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WEST HACKBERRY TERTIARY PROJECT

Annual Report
September 03, 1995 to September 02, 1996

By
Travis H. Gillham
Bruce Cerveny
Ed Turek

May 1997

Performed Under Contract No. DE-FC22-93BC14963

Amoco Production Company
Houston, Texas

National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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1.0 ABSTRACT

1.1 Brief Description of Research

The West Hackberry Tertiary Project is a field test of the concept that air injection can be combined with the Double Displacement Process to produce a tertiary recovery process that is both low cost and economic at current oil prices. The Double Displacement Process is the gas displacement of a water invaded oil column for the purpose of recovering tertiary oil by gravity drainage. In reservoirs with pronounced bed dip such as those found in West Hackberry and other Gulf Coast salt dome fields, reservoir performance has shown that gravity drainage recoveries average 80% to 90% of the original oil in place while waterdrive recoveries average 50% to 60% of the original oil in place. The target for tertiary oil recovery in the Double Displacement Process is the incremental oil between the 50% to 60% waterdrive recoveries and the 80% to 90% gravity drainage recoveries.

In previous field tests, the Double Displacement Process has proven successful in generating tertiary oil recovery. The use of air injection in this process combines the benefits of air's low cost and universal accessibility with the potential for accelerated oil recovery from the combustion process. If successful, this project will demonstrate that utilizing air injection in the Double Displacement Process will result in an economically viable tertiary process in reservoirs (such as Gulf Coast salt dome reservoirs) where any other tertiary process is presently uneconomic.

1.2 Summary of Key Results and Conclusions

Air injection on the west flank began in November of 1994. Although west flank air injection has increased reservoir pressure by 350 pounds per square inch (psi), production response has not yet occurred. The lack of west flank production response is attributed to the fact that the project has not injected sufficient air in the large west flank reservoir to push the oil rim down to the nearest downstructure well. While west flank air injection continues, production response is expected to occur during the upcoming 12 months.

To spread project risk among multiple reservoirs, the project was expanded in 1996 to include air injection in reservoirs on the north flank of the field. The project reservoirs on the west flank are much higher pressure (2500-3300 psi) than the project reservoirs on the north flank (350-800 psi). While west flank air injection has not yet yielded oil production, air injection in the first low pressure north flank reservoir generated an almost immediate increase in oil production. After north flank air injection began in July of 1996, the nearest downstructure well increased production from about 40 barrels of oil per day (BOPD) prior to injection to 177 BOPD in August of 1996. The additional oil production noted in August of 1996 in the low pressure north flank reservoir is: 1) the first oil production resulting from air injection in the West Hackberry Tertiary Project and 2) the

first occasion that air injection has been used to successfully increase oil production in a Gulf Coast salt dome oil reservoir.

While air injection is beginning to demonstrate success in the low pressure north flank reservoirs, additional air injection will be required before production response is seen on the west flank of the field. During the upcoming year, air injection will be split between the higher pressure west flank reservoir and several low pressure north flank reservoirs with the ultimate goal to maximize production response in as many reservoirs as possible.

2.0 EXECUTIVE SUMMARY

2.1 Background

The following report is the Annual Technical Progress Report for the third year of the West Hackberry Tertiary Project and covers the time period from September 3, 1995 to September 2, 1996. The West Hackberry Tertiary Project is one of four mid-term projects selected by the United States Department of Energy (DOE) as part of the DOE's Class 1 Program for the development of advanced recovery technologies in fluvial dominated deltaic reservoirs. Over an 82 month funding period from September 3, 1993 to July 2, 2000, Amoco and the DOE are implementing a field test of the theory that air injection can be combined with the Double Displacement Process to create a tertiary oil process that is economically viable for the domestic oil industry. As part of the project, the Petroleum Engineering Department at Louisiana State University (LSU) has been subcontracted to provide independent study and technology transfer support. To provide a further project description, the Statement of Work for the West Hackberry Tertiary Project is contained in Appendix A.

West Hackberry is a salt dome oil field located in Southwestern Louisiana about 30 miles southwest of Lake Charles, Louisiana. Although the project originally targeted Oligocene Age reservoirs on the west flank of the field, Amoco and the DOE agreed to expand the project to the north flank during 1996. Injection on the west flank of the field will test the process in higher pressure (2500-3300 psi) reservoirs which have watered out. Injection on the north flank will test the process in low pressure (350-800 psi) reservoirs that are approaching depletion. The low pressure north flank reservoirs exhibit slow water encroachment, possess low pressure gas caps and contain thin oil rims.

2.2 Conclusions

The following conclusions have been generated during the third year of the project:

1) Pressure response on the west flank noted thus far is the result of air injection and confirms the original geologic picture.

2) Oil production has not yet occurred on the west flank since the oil rim has not moved sufficiently downstructure to reach the first producing well. The lack of production response on the west flank can be attributed to the large size of the reservoir, the high reservoir pressure which inhibits the growth of the gas cap, uncertainty as to the pre-injection location of the oil rim and an insufficient volume of air injected to date.

3) Air injection in a low pressure north flank oil reservoir has generated almost immediate and promising production response. In this and other low pressure oil reservoirs, additional air injection and production response will be required to prove that air injection can economically produce improved oil recovery in low pressure Gulf Coast oil reservoirs.

2.3 Recommendations

The following recommendations are presented for the upcoming year:

1) Divide air injection between the high pressure west flank reservoirs and several low pressure north flank reservoirs with the ultimate goal to maximize production response in as many reservoirs as possible.
2) Monitor reservoir performance with production data, bottom hole pressure surveys, well tests and produced oil, gas and water analyses.
3) Utilize production response to guide the timing for workovers and the timing for rotating air injection from one reservoir to another.
4) After increased oil production has been achieved in three or more West Hackberry reservoirs, plan and coordinate a technology transfer program with LSU involving workshops, talks with industry groups, articles in industry publications and the publishing of technical papers.

3.0 Introduction

In the West Hackberry Tertiary Project, air is injected into watered out oil reservoirs on the west flank and into lower pressure north flank oil reservoirs that are nearing depletion. In both situations, air injection is combined with the Double Displacement process in an attempt to generate an economically viable tertiary recovery process for Gulf Coast oil reservoirs with pronounced bed dip. The Double Displacement Process is the gas displacement of a water invaded oil column for the purpose of recovering tertiary oil by gravity drainage. In West Hackberry Field, gravity drainage recoveries average 80% to 90% of the original oil in place while waterdrive recoveries average 50% to 60% of the original oil in place. The target for tertiary oil recovery in the Double Displacement Process is the incremental oil between the 50% to 60% waterdrive recoveries and the 80% to 90% gravity drainage recoveries.

For air injection to work successfully with the Double Displacement Process, the reservoir temperature must be high enough for oxygen to be consumed through combustion with the reservoir oil. Amoco has performed laboratory tests which prove that West Hackberry oil will spontaneously combust with oxygen in the pore space. The combustion of oxygen in the reservoir alleviates concerns relating to the presence of oxygen in the reservoir or production equipment. Oxygen in the reservoir can form viscous emulsions hindering the flow of oil in the well and in the production equipment. Oxygen that reaches the producing wells can also produce corrosion and or explosions in the production equipment.

In the higher pressure (2000-3300 psi) west flank reservoirs, the mechanics of the tertiary process involve: 1) injecting air into the crest of a watered out oil reservoir in order to fill the reservoir with a gas from the top down, 2) as the reservoir fills with air, oxygen is consumed through spontaneous combustion, 3) oil and water drain toward the base of the structure through gravity segregation and gravity drainage, and 4) tertiary oil, which previously had been trapped as a residual oil saturation, is now produced in downstructure wells. In this case, the economic potential of the project is enhanced by the low cost associated with using air as the injection gas.

On the north flank of West Hackberry, low pressure (350-800 psi) oil reservoirs are found which have large low pressure gas caps, thin oil rims and slow water encroachment. In the low pressure north flank reservoirs, air injection can increase oil recovery by: 1) pushing the oil rim downstructure to the structural location of existing wellbores, 2) repressurizing the reservoir and 3) obtaining tertiary oil recovery through the Double Displacement Process in the same manner as described in the preceding paragraph. Although injection of nitrogen, carbon dioxide and natural gas have been utilized to increase oil recovery in Gulf Coast reservoirs in the past, this project is unique in the use of air as the injection gas.

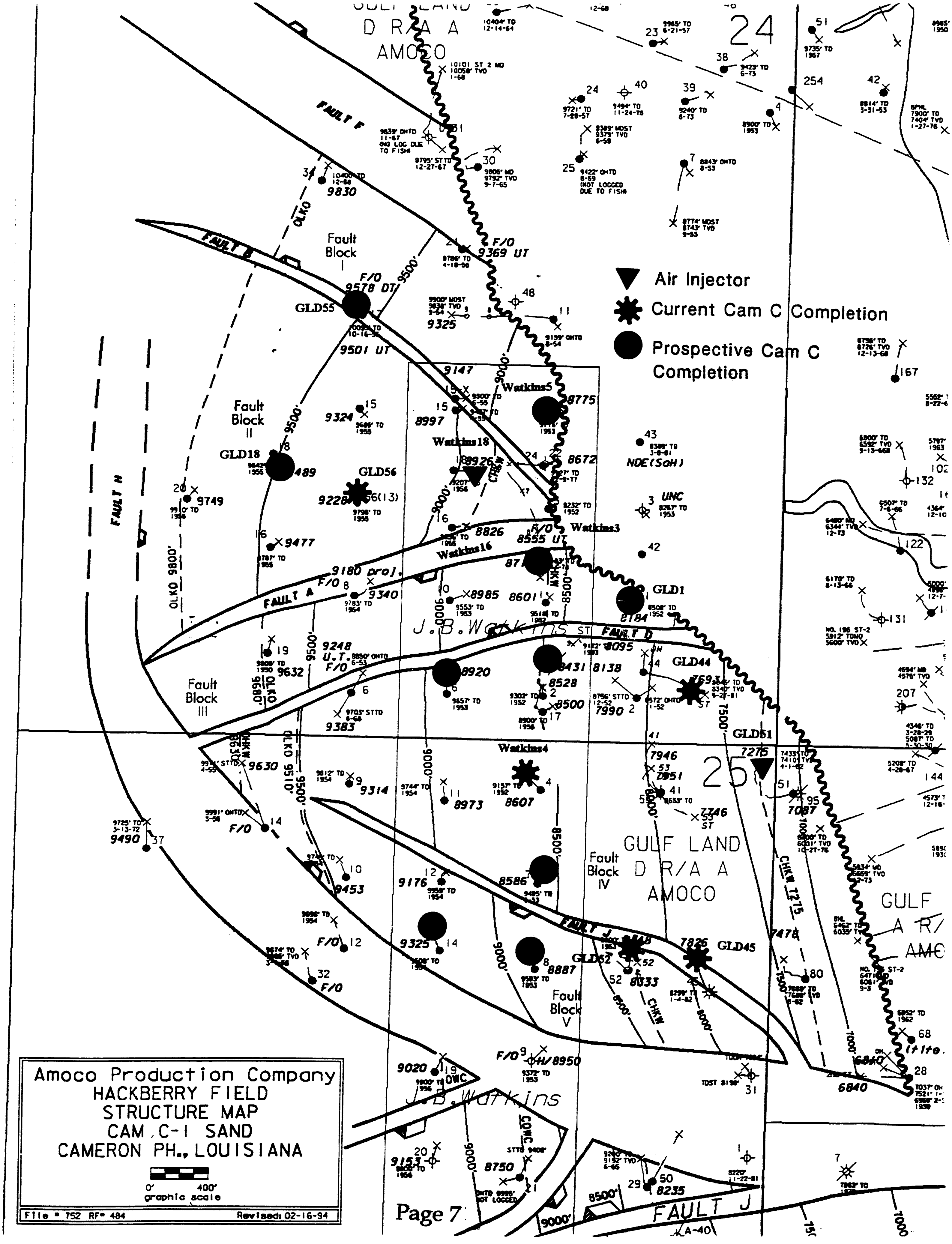
4.0 Discussion

4.1 Project Performance by Reservoir

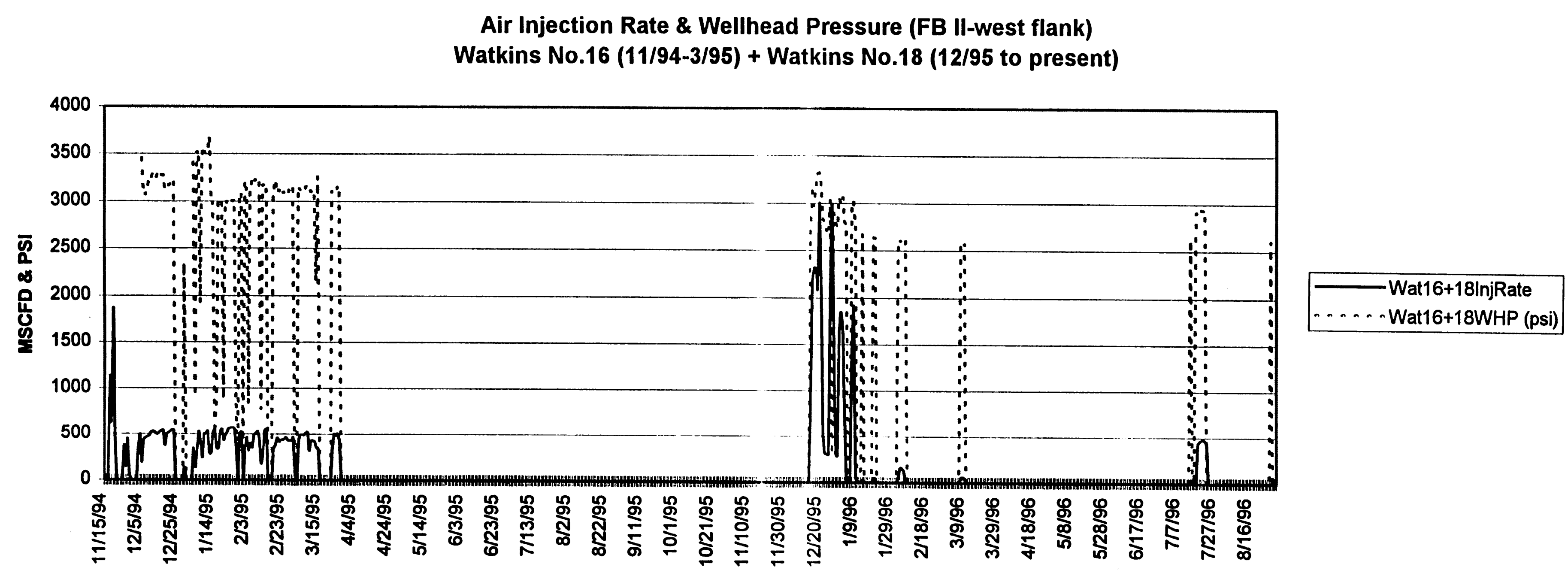
4.1.1 Fault Block IV on the West Flank (in the WH Cam C RI SU)

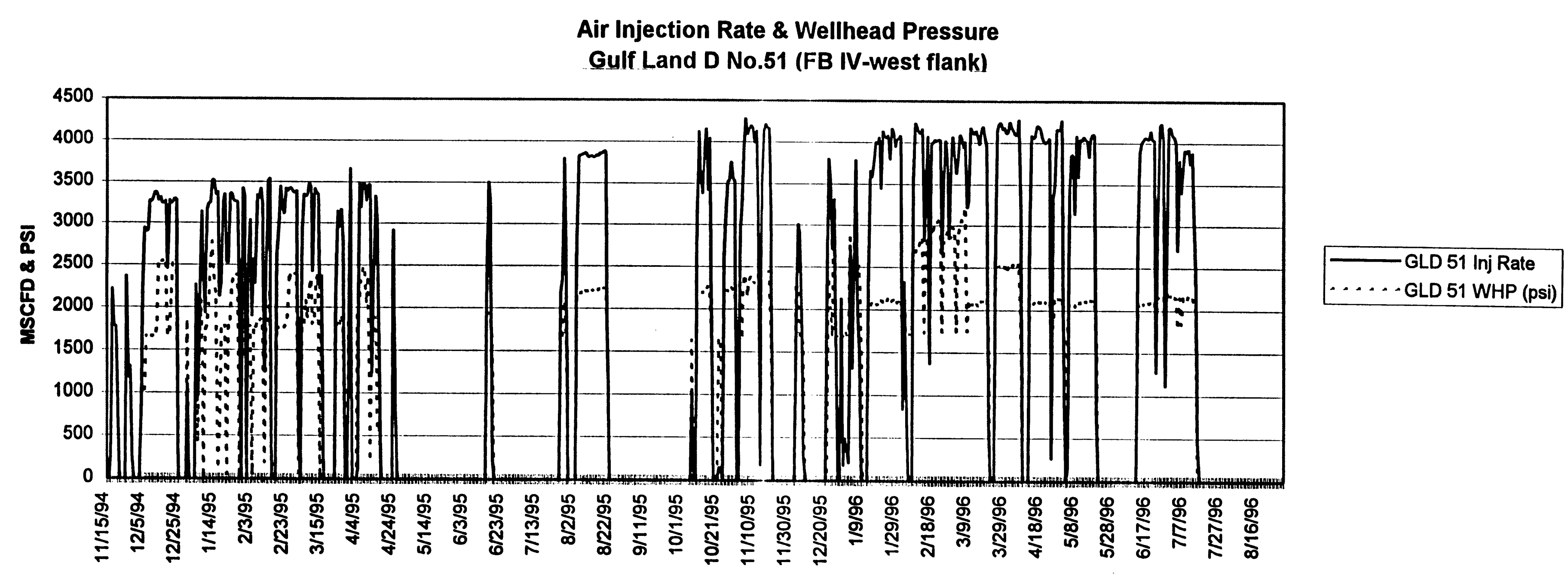
On the following page is a structure map for the top of the Cam C-1 Sand on the west flank of West Hackberry Field. As noted on the structure map, the Gulf Land D (GLD) No.51 serves as the air injector for Fault Block IV and is located near the crest of the structure. From the forth quarter of 1995 through June of 1996, the project's injection strategy has been to inject all of the project's 4 million standard cubic feet per day (MMSCFD) air injection capacity into the GLD No.51. Through August 31, 1996, a total 1127 million standard cubic feet (MMSCF) of air has been injected into the GLD No.51. On Page Nos.8 and 9 are plots of air injection rate, pressure and cumulative injection versus time.

