SEMI ANNUAL TECHNICAL PROGRESS REPORT
FOR THE PERIOD ENDING JUNE 30, 2005

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

DOE Program: Class II Revisited - Field Demonstrations

Award Date: March 8, 2000

Total Project Budget: $5,388,683

DOE Cost Amount: $1,892,094

Program Period: March 8, 2000 – March 7, 2010 (BP1 03/00-2/04, BP2 2/04-12/08, BP3 1/09-03/10)

Reporting Period: DOE January 1, 2005 – June 30, 2005

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DISCLAIMER:

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 two production wells on about 10 acre spacing. Continuous carbon dioxide injection began on December 2, 2003. By the end of June 2005, 16.19 MM lb of carbon dioxide were injected into the pilot area. Carbon dioxide injection rates averaged about 227 MCFD during the last six months of the project. Carbon dioxide is produced in both production wells. The GOR has remained within the range of 4000-5000 for most the last six months. Wells in the pilot area produced 100% water at the beginning of the flood. Oil production began in February 2004, increasing to an average of about 3.78 B/D for the six month period between January 1 and June 30, 2005. Cumulative oil production was 1494 bbls. Neither well has experienced increased oil production rates expected from the arrival of the oil bank generated by carbon dioxide injection. Injection was converted to water on June 21, 2005 to reduce operating costs to a breakeven level with the expectation that sufficient carbon dioxide has been injected to displace the oil bank to the production wells by water injection.

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INTRODUCTION

Objectives - The objective of this Class II Revisited project is 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, and operating costs and methods to aid operators in future floods. The project addresses the producibility problem that these Class II shallow-shelf carbonate reservoirs have been depleted by effective waterflooding leaving significant trapped oil reserves. The objective is to be 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 will characterize the reservoir geologic and engineering properties, model the flood using reservoir simulation, design and construct facilities and remediate existing wells, implement the planned flood, and monitor the flood process. The results of this project will be 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.

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:

Continuous injection of carbon dioxide into the Lansing Kansas City C formation in the Hall Gurney Field near Russell, Kansas began on December 2, 2003. 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 two production wells on about 10 acre spacing. Carbon dioxide is trucked from the ethanol plant operated by US Energy Partners by EPCO where it is unloaded into a portable storage tank on the lease. Carbon dioxide is injected as a compressed fluid using an injection skid provided by FLOCO2. By the end of June 2005, about 16.19 MM lbs of carbon dioxide were injected. The average rate of carbon dioxide injection for the past six months was about 227 MCFD. The initial production was 100% water with oil arriving in February 2004. Oil rates averaged 3.8 B/D from January –June 2005. Cumulative oil production was 1494 bbl. Incremental oil production was 1494 bbls. Neither production well has experienced increased oil production rates expected from the arrival of the oil bank. Volume of carbon dioxide produced has remained low with GORs on the order of 4000-5000. The amount of gas produced was 5.184 MMSCF which is 3.8% of the amount of carbon dioxide injected. Injection was converted to water on June 21, 2005 to reduce operating costs to a breakeven level with the expectation that sufficient carbon dioxide has been injected to displace the oil bank to the production wells by water injection.

RESULTS AND DISCUSSION:

Task 5.4 - IMPLEMENT CO2 FLOOD OPERATIONS

Figure 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 consists 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 is 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.

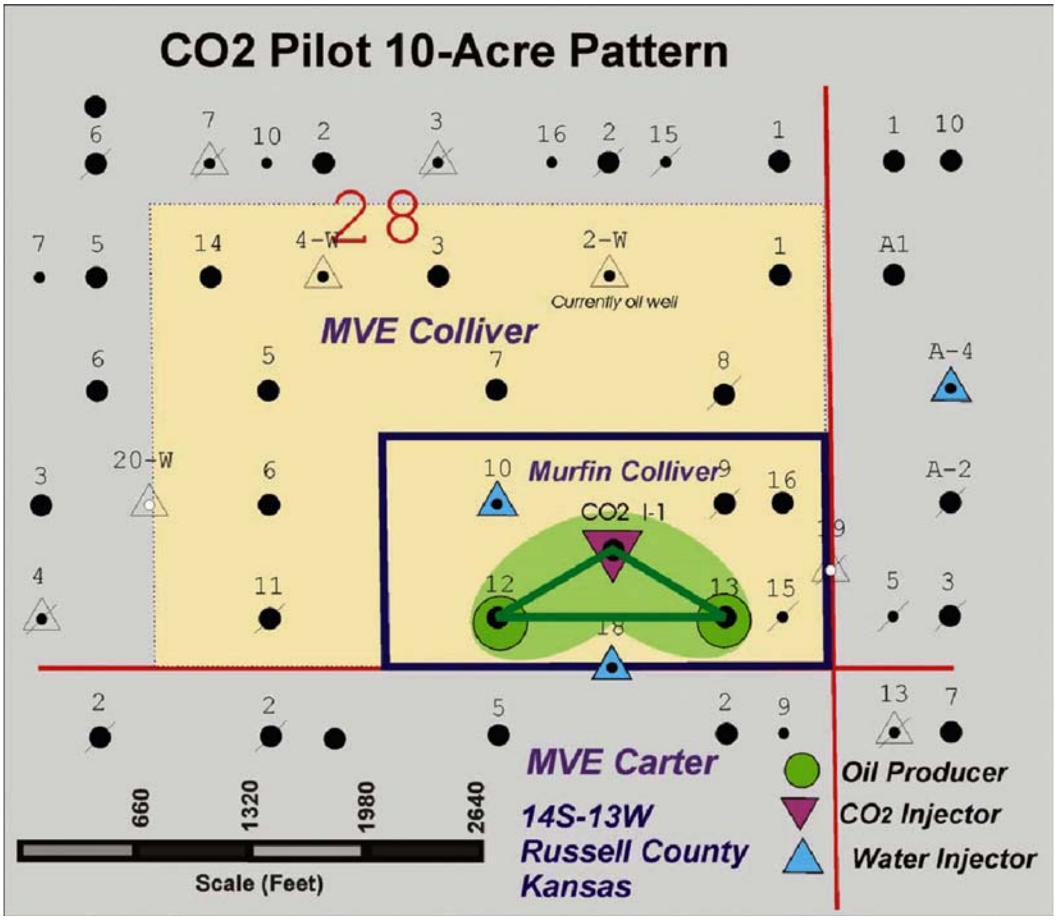


Figure 1: Murfin Colliver Lease in Russell County, Kansas

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 is stored in a 50-ton storage tank provided by FLOCO2. Figure 2 shows the storage tank, Corken charge pump and associated piping.

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 2. 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 has been 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 and were reported in the December 31, 2004 Semi Annual Report (1). Vent losses for the period from July 1, 2004-June 30, 2005 are shown in Figure 3. Vent loss averaged 6.0% for the past six months. Vent loss increased in May and June as hot weather returned to Central Kansas and injectivity in CO2I-1 appeared to decline.

