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SELECTION OF RESERVOIRS AMENABLE TO MICELLAR FLOODING

First Annual Report, October 1978 — December 1979

Work Performed for the Department of Energy
Under Contract Nos. DE-AC19-78BC00048 and DE-AC19-78BC00051

Date Published—December 1980

Gary Energy Corporation
Englewood, Colorado

and

Intercomp Resource Development & Engineering, Inc.
Houston, Texas

U. S. DEPARTMENT OF ENERGY

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SELECTION OF RESERVOIRS AMENABLE TO MICELLAR FLOODING

First Annual Report
for the Period
October 1978 – December 1979

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U.S. DEPARTMENT OF ENERGY

READER'S PREFACE

This report and its appendices are organized so that they may be read in two ways: 1) where the concepts and the results which flow therefrom are derived and examined in detail and 2) where the concepts and the results are presented directly in a declarative manner. Of course, the second is a subset of the first.

For the reader interested in the details contained in the first approach, one proceeds as follows: Report Chapter 1, Appendix I, and Report Chapters 2 through 7. Along this complete route, Chapter 2 will seem redundant since it is a conceptualization of Appendix I; but Chapter 2 should be scanned in order to establish the continuity which it has with the succeeding chapters in the Report. Also, some of the ideas in Appendix I have been adjusted slightly in their transference to Chapter 2 so that they may better fit into the larger construct of the complete project.

For the reader desiring only to understand the concepts and to proceed directly to the results, one proceeds directly through the Report, Chapter 1 through 7. This reader, if he should then read Appendix I, will find it a repetition of Report Chapters 1 and 2, but with the complete details of the background studies.

Appendices II through VI are mostly detailed derivations of results presented in the main body of the Report and are referenced at their respective places.

SELECTION OF RESERVOIRS
AMENABLE TO MICELLAR FLOODING

First Annual Report
October 1978 - December 1979

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PROJECT TASK RESPONSIBILITIES

Development of Predictive Model for Economic Evaluation
of Reservoirs:

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Reservoir Data Base for Micellar Polymer Process
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PECØN, Program for Preliminary Economic Evaluation:

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Validation of Predictive Model by Numerical Simulation:

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NOMENCLATURE

Regular Symbols

A	Spacing, acres/injection
a	Injector-injector distance, ft.
a_s	Active surfactant retention, mg surfactant/ g/rock
$^{\circ}\text{API}$	Oil gravity
b	Constant relating chemical costs to FPV, \$/stb
CL	Confidence level
C_p	Polymer concentration in initial portion of V_{MB}
C'_p	Constant relating pressure drop to depth, psia/ft.
$\bar{C}_p$	Average polymer concentration in V_{MB} , ppm
C_{rs}	Resident salinity, mg Cl/ml
C_s	Injected surfactant concentration, volume fraction active
C_{TP}	Total polymer required, lbm
C_{TS}	Total active surfactant injected, stb
C_o	Injected polymer or preflush concentration, ppm
D	Depth subsurface, ft.
d	Injector-producer distance, ft.
D_s	Dimensionless surfactant retention
D_e	Dispersion coefficient, ft^2/day
D^*	Effective binary diffusion coefficient, ft^2/day
DA	Developed area, acres
E_D	Micellar-polymer displacement efficiency

E_M	Surfactant displacement efficiency, volume oil displaced/volume oil contacted by surfactant
E_R	Recovery efficiency, volume oil recovered/volume target oil
E_{RP}	Primary recovery efficiency
E_v	Waterflood volumetric sweep efficiency
FPV	Floodable pore volume
f_o	Oil cut
f_{bw}, f_{gc}	Fraction OOIP underlain by bottom water or overlain by gas cap
h	Internal thickness, ft.
k	Permeability, md
k_{ro}, k_{rw}	Relative permeability to oil, water
k_v	Vertical permeability, md
L	Characteristic reservoir length, ft.
N_{cap}	Capillary number
N_p	Ultimate waterflood recovery, stb
N_{RP}	Number of repeated patterns in DA
OOIP	Original oil in place at discovery, stb
Q	Steady-state production/injection rate, bbl/day
Q_D	Total injection volumes, fraction FPV
r	Correlation coefficient
r_w	Well radius, ft.
R_O	Micellar-polymer oil recovery, stb
REV	Potential revenue generated from a micellar-polymer flood, \$
ROIP	Remaining oil in place after waterflood, stb

R/E	Revenue to expense ratio
S_{CW}	Connate water saturation
S_o	Oil saturation
S_{orw}	Residual oil saturation to water
S_{orc}	Residual oil saturation in swept regions of micellar-polymer flood
S_{op}	Oil saturation at end of primary production
S_o'	Oil saturation in unswept regions of reservoir after waterflood
TO	Micellar-polymer target oil, stb
t_{life}	Project life, years
u	Superficial velocity, ft/day
v	Interstitial velocity, ft/day
V_{CW}	Volume chase water injected
VDP	Dykstra-Parsons's coefficient
V_{MB}	Mobility buffer volume, fraction FPV
V_{Ps}	Injected surfactant slug size, fraction FPV
W_{clay}	Weight fraction clay in porous volume
X_s	Sulfur correction to base oil price

