SEMI ANNUAL TECHNICAL PROGRESS REPORT
FOR THE PERIOD ENDING JUNE 30, 2004

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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Project Manager: Paul West, NPTO Tulsa, Oklahoma

Contractor Contact: G. Paul Willhite
Tertiary Oil Recovery Project
1530 W. 15th Street
Room 4146B Learned Hall
Lawrence, Kansas 66045-7609
email: willhite@ku.edu
phone: 785-864-2906

Principal Investigators: Alan Byrnes (Program Manager Budget Period 1)
G. Paul Willhite (Program Manager Budget Periods 2&3)
Don Green, Martin Dubois, Richard Pancake, Timothy Carr, W. Lynn Watney, John Doveton, Willard Guy, Rodney Reynolds, Dave Murfin, James Daniels, Russell Martin, William Flanders, Dave Vander Griend, Eric Mork, Paul Cantrell

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. Continuous carbon dioxide injection began on December 2, 2003. By the end of June 2004, 6.26 MM lb of carbon dioxide were injected into the pilot area. Carbon dioxide injection rates averaged about 250 MCFD. Carbon dioxide was detected in one production well near the end of May. The amount of carbon dioxide produced was small during this period. Wells in the pilot area produced 100% water at the beginning of the flood. Oil production began in February, increasing to an average of about 2.5 B/D in May and June. Operational problems encountered during the initial stages of the flood were identified and resolved.

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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. 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 2004, about 6.26MM lbs of carbon dioxide were injected at an average rate of about 250 MCFD. The pilot region consists of one carbon dioxide injection well and two production wells on about 10 acre spacing. The initial production was 100% water with oil arriving in February 2004. Oil rates averaged 2.5 B/D from March –June 2004. Carbon dioxide was detected in CO2#12 in late May. Volume of carbon dioxide produced has remained low with GORs on the order of 3000-4000. Operational problems have been limited to measurement of injection rates and excessive vent losses. The flow meter on the injection skid was found unreliable and a data acquisition package was installed at the wellhead of the injection well. The pump on the skid is oversized, with the recycle rate about four times the injection rate. As ambient temperatures increased, vent losses increased to about 40% by June 2004, which is considered excessive.

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.

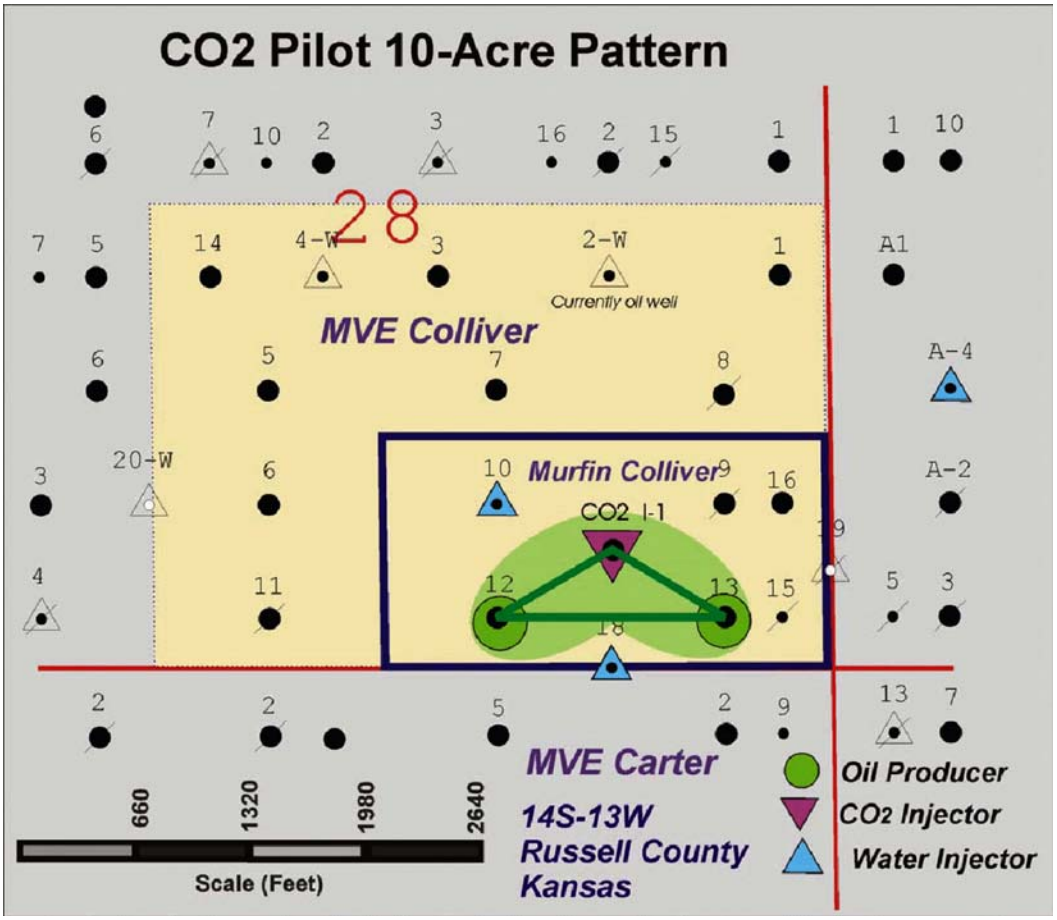

Figure 1: Murfin Colliver Lease in Russell County, Kansas

Liquid carbon dioxide (250 psi and ~-***10F***) is 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 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 seven months, 6.254 MM lbs of carbon dioxide were injected into CO2I-1. 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. During June, the injection pressure averaged 754 psi at an average wellhead temperature of 54°F. Average injection rate was about 209 MSCFD.