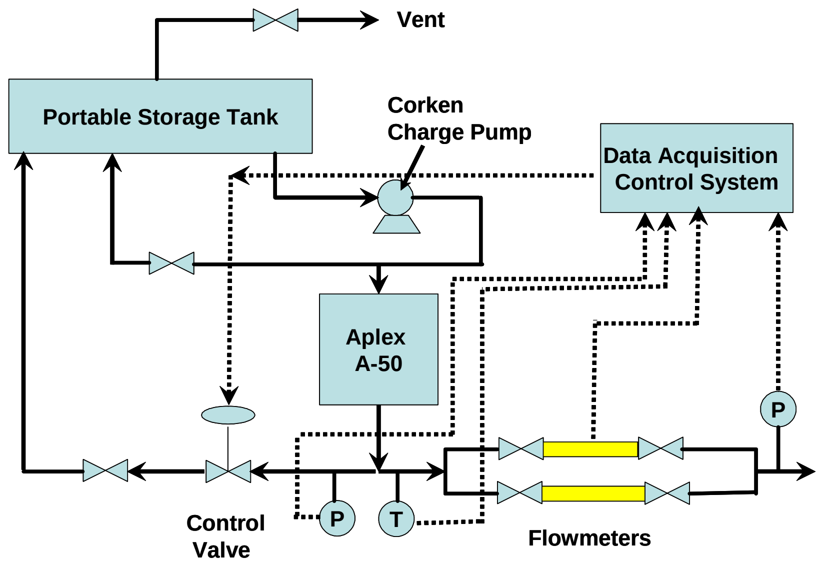


Figure 2: Flow schematic of CO2 Injection Skid and Portable Storage Tank

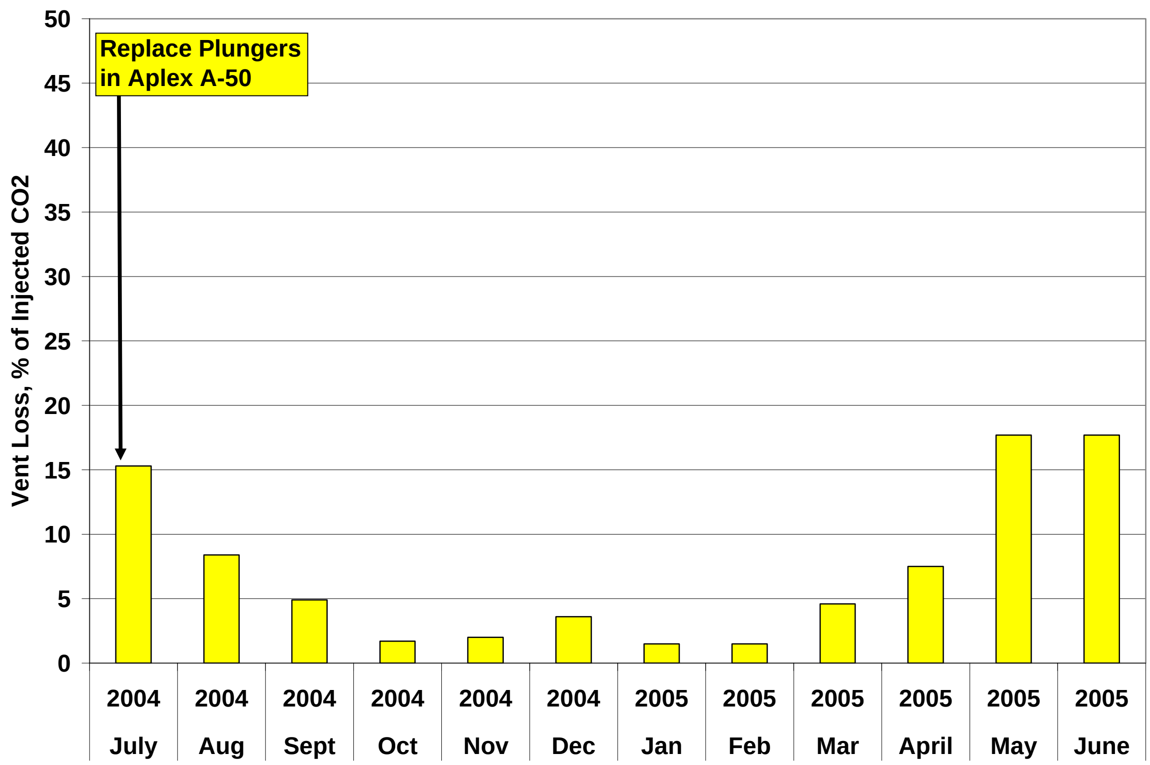


Figure 3: Vent Loss From Storage Tank as a Percentage of Injected CO2

Figure 4 shows the monthly carbon dioxide injection rate. The average injection rate for the six-month period from January 1 through June 30 was 227 MCFD. The injection skid was down for several days in March due to mechanical problems. Injection rates in April-June 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.

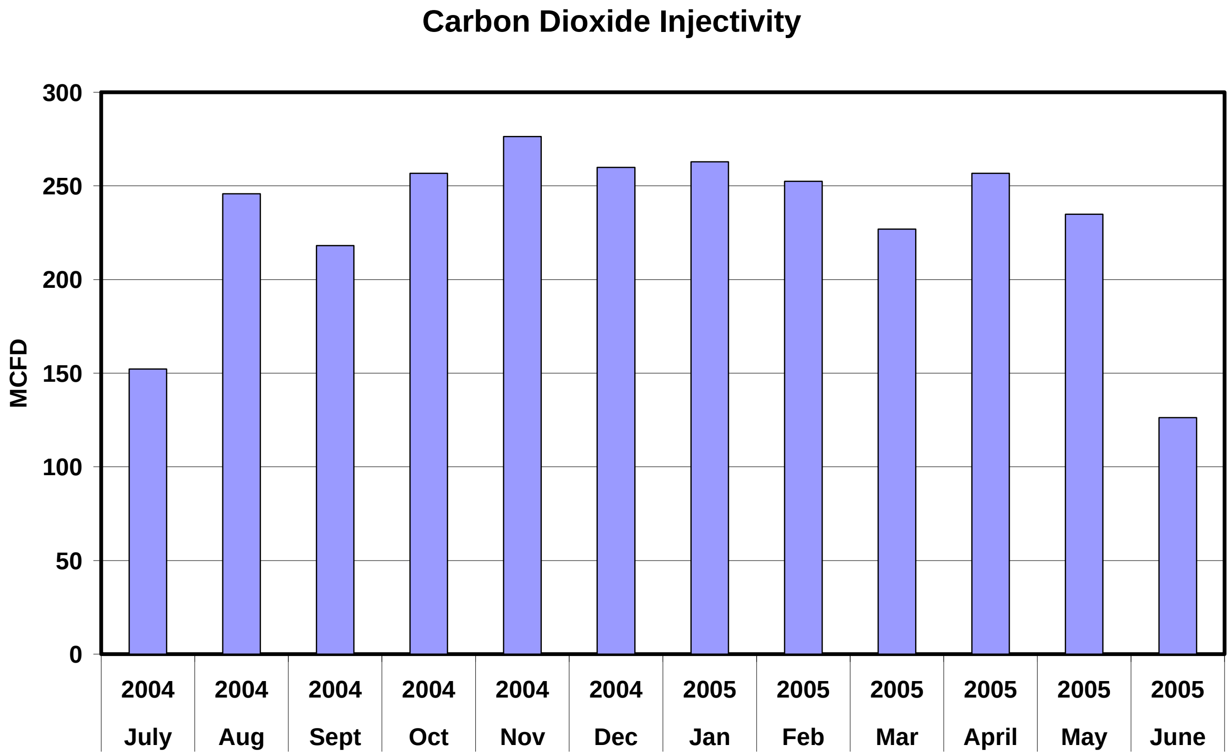


Figure 4: Carbon Dioxide Injection Rate in CO2I-1

The average pressure within the CO2 bubble is monitored by using pressure buildup and falloff analysis. Pressure in the vicinity of the injection well is estimated by conducting short pressure falloff tests on CO2 I-1. The average pressure in the region surrounding CO2#10 is conducted in a similar manner to the falloff test in CO2I-1. Average pressure in the regions surrounding CO2#12 and CO2#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 for each well. Also shown in Figure 5 are pressures at two monitor points. Monitor point 12 is half way between CO2I-1 and CO2#12 and pressure at this point is approximately the average of average pressures for CO2I-1 and CO2#12.