Greek and Other Symbols

$\alpha_{L,T}$	Longitudinal, transverse distances, ft.
ΔP	Injector-producer pressure drop, psia
ΔS_o	$S_{orw} - S_{orc}$
λ_{min}	Minimum λ_T , cp^{-1}
λ_T	Total Relative mobility, cp^{-1}

μ	Viscosity, cp
μ_o, μ_w	Oil, water viscosity, cp
$\bar{\rho}_{MB}$	Average mobility buffer density, lbm/ft ³
σ	Interfacial tension, dynes/cm
$\$c$	Total chemical cost, \$
$\$o$	Oil price for a specific reservoir, \$/stb
$\$o'$	Base oil price, \$/stb
ϕ	Porosity, fraction
ρ_r, ρ_s	Rock, surfactant density, lbm/ft ³

Subscripts

i	Initial (at discovery)
f	Final (at initiation of micellar-polymer flood)
LD	Line drive
1,2	Low, high permeability layers
5	5-spot

Acronyms

CDE	Capillary desaturation curve
CFTE	Chemical flooding ternary equilibria
CRMQ	Critical reservoir and micellar quantities
DCFROR	Direct cash flow rate of return
DOE	Department of Energy
EOR	Enhanced oil recovery
GURC	Gulf Universities Research Consortium
IFT	Interfacial tension, dynes/cm

IPV	Inaccessible Pore Volume
ISP	Information Systems Programs, Univ. of Oklahoma
MCM/EOR	Mid-Continent Micellar(flooding)/enhanced oil recovery
NPC	National Petroleum Council
OTA	Office of Technology Assessment
PDS	Petroleum Data Systems
PECØN	Preliminary economic evaluation program
PM	Predictive model
TDS	Total dissolved solids, ppm

Selection of Reservoirs
Amendable to Micellar Flooding*

Chapter 1 - Executive Summary and Project Objectives

1.1 Project Objectives

The overall project objective of these two DOE contracts is to build a solid engineering base upon which the Department of Energy (DOE) can improve and accelerate the application of micellar-polymer recovery technology to Mid-Continent and California sandstone reservoirs. The purpose of the work carried out under these two contracts is to significantly aid, both DOE and the private sector, in gaining the following Project Objectives:

- (1) to select the better micellar-polymer prospects in the Mid-Continent and California regions;
- (2) to assess all of the available field and laboratory data which has a bearing on recovering oil by micellar-polymer projects in order to help identify and resolve both the technical and economic constraints relating thereto; and
- (3) to design and analyze improved field pilots and tests and to develop a micellar-polymer applications "matrix" for use by the potential technology users; i.e., owner/operators.

Objectives 1, 2 and 3 (corresponding to the three phases of the Statement of Work) will contribute to bringing on-line micellar-flooding recovery production which will contribute toward meeting DOE's tertiary incremental production goals.

*Mid-Continent, DOE Contract No. DE-AC 19-78BC00048.
California, DOE Contract No. DE-AC 19-78BC00051

1.2 Project Statement of Work Tasks

Task I. Selection of Target Reservoirs. Based upon criteria judged to be essential for potential success in micellar-polymer flooding, a list of candidate sandstone reservoirs amenable to this recovery technique is to be developed and the list ranked according to the potential contribution to the DOE incremental production goal for micellar-polymer oil production by 1985. Accordingly, for purposes of the micellar flooding commercialization decision, the owner/operator responsible for the subject decision for each target reservoir is to be identified.

Task II. Assessment of Available Test Data. To assure a solid engineering base is available for extending the technology to commercialization, data from past and current field and laboratory efforts is to be collected and analyzed in order to identify the critical parameters and technical constraints. This data analysis should lead to a "matrix" (correlation graphs) suitable for interfield analyses.

Task III. Design Recommendations. The results of the work in Tasks I and II will be further developed, organized and presented in such a manner so as to be suitable: (i) for potential commercial users of the micellar flooding technology, and (ii) for recommendations with respect to improvements in future micellar flooding research, development, test and evaluation -- especially field testing -- efforts by DOE and industry.

1.3 Technical Approach and Status

It is clear from an analysis of the Project Statement of Work Tasks that an iterative, technically sound approach must be constructed to identify those reservoirs which are deemed to be most suitable for micellar flooding and their potential contribution to the DOE incremental micellar flood production goals.

First, a zeroth order objective function for such reservoir ranking had to be selected. This was taken to be some economic function, including the time value of money; rather than simply the potential size of the recoverable oil by micellar flooding. The reason that the latter criterion alone would be inappropriate for this study is that the project objective is for actual deployment of the respective micellar flood by the responsible owner/operator. And, of course, such a decision would be an economic one.