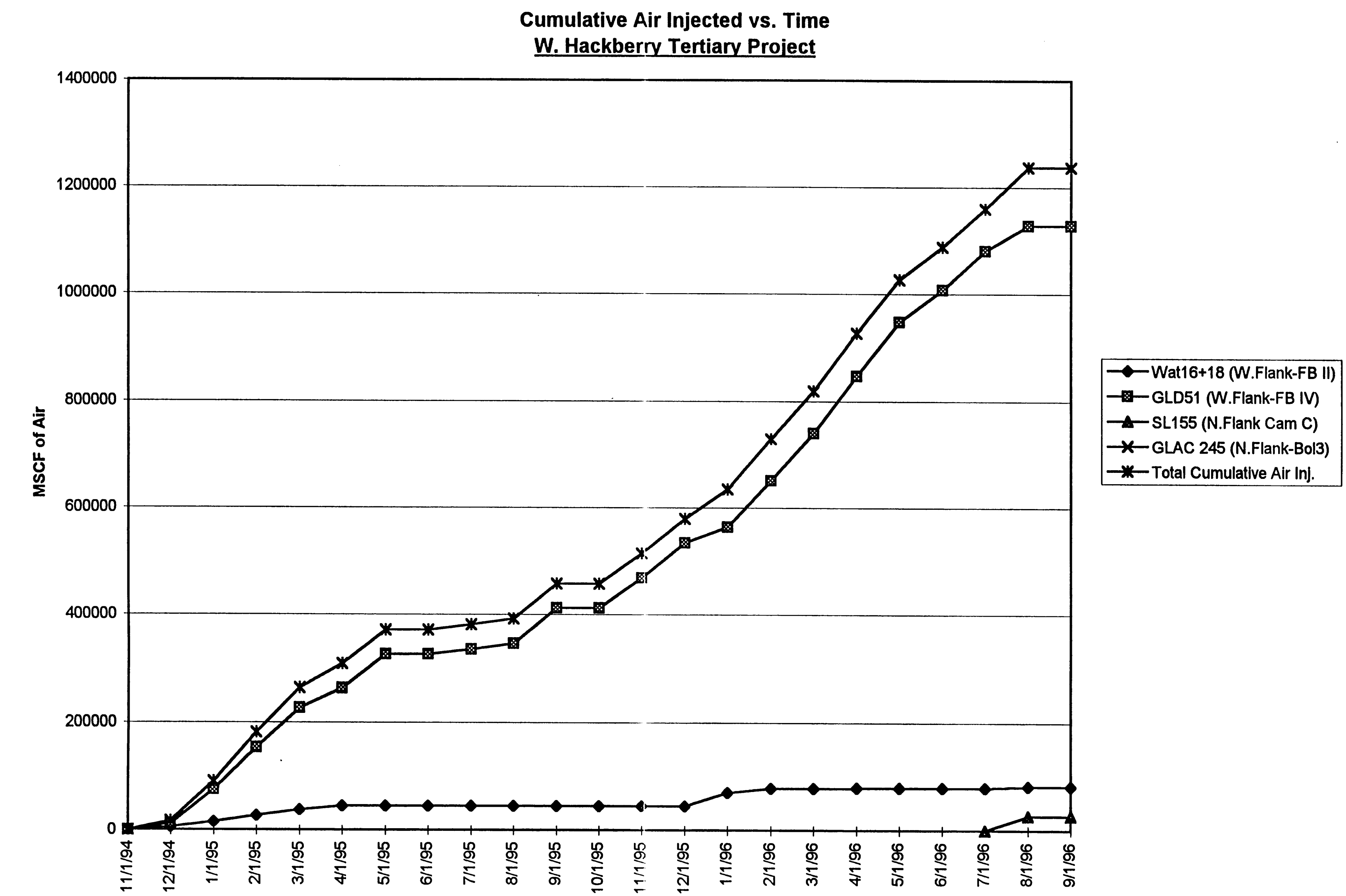
In Fault Block IV, reservoir pressure has increased about 350 psi since the start of air injection. The GLD No.44 (Cam C-1,2), GLD No.45 (Cam C-1,2), GLD No.52 (Cam C-1,2) and Watkins No.3 (Cam C-3) are future producing wells currently completed in the project interval in Fault Block IV. All of these wells have seen an increase in bottom hole pressure as a result of air injection. A table and plot of bottom hole pressure versus time are included on Page Nos.10 and 11. While the Cam C-3 in Fault Block IV has typically seen 150-200 psi lower pressure than the Cam C-1,2, the Cam C-3 has shown a similar increase in reservoir pressure as a result of air injection. The increase in reservoir pressure noted (in both Cam C-1,2 and Cam C-3) in this area appears to prove that: 1) the



Air Injector
Current Cam C Completion
Prospective Cam C Completion
Amoco Production Company
HACKBERRY FIELD
STRUCTURE MAP
CAM, C-1 SAND
CAMERON PH., LOUISIANA
0' 400'
graphic scale
File # 752 RF# 484
Revised: 02-16-94
GULF LAND
D R/A A
AMOCO
Fault Block I
Fault Block II
Fault Block III
Fault Block IV
Fault Block V
FAULT F
FAULT B
FAULT A
FAULT D
FAULT H
FAULT J
J. B. Watkins
GLD55
GLD18
GLD56
GLD1
GLD44
GLD51
GLD52
GLD45
Watkins5
Watkins18
Watkins16
Watkins3
Watkins4


Air Injection Rate & Wellhead Pressure (FB II-west flank)
Watkins No.16 (11/94-3/95) + Watkins No.18 (12/95 to present)
MSCFD & PSI
4000
3500
3000
2500
2000
1500
1000
500
0
11/15/94
12/5/94
12/25/94
1/14/95
2/3/95
2/23/95
3/15/95
4/4/95
4/24/95
5/14/95
6/3/95
6/23/95
7/13/95
8/2/95
8/22/95
9/11/95
10/1/95
10/21/95
11/10/95
11/30/95
12/20/95
1/9/96
1/29/96
2/18/96
3/9/96
3/29/96
4/18/96
5/8/96
5/28/96
6/17/96
7/7/96
7/27/96
8/16/96
Wat16+18InjRate
Wat16+18WHP (psi)


Air Injection Rate & Wellhead Pressure
Gulf Land D No.51 (FB IV-west flank)
MSCFD & PSI
4500
4000
3500
3000
2500
2000
1500
1000
500
0
11/15/94
12/5/94
12/25/94
1/14/95
2/3/95
2/23/95
3/15/95
4/4/95
4/24/95
5/14/95
6/3/95
6/23/95
7/13/95
8/2/95
8/22/95
9/11/95
10/1/95
10/21/95
11/10/95
11/30/95
12/20/95
1/9/96
1/29/96
2/18/96
3/9/96
3/29/96
4/18/96
5/8/96
5/28/96
6/17/96
7/7/96
7/27/96
8/16/96
GLD 51 Inj Rate
GLD 51 WHP (psi)

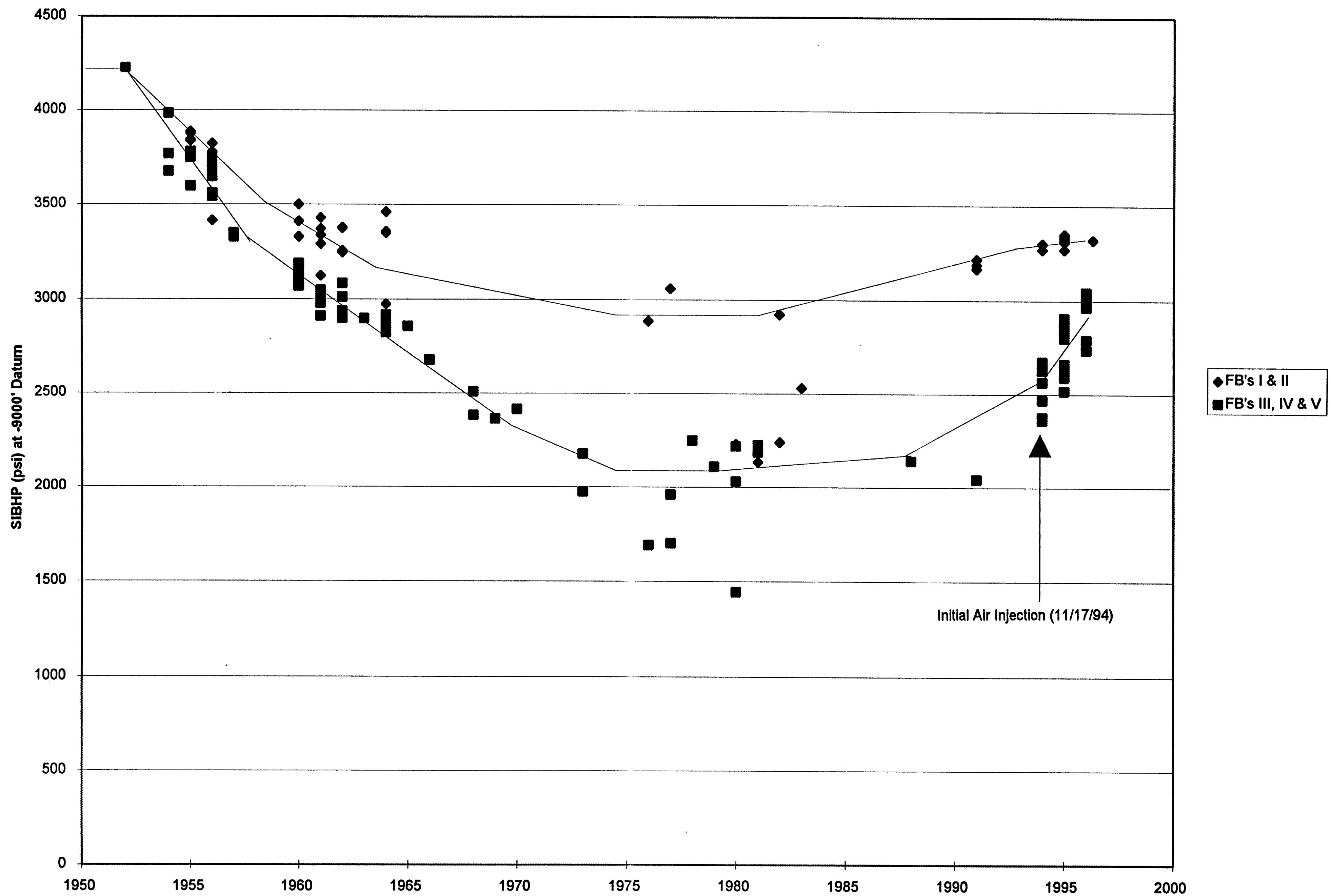

Cumulative Air Injected vs. Time
W. Hackberry Tertiary Project
MSCF of Air
1400000
1200000
1000000
800000
600000
400000
200000
0
11/1/94
12/1/94
1/1/95
2/1/95
3/1/95
4/1/95
5/1/95
6/1/95
7/1/95
8/1/95
9/1/95
10/1/95
11/1/95
12/1/95
1/1/96
2/1/96
3/1/96
4/1/96
5/1/96
6/1/96
7/1/96
8/1/96
9/1/96
Wat16+18 (W.Flank-FB II)
GLD51 (W.Flank-FB IV)
SL155 (N.Flank Cam C)
GLAC 245 (N.Flank-Bol3)
Total Cumulative Air Inj.

West Flank Bottom Hole Pressure (psi) By Reservoir By Fault Block
West Hackberry Field

		Cam C-1					Cam C-2,3				
Fault Block	Well	Pressure	9000'Press.	Date	Depth	Temp.(F)	Pressure	9000'Press.	Date	Depth	Temp.(F)
I	Watkins #5	3711 psi	3839 psi	6/55	8600'						
		2407 psi	2531 psi	4/83	8612'	228					
		3124 psi	3217 psi	6/91	8800'	208					
	Watkins #15x										
	Watkins #22						2943 psi	3059 psi	12/77	8751'	
	GLD #11	3880 psi	3847 psi	1/55	9100'		2974 psi	2974 psi	4/64	9000'	
		3135 psi	3415 psi	3/56	8150'						
		3160 psi	3500 psi	3/60	8000'						
		2843 psi	3125 psi	3/61	8000'						
		2909 psi	3378 psi	3/62	8000'						
	GLD #17										
	GLD #21										
	GLD #34										
II	Watkins #15										
	Watkins #16	2887 psi	2887 psi	10/78		200	2217 psi	2239 psi	7/82	8930'	209
		3233 psi	3271 psi	5/94	8911'		2150 psi	2230 psi	3/80	8750'	
							2115 psi	2134 psi	11/81	8940'	
							3156 psi	3188 psi	6/91	8899'	204
	Watkins #18	2899 psi	2922 psi	8/82	8950'	210					
		3058 psi	3168 psi	8/91	8775'	201					
		3224 psi	3271 psi	3/95	8900'	207					
	GLD #56(13)	3780 psi	3647 psi	3/56	9400'						
		3500 psi	3500 psi	3/60	9000'		3350 psi	3350 psi	6/64	9000'	
		3429 psi	3429 psi	3/61	9000'						
		3375 psi	3375 psi	3/62	9000'						
		3436 psi	3301 psi	5/94	9320'	206					
		3488 psi	3350 psi	2/95	9320'	209					
		3473 psi	3321 psi	6/95	9319'						
		3392 psi	3311 psi	8/95	9167'	206					
		3418 psi	3337 psi	11/95	9168'	207					
		3494 psi	3320 psi	3/96	9320'	208					
		3514 psi	3434 psi	10/96	9167'	205					
	GLD #15	3824 psi	3888 psi	9/55	8800'		3247 psi	3247 psi	3/62	9000'	
		3460 psi	3780 psi	3/56	8000'		3357 psi	3357 psi	6/64	9000'	
	GLD #16	3170 psi	3410 psi	3/60	8500'		3500 psi	3339 psi	11/61	9504'	
		3163 psi	3371 psi	3/61	8500'		4010 psi	3878 psi	9/55	9400'	
							3900 psi	3768 psi	3/56	9400'	
							2740 psi	2922 psi	3/62	8500'	
							3240 psi	3460 psi	6/64	8500'	
	GLD #18						3825 psi	3825 psi	3/56	9000'	
							3330 psi	3330 psi	3/60	9000'	
							3293 psi	3293 psi	3/61	9000'	
							3256 psi	3256 psi	3/62	9000'	
	GLD #20										
III	Watkins #1	4110 psi	4227 psi	5/52	8635'		2300 psi	2382 psi	11/68	8744'	
		1968 psi	2247 psi	6/78	8400'	200					
	Watkins #10	2892 psi	2878 psi	3/64	9044'		1609 psi	1702 psi	4/77	8800'	
	GLD #1	3607 psi	3985 psi	12/54	8170'						
		3505 psi	3768 psi	9/55	8170'						
		3415 psi	3694 psi	3/56	8150'						
	GLD #8										
	GLD #19	3700 psi	3700 psi	3/56	9000'						

		Cam C-1					Cam C-2,3				
Fault Block	Well	Pressure	9000'Press.	Date	Depth	Temp.(F)	Pressure	9000'Press.	Date	Depth	Temp.(F)
IV	Watkins #2										
	Watkins #4						2016 psi	2176 psi	7/73	8500'	
							1962 psi	2042 psi	6/91	8749'	196
							2336 psi	2470 psi	9/94	8716'	198
							2388 psi	2518 psi	2/95	8716'	198
							2487 psi	2593 psi	5/95	8769'	
							2525 psi	2643 psi	8/95	8749'	199
							2534 psi	2664 psi	11/95	8716'	195
							2592 psi	2738 psi	3/96	8706'	196
							2625 psi	2792 psi	6/96	8640'	194
							2755 psi	2871 psi	10/96	9167'	205
	Watkins #6										
	Watkins #7										
	Watkins #11						2400 psi	2364 psi	9/89	9111'	
							1476 psi	1444 psi	2/80	9100'	190
	Watkins #17										
	Watkins#17ST										
	GLD #2						3462 psi	3770 psi	12/54	8000'	
							3178 psi	3782 psi	9/55	8244'	
							3490 psi	3543 psi	3/56	8250'	
							3290 psi	3330 psi	11/57	8200'	
							3030 psi	3090 psi	3/60	8150'	
							2928 psi	2980 psi	3/61	8250'	
							2839 psi	2901 psi	3/62	8000'	
							2857 psi	2918 psi	6/64	8000'	
	GLD #6	3831 psi	3750 psi	1/55	9250'		3202 psi	3084 psi	7/82	9369'	184
		3740 psi	3660 psi	3/56	9250'		2950 psi	2905 psi	6/64	9100'	
		3230 psi	3164 psi	3/60	9200'						
		3098 psi	3003 psi	3/61	9300'						
		3013 psi	3013 psi	3/62	9000'						
	GLD #6ST										
	GLD #9	3754 psi	3754 psi	1/55			1838 psi	1691 psi	8/76	9459'	200
		3650 psi	3650 psi	3/56	9000'						
		3190 psi	3190 psi	3/60	9000'						
		3002 psi	3002 psi	3/61	9000'						
		2937 psi	2937 psi	3/62	9000'						
		2764 psi	2899 psi	1/63	8600'						
		2825 psi	2825 psi	2/64	9000'						
		2792 psi	2681 psi	2/66	9347'	228					
	GLD #12										
	GLD #14ST										
	GLD #41	1752 psi	2218 psi	7/80	7998'		1724 psi	2031 psi	7/80	8041'	
		1771 psi	2225 psi	9/81	8024'	190					
		1715 psi	2187 psi	11/81	7985'						
	GLD #44	1463 psi	3044 psi	4/96	5679'		1612 psi	2141 psi	4/88	7862'	181
		1464 psi	3042 psi	6/96	5679'						
		2511 psi	3096 psi	11/96	7771'	190					
	GLD #45	2480 psi	2967 psi	3/96	7956'	186					
		2542 psi	3023 psi	6/96	7956'	186					
	GLD #51	1898 psi	2636 psi	7/94	7312'	183	1683 psi	2375 psi	7/94	7417'	186
		1896 psi	2630 psi	7/94	7320'		1673 psi	2360 psi	7/94	7427'	187
		1939 psi	2653 psi	7/94	7367'	185					
		1857 psi	2566 psi	8/94	7377'	188					
V	Watkins #8						1975 psi	1975 psi	7/73	9000'	
	Watkins #12	2109 psi	2109 psi	4/79	9000'						
	Watkins #14										
	GLD #5	1750 psi	1959 psi	2/77			3480 psi	3676 psi	12/54	8400'	
							3440 psi	3598 psi	9/55	8400'	
							3400 psi	3751 psi	3/56	8150'	
							3290 psi	3350 psi	11/57	8400'	
							3010 psi	3070 psi	3/60	8400'	
							2843 psi	2912 psi	3/61	8000'	
							2779 psi	2937 psi	3/62	8250'	
							2660 psi	2874 psi	6/64	8250'	
							2618 psi	2858 psi	3/65	8250'	
							2339 psi	2509 psi	3/68	8470'	
							2246 psi	2415 psi	3/70	8472'	
	GLD #10	3759 psi	3759 psi	1/55	9000'						
		3560 psi	3560 psi	3/56	9000'						
		3140 psi	3140 psi	3/60	9000'						
		3049 psi	3049 psi	3/61	9000'						
		2933 psi	2933 psi	3/62	9000'						
		2833 psi	2678 psi	2/66	9485'	196					
	GLD #52	2407 psi	2675 psi	8/94	8386'	193					
		2512 psi	2803 psi	2/95	8386'						
		2577 psi	2855 psi	5/95	8386'	194					
		2594 psi	2883 psi	8/95	8386'	195					
		2629 psi	2907 psi	11/95	8405'	192					
		2713 psi	3009 psi	3/96	8386'	192					

Bottom Hole Pressure (psi) vs. Time
West Hackberry Air Injection Project (west flank)



overall geologic picture for Fault Block IV is correct, and 2) air is being injected into both the Cam C-1,2 and Cam C-3 in Fault Block IV.

