SEMI ANNUAL TECHNICAL PROGRESS REPORT
FOR THE PERIOD ENDING DECEMBER 31, 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

DOE Program: Class II Revisited - Field Demonstrations

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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. Continuous carbon dioxide injection began on December 2, 2003. By the end of December 2004, 11.39 MM lb of carbon dioxide were injected into the pilot area. Carbon dioxide injection rates averaged about 242 MCFD. Vent losses were excessive during June as ambient temperatures increased. Installation of smaller plungers in the carbon dioxide injection pump reduced the recycle and vent loss substantially. Carbon dioxide was detected in one production well near the end of May and in the second production well in August. No channeling of carbon dioxide was observed. The GOR has remained within the range of 3000-4000 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, increasing to an average of about 2.35 B/D for the six month period between July 1 and December 31. Cumulative oil production was 814 bbls. Neither well has experienced increased oil production rates expected from the arrival of the oil bank generated by carbon dioxide 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 December 2004, about 11.39MM lbs of carbon dioxide were injected at an average rate of about 234 MCFD. The initial production was 100% water with oil arriving in February 2004. Oil rates averaged 2.35 B/D from July –December 2004. Cumulative oil production was 814 bbl. Incremental oil production was 814 bbls. Neither well has experienced increased oil production rates expected from the arrival of the oil bank. Carbon dioxide was detected in CO2#12 in late May and in CO2#12 in August. Volume of carbon dioxide produced has remained low with GORs on the order of 3000-4000.

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.

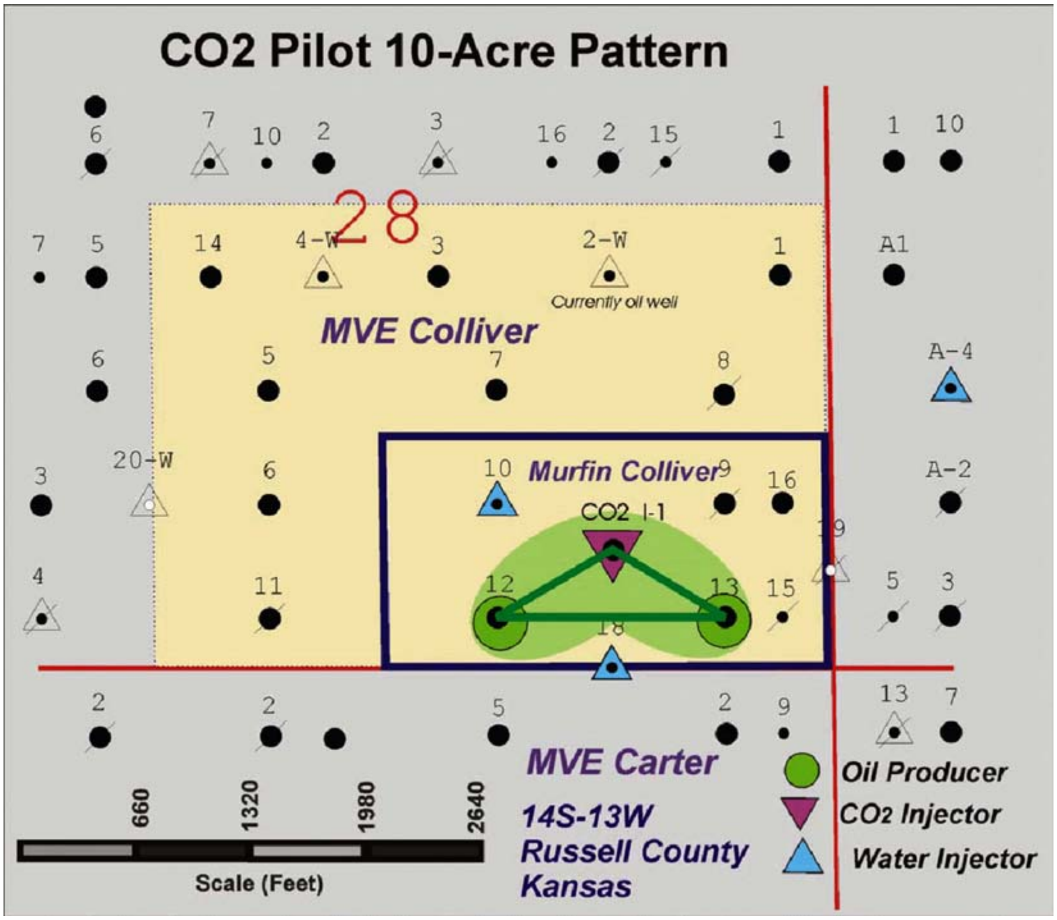

Figure 1: Murfin Colliver Lease in Russell County, Kansas

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 23,2003 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 thirteen months, 11.31 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. On June 29,2004 the plungers in the Aplex A-50 pump were replaced by 1 ¼" plungers, reducing the injection rate. The injection rate was 0.0478 gallons per revolution or 5.74 gpm when the pump ran the minimum rate of 120 rpm. Vent losses were reduced significantly. Vent losses for July averaged 10% of the injected CO2 and 4% of the injected CO2 in August. Vent losses from the beginning of carbon dioxide injection are shown in Figure 3.