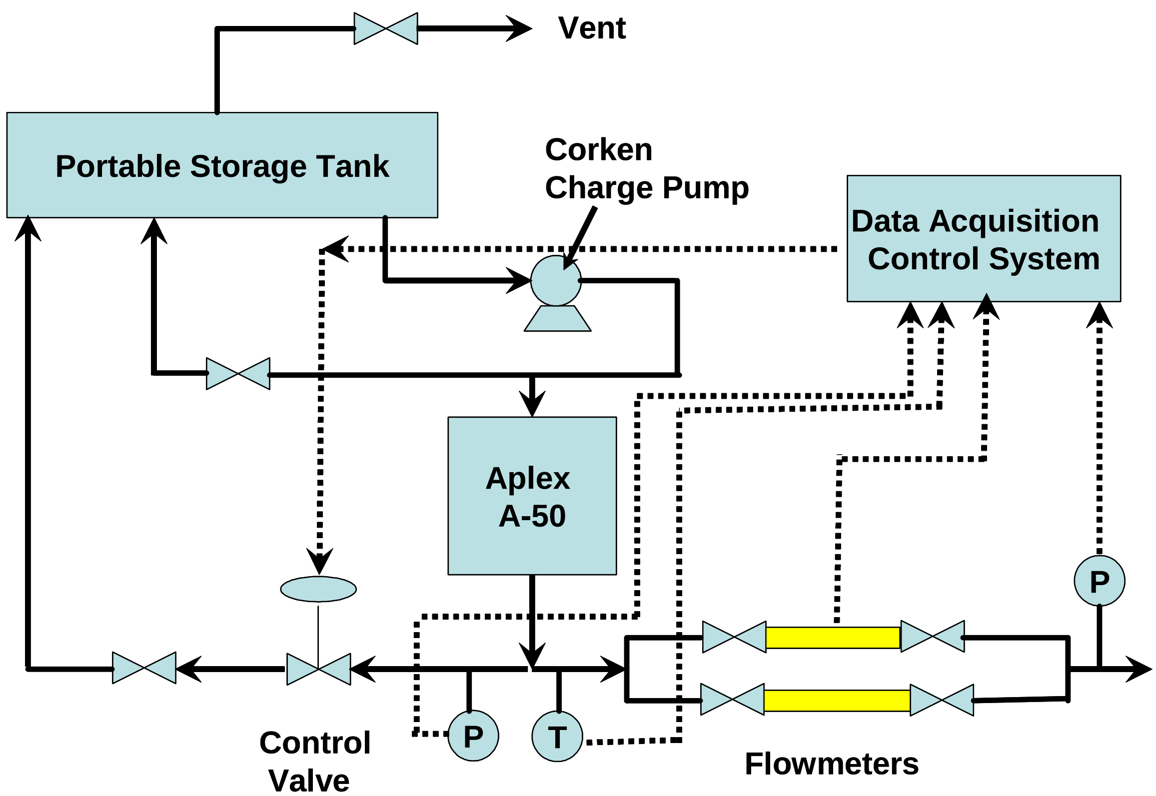

Figure 2: Flow schematic of CO_2 Injection Skid and Portable Storage Tank

Carbon dioxide injection rates into CO2I-1 averaged 110 RB/D assuming the reservoir temperature is 99F and the bottom hole pressure in CO2I-1 was 1700 psi. The estimated fracture pressure for the LKC "C" formation is 1975 psi. Bottomhole pressure is limited in all injection wells to 1900 psi to avoid fracturing the formation. Reservoir quality diminishes rapidly between CO2I-1 and CO2#16. This means that carbon dioxide loss to the northeast is probably limited by the change in reservoir properties. CO2#16 remains shut-in and serves as a pressure observation well.

Carbon dioxide loss to the north is 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 open the possibility that some water may be injected into the LKC-B zone. Since CO2#10 may have communication with LKC-B and G zones. CO2 I-1 is operated by specifying the bottom hole pressure(~1900 psi) and injecting at a rate that will maintain the specified bottom hole pressure needed to control loss from the LKC-C zone to the north. The bottom hole pressure is specified to avoid fracturing the formation.

CO2#18 was recompleted early in the project as a possible injection well. Due to recompletion problems, this well was converted to a confinement well. CO2#18 was fractured during previous operations. Water injection rates into CO2#18 are controlled by setting the maximum bottom hole pressure to 1900 psi to avoid reopening the fracture

Design of the carbon dioxide flood was guided by the analysis of streamlines generated from computer simulation of the carbon dioxide miscible flood. This analysis indicated that about 25-30% of the carbon dioxide would leave the pattern region to the north during the period when carbon dioxide was injected.

During the initial period of injection, a carbon dioxide bubble was established that expands primarily by displacing water and some residual oil from the region contacted. The initial shape was probably radial until affected by surrounding wells. The shape of the carbon dioxide bubble is influenced by loss to the north, water injection into CO2#10 as well as fluid withdrawal from CO2#12 and CO2#13. The carbon dioxide bubble soon loses its initial radial shape due to influence of these wells on fluid flow patterns and the inherent reservoir heterogeneity in the pattern. The precise shape of the CO2 bubble is not known.

It is possible to monitor the flood and the pressure within the CO2 bubble 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. Fall off tests are five hours in duration with wellhead pressure readings taken at half hour intervals for the first two hours and at one-hour intervals thereafter. Change in bottomhole pressure is used to estimate kh as well as the average pressure in the region surrounding CO2I-1 sampled by the fall off test. The average pressure in the region surrounding CO2#10 is conducted in a similar manner to the falloff test in CO2I-1. Values of kh determined from falloff tests in CO2#10 must be used with caution because the well is open to multiple formations, including the LKC "C" zone.

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 3 for each well. Also shown in Figure 3 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 4 is a contour map of the pressure distribution at the end of June based on individual well pressures.