Monitor point 13 is half way between CO2I-1 and CO2#13 and the pressure at this point is approximately the average of the average pressures between CO2I-1 and CO2#13. Figure 6 is a contour map of the pressure distribution at the beginning of March 2005 based on individual well pressures. The pressure in the pilot region increased during the period from April-June due to the increased injection pressure in CO2I-1 and reduced expansion of the portion of the reservoir contacted by carbon dioxide.

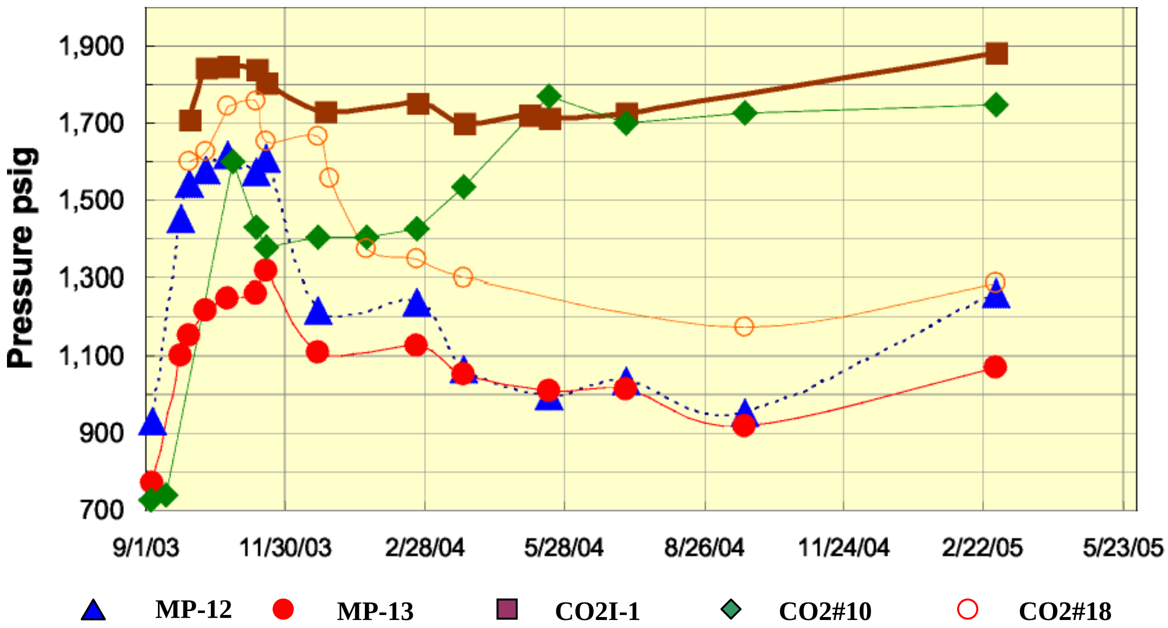
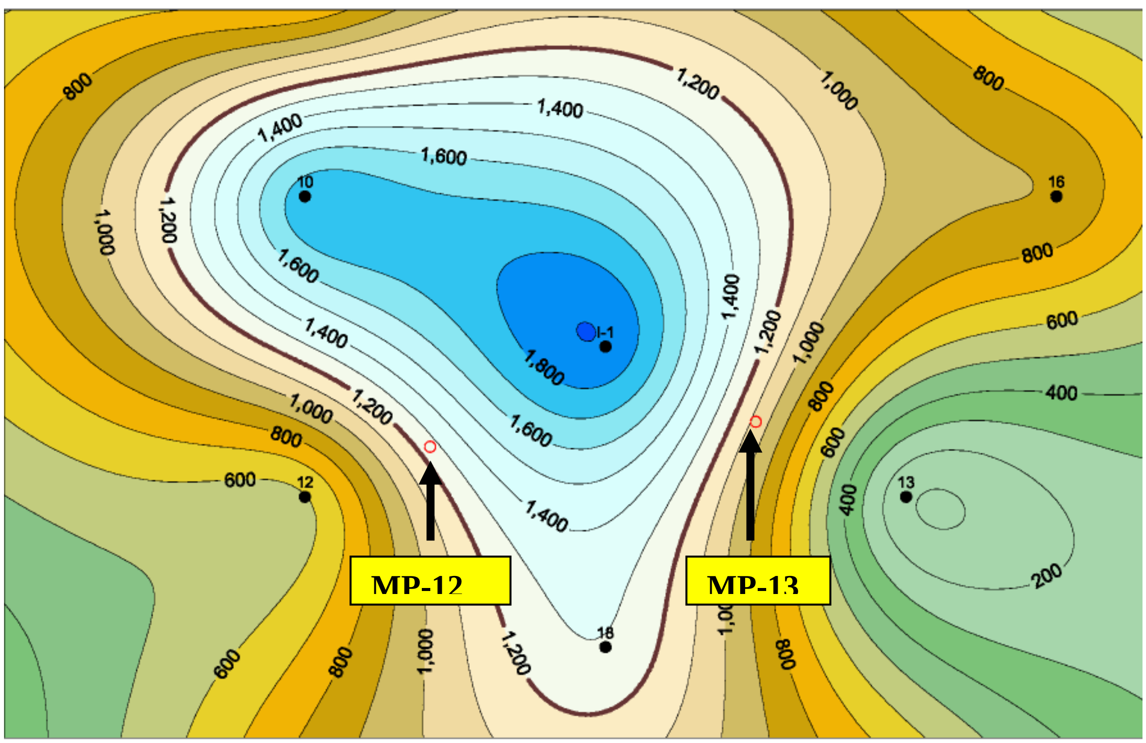


Figure 5: Pressures in the Injection Wells and at Monitoring Points.



LKC-C Pressure 3-2-05

Figure 6: Estimated Pressure Distribution in CO2 Pilot Area

Average daily and monthly data are presented in Tables 1 and 2 for the period from July 1,2004 to June 30,2005. Monthly average liquid production data from wells CO2#12 and CO2#13 are shown in Figure 7.

Production rates for CO2#12 decreased substantially from December-February 2005. During this period, high, apparent fluid levels were measured consistently in the casing annulus. Various tests indicated that the apparent 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 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. 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 is unresolved. There is no indication 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. Top of the C zone is 2887 ft.

Fluid production from CO2#12 increased following replacement of the pump with liquid rates averaging 110 B/D**.** Fluid levels remained high in the well until conversion to water injection even though the well was believed to be pumped off. Reduced withdrawal rate from CO2#12 is a concern because it affects the injection/withdrawal rate from the pattern, increasing carbon dioxide loss to the north.

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. CO2#13 was placed on production on January 4. At that time, the casing pressure was 430 psi, but the well was blown down quickly. Liquid production rates from CO2#13 averaged 51 B/D for the six month period from January 1-June 30, 2005.