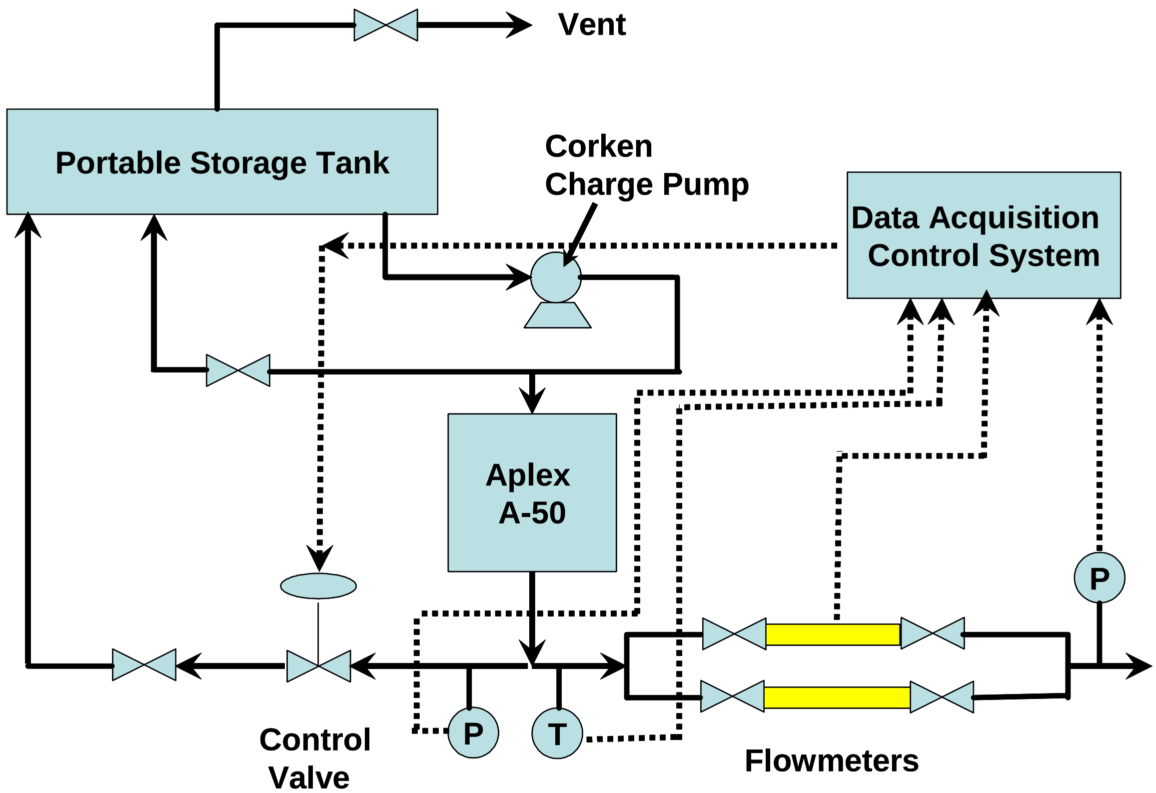

Figure 2: Flow schematic of CO2 Injection Skid and Portable Storage Tank

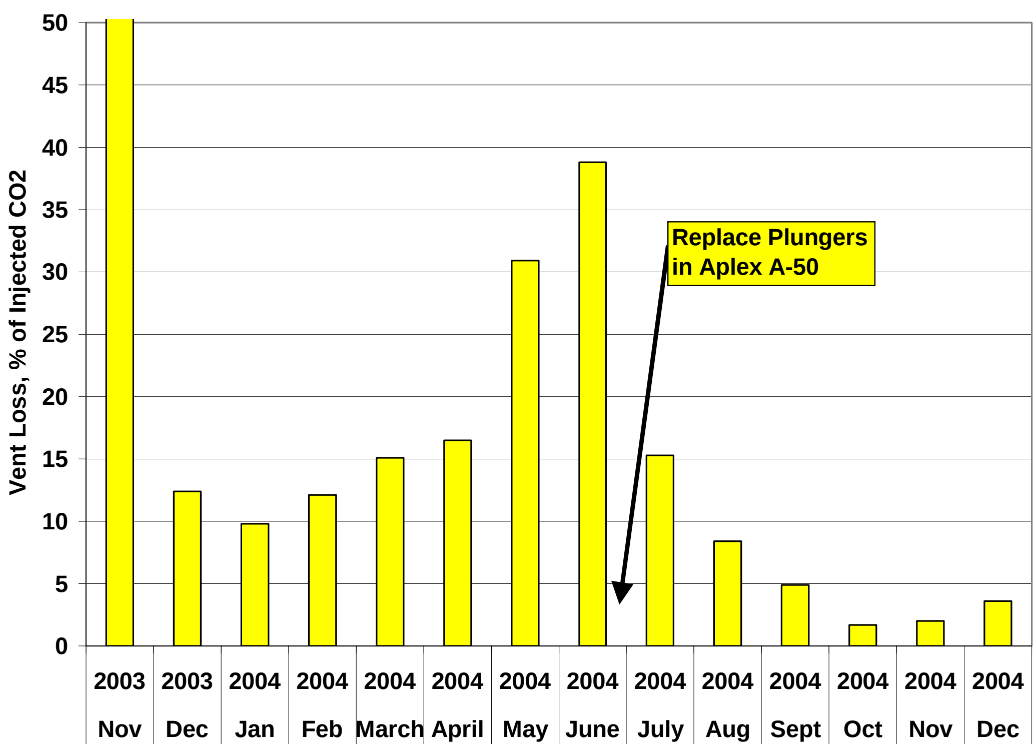

Figure 3: Vent Loss From Storage Tank as a Percentage of Injected CO2

Figure 4 shows the monthly carbon dioxide injection rate. The injection rate declined substantially in May through June 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. The injection skid was down for several days in July due to mechanical problems.