The iterative Technical Approach for this study has the following component tasks:

1. Assessment of Available Test Data
2. Development of a Full Predictive Model for Economic Evaluation of a Reservoir
3. Reservoir Data Bank for Micellar Recovery Evaluations
4. Program for Preliminary Economic Evaluation of Reservoirs (PECØN)
5. Ordering of Candidate Reservoirs
6. Validation of Predictive Model by Numerical Simulation

This first contract year involved the first iteration of proceeding down the Technical Approach component tasks 1 through 5. The work done under each of these tasks for the first iteration is detailed in Chapters 2 to 5 of this First Annual Report (Component Tasks 1 and 2 are both discussed in Chapter 2).

It is not surprising to those working in the micellar-polymer technology area that the biggest and most massive obstacle to a complete reservoir evaluation is the lack of requisite reservoir data. That is why a preliminary economic evaluation program, PECØN, was developed in order to obtain the first ranking of reservoirs. Thus, the first iteration ordering of candidate reservoirs, Chapter 5, is only for the purpose of identifying those 200 reservoirs in the Mid-Continent (100 in California) which qualify under the terms of the Work Statement and thus require a detailed reservoir-specific data acquisition effort in order to provide the technical input conditions for the second ranking iteration during the second contract year. With all of the reservoir specific data in place for the second evaluation iteration, the full Predictive Model of Chapter 2 will be used to provide the prioritized list of 100 Mid-Continent reservoirs (50 California) based upon their potential contribution to the DOE incremental production goals.

Statement of Work Task II, "Assessment of Available Test Data", has been completed and is represented by Appendix I to this First Annual Report.

Statement of Work Task III, "Design Recommendations", will be addressed in the third contract year. The design recommendations will follow, in a technical sense, directly from the "Predictive Model for Economic Evaluation of Reservoirs", Chapter 2, as modified by the validation work done with the Chemical Flood Simulator during the second contract year.

1.4 Schedule Approach and Status

The intent of the DOE and the contractors was to do the Mid-Continent "survey" first; and then, after the structure of the tasks, procedures and algorithms were in place, to follow with the California work. Thus, the accomplishment of the respective California work tasks always follow by several months the completion of the Mid-Continent work tasks. This is evident in this First Annual Report in Chapter 5, where only the first iteration Mid-Continent list is presented. The corresponding California list will be available in 3rd Quarter, 1980.

The schedule of Work Tasks is given in Fig. 7.1. The contracts are on schedule and on budget.

Chapter 2 - Development of a Predictive Model For Economic Evaluation of Reservoirs

2.1 Introduction

The usual "screening" procedure for micellar-polymer flooding, or for that matter, for any tertiary enhanced recovery technique is to assign values to a collection of about 15 parameters -- above or below which a technique is expected not to be successful in a particular reservoir. Table 2.1 summarizes some of the previous parameter values for micellar-polymer "screens". Although it is succinct, Table 2.1 does not rigorously reflect the previous work. (Gogarty's review⁷ probably is a better⁹³ one.) For example, the National Petroleum Council (NPC) study actually used a sliding scale on some of the parameters, and Geffen's criteria⁹⁰ on water purity is actually on make-up water, not on formation water. The intent in compiling Table 2.1 was to see how the criteria have changed over the seven years that the micellar-polymer process has been under evaluation. As can be seen, there has been little evolution of the "screening" parameters, certainly no systematic changes. The consensus seems to be that a given reservoir will be a micellar-polymer candidate if it is a sandstone, has a temperature less than about 200°F, a permeability greater than 20 md, a salinity of less than 50,000 ppm TDS, etc.

While a "screening" approach similar to those described in Table 2.1 can be used to eliminate reservoirs which are either technically unfeasible or have low economic potential, such an approach does not provide a means for ranking reservoirs which pass all the criteria as to their EOR potential. In order to achieve this goal, a method was devised which utilizes the "Critical Reservoir and Micellar Quantities" (identified in Appendix I) to estimate reservoir performance. Simply stated, the method involves determining:

- 1) If a micellar-polymer system can be developed which will mobilize oil in the reservoir?
(Technical Feasibility)
- 2) If so, how much oil can be recovered and at what cost? (Economic Potential)

A four-step approach is being used in the development here of a predictive model for estimating micellar-polymer EOR potential:

Step 1: Identify "Critical Reservoir and Micellar Quantities" (CRMQ)

