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Study of Hydrocarbon Miscible Solvent Slug Injection
Process for Improved Recovery of Heavy Oil From
Schrader Bluff Pool, Milne Point Unit, Alaska

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TABLE OF CONTENTS

	<u>PAGE</u>
TABLE OF CONTENTS	iii
LIST OF FIGURES	v
LIST OF TABLES	xiii
CHAPTER 1: INTRODUCTION	1.1
CHAPTER 2: RESERVOIR DESCRIPTION	2.1
• Characterization of Schrader Bluff Pool, Milne Point Unit	2.1
(Outside Tract 14)	
CHAPTER 3: SLIM TUBE DISPLACEMENT STUDIES	3.1
• Introduction	3.1
• Experimental Results	3.2
• Discussion of Results	3.6
• Conclusions	3.7
CHAPTER 4: COREFLOOD EXPERIMENTS	4.1
• Introduction	4.1
• Unsteady State Waterflood	4.2
• Effect of Miscible Slug Size (MCM Process)	4.2
• Effect of Water-Alternating-Gas (WAG) Ratio	4.4

TABLE OF CONTENTS (continued)

PAGE

APPENDIX:

- Appendix A: Crude Oil and Solvent Compositions A.1
- Appendix B: Raw Data from Coreflood Experiments B.1
- Appendix C: Calculation of Relative Permeability C.1

LIST OF FIGURES

<u>FIGURE</u>	<u>TITLE</u>	<u>PAGE</u>
Chapter 2:		
Figure 2-1	Base Map With Location of Milne Ponit Well Outside Tract 14	2.4
Figure 2-2	NW-SE Stratigraphic Cross Section Along A-A'	2.5
Figure 2-3	NW-SE Stratigraphic Cross Section Along C-C'	2.6
Figure 2-4	Net Pay Isopach For NB1 Sand	2.7
Figure 2-5	Effective Porosity Contour Map For NB1 Sand	2.8
Figure 2-6	Water Saturation Contour Map For NB1 Sand	2.9
Figure 2-7	Sand Quality Distribution For NB1 Sand	2.10
Figure 2-8	Net Pay Isopach For OB1 Sand	2.11
Figure 2-9	Effective Porosity Contour Map For OB1 Sand	2.12
Figure 2-10	Water Saturation Contour Map For OB1 Sand	2.13
Figure 2-11	Sand Quality Distribution For OB1 Sand	2.14
Chapter 3:		
Figure 3-1	P-x Diagram for CO ₂ /NGL Mixture	3.9

LIST OF FIGURES (continued)

<u>FIGURE</u>	<u>TITLE</u>	<u>PAGE</u>
Figure 3-2	P-x Diagram for PBG/NGL Mixture	3.10
Figure 3-3	Slim Tube Displacement Experiment and Simulation Results (Solvent: 100% Kuparuk-Schrader Bluff Gas)	3.11
Figure 3-4	Slim Tube Displacement Experiment and Simulation Results (Solvent: 100% CO ₂)	3.12
Figure 3-5	Slim Tube Displacement Experiment and Simulation Results (Solvent: 90% CO ₂ and 10% NGL)	3.13
Figure 3-6	Slim Tube Displacement Experiment and Simulation Results (Solvent: 85% CO ₂ and 15% NGL)	3.14
Figure 3-7	Slim Tube Displacement Experiment and Simulation Results (Solvent: 100% Prudhoe Bay Gas)	3.15
Figure 3-8	Slim Tube Displacement Experiment and Simulation Results (Solvent: 70% PBG and 30% NGL)	3.16
Figure 3-9	Slim Tube Displacement Experiment and Simulation Results (Solvent: 60% PBG and 40% NGL)	3.17
Figure 3-10	Slim Tube Displacement Experiment and Simulation Results (Solvent: 50% PBG and 50% NGL)	3.18
Figure 3-11	Density vs. No. of Contacts (Solvent: 40% PBG/60% NGL)	3.19

LIST OF FIGURES (continued)

<u>FIGURE</u>	<u>TITLE</u>	<u>PAGE</u>
Figure 3-12	K-values vs. No. of Contacts (Solvent: 40% PBG/60% NGL)	3.20
Figure 3-13	X_i vs. No. of Contacts (Solvent: 40% PBG/60% NGL)	3.21
Figure 3-14	Y_i vs. No. of Contacts (Solvent: 40% PBG/60% NGL)	3.22
Figure 3-15	Density vs. No. of Contacts (Solvent: 36% PBG/64% NGL)	3.23
Figure 3-16	K-values vs. No. of Contacts (Solvent: 36% PBG/64% NGL)	3.24
Figure 3-17	X_i vs. No. of Contacts (Solvent: 36% PBG/64% NGL)	3.25
Figure 3-18	Y_i vs. No. of Contacts (Solvent: 36% PBG/64% NGL)	3.26
Chapter 4:		
Figure 4-1	Oil-Water Relative Permeability Curves for the Sandpack	4.6
Figure 4-2	Oil Recovery vs. PV Injected (Unsteady State Waterflood)	4.7
Figure 4-3	WOR vs. PV Injected (Unsteady State Waterflood)	4.8
Figure 4-4	GOR vs. PV Injected (Unsteady State Waterflood)	4.9
Figure 4-5	Pressure Drop vs. PV Injected (Unsteady State Waterflood)	4.10
Figure 4-6	Oil Recovery vs. PV Injected, MCM Solvent Slug Size: 0.05PV	4.11
	(Solvent: 50% PBG + 50% NGL)	

LIST OF FIGURES (continued)

<u>FIGURE</u>	<u>TITLE</u>	<u>PAGE</u>
Figure 4-7	WOR vs. PV Injected, MCM Solvent Slug Size: 0.05 PV (Solvent: 50% PBG + 50% NGL)	4.12
Figure 4-8	GOR vs. PV Injected , MCM Solvent Slug Size: 0.05PV (Solvent: 50% PBG + 50% NGL)	4.13
Figure 4-9	Pressure Drop vs. PV Injected, MCM Solvent Slug Size: 0.05 PV (Solvent: 50% PBG + 50% NGL)	4.14
Figure 4-10	Oil Recovery vs. PV Injected, MCM Solvent Slug Size: 0.10PV (Solvent: 50% PBG + 50% NGL)	4.15
Figure 4-11	WOR vs. PV Injected, MCM Solvent Slug Size: 0.10 PV (Solvent: 50% PBG + 50% NGL)	4.16
Figure 4-12	GOR vs. PV Injected , MCM Solvent Slug Size: 0.10PV (Solvent: 50% PBG + 50% NGL)	4.17
Figure 4-13	Pressure Drop vs. PV Injected, MCM Solvent Slug Size: 0.10 PV (Solvent: 50% PBG + 50% NGL)	4.18
Figure 4-14	Oil Recovery vs. PV Injected, MCM Solvent Slug Size: 0.20 PV (Solvent: 50% PBG + 50% NGL)	4.19
Figure 4-15	WOR vs. PV Injected, MCM Solvent Slug Size: 0.20 PV (Solvent: 50% PBG + 50% NGL)	4.20

LIST OF FIGURES (continued)

<u>FIGURE</u>	<u>TITLE</u>	<u>PAGE</u>
Figure 4-16	GOR vs. PV Injected , MCM Solvent Slug Size: 0.20PV (Solvent: 50% PBG + 50% NGL)	4.21
Figure 4-17	Pressure Drop vs. PV Injected, MCM Solvent Slug Size: 0.20 PV (Solvent: 50% PBG + 50% NGL)	4.22
Figure 4-18	Oil Recovery vs. PV Injected, MCM Solvent Slug Size: 0.40 PV (Solvent: 50% PBG + 50% NGL)	4.23
Figure 4-19	WOR vs. PV Injected, MCM Solvent Slug Size: 0.40 PV (Solvent: 50% PBG + 50% NGL)	4.24
Figure 4-20	GOR vs. PV Injected , MCM Solvent Slug Size: 0.40PV (Solvent: 50% PBG + 50% NGL)	4.25
Figure 4-21	Pressure Drop vs. PV Injected, MCM Solvent Slug Size: 0.40 PV (Solvent: 50% PBG + 50% NGL)	4.26
Figure 4-22	Oil Recovery vs. PV Injected, Multiple WAG, WAG Ratio: 11 (MCM Solvent: 50% PBG + 50% NGL)	4.27
Figure 4-23	WOR vs. PV Injected, Multiple WAG, WAG Ratio: 11 (MCM Solvent: 50% PBG + 50% NGL)	4.28

LIST OF FIGURES (continued)