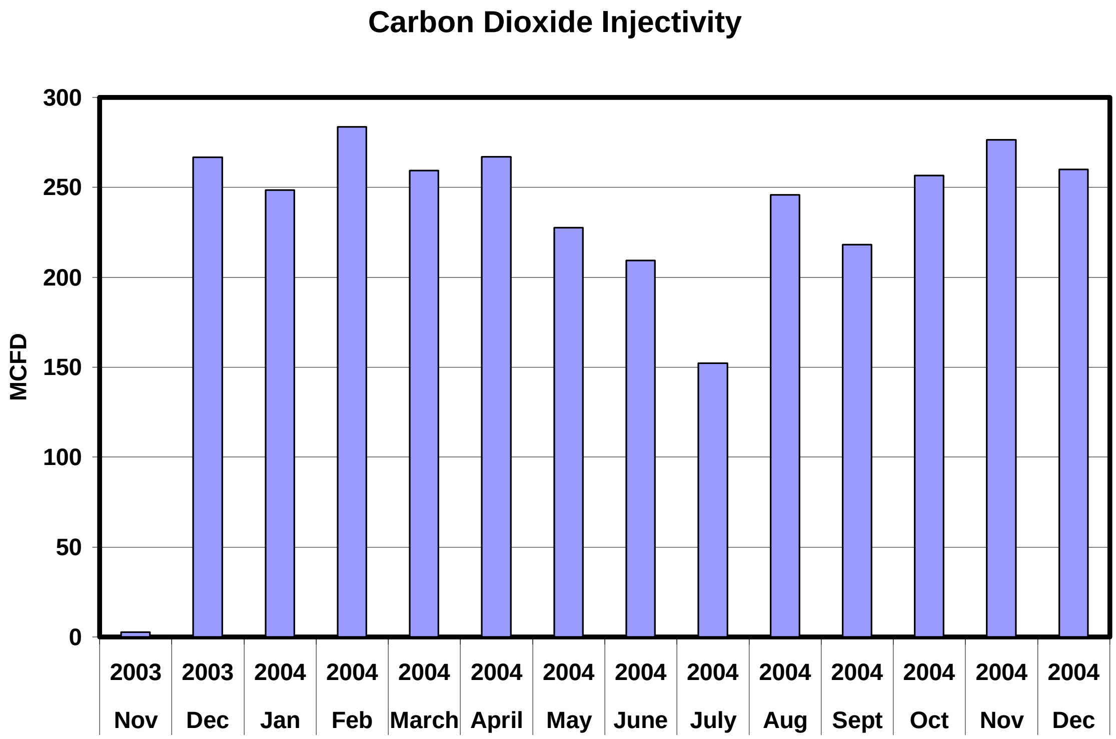

Figure 4: Carbon Dioxide Injection Rate in CO2I-1

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 end of September based on individual well pressures. The pressure in the pilot region declined during the period from July through September due to the under injection of carbon dioxide in July and expansion of the portion of the reservoir contacted by carbon dioxide.

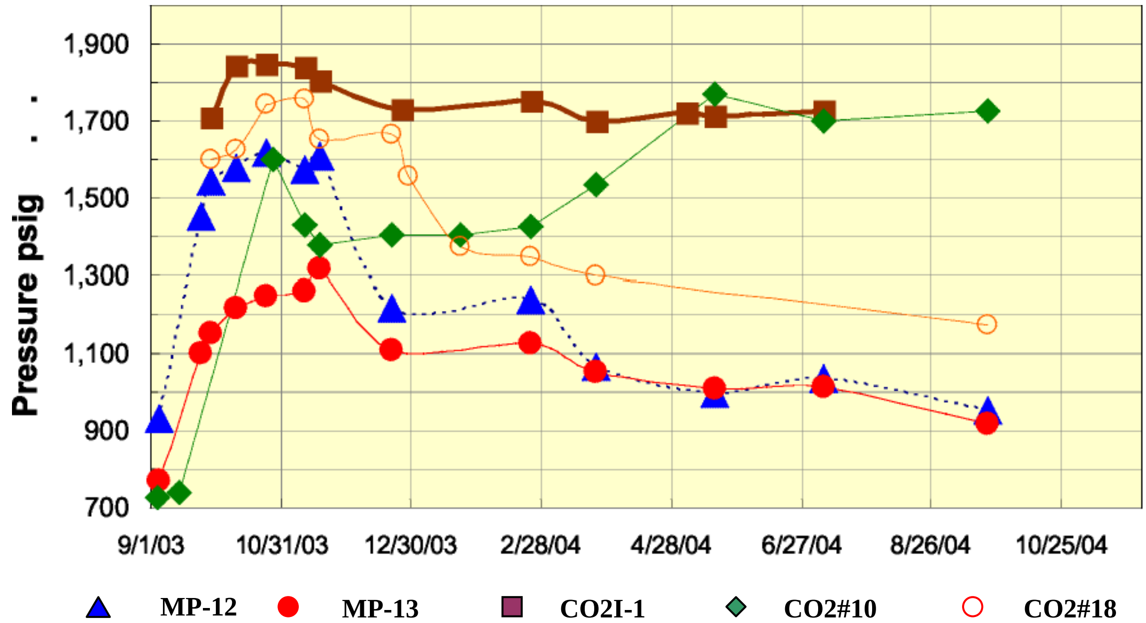

Figure 5: Pressures in the Injection Wells and at Monitoring Points.

