator

Phase	Year	Number of Wells in Pattern: CO2 Oil	Post CO2 Oil	WIW	CO2 Inj	WSW	Flood Mgmt # Patterns	LOE Annual Cost	DOE Cost Share
BP2 Repressure	0	0	0	1	1	1	1	19,303	35%
BP2 CO2 WAG	1	5	0	1	1	1	1	122,605	35%
BP2 CO2 WAG	2	5	0	1	1	1	1	122,605	35%
BP2 CO2 WAG	3	5	0	1	1	1	1	122,605	35%
BP2 CO2 WAG	4	5	0	1	1	1	1	122,605	35%
BP2 CO2 WAG	5	5	0	1	1	1	1	122,605	35%
BP2 CO2 WAG	6	5	0	1	1	1	1	122,605	35%
BP3CO2 WAG	7	5	0	1	1	1	1	122,605	10%
BP3 Post WF	8	0	5	1	0	1	1	90,205	0%
Post WF	9	0	5	1	0	1	1	90,205	0%
Post WF	10	0	5	1	0	1	1	90,205	0%
	11	0	0	0	0	0	0	0	0%
	12	0	0	0	0	0	0	0	0%
	13	0	0	0	0	0	0	0	0%
	14	0	0	0	0	0	0	0	0%
	15	0	0	0	0	0	0	0	0%
							total before DOE cost share and EOR credit	1,148,153	

Projected Oil Production and CO2

Year	Annual Oil (BO) Production	CO2 in MMCF Injected	CO2 Purchased
1	1,190	155,800	155,800
2	4,184	155,800	155,800
3	9,258	101,800	101,800
4	16,441	77,900	77,900
5	15,967	77,900	77,900
6	12,548	77,900	77,900
7	9,539	76,862	76,862
8	6,940	0	0
9	4,751	0	0
10	2,973	0	0
11	0	0	0
12	0	0	0
13	0	0	0
14	0	0	0
15	0	0	0
	83,791	723,960	723,960

Annual Forecasts

Pre-CO2 Well Cap Costs 334,334
Surf Fac Cap Costs 154,789

Year	Prod (BO)	Price	Net WI Op Revenues	Sev & Adv Taxes	Lease Op Expenses	Purchased CO2 Costs	Recycled CO2 Costs	EOR Tax Credit	Cash Flow BFIT	Yr End Discount PVP @ 10.0%	PV Factor 10.0%	Mid-Year Discount PVP @ 10.0%	PV Factor 10.0%	ROR Calc. 3.17%
0	Repressure	*Lost Oil Rever*	(50,000)		12,547				(551,670)	(551,670)	1.0000	(551,670)	1.0000	(551,670)
1	1,190	$20.00	20,829	0	79,693	0	0	25,104	(33,760)	(30,691)	0.9091	(32,189)	0.9535	(33,237)
2	4,184	$20.00	73,223	0	79,693	0	0	0	(6,470)	(5,347)	0.8264	(5,608)	0.8668	(6,174)
3	9,258	$20.00	162,013	0	79,693	0	0	0	82,319	61,848	0.7513	64,866	0.7880	76,135
4	16,441	$20.00	287,720	0	79,693	0	0	0	208,026	142,085	0.6830	149,020	0.7164	186,481
5	15,967	$20.00	279,418	0	79,693	0	0	0	199,725	124,013	0.6209	130,066	0.6512	173,533
6	12,548	$20.00	219,585	0	79,693	0	0	0	139,892	78,966	0.5645	82,820	0.5920	117,808
7	9,539	$20.00	166,930	0	110,345	0	0	0	56,586	29,037	0.5132	30,455	0.5382	46,187
8	6,940	$20.00	121,452	0	90,205	0	0	0	31,247	14,577	0.4665	15,288	0.4893	24,720
9	4,751	$20.00	83,150	0	90,205	0	0	0	(7,055)	(2,992)	0.4241	(3,138)	0.4448	(5,410)
10	2,973	$20.00	52,026	0	90,205	0	0	0	(38,179)	(14,720)	0.3855	(15,438)	0.4044	(28,375)
11	0	$20.00	0	0	0	0	0	0	0	0	0.3505	0	0.3676	0
12	0	$20.00	0	0	0	0	0	0	0	0	0.3186	0	0.3342	0
13	0	$20.00	0	0	0	0	0	0	0	0	0.2897	0	0.3038	0
14	0	$20.00	0	0	0	0	0	0	0	0	0.2633	0	0.2762	0
15	0	$20.00	0	0	0	0	0	0	0	0	0.2394	0	0.2511	0
	83,791		1,416,347	0	871,666	0	0	25,104	80,662	(154,893)		(135,527)		(0)

3.2.3 Commercial Scale Economics: Approximate economics were prepared for a commercial scale CO2 flood in the Hall-Gurney field. Highly productive areas (high recovery per acre) that were also good waterfloods were selected for the commercial scale development. Leases having more than 9 MBO per acre primary and secondary recovery were included in this example Figure 3.2.3 shows leases in Hall Gurney adjacent to the Colliver lease that are prospective for CO2 EOR. Nearby leases including the Rein, Rogg, and Letsch leases exhibited higher primary and secondary production than the Colliver pilot site and are modeled to be more economic for CO2 flooding (Figure 3.2.4).

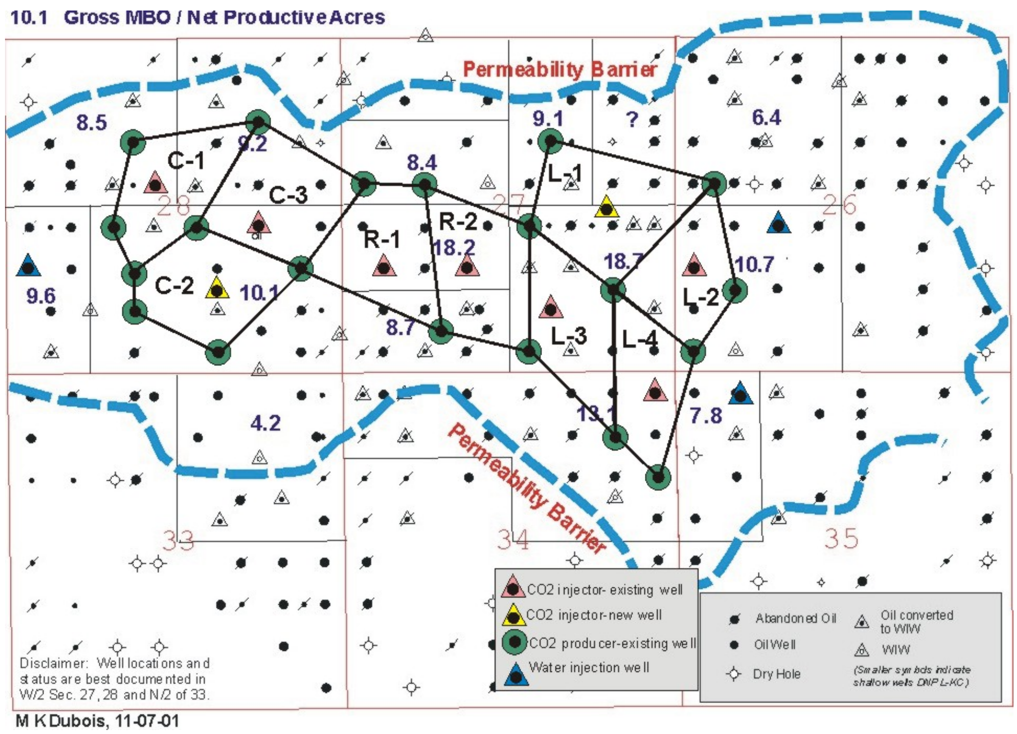


Figure 3.2.3: Potential commercial patterns for leases in vicinity of Colliver pilot area (shown as C-2 in figure).

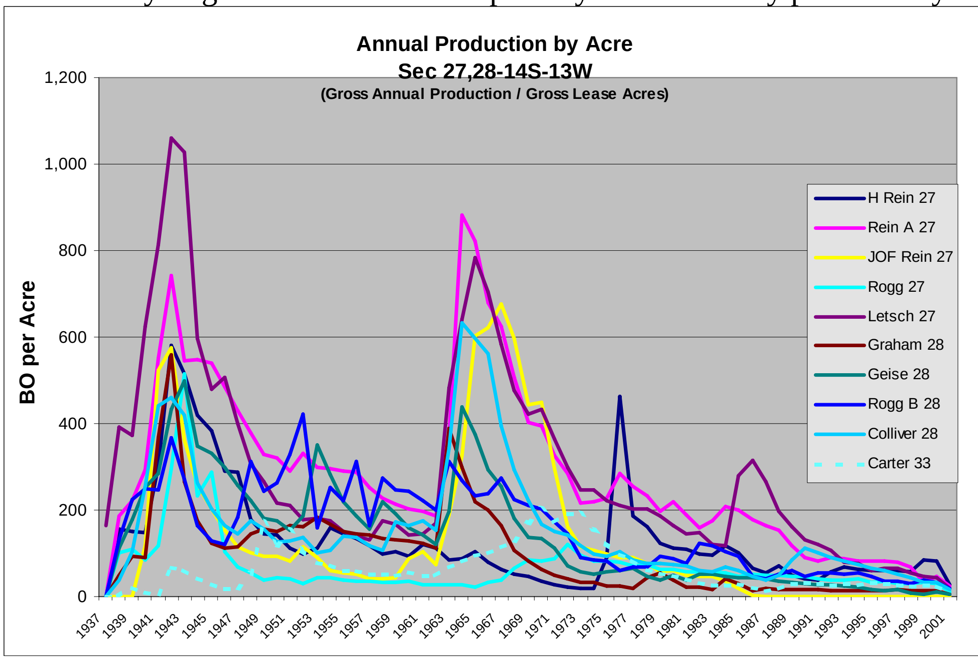
Using the CO2 EOR recovery rate projected from reservoir modeling, commercial scale CO2 flooding at $20/BO appears to be economically attractive (Figure 8):

1. In relatively small floods (240-320 acres, 4-6 patterns) in areas of very high primary and secondary productivity (Letsch and Rein rates, >14 MBO/net acre recovery).
2. Areas with moderately high primary and secondary productivity (Colliver, > 10 MBO/net acre recovery) can be economic when combined with high productivity leases to form larger floods (≥640 acres, 9 or more patterns).

If CO2 EOR recovery rate is 120% of that predicted from reservoir modeling, commercial scale CO2 flooding at $20/BO is possible:

3. On smaller floods (fewer patterns) given the same primary and secondary productivity.

4. In relatively large floods of moderate primary and secondary productivity that



would otherwise be uneconomic.

Figure 3.2.4: Annual production per acre of selected leases in Hall-Gurney near the Colliver pilot site.

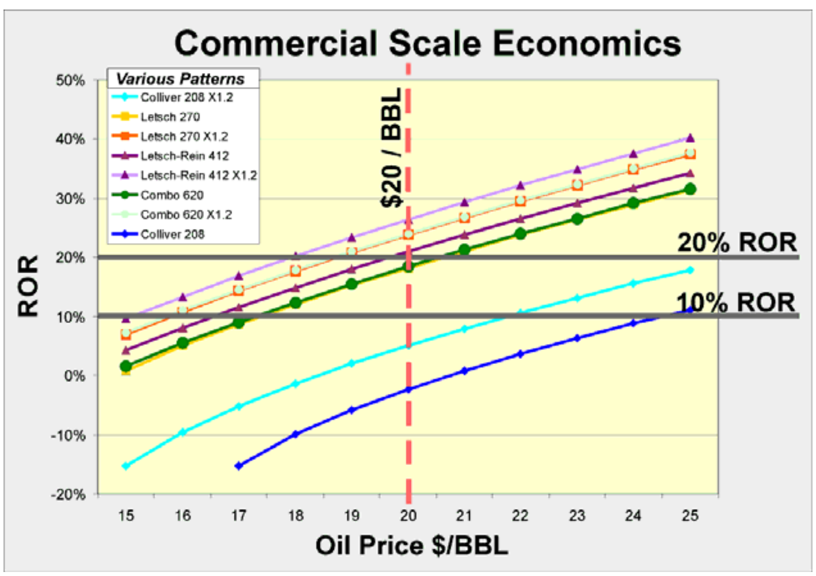


Figure 3.2.5: Rate of return versus oil price for Hall-Gurney leases near Colliver pilot area. Economics indicate that leases that performed better than the Colliver during waterflood are likely to be economic at oil prices equal to or greater than $20/barrel.

3.2.4: Development of 10+ Acre Pilot Pattern: After the economic analyses were completed for the 60 and 73 acre pilot floods on the Colliver Lease, two of the MV Energy partners decided not to participate in the CO2 project. Murfin Drilling formed a working interest partnership with John O. Farmer, Inc. and White Eagle Production Co. to develop a smaller pilot project. The partnership purchased the 70 acre portion of the Colliver lease containing CO2I-1 shown in Figure 3.2.6 for the purpose of conducting the CO2 pilot flood. The proposed flood pattern is shown in Figure 3.2.6.

Oil recovery from CO2 flooding was estimated using several reservoir simulation models. Injectivity in CO2 I#1 was limited to 100-200 RB/D. Minimum predicted recovery from TORP simulations ranged from 22,300 BO assuming Sorw is 30% in all layers to 47,000 BO assuming Sorw is 40% in some layers as predicted by VIP reservoir simulations. Transpetco Eng./Kinder-Morgan predicted recoveries were approximately 27,000-28,000 BO based on displacement calculations and fractional pattern modeling (Figure 3.2.7). Recovery in the economic models was cut-off after the first year the flood exhibits negative cash flow. Figure 3.2.7 illustrates oil production for the various models.

Oil recovery estimates were strongly influenced by:

1. S_{orw}
2. Vertical distribution of horizontal permeability (permeability differences between upper, middle, and lower C flood cycles)
3. More lateral distribution of permeability
4. Presence or absence of vertical permeability barriers (flood cycle bounding bioclastic-rich layers)
5. Gravity override of CO2. Density ratio CO2/oil = 0.6-0.8 (varying with pressure and oil density) – most CO2 projects have ratio of 0.9. Gravity is not a problem in most projects but is here.

CO2 was predicted to stay within the high permeability upper flood cycle and preferentially sweep this layer and not efficiently sweep the middle flood cycle or, if it is injected in the middle flood cycle may quickly migrate from the middle flood cycle up to the upper cycle again only sweeping the upper flood cycle efficiently.

Favorable mobility ratio (M ~ 2) and gravity working for downward migration may have acted to improve the waterflood sweep efficiency in the middle flood cycle. Significantly, lower mobility ratio for CO2 (M = 24, most project have M = 10-15) would act to decrease CO2 sweep in lower-permeability middle flood cycle.

Several factors may provide higher recoveries than predicted:

1. Preferential stimulation and initial injection in the middle flood cycle may provide improved processing of the middle flood cycle and could provide additional recovery of up to ~20%.
2. If the reservoir exhibits the permeability layering as modeled, careful tuning of the WAG cycle to the specific reservoir permeability architecture in the Colliver lease could improve the sweep in lower permeability intervals. Tuned WAG cycles have improved recovery up to 30% in commercial floods- it could be guessed that using a tuned WAG

cycle might produce an additional 20% recovery.

3. If each of the high side potential effects is only 50% effective, additional potential recovery could be up to 20%.
4. Other high-side parameters for which estimation of influence on improved recovery is difficult include the possible presence of vertical permeability barriers (allowing isolated processing of the middle flood cycle), and the role of small-scale bedding architecture such as cross-bedding or stylolites that would act to limit gravity override.
5. There are many unknowns concerning lateral heterogeneity within the flood cycles such as shingling, weathering, and other diagenetic processes that might result in minimizing gravity override and promote more uniform sweep efficiency.

Several factors may provide lower recoveries than predicted:

Low-side potential was predominantly influenced by uncertainty in S_{orw}. Data on Sorw for high permeability rocks indicates these rocks can have both a high S_{orw} (45%) and a low S_{orw} (~20%) depending on initial oil saturation and pore architecture. Wireline logs indicate saturations are approximately 37% but the Archie cementation and saturation exponent log parameters (m and n) in these oomoldic limestones are significantly different than the conventional m and n values of 2 and 2, respectively, and could vary from those measured on the core obtained.

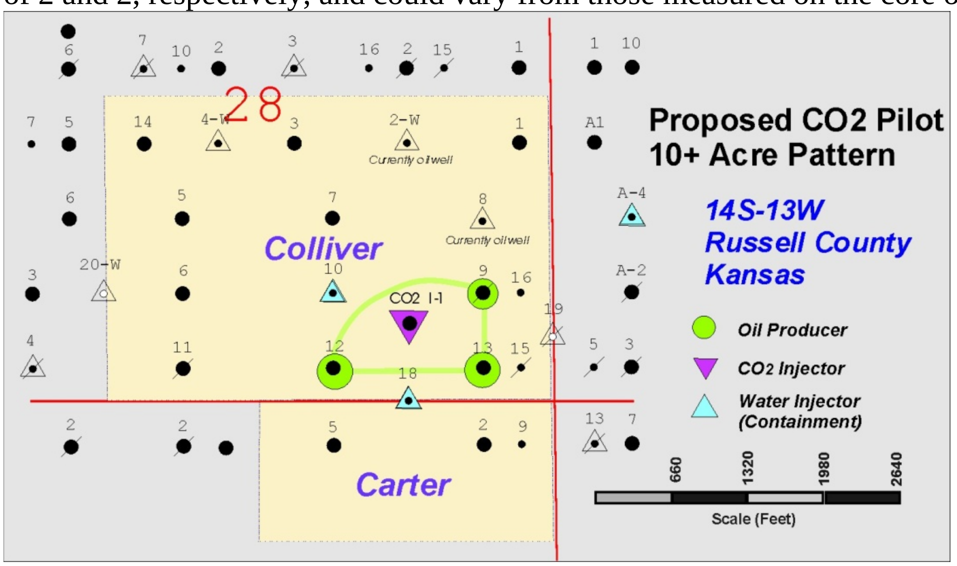


Figure 3.2.6: 10+ acre pilot with WAG injection in CO2#1, water injection in #10 and #18, and production from #9, #12, and #13.

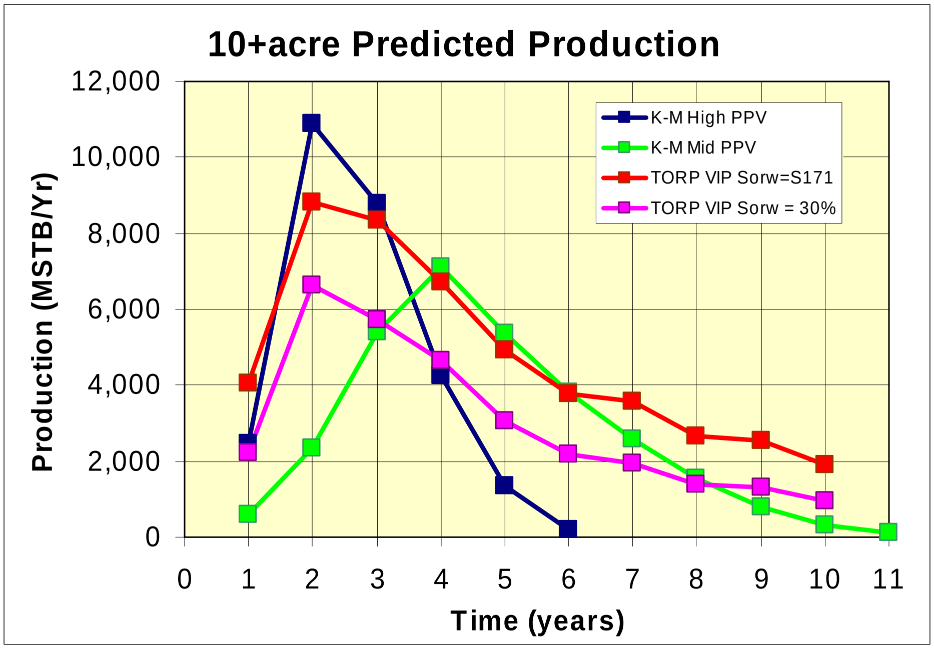


Figure 3.2.7: Comparison of predicted oil recovery for 10+ acre pilot for various models.

The CO2 project budget and milestones were revised to support the 10+ acre pilot. A comparison of the revised budget with the original project budget is shown in Table 3.9 The revised list of tasks and milestone schedule are presented in Table 3.10.

Table 3.9: General Budget Summary for Revised Kansas CO2 Flood Project

	Original Project	Modified Project
Flood Performance		
Acres	40	10+
Total CO2 Injected (mcf)	843,000	290,000
WAG Years	3.7	6
Post CO2 WF years (DOE)	1	1
Oil Produced (Commercial Life)	75,300	28,000
Facilities		
Drill & Equip #1 CO2 I (Task 2.1)	$236,180	$341,750
Rework and upgrade wells (old Task 5.1 /Task 2.3)	$474,500	$259,197
Surface facilities (Task 2.3.5)	$322,575	$282,293
Drill and Equip Water Supply Well (Task 2.3.1)	$35,000	$35,000
Subtotal	$1,068,255	$918,239
Flood Operations		
Repressure Reservoir (Task 2.3.4)	$16,377	$50,576
Well & Pattern Testing (Task 2.3)	$0	$180,576
CO2 Slug, WAG + Admin (Task 5.4)	$734,231	$605,691
Post waterflood (Task 5.4)	$100,858	$91,818
Subtotal	$851,466	$928,661
CO2 Supply		
Value of CO2 contributed	$1,608,900	$870,000
Recycled CO2	$414,045	$0
Subtotal	$2,022,945	$870,000
Research, Data, Tech Transfer, Admin.		
KU Research, Data Collection & Tech Transfer	$1,446,018	$1,633,003
Outside Consulting & Adm.	0	$65,397
Subtotal	$1,446,018	$1,698,400
PROJECT TOTAL EXPENSES	**$5,388,684**	**$4,415,300**
Revenue Sources		
DOE ($Fac $LOE)	$676,261	$766,469
DOE ($CO2)	$708,031	$304,500
DOE (Research, Data, Tech Transfer)	$507,802	$631,343
Murfin ($Cap $LOE)	$830,259	$903,112
Kinder-Morgan In-kind CO2	$268,150	$188,500
Kinder-Morgan Cash	$1,359,858	$54,716
USEP In-kind CO2	$0	$377,000
KUCR In-kind	$938,323	$1,001,660
State Of KS DOC	$100,000	$188,000
PROJECT TOTAL REVENUES	**$5,388,684**	**$4,415,300**
DOE Total	$1,892,094	$1,702,312
DOE Difference from Original Project	$0	-$189,782

Table 3.10 Milestone Plan for Revised Project

1. Project I.D. No. - DE-AC26-00BC15124

3. Performer - University of Kansas Center for Research, Inc.
Youngberg Hall, 2385 Irving Hill Road
Lawrence, KS 66044-7552

4. Project Start Date - March 7, 2000

5. Project Completion Date - March 7, 2009

8. Duration: 2000 (M J S D) · 2001 (D) · 2002 (M J J A S O N D) · 2003 (M J)

6. Identification Number	7. Planning Category (Task Description)
	BUDGET PERIOD 1
	ACTIVITY #1 - RESERVOIR ANALYSIS AND CHARACTERIZATION
1.1	**ACQUISITION OF DATA AND MATERIAL**
1.2	**RESERVOIR CHARACTERIZATION**
1.2.1	Geologic Reservoir Characterization
1.2.2	Fluid Characterization
1.2.3	Engineering Characterization
1.3	**RESERVOIR MODEL**
1.3.1	Develop Qualitative and Quantitative Reservoir Model
1.3.2	Check Reservoir Model for Internal Consistency
1.4	**RESERVOIR SIMULATION (Phase I)**
1.4.1	Calibration of Engineering Model (Primary and Waterflooding)
1.4.2	Simulation of Carbon Dioxide Miscible Displacement (Phase I)
	ACTIVITY #2 - PRODUCIBILITY PROBLEM CHARACTERIZATION
2.1	**DRILL, CORE, AND TEST INJECTION WELL**
2.1.1	Drill CO2 #1 well
2.1.2	Core and analyze CO2 #1
2.1.3	Log and analyze CO2 #1
2.1.4	RFT test and analyze CO2 #1
2.1.5	Complete and equip CO2 #1
2.1.6	Injection test and analyze CO2 #1
2.1.7	Plug Existing Line Injection Well
2.2	**PRODUCIBILITY CHARACTERIZATION USING NEW CORE**
2.2.1	2.2.1 Determine Sorw CO2 #1
2.2.2	2.2.2 Determine Sorm(CO2) CO2 #1
2.2.3	2.2.3 Determine Relative Permeability Endpoints CO2 #1
2.2.4	2.2.4 Determine MMP CO2 #1
2.2.5	2.2.5 Routine Core Analysis CO2 #1
2.2.6	2.2.6 Special Core Analysis CO2 #1
2.2.7	2.2.7 Geologic Characterization CO2 #1
2.3	**REMEDIATION AND TEST WELLS and PATTERN**
2.3.1	Drill, Complete, and Equip Water Supply Well
2.3.2	Workover and Test Producing Wells in Pattern
2.3.3	Workover Containment Water Injection Wells
2.3.4	Injection Well Testing and Analysis
2.3.5	Construct Surface Facilities
2.3.6	Pattern Repressurization and Analysis
2.3.7	Test for Early CO2 Breakthrough
	ACTIVITY #3 - ADVANCED RECOVERY TECHNOLOGY ANALYSIS
3.1	**RESERVOIR SIMULATION(Phase 2)**
3.1.1	Check Primary and Waterflood History Match
3.1.2	Simulate Carbon Dioxide Miscible Displacement
3.2	**ECONOMIC AND RECOVERY ANALYSIS OF PILOT**
3.2.1	Determine CO2 Source for Pilot
3.2.2	Assess Existing Facilities and Necessary Modification
3.2.3	Design Facilities for Pilot and Monitoring
3.2.4	Finalize Cost Estimates
3.2.5	Economic Forecast

6. Identification Number	7. Planning Category (Task Description)	2003 M	J	S	D	2004 M	2005 M	2006 M	2007 M	2008 M	2009 M
	BUDGET PERIOD 2										
	ACTIVITY #5 - FIELD DEMONSTRATION AND ANALYSIS										
5.4	**IMPLEMENT CO2 FLOOD - OPERATIONS**										
5.4.1	Perform Flood - Operations										
5.4.2	Contract for Delivery and Injection of CO2										
5.4.3	Gathering, Dehydration, Recompression, and Reinjection of CO2										
5.4.4	Monitor Flood and Collect Samples and Data										
5.5	**ANALYZE CO2 FLOODING PROGRESS**										
5.5.1	Periodic Analysis										
5.5.2	Reservoir Simulation										
	BUDGET PERIOD 3 -MONITORING AND POST-FLOOD ANALYSES										
	ACTIVITY #6 - MONITORING AND POST-MORTEM ANALYSES										
6.1	**ANALYZE POST-CO2 RESULTS**										
6.1.1	Periodic Analysis										
6.1.2	Reservoir Simulation										
	ACTIVITIES THAT SPAN ALL BUDGET PERIODS										
	ACTIVITY #7 - PROJECT MANAGEMENT										
7.1	**Management Budget Period 1**										
7.1.1	General Management										
7.1.2	Geologic Activities Management										
7.1.3	Engineering Activties Management										
7.1.4	Operator Activties Management										
7.2	**Management Budget Period 2** (subtasks as above)										
7.3	**Management Budget Period 3** (subtasks as above)										
	ACTIVITY #8 - TECHNOLOGY TRANSFER AND REPORTING										
8.1	**TECHNOLOGY TRANSFER Budget Period 1**										
8.1.1	Required DOE Reporting										
8.1.2	Presentation at seminars/workshops/meetings										
8.1.3	Publication of technical papers/Web-site										
8.2	**TECHNOLOGY TRANSFER Budget Period 2** (subtasks as above)										
8.3	**TECHNOLOGY TRANSFER Budget Period 3** (subtasks as above)										

3.2.5 Determine CO2 Source for Pilot – An agreement was reached with Kinder-Morgan CO2 Company (K-M) to provide CO2 in kind for the project. It was estimated that the pilot would use approximately 270 million standard cubic feet of CO2 over a four- to five- year period. The project plan was to inject a CO2 slug followed by a water-alternating-gas (WAG) injection program to control channeling of CO2 to the production wells. K-M provided CO2 in kind on an as-used basis. Murfin signed an agreement with FLOCO2 of Odessa, Texas for FLOCO2 to provide CO2 storage and injection equipment to the pilot in exchange for the Kinder-Morgan CO2. The Murfin/FLOCO2 agreement was initiated in October, 2003. Contacts were developed between Murfin, US Energy Partners, and EPCO for CO2 supply.