Average daily oil production rates are shown in Figure 8. Oil production from CO2#13 averaged 2.9 B/D for January and February, primarily responding to the CO2 stimulation in December. Average oil production rate from CO2#13 for March-June was 1.05 B/D Oil production rates in CO2#12 averaged 2.9 B/D for the previous six months and 3.8 B/D for the period from January 1-June 30, 2005. Water production averaged 155 B/D for the period from January 1-June 30. Carbon dioxide was produced from both wells. Total amount of carbon dioxide produced was 5.18 MMSCF which is about 3.8% of the amount injected. Gas production rates remained relatively constant while the GOR varied within a range of 4-5 MCF/STB as shown in Figure 9. Cumulative oil production was 1494 STB through June 2005 and is shown in Figure 10. Water oil ratios are shown in Figure 11. Water-oil ratios decreased from ~ 80 to ~40 during the last six months.

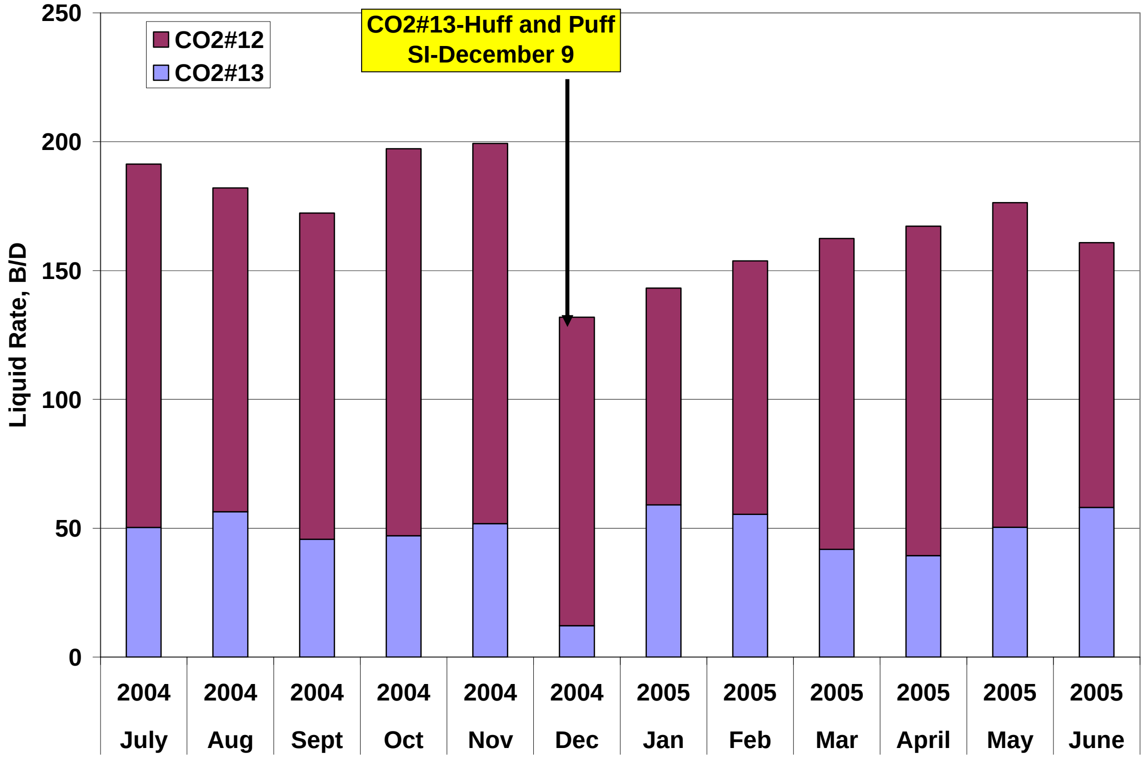


Figure 7: Liquid production rate from CO2#12 and CO2#13