TABLE 2.1

Summary of Previously Used Screening Criteria*

<u>Parameter</u>	<u>Geffen⁹⁰ (1973)</u>	<u>Lewin^{91,92} (1976)</u>	<u>NPC⁹³ (1976)</u>	<u>GURC⁹⁴ (1977)</u>	<u>Lake et al⁹⁵ (1978)</u>	<u>OTA INTERCOMP (1978)</u>
Formation	—	sandstone	sandstone	—	sandstone	sandstone
Temperature, °F	≤ 200	< 200	< 250	< 175	≤ 200	< 275
Residual oil saturation, %	> 25	> 25	≥ 20	> 20	≥ 20	> 30
Permeability, md	> 20-50	> 20	≥ 20	> 20	> 100	> 10
Oil viscosity, cp	< 10	< 20	≤ 30	—	< 10	< 20
Gravity, °API	—	> 28	≥ 25	> 25	—	20-35
Waterflood sweep efficiency	> 50%	> 50%	—	—	> 50%	> 50%
Salinity, ppm Cl ⁻	—	—	—	—	—	< 20,000
Divalent, ppm Ca ⁺⁺ + Mg ⁺⁺	< 500	< 1000	—	< 500	—	< 500
Total dissolved solids, ppm	< 5000	< 50,000	≤ 200,000	< 75,000	—	< 50,000
Producing interval, ft	—	—	—	—	—	> 10
Remaining oil, MM bbls	—	—	—	—	> 1	—
Waterdrive	—	weak	—	—	—	—
Bottom water/gas cap	—	small	—	—	small	—

*Blanks indicate quantity not considered by designated screen.

- Step 2: Based on field test data, assess the relative importance of the CRMQ's on process performance.
- Step 3: Develop procedures for estimating project performance from the CRMQ's.
- Step 4: Test and enhance predictive model by comparison with field test data and simulation results.
- Step 1: Identify Critical Reservoir and Micellar Quantities.

The objective of this part of the development is to identify the quantities most important to the commercial success of the micellar-polymer process. A detailed description of the procedure used and discussion of the results is presented in Appendix I.

Briefly, the procedure used was to:

- A. Amass and review an extensive collection of literature references on currently active and completed micellar-polymer field tests;
- B. Prepare an exhaustive list of quantities that even remotely affect the micellar-polymer process;
- C. Eliminate quantities from this list on the basis of redundancy, inability to measure, inability to ascertain a quantity's effect, or ability to minimize effect of variable by formulation and process design.

The exhaustive list prepared contains 106 separate quantities. Elimination under the criteria of Step 1.C resulted in 29 remaining quantities which were consolidated into 13 groups, constituting the CRMQ. These groups are:

- 1. Residual oil saturation and distribution.
- 2. Reservoir or pilot confinement.
- 3. Natural and induced fractures.
- 4. Temperature and depth.
- 5. Permeability and heterogeneity.

6. Crude oil analysis and properties.
7. Injection water composition.
8. Resident water composition.
9. Relative permeability and rock wettability.
10. Pattern type and size.
11. Clay mineralogy and composition.
12. Rock mineralogy and composition.
13. Volumetric waterflood data.

2.2 Assessment of Field Test Data

The purpose of this part of the approach is to ascertain what quantities have had the most significant effect on performance recoveries in the micellar-polymer field tests that have been or are currently being conducted. It should be emphasized that the fact that no correlation is found between recovery and a certain quantity (particularly controllable quantities such as slug size, surfactant concentration, mobility buffer size, pattern size, etc.) does not necessarily imply that the quantity is unimportant to the process. The lack of a performance correlation could also indicate that the particular quantity did not vary over a wide enough range to show such a correlation; or that the designs meet the requirements of the processes to minimize possible detrimental effects.

Appendix I, Part II contains a detailed description of the data used and analysis performed. Table 2.2 lists the maxima, minima, means and standard deviations for several quantities believed to be important to the micellar-polymer process. These data are based on the 44 proposed, completed, or currently active field tests which have been reported in the literature.¹⁻⁸²

The purpose of Table 2.2 is to illustrate the great variability of the quantities. Note that for most variables, the standard deviations are of the same size as the corresponding means. Furthermore, the extreme values listed in Table 2.2 meet or exceed the various screening criteria listed in Table 2.1 for all respective variables. Hence, Table 2.2 does suggest that the micellar-polymer process may be more widely applicable than is commonly accepted; and/or that the industry applications of micellar flooding has also been subject to the requirements of respective company business strategies, including lease positions.

TABLE 2.2

**Summary of Several Important Variables in Proposed, Completed and
Ongoing MCM/EOR Field Tests**

<u>Variables</u>	<u>No. Samples</u>	<u>Min.</u>	<u>Max.</u>	<u>S.D.</u>	<u>Mean</u>
Depth, ft.	33	600	6256	1447	2850
Temperature, °F	27	60	200	39	103
Acres/pattern*	37	0.625	40	7.0	5.0
Net pay, ft.*	32	3.8	76	19.2	24.6
Permeability, md	28	4	2500	496	319
Perm. variation, V_{DP}	14	0.26	0.85	0.148	0.6
Clay fraction	14	0.0	0.21	0.042	0.093
C.E.C., meg/g	3	0.004	0.035	0.014	0.015
Oil viscosity, cp	28	0.36	40	8.83	7.03
Residual oil saturation, fr.	24	0.2	0.465	0.15	0.31
Resident salinity, mg/l	23	2690	160,000 TDS	43,400	36,600
Resident hardness, mg/l	15	23	7260		1936
Slug size, fr.*	35	0.02	1.14	0.258	0.173
Surfactant conc., fr.*	25	0.00025	0.13	0.193	0.054
Slug size x concentration*	24	0.000114	0.0108	0.0034	0.0059
Mobility buffer size, fr.	31	0	3.3	0.638	0.758
Mobility buffer con., ppm	26	0	2500	716	890
N_{cap}	30	8×10^{-5}	2.1×10^{-2}	8.2×10^{-2}	4.2×10^{-3}

*Test average

Of the 44 tests included in the data base, 20 have had sufficient information published to allow statistical interpretation. These are listed in Table 2.3 along with important quantities. Note that two of these tests (the Benton Pilot and Borregos) were viscously unstable (i.e., at least one of the displacing fluids had a mobility which was greater than that of the fluids it was displacing).