3.2.6 Design Facilities for Pilot and Monitoring - Facilities specifications were developed for the 10+-acre pattern. Testing and reservoir modeling indicated that the 3-phase separator should be sized for a maximum fluid production of 250 BFPD (40 m^3) and gas rate of 200 mcf/D (thousand cubic feet per day; 5,660 m^3/d). Gas rates were expected to average 66 mcf/d and peak around 100 mcf/D (2,830 m^3/d). Production rates would not exceed the injection rates. Controlling injection rates to the 14% PPV rate would result in a maximum CO2 production rate of 125-140 mcf/D (3,540-3,960 m^3/d). Separators were based on HC gas production. Generally 2.5 times the CO2 rate is required for the HC gas design rate due to the high density of CO2 and higher affinity it has for oil.

3.2.7 Economic Forecasts- Economic forecasts for the pilot project were modified with improved reservoir characterization and modeling. Economics for the 2-producer pattern (CO2#12 and CO2#13 producing) are primarily influenced by surface facilities costs, operating costs, and oil price. At projected surface facilities and lease costs but with only 18,000 BO (2,880 m^3). recovery the project was expected to show a slight loss.

TASK 4.1: REVIEW OF BUDGET PERIOD 1 ACTIVITIES AND ASSESSMENT OF FLOOD IMPLEMENTATION

A meeting was held on April 16, 2002 in Tulsa, OK the following personnel were present: TORP) Paul Willhite; KGS) Alan Byrnes; DOE) William Lawson, Dexter Sutterfield. Topics covered included: economics of various patterns and the possibility of modifying the pilot to 10+acres, project shortfalls, CO2 sequestration aspects of the project. It was agreed that a proposal to modify the existing project and do a 10+acre pilot should be submitted and would be reviewed.

David Murfin, of Murfin Drilling Company, and Michael Vess, of Vess Oil Company, met at the office of Vess Oil Company in Wichita, KS on April 26, 2002. Murfin Drilling Company proposed to MV Energy LLP (a partnership of Murfin Drilling, Vess Oil, and GE Capital) the purchase of the portion of the Colliver lease that was involved with the CO2 pilot. This proposal and the possible value of the lease were evaluated by MV Energy and GE Capital.

A revised plan for the project was finalized and submitted to the DOE on May 30, 2002. Slight modifications were made to the proposed 10+ acre pilot plan and the modified plan submitted to USDOE on August 30, 2002. On September 27, 2002 the USDOE approved the 10+-acre modified plan for the CO2 demonstration.

Various members of the Kansas CO2 Team communicated on a nearly daily basis by telephone and email over specific technical or business issues. A conference call was held on April 14, 2003. The following personnel participated in one or more calls and emails: Murfin Drilling) James Daniels; Stan Froetschner, Kevin Axelson, Tom Nichols; Tertiary Oil Recovery Project) Paul Willhite, Richard Pancake; Kansas Geological Survey) Alan Byrnes, Martin Dubois; Kinder-Morgan) William Flanders, Don Schnacke. Topics covered included: 1) Water supply quality, 2) Well completion procedures and results, 3) Rework scheduling and preparation, 4) build-up and drawdown testing, 5) CO2 supply, storage and injection facilities, and 6) Project management.

The project was granted a no-cost time extension to October 7, 2003 by the U.S. DOE to complete necessary Budget Period 1 activities. Some Budget Period 2 activities were moved to Budget Period 1 and a no-cost extension was made to March 6, 2004. Budget Period 2 began March 7, 2004, ending on December 31, 2008. Budget Period 3 was revised to begin on January 1, 2009 and end on March 7, 2010.

TASK 5.1. REMEDIATE WELLS, TEST WELLS AND PATTERN

5.1.1 Drill, Complete, and Equip Water Supply Well - An onsite water supply well was drilled and completed in the shallow (245 ft; 74.7 m) fresh-water Dakota aquifer on 3/27/02. Supply water total dissolved solids was measured by Pace Laboratories to be 4,920 milligrams per liter. A submersible pump is to be run in the well the first week of April. A water injection station located near the Colliver lease tank battery (near CO2 #10, formerly Colliver #10) comprising a 200 bbl (31.8 m^3) fiberglass tank, triplex pump, filter cartridges, metering, valves, etc. was fabricated and installed. The injection equipment was used for short-term injection tests and was relocated into the pump house.

5.1.2 Workover and Test Producing Wells in Pilot Area

Selection of Northeast Producing Well: -The choice of using #9 or #16 for the northeast producer was based on the wellbore conditions. Review of the plugging record and measurements of the top of cement in #9 indicated that the well was plugged to the near-surface. Records for #16 indicated a 7-inch, 20 lbs/ft, casing to 2,222 ft with open hole from 2,222 to 2,252 ft and fill from 2,248 to 2,252 ft. Slotted liner from 2,218 to 2,248 ft should be able to be pulled. Considering the age (1940) and weight (13.8 lbs/ft) of casing in the #9 and the volume of cement to be drilled it was decided to pull the liner in #16 and drill the #16 deeper to the Lansing-Kansas City C zone. This provided a clean wellbore, new logs, the possibility of obtaining another core, and was consider to be performed at less risk and potentially at less cost. Completion of #16 as a production well would slightly increase the pattern size. The 10+-acre flood pattern with the #16 as a producer is shown in Figure 5.1.1.

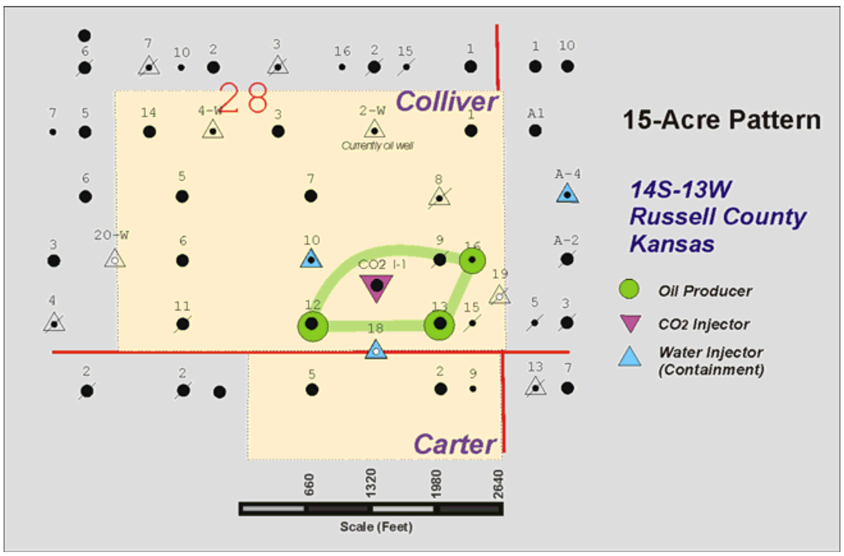


Figure 5.1.1: Planned 10+ acre pilot with WAG injection in CO2#1, water injection in #10 and #18, and production from #16, #12, and #13.

5.1.3 Development of Workover Program for Containment Water Injection Wells in Pilot Area -Analysis of reservoir simulations with and without water injection in the Colliver #10 indicate that injection in #10 was necessary for pressure support and containment. Review of the critical nature of this well resulted in a change in the well rework schedule presented in the original step-wise implementation plan. Well workovers and recompletions were performed in the following sequence: Colliver #12, Colliver #10, Colliver #16, Colliver #13.

CO2 #12 - A workover on the CO2 #12 well (formerly Colliver #12) was completed 3/6/03. For this well, the LKC G was plugged back with cement and a 4-1/2" welded liner was cemented to surface across all shallow zones leaving only the LKC C open with open-hole completion (Figure 5.1.2). Wireline logs were obtained since this well was not previously logged. Porosity and distribution of depositional cycles in the CO2 Project #12 are similar to the CO2I #1 (Figure 5.1.3).

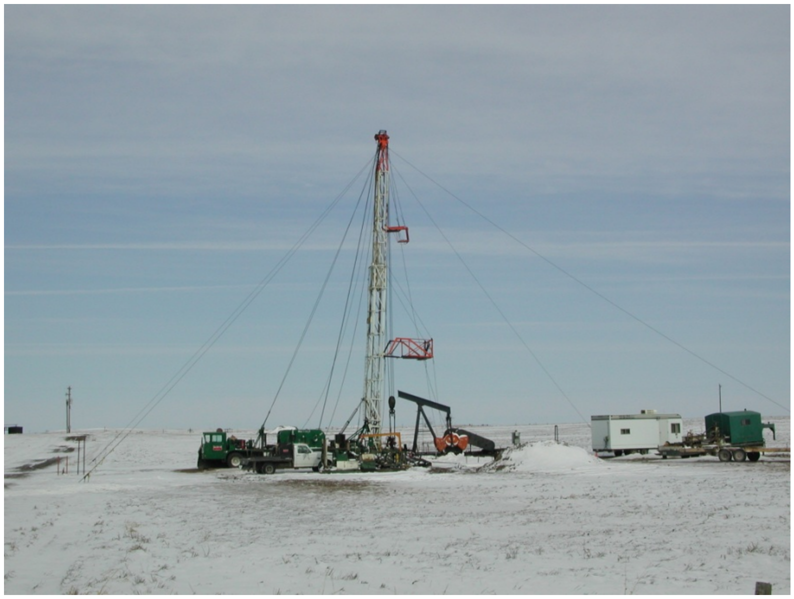


Figure 5.1.2: Workover of the CO2 Project #12 well in late February-early March 2003.

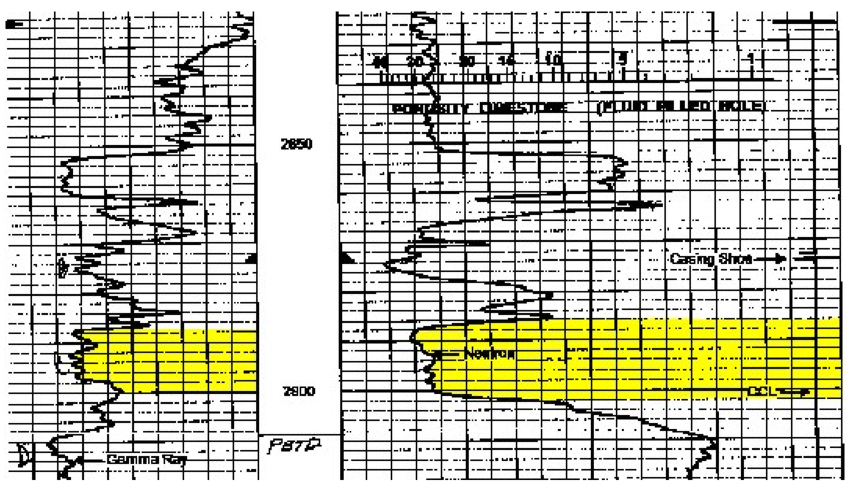


Figure 5.1.3: Wireline neutron log of the CO2 Project #12 logged in March 2003. High porosity in upper cycle and lower porosity in lower cycle are similar to the CO2I#1.

Colliver #7 Tracer and Injection Test

The properties of the reservoir to the northwest of the Carter-Colliver CO2 I#1 and near the proposed second CO_2 injection well site were investigated by tracer and injection testing on the Colliver #7. Following removal of a plug at 2855 ft (870 m), a tracer survey, conducted on September 21,2001 with a packer set in casing at 2892 ft (881.5 m) indicated 100% of the fluid went into the Lansing-Kansas City "C" zone open hole interval at 2894-2904' and no fluid traveled below 2906 ft. A pressure buildup in Colliver #7 was conducted from October 9-11, 2001 as part of a planned buildup/falloff test to characterize the reservoir interval permeability-height (***k***-***h***) around the well.

Water injection began at 10AM on October 9 at a rate of 450 barrels per day (bbl/D; 71.5 m^3/d). The well was shut-in at 10AM on October 11 after injecting 914 barrels (145 m^3)of water. Injection rate was constant during the test and there was no buildup of surface pressure. Bottom hole pressure, measured by a pressure bomb at 2899 ft, at the start of the test was 604 psia. Although the pressure test was planned to include a four-day falloff test, the pressure bomb program incorrectly terminated data collection after ~48 hours at the end of the buildup period. Pressure data from the buildup test are shown in Figure 5.1.3.

The data in Figure 5.1.3 were matched by several models using commercial well test analysis software. Models that successfully matched the data exhibited a range of permeability and bedding configurations that were all generally consistent with a general model comprising a 9-ft thick reservoir interval with 25-35 md permeability that is connected to the well bore by a high permeability fracture, flow channel, or low skin region. General end-member models comprise: 1) a highly conductive fracture or flow channel with half-length of ~766 ft, and skin of 4, connected to a reservoir interval of~9 ft-thick (2.7 m) having an effective water permeability of 34 md(0.034 *u*m^2); and 2) a 25-35 md reservoir, with a skin of -6 to –7, representing the wellbore condition following acid treatments in the past constituting up to 1,000 gal acid/ft (1.15 m^3/m). Following testing the well was returned to production from the L-KC and shallower intervals.

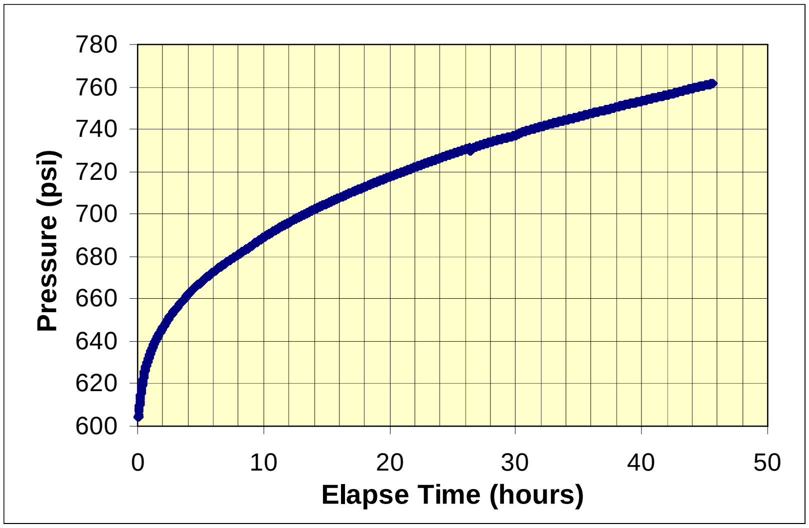


Figure 5.1.4: Bottom hole pressure build-up during water injection into Colliver #7 at a rate of 450 bbl/D(71.5 m^3/d).

<u>Colliver #10 Tracer Test and Workover</u>

Colliver #10 was the first injection well on the Colliver Lease and was completed as an open hole in the L-KC “C” and “G” interval (2884-2894 ft; 879-882 m). On February 12, 1960 a sand fracture/acid treatment was performed. The treatment consisted of a Dowell *Duo-frac* consisting of 19,000 pounds (862 kg) of sand and 15,000 gallons (56.8 m^3) of Dowell 3% “slick acid” with maximum and minimum injection rates of 23 bbls/min @800 psi (3.7 m^3/min @ 5.5 MPa) and 21 <u>bbls/min</u> @1050 psi(3.3 m^3/min @ 7.2 MPa), respectively. Based on records studied, this was the only fracture stimulation performed on the L-KC in the Colliver lease.

Preliminary fracture analysis using available injection data and general reservoir rock properties was performed by Stim-Lab, Inc. of Duncan, Oklahoma (A Core Laboratories Company) using the commercial fracture simulation software *WinGOPHER 2000*.
This analysis indicated that it was possible that the fracture stimulation treatment in the open-hole interval containing both the L-KC “C” and “G” may have created a fracture connecting the “C” and “G” zones with an interval extending up to 10’s of feet from the wellbore containing proppant. To test the possible fracture connection between the L-KC “C” and “G” intervals, from October 17-25, 2001 the well was re-entered, 90-ft (30 m) of PVC pipe was drilled out and a tracer survey conducted.

The tracer survey indicated flow down into the “G” zone but could not be unambiguously interpreted to indicate the presence or absence of a fracture connecting the “C” and “G” zones. Based on all results it was decided that this well would be “dribble” injected with water to prevent possible loss of CO2 into the “G” zone. The open-hole interval, exposing both the “C” and “G” zones, was cemented and the “C” zone was scheduled to be drilled out later in the project. Shallower interval water injection was resumed until the well was needed for the L-KC demonstration.

Workover of the CO2 #10 (formerly Colliver #10) was performed between 3/5/03 and 3/10/03 (Figure 5.1.5) for injection in only the LKC “C” zone by: 1) drilling out the cement plug to +/- 2925, 2) perforating the LKC “C” from 2898-2910 ft (883.3-887.0 m), 3) running a dual packer assembly across the Topeka and Plattsmouth perforations (for isolation), and 4) acidizing the LKC “C” with 500 gallons (1893 L), 15% MCA at ¼ bpm (barrels per minute; 5.18 m^3/h) with an injection surface pressure not exceeding 500 psig (pounds per square inch gauge, 3448 kPa). Flushed acid to perfs and swabbed back acid volume and two load volumes.

Figure 5.1.5: Workover rig on the CO2 Project #10 water injection containment well in early March 2003.

CO2 Project #16 - The CO2 Project #16 is the northeast producer of the CO2 pilot. The well was formerly a shut-in Indian Cave shallow gas producer. The well's slotted liner was successfully removed in January 2003. The well was drilled deeper beginning 3/27/03. Cores were cut in the LKC "C" zone (2877-2905 ft; 876.9-885.4 m) and the LKC "G" zone (2936-2966 ft; 894.9-904.0 m) with 100% recovery. The cores were laid out on the catwalk, photographed, packed in dry ice and transported to Core Laboratories, Midland, TX for analysis.

The upper LKC "C" interval (2882-2888 ft; 878.4-880.3 m) exhibited good oomoldic porosity and cross-bedding (Figure 5.1.6). The lower LKC "C" interval had lower porosity and less dense oomold packing. Wireline logs indicated the upper LKC "C" zone exhibits porosities of 23-26%, about 3-5 porosity units less than in the CO2I#1, with water saturations of approximately 60%, consistent with water saturations in the CO2I#1 and with predicted residual oil saturations (Figure 5.1.7). As of 4/1/03, the well was drilled to 3253 ft (991.5 m), open-hole logged, and 4-1/2 inch (0.114 m) casing surface casing set at 3,252 ft (991.2 m) and cemented to the surface.

Figure 5.1.6: Core obtained from the CO2 Project #16 LKC "C" interval (2877-2905 feet; 876.9-885.4 m). The interval from 2877-2882 ft (876.9-878.4 m) is overlying dense limestone. Upper "C" zone interval from 2882-2888 ft (878.4-880.3 m) exhibits the highest visual porosity and 23-26% porosity on neutron log.

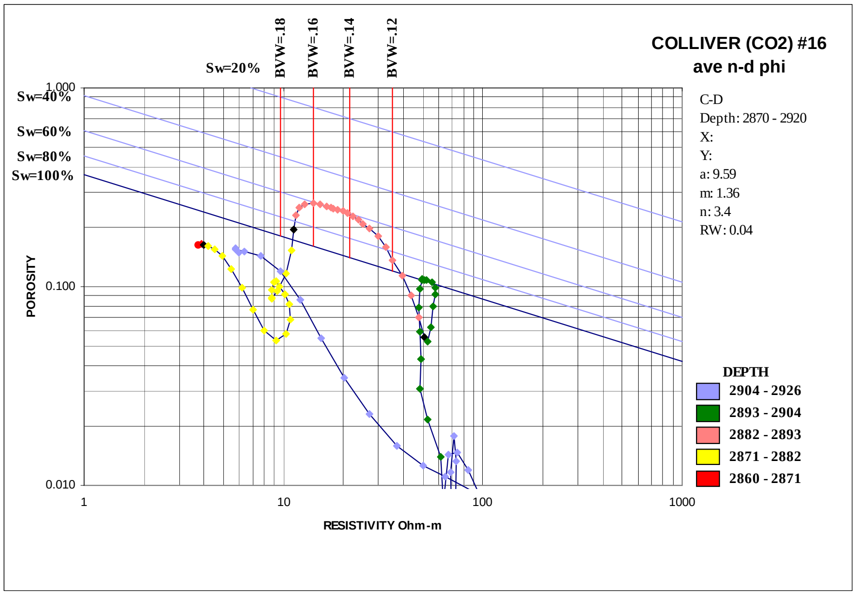


Figure 5.1.7: Pfeffer Pickett plot of the CO2 Project #16 "C" interval (2882-2893 feet; 876.9-881.8 m) exhibits porosities of 23-26% and water saturations of ~60%. Note water saturations for all intervals were calculated using LKC-C zone Archie cementation and saturation exponents of m=1.36, a=9.39, n=3.4. Intervals above and below exhibit Sw=100% for m=2, a=1,n=2.

Core analysis (Figure 5.1.8), log analysis, and swab rate tests indicated that the permeability in and near #16 was lower than that of the other pilot wells (Figure 5.1.8). The upper portion of the #16 LKC "C" interval was interpreted to have been more heavily micritized creating poor matrix permeability and poor oomoldic pore connectivity and consequently low permeability relative to LKC oomoldic limestones (Figure 5.1.9). It was decided to complete the well in the LKC "C" zone and sequentially stimulate the zone with acid to attempt to contact higher quality reservoir. On 4/8/03 the well was perforated in the LKC "C" from 2883-2894 ft (878.7-882.1 m) using 4 shots/ft (13 shots/m). From 4/9/03-4/11/03, the well was treated with a total of 4,500 gallons (17,032 L) acid as indicated in Table 5.1.1.

Table 5.1.1 Acid Simulation Program-CO2#16 where; XTA is a retarded acid, 1 gal = 3.8 L, 1 barrel per minute bpm = 9.54 m^3/h; pounds per square inch gauge, psig = 6.90 kPa; 1 barrel per hour, bph=0.159 m^3/h).

CO2 Project #16 Acid Stimulation Program

Date	Acid Type	Acid Volume (gallons)	Maximum Rate (bpm)	Maximum Pressure (psig)	Approx. Post-treatment Swab Rate (bph)
4/9/2003	15% MCA	500	0.25	250	1.45
4/10/2003	15% MCA	1000	2.5	475	1.74
4/11/2003	XTA-15%	3000	3.2	450	3.48

Based on the post-treatment swab rates, it was interpreted that the acid stimulation established sufficient communication with the surrounding reservoir to run tubing and monitor the well during long-term injection testing.

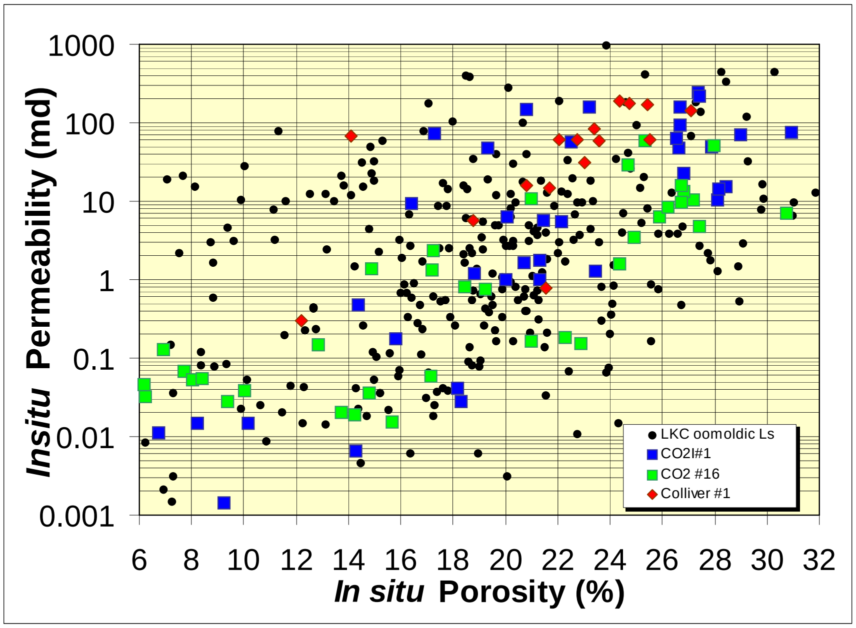


Figure 5.1.8: Comparison of permeability versus porosity in CO2 Project #16 compared to other LKC wells showing low permeability of the LKC "C" interval rock in the #16 well. Some routine air permeability data was converted to approximate *in situ* Klinkenberg permeability (liquid-equivalent). (md = millidarcy, 1 md = $9.87*10^{-4}$ μm^2)

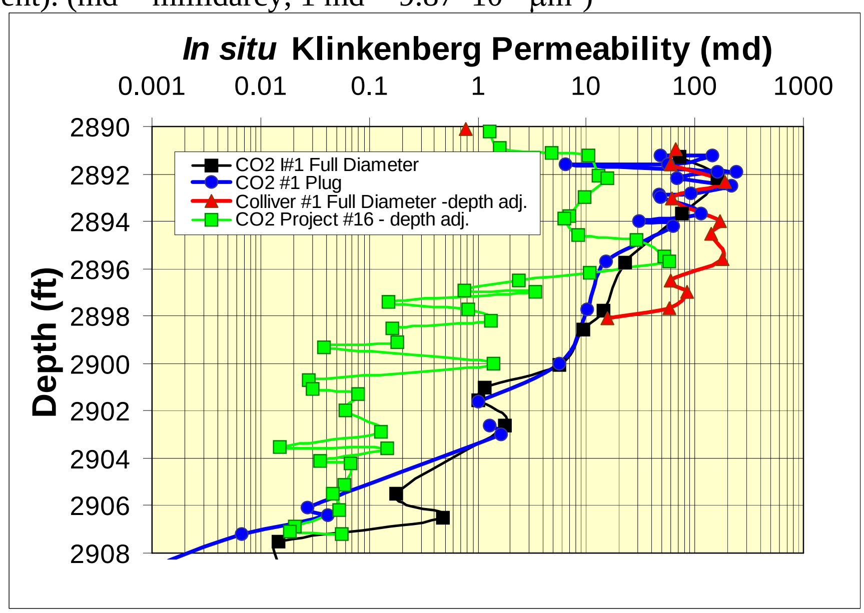


Figure 5.1.9:. Permeability profile for CO2 Project #16 LKC "C" interval measured on full-diameter core (Kmax is shown) and plugs. Full-diameter routine air permeabilities were converted to approximate *in situ* Klinkenberg permeability.

CO2 Project #13 – CO2#13 was completed in several producing intervals. A workover to isolate the LKC "C" interval and close off other producing intervals (LKC G, Douglas, Toronto, Plattsmouth, Topeka, and Tarkio) was completed from 5/15/03-5/30/03. The LKC "C" interval was isolated by cementing a 4-1/2" (0.114 m) liner from TD to surface, perforating the LKC "C" interval from 2886-2894 ft (880-882.1 m), and then acidizing the "C" interval with 2,250 gallons (8,516 L) of 15% HCL acid. New wireline logs were obtained (Figure 5.1.10). Unfortunately, the casing shoe was located in the middle of the LKC C zone which interfered with the interpretation of the neutron log.

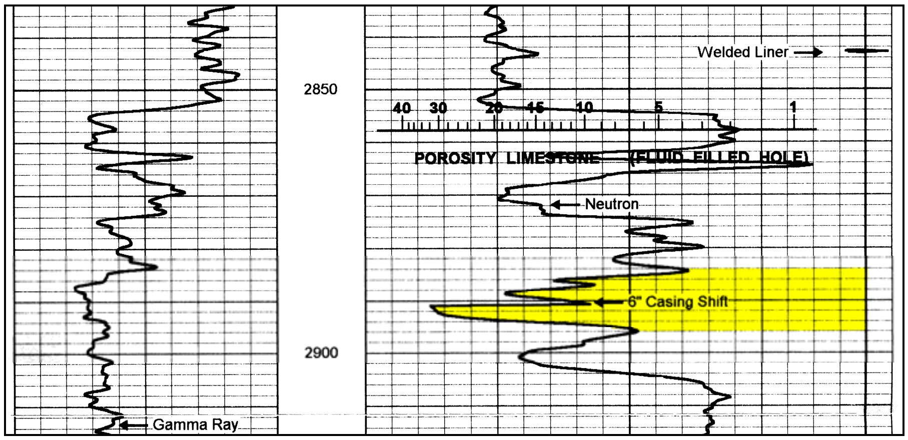


Figure 5.1.10: Wireline gamma ray and neutron log for the CO2 Project #13 well. Gamma ray in API units and porosity scaled for percent.