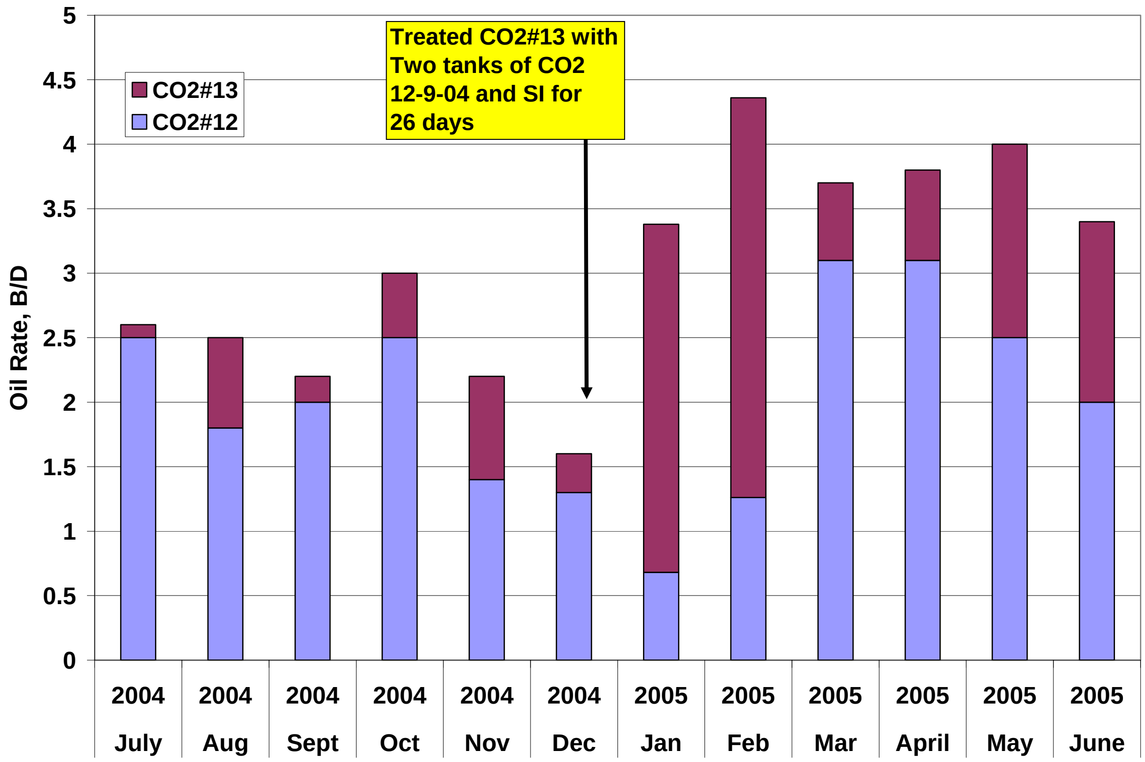


Figure 8: Average daily oil production rate from pilot area

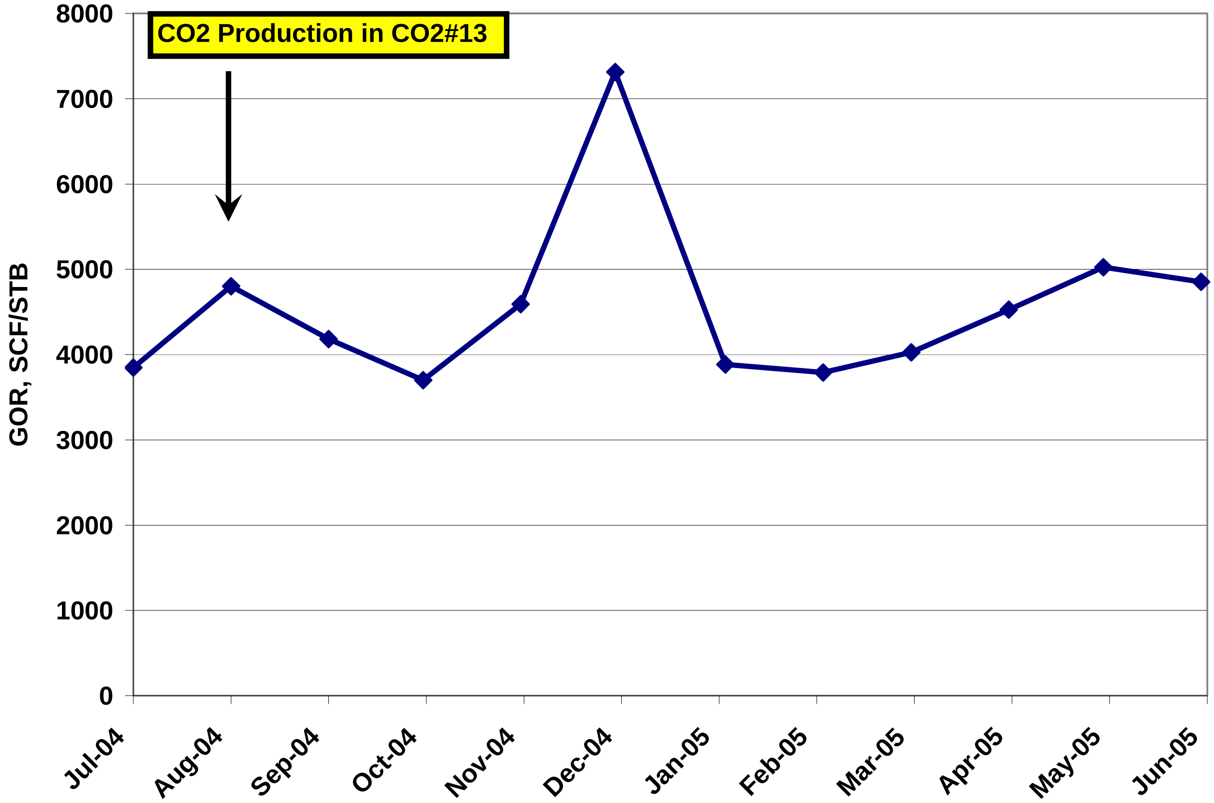


Figure 9: GOR from pilot area

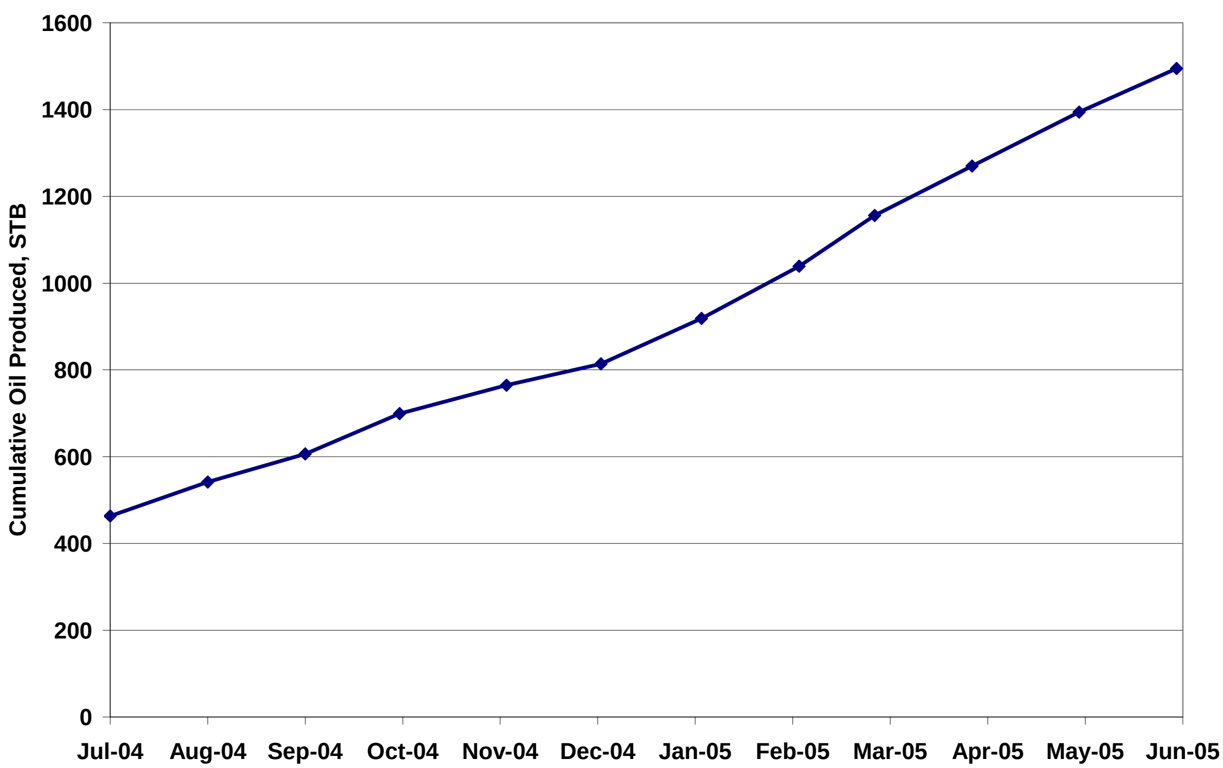


Figure 10: Cumulative oil production from CO2 pilot area

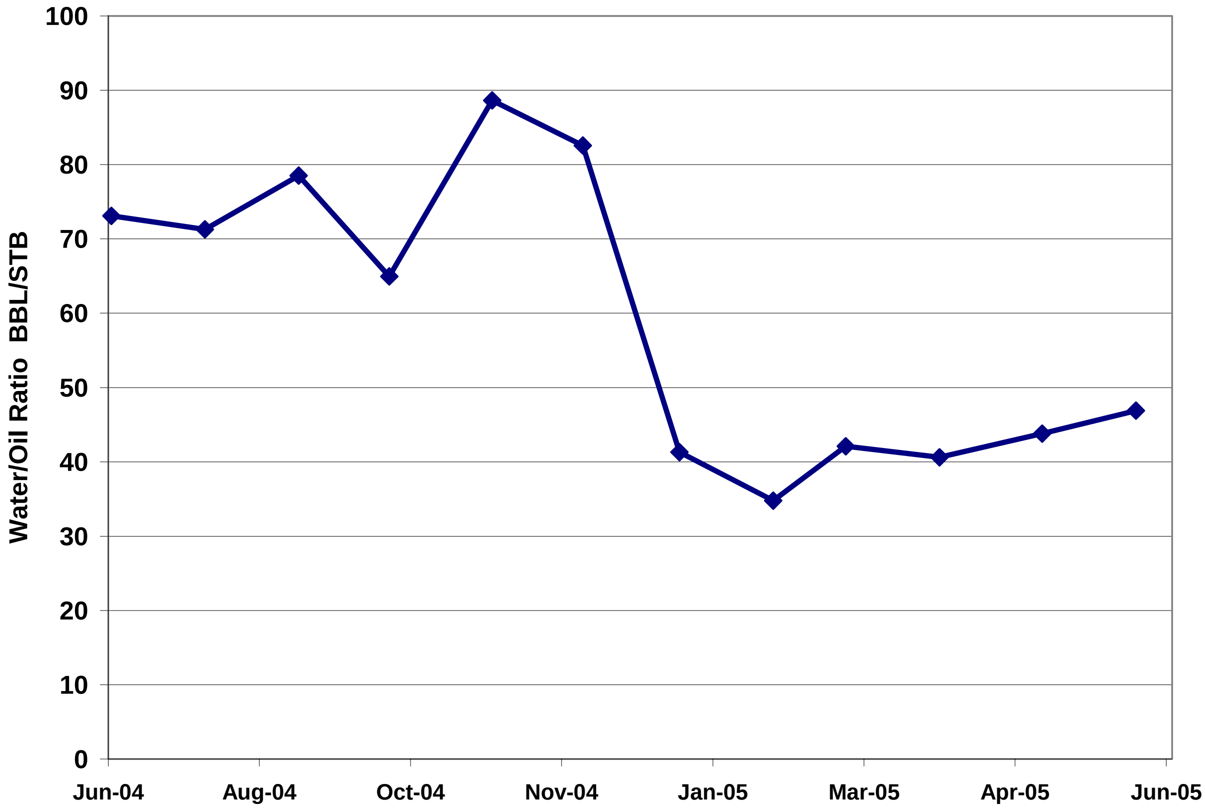


Figure 11: Water/oil ratio from CO2 pilot area

The pilot is not fully confined on the north side of the pattern. Project design and management is based on controlling carbon dioxide loss to the north by maintaining the pressure around CO2#10 by maintaining adequate injection rates into CO2#10, injection into CO2#18 and controlling the injection/withdrawal ratio in the pilot pattern. In calculating the injection/withdrawal ratio, the carbon dioxide loss to the north is estimated to be 30% of the injected volume. Based on analysis of streamlines, it is estimated that 29% of the production from CO2#12 and 87% of the production from CO2#13 was obtained from the pattern. The monthly injection rate