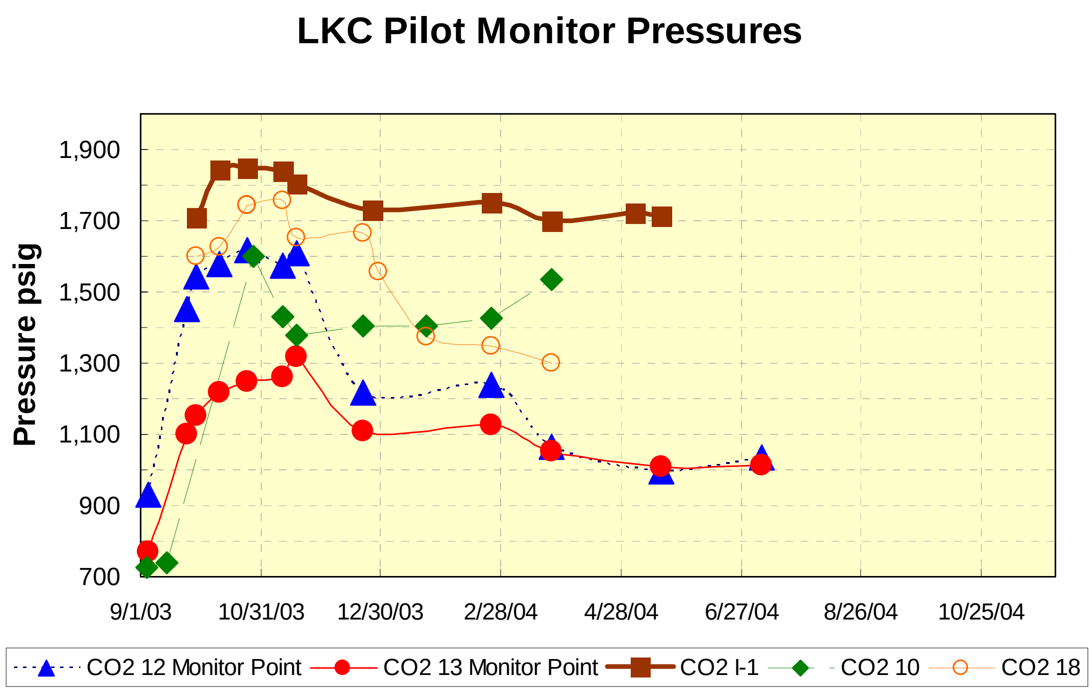

Figure 3: Pressures in the Injection Wells and at Monitoring Points.

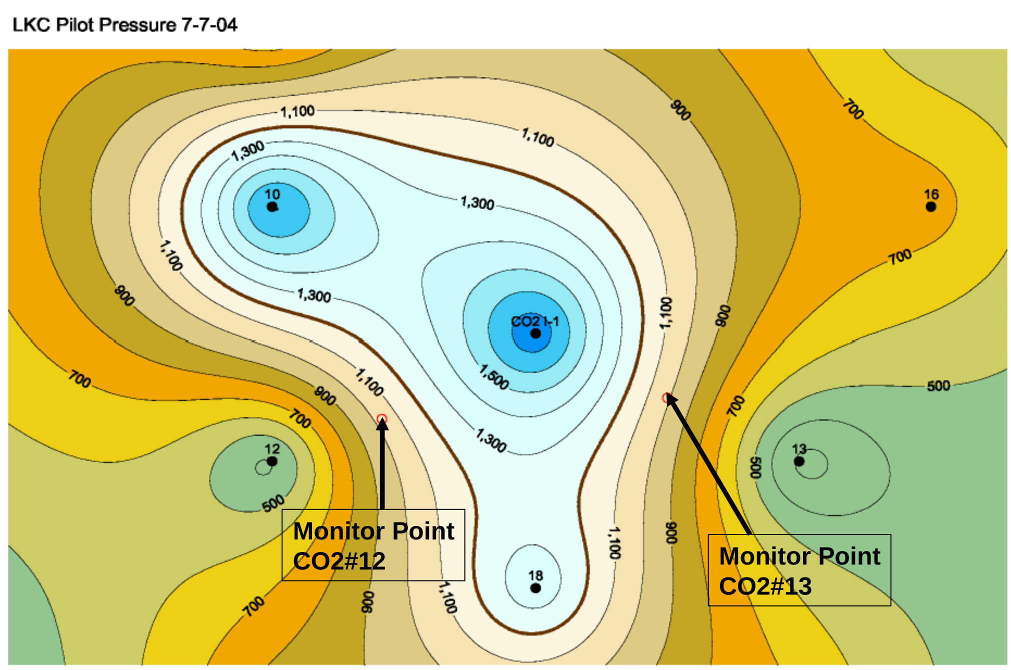

Figure 4: Estimated Pressure Distribution in CO2 Pilot Area

Loss of carbon dioxide is 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. The average production rate for CO2#12 was 97 B/D from November 2003-February 2004, but increased to 139 B/D when the injection rate in CO2#10 was increased from 210 B/D in March to 360 B/D in April 2004 to reduce loss of carbon dioxide to the north. CO2#13 was produced by maintaining a bottom hole pressure of about 200 psi to avoid buildup of gas saturation. Production rate from CO2#13 averaged 56 B/D. 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. During this period, the average carbon dioxide injection rate exceeded fluid withdrawal rate from the pattern by about 8% assuming 30% loss to the north. 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.

At the beginning of the project, both production wells CO2#12 and CO2#13 produced 100% water. By the end of February, oil production averaged 1.6 B/D, primarily from CO#12. Oil production averaged 2.5 B/D for the period from March-June. Water production averaged 161 B/D for the period from November 2003-June 2004. Carbon dioxide arrived at CO#12 on May 31 but did not arrive at CO2#13 during this period. Production of carbon dioxide was preceded by production of CO2 free hydrocarbon gas. Gas production rates remained relatively constant while the GOR varied within a range of 0-3 MCF/STB. Plans were developed to begin WAG if gas production rates became excessive. Cumulative oil production was 383.4 STB through June 2004.

Average daily and monthly data are presented in Tables 1 and 2. Figures 5-13 show graphs of monthly data for the period from November 2003-June 2004.

Table 1
Summary of Monthly Data
November 2003-June 2004

LKC Pilot Monthly Report(November 2003-June 2004)

Field

			Nov 2003	Dec 2003	Jan 2004	Feb 2004	March 2004	April 2004	May 2004	June 2004	Cum	
I/W With 30% North Losses				1.23	1.1	1.27	1.05	1.08	0.93	0.87		
PPV Inj CO2 I-1		%	0.000	0.025	0.048	0.072	0.097	0.120	0.141	0.160		
Production		Loss		0.0075	0.0144	0.0216	0.0291	0.036	0.0423	0.048		
		In Pattern		0.02	0.03	0.05	0.07	0.08	0.10	0.11		
	Oil	bbl	0.5	6.2	27	47.7	85	58	84	75	383.4	bbl
	Wtr	bbl	1,793.80	4,829.00	4,858.00	4,431.90	5,853.00	5,713.30	6,078.00	5,589.00	39.146	Mbbl
	Gas	mcf	0	0	0	0	0	0	33.9	211	244.9	mcf
	WOR		3588	779	180	93	69	99	72	75		
Injection	Wtr	bbl	9,333	7,433	7,514	7,106	8,515	11,200	11,365	11,042	73.51	Mbbl
	CO2	mcf	81.7	8,267.50	7,699.00	8,222.40	8,042.20	8,011.00	7,051.00	6,280.00	53.65	mmcf
		Mlb	9.479	958.773	898.156	959.216	938.195	934.554	822.562	732.618	6.25	MMlb
CO2 Delivered		mcf	745.7	9,405.50	8,309.60	9,294.00	9,304.40	9,656.40	9,007.20	9,010.20	64.73	mmcf
		Mlb	86.48	1,090.74	963.7	1,077.80	1,079.00	1,119.80	1,044.60	1,044.90	7.51	MMlb
		Tons	43.2	545.4	481.8	538.9	539.5	559.9	522.3	522.5	3,754	Tons
Tank Vent		mcf	316.6	1,028.00	753	990.9	1,214.40	1,320.20	2,175.90	2,437.20	10.24	mmcf
		Mlb	36.72	119.22	87.33	114.92	140.83	153.1	252.34	282.64	1.19	MMlb
		% of Injection	387.40%	12.40%	9.80%	12.10%	15.10%	16.50%	30.90%	38.80%	18.98%	