Oil production has not yet occurred in Fault Block IV since the oil rim has not moved sufficiently downstructure to reach the closest producing well, the GLD No.44. The lack of production response in Fault Block IV can be attributed to the large size of the reservoir, the high reservoir pressure (2500 psi) which inhibits the size of the gas cap, uncertainty as to the pre-injection location of the oil rim and an insufficient volume of air injected to date. Although oil production has not yet occurred in Fault Block IV, neither has nitrogen breakthrough which suggests that the air injection flood is proceeding as planned in a gravity stable manner. Plans are to continue air injection in the GLD No.51 in order to maintain the growth of the upstructure gas cap and to bring about oil production in the GLD No.44 within the upcoming 12 months.

The GLD No.44 is the next highest well on structure after the GLD No.51 and is expected to see the earliest oil production when it occurs. Recent tests from the GLD No.44 show production volumes that are gas lifted at a rate of 700-800 barrels of water per day(BWPD) with no gas and no oil. Amoco personnel became concerned that the source of the water production in the GLD No.44 could have been from another reservoir as a result of a casing leak or a channel behind pipe. The tubing in the GLD No.44 was pulled out of the well and the casing was pressure tested with no hint of leakage. Extraneous water production as a result of a channel behind pipe is considered highly unlikely for the following reasons: 1) water from below is not possible since the GLD No.44 encountered no permeable sands below the Cam C-1,2,3 and 2) water from above is unlikely since a low pressure (800 psi) gas sand, the Cam B-1, is immediately above the Cam C-1,2,3 and any water from above this interval would flood the lower pressure Cam B-1 (800 psi) in preference to the higher pressure (2500 psi) Cam C-1,2,3.

One added cause for concern relating to the GLD No.44 is the chlorides content of the produced water. While the chlorides content of the water from the GLD No.44 measures 131,000 parts per million (ppm), the chlorides content of the produced water from the GLD No.45 is 99,000 ppm. A water sample from the Watkins No.4 taken before the start of the project measured 120,000 ppm. Although the reason for the variation in chlorides content in Fault Block IV has not been resolved, all other available data suggests that the source of the water production in the GLD No.44 is the completion interval and that the oil rim has not yet arrived at the GLD No.44's structural position.

The GLD No.45 is the next well downstructure after the GLD No.44. During August of 1995, the GLD No.45 was recompleted to the Cam C-1,2 and tested gas lifting at a rate of 190 BOPD and 451 BWPD. The GLD No.45 had previously watered out in the same completion interval. In the face of continued air injection over the past year in which injection far exceeded withdrawals, the oil production in the GLD No.45 declined while the water cut increased to 90%-95% and the produced gas showed no nitrogen content. The source of the new oil production in the GLD No.45 is believed to be a thin sand interval that was covered with sand during the previous completion. The most recent completion in the GLD No.45 was gravel packed to prevent sand fill while the earlier completion was not.

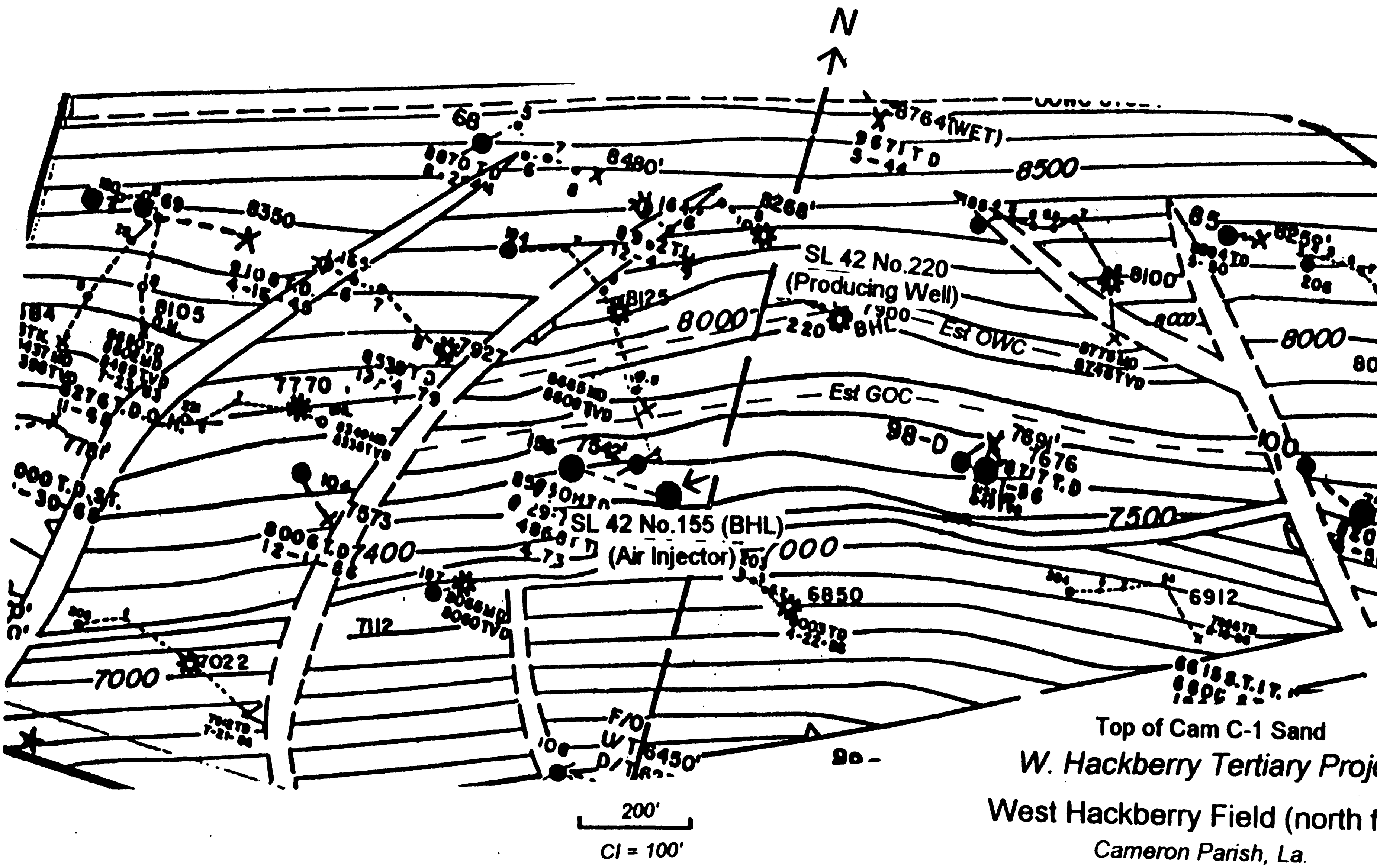
The GLD No.51 serves as the air injector for Fault Block IV. In July of 1996, the GLD No.51 plugged up with sand, magnetite (Fe_3O_4) and pieces of casing which prevented air injection. At least some portion of the problems with the wellbore were caused by the corrosion resulting from the previous use of potassium chloride purge water. To prevent future plugging of the well with fill and or collapsed casing, the GLD No.51 will need either a liner or a gravel pack. During August of 1996, the GLD No.51 was cleaned out in preparation to run a gravel pack inside casing. A workover to run a gravel pack and restart air injection has been deferred to the beginning of October while operating experience is gained with another gravel packed air injector, the SL 42 No.155. After the GLD No.51 is restored to injection, the injection strategy will be to divide the 4 MMSCFD injection capacity between the GLD No.51 and the air injectors in the low pressure reservoirs on the north flank of the field.

4.1.2 Fault Block II on the West Flank (in the WH Cam C RI SU)

In Fault Block II, the Watkins No.18 is the current air injector and the GLD No.56 serves the downstructure future producer. Originally, the Watkins No.16 was the air injector for Fault Block II. When the Watkins No.16 experienced casing collapse during a workover, the well was temporarily abandoned. Both the GLD No.56 and the Watkins No.18 exhibited premature nitrogen breakthrough without evidence of oil production. The nitrogen breakthrough is believed to have been caused by the nitrogen preferentially flowing through a high permeability interval near the top of the Cam C-1. Coincidentally, Fault Block II was more prone to premature nitrogen breakthrough due to the lower bed dip (23 degrees) than the other reservoirs involved in the project. The current operating strategy is to inject air into the Watkins No.18 when the other air injectors are incapable of taking the project's 4 MMSCFD capacity.

4.1.3 Low Pressure Reservoir on the North Flank(WH Cam C RB SU)

To spread project risk among multiple reservoirs, Amoco and the DOE agreed to expand the project to include air injection in low pressure reservoirs on the north flank of the field. The low pressure north flank reservoirs exhibit slow water encroachment, possess low pressure gas caps and contain thin oil rims. Air injection began on the north flank in a low pressure (350-400 psi) oil reservoir, the WH Cam C RB SU, during July of 1996. A structure map for the top of the Cam C-1 is included on the following page. In the WH Cam C RB SU, the SL 42 No.155 serves as the air injector in the gas cap and the SL 42 No.220 is currently producing oil in a downdip structural position. A schematic cross-section for the reservoir is included on Page No.15. The WH Cam C RB SU had previously undergone gas injection which improved the rate for the SL 42 No.220 from 21 BOPD and 89 BWPD in December of 1991 to 43 BOPD and 88 BWPD in April of 1993. The production rate achieved in April of 1993 remained at about that same level up to the middle of 1996. A production plot for the SL 42 No.220 is included on Page No.16. After air injection began in the WH Cam C RB SU in July of 1996, the SL 42 No.220 was tested on August 11, 1996, producing at a rate of 177 BOPD and 145

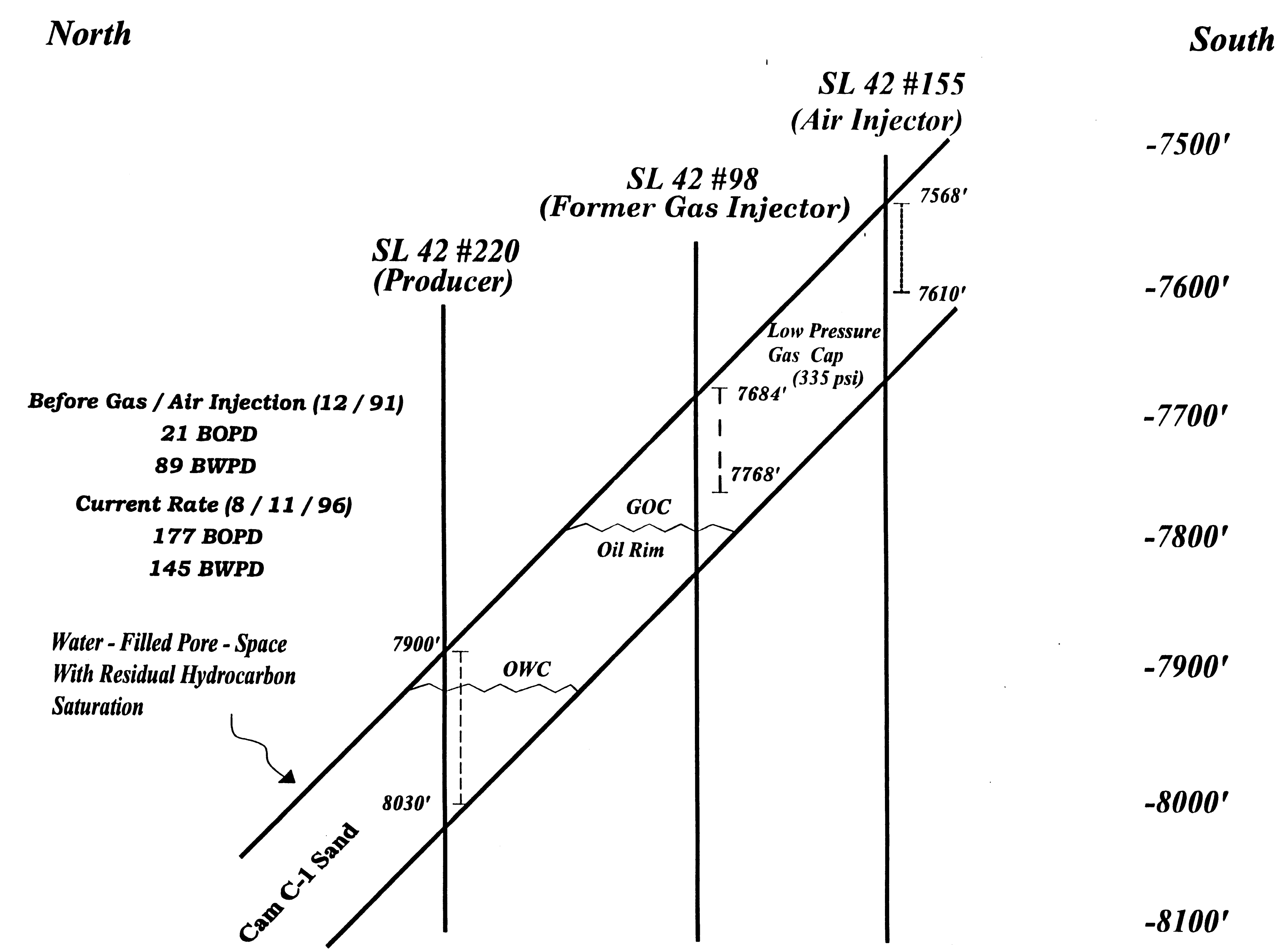


Top of Cam C-1 Sand

W. Hackberry Tertiary Project

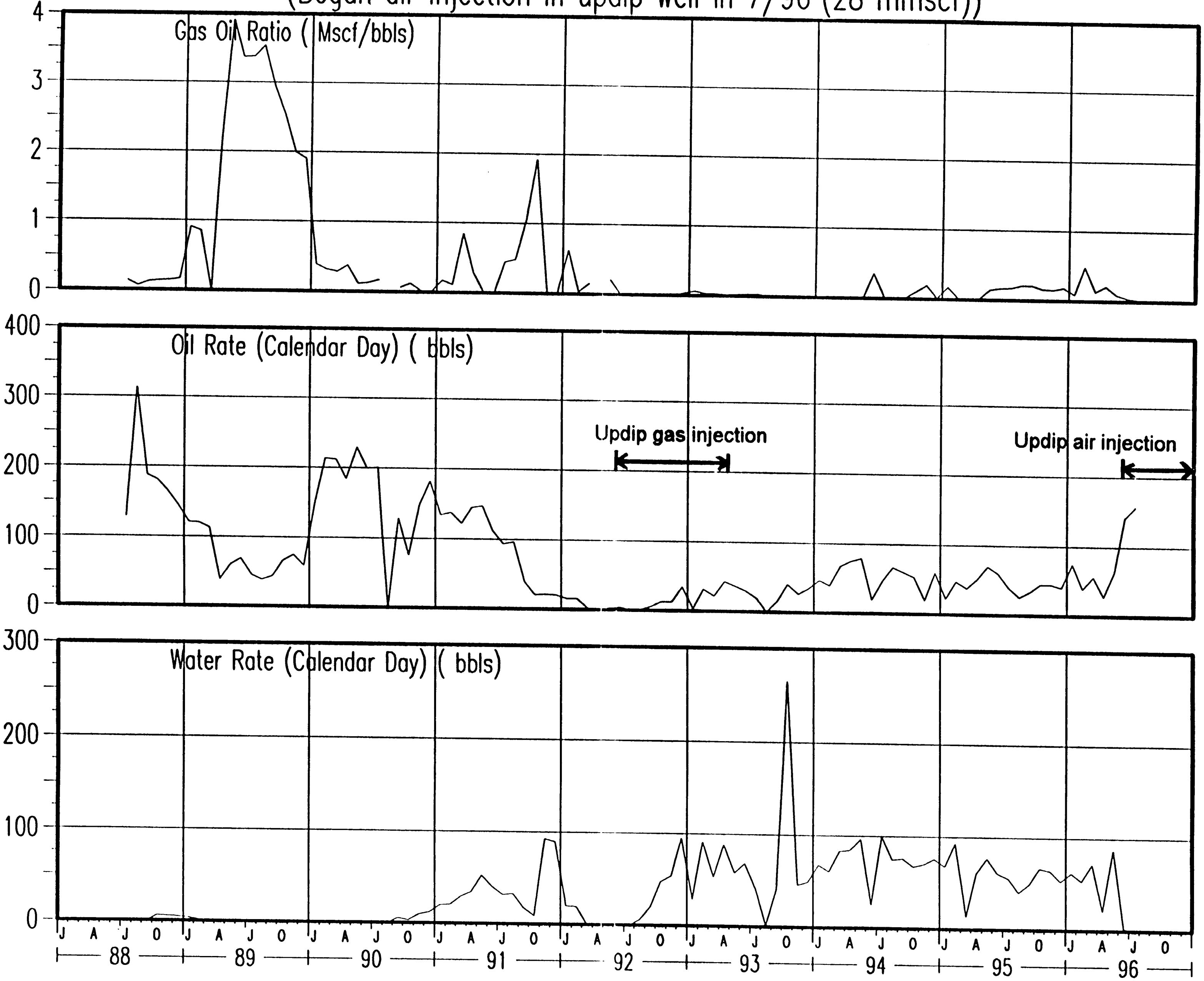
West Hackberry Field (north flank)

Cameron Parish, La.



Reservoir Schematic of Cam C-1 (in the W H Cam C RB SU) on the north Flank of W. Hackberry as of August of 1996

SL 42 No.220 (WH Cam C RB SU)(north flank of W. Hackberry)
(Injected 136 mmscf of gas in updip well (5/92–3/93))
(Began air injection in updip well in 7/96 (28 mmscf))



BWPD. The production increase noted in the SL 42 No.220 is the first demonstration of increased oil production as a result of air injection in the West Hackberry Tertiary Project.

Air injection on the north flank has provided almost immediate production response while prolonged injection on the west flank has only shown an increase in reservoir pressure. The two main reasons for the difference in response are that the north flank reservoir is much smaller and much lower reservoir pressure. In fact, the gas cap in the low pressure WH Cam C RB SU only contains about 100 MMSCF of gas in place. With so little gas cap volume at such a low reservoir pressure, air injection of 28 MMSCF in July would be expected to have an almost immediate impact on production in the downstructure well.

4.2 Results from Amoco's Reservoir Model

During the past year, the reservoir model for Fault Block IV on the west flank was revised to match available injection and pressure data. According to the reservoir model, production response on the west flank is controlled to a large extent by the air injection rate, not just by the cumulative volume of air injected. That is, at high injection rates the gas-oil contact and water-oil contacts are forced downstructure more on the north end of Fault Block IV(closer to the nearest producing well) than on the south end. At lower air injection rates, the gas-oil and water-oil contacts tend to be flatter across the reservoir.

By injecting air on the north flank, less air has been available for injection into Fault Block IV and therefore deferring production response in Fault Block IV. Slowing injection in Fault Block IV has also allowed more time for gravity segregation and gravity drainage. Allowing more time for gravity segregation and gravity drainage is expected to reduce the negative impact of permeability variations thereby resulting in improved vertical sweep efficiency and higher oil recovery.

Verification of reservoir model predictions will only be possible upon arrival of the tertiary oil bank at the first producer, the GLD No.44. In an effort to guide other operators, documentation and technology transfer regarding the reservoir model will occur once verification has been achieved.