The field data given in Table 2.3 were analyzed using single variable linear regression to determine if any correlation exists between oil recovery and the various quantities and the relative magnitude of their effect. The details of the analysis are given in Appendix I, Part II. It should be emphasized that the purpose of the linear regression analysis was not to establish empirical models relating recovery to the various quantities; but merely to show the degree of correlation between the designated variables and the field test results.

Table 2.4 summarizes the results of the analysis of Appendix I, Part II. The column labelled "Fit" indicates the form of regression equation used.

$$\text{logarithmic: } E_R = a + b \log (x)$$

$$\text{linear: } E_R = a + b (x)$$

The correlation coefficient (r) indicates the degree of correlation between recovery performance and the independent variable, with $r = 0$ indicating no correlation and $r = 1$ indicating perfect correlation. The confidence level is the probability that a given set of data is better correlated by the least squares line than by a normal distribution. In other words, it can be said with at least 95% confidence that oil recovery is a function of pattern size for the micellar-polymer process. The sensitivity column in Table 2.4 is the difference between recovery calculated from the regression line at the maximum and minimum of a particular quantity listed in Table 2.2. Note that the sensitivity is most relevant when the correlation coefficient r -value is high.

From Table 2.4 we can see that the correlation between oil recovery and slug size is poor, while that between oil recovery and actual surfactant slug concentration and total active surfactant injected is good. As discussed in Appendix I, Part II, this correlation may be caused by the very good correlation of oil recovery with mobility buffer size (see below), because it has generally been true that large surfactant concentration processes have generally used large mobility buffers.

TABLE 2.3

Data Summary of Field Tests with Reported Oil Recovery

Point #	Test	V_{ps}	C_s	V_{MB}	C_p , ppm	C_{rs} , mg/l	A, acres	k, md	Depth	N_{cap}	E_R
1	Benton Pilot	1.11	0.013	3.30	275 ⁴	41,000	1	90	2120	—	0.29
2	Big Muddy Pilot	0.25	0.025	0.30	200	3050	1.25	52	3050	$(4.3 \times 10^{-4})^1$	0.35
3	Bingham 533	0.064	0.13	1.4	1700	2800	0.75	82	1860	1.9×10^{-3}	0.57
4	Bingham Expansion	0.05	0.12	1.2	1500	2800	2.9	82	1866	8.4×10^{-4}	0.43
5	Borregos	0.47	0.023	0.51	0 ⁴	19,600	1.25	434	4998	1.9×10^{-2}	0.20
6	118 K	0.085	0.09	0.87	—	—	2.4	90	1500	8.3×10^{-4}	0.48 ²
7	Delaware-Childers	0.085	0.054	0.40	1350	5200	2.5	100	620	3.7×10^{-4}	0.0 ³
8	Henry W	0.09	0.10	1.91	1200 ⁵	10,000	0.75	200	1000	2.4×10^{-3}	0.63
9	Henry E (I)	0.40	—	0.44	—	10,000	0.75	200	1000	2.4×10^{-3}	0.27
10	Henry E (II)	0.20	—	0.83	—	10,000	1.5	200	1000	1.6×10^{-3}	0.33
11	Henry E (III)	0.10	—	0.55	—	10,000	3	200	1000	1.1×10^{-3}	0.26
12	Jones City Regular	0.028	0.09	0.34	650	54,000	8.2	500	1870	—	0.19
13	Louden	0.40	0.023	0.32	558	13,000	0.625	103	1460	$(2.0 \times 10^{-4})^1$	0.15
14	North Burbank	0.06	0.038	0.47	2500	53,400	10	52	2900	4×10^{-4}	0.19 ³
15	Salem	0.285	0.016	0.30	700	40,000	5	87	1750	6.1×10^{-4}	0.17
16	Sloss	0.155	0.044	1.0	800	—	9	93	6256	1.7×10^{-3}	0.29 ³
17	Wilkin	0.025	0.072	0.068	—	3700	2.5	200	1000	1.2×10^{-3}	0.14
18	119 R	0.07	0.11	1.0	1200	10,000	2.5	211	1000	3.6×10^{-3}	0.38
19	219 R	0.102	0.10	1.05	1156	9400	3	165	1000	8.9×10^{-4}	0.30 ³
20	Wichita County Regular	0.15	0.015	0.3	500	—	20	53	1700	1.6×10^{-4}	<0.01 ³