Wells

			Nov 2003	Dec 2003	Jan 2004	Feb 2004	March 2004	April 2004	May 2004	June 2004	Cum	
Production	CO2 12 Oil	bbl	0.5	6.2	10.7	19.1	76.6	37.3	71.6	49.2	271.2	bbl
	Wtr	bbl	1,528	3,105	3,029	2,710.30	4,141.00	4,039.40	4,497.00	4,080.00	27.13	Mbbl
	Gas	mcf	0	0	0	0	0	0	33.9	211	244.9	mcf
	CO2 13 Oil	bbl	0	0	16.3	28.6	8.4	20.7	12.4	25.8	112.2	bbl
	Wtr	bbl	266	1,716	1,829	1,722	1,711	1,674	1,581	1,509	12.01	Mbbl
	Gas	mcf	0	0	0	0	0	0	0	0	0	mcf
Injection	CO2 10 Wtr	bbl	5,113	5,848	6,460	6,207.00	7,827.00	10,599.00	10,962.00	10,471.00	63.49	Mbbl
	CO2 18 Wtr	bbl	1,391	1,585	1,054	899	688	601	403	571	7.19	Mbbl
	CO2 I-1 Wtr	bbl	2,829	0	0	0	0	0	0	0	2.83	Mbbl
Vent During Loading			5.20%		5.80%							

Table 2
Summary of Daily Average Data
November 2003-June 2004

LKC Pilot Report(November 2004-June 2004)
Daily Values

				Nov 2003	Dec 2003	Jan 2004	Feb 2004	March 2004	April 2004	May 2004	June 2004
Field											
	Production										
		Oil	bbl	0	0.2	0.9	1.6	2.7	1.9	2.7	2.5
		Wtr	bbl	59.8	155.8	156.7	152.8	188.8	190.4	196.1	186.3
		Gas	mcf	0	0	0	0	0	0	1.1	7
	Injection										
		Wtr	bbl	311.1	239.8	242.4	245	274.7	373.3	366.6	368.1
		CO2	mcf	2.7	266.7	248.4	283.5	259.4	267	227.5	209.3
			Mlb	0.3	30.9	29	33.1	30.3	31.2	26.5	24.4
	CO2 Delivered										
			mcf	24.9	303.4	268.1	320.5	300.1	321.9	290.6	300.3
			Mlb	2.9	35.2	31.1	37.2	34.8	37.3	33.7	34.8
	Tank Vent										
			mcf	10.6	33.2	24.3	34.2	39.2	44	70.2	81.2
			Mlb	1.2	3.8	2.8	4	4.5	5.1	8.1	9.4
			% of Injection	387.40	12.40	9.80	12.10	15.10	16.50	30.90	38.80
Wells											
	Production										
		CO2 12 Oil	bbl	0	0.2	0.3	0.7	2.5	1.2	2.3	1.6
		Wtr	bbl	50.9	100.1	97.7	93.5	133.6	134.6	145.1	136
		Gas	mcf	0	0	0	0	0	0	1.1	7
		Total Liquid		50.9	100.3	98	94.2	136.1	135.8	147.4	137.6
		GOR		#DIV/0!	0	0	0	0	0	478	4375
		CO2 13 Oil	bbl	0	0	0.5	1	0.3	0.7	0.4	0.9
		Wtr	bbl	8.9	55.3	59	59.4	55.2	55.8	51	50.3
		Gas	mcf	0	0	0	0	0	0	0	0
		Total Liquid		8.9	55.3	59.5	60.4	55.5	56.5	51.4	51.2
		GOR									
		Total Liquid-Pattern		59.8	155.6	157.5	154.6	191.6	192.3	198.8	188.8
		Total Gas_pattern		0	0	0	0	0	0	1.1	7
		GOR-Pattern		0	0	0	0	0	0	407	2800
	Injection										
		CO2 10 Wtr	bbl	170.4	188.6	208.4	214	252.5	353.3	353.6	349
		CO2 18 Wtr	bbl	46.4	51.1	34	31	22.2	20	13	19
		CO2 I-1 Wtr	bbl	94.3	0	0	0	0	0	0	0
	Cum Oil Rec		bbl	0.5	6.7	33.7	81.4	166.4	224.4	308.4	383.4