of carbon dioxide in RB/D is estimated from the fluid withdrawal rate from the pattern and the losses to the north. The desired injection rate in reservoir barrels/day should meet fluid withdrawals from the pattern and estimated loss to the north. Figure 12 shows the I/W ratio for the period from July 2004-June 2005.

The I/W ratio should average 1.0 if carbon dioxide injection is in balance with production rates from CO2#12 and #13. Injection exceeded withdrawal in December 2004 due to CO2#13 being shut-in for 26 days and the decrease in the production rate of CO2#12. The I/W ratio remained slightly above 1 for the remainder of the reporting period. The cumulative I/W ratio is 1.06 indicating 35-40% of the carbon dioxide is being lost out of the pilot area.

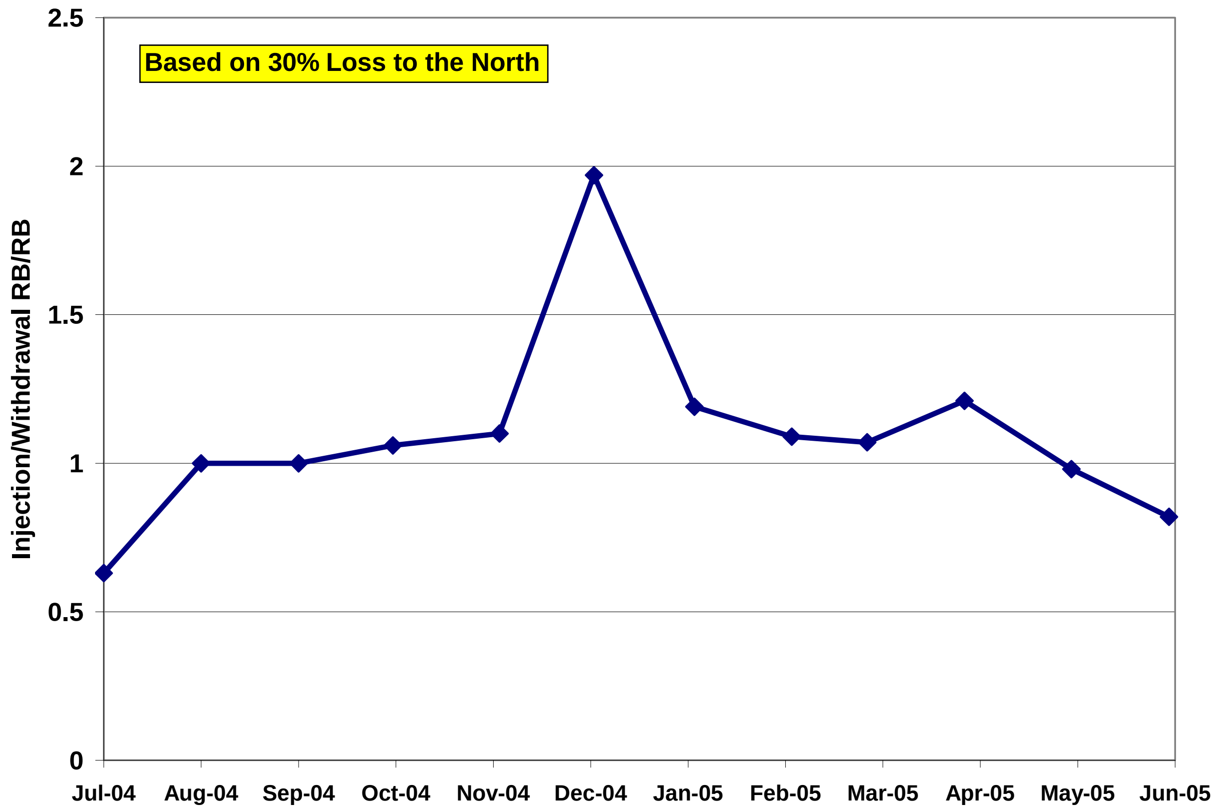


Figure 12: Estimated ratio of injection to withdrawal rates

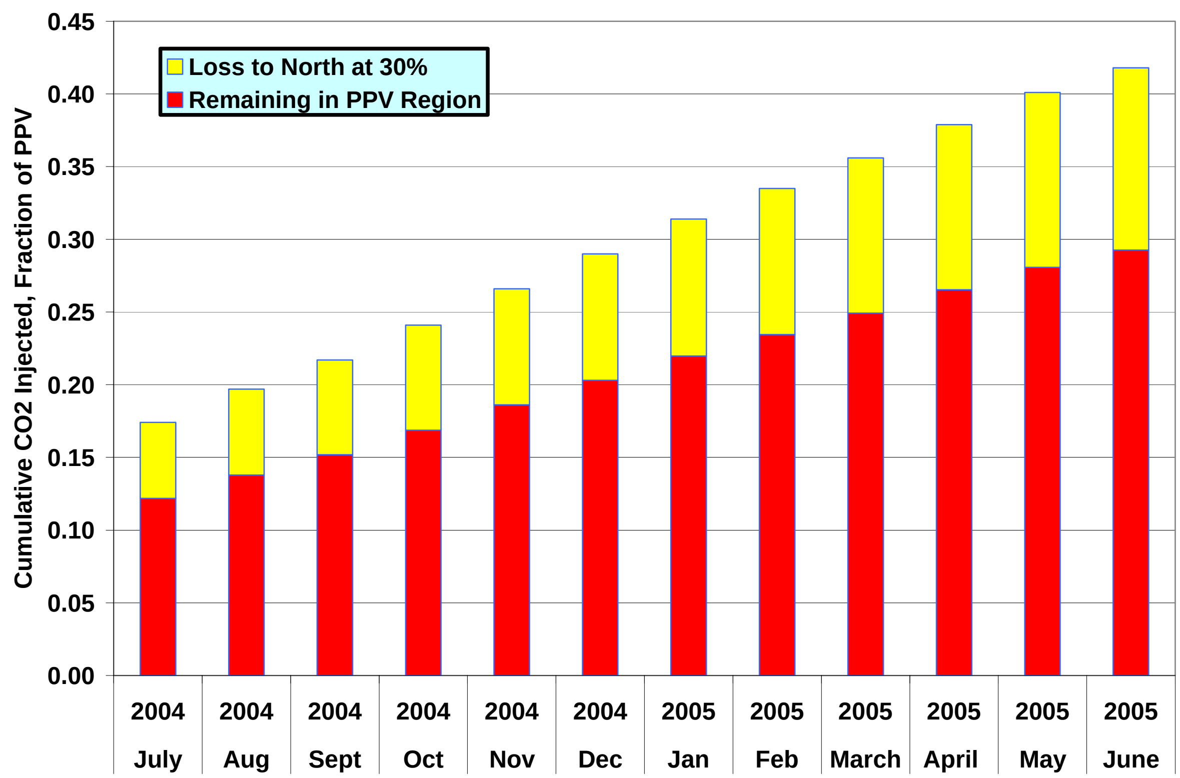


Figure 13: Distribution of injected carbon dioxide between pilot area and estimated losses to the north.