<u>FIGURE</u>	<u>TITLE</u>	<u>PAGE</u>
Figure 4-24	GOR vs. PV Injected, Multiple WAG, WAG Ratio: 11 (MCM Solvent: 50% PBG + 50% NGL)	4.29
Figure 4-25	Pressure Drop vs. PV Injected, Multiple WAG, WAG Ratio: 11 (MCM Solvent: 50% PBG + 50% NGL)	4.30
Figure 4-26	Oil Recovery vs. PV Injected, Multiple WAG, WAG Ratio: 5 (MCM Solvent: 50% PBG + 50% NGL)	4.31
Figure 4-27	WOR vs. PV Injected, Multiple WAG, WAG Ratio: 5 (MCM Solvent: 50% PBG + 50% NGL)	4.32
Figure 4-28	GOR vs. PV Injected, Multiple WAG, WAG Ratio: 5 (MCM Solvent: 50% PBG + 50% NGL)	4.33
Figure 4-29	Pressure Drop vs. PV Injected, Multiple WAG, WAG Ratio: 5 (MCM Solvent: 50% PBG + 50% NGL)	4.34
Figure 4-30	Oil Recovery vs. PV Injected, Multiple WAG, WAG Ratio: 3 (MCM Solvent: 50% PBG + 50% NGL)	4.35
Figure 4-31	WOR vs. PV Injected, Multiple WAG, WAG Ratio: 3 (MCM Solvent: 50% PBG + 50% NGL)	4.36
Figure 4-32	GOR vs. PV Injected, Multiple WAG, WAG Ratio: 3 (MCM Solvent: 50% PBG + 50% NGL)	4.37

LIST OF FIGURES (continued)

<u>FIGURE</u>	<u>TITLE</u>	<u>PAGE</u>
Figure 4-33	Pressure Drop vs. PV Injected, Multiple WAG, WAG Ratio: 3 (MCM Solvent: 50% PBG + 50% NGL)	4.38

LIST OF TABLES

<u>TABLE</u>	<u>TITLE</u>	<u>PAGE</u>
Chapter 2:		
Table 2-1	List of Milne Point Wells for Second Phase Reservoir Characterization	2.15
Table 2-2	List of Normalized Wells	2.16
Chapter 3:		
Table 3-1:	EOS Parameters for Schrader Bluff Reservoir Fluid	3.27
Table 3-2:	Comparison of Recoveries From Slim Tube Experiments and Simulation	3.28

CHAPTER 1

INTRODUCTION

Alaska is the second largest oil producing state in the nation and currently contributes nearly 24% of the nations oil production. Alaska currently has nearly 22% of the total United States proven reserves. Alaska's known heavy oil and tar sand deposits are estimated to be between 26 and 44 billion barrels. Over the past decade, the production of oil has provided over 85% of the state of Alaska's revenue.

The oil production in Alaska has started to decline in the early 1990's which is attributed to decline in the production from super-giant Prudhoe Bay field. In the 1990, the National Energy Strategy Plan developed by U.S. Department of Energy called for 900,000 barrels/day production of heavy oil in the mid 1990's to meet the national demand. To meet this goal, it is imperative that Alaskan heavy oil fields be brought into production.

Schrader Bluff reservoir, located in the Milne Point Unit, which is part of the heavy oil field known as West Sak is estimated to contain 1.5 billion barrels of (14 to 21 degree API) oil-in-place. The field is currently under production by primary depletion. However, the primary recovery was expected to be much less than expected value of 12% due to complex reservoir structure. Hence, waterflood has been implemented earlier than anticipated. The eventual implementation of enhanced oil recovery (EOR) techniques will be vital for the recovery of additional oil from this reservoir.

The availability of hydrocarbon gases (solvents) on the Alaska North Slope make the hydrocarbon miscible solvent injection process an important consideration for the EOR project in Schrader Bluff reservoir. Since Schrader Bluff oil is heavy and viscous (41 cp. oil viscosity at reservoir conditions), a water-alternating-gas (WAG) type of process for oil recovery is appropriate since such a process tends to derive synergetic benefits from both water injection (which provides mobility control and improvement in sweep efficiency) and miscible gas injection (which provides improved displacement efficiency). Since hydrocarbon solvents are costly, a miscible solvent slug injection process rather than continuous solvent injection is considered appropriate.

Slim tube displacement studies, PVT data and asphaltene precipitation studies are needed for Schrader bluff heavy oil to define possible hydrocarbon solvent suitable for miscible solvent slug displacement process. Such studies are essential because the API gravity of the crude in Schrader bluff reservoir varies significantly from well to well. Coreflood experiments are also needed to determine the effect of solvent slug size, WAG ratio and solvent composition on the recovery and solvent breakthrough. A compositional reservoir simulation study will be conducted later to evaluate the complete performance of the hydrocarbon solvent slug process and to assess the feasibility of this process for improving recovery of heavy oil from Schrader Bluff reservoir.

CHAPTER 2

RESERVOIR DESCRIPTION

Characterization of Schrader Bluff Pool (Outside Tract 14), Milne Point Unit:

In the first phase of reservoir characterization of Milne Point Unit, the tract 14 wells from G, H, I and J-pads, Wsak 25 and N1B were included. For the second phase of reservoir characterization, a total of 36 wells were proposed by Conoco Inc. Out of these 36 wells, 29 wells were included in the study. The rest of the wells could not be analyzed due to lack of well log and other pertinent information. The proposed wells and their present status (i.e. whether producer, injector, abandoned or suspended) are listed in Table 2-1.

As in the previous phase, the second phase reservoir characterization was also based on computerized well log analysis. The well log analysis package Workbench developed by Scientific Software Inc. (SSI) was used for this study. All the log data and other well information were obtained from either Conoco Inc. or from Alaska Oil and Gas Conservation Commission (AOGCC). The raw log data were obtained either on diskette in ASCII format or on a magnetic tape spool. The ASCII well log data were directly loaded to Workbench (installed in an IBM RISC 6000 work station) from diskettes. Well log data in magnetic tape spool were first loaded into the VAX mainframe and converted to ASCII format using the LOGCALC software (SSI), and then transferred to the RISC workstation.

For this phase of reservoir characterization a second base map with well locations was generated by digitizing the well locations from a Milne Point Unit map. Figure 2-1 shows this base map with locations of Milne Point Wells Outside Tract 14.

The geologic sand top information for the zones of interest were supplied by Conoco Inc. Using these information, selected curves were plotted and sand tops were picked for each well. The locations of some of the sand tops were then fine tuned upon consultation with Conoco Inc. As suggested by Conoco Inc, two new sand zones were introduced which were not present in the Tract 14 analysis. These sands are the MA1 sand overlying the NA1 sand, and the ND1 sand between the NC1 and NE1 sands. Once the sand tops were finalized, a series of stratigraphic cross sections were generated by correlating these sand tops from well to well. In the base map of Figure 2-1, the orientations of the cross sections are shown. Two sample cross sections are shown in Figures 2-2 and 2-3. Figure 2-2 shows the A-A' (Northwest-Southeast) cross section and Figure 2-3 shows the C-C' (Northeast-Southwest) cross section. The sands exhibit gentle dips between wells in the NW-SE cross section. In the NE-SW cross section, however, there is a steep dip between the wells A2 and A1 indicating possible faulting. Following the generation of cross sections, open hole well log analysis was performed. For this purpose, the log traces were first corrected for borehole environment. Then, the bulk density traces were normalized to account for miscellaneous errors by using the same methodology as that used in normalizing the bulk density traces of Tract 14. Table 2-2 lists the wells whose density traces were normalized and the corresponding shift amounts.

After environmental correction and normalization, open hole analysis was run to determine petrophysical properties of the individual zones from top MA1 to base OE1. The following cut off values were used:

porosity = 25%

water saturation = 60%

shale volume = 0%

Net pay thickness, effective porosity, water saturation and sand quality (net hydrocarbon pore volume) of each zone in each well were obtained from this open hole analysis. Thus, a spatial distribution of the petrophysical properties was obtained.

Based on the results of open hole log analysis, contour maps of net pay thickness, porosity, water saturation and sand quality for the NA1, NB1, NE1, OA1 and OB1 sands were generated. The remaining sands were determined to be of extremely poor quality and hence were not mapped. Sample contour maps of the petrophysical properties for the NB1 and OB1. Sands are shown in Figures 2-4 through 2-11. It is evident that NB1 is the best quality sand. Good quality NB1 sand is seen in the Northern and Eastern sections of the field. OB1 and OA1 show good sand quality in the Southeastern section of the field. The western part of the field generally does not show good sand, NE1 and NA1 are of marginal quality throughout the field.