Footnotes

- 1 Based on experimental interfacial tensions
- 2 Upper limit of recovery used
- 3 Test in progress
- 4 Unstable displacement
- 5 Not graded

TABLE 2.4

Results of Linear Regression Analysis of Micellar-Polymer Recovery, E_R , Field Test Data

<u>Variable</u>	<u>Fit</u>	<u>Slope</u>	<u>Intercept</u>	<u>Correlation Coefficient, r</u>	<u>Confidence Level, CL</u>	<u>Sensitivity $E_R(x_{max}) -$ $E_R(x_{min})$</u>
Depth	log	0.08	0.08	0.09	—	0.060
Pattern size	log	-0.24	0.38	0.53	95%	-0.433
Permeability	log	0.06	0.17	0.08	—	0.168
Resident salinity	lin	1.4×10^{-6}	0.31	0.20	—	-0.131
Slug size	lin	-0.30	0.33	0.23	—	-0.336
Slug concentration	lin	3.25	0.07	0.70	99%	0.422
Total surf. inj.	lin	44.5	0.021	0.63	92%	0.475
Mobility buffer size	lin	0.29	0.09	0.83	99.9%	0.957
Mobility buffer conc.	lin	.00022	0.17	0.70	98%	.550
Capillary number	log	0.3	1.21	0.66	99%	.726

Note that the strongest oil recovery correlation obtained was between size and concentration of the mobility buffer. This supports the premise that it is very important to maintain viscous stability behind the surfactant slug in order to obtain high oil recoveries. Furthermore, the existence of this correlation indicates that, unlike the surfactant slug, some of the process designers have not used an adequate mobility buffer slug in many of the field tests.

2.3 The Capillary Number Parameter

Table 2.4 indicates a significant correlation between E_R and pattern size. Laboratory studies have indicated a rate sensitivity of the micellar-polymer process.^{55, 84-87} It is conceivable that these two observations are essentially the same. The rate sensitivity is usually defined in terms of the capillary number (N_{cap}) which is the ratio of viscous to capillary forces:

$$N_{cap} = u\mu/\sigma \quad (2.1)$$

An expression for a field capillary number can be developed starting from the steady-state production/injection rates given by Muskat⁸⁸ for a line drive:

$$Q_{LD} = 0.002254 \frac{kh \Delta P/\mu}{\frac{d}{a} - 1.17 + \frac{2}{\pi} \ln \frac{a}{r_w}}, \text{ bbl/D}; \quad (2.2)$$

and for a 5-spot

$$Q_5 = 0.003541 \frac{kh \Delta P/\mu}{\ln(\frac{d}{r_w}) - 0.619}, \text{ bbl/D} \quad (2.3)$$

The distance between injectors is a and the injector-producer distance is d . Additional assumptions used in the development are:

- 1) for a line drive, $d = 2a$, which corresponds to the way 5-spots are usually infill drilled to make line drives;
- 2) wellbore radius $r_w = 0.3$ feet;
- 3) the in situ viscosity is equal to the oil viscosity, $\mu \sim \mu_o$;

- 4) the bottom-hole pressure difference between injectors and producers is proportional to depth, D , so that

$$\Delta P = C_p' D;$$

C_p' can be as high as 0.7 psi/ft, if the injectors are injecting at the fracture limit of 0.7 psi/ft and the producers are completely pumped off; or as low as 0.27 psi/ft, if the producers have a water head;

- 5) the superficial velocity for a line drive u_{LD} is

$$u_{LD} = \frac{2 Q_{LD}}{h \sqrt{A}}$$

and, from Parsons⁸⁹ result for the median velocity of a 5-spot, u_5 ,

$$u_5 = 0.016 \frac{Q_5}{h \sqrt{A}}$$

where A is the pattern size.

With these assumptions and Equations (2.1), (2.2), and (2.3), the field capillary numbers are:

$$(N_{cap})_{LD} = 4.3 \times 10^{-10} \frac{C_p' kD/\sigma}{\sqrt{A} (4.56 + \frac{1}{\pi} \ln A)} \quad (2.4)$$

$$(N_{cap})_5 = 1.9 \times 10^{-10} \frac{C_p' kD/\sigma}{\sqrt{A} (5.58 + \frac{1}{2} \ln A)} \quad (2.5)$$

where interfacial tension, σ , is in dynes/cm.

In general, k , D and A are quantities which are readily available for an oil reservoir. However, in situ interfacial tension and C_p' are not so easily obtained. Of the 20 tests reported in Table 2.3, only two tests reported laboratory-measured interfacial tension. Even in these cases, the application of laboratory data to in situ conditions is anything but clear. However, for the purposes of this study, the assumption is made that $\sigma = 10^{-3}$ dynes/cm at in situ reservoir conditions for all reservoirs except the Big Muddy Pilot and Loudon where

the reported σ 's were used. It is believed that chemical systems can always be devised to achieve this value of σ .