Figure 13 shows the estimated distribution of injected carbon dioxide between the pilot area (PPV) and loss to the north. The PPV is the carbon dioxide processed pore volume that is produced by fluid withdrawal from CO2#12 and #13.

Analysis of Project Performance

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

Several possible explanations for the lack of response have been considered. In January, an injectivity survey was completed in CO2I-1 to verify that carbon dioxide was leaving the wellbore in the ***C zone***. Figure 14 shows the distribution of injected carbon dioxide inferred from this survey. All carbon dioxide left the wellbore within the productive interval. Injectivity is 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 has 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.

A second possibility is that loss to the north is greater than estimated. Unfortunately, there are limited means to evaluate loss to the north other than using estimated reservoir pressure based on material balance calculations. Murfin personnel periodically monitor surrounding wells for the possibility of increased production or breakthrough of carbon dioxide. Colliver #7 is not open to the ***C zone***. Colliver #1, located 1 ½ locations NE of the pilot area and Rein A1 are open in the LKC ***C zone*** and have been pumped off throughout the flood. Colliver #6 is located one location west of the pattern area and is pumped off. Carbon dioxide has not broken into any of these wells based on change of oil or gas production rates. The pressure in CO2 #16 is monitored regularly. The bottom hole pressure in this well has increased but there is no evidence of the arrival of carbon dioxide at this well. The ongoing 4D seismic program may provide insight into fluid movement in the pattern area.

The LKC ***C zone*** is more geologically complex than originally estimated. The existence of permeability transitions between CO2I-1 and CO2#13 was recognized from pressure and rate tests before carbon dioxide injection began. Tests indicated that there was sufficient connectivity between CO2I-1 and CO2#13 to conduct the project within the time period of the project. The flood response at CO2#13 is substantially slower than anticipated from reservoir simulation, probably due to complex changes in the reservoir properties between CO2I-1 and CO2#13. Response of CO2#12 to carbon dioxide is also slower than anticipated from pressure and injectivity tests conducted before carbon dioxide injection began. This may indicate that there are partial barriers to flow between CO2I-1 and CO2#12.

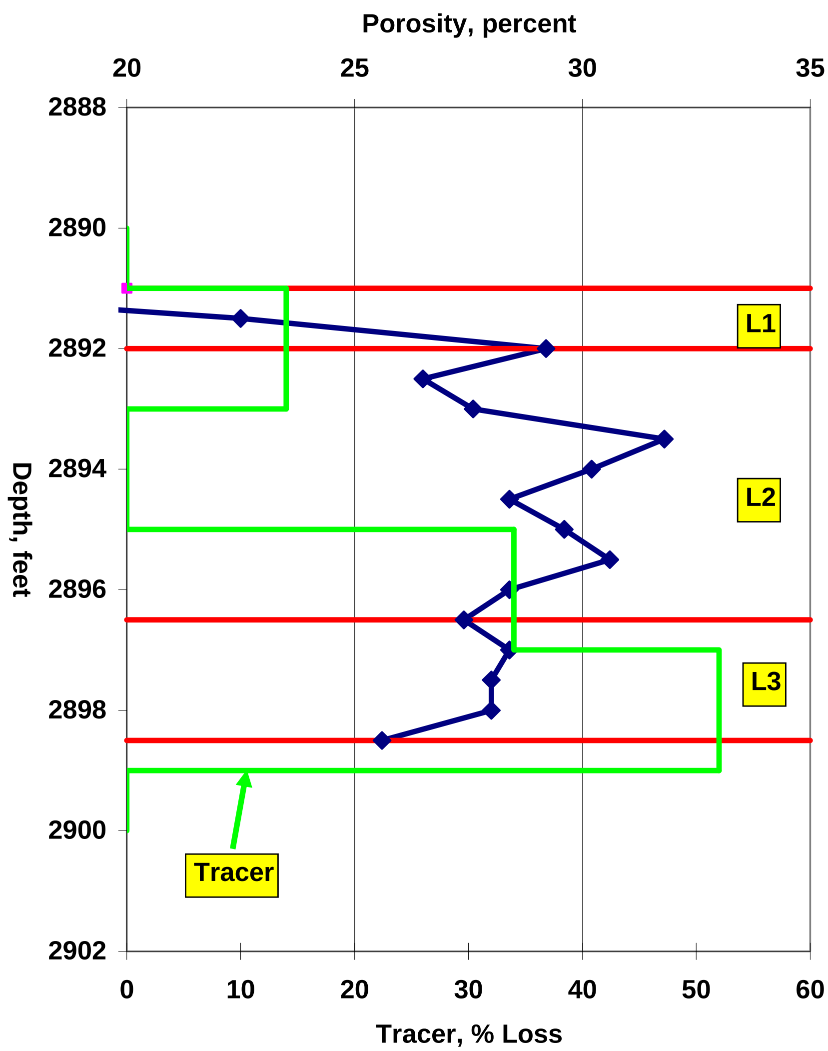


Figure 14: Tracer survey during carbon dioxide injection in CO2I-1 on January 27, 2005

The retention of carbon dioxide in the reservoir appears to be larger than observed in other carbon dioxide projects. This may be due to the oomoldic nature of the reservoir as well as weakly connected shingles created by the depositional environment.

The amount of carbon dioxide injected by mid-June was about 0.42 PPV. Losses to the north at 30% give 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.

Injection was converted to water on June 21, 2005 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. Injection of carbon dioxide could be resumed if oil production increases within a reasonable period of time. Project performance will be reevaluated after two months of water injection to determine the future course of action.

TASK 7.0 PROJECT MANAGEMENT

A project management plan was developed consisting of a Technical Team and an Operational Team. Technical Team members include Paul Willhite, Don Green, Jyun Syung and Alan Byrnes. The Operational Team members include Tom Nichols, Bill Flanders and Richard Pancake. Changes in field operations are initiated through the Operational Team. Coordination of the activities is done between Paul Willhite (Technical Team) and Bill Flanders (Operational Team). Production and injection workbooks are updated daily by personnel in Murfin's office in Russell and transmitted electronically to members of the Technical and Operational Team. These Excel workbooks are archived periodically in an FTP site accessible to members of the Technical and Operational Teams.

Various members of the Kansas CO2 Team communicate primarily by email over specific technical or business issues. Conference calls are arranged when the discussion involves more than two members of a team.

TASK 8.0 TECHNOLOGY TRANSFER

A presentation was made at the 16th Oil Recovery Conference on April 7, 2005. A brief project overview was presented at the Mid-Year meeting of the Kansas Independent Oil and Gas Association held in Russell, Kansas on April 20. A field trip to the U.S. Energy partners ethanol plant and the CO2 project was made after the presentations.