4.3 Ongoing Injection Strategy

Air injection is presently split between the SL 42 No.155 (3.3-3.5 MMSCFD) on the north flank and the Watkins No.18 (0.4-0.5 MMSCFD) in Fault Block II on the west flank. After the GLD No.51 is repaired in October of 1996, the current plan is to split air injection between the GLD No.51 (2 MMSCFD) and the low pressure injectors (2 MMSCFD) on the north flank. In addition to the SL 42 No.155 in the WH Cam C RB SU, other north flank injectors that will be added to the project include: 1) the GLAC No.245 in the Bol-3 RC SU, 2) the CPSB No.56 in the WH Cam D NF SU and 3) the SL 42 No.172 in the WH Cam D NF SU. The air injection line to the north flank is connected to each of the north flank injection wells. Well workovers will be required to complete the additional north flank wells as air injectors. To take advantage of the Double Displacement Process on the north flank, more workovers may be required to enable downstructure wells to produce as the oil rims are pushed downstructure.

4.4 Surface Injection Facilities

4.4.1 Operation and Maintenance of the Air Injection System

During the last year an effort was made to further improve the reliability and run time of the air compression system. A schematic drawing of the air injection system is included on Page No.23. At the time of the last annual report, significant heat and lubrication related mechanical failures had been occurring in higher pressure stages of the reciprocating compressor. This resulted in downtime for the much of the summer of 1995 while components were redesigned, manufactured, and installed. The failures were occurring to the rod packing, piston rings, and valves of the third, fourth, and fifth stages of the reciprocating compressor; the stages of compression from 1250 psi to 4000 psi. The following is a summary of the major changes performed:

1. Installed water cooled packing cases on stages 3, 4, and 5.
2. Changed rod packing material from carbon impregnated Teflon to Cook 094 Teflon.
3. Changed rod packing backup rings from cast iron to bronze.
4. Changed 4th and 5th stage piston ring material from Teflon to Peek.
5. Added Teflon wear band to 5th stage piston.
6. Changed lubricant from Syntholube 150 to Mobil Rarus 829.
7. Installed redesigned lubrication distribution system.
8. Rebuilt valves with spring rates based on actual operating pressures.

This work has proven to be successful as no mechanical failures have reoccurred to the reciprocating compressor since this work was completed. Periodic teardown and inspections were performed this summer and no abnormal wear or problems were noted.

Over the last year two significant failures did occur on the screw compressor package. The first was a failure of the coupling which transmits power from the natural gas engine prime mover to the screw compressor. The cause of failure, as determined by the coupling manufacturer, was that a wrong sized bushing was called for on their Bill of Materials. Although this repair cost was covered by the manufacturer of the coupling it did cause over three weeks of downtime to the project. Also, some additional previous downtime caused by broken lines due to vibration could be attributed to this problem. The second failure that occurred was contamination of the lubricating oil with coolant. This problem occurred once before and was thought to be due to a leak in the oil cooler. Based on subsequent experience, Atlas-Copco diagnosed the coolant-oil communication to probably be occurring across a leaking plug in a machined port in either the low pressure or high pressure compressor assembly. Both the low and high pressure screw compressor assemblies were removed, disassembled, and inspected. The high pressure assembly was found to have the leaking plugs. Atlas-Copco installed a new high pressure screw compressor assembly under warranty and no oil contamination has been noted to date. No additional downtime was experienced due to this repair as it was performed at the time the GLD No.51 injection well was down for repair.

4.4.2 Installation of Equipment for North Flank Air Injection

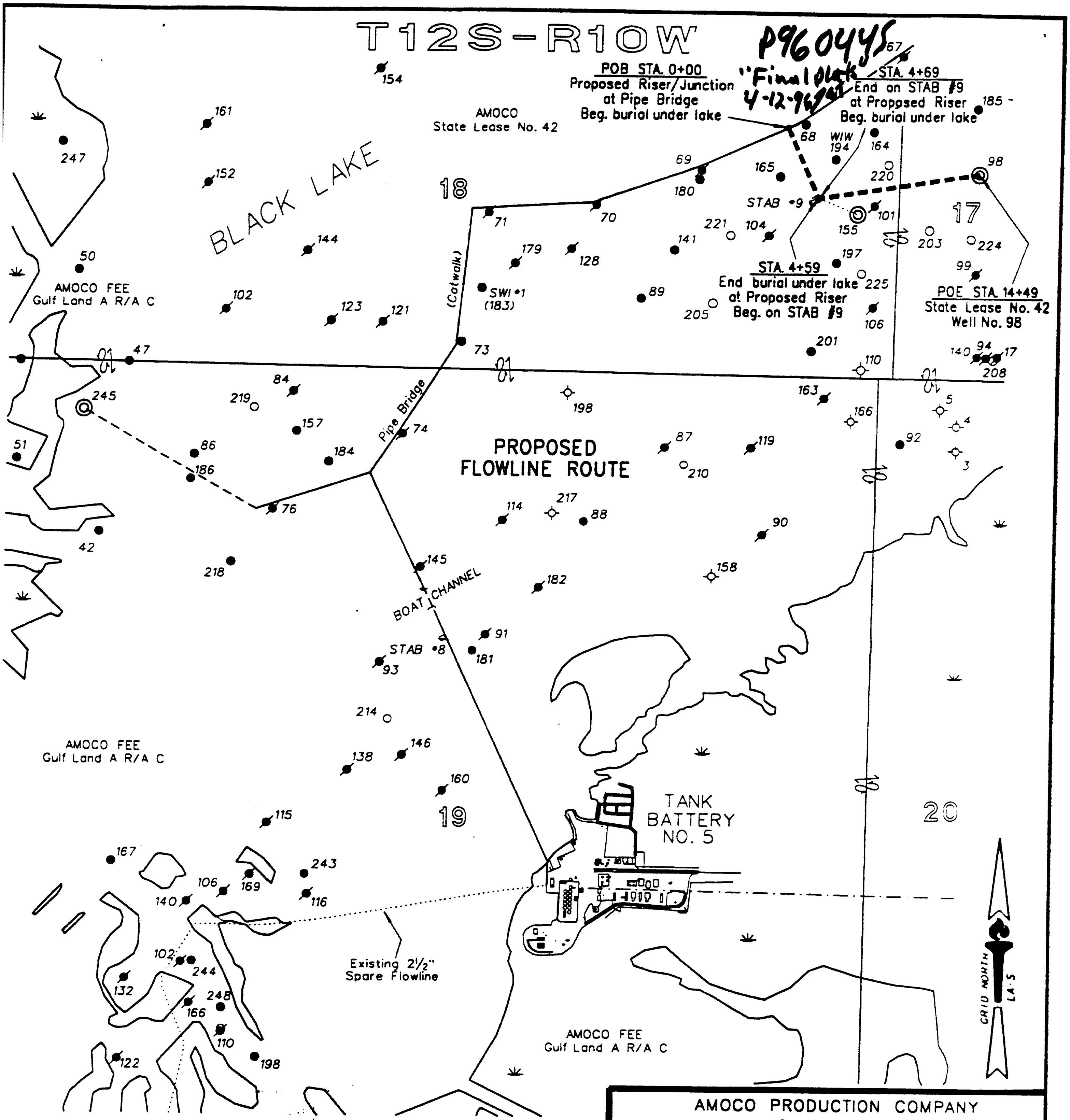
When the project scope was expanded to include air injection in the North Flank reservoirs it created a problem in that the North Flank is a considerable distance from the existing compression equipment. It was decided that the most economical means of transporting air would be to split the flow at the GLD No.51 well, utilize the old GLD No.51 flowline to Central Facility No.2 and install approximately 18,000 feet of new line from C. F. No.2 across Black Lake on an existing pipe rack to serve the four North Flank injection wells. On the following two pages are maps which show the route of the air injection line to the north flank. Since the North Flank reservoirs are lower pressure and do not require injection lines with pressure integrity to 4300 psi as did the West Flank injection lines, the old GLD No. 51 flowline and thinner wall linepipe for the new section of line was used. The air flow is split downstream of the GLD No.51 wellhead scrubber and the pressure and rate is controlled through a control valve. Since the line to the North Flank does not have pressure integrity to 4300 psi, it is protected from overpressure by a pneumatically controlled safety valve and a pressure relief valve. A separator is installed at C. F. No.2 to catch any water vapor that could condense as a result of the Joule-Thompson cooling effect across the control valve as well as any liquids that could have accumulated in low spots of the old line. An orifice meter is installed immediately downstream of the separator to meter the flowrate. As of this date, approximately 90% of the installation has been completed, however, enough of the new line was completed in July 1996 to commence air injection in the SL 42 No. 155.

4.5 Technology Transfer Activities

During the past year, talks were presented at the following venues which reviewed the West Hackberry Tertiary Project:

September 19, 1996	Amoco presentation at the Fluid Imaging Workshop at BP in Houston, Texas
February 14, 1996	Amoco presentation at the Oil Industry Outreach Conference in Houston, Texas
February 21, 1996	Amoco presentation at the Time Lapse Imaging Workshop in Houston, Texas
April 21-24, 1996	At the SPE Symposium on Improved Oil Recovery in Tulsa, Oklahoma, Amoco presented an SPE Paper entitled "The Economics of Light Oil Air Injection Projects" and LSU presented an SPE Paper entitled "Second-Contact Water Displacement Oil Recovery Process"

An on-line version of Amoco's West Hackberry Tertiary Project presentation can be accessed on the Internet file server for the Society of Petroleum Engineers (SPE) at www.neosoft.com/pub/users/s/spe. In addition, Amoco, LSU and DOE personnel contributed to an article entitled "Air injection project breathes fire into aging West Hackberry oil field" which appeared in the February, 1996 edition of "Hart's Oil and Gas



AMOCO PRODUCTION COMPANY
LAND SURVEY DEPT.

Proposed Air Injection Flowline Installation to Serve State Lease 42, Well No. 98, State Lease 42, Well No. 155 and Gulf Land A R/A C, Well No. 245 as Extension to D.O.E. Tertiary Project

West Hackberry Field
Section 17, 18 & 19, T12S-R10W
Cameron Parish, Louisiana

Drw.by RWB 3/25/96	LA038123.dgn Lv 21
Scale: 1 in = 800 ft	SHEET 5 OF 9

LEGEND

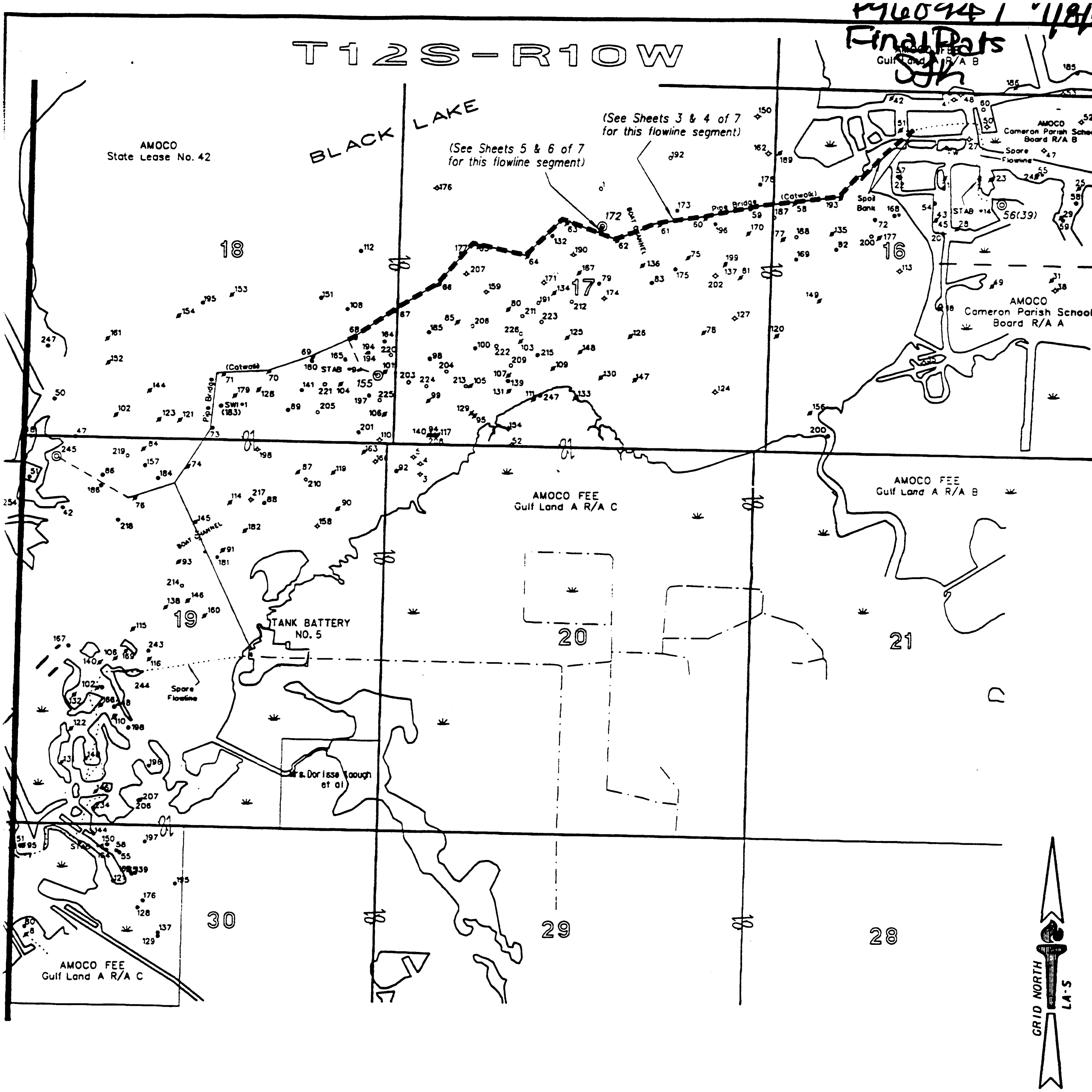
- - - - - - Proposed Flowlines
· · · · · · Existing Pipelines
— · — · — C/L Existing Roads
Open Water Marsh

PROPOSED ROUTE - One 2½" Air Injection Flowline

NAD 27 POB: Lat.-30° 00'47.36", Lon.-93° 25'09.51"
POE: Lat.-30° 00'44.85", Lon.-93° 24'56.19"

NAD 83 POB: Lat.-30° 00'48.13", Lon.-93° 25'10.07"
POE: Lat.-30° 00'45.62", Lon.-93° 24'56.75'

Final Plats



COMPOSITE VIEW

LEGEND

- Proposed Flowlines Route (D.O.E. Tertiary Project)
- Existing Flowlines (D.O.E. Tertiary Project)
- Existing Pipelines
- C/L Existing Roads
- Marsh

The total material to be excavated for the two segments of the proposed Air Injection Flowline - approx. 124 cu. yds.

The total combined length for the two segments of the proposed Air Injection Flowline - 9,475 feet.

AMOCO PRODUCTION COMPANY
LAND SURVEY DEPT.

Proposed Air Injection Flowline Installation to Serve State Lease 42, Well No. 172 and Cameron Parish School Board R/A B, Well No. 56, as Extension to D.O.E. Tertiary Project

West Hackberry Field
Section 16, 17 & 18, T12S-R10W
Cameron Parish, Louisiana

Drw.by RWB 6/5/96	LA038123.dgn Lv 25
Scale: 1 in = 2000 ft	SHEET 2 OF 7

World." Amoco personnel authored another article entitled "Field tests assess novel air-injection EOR processes" which appeared in the May 20,1996 edition of the "Oil and Gas Journal."

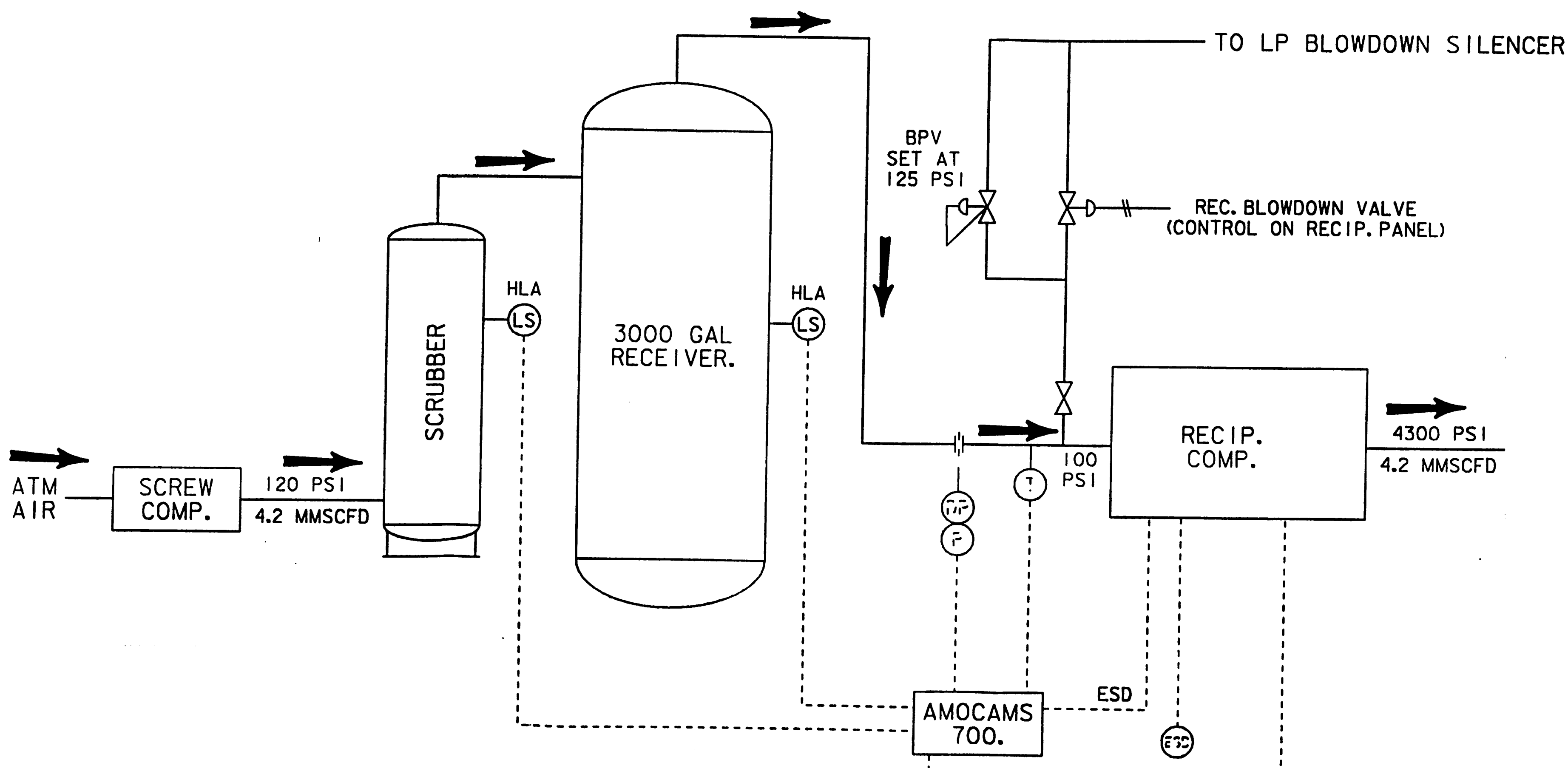
4.6 Independent Project Study by LSU

LSU has allocated two graduate students supported by faculty to independently study the West Hackberry Tertiary Project. Bogdan Lepski, a graduate student preparing for a master's degree in petroleum engineering, conducted core floods to simulate the Double Displacement Process in the laboratory. A vertical water-filled core was flooded with oil and then flooded with water from the bottom to a residual oil saturation. Gas was injected in the top of the core to simulate the Double Displacement Process. As the core was flooded with gas, additional oil was recovered thereby simulating the Double Displacement Process in the laboratory. After the core was flooded with gas and the added oil recovery was almost at an end, water was pumped into the bottom of the core to prepare the core for the next flood. As the water filled the core, a significant volume of additional post-Double Displacement oil was recovered. LSU named the process that recovered oil through water flooding a core after the Double Displacement Process the "Second-Contact Water Displacement" oil recovery process.