Figure 2.1 Base map with locations of Milne Point wells outside Tract 14

Figure 2.2 NW-SE stratigraphic cross section along A-A'

Figure 2.3 NE-SW stratigraphic cross section along C-C'

Figure 2.4 Net pay isopach for NB1 sand

Figure 2.5 Effective porosity contour map for NB1 sand

Figure 2.6 Water saturation contour map for NB1 sand

Figure 2.8 Net pay isopach for OB1 sand

Figure 2.9 Effective porosity contour map for OB1 sand

Figure 2.10 Water saturation contour map for OB1 sand

Table 2-1: List of Milne Point Wells for Second Phase Reservoir Characterization

No	Well Proposed by Conoco	Well Analyzed	Well Status*
1	A-1	A-1	Suspended
2	A-2	A-2	Suspended
3	A-3	A-3	Suspended
4	B-1	B-1	Suspended
5	B-2	B-2	Suspended
6	B-3	B-3	Oil Producer
7	B-4	B-4	Plugged and Abandoned
8	B-4A	B-4A	Oil Producer
9	B-5	B-5	Suspended
10	B-8	B-8	Drilled as a Gas Injector
11	B-10	B-10	Oil Producer
12	B-13	B-13	Oil Producer
13	B-18	No Log Data	Drilled as a Water Injector
14	B-22	No Log Data	Oil Producer
15	C-1	C-1	Suspended Oil Producer
16	C-2	C-2	Oil Producer
17	C-3	C-3	Oil Producer
18	C-4	C-4	Oil Producer
19	C-5	C-5	Plugged and Abandoned
20	C-8	C-8	Converted to Water Injector
21	C-11	C-11	Drilled as a Water Injector
22	C-16	C-16	Converted to WaterInjector
23	C-19	C-19	Suspended
24	D-1	D-1	Suspended
25	D-2	D-2	Plugged and Abandoned
26	D-2A	D-2A	Oil Producer
27	E-2	E-2	Suspended
28	E-6	E-6	Oil Producer
29	L-1	L-1	Suspended
30	L-3	No Log Data	Oil Producer
31	L-10	L-10	Drilled as a Gas Injector
32	M-1	M-1	Plugged and Abandoned
33	M-1A	M-1A	Suspended
34	N-1	No Log Data	Plugged and Abandoned
35	N-1A	No Log Data	Plugged and Abandoned
36	N-1B	Analysed in 1st Phase	Suspended

* Well Status are taken from a AOGCC Map of Jan. , 1992

Table 2-2: List of Normalized Wells

Normalized Well	Shift Amount
A-1	+0.10549
A-3	+0.03672
B-13	-0.02538
CFP2	-0.0267
D-1	+0.03556
D-2A	-0.03013
E-2	-0.03135
M-1A	+0.0467
3012	+0.0927
3k6	+0.070

CHAPTER 3

SLIM TUBE DISPLACEMENT STUDIES

INTRODUCTION:

Various experimental runs were conducted in the slim tube apparatus (description of the apparatus & experimental procedures have been discussed in previous reports) to test for the miscibility between the Schrader Bluff crude and the solvent mixtures. The compositions of the solvent mixtures with various levels of CO₂ and Prudhoe Bay natural gas (PBG) by Natural Gas Liquids (NGL) are given in Appendix A. Experimental oil recovery of 95% or more was set as the criterion for miscibility achievement. Then for each tested solvent in the slim tube, using the same solvent composition slim tube simulation was conducted on GEM compositional simulator (CMG, Canada). Initially pressure-composition (P-x) diagrams (Figure 3-1 and Figure 3-2) were plotted from the data obtained from PVT Coats simulator (SSI) for CO₂/NGL mixture and PBG/NGL mixture, in order to ensure that the solvents injected will be in single phase. The following sections will describe and discuss each experimental and simulation run with various solvent.

EXPERIMENTAL RESULTS:

100% Kuparuk-Schrader Bluff gas at 1300 psi and 82°F

The first experimental run was conducted using the lean gas from Kuparuk and Schrader Bluff formation. This run was conducted at a pressure of 1300 psi and at temperature of 82°F. This run resulted in a ultimate recovery of 37.92% at 1.2 pore volume injection of the solvent(Fig.3-3). Figure 3-3 show the breakthrough in experimental run has occurred at around 0.48 pore volume injection. The capillary sight glass showed the presence of two phases which suggests the lack of miscibility development. Slim tube simulation run resulted in a ultimate recovery of 41.85%. The breakthrough in slim tube simulation is earlier than experiment. The relative deviation between the experimental and slim tube simulation was 9.39%.

100% CO₂ at 1300 psi and 82°F

In this run pure CO₂ was injected as the solvent. This experimental run resulted in a recovery of 71.63% (Fig 3-4). The capillary sight glass showed the presence of two phases which definitely suggests the lack of miscibility. The breakthrough occurred after 67% of pore volume injection (Fig 3-4). The slim tube simulation predicted a recovery of 76.45% (Fig 3-4). In this case also the slim tube breakthrough occurred slightly earlier than experiment. The density plot (Fig 3-4) and K-values plot (Fig 3-4) were plotted from the data obtained from the multicontact test (MCT) runs conducted on PVT Coats simulator. From Fig 3-4, it is clear that there is grate increase in gas density. This is due to the transfer of intermediates and heavies from the oil to the solvent. It can also be seen from this graph that there is a

slight increase in liquid density. This is due to the partial dilution of high density CO₂ into the liquid phase. From this plot it is clear that miscibility didn't occur, because the two curves did not converge. But the density & K-values plots (Fig 3-4) suggest that there is a high degree of mass transfer.

90% CO₂ & 10% NGL at 1300 psi & 82°F

This run resulted in a recovery of 88.48% and the breakthrough occurred after 89% of pore volume injection (Fig. 3-5). The slim tube simulation run resulted in a recovery of 95.25% and breakthrough occurred after 89% of pore volume injection. The increase in recovery in slim tube experiments is due to the presence of intermediates in the solvent. Both slim tube simulation and the MCT results (Fig. 3-5) verify that this run resulted in miscibility but from the recovery from experiment and the sight glass observation indicates that there is a occasional presence of two phase zone. So it is inferred that complete miscibility did not occur. From Fig. 3-5, it can be inferred that there is a high degree of mass transfer.

85% CO₂ & 15% NGL at 1300 psi and 82°F

This experimental run resulted in a 98.01% oil recovery after 1.2 pore volume of solvent injection (Fig. 3-6). The breakthrough occurred after 1.08 pore volume injection (Fig. 3-6). In slim tube simulation the breakthrough occurred slightly before the experimental run. The simulation recovery is 100%. The sight glass observations did not indicate any presence of two phase region. MCT run results (Fig. 3-6) on PVT coats simulator indicated achievement of direct contact miscibility. In density plot (Fig. 3-6) the gas density was zero due to achievement of direct contact miscibility.

The following runs were conducted using mixtures of Prudhoe Bay Gas and NGL at the bubble point pressure of 1300 psi and at the reservoir temperature of 82°F.

100% Prudhoe Bay Gas at 1300 psi and 82°F

The first run in this set of runs was conducted using Prudhoe Bay Gas obtained from Prudhoe Bay reservoir. This experiment resulted in a recovery of 45.01% (Fig. 3-7) and solvent breakthrough occurred around after 0.46 pore volume injection (Fig. 3-7). The slim tube simulation resulted in a recovery of 48.46% and solvent breakthrough occurred 0.35 pore volume injection (Fig. 3-7). From sight glass observation, it is clear that there is presence of two phase region. This clearly show there is no miscibility development. Also from density & K-values plots (Fig. 3-7) it is apparent that there is no miscibility development.

70% Prudhoe Bay Gas & 30% NGL at 1300 psi and 82°F

In this run PBG was enriched with 30% NGL and used as a solvent. This resulted in a recovery of 83.63% after 1.2 pore volume of solvent injection (Fig. 3-8). The solvent breakthrough occurred after 0.92 pore volume of solvent injection (Fig. 3-8). From Fig. 3-8 the ultimate recovery from slim tube simulation is 85.56%. Sight glass observations clearly indicate the presence of two phases. Thus, miscibility is not achieved in this case.

The density and K-values plots (Fig. 3-8) clearly show that there is no development of miscibility.

60% Prudhoe Bay Gas & 40% NGL at 1300 psi and 82°F

Further enrichment of PBG by increasing the NGL content to 40% resulted in a recovery of 92.57% (Fig. 3-9). From Fig. 3-9, the solvent breakthrough occurred after 0.97 pore volume injection. The slim tube simulation recovery after 1.2 pore volume injection was 94.55% (Fig. 3-9). The slight glass observation did not indicate any clear two phase region. Based on recovery it is concluded that miscibility hasn't developed completely. The density and K-value plots (Fig. 3-9) obtained from MCT runs do not indicate any presence of miscibility.

50% Prudhoe Bay Gas & 50% NGL at 1300 psi and 82°F

50% NGL in the solvent resulted in the recovery of 99% oil in the slim tube experimental run (Fig. 3-10). The solvent breakthrough occurred after nearly 1 pore volume of solvent injection (Fig. 3-10). The slim tube simulation resulted in a recovery of 100% after 1.2 pore volume of solvent injection. Sight glass observation did not show any presence of two phases. Even though the density and K-value plots (Fig. 3-10) did not indicate miscibility development, based on slim tube recovery it is concluded that this run resulted miscibility.

40% Prudhoe Bay Gas and 60% NGL at 1300 psi and 82°F

Using PVT coats simulator MCT run was conducted by using 40%PBG/60%NGL as solvent. From the density and K-value plots (Fig. 3-11 & Fig. 3-12) obtained for this run did not indicate the achievement of miscibility. Fig. 3-13 and Fig 3-14 are plotted from the liquid and gas fractions of various components obtained at various contacts during MCT run. It is possible that a second liquid hydrocarbon

phase may have formed at these solvent compositions, but since the simulator is two-phase simulator, it was unable to handle such situation.