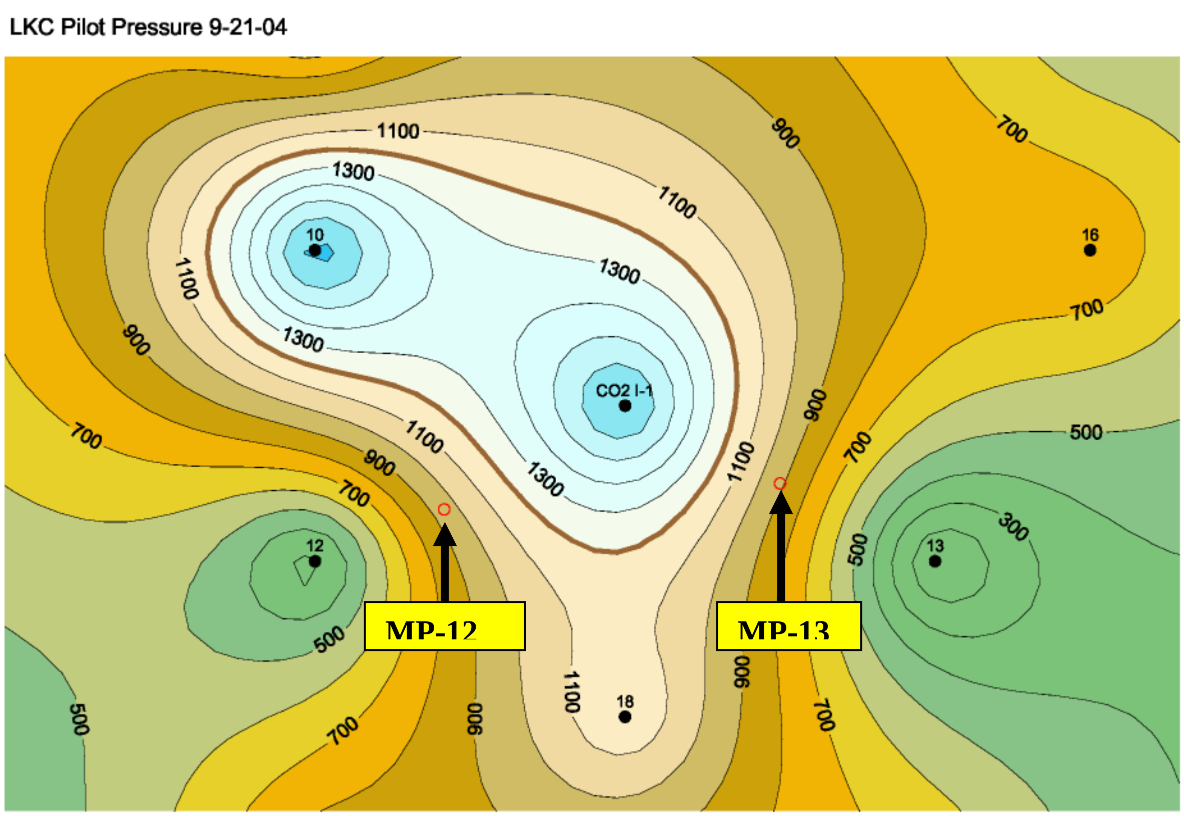

Figure 6: Estimated Pressure Distribution in CO2 Pilot Area

Average daily and monthly data are presented in Tables 1 and 2 for the period from November 2003-December 2004. Monthly average liquid production data from wells CO2#12 and CO2#13 are shown in Figure 7. 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 averaged 139 B/D for the period for July-November. In December, 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. 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.

CO2#13 did not respond to carbon dioxide injection by the beginning of December other than a small amount of produced CO2 and some changes in the gas composition. 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. Water and oil production rates decreased in December due to reduction of the total fluid withdrawal rate in CO2#12 and shutting in CO2#13.

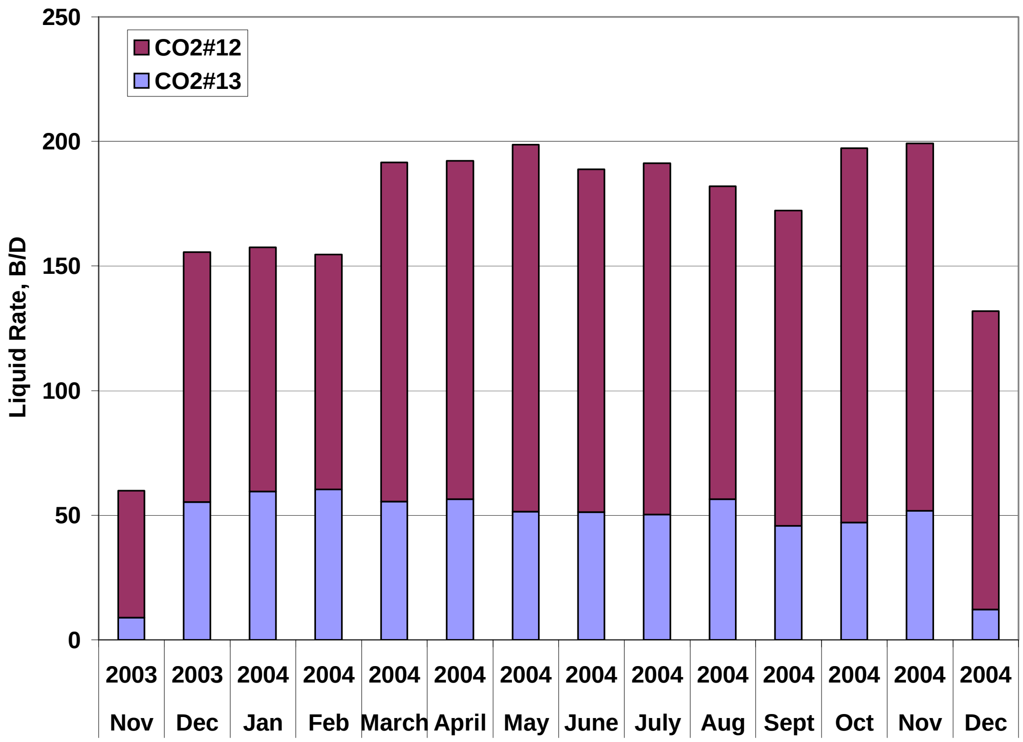

Figure 7: Liquid production rate from CO2#12 and CO2#13

At the beginning of the project, both production wells CO2#12 and CO2#13 produced 100% water. By the end of December, oil production averaged 1.6 B/D, primarily from CO#12. Oil production averaged 2.5 B/D for the period from March-June. Average daily oil production rates are shown in Figure 8. Water production averaged 161 B/D for the period from November 2003-June 2004. Carbon dioxide arrived at CO#12 on May 31 and arrived at CO2#13 in August. 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 0-4

MCF/STB as shown in Figure 9. Cumulative oil production was 814 STB through December 2004 and is shown in Figure 10. Water oil ratios are shown in Figure 11.