In the field, the Second-Contact Water Displacement Process could be used for improved oil recovery in two ways: 1) allowing the water level to push back up through the reservoir after the Double Displacement Process has reached depletion or, 2) injecting a gas into a watered out reservoir with a single well and then allowing the aquifer to push water back through the reservoir to recover more oil. LSU presented an SPE paper documenting the Second-Contact Water Displacement Process at the SPE Symposium on Improved Oil Recovery on April 21-24, 1996, in Tulsa, Oklahoma. A summary of Bogdan Lepski's work with the core floods is included within a proposal for a doctorial research project Appendix B.

Tammy Bourgoyne, a doctoral student in petroleum engineering, has prepared a model simulation of the core tests of the Double Displacement Process. An introduction to the modeling work performed by LSU is included in Appendix C.

AIR INJECTION SYSTEM



APPENDIX A

STATEMENT OF WORK

STATEMENT OF WORK

WEST HACKBERRY TERTIARY PROJECT

Amoco Production Company
October 16, 1992

Background and Objectives

The goal of the West Hackberry Tertiary Project is to demonstrate the technical and economic feasibility of oil recovery using air injection in the Double Displacement Process. The Double Displacement Process is the gas displacement of a water invaded oil column for the purpose of recovering oil through gravity drainage. A novel aspect of this project is the use of air as the injection fluid. This technology will be applicable to reservoirs which have both sufficient bed dip for gravity drainage and sufficient reservoir temperature for the consumption of oxygen. Numerous water-drive reservoirs associated with salt dome fields along the Gulf Coast would be potential follow-up candidates for this technology. The use of air injection in this process offer the benefits of air's excellent accessibility and low cost combined with potentially greater recovery due to the combustion process. If successful, this project will demonstrate that the use of air injection in the Double Displacement Process can economically recover oil in reservoirs where tertiary oil recovery is presently uneconomical.

Based on a preliminary project design developed prior to commencement of the project, the following basic operational information has been determined for the study: injection rates; selection of reservoirs and fault blocks; required number of producing and injection wells; requirements for new wells versus re-completing existing wells; requirements for continuous injection versus intermittent injection; assessment of the disposal of produced gases by flaring or injection into low pressure reservoirs; unitization; and the design of surface production and injection facilities. The project is designed for injection into two separate fault blocks (Fault Blocks II & IV). In Fault Block IV, the technology will be assessed using a line of four producers at structurally equivalent positions in a heavily developed area. In Fault Block II, the technology will be assessed using a single producer in a sparsely developed area.

A description of each task associated with the project is provided below.

Task 1 - Environmental Study

It is anticipated that this project will be categorically excluded from the DOE NEPA requirements. Upon DOE certification, if this project does qualify for a categorical exclusion, this task will not be required. If this project does not qualify for a categorical exclusion, then this task will involve activities, such as data collection and reporting, that are required by the DOE to meet NEPA requirements.

Task 2 - Construction of Surface Facilities

The necessary permits required for construction of the surface facilities will be obtained. Based on the preliminary project design, Amoco will acquire the necessary equipment/facilities to inject 4-4.5 MMCFD of air at pressures greater than 4000 psi. Surface injection facilities will be installed which consist primarily of the air compressors and water purge system for the injection wells. The timing for the installation of production facilities will be tied to workovers on the producing wells conducted in Task 5. The production facilities will consist of flowlines, possibly an Natural Gas Liquids recovery unit, and a separate-test-and-boost (STAB) facility. After separation and testing, produced fluids will be piped to Amoco's central production facility. Undesired produced gasses will be flared or injected into low pressure reservoirs.

Task 3 - Conversion of Producing Wells to Injection Wells

Two producing wells will be converted to injection wells. Initially, a single injection well will be dedicated to each of the two fault blocks. Two additional injectors (i.e. converted producing wells) may be required to improve the economics of the process. A typical workover to convert a producing well to an injector would require cleaning out the wellbore, perforating the full prospective injection interval, and completing the well with new packers, tubing, and wellhead (i.e. valves, etc.).

Task 4 - Operations and Maintenance of Injection Facilities

The operation of the high pressure air compressors in the injection facilities requires close attention to safety issues. Synthetic lubricants and periodic cleaning of injection equipment will be conducted to prevent the possibility of a detonation resulting from the combination of high pressure air and hydrocarbon deposits. Additionally, routine maintenance of injection equipment will be conducted to avoid the possibility of catastrophic mechanical failure. Workovers to repair injection wells will be performed on an as needed basis.

Task 5 - Workovers for Monitoring and Producing Wells

A total of 9 wells will be repaired and/or re-completed to serve as producing wells and/or monitoring wells for the project. The timing of the workovers will be dictated by the advance of the flood front. The task of monitoring the flood front is addressed in Task 6. Once the project is underway, workovers to repair producing and monitoring wells will be performed on an as needed basis.

Task 6 - Production Operations

All production operations for the project will be handled by Amoco field personnel assigned to West Hackberry Field. Produced liquids will be transported through existing collection lines to be handled at an Amoco Tank Battery. Initially, producing wells will be gas lifted within Amoco's field-wide gas lift system. When the produced gasses become concentrated with undesirable components (e.g. nitrogen and carbon dioxide) due to breakthrough, it will be necessary to install a separate gas lift system for the project. The separate gas lift system will require a gas lift compressor. Produced gasses will either be sold, burned as fuel, flared or re-injected into low pressure reservoirs on the north flank of the field. Booster compressors may be required to generate sufficient pressure for injection of produced gasses. A flowline will be installed to the north flank of West Hackberry Field in order to carry the produced gasses to the low pressure reservoirs in that area. Monthly production tests, at a minimum, will be performed on all producing wells. Gas analyses will be conducted periodically to monitor the composition and oxygen content of the produced gasses. Produced oil and water samples will be analyzed periodically to determine their composition and physical properties. Pulsed neutron logs, bottom hole pressure surveys, temperature surveys, and spinner surveys may be run in both producing and monitoring wells in order assess the effectiveness of the project. Periodic replacement of surface production and injection equipment (including flowlines) may also be required due to wear and tear on these items.

Task 7 - Reservoir Management

Reservoir modeling studies will be conducted to effectively manage the project. These studies will assist in assessing the following: distribution of injection volumes; timing of repairs and re-completions; and the determination of monitoring schemes and schedules. Amoco's "THERM" reservoir model will be used to history match reservoir performance and to predict future reservoir performance. Specialized combustion tests will be conducted at Amoco's Combustion Laboratory in Tulsa, Oklahoma to assist in monitoring and predicting the performance of the project. Reservoir fluid property analyses will be conducted to calibrate the reservoir model. The results of reservoir management will be continually documented and reported in a manner consistent with the DOE reporting requirements and technology transfer needs of the project.

Task 8 - Louisiana State University Technology Transfer

A yearly Amoco grant will be provided to the Petroleum Engineering Department at Louisiana State University (LSU). LSU will study various aspects of the project and report their findings. LSU will publish and make industry presentations on all results from their analyses. Amoco plans to provide LSU with all pertinent data and information from the project. Examples of typical data and information that will be made available to LSU include the following: individual well production rates; individual well injection rates; structure maps; net pay isopachs; core data; well logs; gas analyses; and fluid property data.

Task 9 - Amoco Technology Transfer

Amoco will assess the technical and economic feasibility of Double Displacement Process based on the data and information acquired from the project. These results will be documented and submitted to various technical conferences for presentation and/or publication. Since the Double Displacement Process will probably have its greatest applicability to salt dome fields along the Gulf Coast, Amoco personnel will focus on technical conferences in the Houston, Texas and New Orleans, Louisiana areas. It is anticipated that presentations and/or papers will be completed at the beginning, middle, and end of the project. Amoco does not intend to regard any data and/or information on this project as proprietary.

APPENDIX B

SUMMARY OF LSU'S LABORATORY RESEARCH

(Doctorial Research Proposal)

SCREENING WATERFLOODED OIL RESERVOIRS FOR GAS INJECTION IMPROVED OIL RECOVERY METHODS

A Proposal Submitted to General Examination Committee
September 1996

by
Bogdan Lepski

M.S. University of Mining and Metallurgy, Cracow, 1992.
M.S. in PETE Louisiana State University, Baton Rouge, 1995.

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STUDY OBJECTIVES AND METHODOLOGY

Conventional production techniques leave substantial quantities of oil in the reservoir. Various IOR processes target that oil. In steeply dipping, water driven reservoirs substantial incremental production can be obtained using Double Displacement Process (DDP) and Second Contact Water Displacement (SCWD). Both processes target water displaced residual oil. Experimental work and case histories indicate that up to 95 % initial oil in place can be recovered using DDP.

DDP utilizes updip gas injection and subsequent oil gravity drainage to mobilize and displace oil left behind the waterfront. While investigating the DDP, substantial oil was recovered when the gasflooded cores were subjected to downdip water injection. High pressure, high temperature corefloods and transparent micromodel experiments were performed in order to quantify and confirm this phenomenon referred to as SCWD. The advantage of SCWD over DDP is shorter duration of the recovery process and its suitability to larger number of reservoirs.

Research is needed to establish reservoir selection criteria and practical predictive techniques for the SCWD process. The efficiency of the process depends on phase distribution in the pore space after gas injection which in turn depends on interfacial and surface tensions (IFT) of the phases involved. Part of the planned study will concern designing a practical method of IFT measurement under reservoir conditions.

LITERATURE REVIEW

Theoretical Work

The Double Displacement Process (DDP) involves updip gas injection into a water-invaded oil column in order to mobilize and produce incremental oil.[1] The incremental oil results from the difference in residual oil saturation in the presence of water as compared to that in the presence of gas. Gravity stable displacement causes the formation of an oil bank which builds up progressively as it migrates downward the reservoir towards the producing wells. A simplified schematic of a dipping reservoir subjected to DDP is shown in Figure 1.

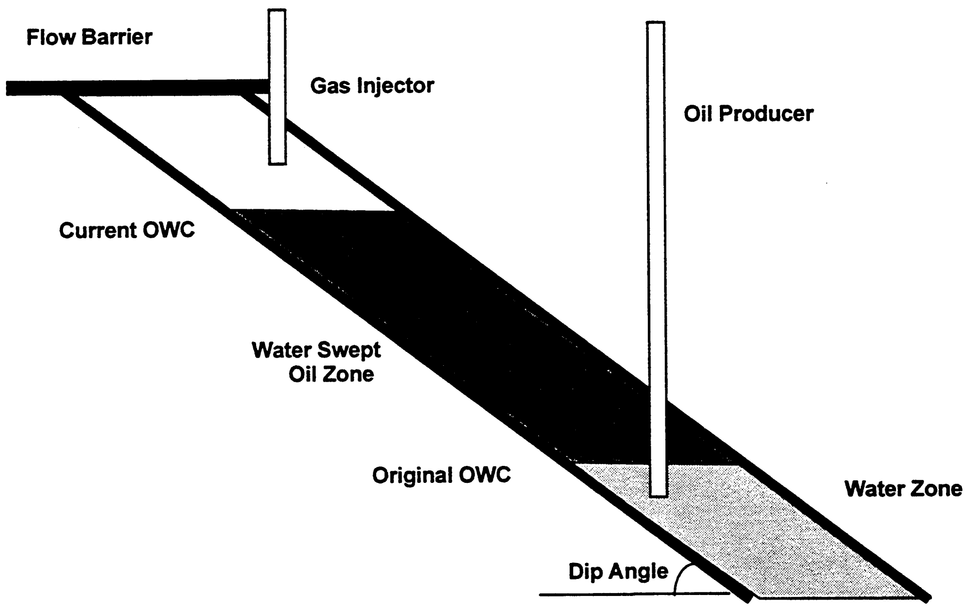

Fig. 1. Reservoir undergoing DDP.

Gas injection will help mobilize oil until the oil-water contact is lowered to its initial position at the beginning of reservoir production. Under favorable conditions, incremental oil recovery on the order of 40% of the initial oil-in-place may be recovered using DDP.[1-5]

Residual oil is left behind a waterfront because it is trapped by capillary retention forces that are greater than the forces applied during the waterflood. Residual oil may be in contact with the surface of the pore network (oil-wet rocks), trapped as globules surrounded by water contacting the pore network surface (water - wet rocks) or a combination of the preceding may occur in the case of mixed wettability.[6]

In order to recover waterflood residual oil, we must restore effective permeability to oil which is essentially zero in the water-swept zone. By injecting gas, some of the excessive water is displaced from pores where oil globules are trapped. For initially water wet systems with oil trapped in the pores, introduction of a gas phase creates conditions for three phase flow. When gas enters a pore containing a residual oil blob, capillary forces cause oil to spread between water coating the pore wall and the gas bubble occupying the center of the pore. This creates conditions allowing oil globules and blobs to reconnect. The reconnected oil film flows downward due to gravity forces and creates an oil bank. As more gas is injected, the existing oil bank flows downwards encompassing residual oil blobs as it travels. If gas front progresses slowly, no movable oil is left behind the gas front. However if the gas front advances rapidly, residual oil blobs are bypassed. These isolated oil blobs. can be reconnected to form a continuous phase which is efficiently displaced by SCWD process. Single pore scale gas displacement of waterflood residual oil is illustrated in Figure 2.

Efficiency of the DDP is governed by several different processes, including gravity drainage and the oil spreading coefficient. Gravity drainage is an oil recovery mechanism in which gravity acts as the main driving force for mobilization of oil with gas replacing the voided volume. A comprehensive description of the process was given by Hagoort.[7]

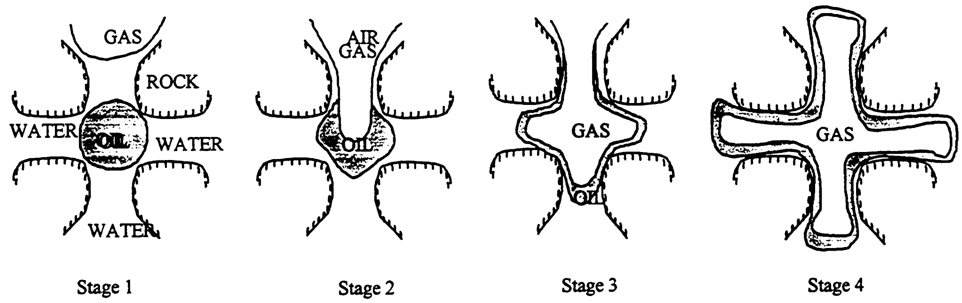

Fig. 2. Pore scale gas displacement of water residual oil.

A schematic of a reservoir subjected to gravity drainage process after gas injection is given in Figure 3.

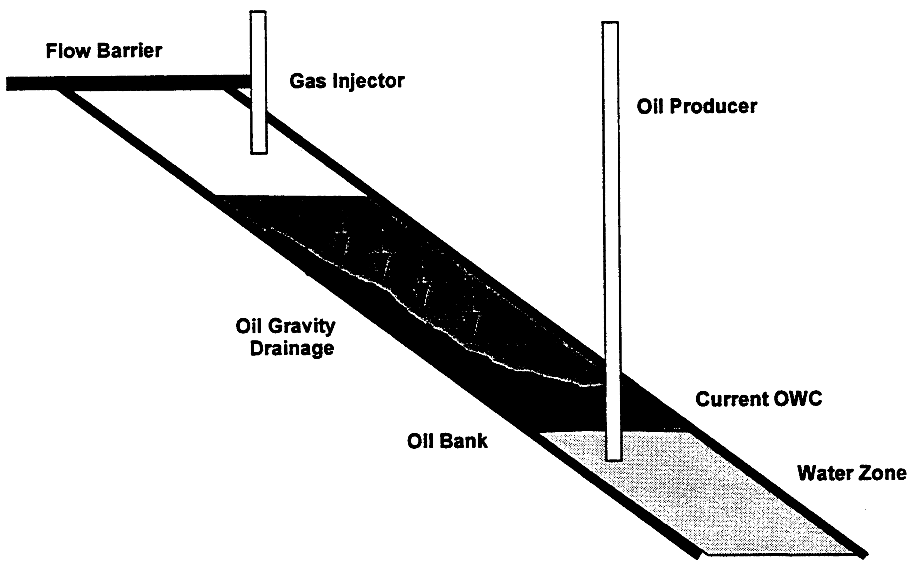

Fig. 3. Oil gravity drainage after gas injection

According to Chatzis et al[8], process efficiency is dependent on the spreading of oil over water in presence of gas. The spreading coefficient is given by:

$$S'_{o/w} = \sigma'_{wg} - \sigma'_{og} - \sigma'_{ow} \quad \text{...(1)}$$

where:

$S'_{o/w}$ = final spreading coefficient of oil over water

σ'_{wg} = water/gas interfacial tension

σ'_{og} = oil/gas interfacial tension

σ'_{ow} = oil/water interfacial tension

When $S'_{o/w}$ is positive, oil tends to spread on water and form a continuous film. When $S'_{o/w}$ is negative, oil does not spread on water and stays discontinuous. This observations were further investigated by Oren at al[9] using a 2D glass micromodel containing a regular square network of intersecting capillaries. Soltrol 130™ was used to simulate the oil phase. Gas injection was performed with the cell positioned horizontally. Combinations of both positive were negative spreading coefficient systems were tested. Film formation and high oil recovery was observed for positive spreading coefficient systems. For negative spreading coefficient systems, the residual oil after gasflood tended to coalesce instead and form blobs occupying several pore spaces.

The spreading coefficient changes with time, as two substances initially contact than become mutually saturated. If an initially positive S' becomes negative, the initial oil film retracts and forms a lens.[10]

Experimental Work

Water-flood residual oil production has been modeled experimentally by performing floods in unconsolidated and consolidated cores, glass bead columns and glass micromodels. In general, the experiments demonstrated that a high percentage of the residual oil can be recovered for various sets of rock-fluid combinations.[2,4,5,12] Most of the studies showed that the residual oil saturation after gas displacement was the same for waterflood residual oil and initial oil saturation in presence of irreducible water.