The value of C' was estimated from the data given in Table 2.5. The rates^P here are the averages beginning at the start of surfactant injection. Eliminating those tests with injectivity/productivity irregularities, an average value of $C'_p = 0.3$ psi/ft is obtained.

Thus, using $\sigma = 10^{-3}$ dynes/cm and $C'_p = 0.3$ psi/ft, Equations (2.4) and (2.5) become:

$$(N_{cap})_{LD} = 1.29 \times 10^{-7} \frac{kD}{\sqrt{A} (4.56 + \frac{1}{\pi} \ln A)} \quad (2.6)$$

$$(N_{cap})_5 = 5.7 \times 10^{-8} \frac{kD}{\sqrt{A} (5.58 + \frac{1}{2} \ln A)} \quad (2.7)$$

These equations were used to estimate N_{cap} for the field tests, and a regression of E_R with N_{cap} was performed. The results (given in Table 2.4) indicate a definite correlation (99% confidence level) exists.

Summarizing these results, the current field test data show significant correlation with (in order of decreasing r): mobility buffer size, slug concentration, capillary number, mobility buffer concentration, pattern size and total surfactant injected. In order of decreasing process sensitivity, the important variables are: mobility buffer size, capillary number, mobility buffer concentration, and total surfactant injected.

Since the mobility buffer size and capillary number appeared to have the strongest effect on recovery, a regression of E_R versus a linear combination of V_{MB} and $\log (N_{cap})$ was performed. The resulting regression equation was:

$$E_R = 0.60 + 0.20 V_{MB} + 0.15 \log (N_{cap}) \quad (2.8)$$

The correlation coefficient ($r = 0.87$) indicates a significant correlation with a confidence level in excess of 99.9%.

TABLE 2.5

Data Used to Estimate C_p'

<u>Test</u>	<u>Project</u>	<u>Production (P) or Injection (I) Rate, BPD</u>	<u>C_p', psia/ft</u>	<u>Comments</u>
Big Muddy	Pilot	130 (P)	0.13*	Fractured injectors
Bradford	Bingham 533	106 (I)	0.23	—
Bradford	Bingham expansion	83 (I)	0.21	—
Bradford	Lawry	19 (I)	0.24	—
El Dorado	Chesney	438 (I)	0.34	Oil wet
El Dorado	Hegberg	378 (I)	0.36	Oil wet
Louden	—	30 (I)	0.28	—
North Burbank	—	730 (I)	0.60*	Oil wet fractured
Henry W	—	70 (I)	0.39	—
Henry E	—	66 (I)	0.39	—
119 R	—	68 (I)	0.19	—
219 R	—	81 (I)	0.37	—
M-1	—	67 (I)	0.25	Based on average pattern size
Salem	—	600 (P)	1.01*	—
Sloss	—	400 (P)	0.087*	Productivity problems
Wichita County Regular	—	900 (I)	3.63*	Injection pressure above fracture gradient

average = 0.54 ± 0.85 average without* = 0.30 ± 0.08

Figure 2.1 is a plot of the actual recovery efficiency versus that calculated from Equation (2.8).^{*} Note that a 45° line indicates perfect correlation. The mean deviation between the actual and estimated recovery efficiencies is 9%. N_{cap} can be looked upon as a screening parameter and is so treated in Appendix I, Sec. II.3.iv.

2.4 Development of a Predictive Model for Economic Evaluation of Reservoirs

The various "screening" parameters enumerated in Table 2.1 can, to some extent, be separated into two groups: 1) those that determine whether or not a micellar-polymer system can be designed with current technology for a particular reservoir; and 2) those that determine how economically viable a micellar-polymer process will be in that reservoir. The approach which will be used in this study is to make a distinct separation between the technical feasibility of a reservoir and its economic potential. In this way, it is possible to determine not only the reservoirs which can be subjected to a micellar-polymer process, but also order those reservoirs with respect to their economic attractiveness. Figure 2.2 illustrates the procedure being used.

2.4.1 Technical Feasibility Screen

The success of a micellar-polymer project is highly dependent on the formulation chemistry. Today, the design of the various injected fluids is still as much art as science. However, as can be seen from the data in Section 2.2 of this chapter, micellar-polymer projects have been conducted in a large variety of reservoirs, indicating that a micellar-polymer system can be designed for a large variety of reservoir conditions. However, there does appear to be two overriding technical constraints that must be applied with the current technology. The first of these is reservoir temperature, since the polymers currently available for mobility control have a tendency to chemically degrade at higher temperatures. Based upon current industry consensus (Table 2.1), it appears that an upper limit on reservoir temperature is 175°F. However, a polymer flood⁹⁶ has been reported which is being conducted

^{*}The data point numeration corresponds to that of Table 2.3.

RECOVERY EFFICIENCY CROSS PLOT **ACTUAL VS. PREDICTED, ON MOBILITY BUFFER SIZE, V_{MB}** **AND CAPILLARY NUMBER, N_{CAP}**

FIGURE 2.1

FIGURE 2.2

FLOW DIAGRAM OF MICELLAR - POLYMER PREDICTIVE MODEL

at 229°F, indicating that micellar-polymer processes might be possible in reservoirs with higher temperatures than previously thought possible.