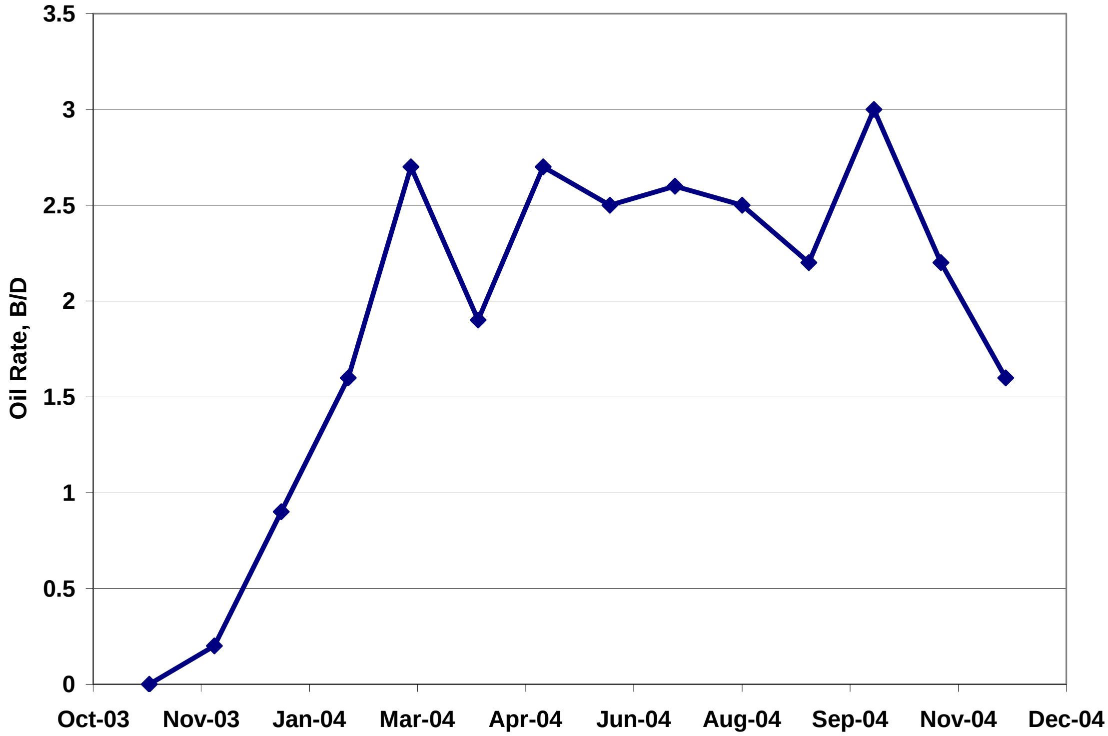

Figure 8: Average daily oil production rate from pilot area

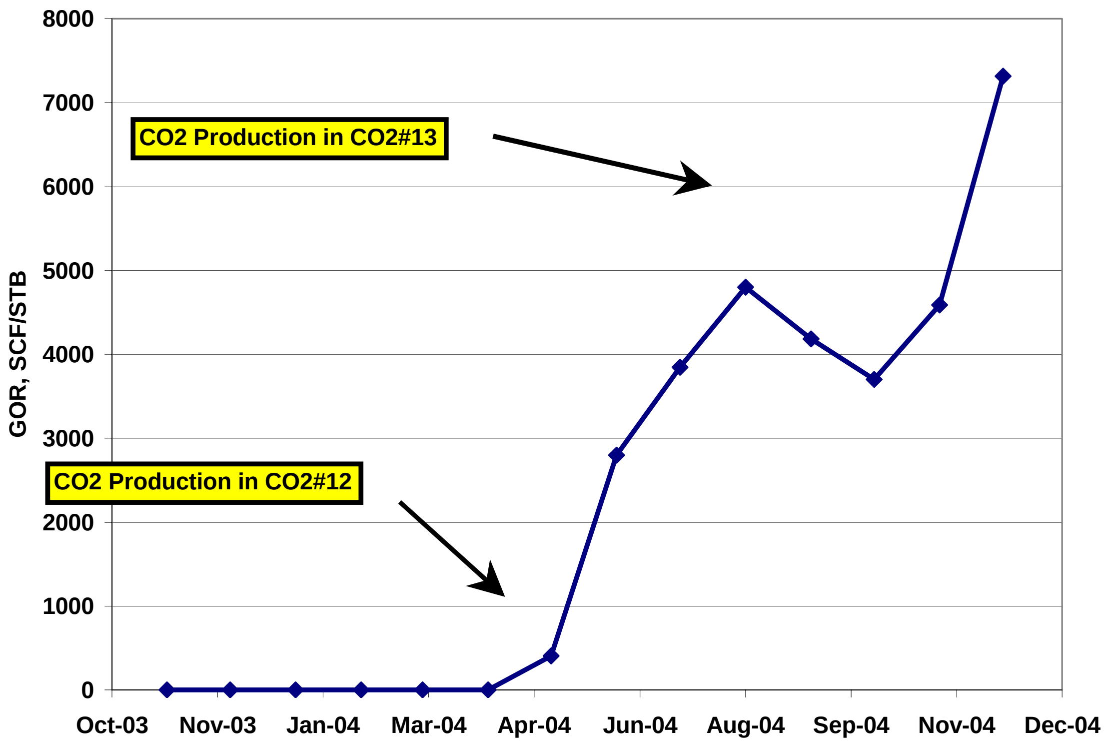

Figure 9: GOR from pilot area

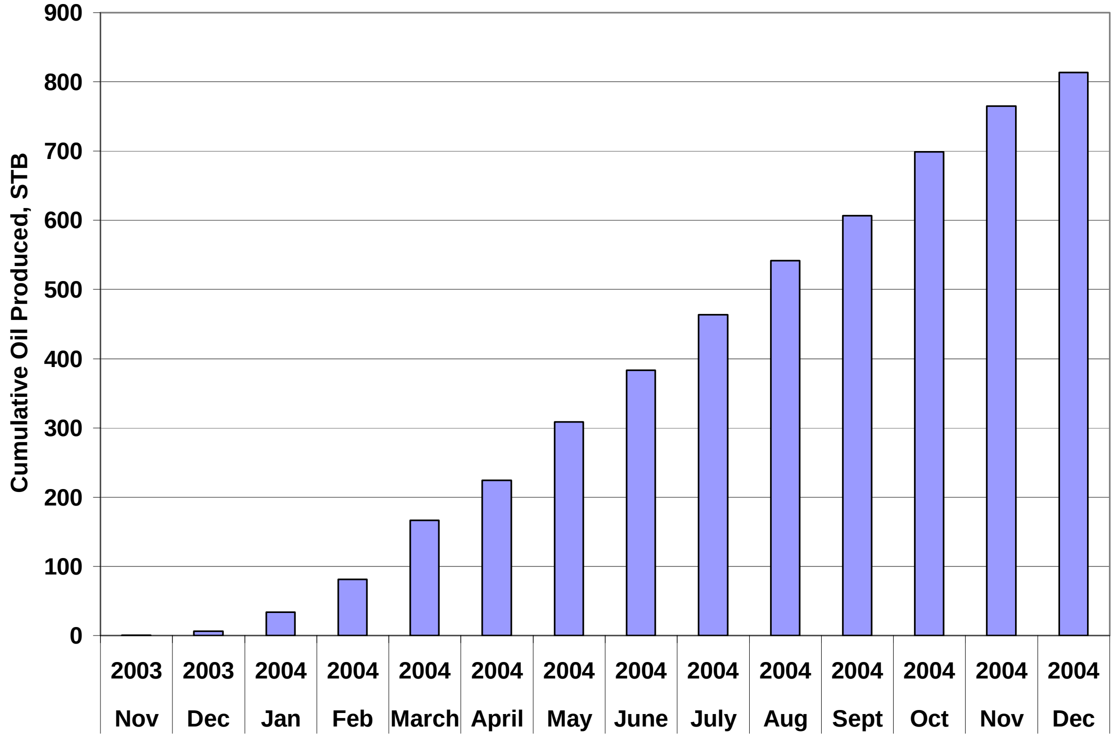

Figure 10: Cumulative oil production from CO2 pilot area

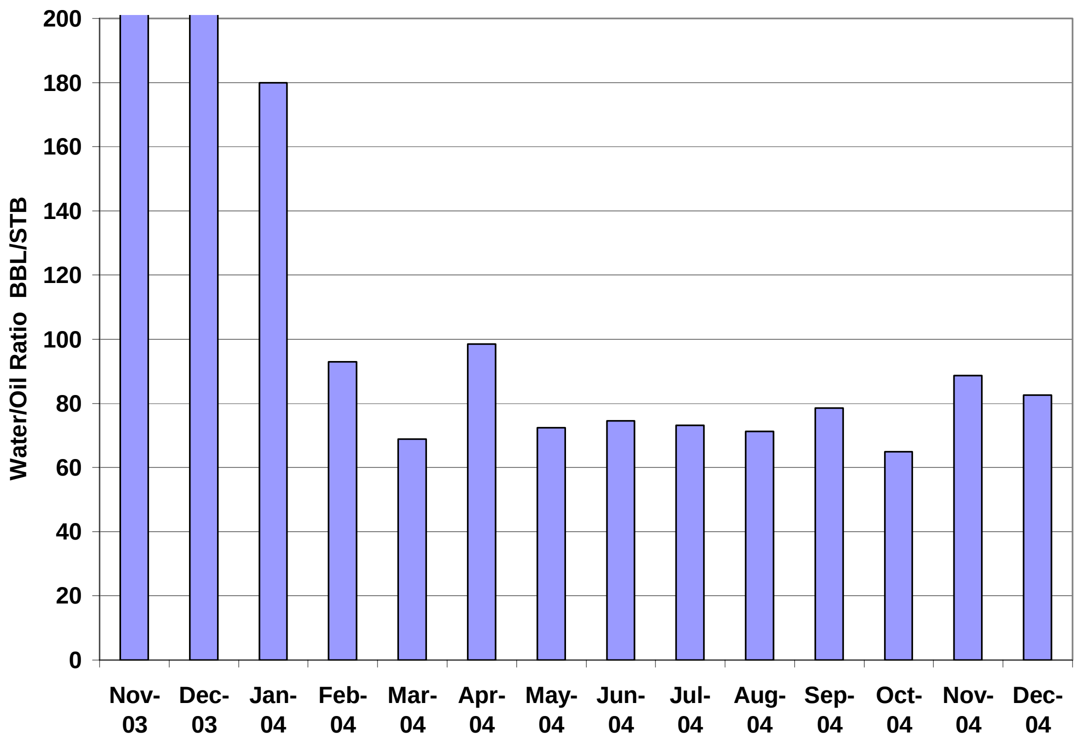

Figure 11: Water/oil ratio from CO2 pilot area

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. 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 November 2003-December 2004

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 from December 2003-February and stabilized ~1 after the production rate in