In 1983, Carlson[1] conducted laboratory tests to evaluate the DDP. A composite core made of 17 Dexter sand core plugs was mounted in a Hassler-type device. The core was oilflooded then waterflooded in a gravity stable manner to establish a residual oil saturation. Nitrogen was then injected at a very slow rate. All experimental steps were performed at reservoir temperature and pressure. Only 35% was recovered by waterflooding. An additional 1% was recovered by nitrogen injection. Poor flood performance was attributed to the lack of capillary continuity between core plugs. Additional experiments using Dexter sand core plugs mounted in triaxial core holders and a high speed centrifuge were performed to measure two-phase and three-phase end point saturations. An average residual oil saturation of 12% was measured for gas drive and 35% for water drive displacements.

Kantzas et al[12] evaluated the DDP using glass bead columns 0.05 to 0.10 m in diameter and 0.2 - 1.5 m in length. Experiments were carried out with "continuous oil" i.e. oil was the continuous phase in the presence of irreducible water, and "discontinuous oil" i.e. residual oil after waterflooding. Oil displacement was performed under "free drainage" and "controlled drainage" conditions. These terms refer to drainage of oil due to its own weight and due to the hindrance of a semipermeable membrane, respectively. The oil front advancement ranged from 0.01 to 0.1 m per day. A needle valve or semi-permeable membrane was used to control the flow rate. Using controlled displacement, the recovery of continuous oil approached 100% of the original oil-in-place, while the recovery of discontinuous oil was 85-95%. Under free drainage conditions, recoveries of continuous oil were lower and ranged from 73-79% of the initial oil-in-place. Reported gas injection time ranged from 350 to 2700 hours.

Kantzas et al[12] also examined the DDP in consolidated Berea sandstone (0.038 m in diameter and 0.29 m in length). The controlled drainage mode was used for Berea sandstone. Recoveries of continuous oil reached about 76% of initial oil-in place after 3200 hours of gas injection. Recoveries of discontinuous oil were lower and frequent changes of the semipermeable membrane were required to enhance oil production.

Chatzis et al[8] performed tests to visualize oil film formation and its influence on recovery efficiency. Square 500 mm and smaller capillary tubes were used to observe the flow behavior of the wetting phase. The DDP was performed in 1.2 m long, 0.038 m in diameter Berea sandstone cores with Computer-Assisted Tomography used to visualize the gas injection process and oil bank formation. The gas injection rate was 1 cc/day and the injection pressure was 34.5 kPa. About 40% of residual oil was produced at the time the report was published.

Field Cases

The DDP can be an economical IOR method for reservoirs with substantial oil left after water invasion, assuming optimum permeability, bed dip and oil viscosity for gravity drainage. As this is a gas injection project, a source of cheap gas must be readily available. Typically there is no need to drill a significant number of new wells for gas injection and oil production. The SCWD extends application of the DDP to single-well, water-driven reservoirs, where SCWD can be combined with attic oil recovery process to maximize oil recovery.

The Weeks Island field pilot DDP with CO_2 and methane was completed by Shell. The Hawkins Field DDP nitrogen injection project operated by Exxon is currently in progress, while the West Hackberry air injection project operated by Amoco is in its initial stage. A more detailed description of these reservoirs is provided in Table 1.

The Weeks Island field located in New Iberia Parish, Louisiana, is a typical Gulf Coast salt-dome field. It has a strong water drive, good sand quality and reservoir continuity with water drive sweep efficiencies ranging from 60 to 70% of initial oil-in-place. A mixture of CO_2 and natural gas was chosen to arrive at a relatively low gas density which would help achieve a stable displacement front. The gas injection started in 1978 and oil production began in 1981. Upon completion of the project in 1988, it was estimated that about 60% of the oil trapped behind the waterfront was recovered.[3]

The Hawkins Field unit was subjected initially to gas cap injection pressure maintenance between 1975 and 1987. In 1987, the DDP was initiated in the eastern part of the field which was subjected to a water drive. It was hoped that injection of a mixture of nitrogen and natural gas would lower the waterflood residual oil saturation from 35% down to 12% by the end of the project. The rate of oil bank downdip movement was originally anticipated to be approximately 25 feet per year.[5] During the early stages of the process, the gravity drainage rate was found to be about 12 ft/year. As a result, some oil remained trapped behind the gas front. After three years of project life, the oil column thickness increased by 10 ft, about 50% of the expected increase. The slower gravity drainage rate was attributed to an increase in the in-situ oil viscosity and gravity. It was found that the increase in oil viscosity was not due to gas injection, but to recovery of heavier oil that had been displaced upward during waterflooding. The reservoir oil relative permeability at low oil saturations was lower than expected, which also caused a delay in oil bank formation. Even though oil drainage was slower than expected, the DDP was considered to be successful based on the amount of oil recovered.[4]

Table 2.1 Rock and Fluids Properties of Weeks Island, Hawkins and West Hackberry Reservoirs[5]

Reservoir Property	Weeks Island	Hawkins Field	West Hackberry
Porosity, %	26	27	24 - 28
Permeability, md	1200	3400	300-1000
Swi, %	10	13	19-23
Sorw, %	22	35	26
Sorg, %	1.9	12	8 (est.)
Reservoir Temperature, °F	225	168	195-205
Dip Angle, deg	26	8	23-35
Pay Thickness, ft	186	230	30-31
API Oil Gravity	32.7	25	33
Viscosity, cp	0.45	3.7	0.9
Bubble Point Pressure, psig	6013	1985	3295
Solution GOR, SCF/STB	1386	900	500
Oil FVF at Bubble Point	1.62	1.225	1.285
Waterflood Recovery Factor, % of IOIP	78	60	60
Gasflood Recovery Factor, % of IOIP	95	85	90 (est.)

The West Hackberry field is characterized by a waterflood residual oil saturation of about 26 %. The residual oil saturation after gasflooding is expected to be 5%. Air is the injection gas. Combustion is expected at prevailing reservoir temperature producing flue gas composed of 85% nitrogen and 15% carbon dioxide. It is also expected, that carbon dioxide will go into solution and decrease the residual oil viscosity thus easing the gravity drainage process.[5]

ACCOMPLISHED INVESTIGATIONS

Transparent Micromodel Experiments

In order to visually observe the mechanisms responsible for oil mobilization and displacement, a transparent micromodel was built. The cell used in the experiment is similar to the cells described by Dahmani.[12] Figure 4 is a schematic of the transparent micromodel.

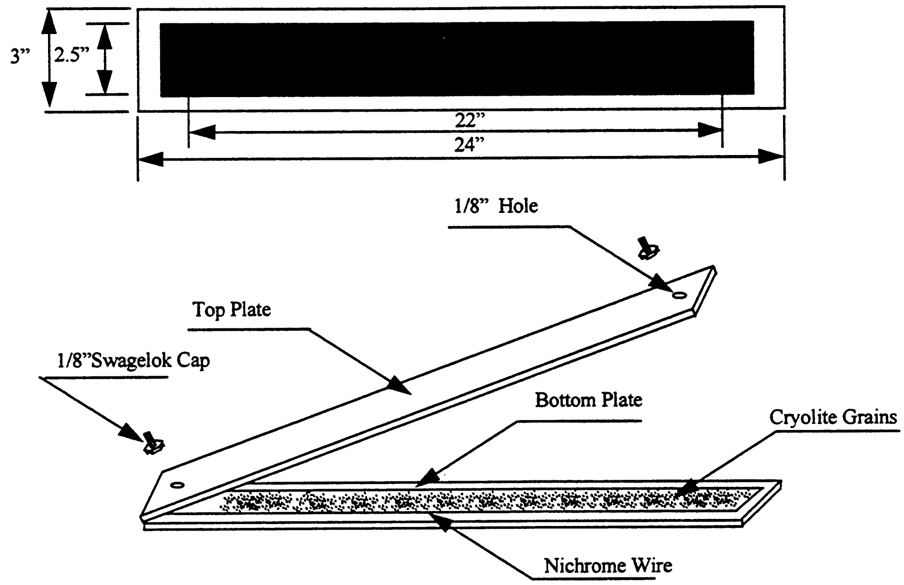

Fig. 4. Schematic of the Transparent Micromodel.

Two 24" x 3" glass plates were used as the bottom and the top of the cell. Two 1/8" holes were drilled at both ends of the top plate and stainless steel Swagelok caps (1/8" in diameter) were glued to the glass to serve as an inlet and outlet for fluid flow. The glass plates were glued together with two pieces of 28 gauge (0.015" in diameter) Ni-Cr wire serving as a spacer. The total volume of the cell was 14 cc. The glue used in the construction was Devcon 2-Ton Epoxy. To provide the cell with a porous medium, cryolite (Na_3AlF_6) granules were injected. Cryolite was chosen because it is highly water-wet. Most importantly, the cryolite refractive index is close to that of water rendering it transparent when it is in contact with water. Cryolite rocks, purchased from Ward's Natural Science Establishments, Inc, were crushed and sieved. The 100-150 mesh fraction was used to pack the cell. The cell was packed by applying a vacuum on one end of the cell; glass wool was placed in the outlet fitting, to prevent the grains from entering the vacuum pump. The grains were consolidated by injecting a fresh mixture of 60% tetraethyl orthosilicate, 32% ethanol, and 8% 0.1 N HCl into the cell. Excess mixture was removed from the cell by flushing the cell with air. The orthosilicate mixture solidified as non-reactive silica and cemented the cryolite grains to streaks of different permeability. The transparent micromodel was incorporated in the experimental setup shown in Figure 5. For all injections, a Sage Instruments Model 355 syringe pump was used. The injection rate was adjustable. The cell was initially flooded with CO_2 to remove air from the cell. The cell was then positioned vertically and saturated with deaerated water. Residual CO_2 dissolved in the water which was subsequently displaced from the cell. About 4 PV of water were injected into the cell from each direction to remove CO_2. After the cell was saturated anew with water, oil was injected into the top of the cell until no additional water was produced and the system was allowed to stabilize for one day. The oil used was a mixture of 67% decane and 33% crude from the West Hackberry, LA, field. This opaque mixture was selected to yield a mobility ratio close to unity. Next, deaerated water was injected into the bottom of the cell until no additional oil was produced, and the cell was again stabilized for one day. Gas was then injected at the slowest possible rate of 0.08 cc/day into the top of the cell to simulate DDP. After gas breakthrough, the cell was shut-in for two days for stabilization. After the shut-in period, water was injected into the bottom of the cell to simulate the SCWD process. The experiment was filmed using a VCR camera. The VCR camera was fixed on a tripod and fitted with additional optical equipment such as a teleconverter, bellows unit, three close-up lenses and a polarizing filter. This arrangement reduced unwanted light reflections and permitted variable scales of magnification from whole cell size, down to single pore level, 450:1.[13]

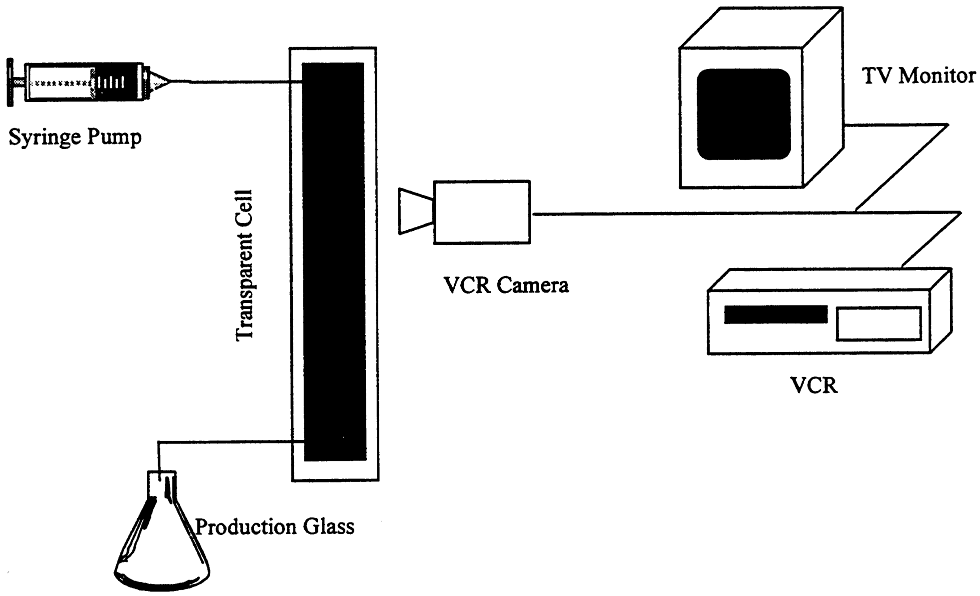

Fig. 5 Transparent Micromodel Setup.

The transparent micromodel experiments succeeded in visualizing microscopic gas-oil-water displacements, oil film development and oil bank growth. It was also observed that injected water, simulating the SCWD displaced most of the gas and remaining oil. This created an oil bank which grew with time and progressed updip. Only insignificant amount of oil was left behind the SCWD waterfront. The stages of the second contact water displacement are shown in the magnified pictures of Figures 6a-6d.

High Pressure and Temperature Corefloods

Experimental conditions were selected to be as close as possible to West Hackberry field reservoir conditions.[5] However, certain constraints were imposed by the equipment design and capabilities. The pressure and temperature selected for all floods were 2000 psig and 205°F respectively. The West Hackberry oil was used. The oil API gravity was 31.5° and its asphaltene content was 0.52%. The asphaltene content is sufficiently low that core plugging was unlikely. Oil viscosity at 205°F was 2.15 cp, which made gas gravity drainage and SCWD investigation feasible within a reasonable time period.

Two experimental setups were used and a total of four experiments were performed. The main part of the first experimental setup, shown in Fig. 7, consisted of a consolidated Berea sandstone core 6 feet in length and two inches in diameter.

Fig. 6a. Transparent cell prior to water invasion, after gas injection. Water and cryolite grains--light, oil and gas--dark)

Fig 6b. Water invasion from the left causes oil displacement.

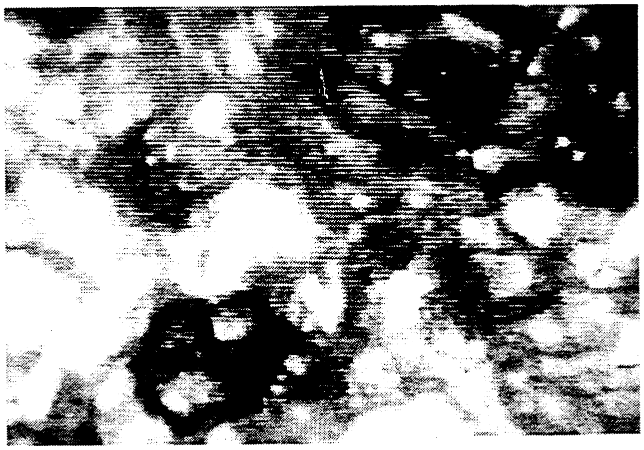

Fig. 6c. Continued water invasion from the left, further oil displacement.

Fig. 6d. Final fluid distribution, black zones--gas bubbles left behind the waterfront.

Berea sandstone was used to simulate a heterogeneous reservoir rock with permeability streaks. The core was coated with epoxy resin and fiberglass tape and placed in a stainless steel coreholder. Stainless-steel tube coils were wrapped around the core and used to circulate a heated mixture of ethylene glycol and water to create a uniform temperature distribution. The coreholder was insulated to minimize heat losses. The annulus of the coreholder was filled with hydraulic oil and pressurized to at least 1000 psi higher than the highest pressure expected in the core during the experiment. The goal was to keep the core under permanent compression.

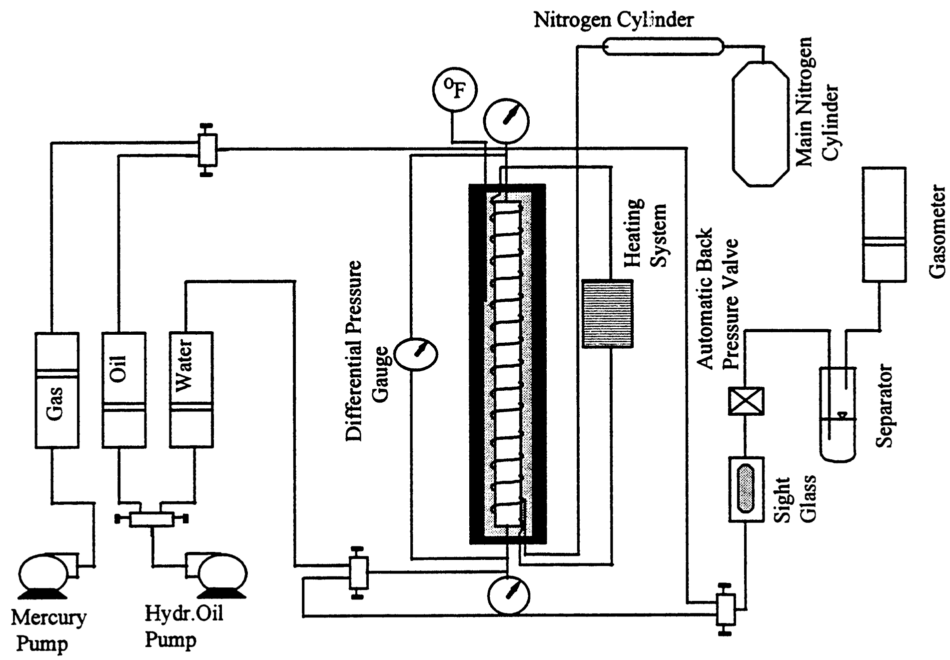

Fig. 7. Consolidated core setup

To maintain a constant pressure in the annulus of the coreholder, 500 cc and 1000 cc high pressure stainless steel cylinders filled with nitrogen were connected to the annulus. This safety device is necessary to maintain the core under compression in case of failure of the heating system when the core is saturated with gas.[13]

The core assembly was mounted vertically and both ends were connected to floating piston transfer vessels. The other ends of the transfer vessels were connected to positive displacement Ruska pumps filled with hydraulic oil. The transfer vessels were used to transfer fluids in and out of the core. The producing end of the core, which changed during the experiment, was connected to the production panel with a sight glass for visual observations at high pressure and a back pressure valve was used to maintain a preset pressure at the producing end. Produced fluids were separated and measured in an atmospheric pressure separator connected to a gasmeter. Pressures at both ends were measured using digital-meters and Bourdon tube gauges. The differential pressure across the core was also monitored.

In order to investigate the process in a homogeneous rock environment, a second setup incorporating a sandpack apparatus with a much higher permeability and core crossectional area was also built, Figure 8.