Production testing of the LKC-"C" interval, began on 6/12/03. The the well produced ~45 BFPD (barrels fluid per day; 7.2 m^3/d) at a bottom hole pressure (BHP) of ~417 psig (pounds per square inch gauge; 2875 kPa). Drawdown to obtain production rates for fluid levels less than 50 ft (15 m; equivalent to 23 psig, 159 kPa) above the perforations was begun on 6/27/03. Production rates at these pressures average ~93 BFPD (14.8 m^3/d) and decreased as the well approached long-term equilibrium. Production rates were consistent with a surrounding reservoir average absolute permeability of ~80 md.

5.1.3 Injection Well Testing and Analysis – Analysis of the June, 2000 acid stimulation job performed on Colliver #18 indicated that this treatment provided information on the mechanical properties of the Lansing-Kansas City in the pilot area. Based on injection pressures and injection rates of 720-1,400 barrels per day, the data can be interpreted to indicate the following properties: Breakdown Pressure > 2,200 psi, Fracture propagation pressure ~ 2,114 psi, and closure pressure ~ 1,965 psi. Based on these pressures, and the current lower reservoir pressure around the CO2I#1 due to production, the short-term injection test was designed to not exceed 50 psi at the surface or 1,300 psi bottom hole pressure. This represents a short-term injection pressure that is approximately 600 psi greater than the reservoir pressure.

A short-term injectivity test in CO2I#1 was performed on 2/5/03-2/6/03 to confirm adequate injectivity. A longer-term test was planned but the test was cut short by transformer failure following an ice storm. Injection began on vacuum and caught pressure after 40 barrels (6.4 m^3) injected. Injection rates at the end of the test at 36 hours were 170 BPD (barrels per day; 27

m^3/d) at 60 psig (414 kPa) surface pressure (Figure 5.1.11). Extrapolation of these rates to long-term injection conditions indicated that the well had sufficient injectivity for the demonstration and to move forward with the long-term injectivity test without additional stimulation.

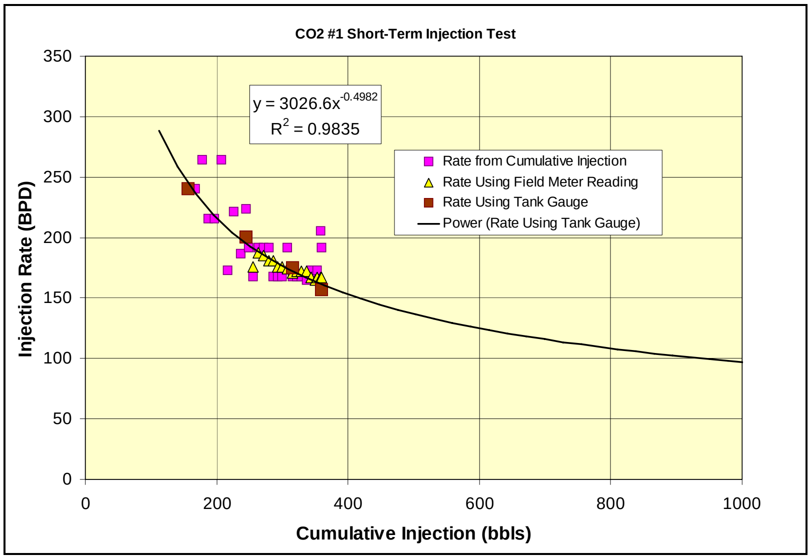


Figure 5.1.11: Injection rate versus cumulative injection for the CO2I#1 during short-term injectivity test.

Long-term water injection began in CO2 I#1 on 4/23/03. The purpose of this long-term injection test was to verify connectivity and sufficient conductivity between CO2 I#1 and the pilot producers and containment wells for a viable CO2 flood and to gather additional reservoir data to refine the reservoir model for improved CO2 flood design and performance prediction. The Cumulative Water Injected versus Injection Rate crossplot shows that CO2 I#1 injection approximately stabilized at rates of 140$\pm$5 barrels of water per day (BWPD; 25.1$\pm$0.8 m^3/d) at 500$\pm$5 psig (3448$\pm$38 kPa) surface injection pressure after 5,000 bbls (795 m^3) injected (Figure 5.1.12). These results were consistent with core- and log- and build-up test-measured average absolute permeability of ~85 millidarcies (md).

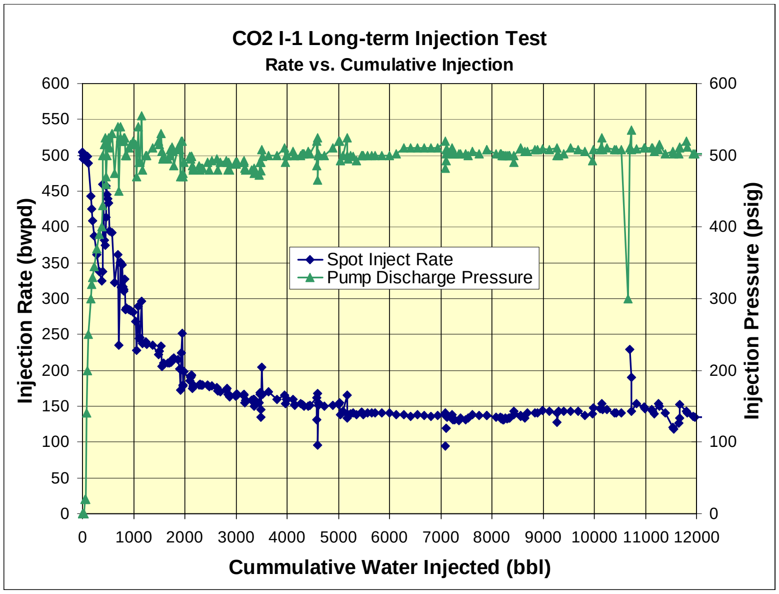


Figure 5.1.12: Injection rate versus cumulative injection for the CO2I#1 during ongoing long-term injectivity test. (1bwpd = 0.16 m^3/d, 1 bbl = 0.16 m^3, 1 psig = 6.89 kPa)

<u>CO2 #13</u> – Production rate tests conducted following the recompletion of CO2 #13 were consistent with an average reservoir absolute permeability of ~80 md (millidarcy; 0.079 $u\mathrm{m}^2$) surrounding the CO2#13 but did not confirm sufficient conductivity between the CO2I#1 and the CO2#13 wells for adequate flood rates for the demonstration. A conductivity test was conducted over the period 08/20/03 through 09/05/03 to confirm adequate conductivity between the CO2 I#1 and CO2 #13 wells. In this test, the injection rate of CO2 I-1 was reduced from ~140 BWPD to ~70 BWPD (barrels water per day; 22.4-11.2 m^3/d) while continuing to produce and pump-off CO2 #13. The test for conductivity was based on observation of production rate falling below the pre-test hyperbolic production rate decline trend defined for CO2#13 at CO2I#1 injection rates of ~140 BWPD (22.4 m^3/d).

Figure 5.1.13 shows that production rates from the CO2#13 decreased from ~ 72 BPD (barrels per day) to ~ 63 BPD (11.5-10.0 m^3/d) over a 2 week period. This observed production rate decline trend for the CO2#13 fell preceded the trend predicted by reservoir modeling, indicating slightly better conductivity. Rates were consistent with sufficient permeability between CO2I#1 and CO2#13 for a viable CO2 flood with a sufficient Process Pore Volume Rate (PPV).

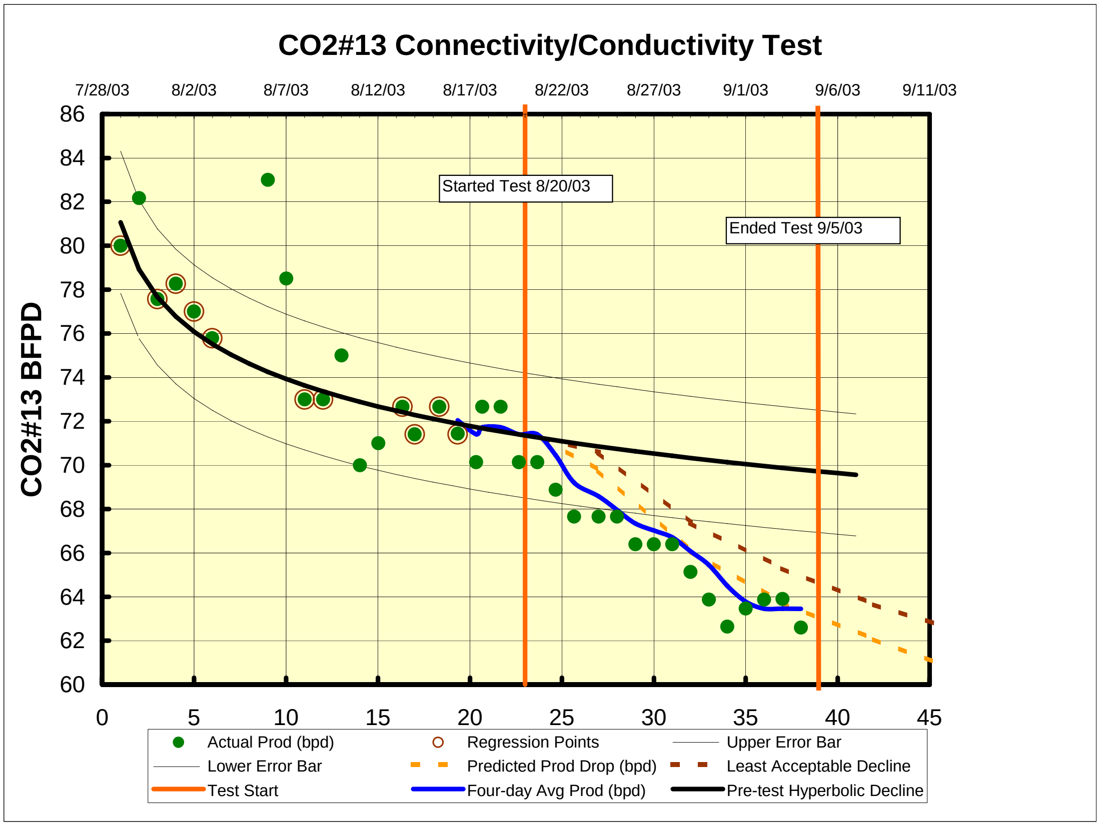


Figure 5.1.13: Production rates for the CO2#13 well prior to start of CO2I#1-CO2#13 conductivity test and during test. The change in CO2#13 production confirmed sufficient conductivity for adequate flood rates between the wells. (1bwpd = 0.16 m^3/d, 1 bbl = 0.16 m^3, 1 psig = 6.89 kPa)

TASK 5.2*:* CONSTRUCT SURFACE FACILITIES

-A new tank battery was installed near the Colliver #10 well and the existing producers plumbed to the new tank battery to isolate production from the pilot area. The injection facility consisted of the shallow Dakota sandstone water supply well (WSW), a 200 barrel (31.8 m^3) fiberglass injection tank, a triplex pump, filter cartridges, metering, valves, etc (Figures 5.2.1-3).

Figure 5.2.1: CO_2 Injection plant near CO_2 Project Injection Tanks and Tank Battery

Figure 5.2.2: CO_2 pilot water injection tanks and tank battery.
with treatment chemicals.

Injection water was filtered to 5 microns. The incoming shallow Dakota sandstone freshwater had a dissolved oxygen concentration of approximately 2-4.4 ppm (parts per million). After treatment with an oxygen scavenger (~2-3 quarts/d; 1.7-2.8 L/d), dissolved oxygen concentration of the injection water before the filter was 0.00-0.08 ppm. Following batch treatments using biocide WCW 5827 on 4/23/03 and 3/28/03, approximate biweekly RapidCheck™ tests indicated no detectable levels of bacteria in the injection water before the filter. A fiberglass injection line was laid to CO_2 I#1. The pilot water injection plant became operational 4/18/03 and began long-term injection in the CO_2I#1 on 4/23/03.

Figure 5.2.3: CO2 Pilot water injection pump and filters.

Between 09/09/03 and 09/15/03 a 350-foot (107 m) trench was dug from the water production plant to the CO2#10 wellhead and 330-foot (100 m) new Centron 2" (5 cm) 1,500 psi (pounds per square inch; 10.3 MPa) fiberglass pipe were laid. The line was pressure tested to 1,000 psi (6.9 MPa) using water and three very small seeps were repaired (Figure 5.2.16).

Figure 5.2.4: Laying fiberglass injection line from the water supply plant to the CO2#10 water injection containment well. View is looking to the northwest.

Between 09/15/03 and 09/16/03 a 240-foot trench was dug from the CO2 pump site SE to the lease road crossing and a 735-foot (224 m) trench was dug from the lease road to the CO2I#1 wellhead. Lines to the Colliver #7 and the CO2#13 were cut and modified. 980-feet (300 m) of 2" (5 cm) SCH 80 CO2 steel injection pipe were welded and pressure tested to 1,550 psi (10.7 MPa) using water and placed in the ditch and the ditch back-filled to near the CO2I#1 wellhead.

A 3-phase separator from McDonald Tank of Great Bend, Kansas was installed to permit measurement of oil, water and gas rates from the pilot wells.

TASK 5.3 PATTERN REPRESSURIZATION AND ANALYSIS

Beginning on 3/7/03 the CO2 Project #18 injection well was shut-in and a program of measuring fluid levels in the pattern wells was initiated. Bottom-hole pressures were calculated from the fluid levels. Long-term injection in the CO2I#1 began on 4/23/03 (Figure 5.3.1). Based on first arrival times of 3-5 days for pressure response in the #10, #12, #18, #16, and Carter #5 to injection in CO2I#1, the absolute average permeability between the CO2I#1 and the #10, #12, and #18 is interpreted to range from 50-80 md. Average permeability near the CO21 #16 is ~25-35 md. Pressure response to injection in CO2I#1 gave clear indication that the #10, #12, #18 and Carter #5 wells are well connected to CO2I#1. A drawdown and buildup test on the CO2#12 provided permeability values that were consistent with first arrival times from the CO2I#1. Response of the #18 to changes in the #12 indicated that these wells may have enhanced interwell conductivity.

Pressure response indicated that CO2#16 communicates with flood pattern area but permeabilities in this well and the surrounding area are significantly lower than in the rest of flood pattern area. Low pressure in the CO2#16 may result from production in the region to east. Based on these permeabilities, the rate at which the CO2#16 would process the pore volume between the CO2I#1 and the CO2#16 was too low to use this well effectively in the time period of the demonstration without additional stimulation. Decisions about additional testing or stimulation of this well were delayed until after completion and testing of the CO2#13 well was complete. The CO2#13 exhibited low pressure similar to the CO2#16. This was interpreted to reflect pressure drawdown from the pumped-off Rein #1 and Letsch #7 wells in adjoining leases to the east and southeast.

Following completion of the CO2I#1-CO2#13 conductivity test and confirmation of adequate conductivity between these wells the injection rate in CO2I#1 was increased to 140 BWPD (barrels water per day; 22.4 m^3) on 09/05/03 to begin repressuring the pilot area in preparation for CO2 injection. Water injection began in the CO2#10 and CO2#18 containment wells on 09/15/03 and 09/16/03, respectively. Pilot area reservoir pressure increased and was predicted to reach sufficient pressure for CO2 injection in November. With increasing reservoir pressure and injection in the CO2#10 and CO2#18 injection rates in the CO2I#1 decreased as shown in Figure 5.3.2. Injection water for CO2 #18 was supplied by the existing produced-water injection system. Water injection into CO2#18 was cyclic due to a shortage of produced water at that plant. Maximum injection pressures of 640 psig (pounds per square inch gauge; 4.4 MPa), 500 psig (3.5 MPa), and 560 psig (3.9 MPa) were set for CO2I#1, CO2#10, and CO2#18, respectively. Pressure relief valves were used to regulate the individual injection pressures (water was circulated back to the injection tank to maintain the desired pressure).

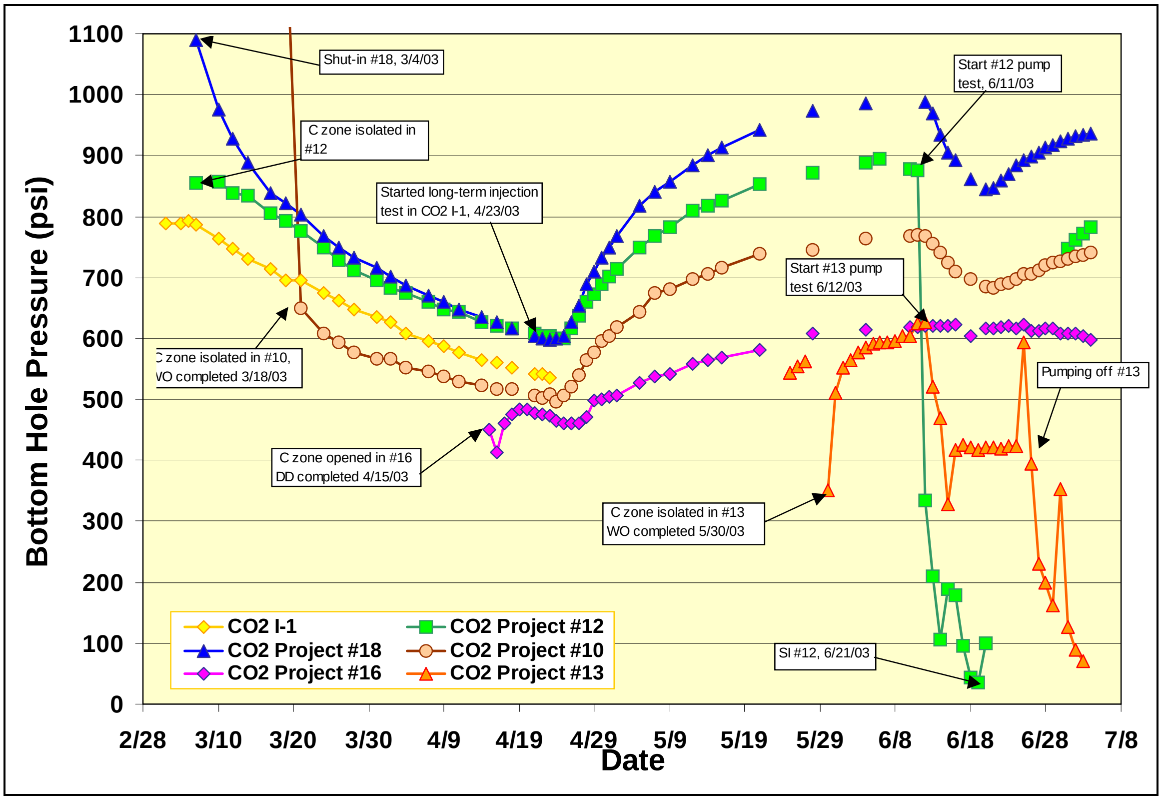


Figure 5.3.1: Bottom-hole pressures (BHP) through time and notes marking events. BHP values calculated from measured fluid levels. (1 psi = 6.89 kPa)

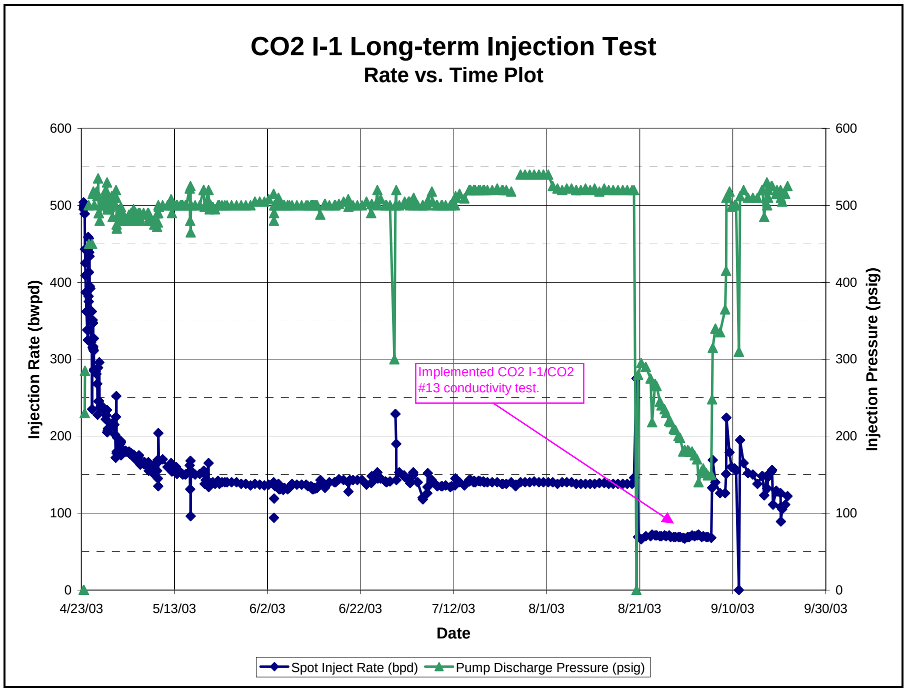


Figure 5.3.2: Bottom-hole pressure (BHP) and injection rate of the CO2I#1 through time and notes marking events. . (1bwpd = 0.16 m^3/d, 1 bbl = 0.16 m^3, 1 psig = 6.89 kPa)

TASK 5.4 - IMPLEMENT CO2 FLOOD OPERATIONS

5.4.1 Carbon Dioxide Injection

Figure 5.4.1 shows the CO2 pilot pattern located on the Colliver Lease in Russell County Kansas. The pilot pattern is confined within the 70 acre lease owned and operated by Murfin Drilling Company and WI partners. The ~10 acre pilot pattern consisted of one carbon dioxide injection well (CO2I-1), two production wells(CO2#12 and CO2#13) two water injection wells(CO2#10 and CO2#18) and CO2#16, an observation well. The pilot pattern was designed recognizing that there would be loss of carbon dioxide to the region north of the injection well. This portion of the LKC "C" zone contains one active production well on the Colliver Lease(Colliver #1) which was open in the LKC "C" and "G" zones as well as several zones up hole. CO2#16 was recompleted as a potential production well in 2003 in the LKC "C" zone. Core data indicated that the permeability-thickness product of the LKC "C" in this well was inadequate to support including this well in the pattern.

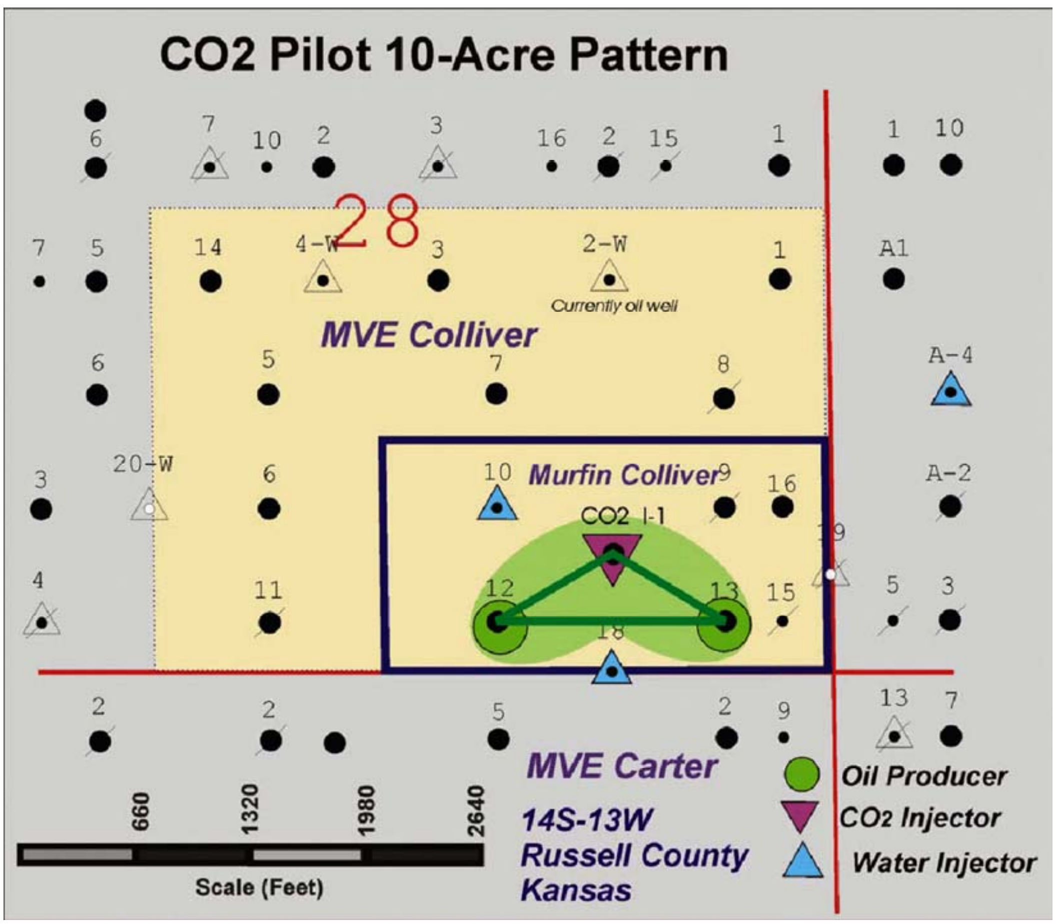


Figure 5.4.1: Murfin Colliver Lease in Russell County, Kansas

Liquid carbon dioxide (250 psi and ~-***10F***) was trucked to the lease from by EPCO from the ethanol plant in Russell operated by US Energy Partners where it was stored in a 50-ton storage tank provided by FLOCO2. Figure 5.4.2 shows the storage tank, Corken charge pump and associated piping.

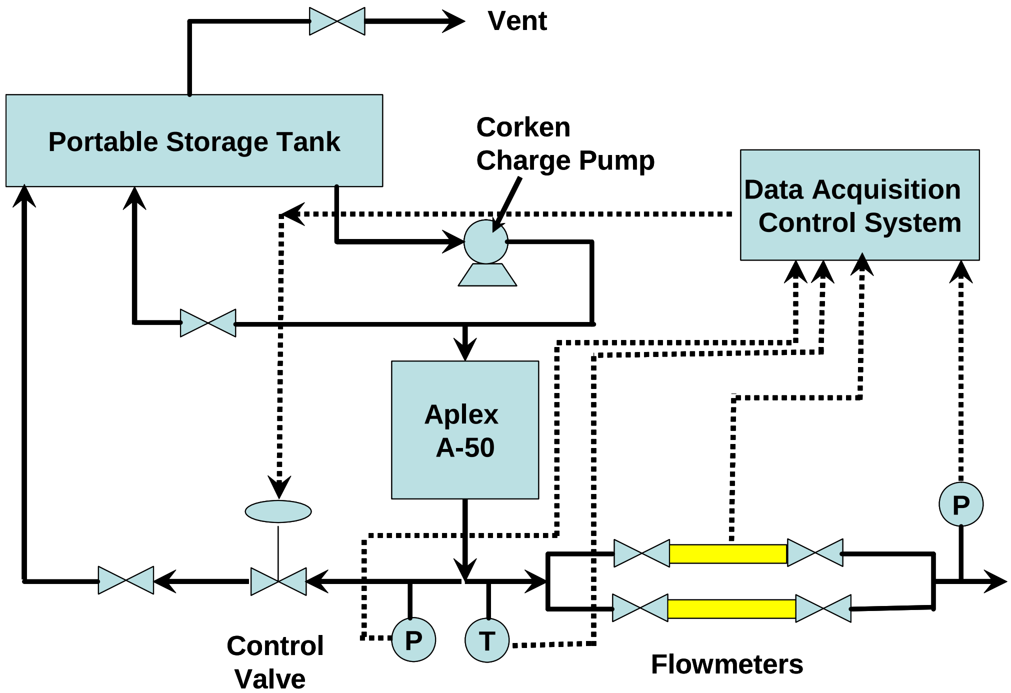


Figure 5.4.2: Flow schematic of CO2 Injection skid and portable storage tank

Injection of carbon dioxide began on November 23, 2003 using the pump skid shown in Figure 2 provided by FLOCO2. Operational problems were encountered on startup that delayed continuous injection until December 3. In the next seventeen months, 16.19 MM lbs(138.05 MM SCF) of carbon dioxide were injected into CO2I-1. Carbon dioxide injection was discontinued on June 17, 2005 and water injection began on June 21. Injection was converted to water to reduce operating costs to a breakeven level. Sufficient carbon dioxide has been injected to displace the oil bank to the production wells by water injection in the initial WAG cycle.