CO2#12 was increased in March. The decline in I/W ratio from May-July is due to excessive vent loss and down time on the injection skid. Three months of stable operation in August-November were followed by a large increase in I/W ratio for December due to reduction in the production rate of CO2#12 and shutting in of CO2#13 for the carbon dioxide stimulation that was done on December 9. Restoring the I/W ratio to 1.0 is necessary for effective management of the pilot project.

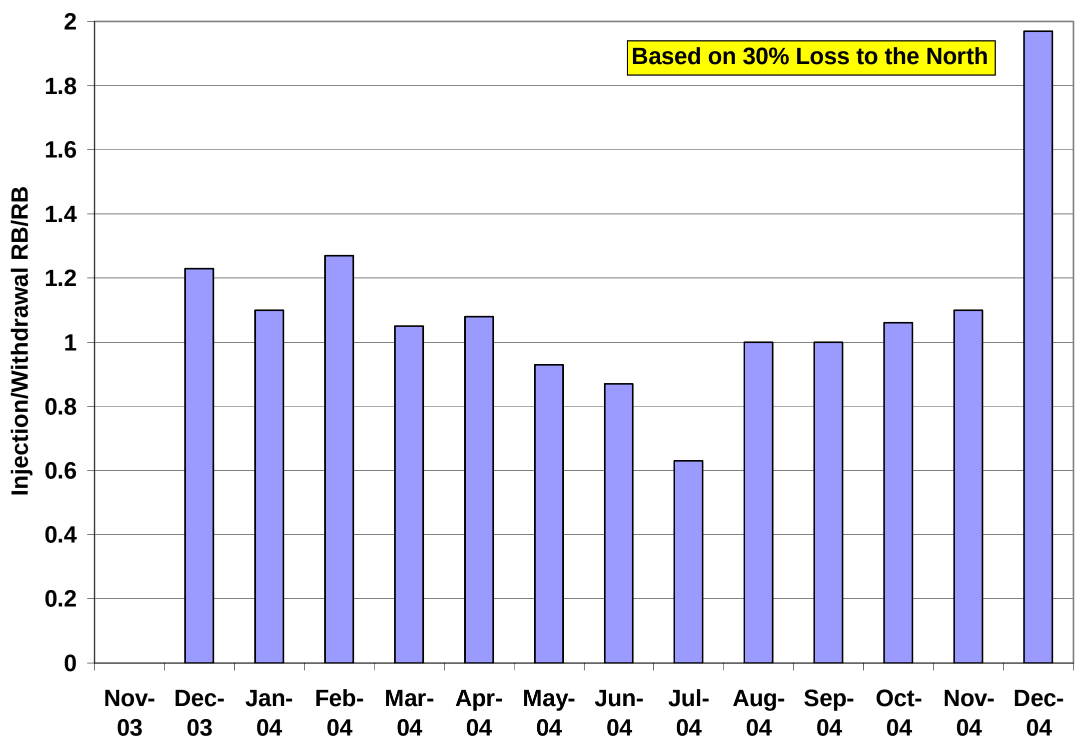

Figure 12: Estimated ratio of injection to withdrawal rates

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.