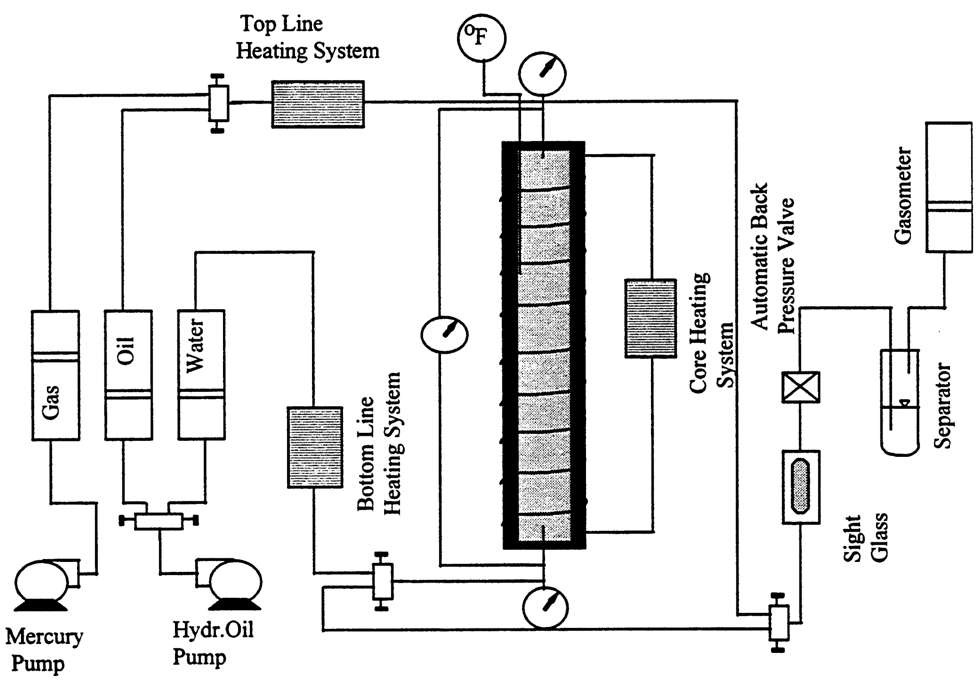

Fig. 8. Unconsolidated core setup

The apparatus consisted of a 9.5 ft long, 0.2225 ft diameter steel cylinder, packed with 80-120 mesh Ottawa sand. Sand and water were added simultaneously and the holder was vibrated to ensure a tight pack. The sandpack assembly was mounted vertically and a brass tube heating coil was wrapped around the coreholder. The system was insulated to minimize heat losses. The flowlines closest to the core were preheated to 205°F by placing 15 feet of coiled tubing in the ethylene glycol/water mixture. This sort of preheating system was unnecessary in the Berea sandstone core since more than 5 feet of flowlines were already immersed in the coreholder annulus filled with hot hydraulic oil. The average core porosity was calculated to be 36% based on the amount of water retained by the sand pack. Pore volume was calculated to be 4785 cc.

Clean, water-saturated cores were used for each experiment. An initial permeability check was performed before each experiment by pumping water at constant flow rate and constant pressure drop across the core. Permeability was measured in both flow directions of the linear core. The absolute permeability measurements were performed at 205 °F and 2000 psig, the same conditions planned for the displacement experiment. The core was then subjected to an oilflood to establish an irreducible water saturation. The oil was injected in the top and water was produced from the bottom of the core. After one day of stabilization time, a waterflood was performed to establish residual oil saturation in the presence of water. The injection rates for oil and water ranged from 16 to 160 cc/hr. The flood ended when the fraction of the displacing fluid reached 95%. After the oilflood and the waterflood, effective permeabilities to oil and water at residual saturations were measured in both directions. Permeability and saturation values are listed in Table 2. Permeability measurements were performed in top to bottom (t-b subscript) and bottom to top (b-t subscript) directions.

Gas injection was initiated by pressurizing all lines of the production side with only the back pressure valve closed. The same gas injection rate was maintained during all cycles of gas injection. An exact measurement of the produced gas was difficult due to the very slow injection rate; therefore the cut-off point was established by observing the produced fluids through the sight glass. After gas breakthrough, the cores were shut-in for oil mobilization. After the shut-in period, the gas injection was resumed to displace the oil mobilized during the previous shut-in period. Lastly, water was injected into the bottom of the core.

The fluids used during all coreflood experiments and their properties are listed together with gas injection rates in Table 3. Water and oil properties were measured and gas properties were interpolated from existing tables. After each experiment the core was cleaned to restore the initial strongly water-wet and water saturation conditions[13].

Table 2. Permeability and Saturation Summary.

Property	Sandpack Run #1	Berea Run #1	Sandpack Run #2	Berea Run #2
$k_{(t-b)}$	1.72 d	417 md	1.53 d	286 md
$k_{(b-t)}$	1.38 d	469 md	1.46 d	327 md
$k_{oiw(t-b)}$	1.22 d	179 md	0.78 d	250 md
$k_{oiw(b-t)}$	1.34 d	239 md	0.95 d	239 md
$k_{wor(t-b)}$	0.18 d	53 md	0.60 d	32 md
$k_{wor(b-t)}$	0.15 d	46 md	0.50 d	28 md
S_{iw}	13.88 %	44.5 %	14.13 %	43.6 %
S_{or}	15.53 %	30.3 %	15.56 %	35.0 %

Table 3. Fluid Injection Rates, Densities and Viscosities.

Experiment	Type of Fluid	Flow Rate (cc/hr)	Density (g/cc) @ 205°F	Viscosity (cp) @205°F
Sandpack Runs	Deaerated Water	96 cc/hr	0.9623	0.3873
	West Hackberry Crude (Recycled)	160 cc/hr	0.8234	2.40
	Pure Nitrogen	20 cc/hr	0.1177	0.0230
Berea Runs	30k ppm KCl Brine	16 cc/hr	0.9810	0.3721
	West Hackberry Crude	32. cc/hr	0.8182	2.1528
	Pure Nitrogen	2.5 cc/hr	0.1177	0.0230

One of the important design parameters of the experiment was the gas injection rate. Since only water was initially produced followed by the oil bank, a gravity stable displacement must have been maintained throughout gas injection.

The critical gas injection rate (flux) was predicted using Eq. 2 proposed by Dietz.[14]

$$u_c = \frac{0.044 k_o \Delta \rho_{o/g} \sin \alpha}{\mu_o} \qquad \text{.....................................(2)}$$

where:

k_o = permeability to oil, Darcy

$\Delta\rho_{o/g}$ = oil/gas density difference, lbs/cu ft

α = dip angle, degrees

μ_o = oil viscosity, cp

After the first Berea sandstone experiment was completed, the same core was used in a second experiment. The goal of the second experiment was to determine if the duration of the shut-in period following gas breakthrough affected process performance. The experimental procedures were the same except for a shorter duration of the shut-in period.

All procedures in the unconsolidated core experiments were the same as in the Berea experiments, except the gas injection rate, which was 20 cc/hr. A sufficiently low gas injection rate was selected to avoid gas fingering. Fluid saturations and core permeabilities for all experiments are summarized in Table 2.

The sandpack experiments yielded significant oil production. Experiment #1 was performed with a short gas gravity drainage shut-in period of 5 days. In experiment #2, the gas gravity drainage period was extended to 38 days. The duration of the shut-in period had no effect on oil recovery. Even though the initial waterflood residual oil saturation was low in both experiments, about 15.5% PV, that value was reduced by SCWD to 11.3% PV in the first experiment and 11.9% PV in the second. Subsequent gas injection-shut-in cycles did not yield significant oil production. The plot of oil saturation vs. time for both sandpack experiments is given in Figure 9.

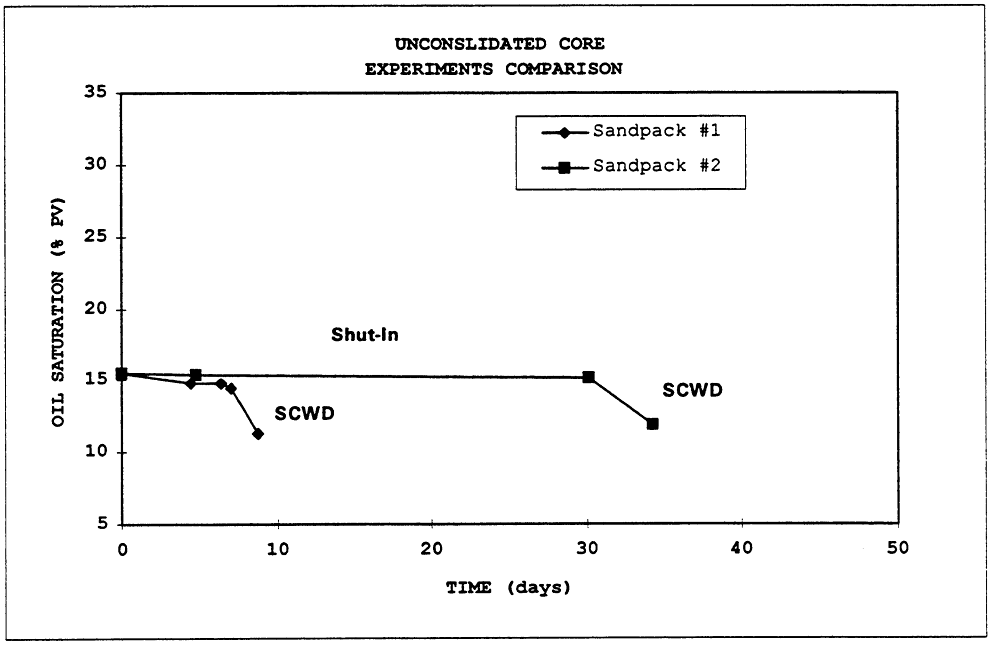

Fig. 9. Unconsolidated core experimental results

In the consolidated core experiments, unlike the sandpack experiment, significant oil production was observed prior to gas breakthrough. The increase in early oil production may be attributed to gas penetration of zones unwept by water. Only a fraction of the movable water (about 70%) was displaced before gas breakthrough. Additional water production was observed during subsequent gas injection period. The residual oil saturation after initial gas injection was lowered from 30.3% to 20.3% PV in the first Berea experiment and from 35.0% PV down to 24.2% PV in the second experiment. In the first experiment, the core was shut-in after gas breakthrough for 5 days, gas was injected again and additional oil was produced. Immediately after the second cycle of gas injection/oil production, water was injected downdip.

The oil saturation was reduced to 17.3% at the end of the experiment. SCWD resulted in an additional 3.6% PV of oil. In the second experiment, the duration of the shut-in period was extended to 38 days. Gas was injected again and additional oil was produced. Subsequent SCWD produced an additional 2.51% PV of oil bringing the final oil saturation down to 17.8% PV.

The amount of incremental oil produced prior to gas breakthrough during both Berea experiments was in good agreement with the amount obtained in DDP Berea experiments.[13] The saturation summary for both Berea experiments is shown in Figure 10.

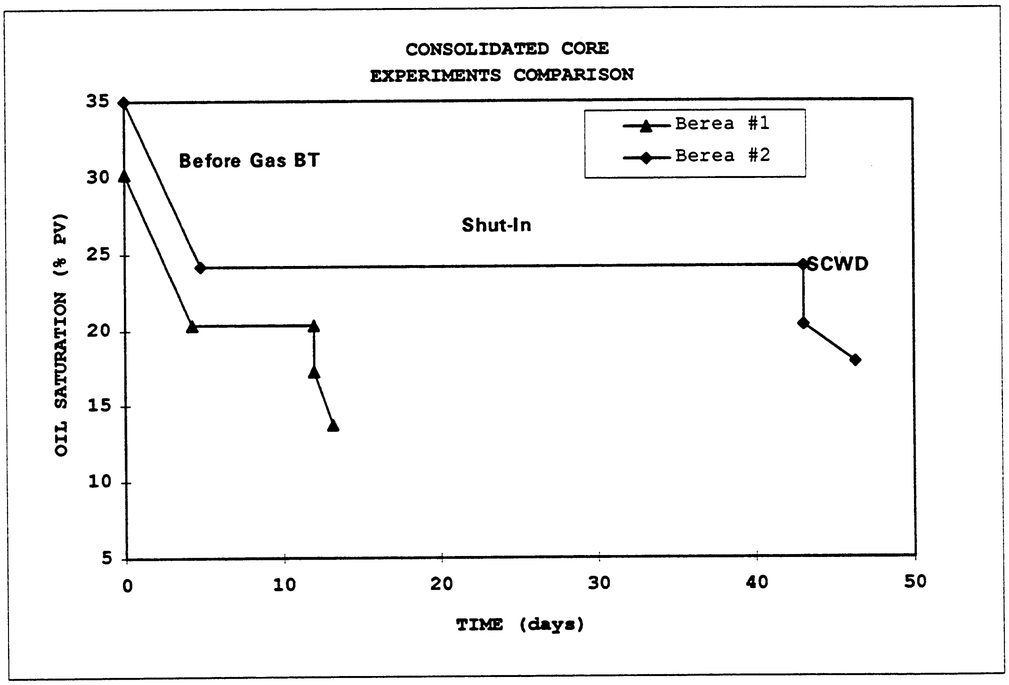

Fig. 10. Consolidated core experimental results

Interfacial Tension measurements (Drop Volume Method)

IFT measurements for spreading coefficient calculation have to be performed under reservoir conditions with recombined oil phase used. In order to achieve that, a Through Window

Ruska PVT Cell (Fig. 11) and HP Ruska mercury pump is used. Recombined oil is injected via a transfer vessel. The system is capable of going up to 5000 psi and 300 °F, thus covering reservoir conditions where SCWD is applicable.

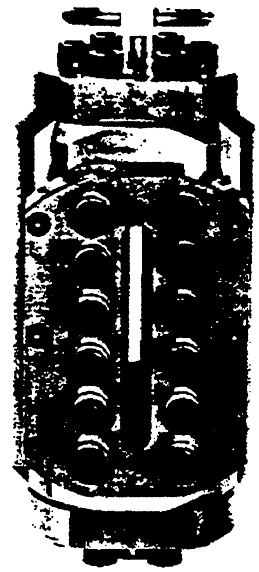

Fig. 11. Through Window Ruska PVT Cell

The IFT measurement using this method is made by pumping the light phase into the dense phase at constant flow rate. Drops form at the tip of the specially designed capillary, Fig. 12, and IFT is calculated using Eq. 3. To avoid necessary corrections due to liquid that can wet and accumulate on the tip, the tip was designed to be very sharp as shown in Fig 13.[15]

$$\sigma_i = \frac{V_{drop}(\rho_H - \rho_L)g}{\pi d} \quad \text{...(3)}$$

Where:

ρ_H = density of the heavy phase

ρ_L = density of the light phase

V_{drop} = volume of the drop

g = acceleration of gravity

d = inside diameter of the tip

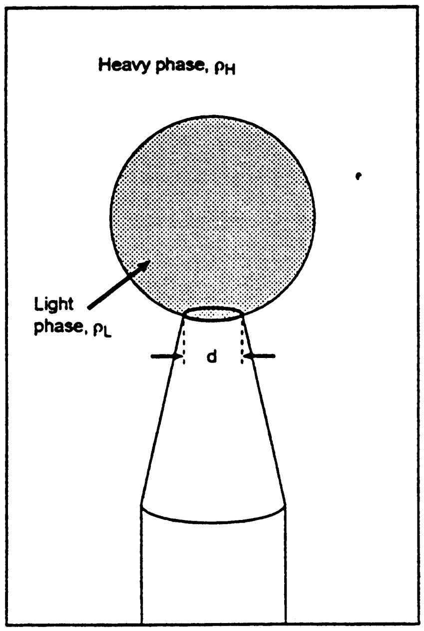

Fig. 12. Drop Volume Method Schematic (after Gilman[15]).

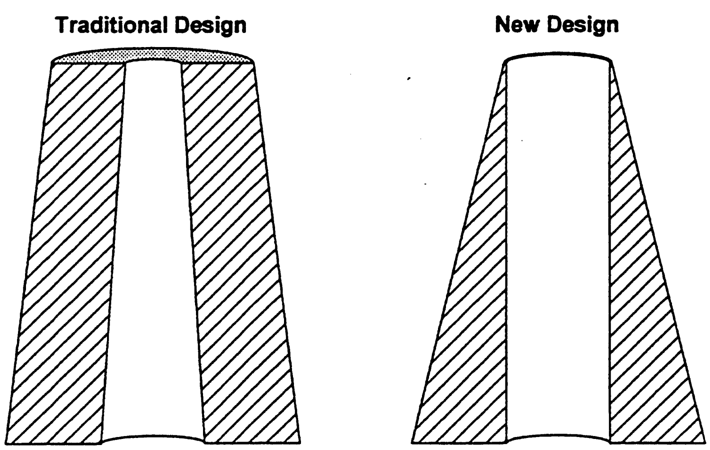

Fig. 13. Capillary Tip Design (after Gilman[15]).

Drop volume method was believed to be the simplest method available and sufficiently accurate for IFT measurements. Unfortunately, the method was originally designed to be applicable only for the measurement of liquid/liquid IFT. The measurement of IFT for heptane-distilled water system is shown in Fig. 14. Results obtained are in very good agreement with published values.[16]

Fig. 14. Oil-Water IFT Measurement.

The difficulty in using the drop volume method for liquid/gas IFT (surface tension measurements) comes from the wettability of the capillary tip in presence of gas. This phenomena causes liquid to climb over the tip instead of forming a regular shape drop Fig 15.

Fig. 15. Attempted Oil Surface Tension Measurement.

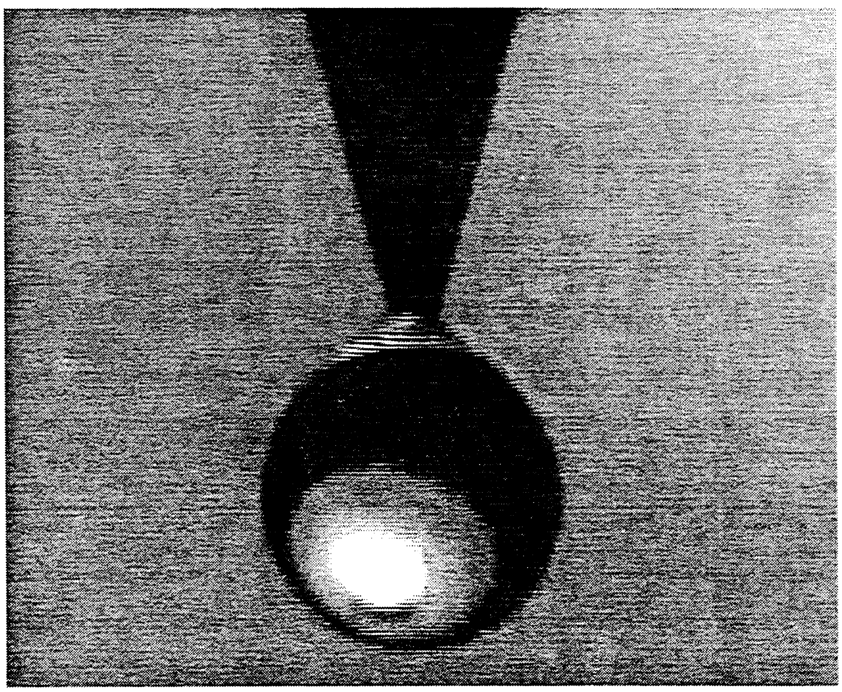

Fig. 16. Water Surface Tension Measurement.

In case of water surface tension measurement, the problem was overcome by soaking the tip in mineral oil thus forming thin oil film coating on the tip. Using oil-wet tip, injected water formed a regular shape drop (Fig.16) and detached in a way that Eq. 3 was valid again for calculation of surface tension. Results obtained were in good agreement with literature values.

Several methods were tried to change wettability of the tips used for oil/gas IFT measurements, but none succeeded in producing a regular shaped oil drop.