The injection rates of carbon dioxide into CO2I-1 and water into confinement wells were managed based on estimating the processible pore volume(PPV) contacted by carbon dioxide in the region produced by pattern production wells CO2#12 and CO2#13. The PPV was estimated from the analysis of fluid flow from the simulation of flood performance confined by water injection wells CO2#10 and CO2 #18. Figure 5.4.3 shows the PPV region that was estimated to be produced by CO2#12 and CO2#13. The PPV region is bounded by the solid line. All carbon dioxide leaving CO2I-1 within the PPV boundary displaces oil toward CO2#12 or CO2#13. Carbon dioxide leaving CO2#I-1 on the north side of the PPV boundary was lost. This amount was estimated to be 30% of the injected carbon dioxide. Also shown on Figure 5.4.3 are flow vectors from CO2#10 and CO2#18 showing the direction and intensity of flow from those injection wells as well as the effectiveness of the containment.

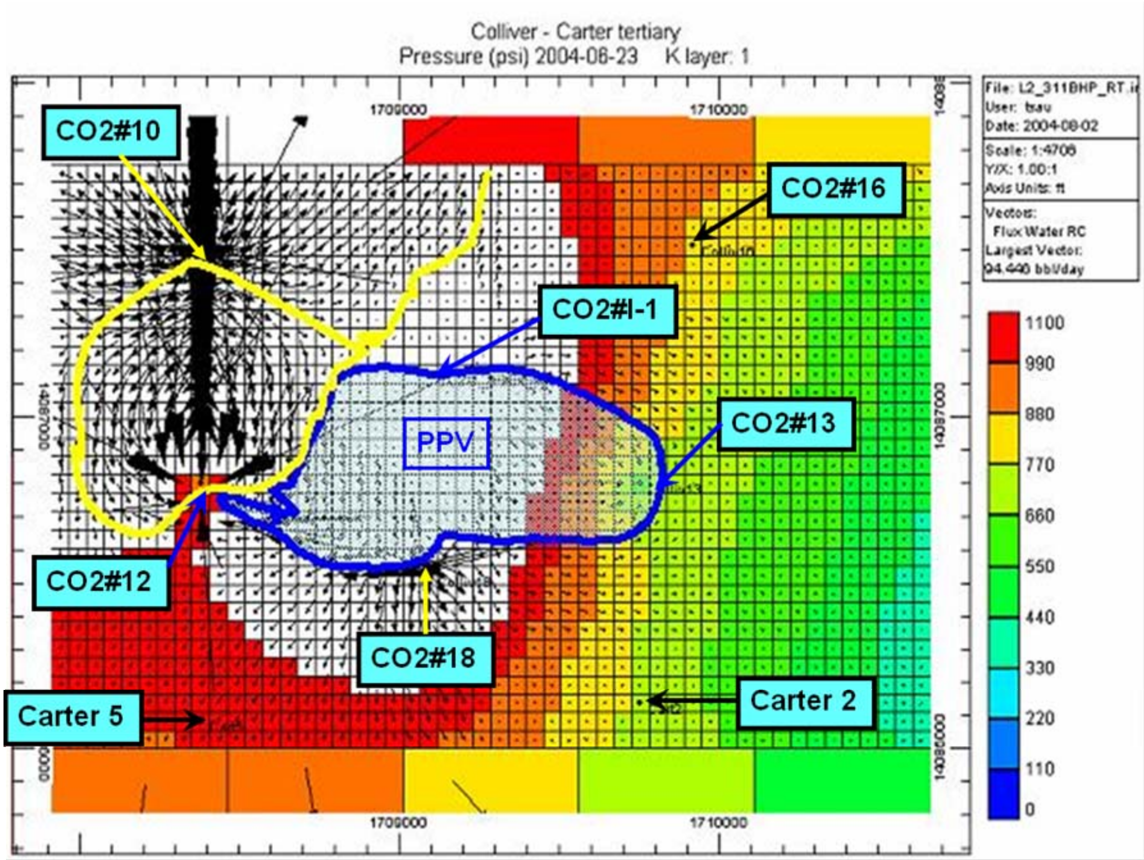


Figure 5.4.3: Estimated processible pore volume(PPV) for CO2 pilot

In Figure 5.4.3, the PPV was estimated from Equation 1.

$$PPV = V_p(1 - S_{iw} - S_{orCO2}) \text{...} (1)$$

V_p = pore volume of PPV region, RB

S_{iw} = initial water saturation, fraction

S_{orCO2} = residual oil saturation after carbon dioxide miscible flooding

Values used for calculating the PPV were S_{iw}=0.23 and S_{orCO2} =0.10. The estimated PPV in Figure 3 was about 170,000 RB. Design rate for carbon dioxide injection was 84.8 RB/D to account for losses to the north. CO2#12 and CO2#13 must produce fluid from the PPV region at a rate of 14PPV%/year (65.2 RB/D) to complete the demonstration project within the 5 year time window in this project. Management goal was to control the injection/withdrawal ratio (I/W) from the PPV region to 1 after allowance for carbon dioxide losses to the north.

Loss of carbon dioxide from the pattern area was estimated monthly from volume balances. Wells CO2#12 and CO2#13 were placed on production in November 2003 prior to the beginning of carbon dioxide injection to establish a pressure gradient between CO2I-1 and each well. In design and monitoring calculations, it was assumed that 29% of the production from CO2#12 was from the PPV region and 87% of the production from CO2#13 was from the PPV region. The monthly injection rate of carbon dioxide in RB/D was estimated from the fluid withdrawal rate from the pattern and the losses to the north. The desired injection rate in reservoir barrels/day was selected to meet fluid withdrawals from the pattern and estimated loss to the north.

The I/W ratio should average 1.0 if carbon dioxide injection into the PPV region is in balance with production rates from CO2#12 and #13. Injection exceeded withdrawal from December 2003-February and stabilized ~1 after the production rate in CO2#12 was increased in March 2004. The decline in I/W ratio from April-July 2004 was due to excessive vent loss and down time on the injection skid. Three months of stable operation in August-November 2004 were followed by a large increase in I/W ratio for December 2004 caused by shutting in CO2#13 for the carbon dioxide stimulation that was done on December 9. CO2#13 was shut-in for 26 days and the production rate of CO2#12 decreased. The cumulative I/W ratio is 1.07 indicating 34% of the carbon dioxide was lost out of the pilot area.

Figure 5.4.4 presents the injection/withdrawal ratio during the time when carbon dioxide was injected.

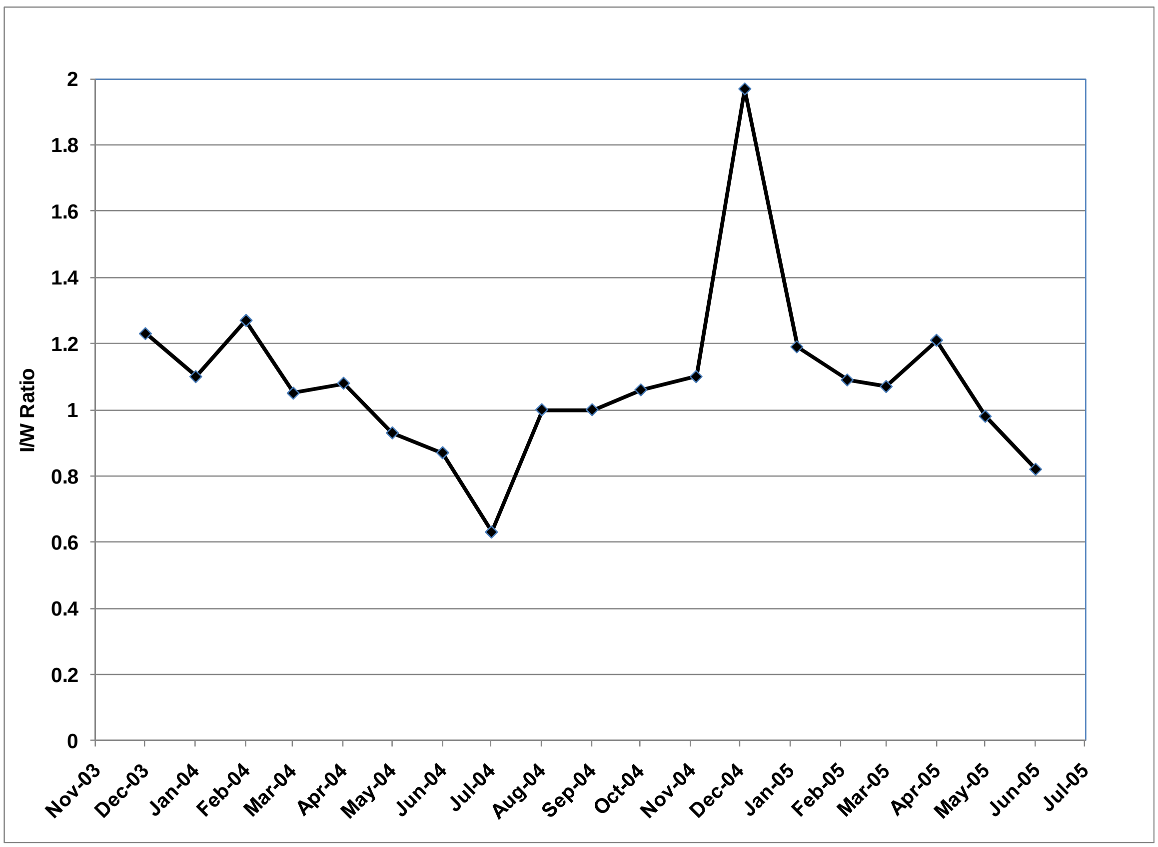


Figure 5.4.4: Injection withdrawal ratio for carbon dioxide pilot

The amount of carbon dioxide injected by mid-June 2005 was about 0.42 PPV (processed pore volume). Losses to the north at 30% gave an effective injection of 0.29 PPV. In other projects, water injection would begin at this stage of a carbon dioxide project to control carbon dioxide breakthrough and reduce channeling. As noted earlier, channeling has not been observed in this project, so there it was not necessary to begin water-alternating gas injection to control channeling.

Carbon dioxide injection was continuous with some interruptions caused by problems with equipment on the pumping skid. Most of these problems were resolved or solutions identified by the end of June 2004. During June 2004, the injection pressure averaged 754 psi at an average wellhead temperature of 54°F. Average injection rate was about 209 MSCFD.

Figure 5.4.5 shows the average daily carbon dioxide injection rate for the project. The injection rate declined substantially in May through June 2004 due to the excessive vent loss. Reduction of vent loss permitted maintenance of an average injection rate of 242 MCFD for the six-month period from July 1 through December 31 2004. The injection skid was down for several days in July 2004 due to mechanical problems. The average injection rate for the six-month period from January 1 through June 30, 2005 was 227 MCFD. The injection skid was down for several days in March 2005 due to mechanical problems. Injection rates in April-June 2005 were limited by the maximum bottom hole pressure (1975 psi) set to avoid fracturing the well. The decline in average injection rate may indicate reduced fluid from the region contacted by carbon dioxide. Figure 5.4.6 shows the cumulative injection of carbon dioxide(Mlbs) against time.

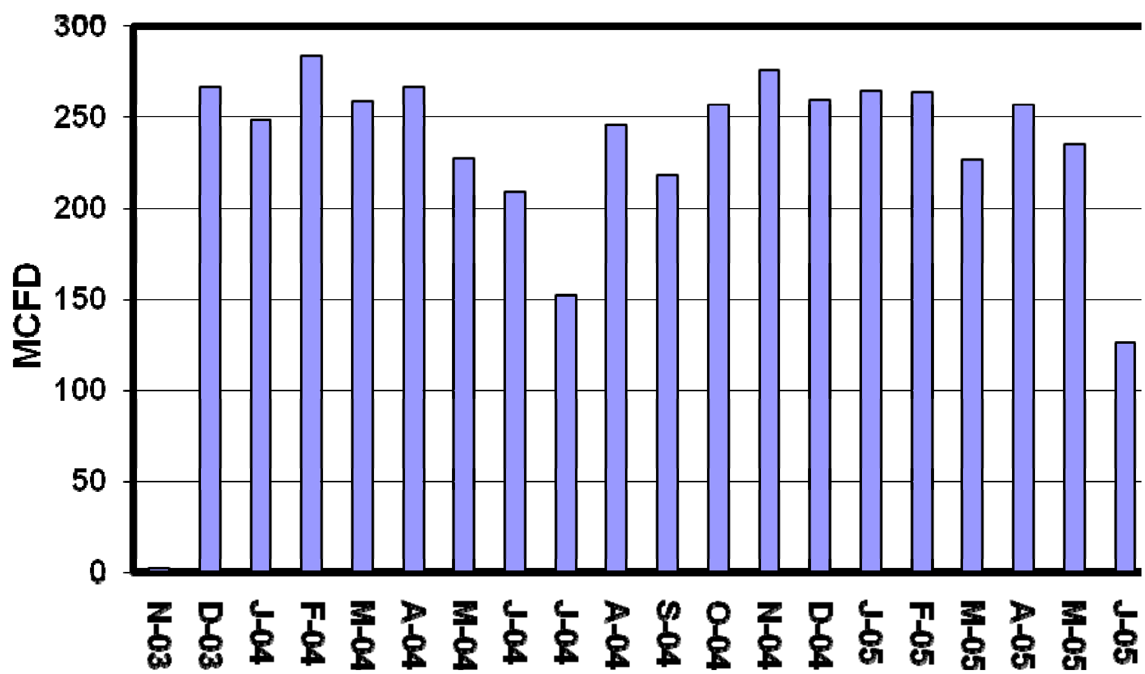


Figure 5.4.5: Carbon Dioxide Injection Rate in CO2I-1

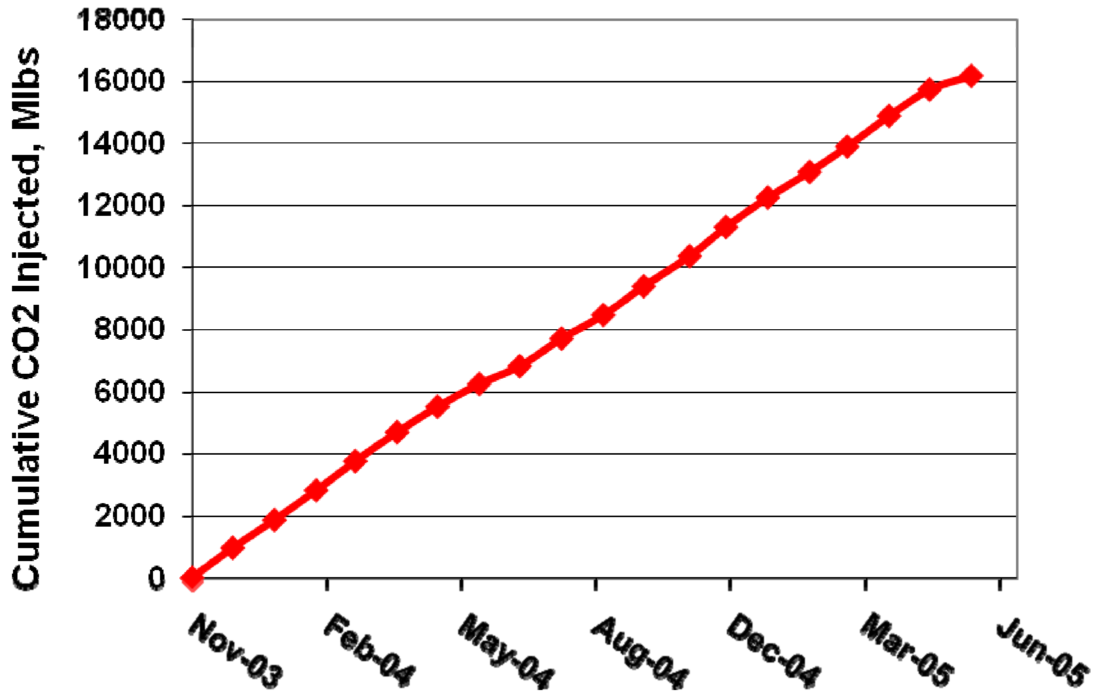


Figure 5.4.6: Cumulative carbon dioxide injected

Analysis of Project Performance

Although the average oil rate increased from 0 B/D to 3.4 B/D following seventeen months of carbon dioxide injection, a well-defined oil bank did not arrive at either production well. The gas-oil ratio remained in the range of 4-6 MCF/Bbl indicating that a direct channel did not exist between CO2I-1 and either production well. A low GOR at this point in project flood time had not been reported in other carbon dioxide miscible floods. Furthermore, other carbon dioxide floods responded with arrival of an oil bank by that time.

Several possible explanations for the lack of response were considered. In January 2005, an injectivity survey was completed in CO2I-1 to verify that carbon dioxide was leaving the wellbore in the ***C zone***. Figure 5.4.7 shows the distribution of injected carbon dioxide inferred from this survey. All carbon dioxide left the wellbore within the productive interval. Injectivity was not uniform. Fourteen percent of the carbon dioxide entered Layer 1, a high permeability interval and the only interval where a complete core was obtained. At the time of the survey, no carbon dioxide was entering the two-foot interval between 2893 ft and 2895 ft, an occurrence that was not expected since this was believed to be a high permeability interval. Eighty four percent of the carbon dioxide was entering intervals with lower porosity and apparent permeability. The injectivity in the lower interval was not anticipated from analysis of core and well logs.

An earlier injectivity survey was not taken so it is not known if the lack of injection in the 2893-2895 ft interval is due to poor permeability. This interval had good porosity and inferred good permeability but may be a shingle of limited volume. In the latter case, the zone may have taken carbon dioxide earlier in the project but reached its capacity based on limited vertical leakoff to zones above and below this interval. During the last few months of carbon dioxide injection, there were indications that injection rates were dropping with time, suggesting that losses from the total pattern volume were decreasing and that the region contacted by carbon dioxide was pressuring up.

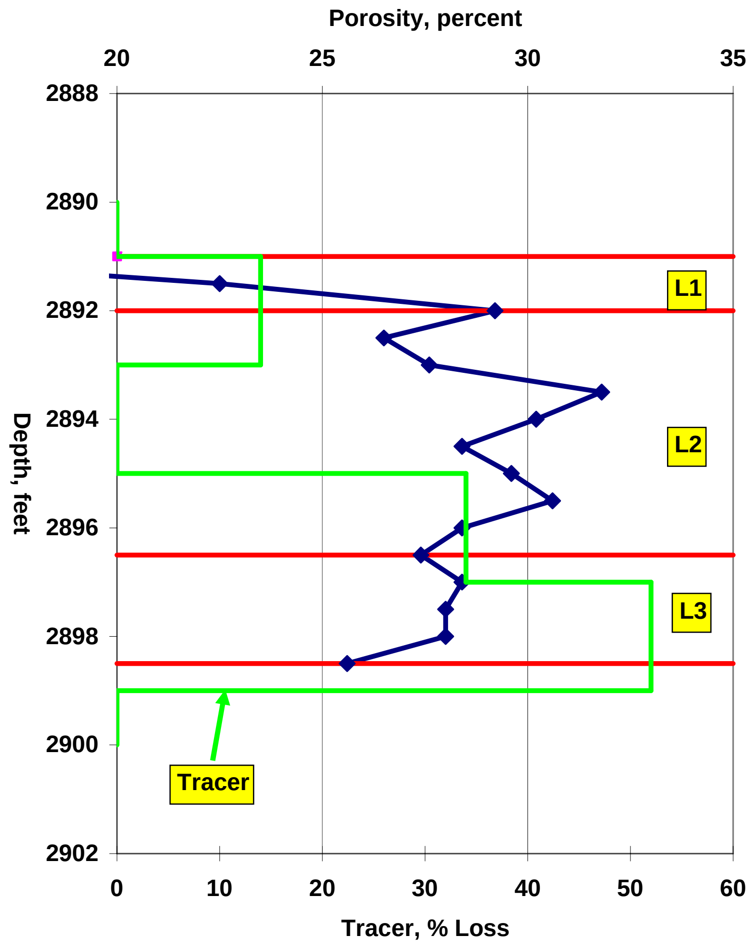


Figure 5.4.7: Tracer survey during carbon dioxide injection in CO2I-1 on January 27, 2005

5.4.2 Water Injection Into CO2#I-1

Conversion from carbon dioxide injection to water injection resulted in a decrease in the water injection rate from ~120 B/D to 64 B/D or lower in the four month period following conversion as shown in Figure 5.4.8. A decline in injection rate was expected because the pressure drop in the water-contacted region should increase due to the fact that the viscosity of water is about 10 times larger than supercritical carbon dioxide. The bottom hole pressure was increased to maintain the injection withdrawal ratio. The injection rate into CO2I-1 increased by an average of 28 B/D after the BHP was increased in CO2I-1. Injection rate remained low until February 2006 when the injected water was switched from fresh water to produced water.

Figure 5.4.9 shows the injection rate and bottom hole pressure before and after converting from fresh water to produced water injection. The bottom hole pressure decreased by about 200 psi after conversion, probably due to water sensitivity that was described earlier in Section 2.1.2. The increase in injection rate by a factor of two is due to the bottom hole pressure exceeding the fracture pressure in this well.

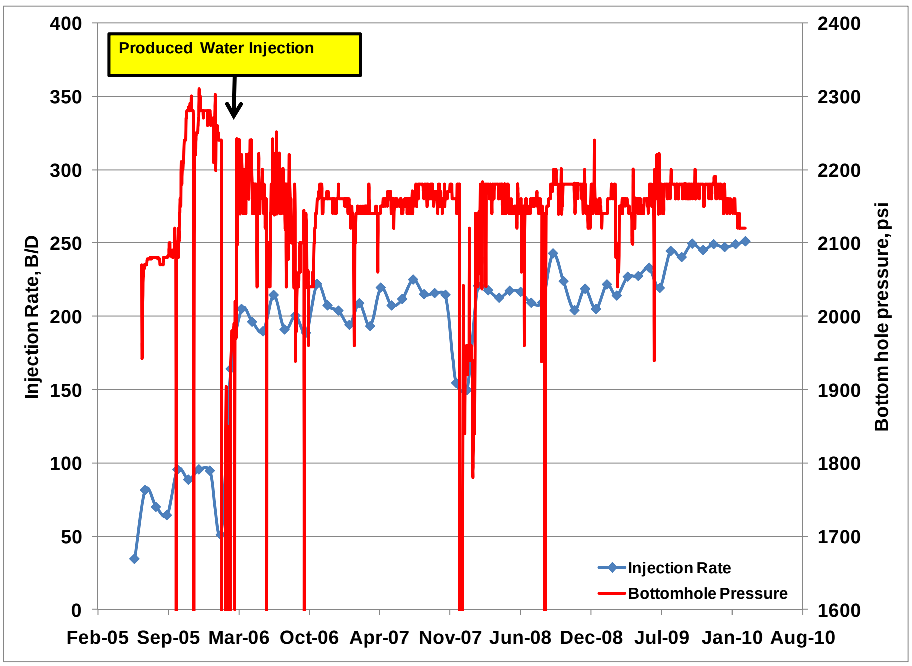


Figure 5.4.8: Water injection rate and bottomhole pressure in CO2#I-1

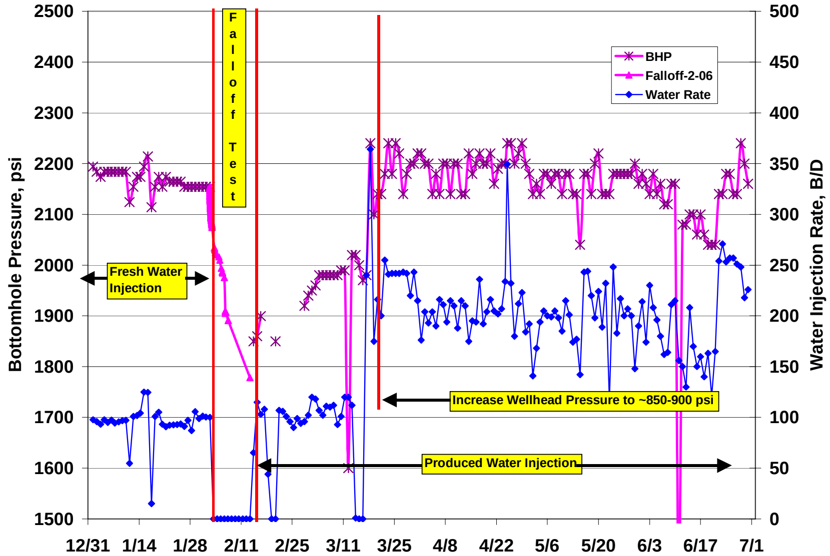


Figure 5.4.9: Injection rate and bottomhole pressure during injection into CO2I-1 before and after conversion from fresh water to produced water injection.

5.4.3 Operational Problems

Most of the day-to-day operations of the project were carried out as normal oilfield practices. Several problems were encountered with the CO2 pumping skid that were not anticipated. The first problem involved the data acquisition system used to measure flow rates and pressure. The CO2 skid contained two ½" Halliburton Flow meters and a MCII+ Flow Analyzer to measure flow rates. One flow meter is on stream and the second served as a backup. The active flow meter was connected to the MCII+ Flow Analyzer. The flow rate signal from the MCII+ analyzer was recorded by the data acquisition system and converted to flow rates using a calibration factor. The origin of the calibration factor was not known. Cumulative volumes of CO2 injected were calculated by the data acquisition system. Temperature sensors and pressure transducers were used to measure the pressure at the pump outlet upstream of the flow meter and at a distance of about 20 feet from the skid where the flow line was submerged on the way to the injection well.

Initial flow rate readings were recorded manually from the computer screen at specific times. Flow rates were observed to vary over wide ranges. In January 2004, initial attempts were made to determine the source of the flow rate variations. Pressure transducer data taken over small time increments demonstrated that pressure fluctuations on the order of 100 psi occurred over time intervals of 0.2-0.3 seconds between the pressure transducer before and after the flow meter. By February, we were able to down load data acquired by the data acquisition system and verified that flow rates fluctuated in a similar manner with the pressure fluctuations. The pressure fluctuations were regular and were believed to be caused by pulsation of the triplex.

During the course of the investigation, we determined that the Halliburton flow analyzer counts pulses and could not distinguish between forward and reverse flows. Fluctuations in the flow rate were believed to be due to rapid changes in velocity and flow direction through the flow meter caused by pulsations in fluid flow from the triplex. The analyzer counted both forward and reverse flow as flow through the meter. Cumulative volume of carbon dioxide injected based on the Halliburton MCII+ analyzer overstated the amount injected by about 10%. These observations led to the conclusion that accurate volumes of carbon dioxide injected could not be measured using the skid flow meter and the Halliburton MCII+ analyzer installed on the CO2 skid.

A Halliburton MCII flow analyzer, temperature sensor, pressure transducer and data logger were installed at the wellhead of CO2I-1. Installation was completed the end of May 2004 and reliable wellhead data were obtained. Wellhead data confirmed the upside bias of cumulative volume data obtained from the Halliburton MCII+ flow analyzer on the CO2 skid.

The CO2 injection pump was an Aplex A-50 with a capacity of 10 gpm at maximum speed. This was the only pump available from FLOCO2 at the beginning of the project. Since the anticipated injection rate was on the order of 2 gpm, about 80% of the fluid pumped was recycled, adding energy to the portable storage tank and increasing the vent loss. The amount recycled was reduced by reducing the pump rpm to the minimum value permitted (about 120 rpm) but the amount was still on the order of 7-8 gpm. The large recycle rate caused increased vent loss from the portable storage tank. Vent loss increased as ambient temperatures increased moving from winter to summer months. By June, the estimated vent losses were 25 % of the injected fluid and were becoming excessive. There was concern that excessive vent losses would cause the project to run out of carbon dioxide before the required amount was injected. At the end of June, maintenance of the pump allowed replacement of the 1 ½” pistons with 1 ¼” pistons. The maximum pump rate was reduced to a maximum of 8 gpm with a recycle of about 5 gpm. Vent loss was reduced significantly as demonstrated by the data presented in Figure 5.4.10.