36% Prudhoe Bay Gas and 64% NGL at 1300 psi and 82°F

MCT run was conducted on PVT simulator using 36%PBG/64%NGL as solvent. This run indicated that this resulted in a direct contact miscibility. Fig. 3-15 and Fig. 3-16 are the density and K-value plots, plotted for the data obtained from the MCT run. In Fig. 3-15 the gas density is zero because this run resulted in a direct contact miscibility. Fig. 3-17 and Fig. 3-18 give the liquid and gas fraction at each contact during MCT run.

DISCUSSION OF RESULTS:

The first slim tube run was conducted using 100% lean gas from Kuparuk-Schrader Bluff formation. This run resulted in a immiscible displacement with very low recovery. After this, slim tube runs were conducted using the mixtures of CO₂ and NGL, and of PBG and NGL . 85%CO₂/15%NGL mixture showed miscibility experimentally at 1300 psi and 82°F, but slim tube simulation and PVT Coats MCM tests showed multiple contact miscibility at 90%CO₂/10%NGL, but for this composition experimental run sight glass observations showed the presence of two phase zone. PVT coats simulator for 85%CO₂/15%NGL solvent mixture predicted direct contact miscibility. The runs using CO₂ as solvent showed that primarily vaporizing drive mechanism is responsible for the development of miscibility.

In case of PBG/NGL mixtures, 50%PBG/50%NGL mixture developed miscibility during experimental run. Slim tube simulation also predicted the miscibility for this solvent. But PVT Coats and

MCM tests did not indicate the presence of miscibility. This may be due to the fact that a second hydrocarbon phase may be formed at these solvent compositions and the simulator is not capable of handling three phases. PVT Coats has predicted direct contact miscibility for 36%PBG/64%NGL mixture. For PBG/NGL also vaporizing mechanism is responsible for development of miscibility. Table 3-1 compares the recoveries obtained from experiment and slim tube simulation.

CONCLUSIONS:

From the results discussed in this chapter, the following conclusions were drawn:

1. The pure lean gas from Kuparuk-Schrader Bluff formation is immiscible at reservoir pressure of 1300 psia and temperature of 82°F, yielding very low recovery in slim tube experiment. Thus if this gas is to be used in field applications, it will be immiscible WAG type process.
2. Pure CO₂ and PBG are also immiscible with Schrader Bluff crude at reservoir conditions. Very high recovery is obtained during pure CO₂ slim tube experimental run. This indicates that use of CO₂ may be promising in the field application.
3. The enrichment of CO₂ by NGL at 15 mol% NGL resulted in dynamic miscibility at reservoir conditions. This run resulted in 98% oil recovery after injection of 1.2 pore volume. The compositional slim tube simulation and the EOS predictions also confirmed generation of miscibility. The miscibility was developed by primarily vaporizing gas drive mechanism.
4. PBG achieved miscibility after enriching it at 50 mol% of NGL. This slim tube experimental run resulted 99% recovery after injection of 1.2 pore volume of solvent. The compositional simulation

predicted 100% recovery after injection of 1.2 pore volume of solvent. But the MCT runs conducted on 2-phase EOS simulator did not predict miscibility development for this mixture.

5. The lumping of pseudo-components and determination of equation of state parameters appeared to be very critical in matching laboratory slim tube data.

Figure 3-1 P-X Diagram for CO₂/NGL Mixture

Figure 3-2 P-X Diagram for PBG/NGL Mixture

Recovery vs Pore Volume Injected

Solvent: 100% Kuparuk-Schrader Bluff Gas

GOR vs Pore Volume Injected

Solvent: 100% Kuparuk-Schrader Bluff Gas

Figure 3-3 Slim Tube Displacement Experiment and Simulation Results

(Solvent: 100% Kuparuk-Schrader Bluff Gas)

Recovery vs. Pore Volume Injected
Solvent: 100% CO₂

GOR vs Pore Volume Injected
Solvent: 100% CO₂

Density vs No of Contacts
Solvent 100% CO₂

K-Values vs No. of Contacts
Solvent: 100 CO₂

Figure 3-4 Slim Tube Displacement Experiment and Simulation Results

(Solvent: 100% CO₂)

Recovery vs. Pore Volume Injected
Solvent: 90% CO₂/10% NGL

GOR vs Pore Volume Injected
Solvent: 90% CO₂/10% NGL

Density vs No. of Contacts
Solvent: 90% CO₂/10% NGL

K-Values vs No. of Contacts
Solvent: 90% CO₂/10% CO₂

Figure 3-5 Slim Tube Displacement Experiment and Simulation Results

(Solvent: 90% CO₂ and 10% NGL)

Recovery vs Pore Volume Injected

solvent: 85% CO₂/15% NGL

GOR vs Pore Volume Injected

Solvent: 85% CO₂/15% NGL

Density vs No. of Contacts

Solvent: 85% CO₂/15% NGL

K-Values vs No of Contacts

Solvent: 85% CO₂/15% NGL

Figure 3-6 Slim Tube Displacement Experiment and Simulation Results

(Solvent: 85% CO₂ and 15% NGL)

Recovery vs Pre Volume Injected

Solvent: 100% PBG

GOR vs Pore Volume Injected

Solvent: 100% PBG

Density vs No. of Contacts

Solvent: 100% PBG

K-Values vs No of Contacts

Solvent: 100% PBG

Figure 3-7 Slim Tube Displacement Experiment and Simulation Results

(Solvent: 100% Prudhoe Bay Gas)

Recovery vs Pore Volume Injected
Solvent: 70% PBG/30% NGL

GOR vs Pore Volume Injected
Solvent: 70% PBG/30% NGL

Density vs. No. of Contacts
Solvent: 70% PBG/30% NGL

K-Values vs No of Contacts
Solvent: 70% PBG/30% NGL

Figure 3-8 Slim Tube Displacement Experiment and Simulation Results

(Solvent: 70% PBG and 30% NGL)

Recovery vs Pore Volume Injected
Solvent: 60% PBG/40% NGL

GOR vs Pore Volume Injected
Solvent: 60% PBG/40% NGL

Density vs No. of Contacts
Solvent: 60% PBG/40% NGL

K-Values vs No of Contacts
Solvent: 60% PBG/40% NGL

Figure 3-9 Slim Tube Displacement Experiment and Simulation Results

(Solvent: 60% PBG and 40% NGL)

Recovery vs Pre Volume Injected

Solvent: 50% PBG/50% NGL

GOR vs Pore Volume Injected

Solvent: 50% PBG/50% NGL

Density vs No. of Contacts

Solvent: 50% PBG/50% NGL

K-Values vs No of Contacts

Solvent: 50% PBG/50% NGL

Figure 3-10 Slim Tube Displacement Experiment and Simulation Results
(Solvent: 50% PBG and 50% NGL.)

Figure 3-11 Density vs. No. of Contacts (Solvent: 40% PBG/60% NGL)

Figure 3-12 K-values vs. No. of Contacts (Solvent: 40% PBG/60% NGL)

Figure 3-13 X_i vs. No. of Contacts (Solvent: 40% PBG/60% NGL)

Figure 3-14 Y_1 vs. No. of Contacts (Solvent: 40% PBG/60% NGL)

Figure 3-15 Density vs. No. of Contacts (Solvent: 36% PBG/64% NGL)

Figure 3-16 K-values vs. No. of Contacts (Solvent: 36% PBG/64% NGL)

Figure 3-17 X_1 vs. No. of Contacts (Solvent: 36% PBG/64% NGL)

Figure 3-18 Y_i vs. No. of Contacts (Solvent: 36% PBG/64% NGL)

Table 3-1

EOS PARAMETERS FOR SCHRADER BLUFF RESERVOIR FLUID

Component	Z ₁	MW	P _c , (Psi)	T _c , °R	ω	Ω _a	Ω _b	Ref. Density
N ₂	0.0024	28.02	493	227.6	0.04	0.457236	0.0778	0.804
C ₁	0.263	16.04	673.1	344.2	0.008	0.452477	0.08793	0.3
CO ₂	0.0022	44.01	1070	547.8	0.225	0.457236	0.0778	0.777
C ₂	0.0035	30.07	709.8	550.3	0.098	0.457236	0.0778	0.3771
C ₃	0.008	44.09	617.4	666.4	0.152	0.457236	0.0778	0.5077
C ₄	0.0159	58.12	550.7	765.6	0.193	0.457236	0.0778	0.5844
C ₅	0.0105	72.14	489.5	845.9	0.251	0.457236	0.0778	0.6101
C ₆ -C ₈	0.0667	104.71	382.8	994	0.3684	0.28	0.05945	0.7444
C ₉ -C ₁₀	0.102	128.8	318.4	1090.7	0.466	0.470967	0.04968	0.7764
C ₁₁ +	0.5229	363.0	210.8	1605.7	0.7303	0.303265	0.07023	0.9895