Summary of average daily data for carbon dioxide pilot

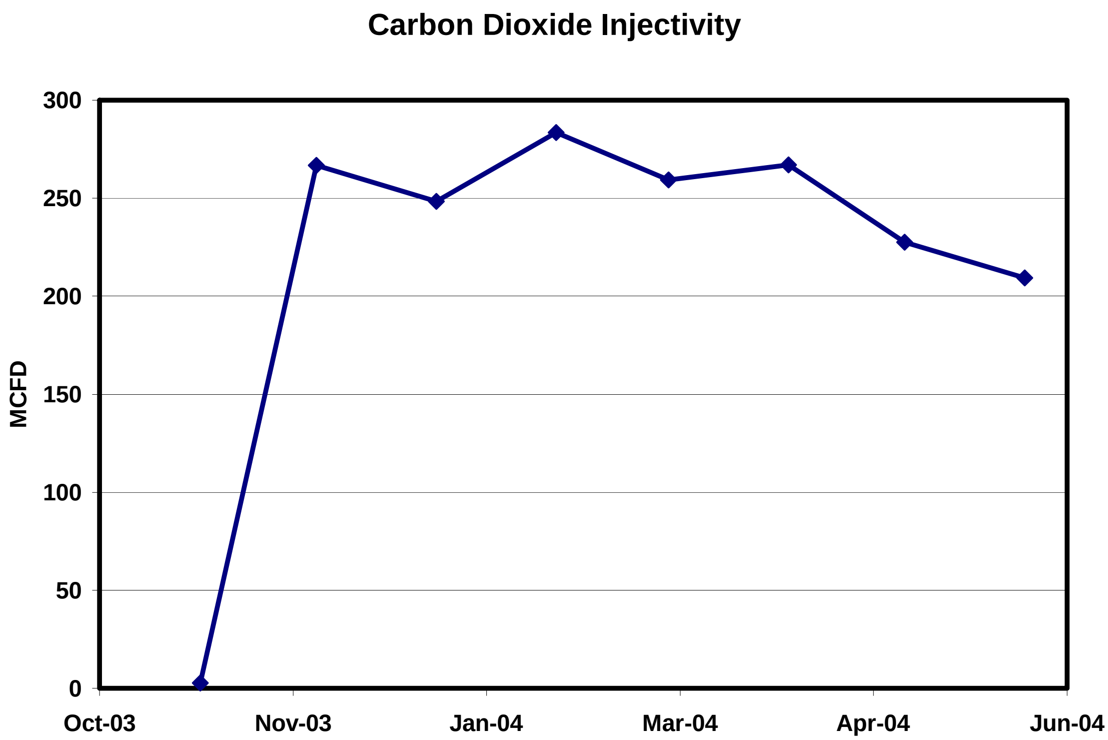

Figure 5: Carbon dioxide injection rate into pilot area

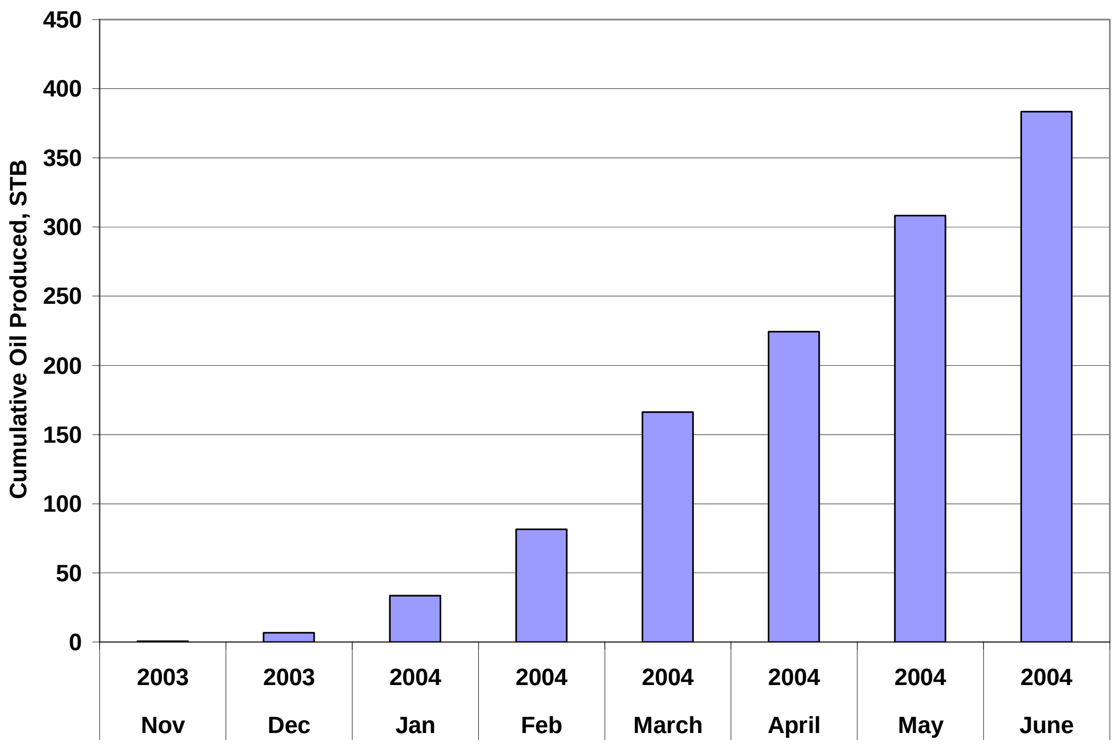

Figure 6: Cumulative oil production from CO2 pilot area

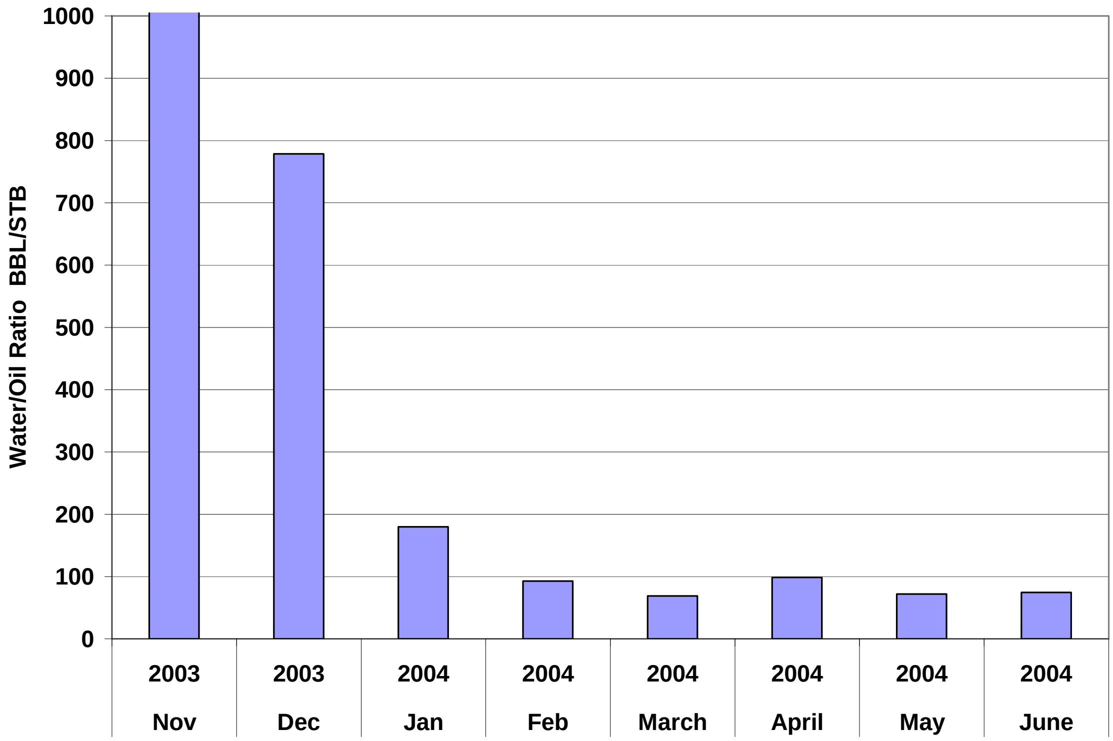

Figure 7: Water/oil ratio from CO2 pilot area

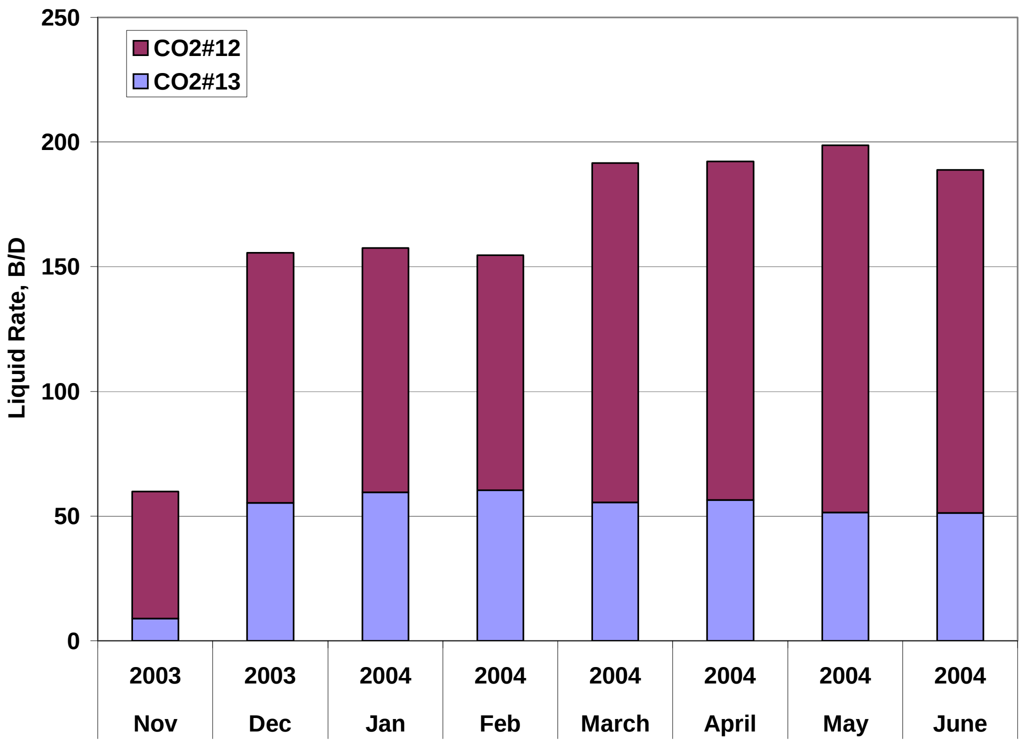

Figure 8: Liquid production rate from CO2#12 and CO2#13

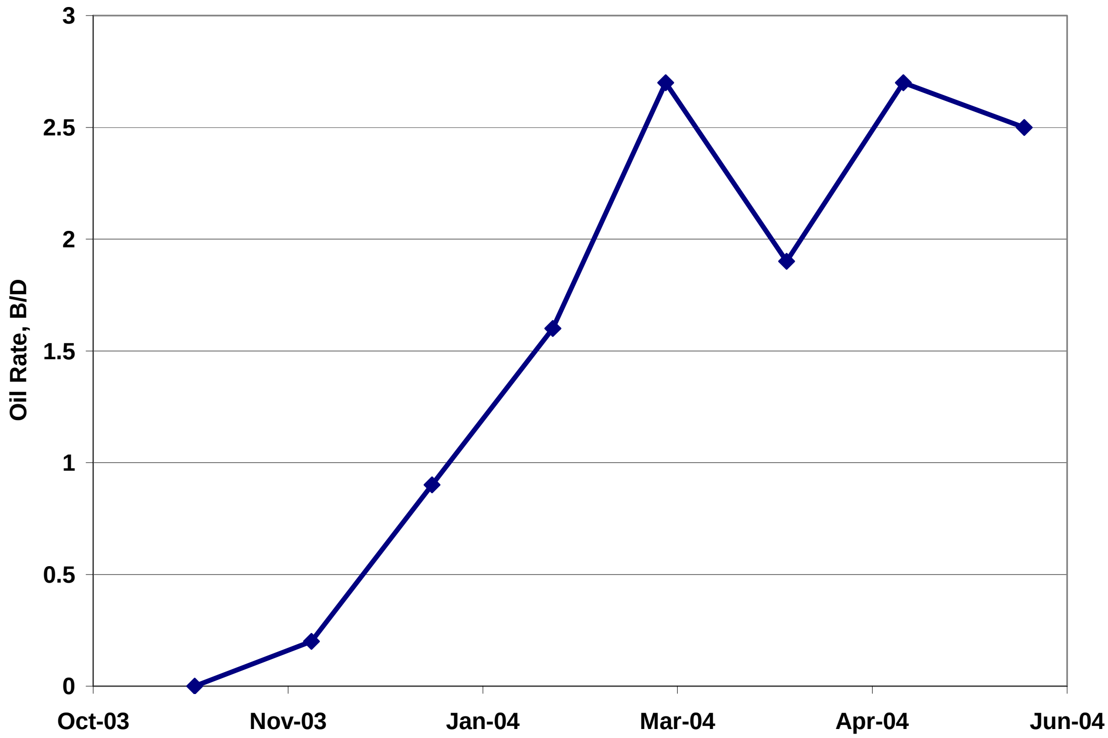

Figure 9: Average daily oil production rate from pilot area

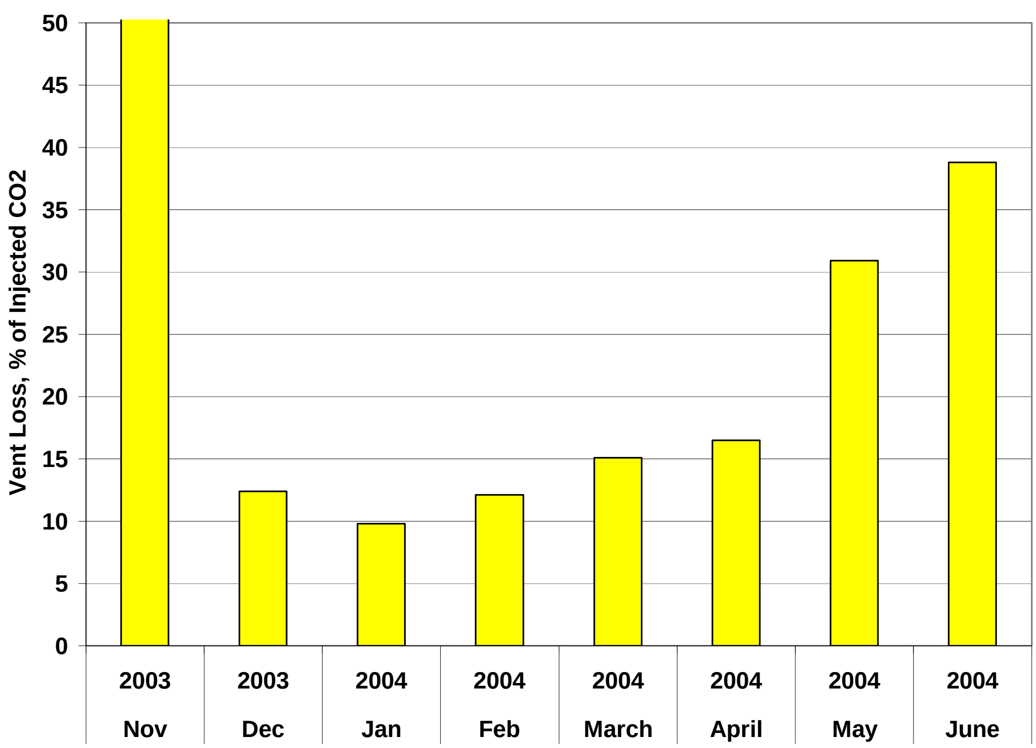

Figure 10: Average loss of carbon dioxide from tank vent

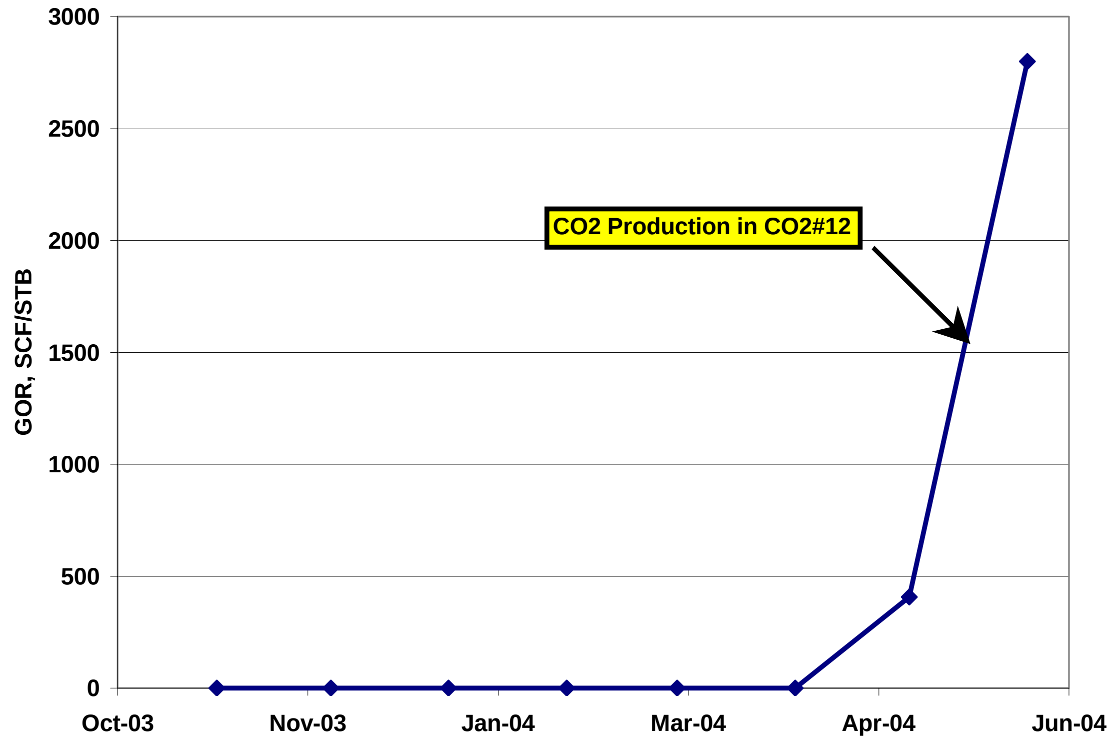

Figure 11: GOR from pilot area

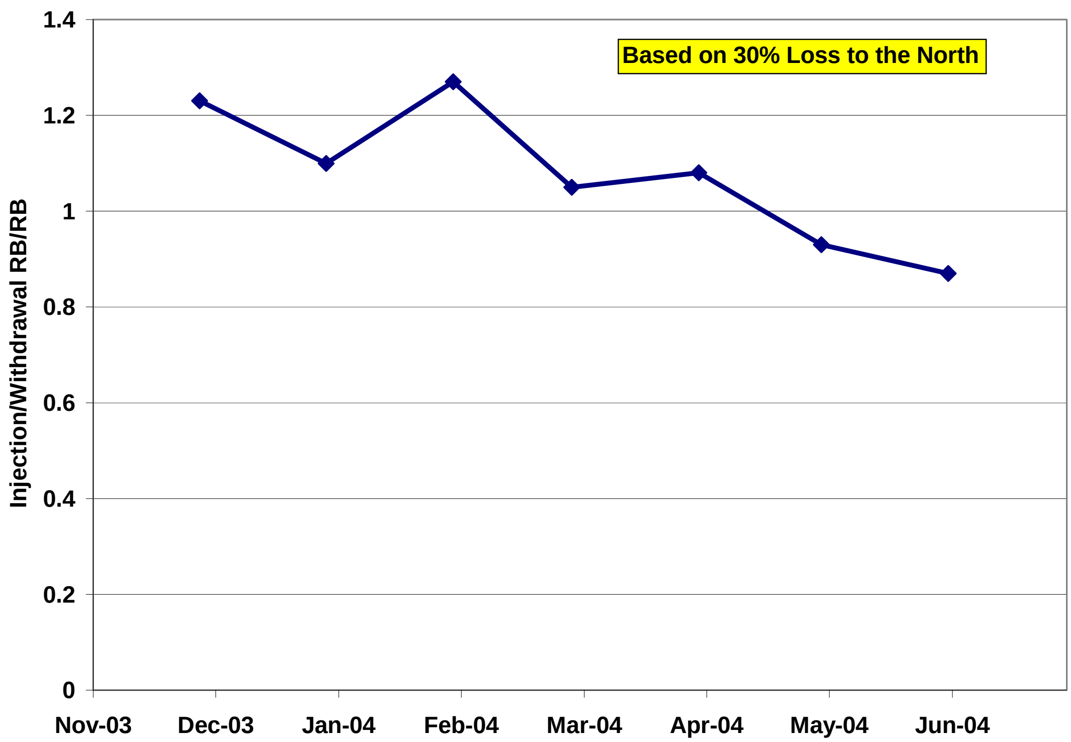

Figure 12: Estimated ratio of injection to withdrawal rates

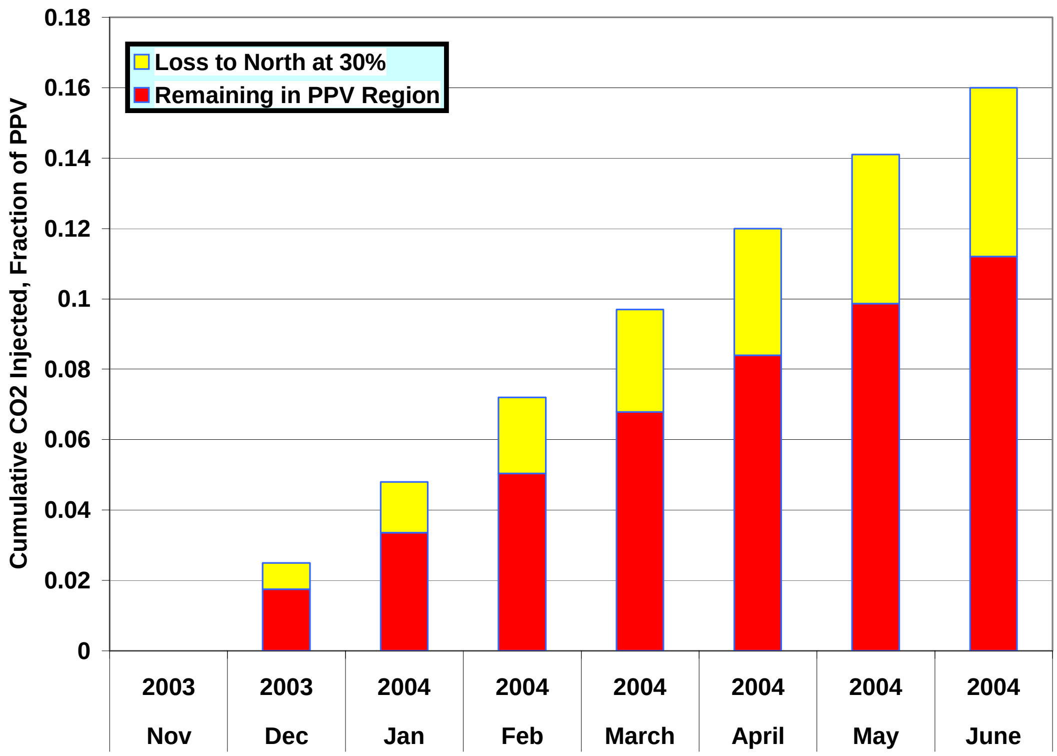

Figure 13: Distribution of injected carbon dioxide between pilot area and estimated losses to the north.