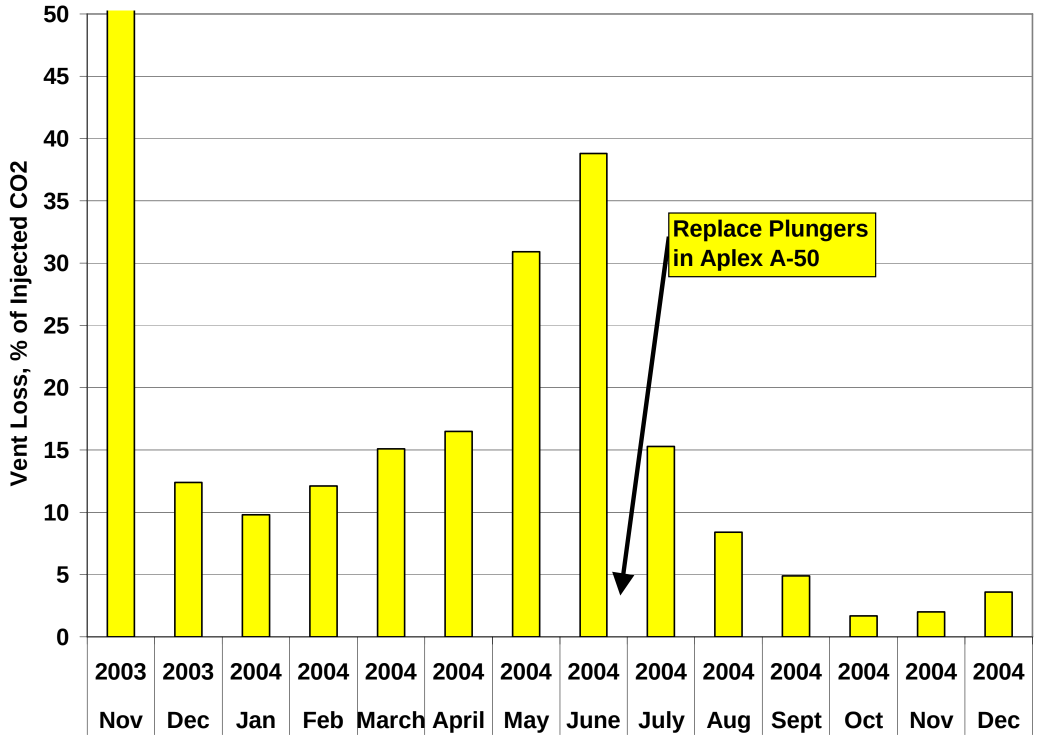


Figure 5.4.10: Vent loss from storage tank as a percentage of injected CO2

5.4.4 Confinement and Monitoring of Pilot Area Pressure

The CO2 project was designed so that the average pressure in the pilot area was well above the estimated minimum miscibility pressure, estimated to be 1250 psi from laboratory displacement experiments. Pressure in the pattern was maintained by controlling the BHP of CO2I-1, CO2#10 and CO2#18 by monitoring wellhead pressures daily and adjusting injection rates. Pressure was monitored in CO2#16, Carter 2 and Carter 5 periodically using fluid level measurements. Production wells CO2#12 and CO2#13 were pumped off if possible. Average pressures between CO2I-1 and CO2#12 and CO2#13 were estimated from short term pressure buildup tests.

Carbon dioxide loss to the north was controlled by water injection into CO2#10. Well CO2#10 was a water injection well during secondary recovery operations. The well was open in the LKC-G zone and fractured to increase the injection rate. Although the well was recompleted into the LKC-C zone by cementing the G zone, tracer tests indicated that there was some communication to the LKC-G zone. In addition, operational problems during recompletion opened the possibility that some water may have been injected into the LKC-B zone.

When the project was planned, carbon dioxide losses to the north were anticipated and estimated in designing, managing and interpreting the pilot performance. Water injection into CO2#10 was managed to minimize carbon dioxide loss to the north and injection into CO2#18 was managed to minimize carbon dioxide loss to the south. However, there is substantial uncertainty in the actual loss. Interpretation of 4D seismic data suggest that some carbon dioxide moved as far north as ~600-1000 ft. The uncertainty is tempered by other information. Colliver #1 is open in the C zone and has been pumped off during the entire time the project has been ongoing. Carbon dioxide has not broken into that well in observable quantities.

The injection rate into CO2I-1 was managed to:1) maintain minimum miscibility pressure in the pilot region containing carbon dioxide, 2) complete the project within the time frame of the DOE project, 3) replace fluid production in CO2#12 and CO2#13 from the pilot region and 4)compensate for fluid loss to the north. CO2 I-1 was operated by specifying the bottom hole pressure(~1900 psi) and injecting at a rate needed to control loss from the LKC-C zone to the north. During CO2 injection, the average bottom hole pressure ranged between 1800 and 1900 psi. The initial bottom hole pressure limit was specified to avoid fracturing the formation. After switching to water injection, the bottomhole pressure limitation was increased to ~2100 psi to increase injection rates.

Figure 5.4.11 shows bottom hole pressures during the water injection into CO2#10 and CO2#I-1. The pressure in CO2#10 declined from an average of ~1900 psi during carbon dioxide injection to ~1550 psi during water injection from January 2006 to March 2010. Bottom hole pressure in CO2#I-1 was maintained at an average pressure of about 2150 psi after water injection began. Pressure drop between CO2#I-1 and CO2 #10 increased to about 600 psi which suggests that fluid flow north of the pattern increased substantially by the end of 2005. It is not known whether this additional fluid flow contributed to the production response in Colliver A7 and other wells in adjacent leases.

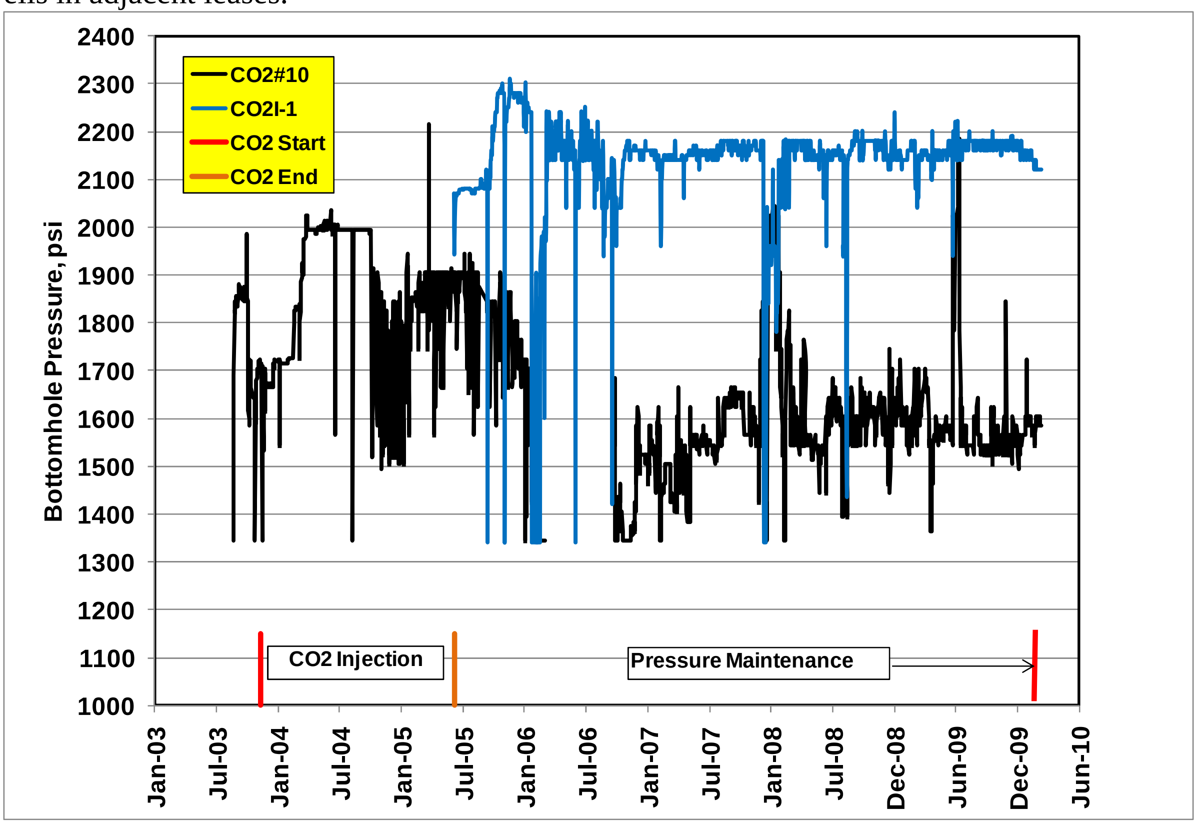


Figure 5.4.11: Bottom hole pressures during water injection into CO2#10 and CO2#I-1.

Figure 5.4.12 shows water injection rates during the project. CO_2#18 was recompleted early in the project as a possible injection well. Due to recompletion problems, this well was converted to a confinement well. CO_2#18 was fractured during previous operations. Water injection rates into CO_2#18 were controlled by setting the maximum bottom hole pressure to 1900 psi to avoid reopening the fracture. Injection into CO_2#18 was intermittent. There was no evidence that substantial fluid movement occurred south of CO_2#18.

Pressure in the flood and the pressure within the CO_2 bubble was monitored by using pressure buildup and falloff analysis. Pressure in the vicinity of the injection well was estimated by conducting short pressure falloff tests on CO_2 I-1. Fall off tests were five hours in duration with wellhead pressure readings taken at half hour intervals for the first two hours and at one-hour intervals thereafter. Changes in bottomhole pressure were used to estimate kh as well as the average pressure in the region surrounding CO_2I-1 sampled by the fall off test. The average pressure in the region surrounding CO_2#10 was conducted in a similar manner to the falloff test in CO_2I-1. Values of kh determined from falloff tests in CO_2#10 were used with caution because the well was open to multiple formations, including the LKC "C" zone.

Average pressure in the regions surrounding CO_2#12 and CO_2#13 is estimated from short buildup tests obtained by shutting in each well and shooting fluid levels at time intervals of 30 minutes for the first two hours and hourly for the next three hours. Average pressures determined from these tests are shown in Figure 5.4.13 for each well. Also shown in Figure 5.4.10 are pressures at two monitor points. Monitor point 12 was half way between CO_2I-1 and CO_2#12 and pressure at this point was approximately the average of average pressures for CO_2I-1 and CO_2#12. Monitor point 13 was half way between CO_2I-1 and CO_2#13 and the pressure at this point was approximately the average of the average pressures between CO_2I-1 and CO_2#13. Figure 5.4.14 is a contour map of the pressure distribution at the beginning of March 2005 based on individual well pressures.

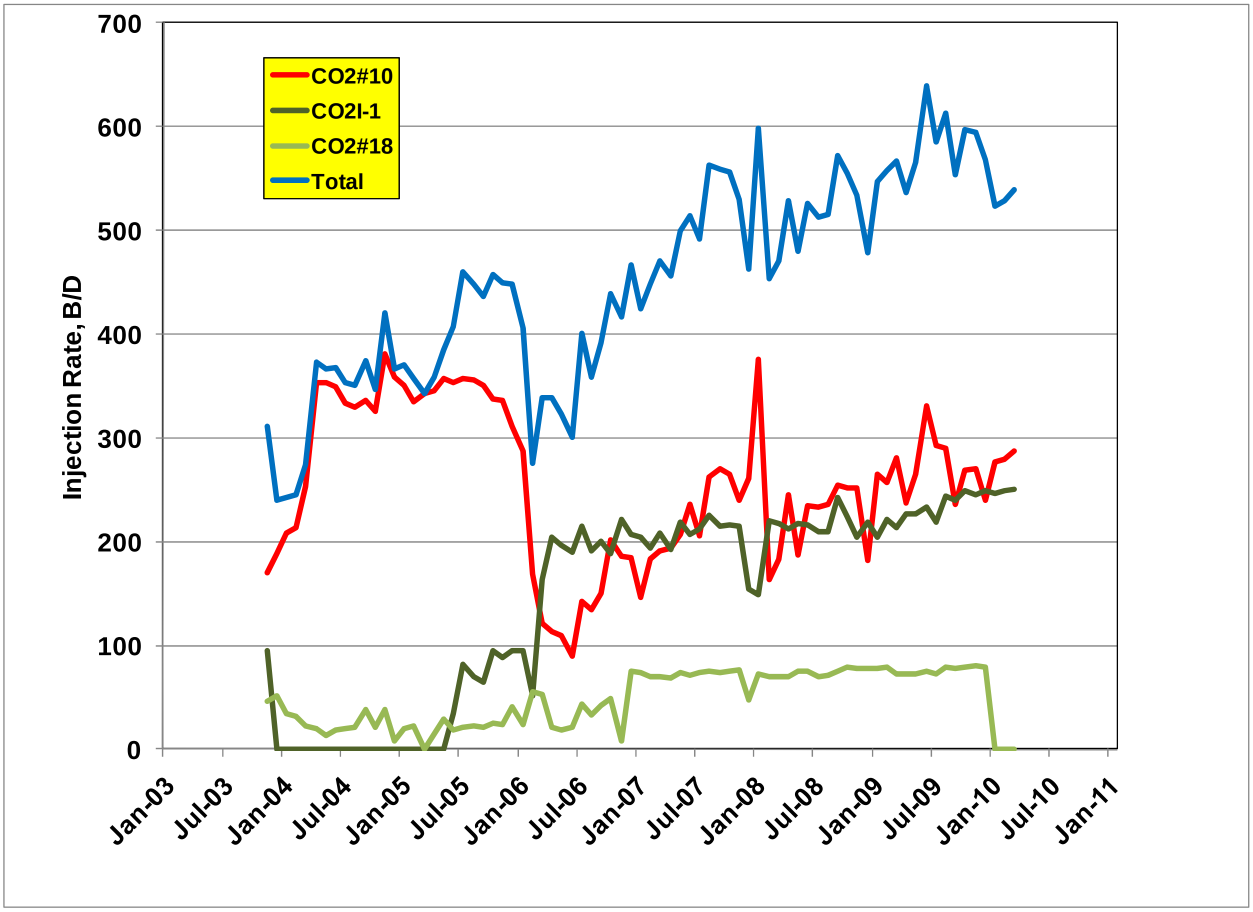


Figure 5.4.12 Water injection rates into CO2#10, CO2#I-1 and CO2#18 during the project.

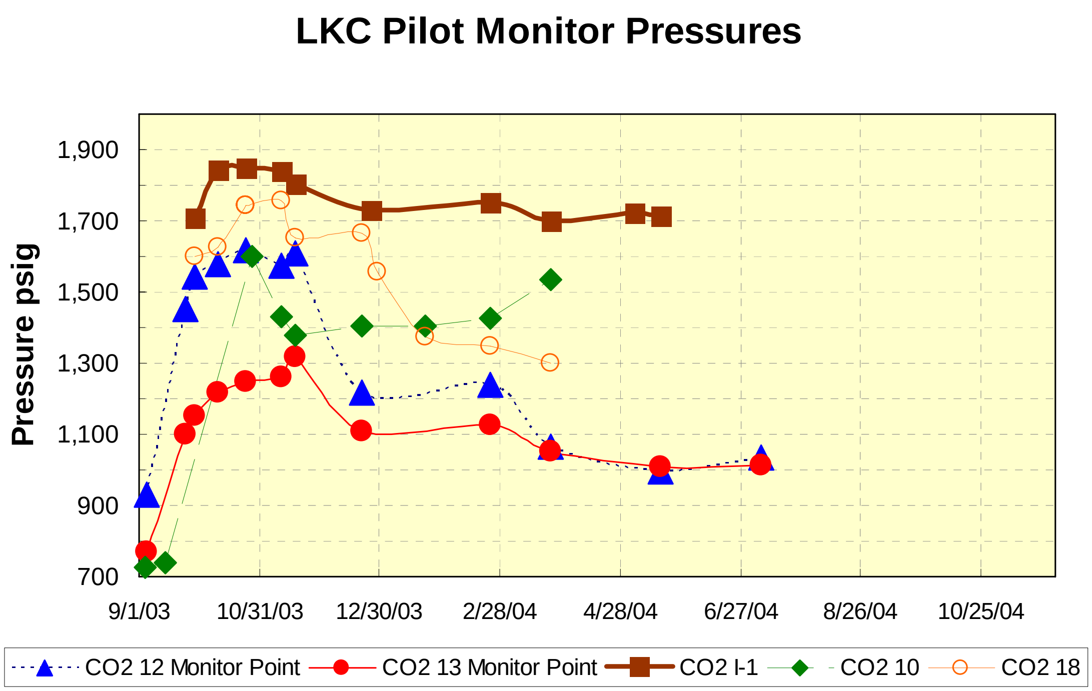
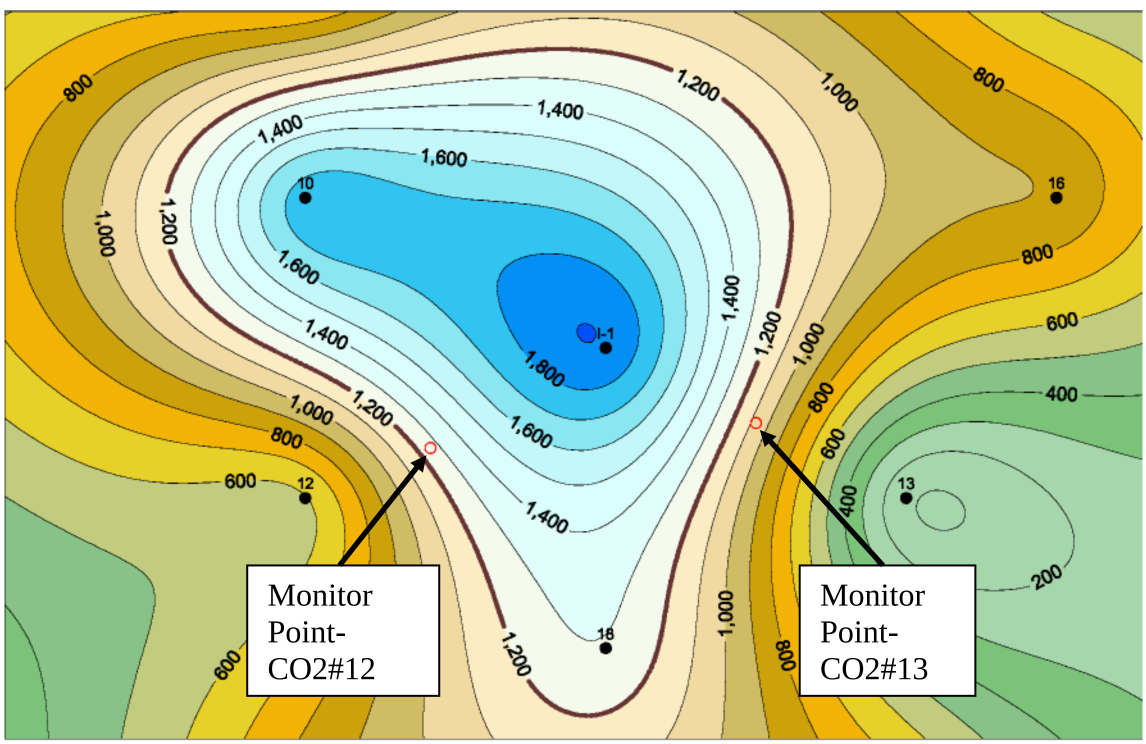


Figure 5.4.13: Pressures in the injection wells and at monitoring points.



LKC-C Pressure 3-2-05

Figure 5.4.14: Estimated pressure distribution in CO2 pilot area

The average pressure in the PPV region was estimated using Surfer, a mapping program. In developing Figure 5.4.15, Pressure distribution in the pilot region was estimated from pressures measured in CO2 I-1, CO2#10 , CO2#18 and fluid levels measured in CO2#12, CO2#13, CO2#16 and Carter #2. Colliver #1, Carter #2, Rein A-1, Letsch #7 and Colliver #6 were assumed pumped off. The fluid head in Colliver #7 is equivalent to a pressure of 187 psi. Colliver #3 was assumed to have a pressure of 100 psi. No data were available in the white areas beyond the pilot area. Also shown on Figure 5.4.15 is the outline of the region where carbon dioxide was estimated to displace reservoir oil and water.

Table 5.4.1 summarizes the average pressure of the pilot area outlined in Figure 5.4.15 at mid and end of the year.

Table 5.4.1: Average Pressure in Pilot Area

Date	Average Pressure, psig
February 2006	1435
June 2007	1454
December 2007	1451
June 2008	1506
December 2008	1494
June 2009	1518

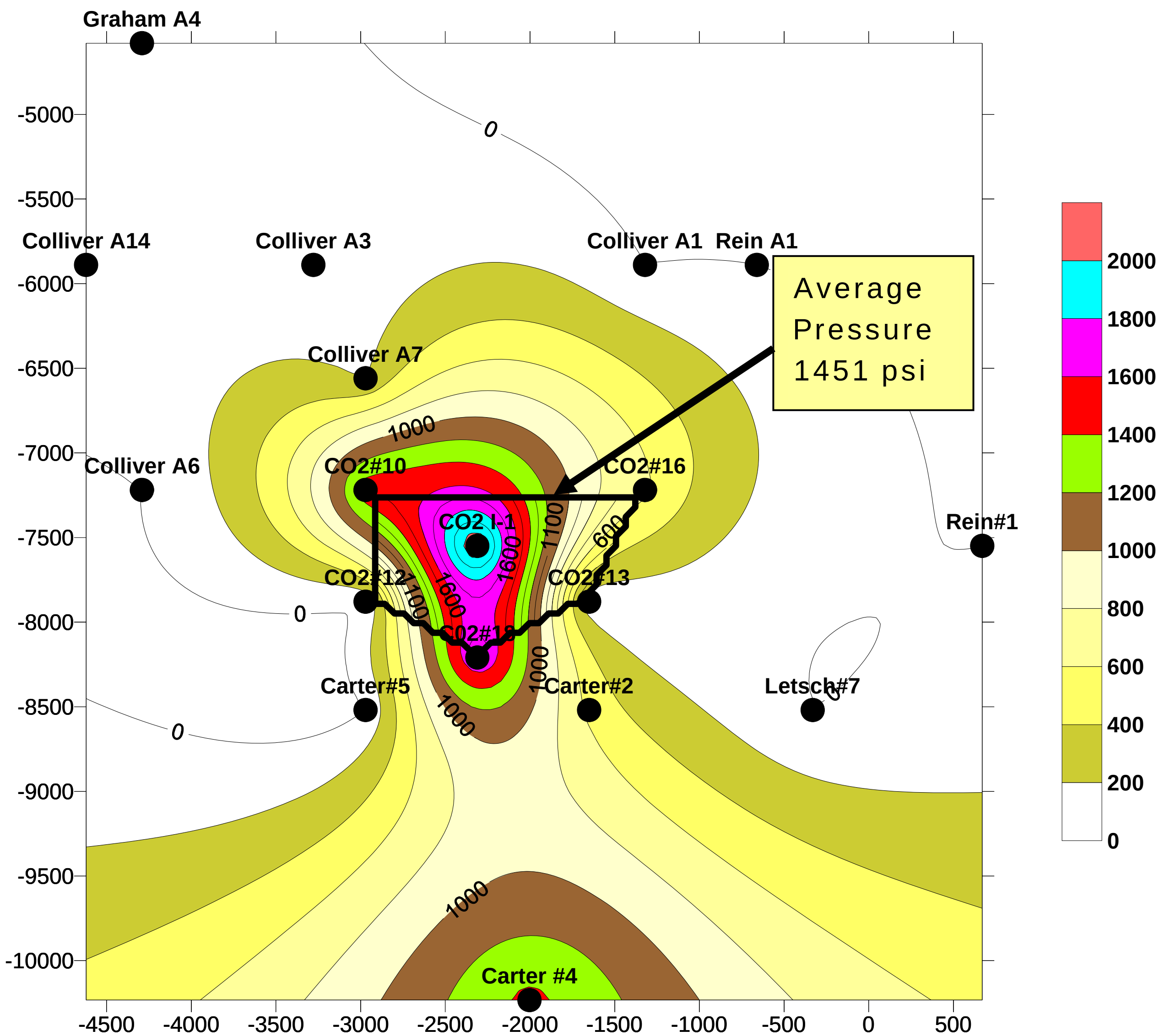


Figure 5.4.15: Estimated pressure distribution on Colliver-Carter Leases in December 2006

5.4.5 Production Response

This section contains two subsections: 1) CO2 Pilot Area and 2) Production from Surrounding Leases. When the project was designed, CO2#10 and CO2#18 were used to confine carbon dioxide to the pilot area by water injection. The northeast portion of the pilot area was not confined (other than by the low permeability region surrounding CO2#16). Reservoir models indicated that about 30% of the injected CO2 would flow from the CO2 Lease to the Colliver A lease north of the pilot. The only wells producing from the LKC C zone on the Colliver A lease were Colliver A#6 and Colliver A#1. Neither well responded to CO2 injection in the pilot area. However, in August 2006, the production packer in Colliver A#7 isolating the LKC C zone was unseated, opening the LKC C zone for production. The well produced oil at a significantly higher rate which is due to CO2 injection in the pilot area.

Incremental oil from CO2 injection through March 7, 2010 was estimated to be 27,902 bbl. About 8,736 bbl were produced from the CO2 pilot. The remaining 19,160 bbls were produced from surrounding leases, primarily the Colliver A lease. By March 7, 2010, the gross CO2/oil ratio was 4.8 MCF/bbl which is comparable to values observed in large scale West Texas carbon dioxide floods. This demonstrates that carbon dioxide mobilized oil in the LKC ***C*** zone, a key objective of the pilot project.

CO2 Pilot Area

The response of the pilot area to the injection of CO2 is shown in Figures 5.4.16-5.4.18 where cumulative oil, cumulative produced water and CO2 are plotted as functions of time. Cumulative oil produced from November 2003-March 2010 was 8736 bbls. Cumulative water production was 491000 bbls. Cumulative CO2 produced was 6815 MCF.