Table 3-2

RECOVERIES FROM SLIM TUBE EXPERIMENTS AND SIMULATION

Solvent	Slim Tube Simulation	Slim Tube Experiments	% Relative Deviation
100% KUPSCH Gas	41.85	37.92	9.39
100% PBG	48.46	45.01	7.12
70% PBG/30% NGL	85.56	83.63	2.6
60% PBG/40% NGL	94.55	92.57	2.09
50% PBG/50% NGL	100.0	99.0	1.0
100% CO ₂	76.45	71.63	6.31
90% CO ₂ /10% NGL	95.25	88.49	7.09
85% CO ₂ /15% NGL	100.0	98.01	1.99

* KUPSCH = Kuparuk/Schrader Bluff lean gas mixture (90:10)

CHAPTER 4

COREFLOOD EXPERIMENTS

INTRODUCTION:

A total of eight core flood experimental runs were conducted with a 4 feet long, 2 inches diameter sandpack as part of the study to design and develop a suitable miscible solvent slug injection process for the improved recovery from Schrader Bluff heavy oil reservoir. The experimental apparatus & procedures are reported in earlier reports. The experiments were divided into the following three groups:

- 1) Unsteady state waterflood (Run #1)
- 2) Effect of miscible solvent slug size (single solvent slug followed by water injection, multicontact miscible (MCM) solvent, Runs 2, 3, 4, 5)
- 3) Effect of WAG ratio with MCM solvent (multi-slug WAG, Runs 2, 6, 7, 8)

In each of these runs recombined Schrader Bluff oil samples were used. The following sections will describe and discuss each experimental run individually. All runs were conducted at 1300 psi pressure and room temperature conditions. The basic data collected is given in tables B1 through B8 in Appendix B.

UNSTEADY STATE WATERFLOOD:

The first experimental run was an unsteady state waterflood. This run was conducted to provide base case data for the comparison purposes. Oil-water relative permeability data (Table B9) was also obtained from this run and is plotted on Fig. 4-1. The method used in obtaining the relative permeability data is briefly discussed in Appendix C. The oil recovery at 1.2 pore volume (PV) injection was 61.45% (Fig. 4-2). Fig. 4-3 shows that water breakthrough occurred at 0.31 PV injection. The GOR behavior (Fig. 4-4) was as expected in a waterflood. The plot of pressure drop versus PV injected is given in Fig. 4-5 and is indicative of the propagation of the water flood front. The oil water relative permeability data suggests the core to be oil wet in nature.

EFFECT OF MISCIBLE SLUG SIZE (MCM PROCESS):

A total of four runs with different slug sizes of a multi-contact miscible solvent were conducted to study the effect of solvent slug-size on the displacement behavior and oil recovery. The solvent was 50 mol% PBG + 50 mol% NGL mixture and the sizes used were 0.05, 0.10, 0.20 and 0.40 PV. In each of the case, a predetermined amount of solvent was injected into the core and was followed up by water as a chase fluid in a water alternating gas (WAG) mode. Each experimental run is described below:

(a) 0.05 PV Slug Size: This run resulted in a recovery of 72.64% at 1.2 PV injection (Fig. 4-6) The water breakthrough was at 0.43 PV and the WOR (Fig. 4-7) increased sharply after about 0.7 PV injection. The GOR (Fig. 4-8) increases slightly at around 0.3 PV injection indicating possible solvent breakthrough, followed closely by water breakthrough which causes it to decrease for some time. The GOR increase again after 0.7 PV injection is due to the production of oil /solvent mixture, of which the

solvent flashes into gas phase at the outlet. Fig. 4-9 is a plot of the pressure drop versus PV injected along the length of the core. The plot indicates a quite smooth displacement with the solvent/oil front moving in the core with a good sweep.

(b) 0.10 PV Slug Size: In this run a recovery of 74.16% at 1.2 PV injection was obtained (Fig. 4-10), with water breakthrough at 0.46 PV injection (Fig. 4-11). From the GOR plot (Fig. 4-12), solvent breakthrough appears to have occurred at 0.2 PV injection. The trailing edge of solvent slug gets produced after approximately 1.0 PV injection. The pressure drop plot (Fig. 4-13) indicated the propagation of the solvent slug front in the core. There appears to be minor fingering of the solvent occurring initially until miscibility is achieved and a transition zone established.

(c) 0.20 PV Slug Size: The oil recovery of 77.88% at 1.2 PV injection (Fig. 4-14) is higher than the earlier cases because of the obvious reason of more solvent injection. The WOR plot is shown in Fig. 4-15. The GOR plot (Fig. 4-16) indicates solvent breakthrough at 0.15 PV injection with a steep rise in GOR. The pressure drop plot (Fig. 4-17) indicates possible viscous fingering caused by the finger getting a chance to grow because of larger slug size, resulting in early breakthrough of solvent and a drop in pressure drop. There is also a possibility of the solvent channeling along the walls of the coreholder hence resulting in very early solvent breakthrough after only 0.15 PV injection. This seems likely due to the fact that no overburden pressure could be applied to the sandpack because of equipment constraints.

(d) 0.40 PV Slug Size: The oil recovery of 78.29% at 1.2 PV injection (Fig. 4-18) is the highest amongst all these four runs, but the incremental gain in recovery for additional amount solvent injected is

the least. Water breakthrough in this case is delayed until 0.78 PV (Fig. 4-19) after which WOR shoots up sharply. The GOR data (Fig. 4-20) indicates continuous solvent and solvent-oil mixture production after 0.2 PV onwards. The pressure drop plot (Fig. 4-21) in this case also indicates severe viscous fingering resulting in sharp drop in pressure drop initially followed by gradual rise in between (due to the sweep provide by water) and finally a slow decline as the oil is mobilized and produced from the core. Fig. 4-21 also suggest a near complete mobilization of oil from the 0-1 foot length of the core by the solvent.

EFFECT OF WATER-ATERNATING-GAS (WAG) RATIO:

A total of three runs in addition to the run number 2 (with a WAG ratio of 23) were conducted to study the effect of WAG ratio. In all cases the solvent used was a mixture of 50% PBG + 50% NGL and the slug size was 0.05 pore volume, with the number of slugs varying in each run. The results for each run are given below.

(a) WAG Ratio of 11: In this run two slugs of 0.05 PV size were injected and separated by water slugs of 0.55 PV. The run resulted in a recovery of 74.67% at 1.2 PV injection (Fig. 4-22). From the WOR plot (Fig. 4-23) and GOR plot (Fig. 4-24) the formation of oil bank in front of both the solvent slugs is evident. The second oil bank gets produced at 0.9 PV injection resulting in a sharp decrease in WOR and a marked increase in recovery. There are two water breakthrough as identified from the WOR plot (Fig. 4-23) the first occurring at 0.36 PV injection and the second occurring at 1 PV injection. The pressure drop plot (Fig. 4-25) corroborates the above behavior of multi-slug WAG process.

(b) WAG Ratio of 5: A total of four slugs of 0.05 PV each separated by 0.25 PV slugs of water were injected alternately in this run. A recovery of 78.64% at 1.2 PV injection was obtained (Fig. 4-26). The WOR, GOR and the pressure plots (Figs. 4-27, 4-28 and 4-29 respectively) are typical of a WAG type process. As in earlier case (a), the formation of oil bank occurred except that the size of oil bank reduced considerably as suggested by the WOR plot (Fig. 4-27). Again in this case three water breakthrough points can be identified at 0.41, 0.90 and 1.4 PV injection.

(c) WAG Ratio of 3: In this run, six solvent slugs again of 0.05 PV each were alternately injected with 0.15 PV water slugs. The highest oil recovery of 81.55% at 1.2 PV injection (Fig. 4-30) resulted in this case. The WOR behavior (Fig. 4-31) again reflects the nature of the WAG process. The GOR plot is shown in Fig. 4-32 and the pressure drop versus PV injected plot in Fig. 4-33.