CONCLUSIONS

Continuous carbon dioxide injection began on the Murfin Colliver Lease on December 3, 2003. Oil rate from the pilot area increased from 0 B/D to about 3.4 B/D. The GOR remained within a range of 4000-5000 indicating no channeling of carbon dioxide into production wells. Incremental oil production was 1494 bbls. Neither well has experienced increased oil production rates expected from the arrival of the oil bank. Water injection began in CO2I-1 on June 21 to displace the oil bank generated by carbon dioxide injection to the production wells.

REFERENCE

1. "Field Demonstration of Carbon Dixoide Miscible Flooding in the Lansing Kansas City Formation, Central Kansas", Semi Annual Report July 1, 2004-December 31, 2004, DOE Contract No. DE-AC26-00BC15124.

Table 1
Summary of Monthly Data
July 2004-June 30, 2005

Field			July 2004	Aug 2004	Sept 2004	Oct 2004	Nov 2004	Dec 2004	Jan 2005	Feb 2005	March 2005	April 2005	May 2005	June 2005
I/W With 30% North Losses			0.63	1	1	1.06	1.1	1.97	1.19	1.09	1.07	1.21	0.98	0.82
PPV Inj CO2 I-1		%	0.174	0.197	0.217	0.241	0.266	0.29	0.314	0.335	0.356	0.379	0.401	0.42
		Loss	0.0522	0.0591	0.0651	0.072	0.080	0.087	0.094	0.101	0.107	0.114	0.120	0.125
		In Pattern	0.12	0.14	0.15	0.169	0.186	0.203	0.2198	0.2345	0.249	0.265	0.281	0.29
Production	Oil	bbl	80	78.1	65	92.7	66	48.9	104.9	120.3	117	114	124	101
	Wtr	bbl	5,849	5,567	5104	6022	5814	4038	4333	4184	4926	4631	5431	4,721
	Gas	mcf	312	374	274	344.5	304	363.4	408.3	456.6	471	515	623	494.4
	WOR	bbl/bbl	73	71	78.52	64.96	88.63	82.58	41	35	42	41	44	46.88
	Cumulative Oil		463.4	541.5	606.5	699.2	764.8	813.7	919	1039	1156	1270	1394	1495
Injection	Wtr	bbl	10,958	10,882	11228	10745	12,596	11,357	11466	10012	10618	10775	11945	12,221
	CO2	mcf	4918	7613	6542	7958	8290	8057	8,146	7,071	7035	7701	7281	3,787
		Mlb	573.728	888.824	763.224	928.371	967.049	939.93	950.303	824.837	820.695	989.39	849.393	441.79
CO2 Delivered		mcf	5,724.50	8,128.00	7006.9	7891.9	8786.3	8475.2	8164.9	7250.6	7211.9	8354.3	8657.8	4,193.70
		Mlb	664	943	813	915	1019	983	946.9	840.8	836.4	968.8	1004	486.3
		Tons	331.9	471.3	406.3	457.6	509.5	491.4	473.4	420.4	418.2	484.4	502	243.2
Tank Vent		mcf	753.2	637.5	321.8	134.2	165.1	293.1	122.3	106	326.8	575.5	1285.6	671.7
		Mlb	87.35	73.93	37.21	15.56	19.14	34	14.18	12.3	37.89	66.75	149.09	77.9
		% of Injection	15.30%	8.40%	4.90%	1.70%	2.00%	3.60%	1.5	1.5	4.6	7.5	17.7	17.70%

Table 2
Summary of Daily Average Data
July 2004-June 30, 2005

Field			July 2004	Aug 2004	Sept 2004	Oct 2004	Nov 2004	Dec 2004	Jan 2005	Feb 2005	Mar 2005	April 2005	May 2005	June 2005
Production														
	Oil	bbl	2.6	2.5	2.2	3	2.2	1.6	3.4	4.3	3.8	3.8	4	3.4
	Wtr	bbl	188.7	179.6	170.1	194.3	193.8	130.3	139.8	149.4	158.9	154.4	172.3	157.4
	Gas	mcf	10.1	12.1	9.1	11.1	10.1	11.7	13.2	16.3	15.2	17.2	20.1	16.5
Injection														
	Wtr	bbl	353.5	351	374.3	346.6	419.9	366.4	369.9	357.6	342.5	359.2	385.3	407.4
	CO2	mcf	152.2	245.8	218.1	256.7	276.3	259.9	262.8	252.5	226.9	256.7	234.9	126.2
		Mlb	17.8	28.7	25.4	29.9	32.2	30.3	30.7	29.5	26.5	29.9	27.4	14.7
CO2 Delivered														
		mcf	184.7	262.2	233.6	254.6	292.9	273.4	263.4	258.9	232.6	278.5	279.3	139.8
		Mlb	21.4	30.4	27.1	29.5	34	31.7	30.5	30	27	32.3	32.4	16.2
Tank Vent														
		mcf	24.3	20.6	10.7	4.3	5.5	9.5	3.9	3.8	10.5	19.2	41.5	22.4
		Mlb	3.6	2.4	1.2	0.5	0.6	1.1	0.5	0.4	1.2	2.2	4.8	2.6
		% of Injectio	15.30	8.40	4.9	1.70	2.00	3.60	1.5	1.5	4.6	7.5	17.7	17.7
Wells														
Production														
CO2 12	Oil	bbl	2.5	1.8	2	2.5	1.4	1.3	0.7	1.26	3.1	3.1	2.5	2
	Wtr	bbl	138.5	123.9	124.6	147.7	146.1	118.4	83.4	97.1	117.5	124.7	123.4	100.7
	Gas	mcf	9.5	11.6	9	10.9	9.8	11.6	9.2	5.7	9.4	12.3	13	12.0
	Total Liquid(bbl)		141	125.7	126.6	150.2	147.5	119.7	84.08	98.36	120.6	127.8	125.9	102.7
	GOR		3800	6444	4500	4360	7000	8923	13529	4524	3032	3968	5200	6000
CO2 13	Oil	bbl	0.1	0.7	0.2	0.5	0.8	0.3	2.7	3.1	0.6	0.7	1.5	1.4
	Wtr	bbl	50.2	55.7	45.5	46.6	51	11.9	56.4	52.3	41.2	38.7	48.9	56.7
	Gas	mcf	0.5	0.4	0.2	0.2	0.3	0.1	4	10.6	5.9	4.9	7.1	4.4
	Total Liquid(bbl)		50.3	56.4	45.7	47.1	51.8	12.2	59.1	55.4	41.8	39.4	50.4	58.1
	GOR	bbl/bbl	5000	571	1000	400	375	333	1481	3419	9833	7000	4733	3143
Total Liquid-Pattern		bbl	191.3	182.1	172.3	197.3	199.3	131.9	143.18	153.76	162.4	167.2	176.3	160.8
Total Gas_pattern		mcf	10	12	9.2	11.1	10.1	11.7	13.2	16.3	15.3	17.2	20.1	16.5
GOR-Pattern		mcf/bbl	3846	4800	4182	3700	4591	7313	3882	3791	4026	4526	5025	4853
Injection														
CO2 10	Wtr	bbl	333.1	329.9	336	326	381.2	359.1	350.1	334.8	342.5	345.1	356.6	353.8
CO2 18	Wtr	bbl	20.4	21.2	38.2	20.6	38.7	7.3	19.8	22.8	0	14.1	28.7	19
CO2 I-1	Wtr	bbl	0	0	0	0	0	0	0	0	0	0	0	34.5