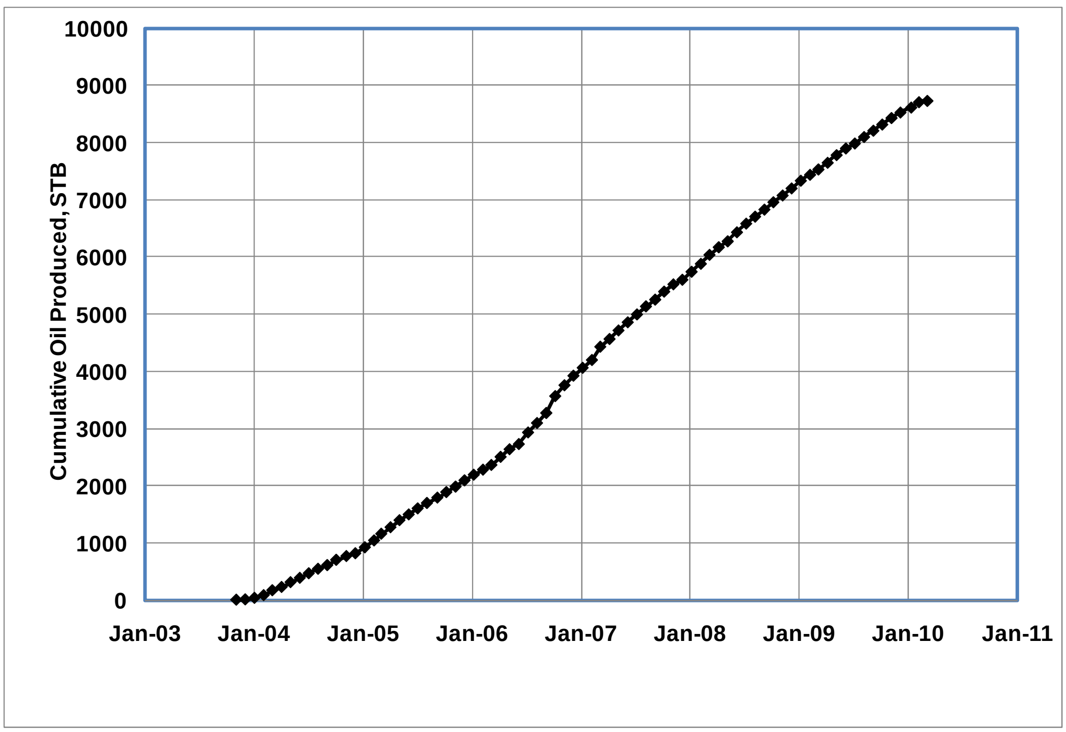


Figure 5.4.16: Cumulative oil production from CO2 pilot area

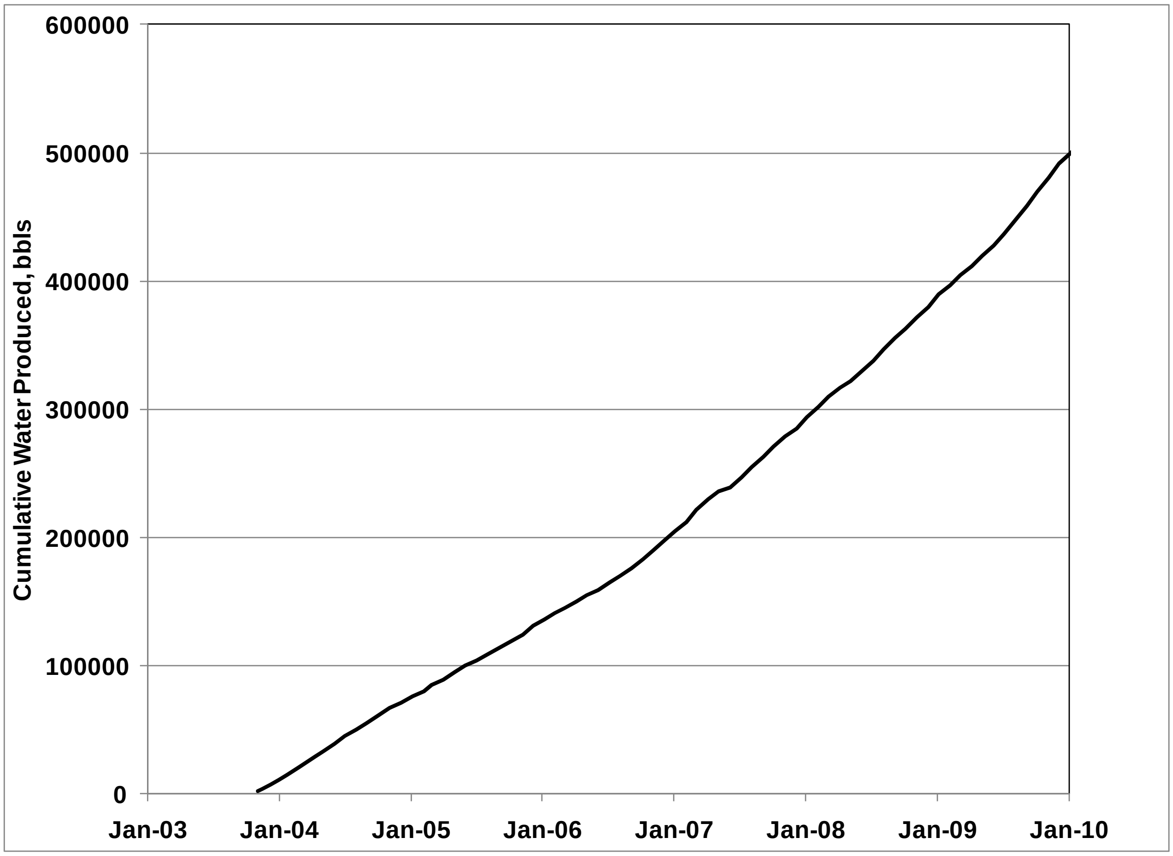


Figure 5.4.17: Cumulative water produced

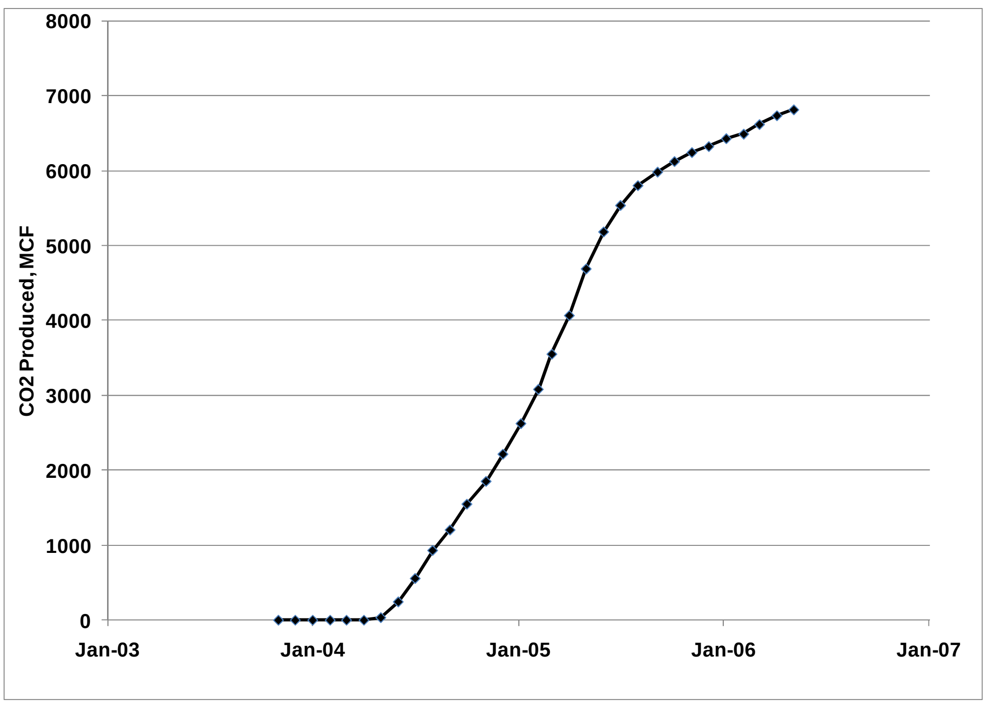


Figure 5.4.18: Cumulative carbon dioxide produced from pilot area

At the beginning of the project, wells CO2#12 and CO2#13 produced 100% water. By the end of February 2004, oil production averaged 1.6 B/D, primarily from CO#12. Oil production averaged 2.5 B/D for the period from March-June 2004. Carbon dioxide arrived at CO#12 on May 31 and arrived at CO2#13 in August 2004. Production of carbon dioxide was preceded by production of CO2 free hydrocarbon gas. Plans were developed to begin WAG if gas production rates became excessive. However, the maximum GOR during sustained CO2 injection was less than 5000 and WAG was not necessary to control CO2 production.

Monthly oil production rates for CO2#12 and CO2 #13 are shown in Figure 5.4.19 for the period from November 2003 through December 2009. After the initial production response to the injection of carbon dioxide in the pilot area, CO2#13 did not respond to carbon dioxide injection other than a small amount of produced CO2 and some changes in the gas composition. At the beginning of December 2004, a decision was made to treat CO2#13 with carbon dioxide in an attempt to increase the permeability to carbon dioxide in the region around CO2#13 and to establish communication with the oil bank, which was believed to be near CO#13. Two loads of carbon dioxide (86,260 lbs) were pumped into CO2#13 on December 9 and the well was shut-in for 26 days. Response to the CO2 treatment was minimal and CO2#13 averaged 51 BFD for the next six months. The oil production rate of CO2#13 was about 1 B/D throughout the project. The well produced little CO2 indicating poor communication with CO2I-1. The lack of response from CO2#13 reinforced the growing perception that there was a geologic feature between CO2I-1 and CO2#13 that restricted fluid flow. Peak oil rate was about 9.5 B/D in October 2006 following installation of a high volume pump in CO2#12 and flush production from installing a pump in CO2#16.

Water and total liquid production rates are summarized in Figures 5.4.20 and 5.4.21. The monthly average water oil ratio is presented in Figure 5.4.17. During most of the project, the WOR averaged about 60, ranging from as low as 22-25 during 2006, increasing toward the later stages of the project. Oil production rate correlated closely with total fluid production rate. Most of fluid production was from CO2#12. Fluctuations in fluid production rate were directly related to operating problems in CO2#12. The increase in fluid production rate in October 2006 corresponds to installation of a high volume pump as well as increased fluid injection rates in CO2I-1.

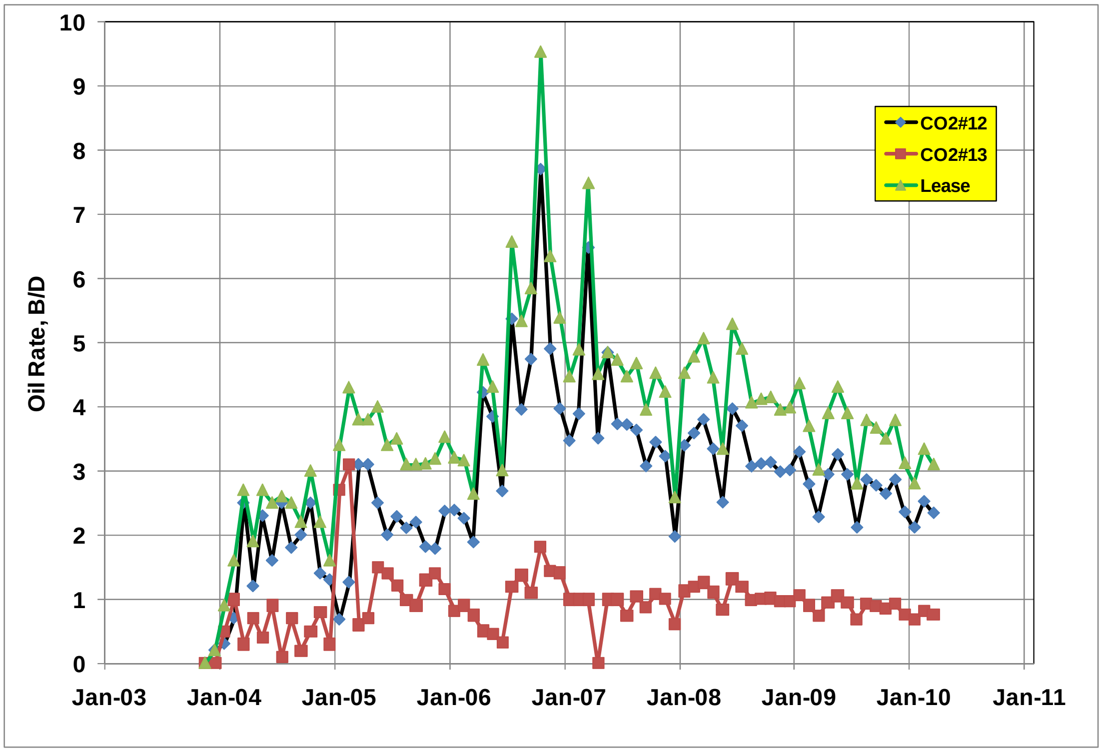


Figure 5.4.19: Average daily oil rate from CO2 pilot

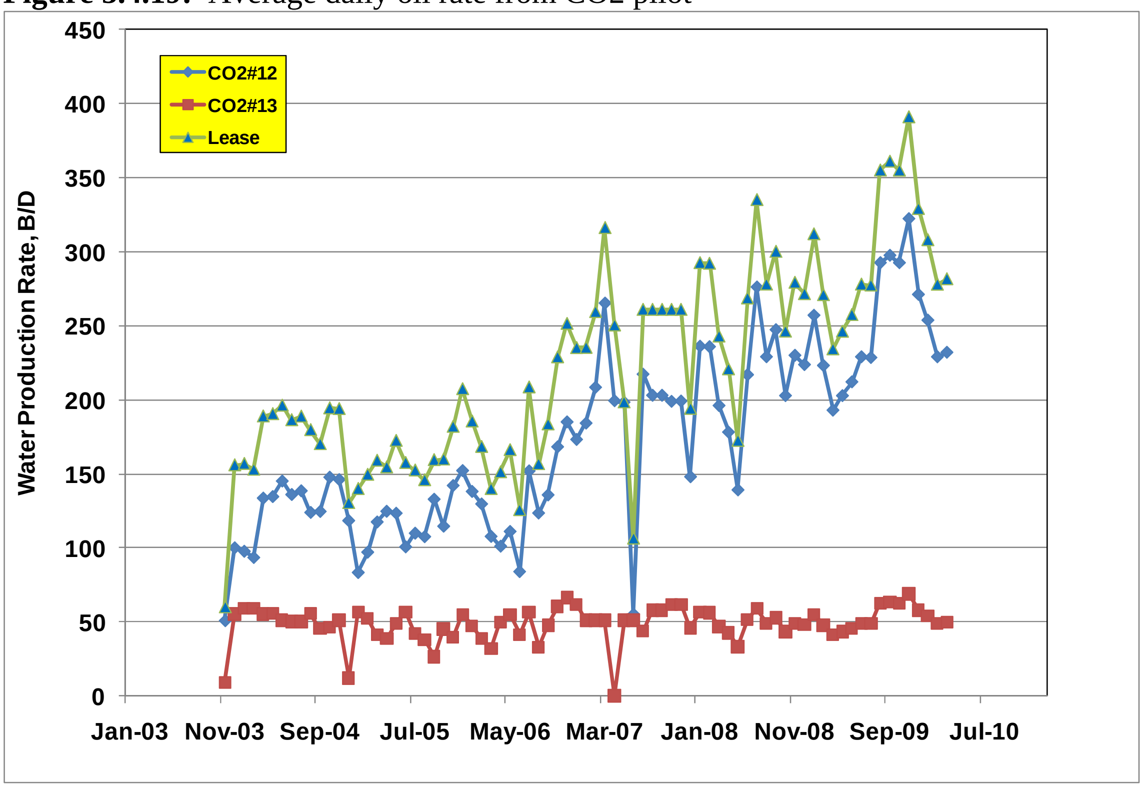


Figure 5.4.20: Water production rates from pilot area

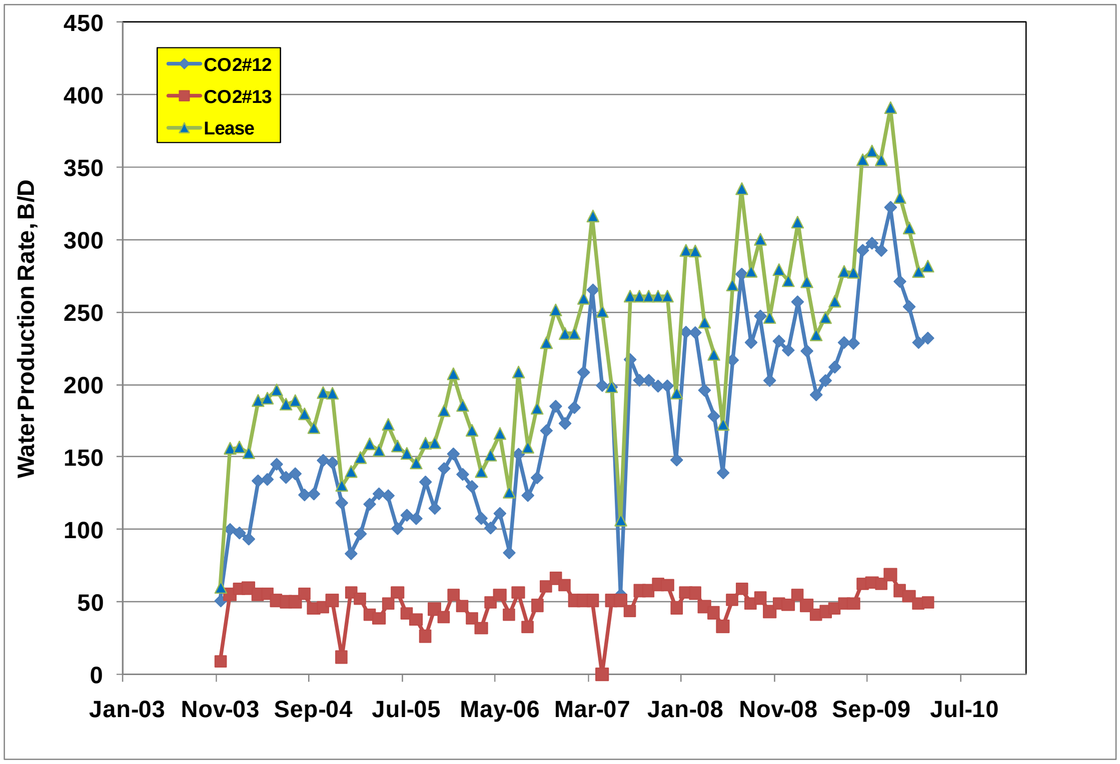


Figure 5.4.21: Liquid production rate from pilot wells

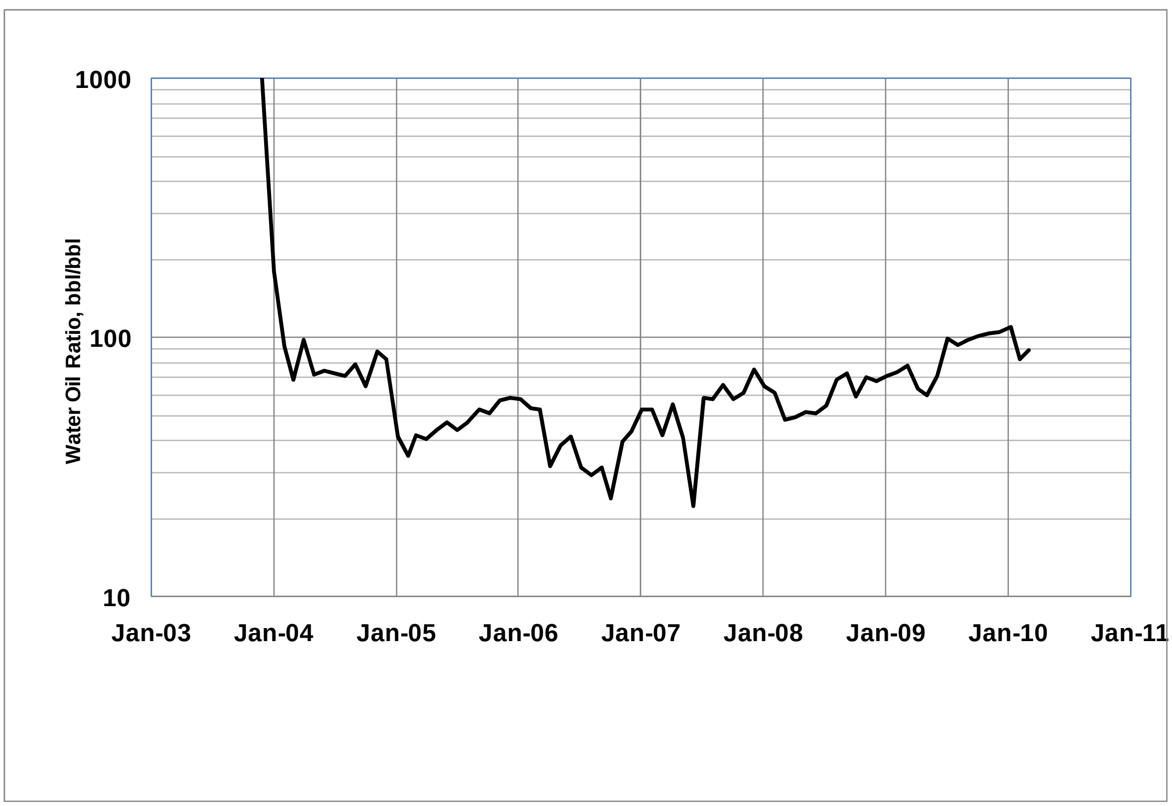


Figure 5.4.22: WOR from pilot area

Production rates were affected by several operating problems. In December 2004, high fluid levels were present consistently in the casing annulus. Various tests indicated that foam was generated in the casing annulus and appeared to be affecting the performance of the pump. Fluid production decreased from CO2#12 decreased to 118 B/D in December even though the well was thought to be pumped off. High fluid levels were persistent in CO2#12 beginning in December 2004 and the production rate decreased throughout the month. Several tests were completed in December to determine whether the cause of the decline in pump rate was due to reduced flow from the formation into the wellbore, a problem in the pump or foam in the annulus.

Various tests indicated that the apparent high fluid levels were caused by CO2-foam generated in the casing annulus. Gas production appeared to be affecting the performance of the pump. In addition, analysis of pump tests indicated that the pump was not working at capacity. The pump was pulled from CO2#12 on March 11, 2005 and found to be defective. A sand pump run to clean out the well tagged bottom at 2888 ft indicating fill of about nine feet from original completion depth of 2907 ft. A total of 3 gallons of large-grain sand and iron sulfide was recovered from swabbing the well to a depth of 2891 ft. Top of the C zone was 2887 ft so the C zone remained covered with sand grains. The fill consisted primarily of well-rounded, well-sorted quartz grains coated with iron sulfide, characteristic of frac sand. The source of the sand grains was unresolved. There was no record that the well had been fractured. Only known fracture was CO2#10 which was fractured in 1960 with 17,000 lbs sand. Part of an old 6” CIBP was stuck in open hole at 2890 ft and prevented complete cleanout of well and installation of a pump with a gas anchor that might be able to handle gas production.

Water production rates fluctuated around 200 B/D until October 2006 when a larger pumping unit was installed at CO2#12. CO2#16 was completed and placed on pump in October 2006 on an 8 hour clock. There was a small amount of production and the well was pumped intermittently when the fluid level built up. Increased water production is due primarily to the larger pumping unit on CO2#12 and increased water injection rates into CO2I-1.

Carbon dioxide injection into CO2I-1 terminated on June 17, 2005 and water injection in CO2I-1 began on June 21 to displace the CO2 bank and oil mobilized by CO2. At that time, there was no evidence that the oil bank generated by carbon dioxide injection has reached either CO2#12 or CO2#13. Short term production tests on both wells occasionally extrapolate to higher production rates that do not appear in the 24 hour measurements based on the stock tank oil. Production rates in CO2#13 were erratic, possibly due to presence of gas saturation in the vicinity of the well. During the period from July-December 2006, the oil rate averaged about 4.7 B/D. This was the only evidence of a “kick” due to carbon dioxide injection and a slow decline began in early 2007.

Carbon dioxide production rates are plotted in Figure 5.4.23. By the end of May 2006, the volume of carbon dioxide produced from the pattern declined below the level of measurement. Maximum CO2 production rate was 20 MCFD. Since the CO2 injection rate at this time was about 200 MCFD, about 10% of the injected CO2 was flowing directly from CO2 I-1 to CO2#12. Total amount of carbon dioxide produced is approximately 6.8 MMSCF. This is about

5% of the total amount of carbon dioxide injected into the reservoir. Thus, 95% of the carbon dioxide that was injected remained in the reservoir. GOR data are shown in Figure 5.4.19. Maximum GOR was about 5000 SCF/BBL. CO2 production was within acceptable limits, so WAG was not used.

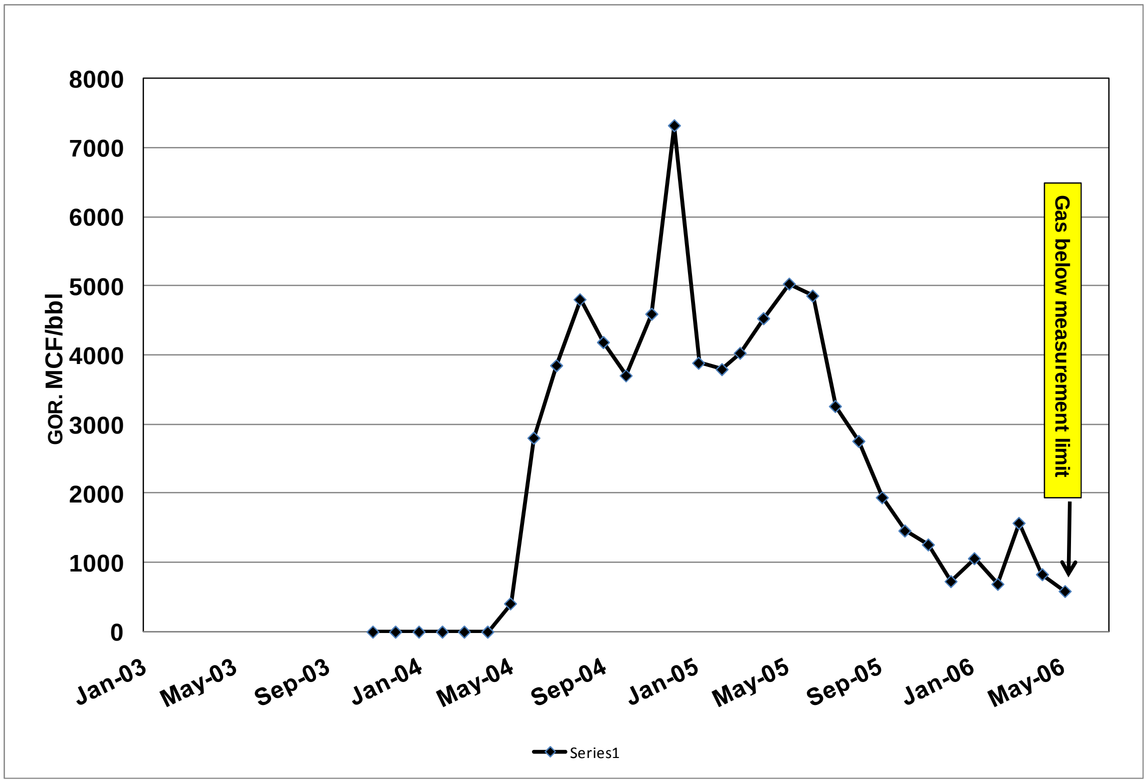


Figure 5.4.23: CO2 production rate, MCFD

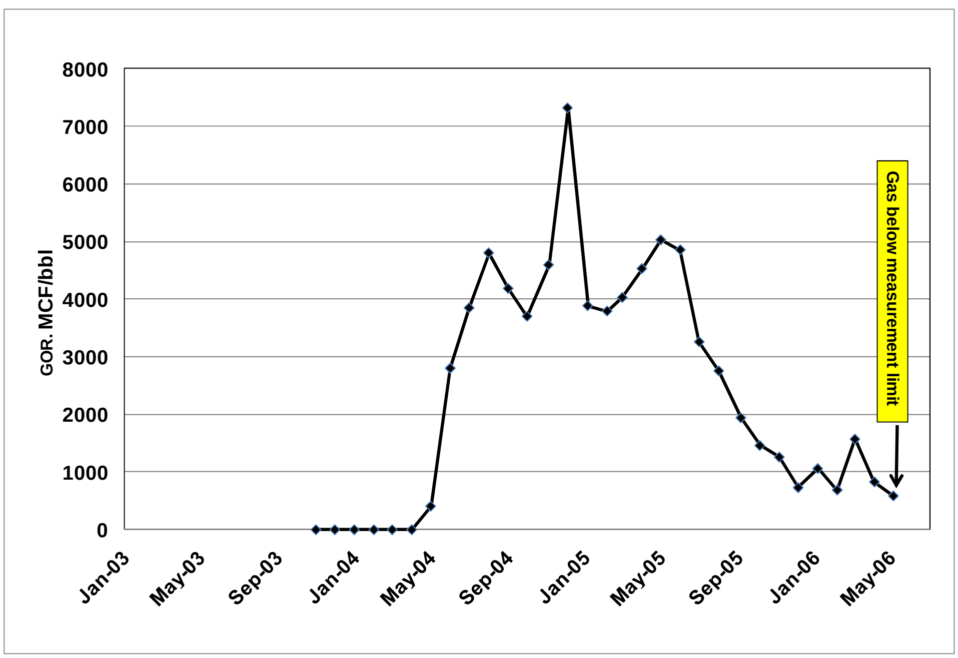


Figure 5.4.24: GOR from pilot area

Production from Surrounding Leases

Project personnel monitored production from the Colliver Lease (north of the pilot), Carter Lease(south of pilot), Rein Lease(east of pilot) and Letsch Lease(southeast of the pilot) periodically since the beginning of carbon dioxide injection to determine if oil or carbon dioxide was produced that could be attributed to the CO2 Project. Colliver #1 and Rein A-1, north east of the pilot region and Colliver #6, west of the pilot region have been pumped off since the beginning of the project and were checked frequently. Until August 2006, there was no evidence of effects of the project on surrounding leases.

In August, the operator of the Graham A lease, northwest of the pilot area mentioned that oil production from his lease increased in April-May with no apparent cause. Murfin staff obtained permission to test wells on this lease and determined that the additional production was coming from Graham A4, a well located 3570 feet from CO2 I-1 as shown in Figure 5.4.25.

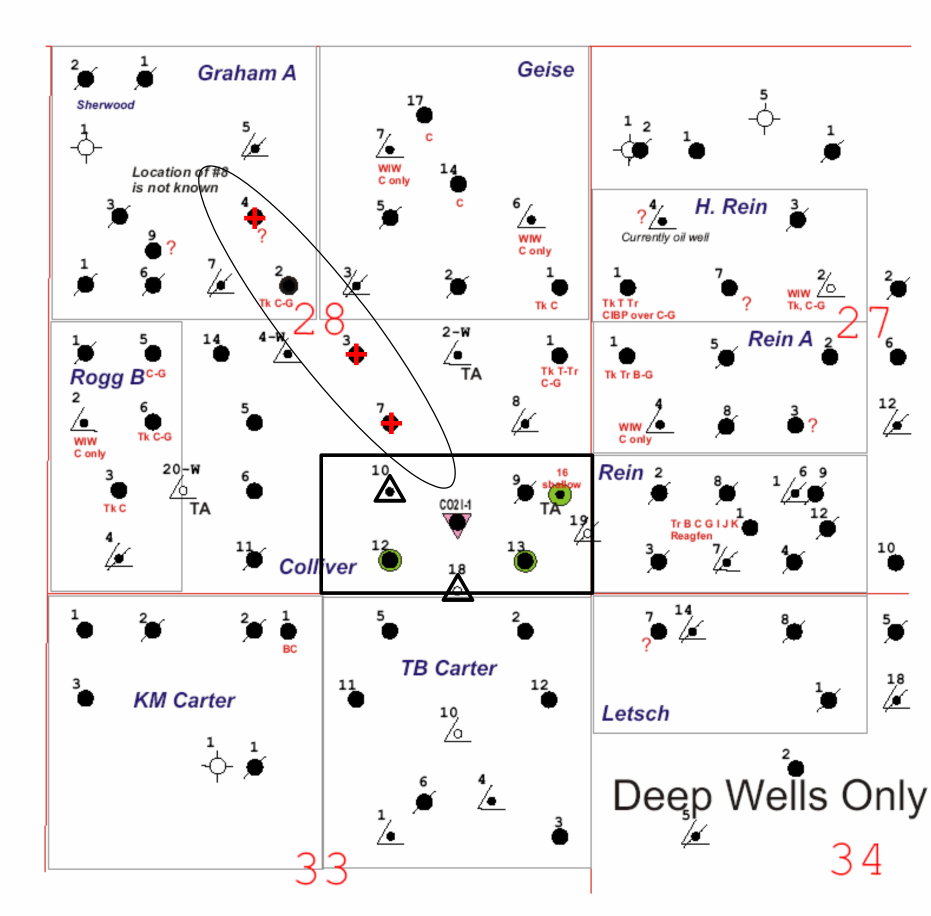


Figure 5.4.25: Map showing location of wells completed in the Lansing-Kansas C zone in the area of the CO2 pilot. The elliptical region includes wells marked with a + that appear to have produced oil displaced from the CO2 pilot area.