—+— Kro —*— Krw

Figure 4.1: Oil-Water Relative Permeability Curves For The Sandpack

—*— Recovery(%)

Figure 4.2: Oil Recovery vs. PV Injected (Unsteady State Waterflood)

Figure 4.3: WOR vs. PV Injected (Unsteady State Waterflood)

—*— GOR(scF/stb)

Figure 4.4: GOR vs. PV Injected (Unsteady State Waterflood)

Figure 4.5: Pressure Drop vs. PV Injected
(Unsteady State Waterflood)

Figure 4.6: Oil Recovery vs. PV Injected, MCM Solvent
Slug Size: 0.05PV (Solvent: 50%PBG+50%NGL)

Figure 4.7: WOR vs. PV Injected, MCM Solvent
Slug Size: 0.05PV (Solvent: 50%PBG+50%NGL)

—+— GOR(scF/stb)

Figure 4.8: GOR vs. PV Injected, MCM Solvent
Slug Size: 0.05PV (Solvent: 50%PBG+50%NGL)

Figure 4.9: Pressure Drop vs. PV Injected, MCM Solvent
Slug Size: 0.05PV (Solvent: 50%PBG+50%NGL)

Figure 4.10: Oil Recovery vs. PV Injected, MCM Solvent
Slug Size: 0.10PV (Solvent: 50%PBG+50%NGL)

Figure 4.11: WOR vs. PV Injected, MCM Solvent
Slug Size: 0.10PV (Solvent: 50%PBG+50%NGL)

—+— GOR(sc_f/st_b)

Figure 4.12: GOR vs. PV Injected, MCM Solvent
Slug Size: 0.10PV (Solvent: 50%PBG+50%NGL)

Figure 4.13: Pressure Drop vs. PV Injected, MCM Solvent
Slug Size: 0.10PV (Solvent: 50%PBG+50%NGL)

—*— Recovery(%)

Figure 4.14: Oil Recovery vs. PV Injected, MCM Solvent
Slug Size: 0.20 PV (Solvent: 50%PBG+50%NGL)

Figure 4.15: WOR vs. PV Injected, MCM Solvent
Slug Size: 0.20 PV (Solvent: 50%PBG+50%NGL)

—+— GOR(sc_f/st_b)

Figure 4.16: GOR vs. PV Injected, MCM Solvent
Slug Size: 0.20 PV (Solvent: 50%PBG+50%NGL)

Figure 4.17: Pressure Drop vs. PV Injected, MCM Solvent
Slug Size: 0.20 PV (Solvent: 50%PBG+50%NGL)

Figure 4.18: Oil Recovery vs. PV Injected, MCM Solvent
Slug Size: 0.40 PV (Solvent: 50%PBG+50%NGL)

Figure 4.19: WOR vs. PV Injected, MCM Solvent
Slug Size: 0.40 PV (Solvent: 50%PBG+50%NGL)

Figure 4.20: GOR vs. PV Injected, MCM Solvent
Slug Size: 0.40 PV (Solvent: 50%PBG+50%NGL)

Figure 4.21: Pressure Drop vs. PV Injected, MCM Solvent
Slug Size: 0.40 PV (Solvent: 50%PBG+50%NGL)

Figure 4.22: Oil Recovery vs. PV Injected, Multiple WAG
WAG Ratio: 11, (MCM Solvent: 50%PBG+50%NGL)

Figure 4.23: WOR vs. PV Injected, Multiple WAG
WAG Ratio: 11, (MCM Solvent: 50%PBG+50%NGL)

Figure 4.24: GOR vs. PV Injected, Multiple WAG
WAG Ratio: 11, (MCM Solvent: 50%PBG+50%NGL)

Figure 4.25: Pressure Drop vs. PV Injected, Multiple WAG
WAG Ratio: 11, (MCM Solvent: 50%PBG+50%NGL)

Figure 4.26: Oil Recovery vs. PV Injected, Multiple WAG
WAG Ratio: 5, (MCM Solvent: 50%PBG+50%NGL)

Figure 4.27: WOR vs. PV Injected, Multiple WAG
WAG Ratio: 5, (MCM Solvent: 50%PBG+50%NGL)

Figure 4.28: GOR vs. PV Injected, Multiple WAG
WAG Ratio: 5, (MCM Solvent: 50%PBG+50%NGL)

Figure 4.29: Pressure Drop vs. PV Injected, Multiple WAG
WAG Ratio: 5, (MCM Solvent: 50%PBG+50%NGL)

Figure 4.30: Oil Recovery vs. PV Injected, Multiple WAG
WAG Ratio: 3, (MCM Solvent: 50%PBG+50%NGL)

Figure 4.31: WOR vs. PV Injected, Multiple WAG
WAG Ratio: 3, (MCM Solvent: 50%PBG+50%NGL)

Figure 4.32: GOR vs. PV Injected, Multiple WAG
WAG Ratio: 3, (MCM Solvent: 50%PBG+50%NGL)

Figure 4.33: Pressure Drop vs. PV Injected, Multiple WAG
WAG Ratio: 3, (MCM Solvent: 50%PBG+50%NGL)

APPENDIX A

CRUDE OIL AND SOLVENT COMPOSITIONS

TABLE A1 : Experimental Materials and Sandpack Properties

<u>Materials</u>	<u>Properties</u>
Sand	Oklahoma #1 sand
Sandpack	Porosity ($\emptyset$) = 33.75%
	Pore Volume (PV) = 925 cc
	Abs. Permeability (K) = 5.12 darcys
	Swi = 0.065
Water	Distilled
Methane	C.P. Grade 99.0%
CO ₂	C.P. Grade 99.8%
Toulene	Industrial Grade

Table A-2 : Composition of Schrader Bluff Live Oil

Component	Mole %
N ₂	0.24
CO ₂	0.22
C ₁	26.29
C ₂	0.35
C ₃	0.80
i-C ₄	0.57
n-C ₄	1.02
i-C ₅	0.81
n-C ₅	0.24
C ₆	0.93
C ₇	1.89
C ₈	3.85
C ₉	5.23
C ₁₀	4.97
C ₁₁₊	52.59

Table A-3 : Prudhoe Bay NGL Composition

Component	Mole %
C ₃	0.88
i-C ₄	10.09
n-C ₄	36.83
i-C ₅	12.21
n-C ₅	15.49
C ₆	13.20
Benzene	0.86
Cyclohexane	1.63
C ₇	5.48
C ₈ Aromatics	0.56
C ₈₊	2.77

Table A-4 : 50 mol % PBG + 50 mol % NGL Solvent Mixture Composition

Component	Mole %
N ₂	0.22
C ₁	36.12
CO ₂	6.08
C ₂	3.935
C ₃	2.9
C ₄	24.2
C ₅	14.11
C ₆	7.96
C ₇	2.79
C ₈	1.685

APPENDIX B

RAW DATA FROM EXPERIMENTS

Table B1 : Run 1 (Unsteady State Waterflood)

PV Injected	Np (cc)	Total Pr. Drop(psi)	Pr. Drop Along The Length (psi)				Wp (cc)	Gp (scf)	WOR (cc/cc)	GOR (scf/stb)
			(1 ft)	(2 ft)	(3 ft)	(4 ft)				
0	0	49.10	12.35	12.28	11.98	12.49	0	0	0	0.00
0.10	86.0	36.45	3.50	9.40	11.10	12.45	0	0.089	0	164.55
0.20	173.0	27.50	2.10	4.13	8.85	12.42	0	0.178	0	162.66
0.30	259.0	20.49	1.71	2.70	4.94	11.14	0	0.266	0	162.70
BT 0.31	268.0									
0.40	339.0	16.00	1.55	2.25	2.96	9.24	5.7	0.345	0.08	157.01
0.45	375.0	14.20	1.45	2.03	2.66	8.06	14.8	0.384	0.25	172.25
0.50	406.0	13.10	1.41	1.86	2.50	7.33	29.2	0.417	0.46	169.26
0.60	440.8	12.10	1.37	1.70	2.35	6.68	77.7	0.453	1.39	164.48
0.70	466.8	10.80	1.21	1.61	2.26	5.72	159.7	0.482	3.15	177.35
0.80	486.8	9.20	1.17	1.42	1.96	4.65	246.7	0.504	4.35	174.90
0.90	501.2	8.30	1.05	1.35	1.76	4.14	324.7	0.520	5.42	176.67
1.00	512.2	7.20	1.02	1.24	1.49	3.45	407.0	0.532	7.48	173.45
1.20	532.2	6.30	1.02	1.13	1.25	2.90	573.0	0.553	8.30	166.95
1.40	548.2	5.60	0.99	1.01	1.18	2.42	741.0	0.570	10.50	168.94
1.60	560.2	4.78	0.92	0.98	1.12	1.76	906.0	0.583	13.75	172.25
1.80	570.2	4.50	0.90	0.92	1.00	1.68	1082.0	0.594	17.60	174.90

Table B2 : Run 2 (Effect of Slug Size)

Solvent = 50%PBG+50%NGL (Slug Size = 5% PV)

PV Injected	Np (cc)	Total Pr. Drop(psi)	Pr. Drop Along The Length (psi)				Wp (cc)	Gp (scf)	WOR (cc/cc)	GOR (scf/stb)
			(1 ft)	(2 ft)	(3 ft)	(4 ft)				
0	0	49.56	12.32	12.12	12.27	12.85	0	0	0	0.00
0.10	86.0	34.65	3.10	6.80	12.10	12.65	0	0.088	0	162.70
0.20	173.5	26.14	2.54	3.41	7.75	12.44	0	0.181	0	168.99
0.30	257.5	20.30	2.16	2.60	5.05	10.49	0	0.271	0	170.36
0.40	338.2	15.80	1.98	2.16	3.50	8.16	0	0.360	0	175.35
BT 0.43	362.2									
0.50	418.2	12.40	1.88	1.78	3.18	5.56	2.0	0.438	0.04	155.03
0.60	470.1	10.10	1.77	1.60	2.69	4.04	14.1	0.491	0.23	162.37
0.70	512.9	8.60	1.71	1.46	2.49	2.94	58.8	0.541	1.04	185.75
0.80	544.9	8.10	1.65	1.39	2.39	2.67	113.8	0.578	1.72	183.84
0.90	572.9	7.80	1.60	1.34	2.32	2.54	172.0	0.611	2.08	187.39
1.00	593.0	7.01	1.24	1.23	2.12	2.42	242.0	0.637	3.48	205.67
1.20	629.0	6.35	1.05	1.07	1.93	2.30	402.0	0.683	4.44	203.17
1.40	651.5	5.50	1.00	1.02	1.66	1.82	563.0	0.715	7.16	226.13
1.60	667.5	4.41	0.99	1.01	1.18	1.23	731.0	0.740	10.50	248.44
1.80	679.5	3.45	0.65	0.89	0.93	0.98	906.0	0.760	14.58	265.00

Table B3 : Run 3 (Effect of Slug Size).