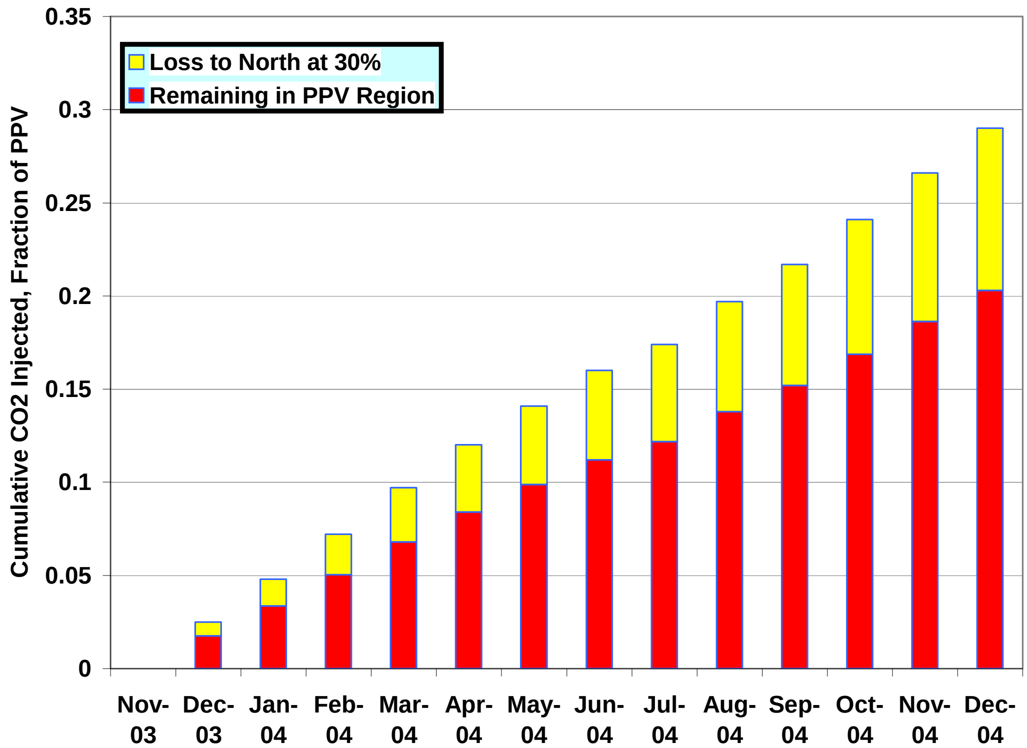

Figure 13: Distribution of injected carbon dioxide between pilot area and estimated losses to the north.

Operational Problems

The CO2 injection pump is 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 3.

High fluid levels were persistent in CO2#12 beginning in December. 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. The cause of the production rate decline remained under study throughout December and remained unresolved.

In October, injection into CO2#10 and CO2#18 was switched from fresh water to produced water. Produced water was injected intermittently into CO2#10 at instantaneous rates that were 2-3 times larger than the required rate to maintain the pressure in the vicinity of the well. A uniform injection rate is needed in CO#10.

In December, the Project Team became concerned that there was no oil response in CO2#13 even though our reservoir simulations indicated that there was an oil bank in the vicinity of the well. A decision was made to attempt to create a favorable permeability path for the oil bank to move into CO2#13 by conducting a carbon dioxide stimulation treatment as reported earlier in this report. Two loads of carbon dioxide were injected into the well on December 9 and the well was shut-in for 26 days.

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 on the project at NETL's Tulsa's office on September 15, 2004, the Tertiary Oil Recovery Advisory Board on November 12, 2004 and the 10th Annual Carbon Dioxide Conference, held in Midland, TX, December 8, 2004. Presentations are planned for the 16th Oil Recovery Conference in April 7, 2005.

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 and in CO2#13 in August. Oil rate from the pilot area increased from 0 B/D to about 2.5 B/D following the beginning of carbon dioxide injection. The GOR remained constant at ~4000 indicating no channeling of carbon dioxide into production wells. Incremental oil production was 814 bbls. Neither well has experienced increased oil production rates expected from the arrival of the oil bank. 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. Balancing injection and withdrawal rates remains an operating challenge.