The discovery of increased oil production from the Graham A lease in August 2006 with no other activity in the area appeared to indicate that oil mobilized by carbon dioxide injection on the CO2 pilot lease was displaced to Graham A4. Monthly oil sales from the Graham A lease are shown in Figure 5.4.26. Based on monthly production, we estimate about 1000 bbl of incremental oil were produced from April through September. There is no evidence of carbon dioxide breakthrough in this well. The solubility of carbon dioxide in oil and water is so large that it is unlikely that much CO2 will show up as a flowing phase at any location some distance from the pilot region.

On August 28, 2006 the packer was released from Colliver #7 and oil production increased substantially from the Colliver A lease. Increased oil production is further evidence that that oil displaced by carbon dioxide injection moved off lease in a Northwesterly trend from the CO2 pilot region. The CIBP in Colliver A#3 was knocked out and the well was placed on production on October 11, 2006. Figure 5.4.27, shows the Colliver A production data. Colliver #3 production declined to 1 B/D by December 2006. Incremental oil production on the Colliver A Lease appears to be coming from Colliver #7. The elliptical shape on Figure 5.4.25 suggests a preferential permeability trend from the northwest toward CO2 I-1.

Bottom hole pressures in CO2 I-1 and CO2#10 were maintained well above the minimum miscibility pressure to enhance the capability of the remaining carbon dioxide to displace oil. Production of CO2, primarily from CO2#12 is on the order of 5-6% of the injected CO2. About 95% of the carbon dioxide remained in the reservoir. We believe that the CO2 mobilized oil as it was displaced by the injected water. Some carbon dioxide was trapped as a residual saturation.

Demonstrating that Incremental Oil is Attributable to CO2 Injection

An issue raised at this time was to demonstrate that incremental oil from Graham A and Colliver A leases was from CO2 injection as opposed to water injection. These leases were waterflooded extensively from the mid 1960's to 1987. A CIBP was installed above the LKC interval in Colliver A7 in 1989. Colliver Lease production in 1988 was 32.7 BOPD from 7 wells with 50% allocated to ***C zone***, so at most 2.3 B/D might be attributed to ***C zone*** production from Colliver A7 without the carbon dioxide flood.

Another approach to identify carbon dioxide displaced oil was to analyze carbon dioxide produced from each well to determine if the carbon dioxide originated from the EPCO plant. Carbon dioxide contains two stable carbon isotopes, C-12 and C-13. Carbon dioxide generated by ethanol production has a different ratio of C-12 to C-13 than carbon found in fossil fuels. Analysis of isotope concentrations was done on surrounding wells, but results were inconclusive.

Timing of Oil Production Response

Our reservoir model does not predict the oil production rates corresponding to field results. This was important for economic analysis and consideration of application of carbon dioxide flooding to the Hall Gurney Field in a commercial scale. Although the initial response to carbon dioxide injection resulted in an increase in oil production from 0 B/D to ~3 B/D, an oil bank has never arrived at CO2#13. The arrival of an oil bank at CO2#12 probably occurred in April or May 2006, coinciding with pump difficulties. Arrival may have been sooner if pump problems had not occurred. In addition, the increase in oil rate was less than predicted from our reservoir models.

The increase in oil production on the Graham A lease occurred in April 2006, about 850 days after the beginning of carbon dioxide injection into CO2 I-1. The common arrival time of an increase in oil production in both the pilot and the Graham A lease was probably coincidental. However, the arrival time does help estimate the velocity of the oil bank. Well Graham A4 is located about 3570 feet from CO2 I-1. An oil bank flowing through a thin high permeability streak at the top of the LKC ***C*** would need to have an average frontal velocity of 4.2 ft/D from CO2 I-1 to reach Graham A4. As discussed earlier, the bottom hole pressure in CO2#10 decreased about 350 psi in July, 2005, enhancing fluid flow from the pattern to the north.

Colliver A7 is about 1190 feet from CO2 I-1. At a frontal velocity of 4.2 ft/D, the oil bank that arrived at Graham A4 in April 2006 would have passed in the vicinity of Colliver A7 about 283 days after the beginning of injection or ~ September 9, 2004. It appears that the oil production response would have been substantially earlier if Colliver A7 was part of the pilot project. This well was excluded from consideration in the pilot region because of a suspected connection to the G zone (later shown to be incorrect) and the high productive capacity of this well.

It is evident from the field response that reservoir heterogeneity dominates the response of the pilot pattern to CO2 injection. There is clearly a SE-NW permeability trend that was not properly described in our reservoir model. The continuity between CO2 I-1 and CO2#13 must be less than what is currently in the model. Remediation of CO2#18 permitted maintenance of more uniform injection rates and pressures at the south end of the CO2 pilot. This was done to enhance the productivity of CO2#12. Increase in BHP in CO2#18 caused the fluid level in Carter 2 to increase.

Disposal of produced water began in November 2006 in Carter #4. However, the increase in fluid level in Carter #2 began well before disposal of water resumed on the Carter Lease after being discontinued for several months. There has been no effect of CO2#18 on the productivity of either CO2#12 or CO2#13 as of the end of December. This is further evidence that CO2 #13 is poorly connected to the pilot region. Colliver A1 is located 2113 feet NE of CO2 I-1. There has been no production response in this well.

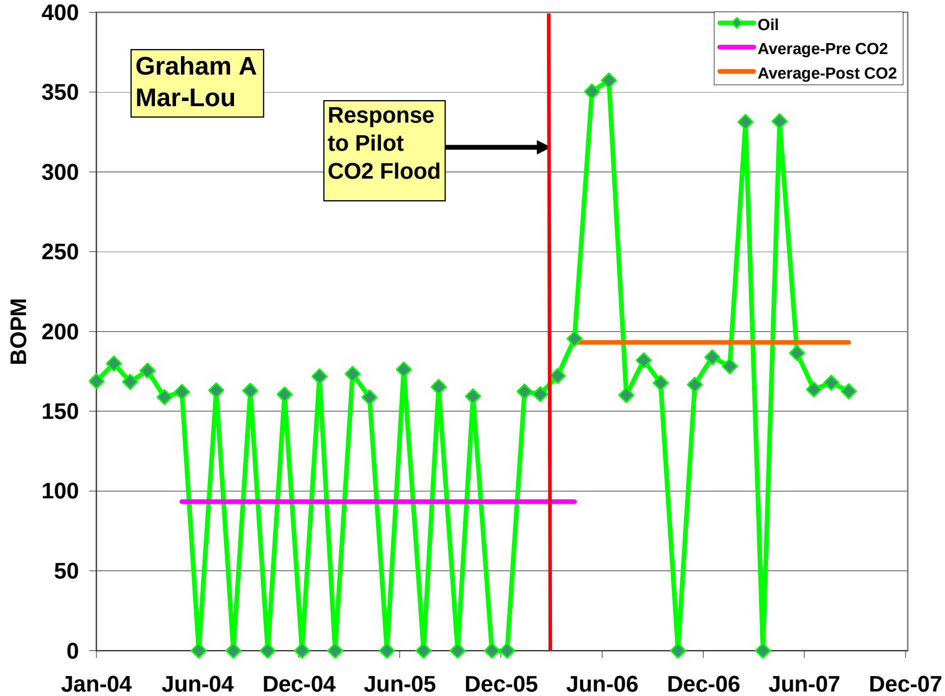


Figure 5.4.26: Monthly oil sales from the Graham A lease

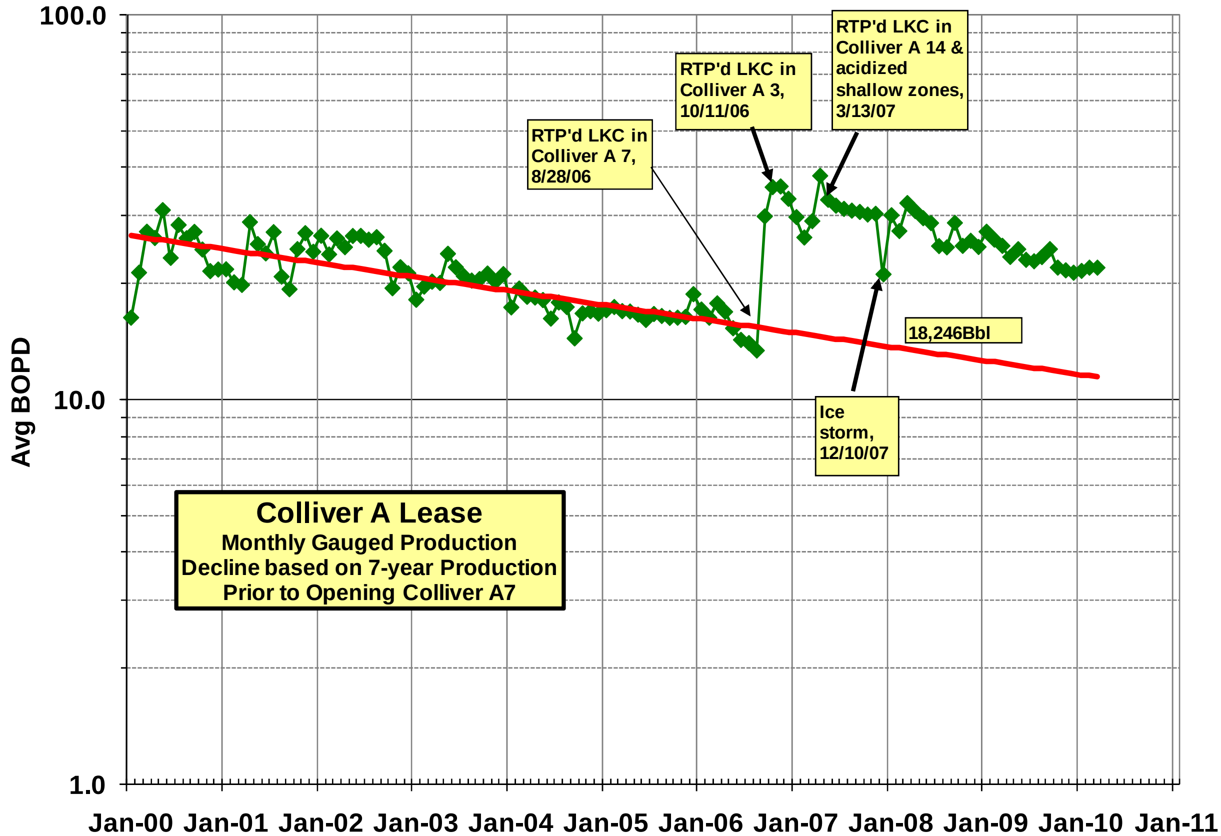


Figure 5.4.27: Colliver A lease production after C zone was opened in Colliver A #7, Colliver A3 and Colliver A14.

Figure 5.4.28 shows the carbon dioxide concentration in the casing gas from shortly after the LKC "C" zone was opened in the well. Carbon dioxide concentration rose steadily from 1% in September 2006 to 11.1% in December 2008 before decreasing to 3% in July 2009.

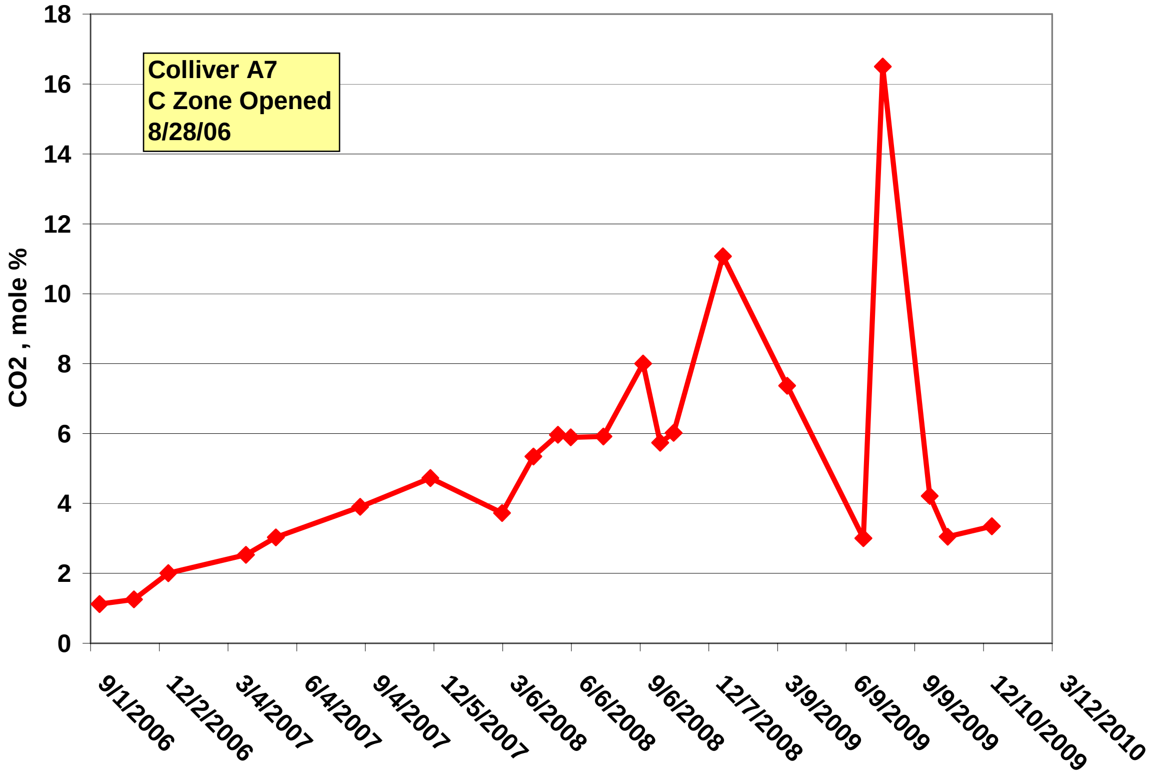


Figure 5.4.28: Carbon dioxide concentration in casing gas from Colliver A7

Carbon dioxide concentration spiked at 16.4%in August 2009 but has decreased to about 3.6% by December 2009. There has been no increase in carbon dioxide concentrations in casing gas from Colliver A3 and Colliver A14. The amount of carbon dioxide produced from the Colliver A wells is negligible.

The carbon dioxide concentration in the casing gas from Colliver A7, the principal well producing incremental oil on the Colliver A lease , decreased from 11.1% at the end of December 2008 to ~3.6% in December 2009 . This suggests that oil mobilized by carbon dioxide injected into the CO2 Pilot Pattern and produced on the Colliver A Lease will continue to decline. Incremental production from the Colliver A Lease during the past fifteen months is on a well established decline which is expected.

The project was designed assuming that 30% of the CO2 would leave the pilot area. In the early stages of this project, there was speculation that substantial quantities of carbon dioxide were leaving the north side of the project area, moving toward Colliver A #1. This well was pumped off prior to the beginning of the CO2 project and continues to be pumped off. There is no evidence of incremental oil production from this well. Samples of gas from the casing annulus in this well have been analyzed since mid November 2006. Figure 5.4.29 shows the concentration of carbon dioxide at several points in time. The high concentration of CO2 in the first sample appeared to be anomalous as subsequent samples had low concentrations. Recent samples show increasing levels of carbon dioxide in casing gas which may indicate that oil or water containing dissolved carbon dioxide is reaching Colliver A1. Colliver A1 produces from multiple zones including Topeka, Toronto, Tarkio and the Lansing Kansas City C-G intervals.

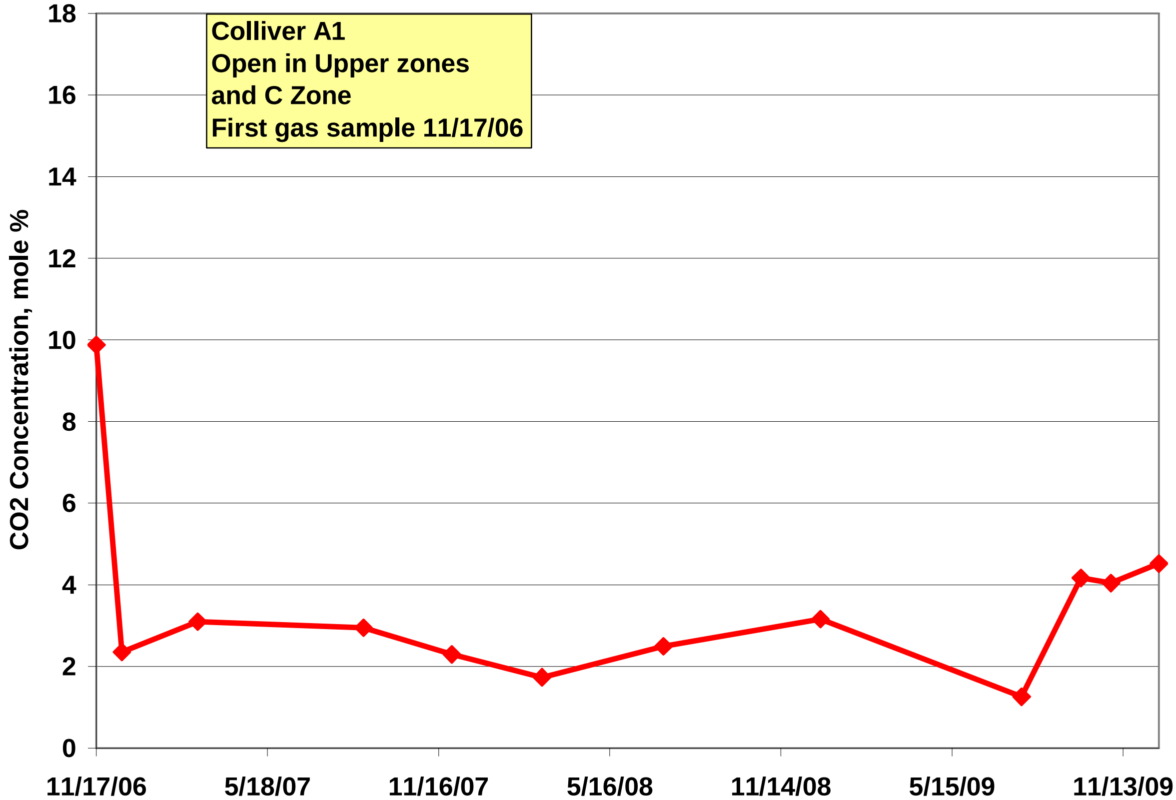


Figure 5.4.29: Carbon dioxide concentration in casing gas from Colliver A1

Table 5.4.2 contains an estimate of incremental oil from CO_2 injection through March 7, 2010. Total incremental oil attributed to the CO_2 project is 27,902 bbl. No additional incremental oil from the Graham A lease was added to the total after October 2006. There is a well established production decline on the Colliver A Lease and substantial additional incremental production should occur before rates decline to the red line indicating the estimated decline rate prior to opening Colliver A wells to the C zone.

By March 7, 2010, the gross CO_2/oil ratio was 4.8 MCF/bbl which is comparable to values observed in large scale West Texas carbon dioxide floods. This demonstrates that carbon dioxide mobilized oil in the LKC ***C*** zone, a key objective of the pilot project.

Table 5.4.2: Estimated Incremental Oil from CO_2 Injection into LKC ***C***

Date	CO2 Pilot	Colliver A Lease	Graham A Lease	Total BBL	MCF/BBL
3/7/2010	8,736	18,246	920	27,902	4.8

5.5 Revision of Reservoir Description(W. Lynn Watney, Kansas Geological Survey)

Overview

The geologic model used to simulate CO_2 injection into the C Zone (Plattsburg Limestone) reservoir at Hall-Gurney is being refined. New information acquired since the original modeling including acquisition of seismic data provided an opportunity to modify the original geologic model. Also recent work on a Modern analog for ooid shoals from the Bahama Platform was applied to this ancient oolitic limestone reservoir to help understand reservoir geometries that obtained in remapping the pilot project area. Finally, incremental oil recovered from CO_2 injection has moved off pattern, northwest of the injector and has further warranted revising the geologic model. The revised geologic model will be used in the reservoir simulator. The revision of the geomodel and re-simulation are important for future considerations and planning for CO_2-IOR in Kansas and other mature producing areas like Kansas.

Latest Seismic Interpretation Suggest Reservoir Compartmentalization and Lineaments

The 4D seismic survey in the CO_2 pilot area identified distinct and separate areas of seismic reflection character, quantitatively defined here as seismic facies similarity (Figure 5.5.1A). A number of properties comprising seismic facies are statistical analyzed to create this map of seismic facies similarity (Raef et al., 2005; Raef et al., 2007). Areas of homogeneous seismic facies, depicted by various shades of blue and outlined by the addition of thin black lines, suggest continuity of reservoir properties including those that may be related to fluid storage or flow.

Well logs and cuttings were reexamined to refine the lithofacies and stratigraphy. Latest ideas ooid shoal composition and geometries were incorporated into new maps and cross sections of the C Zone (Plattsburg Limestone) reservoir. This information was subsequently compared with the new seismic data. The results of this examination lead to identifying possible reservoir compartments in the vicinity of the CO_2 pilot project. Three temporally-distinct ooid shoals are recognized, labeled in Figure 5.5.1A as Shoal #1, Shoal #2, and Shoal #3. These separate shoals became the basis to refine the geologic model as described in the next section.

A map of the seismic maximum curvature attribute is shown in Figure 5.5.1B that indicates linear areas of abrupt change in elevation of a seismic reflection horizon near the top of the ooid shoal reservoir. The discontinuous lineaments denoted by red and black areas show a preferred orientation of northeast-southwest with less continuous, but abundant northwest-trending lineaments. Superimposed are thin black lines outlining the seismic facies similarity also in Figure 5.5.1A.

The CO_2 #1 well is located as a white dot on the curvature map (Figure 5.5.1B) and is located in a concentration of lineaments, mainly trending northeasterly. As a potential indicator of fractures this attribute may indicate conduits for CO_2 migration. However, fractures tend to be open or closed in orthogonal directions, one direction open (usually parallel to maximum compressive stress) and the other direction closed, perpendicular to maximum compressive stress. Fracture apertures can be partially cemented to keep fractures open or fracture porosity can be lost due to cementation so there is no fast rule outside of understanding local conditions. Furthermore, local structure can influence stress field and affect orientation of fractures and aperture widths. For example, in an analysis of seismic coherency and production data at Dickman Field in Ness County, Kansas, northwest-trending fractures are open and positively affect production (Nissen et al., 2006). This latter result is not consistent with a regional maximum compressive stress direction that trends northeast-southwest (World Stress Map, 2005).

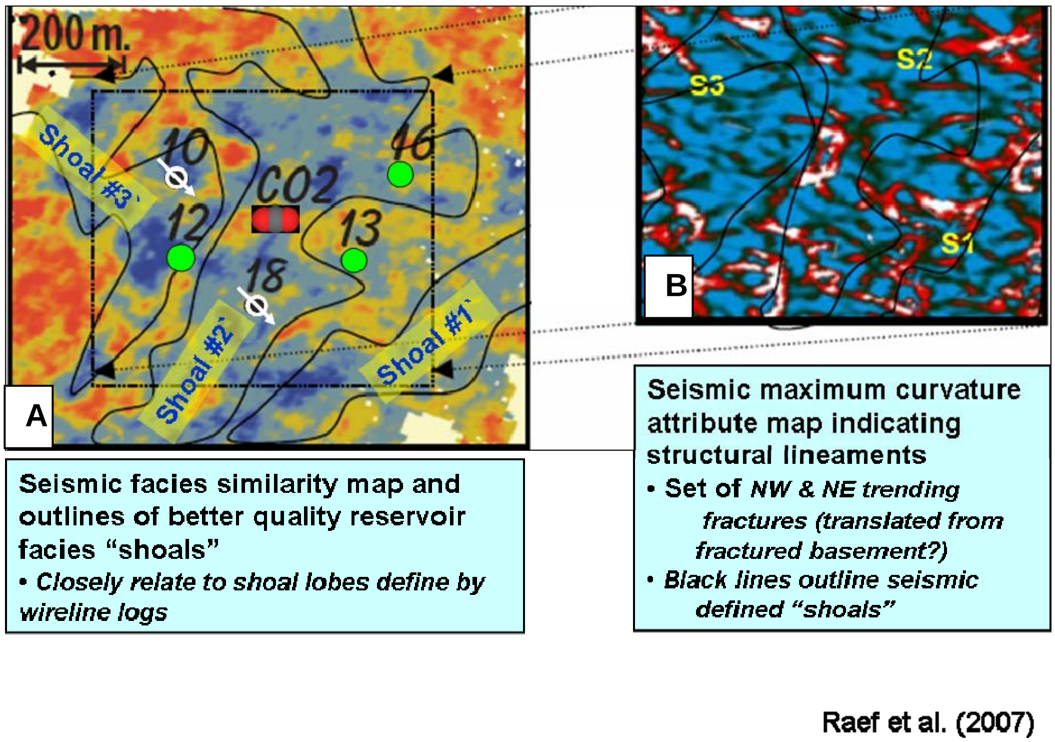
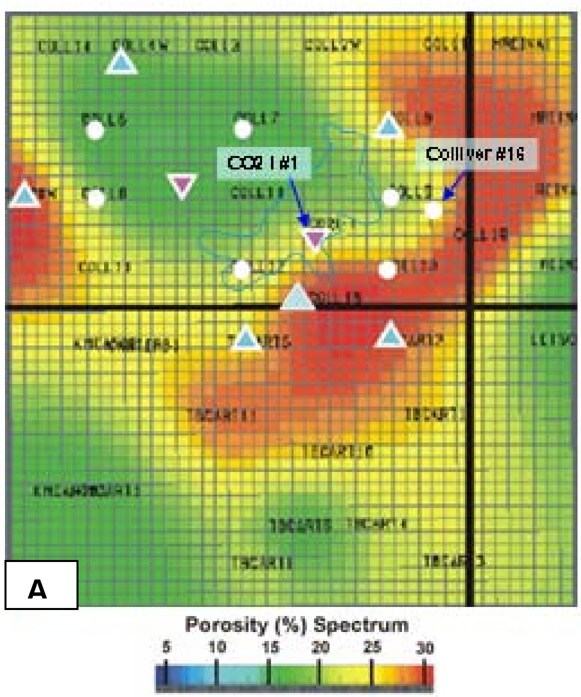


Figure 5.5.1. Seismic facies similarity map (A) on left and seismic maximum curvature attribute map on right (B)

New Geologic Information

Analysis of cuttings and wireline logs in the vicinity of the CO2 injection well were used to refine the interpretation of the geologic reservoir model. A map of average porosity in Layer #2 of the original six layer geologic reservoir model shows a strong northeast-southwest trend of higher porosity (Figure 5.5.2A). Layer #2 is the most porous of the six layers and is located at the top of the reservoir interval and presumably where the CO2 would move most readily to mobilize oil (Figure 5.5.2B). Overlain on the porosity map of Layer #2 is an outline of the CO2 plume inferred from seismic measurements in 2005 delineated by a light blue line. The trend of the CO2 plume at this time was parallel to the high porosity zone of Layer #2.