Solvent = 50%PBG +50%NGL (Slug Size = 10% PV)

PV Injected	Np (cc)	Total Pr. Drop(psi)	Pr. Drop Along The Length (psi)				Wp (cc)	Gp (scf)	WOR (cc/cc)	GOR (scf/stb)
			(1 ft)	(2 ft)	(3 ft)	(4 ft)				
0	0	48.95	11.90	12.01	12.50	12.54	0	0	0	0.00
0.10	87.0	32.50	1.58	6.91	11.62	12.39	0	0.088	0	160.83
0.20	173.5	24.20	1.61	2.50	8.32	11.77	0	0.183	0	174.62
0.30	258.5	18.60	1.20	2.60	4.05	10.75	0	0.277	0	175.84
0.40	344.5	13.80	1.00	1.95	3.80	7.05	0	0.393	0	214.47
BT 0.46	397.4									
0.50	429.7	11.90	0.89	1.50	3.00	6.51	1.8	0.515	0.06	227.68
0.60	484.8	9.90	0.81	1.27	2.19	5.63	22.6	0.585	0.38	202.00
0.70	529.5	8.85	0.74	1.19	1.80	5.12	67.3	0.632	1.00	167.18
0.80	560.0	7.78	0.73	1.16	1.63	4.26	124.3	0.665	1.87	172.03
0.90	584.2	7.45	0.69	1.08	1.46	4.22	192.7	0.692	2.83	177.40
1.00	604.9	6.71	0.62	1.07	1.35	3.67	273.2	0.715	3.89	176.67
1.20	642.3	5.97	0.58	0.93	1.22	3.24	420.8	0.760	3.95	191.31
1.40	660.1	5.43	0.55	0.89	1.14	2.85	587.1	0.792	9.34	285.84
1.60	672.4	5.01	0.51	0.86	1.12	2.52	759.6	0.820	14.02	361.95
1.80	681.4	4.74	0.47	0.75	1.09	2.43	932.6	0.845	19.22	441.67

Table B4 : Run 4 (Effect of Slug Size)

Solvent = 50%PBG + 50%NGL (Slug Size = 20% PV)

PV Injected	Np (cc)	Total Pr. Drop(psi)	Pr. Drop Along The Length (psi)				Wp (cc)	Gp (scf)	WOR (cc/cc)	GOR (scf/stb)
			(1 ft)	(2 ft)	(3 ft)	(4 ft)				
0	0	46.60	10.80	11.40	11.65	12.75	0	0	0	0.00
0.10	87.5	28.75	0.91	3.68	11.26	12.90	0	0.089	0	161.73
0.20	173.8	11.20	0.44	0.80	2.62	7.34	0	0.195	0	195.30
0.30	258.9	9.75	1.30	0.39	1.70	6.36	0	0.357	0	302.68
0.40	340.9	6.60	1.20	1.26	1.52	2.62	0	0.548	0	370.35
0.50	419.1	5.52	1.15	1.14	1.41	1.82	0	0.738	0	386.32
0.60	494.7	4.80	1.06	1.09	1.24	1.41	0	0.930	0	403.81
BT 0.62	513.9									
0.70	554.7	4.69	0.96	0.92	1.06	1.75	20.7	1.087	0.57	416.05
0.80	594.6	4.62	0.91	0.86	1.02	1.83	70.1	1.170	1.24	330.75
0.90	624.1	3.92	0.80	0.83	0.92	1.37	129.0	1.227	2.00	307.22
1.00	645.0	3.80	0.75	0.82	0.82	1.41	198.2	1.270	3.31	327.13
1.10	663.2	3.52	0.73	0.78	0.80	1.21	270.0	1.307	3.95	323.24
1.20	674.5	3.39	0.69	0.77	0.78	1.15	352.2	1.333	7.27	365.84
1.40	691.1	3.05	0.65	0.74	0.75	0.91	519.6	1.378	10.08	431.02
1.60	701.3	2.85	0.54	0.70	0.71	0.90	694.4	1.407	17.14	452.06
1.80	707.8	2.63	0.47	0.68	0.70	0.78	874.4	1.434	27.69	660.46

Table B5 : Run 5 (Effect of Slug Size)
Solvent = 50%PBG+50%NGL (Slug Size = 40% PV)

PV Injected	Np (cc)	Total Pr. Drop(psi)	Pr. Drop Along The Length (psi)				Wp (cc)	Gp (scf)	WOR (cc/cc)	GOR (scf/stb)
			(1 ft)	(2 ft)	(3 ft)	(4 ft)				
0	0	49.05	12.01	12.22	11.85	12.97	0	0	0	0.00
0.10	86.0	34.55	1.91	8.64	11.39	12.61	0	0.092	0	170.09
0.20	173.5	21.60	0.49	3.40	7.05	10.66	0	0.192	0	181.71
0.30	260.5	15.60	0.36	1.80	4.08	9.36	0	0.322	0	237.59
0.40	342.5	10.92	0.37	1.63	1.58	7.34	0	0.575	0	490.57
0.50	418.5	6.50	0.84	1.42	2.05	2.19	0	0.851	0	577.42
0.60	493.5	5.84	0.90	2.30	1.70	0.94	0	1.136	0	604.20
0.70	561.5	7.02	0.88	2.44	2.63	1.07	0	1.397	0	610.28
BT 0.78	597.5									
0.80	607.4	7.56	0.81	2.05	2.51	2.19	0.2	1.586	0.02	654.71
0.90	630.9	7.28	0.88	1.83	1.99	2.58	2.1	1.678	0.08	622.47
1.00	652.8	6.10	0.77	1.70	1.62	2.01	14.1	1.764	0.55	624.38
1.20	678.1	5.52	0.76	1.55	1.56	1.65	150.1	1.884	5.38	754.15
1.40	694.1	4.86	0.78	1.28	1.38	1.42	305.1	1.987	9.69	1023.71
1.60	704.3	4.62	0.78	1.20	1.34	1.30	467.1	2.063	15.88	1184.71
1.80	712.3	4.34	0.76	1.18	1.16	1.24	632.1	2.132	20.63	1371.37

Table B6 : Run 6 (Effect of WAG Ratio)

Solvent = 50%PBG +50%NGL (Slug size = 5% PV)

WAG Ratio = 11

PV Injected	Np (cc)	Total Pr. Drop(psi)	Pr. Drop Along The Length (psi)				Wp (cc)	Gp (scf)	WOR (cc/cc)	GOR (scf/stb)
			(1 ft)	(2 ft)	(3 ft)	(4 ft)				
0	0	45.20	10.85	11.05	11.20	12.10	0	0	0	0.00
0.10	87.5	24.90	3.99	4.96	5.24	10.71	0	0.089	0	161.73
0.20	175.5	20.90	2.60	5.14	4.89	8.27	0	0.186	0	175.26
0.30	262.5	17.50	1.81	3.53	5.11	7.05	0	0.301	0	210.17
BT 0.36	319.1									
0.40	344.1	14.80	1.47	2.59	3.48	7.26	0.5	0.415	0.02	222.13
0.50	412.7	12.00	1.35	2.12	2.54	5.99	8.0	0.488	0.11	169.20
0.60	476.2	10.85	1.11	1.90	2.58	5.26	36.9	0.552	0.46	160.25
0.70	497.8	9.47	1.16	2.07	2.41	3.83	106.9	0.578	3.24	191.39
0.80	515.7	9.90	1.04	1.46	3.00	4.40	181.9	0.605	4.19	239.83
0.90	522.7	11.10	0.90	1.19	2.02	6.99	261.9	0.620	11.43	340.71
1.00	582.7	8.22	0.80	1.08	1.65	4.69	286.9	0.718	0.42	259.70
1.20	646.7	5.95	0.76	0.97	1.21	3.01	387.9	0.788	1.58	173.91
1.40	676.7	5.51	0.66	1.06	1.30	2.49	541.9	0.860	5.13	381.60
1.60	706.7	4.92	0.60	0.86	1.02	2.44	702.9	0.919	5.37	312.70
1.80	760.7	3.50	0.66	0.70	0.87	1.27	837.9	1.063	2.50	424.00