Oil Spreading Experiments

Estimation of the spreading coefficient was attempted by observing oil spreading observed visually under ambient conditions. The setup consisted of beaker filled with distilled water mounted on a holder, and a syringe used for oil injection. Diluted oil used for transparent micromodel experiments (66% decane and 33% West Hackberry oil) and West Hackberry oil used for coreflood experiments were investigated. The diluted oil spread over water and formed a thin film that remained the same after overnight maturation. West Hackberry crude behaved initially the same way, but the thin film contracted after overnight maturation and formed a small lens as shown in Fig. 17.

Further investigation using this method under reservoir conditions was not possible. A single oil drop spreads over an area far greater than that available within the Ruska PVT cell.

INVESTIGATIONS IN PROGRESS

Pendant Drop Method IFT Measurements

The research is now concentrated on pendant drop method of IFT measurement. A drop hanging from a capillary tip (or a clinging bubble) elongates as it grows larger. Then, the drop shape dependent quantity $S = d_s/d_e$ (d_s measurement is taken within d_e from the bottom of the drop, Fig. 18) is used in calculation of the IFT.[17]

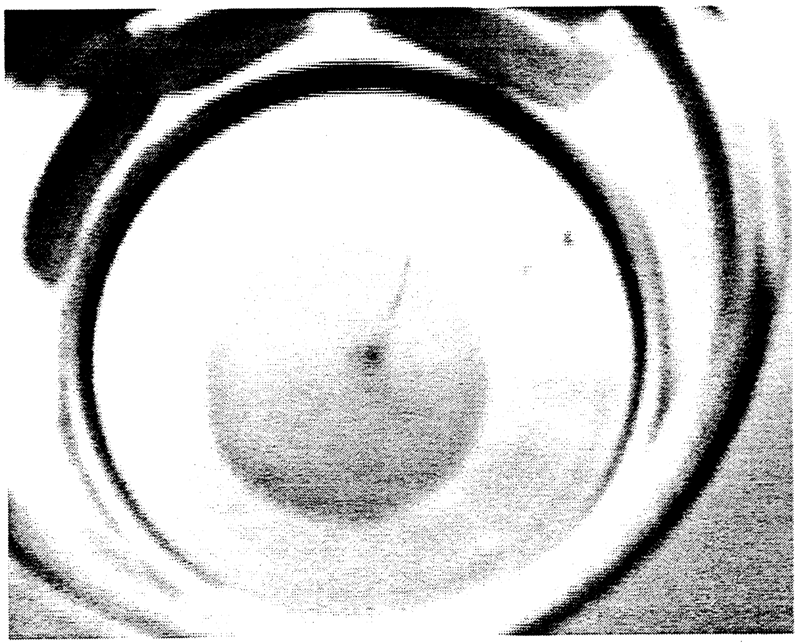

Fig. 17. West Hackberry crude final spreading over water

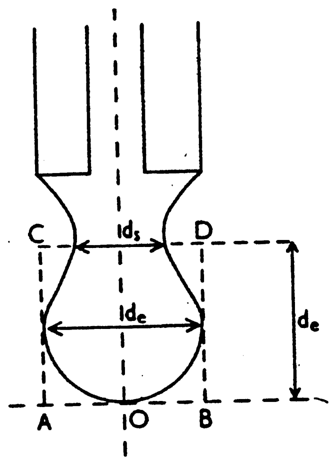

Fig. 18. Pendant Drop IFT Measurement Method (after Padday[17]).

IFT can be calculated quickly using following algorithm:[18]

$$\sigma_i = \frac{\Delta \rho g R_o^2}{\beta} \qquad \text{....(4)}$$

$$\beta = 0.12836 - 0.7577S + 1.7713S^2 - 0.5426S^3 \qquad \text{....(5)}$$

$$R_o = \frac{d_e}{2\left(0.9987 + 0.1971\beta - 0.0734\beta^{3^2} - 0.34708\beta^3\right)} \qquad \text{....(6)}$$

In order to perform the measurement with sufficient accuracy and simplicity, pendent drop will be filmed with VCR camera equipped with set of additional lenses, taped on VCR and then the image will be transferred to a computer using the frame capture software Minolta - Play Snappy. Transferred image will be then measured using Jandel SigmaScan Measuring software. Preliminary measurements performed with these two pieces of software provided sufficient accuracy for the SCWD process spreading coefficient calculation. An example measurement is illustrated in Fig. 19.

FUTURE INVESTIGATIONS

Combination of the Drop Volume and Maximum Bubble Pressure Methods

Drop volume method is not designed for surface tension measurement of liquids. When liquid is pumped through the capillary tip in presence of gas, liquids tend to wet the tip and, instead of forming regular shape drop hanging at the tip, it climbs over the tip and forms irregularly shaped drop, as demonstrated in Fig. 16. When gas is bubbled through the capillary, expansion of the bubbles makes drop volume method calculation invalid. Due to the method's simplicity and convenience of use within the transparent PVT cell, I plan to improve drop volume method by trying to combine it with maximum bubble pressure method.

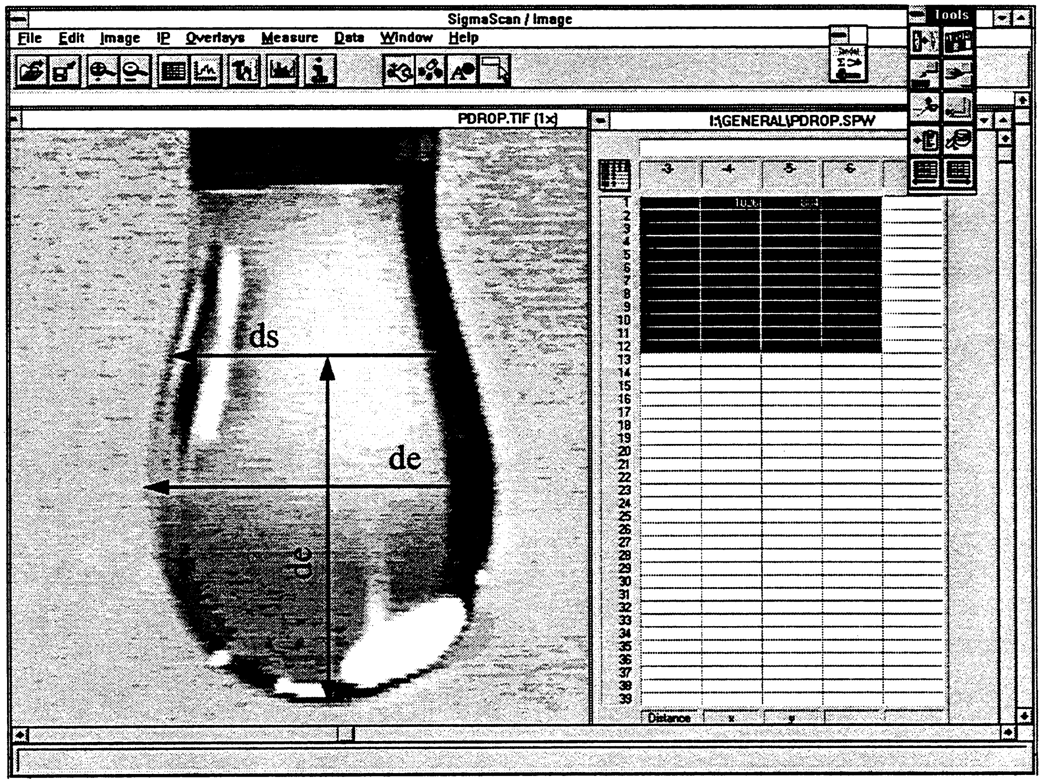

Fig. 19. Schematic of Pendant Drop Image Processing.

The procedure for maximum bubble method is to slowly blow bubbles of gas in the liquid by means of a tube projecting below the surface. For small tube, the sequence of shapes of the bubble is such that the bubble radius reaches its minimum when it reaches the inner or outer radius of the tube (depending on tube wettability), as shown in Fig. 20 and Fig. 21. At the same time, pressure needed to pump this gas bubble into a liquid reaches its maximum. The value of IFT is proportional to the value of that maximum pressure. [10]

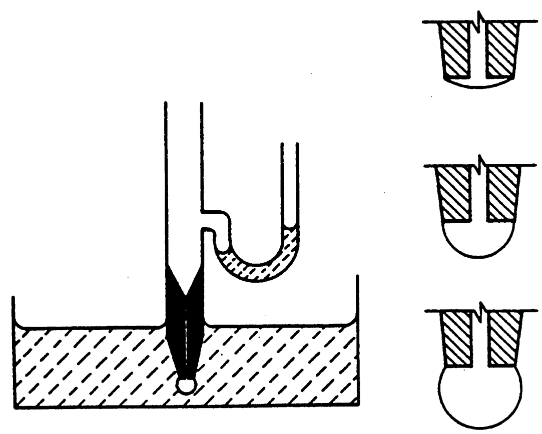

Fig. 20. Maximum Bubble Pressure Method (after Adamson[10]).

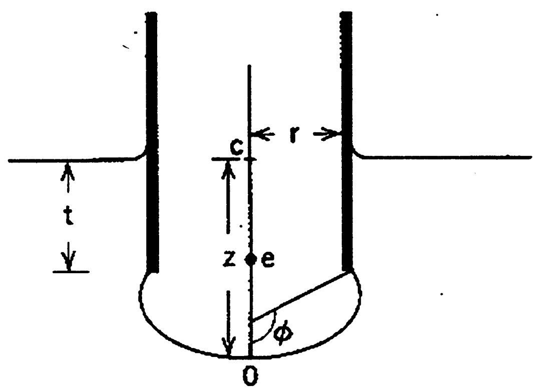

Fig. 21. Schematic of the Maximum Bubble Pressure Method (after Adamson[10]).

Under reservoir conditions where compressibility effect is less pronounced, drop volume method for liquid/gas interfaces combined with maximum bubble pressure method should provide sufficient accuracy required for spreading coefficient calculation.

Screening Criteria for SCWD

Since SCWD is a new process, little is known about screening criteria to be used for candidate reservoir selection. SCWD is an extension of DDP, thus DDP screening criteria should apply.

However, additional criteria governing water encroachment in the gasflooded oil zone are needed.

The following are some general screening criteria for DDP developed experimentally and with reservoir simulation:

- minimum of two wells in good mechanical condition,
- reservoir dip angle should be over 10^{o},
- reservoir permeability should be no less than 300 md,
- reservoir depth should be considered in view of optimizing gas/oil density difference.

When considered together, lower permeability has more detrimental effect on process efficiency than dip angle.[19]

It is believed that oil spreading over water in presence of gas will be one of crucial factors for predicting process performance.

Further investigation of the SCWD process will be performed with transparent micromodel and HPHT Ruska PVT cell. After a method of IFT measurement is developed, other corefloods are planned to investigate process performance for negative spreading coefficient. By the time these experiments are finished, a numerical simulator for DDP should be available to help in development of some practical screening criteria for SCWD.

CONCLUSIONS

Original contribution of this work is discovery and initial investigation of the new Improved Oil Recovery method, the Second Contact Water Displacement (SCWD). Additional contribution came from development of practical IFT measurement under reservoir conditions. Further study of the SCWD is planned including development of practical screening criteria for the new process. Ongoing IFT experimental work has attracted attention of industry including Krüss and Dow Chemical.

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VITA

Bogdan Lepski, son of Maria Lepski and Roman Lepski was born on March 22, 1966 in Paslek, Poland.

He was admitted to University of Mining and Metallurgy, Cracow, Poland in October 1986. He obtained his Master of Science and Engineering degree in June 1992 and started his career as a drilling engineer with the Polish Oil and Gas Company in Zielona Gora, Poland. After coming to USA in August 1993, he obtained his Master of Science in Petroleum Engineering in May 1995 and entered a Doctor of Philosophy program at Louisiana State University in Baton Rouge.

APPENDIX C

SUMMARY OF LSU'S MODELING RESEARCH

(Introduction to Doctorial Paper)

Summary

Currently, U. S. producers are faced with economically unfavorable conditions such as competition from less mature areas, lower oil prices, and increasing environmental regulations which lead to higher operating costs. With current technology, more than half of the oil discovered is being left in the ground. Technological improvements, which increase the recovery of bypassed oil, would further aid the aging domestic oil industry to maximize production from previously developed reservoirs. Without significant advances to improve recovery, the domestic oil and gas industry will continue to decline at the same or at a higher rate.

Oil can be bypassed on both a macroscopic scale and a microscopic scale. Oil is bypassed on a macroscopic scale when regions of the reservoir remain unswept due to well placement or reservoir inhomogeneities. Oil is bypassed on a microscopic scale when it becomes immobile within the porous medium due to capillary and wettability effects. Oil bypassed in this manner is referred to as *residual oil* and can be recovered with any process which creates conditions under which the mobility of the oil is restored. An emerging technology which targets the oil remaining after natural water influx or waterflooding is the tertiary injection of gas. The term *tertiary* refers to the recovery of oil remaining after completion of a secondary recovery process such as waterflooding. In this body of work, it implies that the original oil column has been invaded by water and that remaining oil is discontinuous. A process in which gas displaces mobile water and re-establishes the hydraulic continuity of the oil is referred to in this study as a tertiary gas injection. This is in contrast to a secondary gas injection process which involves the displacement of a continuous oil phase by gas.

Another term which is often used to refer to a particular tertiary gas injection process is the phrase *Double Displacement Process*. The term Double Displacement Process (DDP) was coined by Carlson (1988) in his discussion of the Hawkins Field operated by Exxon. Carlson (1988) defined DDP as the displacement by gas of a water-invaded oil column. In a non-horizontal system, gas is injected into the up-dip portion of the reservoir to drive the current water oil contact back to its original (pre-production) level. Gas acts to mobilize the oil trapped due to capillary pressure effects in the water invaded zone. In a steeply dipping reservoir, the density differences among the gas, oil, and water tend aid in the drainage process. The oil may accumulate between the gas (up-dip) and water-invaded oil zone (down-dip). The oil bank grows as oil drains to the bottom of the gas-invaded zone and flows down-dip. The oil bank can be produced once it reaches a down-dip production well.

The key parameters in the economic success of any enhanced oil recovery (EOR) process is the oil production rate as a function of time from the start of gas injection. A long delay between the initial injection and the initial production response and a low oil production rate will both adversely affect the economic viability of the process. Even though numerous laboratory studies have proven that oil can be efficiently displaced in this type of process, implementation in the field has been less successful. If the double displacement process is initiated in a dipping bed, the sweep efficiency should be maximized if the gas is injected slowly enough that the gas-fluid interface remains stable and approximately horizontal.

Gravity segregation of the oil and gas behind the front will tend to drive the oil down-dip and the gas up-dip behind the advancing gas front. A key parameter in conventional modelling of the drainage rate of oil in any process is the relative permeability to oil as a function of fluid saturation.

Currently, Amoco, in partnership with the U. S. Department of Energy, is conducting a field test of the Double Displacement Process in a portion of the West Hackberry Field in Cameron Parish, Louisiana. Although this is not the first time the DDP has been implemented on a field-wide level, this is the first instance of using air as the injection fluid in the DDP. In theory, the use of air should improve the economics of the process by both reducing the operating costs and accelerating recovery of the oil. Operating costs are reduced since air is less expensive and more accessible than other gases, such as carbon dioxide and natural gas. Amoco further expects that the recovery process will be accelerated by in-situ combustion of the air in the presence of hydrocarbons at high temperature and pressure. Although the past DDP projects have been a technical success in that significant volumes of tertiary oil were recovered, the projects have been less successful economically due to delayed oil recovery. Amoco hopes to demonstrate that the DDP can be both a technical and economic success if air is used as the injection fluid. To make a distinction between the DDP combined with in-situ-combustion (as for West Hackberry Tertiary Project) and the DDP without thermal effects, I will refer to the DDP at West Hackberry as the *West Hackberry Process*.

As part of a technology transfer agreement among Amoco, the U. S. Department of Energy (DOE), and Louisiana State University (LSU), independent research on regarding the tertiary recovery of oil by up-dip gas injection is currently being conducted at LSU. In 1995, a physical linear modelling study of the process was conducted at elevated temperature and pressure in both unconsolidated and consolidated vertically-oriented porous media (Lepski, 1995). The study conducted by Lepski (1995) showed that residual oil remaining after a waterflood can indeed be re-mobilized by up-dip gas injection.

The objective of the current study is to develop a method for estimating the relative permeability to oil for use in modelling of a double displacement process in a high permeability, strongly water-wet sandstone reservoir. To investigate mechanisms involved in the tertiary recovery of oil by up-dip gas injection, the published literature was surveyed for laboratory and field studies investigating the displacement of waterflood residual oil by gas and for information related to gravity drainage and surface forces among fluids. To develop a method for modelling the oil relative permeability for the double displacement process, the literature was also surveyed for existing three-phase relative permeability models and correlations. A goal strived for during the development of the proposed relative permeability model was use of a function which could be easily implemented in any of the available commercial reservoir simulators.

The review of literature revealed a series of both theoretical and laboratory studies investigating the pore-level mechanisms involved in a horizontal double displacement process and another series of both theoretical and laboratory studies investigating the relative permeability to oil during a vertical double displacement process. Based on the results reported in these studies, a simple power-law relationship relating the relative permeability of oil to the oil saturation was developed. A one-dimensional, numerical model which included the effects of gravity and capillarity was then developed to test the proposed oil relative permeability function using the data collected previously by the LSU-Amoco Technology Transfer Project Research Team (Lepski, 1995).

Once the oil relative permeability function had been tested and verified using the available experimental data, a simplified approach for applying the oil relative permeability function was developed. This simplified approach can be used to predict the oil rates which could be achieved during up-dip gas injection into a water-invaded, anisotropic, stratified reservoir. As a means of illustrating its application, this simplified approach has been applied to one of the fault blocks involved in the West Hackberry Tertiary Project. This simplified approach applies only to a gravity-stable gas injection process which is steady-state at reservoir conditions. This approach neither considers the gas solubility in the oil phase nor the resulting changes in oil properties. It also does not account for the stripping of the lighter components of the oil phase to the gas phase. Also neglected in this simplified approach are the effects of in situ combustion which may occur if air is the injected fluid.

These limitations are considered to be acceptable in view of the unusual difficulty in accurately describing the reservoir inhomogeneity, the effects of which are generally much more important. By performing a sensitivity study on those parameters which are believed to be beneficially affected by gas solubility and in situ combustion (if applicable), the beneficial effects of these factors on oil recovery may be bracketed. The other simplifying assumptions (gravity-stable, steady-state, no stripping) will tend to provide the most optimistic estimate of oil recovery. Since this approach would tend to predict an upper limit on the oil recovery which could be expected for a given reservoir lacking any unidentified inhomogeneities beneficial to the process, the techniques presented in this work could be applied as a tool for screening candidates for tertiary oil recovery by up-dip gas injection.

The following body of work includes (1) a chronological summary of previously published field and laboratory studies which pertain directly to the mobilization of residual oil by gas injection, (2) a discussion of the efficiency of oil recovery by gas injection based on both field and laboratory observations, (3) a discussion of interfacial forces and the mechanisms involved in the displacement of residual oil, (4) a summary of the currently available relative permeability correlations and models, (5) a discussion of the development of the proposed relative permeability functions for the tertiary up-dip gas injection process, (6) a discussion of the implications of the proposed relative permeability functions on oil recovery, and (7) a summary of the study which provides conclusions and recommendations for future work.