Re-evaluation of core from the CO2 #1 and Colliver #16 and wireline logs and cuttings from wells in the vicinity of the CO2 #1 well led to a revision of the primary ooid shoal geometry based on an approach patterned from current studies of Modern Bahamian ooid shoals (Rankey et al., 2006). The better sorted areas of the ooid shoals tend to be located on the crests of Modern tidally-dominated ooid bars including elongate tidal ridges and lobate bars related to incoming or outgoing tides. Petrologic and petrophysical analysis of the oomoldic reservoirs including the "C" Zone indicates that that the highest permeability appears to be located in better sorted oomolds reflecting the original hydrodynamics during deposition. The rationale is that the better sorting leads to more efficient grain contact. Then when ooids are dissolved, the dissolution is more complete in areas of better sorting. Later cements then occlude some of this pore space. Permeability tends to be best near the top of the reservoir, apparently in proximity to the subaerial exposure surface that typifies many Pennsylvanian and Permian carbonate reservoirs including the "C" zone/Plattsburg Ls. at Hall-Gurney Field.



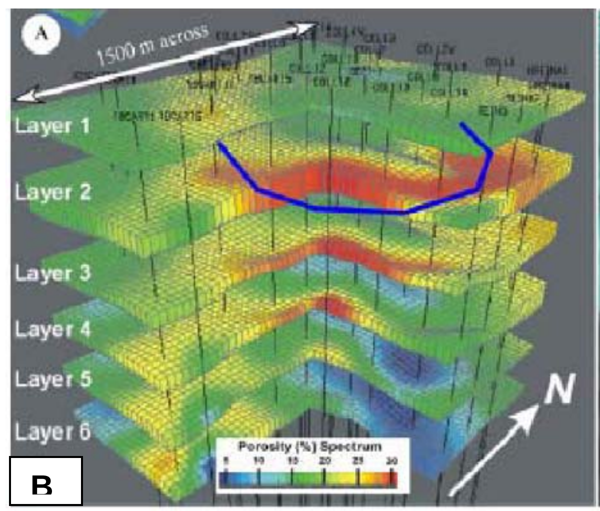


Figure 5.5.2. A. Average porosity for Layer #2 of the original six-layer geologic model shown in Figure 5.5.2 B. B. The six-layer geologic model illustrates average porosity of each layer.

Figure 5.5.3 illustrates the gamma ray, permeability, and porosity profiles obtained from core and wireline logs for the Colliver #16. The high permeability zones are located in thin (several feet thick) intervals at the tops of layer #2 and #4. Each of the more permeable beds exhibit better sorting of the ooid grainstone (now oomolds). Besides better sorting the more permeable beds have lower gamma ray (cleaner carbonate) representing cleaner carbonate that appears to typify the better sorted porous oomoldic lithofacies.

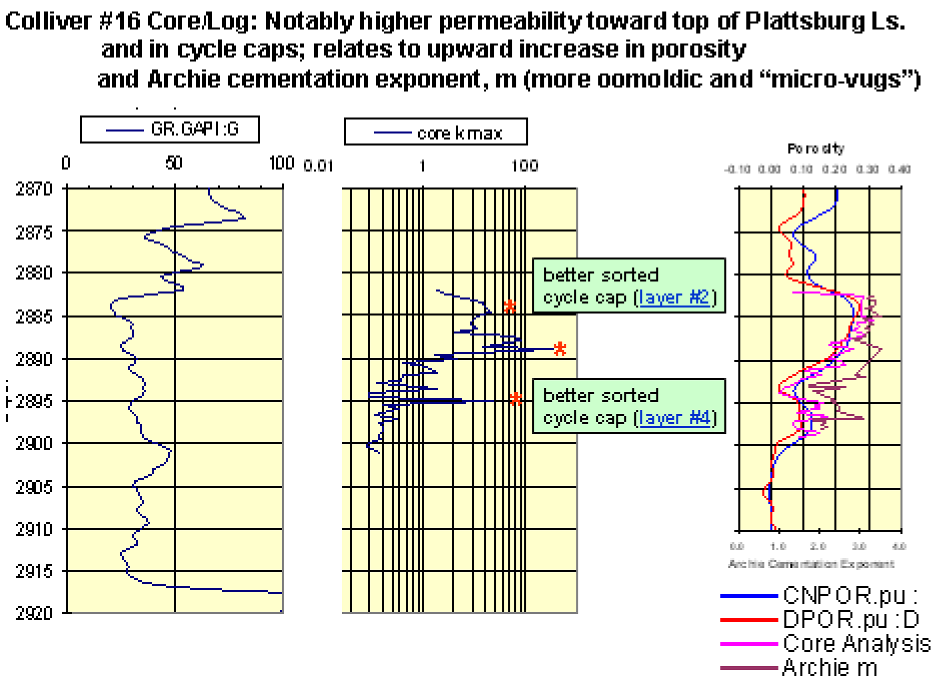


Figure 5.5.3. Depth profile of the "C" zone showing gamma ray, maximum permeability, and Archie cementation exponent, m, compared to various measures of porosity. Note that m increases upward from around 2 to near 3.5. Higher m indicates more tortuous paths for fluid to move as m increases.

A cross plot of the permeability vs. gamma ray in the Colliver #16 well indicates that samples with permeability in excess of 10 md also have natural gamma ray below 30 API. The porosity-gamma ray cross plot also indicates that highly porous oomoldic rocks with intermediate gamma ray values (>30 and <40 API) have a significant range in permeability (0.1 to 100 md, but generally less than 10 md).

Estimating permeability from a porosity-permeability cross plot is fraught with uncertainty due orders of magnitude variation in permeability at a given porosity value. Also, lack of core analyses further limit correlations. Thus, delineation of intervals of both high porosity and low gamma ray appears to be important in estimating whether the interval is sufficiently permeable.

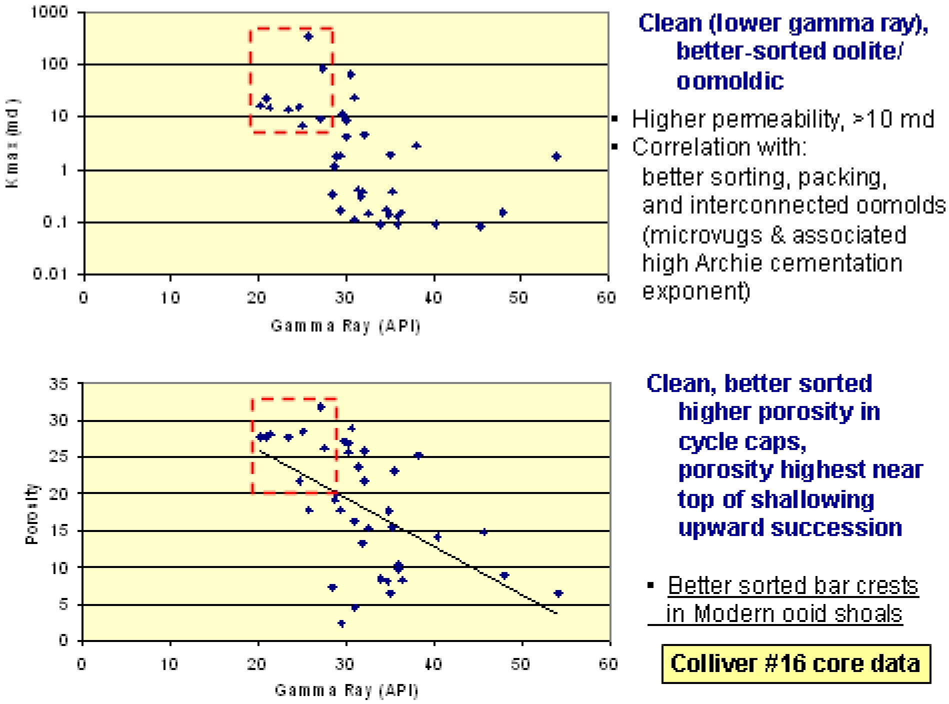


Figure 5.5.4. Cross plots of porosity and permeability vs. gamma ray for analyzed core taken from "C" zone/Plattsburg Limestone in Colliver #16.

An isopachous map of net thickness of porous interval in Layer #2 with low gamma ray shows clear northeast-southwest and northwest-southeast orientations (Figure 5.5.5). The CO2 injection well, CO2 #1 is located in the northeast-trending segment. The initial CO2 plume (imaged in early 2005) defined by 4D seismic (dark blue lined area around CO2 #1) conforms closely with the area of thick low gamma ray in layer #2. The general pattern of this map resembles the porosity map in layer #2 (Figure 5.5.2B), but departs in detail.

The lime green lines on this map are lineaments drawn manually from the current day structure as shown in Figure 5.5.6, corresponding to dominant ridges and their edges along a gently northwesterly plunging anticline. These lineaments closely correspond to the trend and locations of low gamma ray. Correspondence of low gamma ray (better sorted) portions of the oolitic grainstone reservoir with current structure suggests that paleotopography may have been associated with contemporaneous structural deformation along trends paralleling current structure (Watney et al., 2008). Underlying paleotopography in Modern ooid shoals (created by Pleistocene islands and shoals) is very important in channeling ocean currents that led to formation of the ooid shoals.

The maps also include the location of wells currently producing incremental oil northwest of CO2 #1. This apparent response from CO2 injection falls outside of the low gamma ray areas including wells with marginal porosity and extends well beyond the confines of the initial CO2 plume that was seismically imaged. While perplexing, additional factors are also contributing to the movement of the CO2 beyond what was seismically imaged and initially modeled. These additional factors should be considered in a revised geologic model.

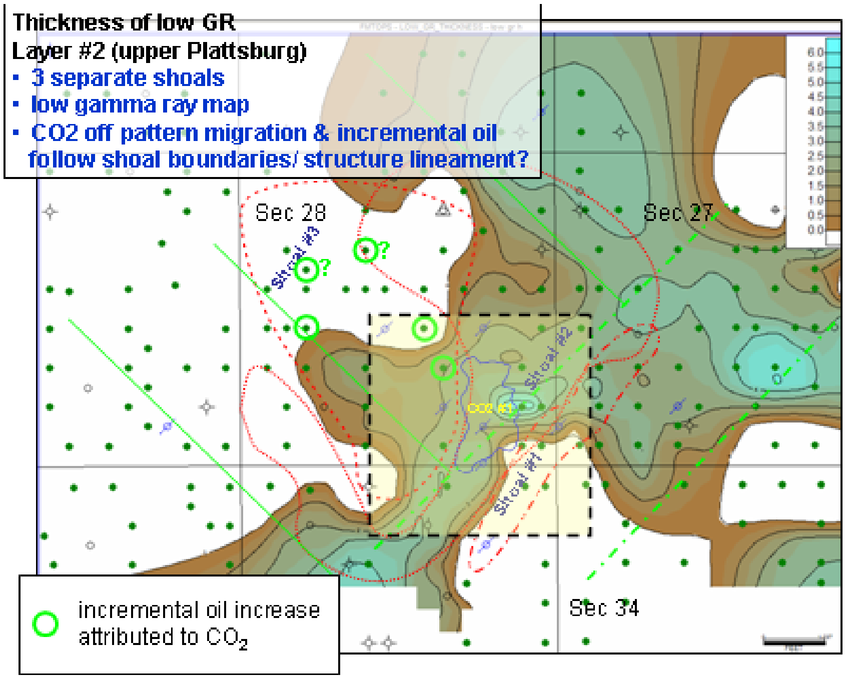


Figure 5.5.5. Thickness of low gamma ray in Layer #2 of the "C" zone/Plattsburg Limestone. Black lines delimit squares, one mile on a side.

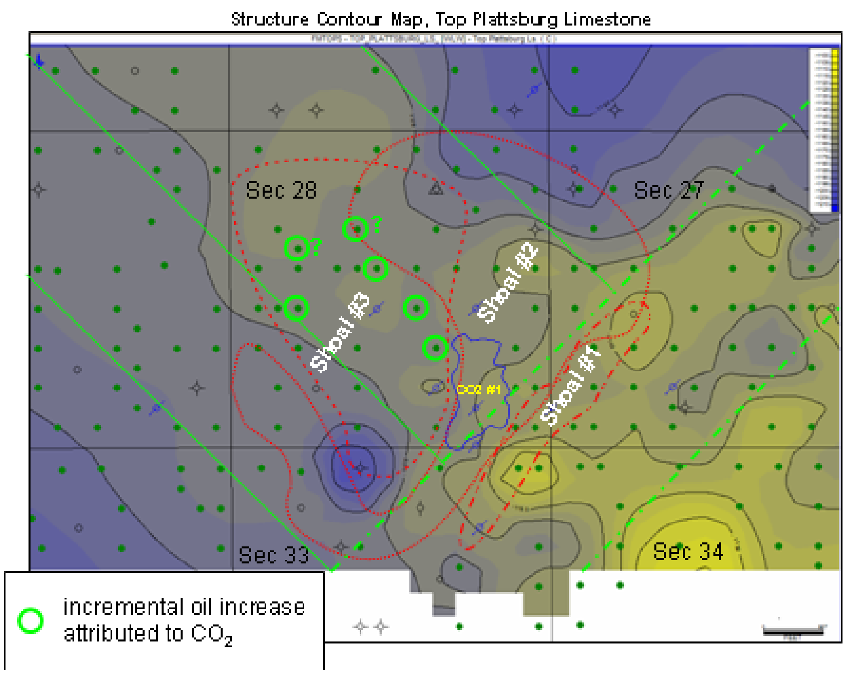


Figure 5.5.6. Structure contour map of the top of the Plattsburg Limestone.

Individual ooid shoals in the Modern environment are often imbedded within a shoal complex, developed in response to an equilibrium hydrodynamic configuration. In spite of frequent storms and hurricanes, the basic distribution of Modern shoals is maintained that conforms to day-to-day processes such as tides and trade winds (Rankey et al., 2006). The controls on the shoals include pre-existing topography, sea level, landward-basinward orientation, and prevailing wind direction. In ancient rocks, the delineation of individual shoals is difficult especially in the subsurface outside of generally locating the complex of shoals when present. To add to the complexity, meter-scale thick high-frequency cycles typify Pennsylvanian carbonate reservoirs, believed to reflect temporally distinct variations in sea level. Each sea level stand will likely invoke a different response as to location and type of ooid shoal that is deposited.

A preliminary methodology was developed to discriminate between separate shoals of oolite in the vicinity of the CO2 #1 injection well in an attempt to examine their possible role in reservoir compartmentalization. The approach taken was to establish the elevation of the base of the oolitic strata comprising the "C" Zone with respect to the elevation of the base of the "C" Zone carbonate. The base of the "C" is the subtidal, low energy portion of the cycle. This lowermost subtidal carbonate interval accumulated slowly in deeper water, so effectively, it was a blanket deposit. The ooid shoal was deposited during a lower stand in sea level, since ooid shoals are formed at depths under a couple of meters. It is probable that the lower the elevation of the base of the porous oolitic strata, a distinctive contact on wireline logs, the earlier the formation of the ooid shoal. This may reflect a site with higher elevation (paleotopographically higher and shallower) or in closer proximity to focused currents and waves needed in the formation of oolite.

When abrupt changes are noted in the relative elevation of the base of the shoal to the base of the underlying subtidal limestone between adjoining wells, the wells may be part of different bar/shoals of oolite. Alternatively, when the relative base of the oolite stays the same or slowly changes between wells, these wells may be part of the same ooid shoal. Shoals forming at distinctly different times would have contrasting elevation of their lower stratigraphic contact relative to the base of the subtidal carbonate.

As we have seen elsewhere in Kansas' Pennsylvanian oolites, subsequent sea levels can place ooid shoals in juxtaposition, i.e., a shoal of oolite building upward or laterally from an older shoal/shoal (French and Watney, 1993) or filling in the space between exiting shoals if the later sea level is lower.

Applying the relative elevation of the base of the oolite to delineate the ooid shoals was substantiated by describing sample cuttings of wells in each of the presumably separate shoals. In the Modern, besides the decline in sorting of ooids with distance from shoal crest, the ooids also contain increasing skeletal grains and micrite mud when energy has significantly declined. In the ancient record, temporally distinct ooid shoals in a complex may have characteristic and contrasting compositions that might reflect variations in climate conditions, energy level, or water circulation. These changes might be detected in the well cuttings to substantiate the interpretations from well logs.

The result of comparing the log correlations and cuttings appear to be consistent in resolving three separate oolite shoals in the area of the CO2 pilot as identified as light red dotted and dashed lines on the maps of the low gamma ray in the porous layer #2 and the top of the Plattsburg Limestone (Figures 5.5.5 and 5.5.6). Two cross sections follow (Figures 5.5.7 and 5.5.8), using the low gamma ray map as an index map, to illustrate the nature of the lateral boundaries of the oolite shoals defined by abrupt changes in elevation of the base of the oolite shoal, distinctly different shapes in of the well profiles, and contrasting composition of grains and oolite content based on sample cuttings.

The red dashed and dotted lines define separate ooid shoals. The green circles define wells that have responded to CO_2 flooding with incremental oil recovered (Willhite, 2008). These wells all are inside the shoal #3 lying northwest of the CO_2 injection well. The quality of the reservoir in shoal #3 is not as good as in shoal #2, the latter with overall lower gamma ray. The boundaries of shoal #3 appear to serve as barriers to flow.

It appears that shoal #3 and #1 began earlier that shoal #2 based on their lower elevations with respect to the base of the subtidal interval. Shoal #3 is at the structurally lowest position but is still along the regional structural saddle within this large field. Shoal #3 is also more poorly sorted as suggested by cuttings, but still has thin intervals of clean (low gamma ray) that are porous, that could be the preferred conduits for the injected CO_2 and the resulting oil bank.

The injection well is in shoal #2, while the oil recovery is all located in shoal #3. The initial CO_2 plume as imaged seismically is all within shoal #2, so that some other factor such as structure may have contributed to directing the CO_2 to eventually cross between shoal #2 into shoal #3. Fracturing may have allowed the CO_2 to breach the shoal boundaries that initially limited the flow of CO_2. This may be been a matter of reaching adequate parting pressure of existing fractures. The general linear nature of the wells with incremental oil recovery may indicate a fracture contribution to the overall flow and recovery direction. Additionally, a preferred lineament direction based on the structure map is northwest-trending paralleling the general direction of this oil recovery.

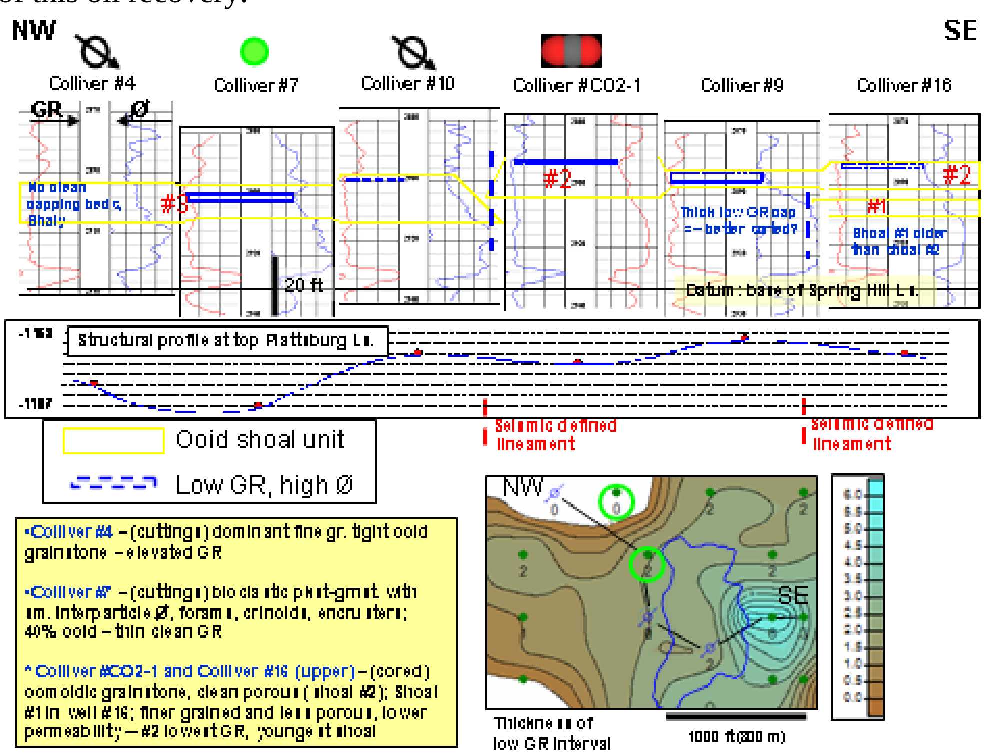


Figure 5.5.7. Northwest-southeast stratigraphic cross section crossing the CO2 #1 well that delineates three shoals #1, #2, and #3 (light yellow lines). The higher porosity and low gamma ray

are outlined on the logs by blue bars. The sample descriptions are highlighted in the yellow box. A structural profile is shown in the middle of the graphic.

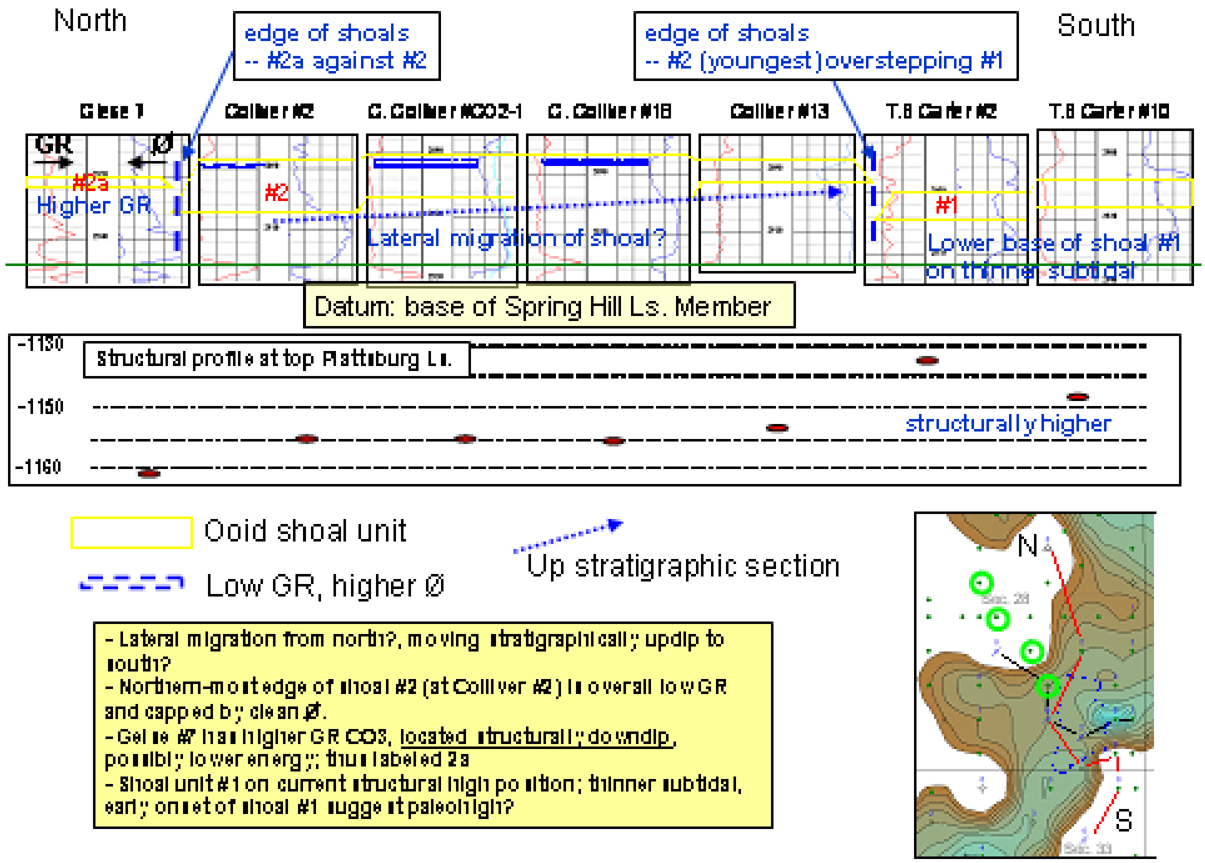


Figure 5.5.8. North-south stratigraphic cross section crossing the CO2 #1 well that delineates three shoals #1, #2, and #3 (light yellow lines). The higher porosity and low gamma ray are outlined on the logs by blue bars. The sample descriptions are highlighted in the yellow box. A structural profile is shown in the middle of the graphic.

Revised Geological Model(Continuation of Phase 2)

A revised geologic model of the “C” Zone (Plattsburg Limestone) reservoir was developed for reservoir simulation using the methodologies described above. The delineation of permeability reflected new mapping of high permeable zones based on correlation of low gamma ray porous intervals primarily in layer #2 of the reservoir. Also, addition of permeability anisotropy was considered with a biased higher permeable northwesterly trend representing possible open fractures that are suggested by the pattern of wells experiencing incremental oil recovery in shoal #3. These wells are located on the western (northwest-trending) ridge extension of the mapped structure (Figure 5.5.6). It might also be the case that northeast-trending fractures are more sealing since incremental oil has not been observed east of the CO2 injector. These observations are consistent with interpretations by Nissen et al. (2006) in Dickman Field (one fracture direction open and the other closed). Introducing directional permeability was recommended by Willhite (2008) based on fluid production history of the project and this analysis supports that

conclusion. It may also be necessary to refine this model as considerations are taken for pore volume actually swept by the CO2 and recovered as incremental oil.
The improved simulation model was not able to match the production from the CO2 project. The reservoir geology is more complex than can be understood from the limited data available.

TASK 6.1: COLLECTION AND ANALYSIS OF POST-CO2 FLOOD MONITORING

Injection of carbon dioxide was completed in June 2005. As discussed earlier, carbon dioxide injection was continuous from December 2003 to June 2005. Thereafter, water was injected into CO2I-1. The pilot area was monitored until March 7, 2010 when the DOE program was completed. Summaries of field data are available in Semi Annual Reports submitted to the USDOE. These reports and the analysis are available on the CO2 project website which can be accessed using the following URL: : http://www.kgs.ku.edu/CO2/index.html .

TASK 7.0: PROJECT MANAGEMENT

The project was managed by a team of project participants which changed as the project developed. Details on project management including meetings and participants are described in Quarterly and Semi Annual Reports. A communication network was established between participants with an active involvement in the project. Primary participants were the Kansas Geological Survey, Tertiary Oil Recovery Project, Murfin Drilling Co. LLC, Kinder Morgan CO2 LLP and the US DOE. Day to day operation of the project and field implementation was done by Murfin Drilling Co personnel. Murfin field personnel were excellent and played an important role in operating the project.

Daily injection and production data were recorded on Excel spreadsheets and distributed to key participants. Data were analyzed and discussed via email and telephone conversations. Mr. Bill Flanders, Transpetco, representing Kinder Morgan, provided guidance on project management based on extensive experience in operation of West Texas carbon dioxide floods. Meetings were scheduled as needed for development of the project and decision making.

TASK 8.0 TECHNOLOGY TRANSFER AND REPORTING REQUIREMENTS

Quarterly and Semi-Annual Progress reports were submitted to USDOE and are available through the USDOE report system : http://www.osti.gov/bridge/. Reports and all presentations are available through the website: http://www.kgs.ku.edu/CO2/index.html .

CONCLUSIONS

- We demonstrated that a CO2 miscible flood can be operated by a Kansas operator as a normal oil field operation with adjustment for the characteristics of carbon dioxide. Field experience developed the confidence that a larger scale project could be operated with proper personnel.
- Operating cost data were obtained which are appropriate for scaling to a larger project.
- Residual oil was mobilized by carbon dioxide injection but proved difficult to capture in pilot wells.

- Substantial oil mobilized by carbon dioxide was produced from leases to the northwest of the pilot area.
- Oil recovery attributed to carbon dioxide injection was estimated to be 27,902 BBL by March 7,2010.
- Gross CO2/Oil ratio is estimated to be 4.8 MCF/BBL, which is equivalent to field performance in West Texas CO2 floods.
- About 95% of the injected carbon dioxide remained(131 MM SCF) in the reservoir when the project ended.
- Reservoir heterogeneities were identified from production data both on the pilot lease and from leases north and northwest of the pilot project that were not known prior to the operation of the pilot. These heterogeneities appear to be regional permeability trends which may be identifiable from 3D seismic and other geophysical data. This is an important development in evaluating how a large scale project should be planned. Due to reservoir heterogeneities, we could not determine the oil recovery from CO2 injection by only considering oil produced from wells within the pilot.
- The Lansing Kansas City interval in the Hall Gurney Field is more heterogeneous than originally believed.
- There is a pronounced directional permeability trend from NW to SE through the pilot area which is consistent with lineaments inferred from the magnetic field map of the field.
- Barriers to fluid flow exist vertically and laterally between ooid shoal deposits.
- A fully developed CO2 miscible flood is necessary to overcome the effects of reservoir heterogeneities known to exist.
- The pilot project was not economic

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