Table B7 : Run 7 (Effect of WAG Ratio)
Solvent = 50%PBG +50%NGL (Slug size = 5% PV)
WAG Ratio = 5

PV Injected	Np (cc)	Total Pr. Drop(psi)	Pr. Drop Along The Length (psi)				Wp (cc)	Gp (scf)	WOR (cc/cc)	GOR (scf/stb)
			(1 ft)	(2 ft)	(3 ft)	(4 ft)				
0	0	46.50	11.32	11.55	11.21	12.42	0	0	0	0.00
0.10	87.0	26.50	4.10	3.12	7.94	11.34	0	0.088	0	160.83
0.20	173.0	21.40	3.03	4.22	5.14	9.01	0	0.178	0	166.83
0.30	259.0	17.05	2.06	3.38	4.16	7.45	0	0.267	0	164.55
0.40	342.1	13.38	1.35	2.49	3.09	6.45	0	0.371	0	202.65
BT 0.41	350.1									
0.50	414.4	12.10	1.32	2.00	2.65	6.13	4.5	0.447	0.07	167.14
0.60	477.1	8.65	1.05	1.49	2.03	4.08	26.9	0.531	0.36	213.01
0.70	531.1	7.91	0.70	1.32	1.70	4.19	54.9	0.627	0.52	282.67
0.80	575.1	7.02	0.82	1.19	1.48	3.53	93.9	0.675	0.89	173.45
0.90	625.1	5.01	0.70	1.07	1.48	1.76	125.9	0.788	0.64	359.34
1.00	655.1	4.85	0.64	0.92	1.27	2.02	173.9	0.896	1.60	572.40
1.20	681.1	4.22	0.46	1.03	1.20	1.53	309.9	1.069	5.23	1057.96
1.40	707.1	3.47	0.59	0.75	0.89	1.24	429.9	1.271	4.62	1235.31
1.60	729.1	3.30	0.28	0.76	0.82	1.44	574.9	1.434	6.59	1178.05
1.80	756.1	2.81	0.42	0.69	0.76	0.94	719.9	1.575	5.37	830.33

Table B8 : Run 8 (Effect of WAG Ratio)
Solvent = 50%PBG+50%NGL (Slug size = 5% PV)
WAG Ratio = 3

PV Injected	Np (cc)	Total Pr. Drop(psi)	Pr. Drop Along The Length (psi)				Wp (cc)	Gp (scf)	WOR (cc/cc)	GOR (scf/stb)
			(1 ft)	(2 ft)	(3 ft)	(4 ft)				
0	0	48.20	11.45	11.85	12.01	12.89	0	0	0	0.00
0.10	88.0	25.60	1.89	3.51	8.86	11.34	0	0.090	0	162.61
0.20	175.0	20.08	1.89	3.46	3.98	10.75	0	0.186	0	175.45
0.30	262.0	13.10	1.29	1.31	3.82	6.68	0	0.289	0	188.24
0.40	348.0	9.54	1.01	1.98	2.20	4.35	0	0.414	0	231.10
0.50	430.0	6.47	0.62	1.20	1.90	2.75	0	0.564	0	290.85
BT 0.55	471.2									
0.60	498.6	6.75	0.61	1.39	1.51	3.24	4.4	0.699	0.16	312.90
0.70	557.2	4.66	0.27	1.05	1.36	1.98	22.3	0.917	0.31	591.50
0.80	589.3	4.01	0.52	1.16	0.99	1.34	62.1	1.024	1.24	530.00
0.90	634.3	3.87	0.28	0.97	1.12	1.50	92.1	1.254	0.67	812.67
1.00	660.3	3.53	0.29	1.11	0.98	1.15	146.1	1.357	2.08	629.88
1.20	706.3	3.45	0.26	1.09	0.79	1.31	236.1	1.718	1.96	1247.80
1.40	738.3	3.62	0.41	0.78	0.71	1.72	346.1	2.080	3.44	1798.69
1.60	753.3	4.72	0.51	0.67	0.79	2.75	491.1	2.427	9.67	3678.20
1.80	763.3	5.02	0.51	0.82	0.80	2.89	628.1	2.772	13.70	5484.50

Table B9 Oil-Water Relative Permeability Data From Unsteady State Waterflood

WATER VISCOSITY = 1.00 OIL VISCOSITY = 41.00
 INITIAL WATER SATURATION = 0.0650 PORE VOLUME = 925.00 CC
 BASE RATE = 20.00 CC/MIN BASE DELTA P = 235.8 PSI
 EXPERIMENT FLOW RATE = 4.00 CC/MIN

REGRESSION PARAMETERS:

A1, A2, A3 = -1557.56091 453.92166 -21.58469
 B1, B2, B3 = -0.27063 0.71520 0.08654

	QI	QO	QOF	DELTA P	SW2	FO2	KRO	KRW
1	92.50	92.50	55.05	36.45	-0.155	2.794	2.412	-0.038
2	185.00	185.00	223.84	27.50	0.060	1.235	1.309	-0.006
3	277.50	277.50	312.97	20.49	0.175	0.761	1.036	0.008
4	286.75	286.75	319.87	20.00	0.184	0.731	1.017	0.009
5	370.00	362.05	371.90	16.00	0.252	0.537	0.910	0.019
6	416.25	400.50	395.00	14.20	0.283	0.465	0.878	0.025
7	462.50	433.61	415.15	13.10	0.309	0.409	0.828	0.029
8	555.00	470.77	448.89	12.10	0.354	0.326	0.703	0.035
9	647.50	498.54	476.30	10.80	0.391	0.269	0.641	0.042
10	740.00	519.90	499.22	9.20	0.422	0.228	0.629	0.052
11	832.50	535.28	518.79	8.30	0.449	0.197	0.594	0.059
12	925.00	547.03	535.79	7.20	0.472	0.172	0.594	0.070
13	1110.00	568.39	564.08	6.30	0.511	0.136	0.529	0.082
14	1295.00	585.48	586.87	5.60	0.543	0.112	0.481	0.093
15	1480.00	598.29	605.79	4.78	0.570	0.094	0.468	0.110
16	1665.00	608.97	621.84	4.50	0.593	0.080	0.421	0.118
17	1850.00	616.45	635.69	4.10	0.613	0.070	0.398	0.129

APPENDIX C

CALCULATION OF RELATIVE PERMEABILITY

To calculate relative permeabilities from an unsteady state displacement experiment, Welge developed a method for calculating the ratio of relative permeabilities as a function of saturation at the core outlet. For linear immiscible displacement of one incompressible fluid by another, Welge derived the following relationship to compute the oil-water relative permeability ratio from oil and water production data. For water displacing oil:

$$\frac{K_{rw}}{K_{ro}} = \frac{\mu_w}{\mu_o} \left[\frac{1}{f_{o2}} - 1 \right]$$

The quantity f_{o2} is given by the slope of the recovery plot, that is the plot of Q_o against Q_i :

$$f_{o2} = \frac{dQ_o}{dQ_i}$$

Welge also showed that the saturation of the displacing phase at the core outlet can be obtained from the average saturation of the displacing phase in the core as:

$$S_{w2} = S_{wav} - f_{o2} Q_i$$

The average saturation can be easily obtained from material balance.

Welge's theory was further extended by Johnson, Bossler and Naumann (1959) to permit the calculation of individual oil and water relative permeabilities. By integrating Darcy's law for each phase along the length of the core, Johnson et. al. derived the following relationship:

$$\frac{f_{o2}}{K_{ro}} = \frac{d}{d[\frac{1}{Q_i}]} [\frac{1}{Q_i I_r}]$$

where:

$$I_r = \frac{[\frac{q}{\Delta P}]}{[\frac{q}{\Delta P}]_{base}}$$

Relative permeability to water could then be computed from oil relative permeability using Welge's equations.

Implementation of the Welge and Johnson et. al.'s technique requires the determination of two derivatives at the same value of cumulative data by measuring slopes manually may involve significant amount of inaccuracy because of the usual scatter present in the experimental data. To overcome this problem, smooth functional relationships were fitted through the observed data by the least square method and then these functions were differentiated. This procedure was suggested by Miller and Ramey (1983). They also suggested the following functional relationships:

$$Q_o = A_1 + A_2(\ln Q_i) + A_3(\ln Q_i)^2$$

$$\ln(Q_i I_r) = B_1 + B_2 (\ln Q_i) + B_3 (\ln Q_i)^2$$

These equations fitted the experimental data of this study satisfactorily.

NOMENCLATURE:

f_{o2} = oil fractional flow at core outlet

I_r = injectivity ratio

K_{ro} = oil relative permeability

K_{rw} = water relative permeability

q = water injection rate

Q_i = cumulative water injection

Q_o = cumulative oil production

S_{w2} = water saturation at core outlet

μ_o = oil viscosity

μ_w = water viscosity

REFERENCES:

1. Johnson, E. F., Bossler, D. P., and Naumann, V. O.: "Calculation of Relative Permeability from Displacement Experiments," Trans., AIME, (1959), 216, pp. 370-372