Table 1
Summary of Monthly Data
November 2003-December 2004

Field			Nov 2003	Dec 2003	Jan 2004	Feb 2004	Mar 2004	April 2004	May 2004	June 2004	July 2004	Aug 2004	Sept 2004	Oct 2004	Nov 2004	Dec 2004
I/W With 30% North Losses				1.23	1.1	1.27	1.05	1.08	0.93	0.87	0.63	1	1	1.06	1.1	1.97
PPV Inj CO_2 I-1		%	0.000	0.025	0.048	0.072	0.097	0.120	0.141	0.160	0.174	0.197	0.217	0.241	0.266	0.29
Production		Loss		0.0075	0.0144	0.0216	0.0291	0.036	0.0423	0.048	0.0522	0.0591	0.0651	0.072	0.080	0.087
		In Pattern		0.02	0.03	0.05	0.07	0.08	0.10	0.11	0.12	0.14	0.15	0.169	0.186	0.203
	Oil	bbl	0.5	6.2	27	47.7	85	58	84	75	80	78.1	65	92.7	66	48.9
	Wtr	bbl	1,794	4,829	4,858	4,432	5,853	5,713	6,078	5,589	5,849	5,567	5104	6022	5814	4038
	Gas	mcf	0	0	0	0	0	0	33.9	211	312	374	274	344.5	304	363.4
	WOR	bbl/bbl	3588	779	180	93	69	99	72	75	73	71	78.52	64.96	88.63	82.58
	Cumulative Oil		0.5	6.7	33.7	81.4	166.4	224.4	308.4	383.4	463.4	541.5	606.5	699.2	764.8	813.7
Injection	Wtr	bbl	9,333	7,433	7,514	7,106	8,515	11,200	11,365	11,042	10,958	10,882	11228	10745	12,596	11,357
	CO_2	mcf	82	8268	7699	8222	8042	8011	7051	6280	4918	7613	6542	7958	8290	8057
		Mlb	9.479	958.773	898.156	959.216	938.195	934.554	822.562	732.618	573.728	888.824	763.224	928.371	967.049	939.93
CO_2 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	5,724.50	8,128.00	7006.9	7891.9	8786.3	8475.2
		Mlb	86	1091	964	1078	1079	1120	1045	1045	664	943	813	915	1019	983
		Tons	43.2	545.4	481.8	538.9	539.5	559.9	522.3	522.5	331.9	471.3	406.3	457.6	509.5	491.4
Tank Vent																
		mcf	316.6	1,028.00	753	990.9	1,214.40	1,320.20	2,175.90	2,437.20	753.2	637.5	321.8	134.2	165.1	293.1
		Mlb	36.72	119.22	87.33	114.92	140.83	153.1	252.34	282.64	87.35	73.93	37.21	15.56	19.14	34
		% of Injection	387.40%	12.40%	9.80%	12.10%	15.10%	16.50%	30.90%	38.80%	15.30%	8.40%	4.90%	1.70%	2.00%	3.60%

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

Field			Nov 2003	Dec 2003	Jan 2004	Feb 2004	March 2004	April 2004	May 2004	June 2004	July 2004	Aug 2004	Sept 2004	Oct 2004	Nov 2004	Dec 2004
Production																
	Oil	bbl	0	0.2	0.9	1.6	2.7	1.9	2.7	2.5	2.6	2.5	2.2	3	2.2	1.6
	Wtr	bbl	59.8	155.8	156.7	152.8	188.8	190.4	196.1	186.3	188.7	179.6	170.1	194.3	193.8	130.3
	Gas	mcf	0	0	0	0	0	0	1.1	7	10.1	12.1	9.1	11.1	10.1	11.7
Injection																
	Wtr	bbl	311.1	239.8	242.4	245	274.7	373.3	366.6	368.1	353.5	351	374.3	346.6	419.9	366.4
	CO2	mcf	2.7	266.7	248.4	283.5	259.4	267	227.5	209.3	152.2	245.8	218.1	256.7	276.3	259.9
		Mlb	0.3	30.9	29	33.1	30.3	31.2	26.5	24.4	17.8	28.7	25.4	29.9	32.2	30.3
CO2 Delivered																
		mcf	24.9	303.4	268.1	320.5	300.1	321.9	290.6	300.3	184.7	262.2	233.6	254.6	292.9	273.4
		Mlb	2.9	35.2	31.1	37.2	34.8	37.3	33.7	34.8	21.4	30.4	27.1	29.5	34	31.7
Tank Vent																
		mcf	10.6	33.2	24.3	34.2	39.2	44	70.2	81.2	24.3	20.6	10.7	4.3	5.5	9.5
		Mlb	1.2	3.8	2.8	4	4.5	5.1	8.1	9.4	3.6	2.4	1.2	0.5	0.6	1.1
		% of Injection	387.40	12.40	9.80	12.10	15.10	16.50	30.90	38.80	15.30	8.40	4.9	1.70	2.00	3.60
Wells																
Production																
CO2 12	Oil	bbl	0	0.2	0.3	0.7	2.5	1.2	2.3	1.6	2.5	1.8	2	2.5	1.4	1.3
	Wtr	bbl	50.9	100.1	97.7	93.5	133.6	134.6	145.1	136	138.5	123.9	124.6	147.7	146.1	118.4
	Gas	mcf	0	0	0	0	0	0	1.1	7	9.5	11.6	9	10.9	9.8	11.6
	Total Liquid		50.9	100.3	98	94.2	136.1	135.8	147.4	137.6	141	125.7	126.6	150.2	147.5	119.7
	GOR			0	0	0	0	0	478	4375	3800	6444	4500	4360	7000	8923
CO2 13	Oil	bbl	0	0	0.5	1	0.3	0.7	0.4	0.9	0.1	0.7	0.2	0.5	0.8	0.3
	Wtr	bbl	8.9	55.3	59	59.4	55.2	55.8	51	50.3	50.2	55.7	45.5	46.6	51	11.9
	Gas	mcf	0	0	0	0	0	0	0	0	0.5	0.4	0.2	0.2	0.3	0.1
Total Liquid		bbl	8.9	55.3	59.5	60.4	55.5	56.5	51.4	51.2	50.3	56.4	45.7	47.1	51.8	12.2
GOR		bbl/bbl									5000	571	1000	400	375	333
Total Liquid-Pattern		bbl	59.8	155.6	157.5	154.6	191.6	192.3	198.8	188.8	191.3	182.1	172.3	197.3	199.3	131.9
Total Gas_pattern		mcf	0	0	0	0	0	0	1.1	7	10	12	9.2	11.1	10.1	11.7
GOR-Pattern		mcf/bbl	0	0	0	0	0	0	407	2800	3846	4800	4182	3700	4591	7313
Injection																
CO2 10	Wtr	bbl	170.4	188.6	208.4	214	252.5	353.3	353.6	349	333.1	329.9	336	326	381.2	359.1
CO2 18	Wtr	bbl	46.4	51.1	34	31	22.2	20	13	19	20.4	21.2	38.2	20.6	38.7	7.3
CO2 I-1	Wtr	bbl	94.3	0	0	0	0	0	0	0	0	0	0	0	0	0