Few operational problems have been encountered during the first seven months of the project. Those which were encountered have been resolved or solutions identified for application in July and August. Further discussion follows in the remainder of this report.

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 contains two ½" Halliburton Flow meters and a MCII+ Flow Analyzer to measure flow rates. One flow meter is on stream and the second serves as a backup. The active flow meter is 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, 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 cannot distinguish between forward and reverse flows. Fluctuations in the flow rate are 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. Cumulative volume of carbon dioxide injected based on the Halliburton MCII+ analyzer overstated the amount injected by about 10%. The analyzer counts both forward and reverse flow as flow through the meter. 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 recommendation was made by the Technical Committee to install a flow meter, Halliburton MCII flow analyzer, temperature sensor, pressure transducer and data logger at the wellhead of CO2I-1. Installation was completed the end of May and reliable wellhead data were obtained throughout June. Wellhead data confirmed the upside bias of cumulative volume data obtained from the Halliburton MCII+ flow analyzer on the CO2 skid.

The primary CO2 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.

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 Technial 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 communicated on a nearly daily basis by telephone and 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

The beginning of carbon dioxide injection was celebrated on December 3,2003 at meeting and dinner in Russell, Kansas attended by 122 oil operators, representatives of the Working Interest Owners, the Lieutenant Governor of Kansas, representatives of the Department of Energy and the Chancellor of the University of Kansas and the City of Russell. Following brief remarks, participants were bused to the Murfin Colliver lease to see the injection equipment in operation. A tour was arranged of the ethanol plant operated by U.S. Energy Partners. The opening celebration was covered extensively by local and regional newspapers and television stations.

Figure 14: Celebration at Murfin Colliver Lease on December 3, 2003 initiating the beginning of carbon dioxide injection.

CONCLUSIONS

Continuous carbon dioxide injection began on the Murfin Colliver Lease on December 3, 2003. Operational problems associated with measurement of the injection rate were identified and resolved. The first carbon dioxide was detected in CO2#12 slightly more than six months after the beginning of injection. Oil rate from the pilot area increased from 0 B/D to about 2.5 B/D following the beginning of carbon dioxide injection. Interpretation of pressure measurements in the pilot area indicates that losses from the pilot area to the north are within the estimates based on the design of the flood.