The other technical constraint to be applied is to salinity. Based on current technology, the deleterious effect of divalent ions on the ability to achieve and maintain low interfacial tensions and the higher surfactant retentions at high salinity would indicate a maximum salinity of 80,000 ppm TDS (Table 2.1). It does appear that new, experimental surfactants may be available that have higher salinity tolerance. This, along with the graded salinity concept¹⁰⁶, indicates that the micellar-polymer process may be applicable to much higher salinities (~200,000 ppm TDS). However, for the purposes of this study which is aimed at deployment of micellar-polymer floods in the mid-1980's, a technical constraint on salinity at 80,000 ppm will be employed.

Thus, the technical feasibility or "screening" portion of this analysis uses only two quantities - reservoir temperature and salinity. The assumption is made that if a reservoir meets these criteria, then a chemical system can be devised that will mobilize waterflood residual oil. Here we define waterflood residual oil to be that oil remaining in the regions of the porous medium that have been thoroughly flushed by water. Furthermore, in the development of the economic model which follows, it is assumed that the specific micellar formulation does not significantly affect overall project performance. In other words, once a surfactant slug/mobility buffer slug system has been tailored to a specific reservoir, the oil recovery will be determined by reservoir parameters (e.g., spacing, relative permeability, heterogeneity, capillary desaturation, etc.), rather than the specific phase behavior of the surfactant/crude oil/brine system. While this assumption implies an oversimplification, it is necessary if a simply predictive model is to be developed. This assumption will have to be verified by numerical simulation, Chapter 6.

Without this assumption, the only way to estimate recovery for the reservoirs contained in the data bank (see Chapter 5) would be to perform a detailed simulation for each reservoir, incorporating both the specific reservoir parameters as well as the specific

phase behavior. Support for the assumption of non-sensitivity to micellar phase behavior can be drawn from the fact that a reasonable correlation was obtained between recovery and capillary number, with the only assumption with respect to formulation chemistry being that an in situ IFT of 10^{-3} dynes/cm was achieved.

2.4.2 Economic Evaluation of the Reservoir

Once a reservoir passes the technical feasibility screen of Section 2.4.1, its economic potential is estimated. The individual steps involved in this predictive model are indicated on Figure 2.2 and the procedures employed are described below. In order to develop such a predictive model, it is necessary to utilize many assumptions, idealized models and empirical relationships. Wherever possible, the relationships used will be verified and/or improved by comparison with actual field data and with numerical simulation in Phase II of this study contract. (This work is described in Chapter 6.) Thus, the development of the predictive model will be an iterative process, with the procedure outlined below being the first iteration. The goal of this development is a model capable of predicting oil recovery and project economics for micellar-polymer floods with enough certainty that reasonable decisions can be made about the potential for success of a particular micellar-polymer project in a given reservoir. The eight estimation steps in Fig. 2.2 are detailed below.

(1) Target Oil. Micellar-polymer target oil (TO) is defined as the oil remaining in the waterflood swept portion of the reservoir at the termination of the waterflood (or start of the micellar-polymer process). Based upon a material balance analysis (See Appendix II for details), the following expression for TO is obtained:

$$TO = OOIP \left[\frac{1 - \frac{S'_o}{S_{oi}} \frac{B_{oi}}{B_{of}} - \frac{N_p}{OOIP}}{\frac{B_{oi}}{B_{of}} \left\{ \frac{S_{orw}}{S_{oi}} - \frac{S'_{oi}}{S_{oi}} \right\}} \right] \frac{S_{orw}}{S_{oi}} \frac{B_{oi}}{B_{of}} (1-f_{bw})(1-f_{gc}) \quad (2.9)$$

where S_o' is the oil saturation remaining in the unswept portions of the reservoir, S_{orw} is the oil saturation in the waterswept portions, and N_p is the cumulative oil recovery. In Equation (2.9), the target oil has been reduced by the fraction of the reservoir above bottom water (f_{bw}), since the potential loss of chemical to this bottom water precludes micellar-polymer flooding in this portion of a reservoir. Similarly, resaturation losses to a gas cap would make micellar-polymer flooding unattractive near the gas-oil contact of a reservoir, and hence TO was reduced by the fraction of the reservoir directly below a gas cap (f_{gc}). By using the waterflood volumetrics to estimate TO and making the assumption that micellar-polymer and waterflood sweep efficiencies are the same, Equation 2.9 incorporates, to some extent, corrections for undeveloped and unswept areas of the reservoir during the waterflood. Equation (2.9) applies, of course, only to a reservoir that has been previously waterflooded, which assumption we make throughout this report. A suitable substitution for this equation will be developed if the data bank reveals a significant number of secondary micellar-polymer candidates.

(2) Micellar-Polymer Recoverable Oil. The ultimate oil recovery, RO, from a micellar-polymer process is estimated from

$$RO = 0.8 E_D (TO) \quad (2.10)$$

where E_D is the micellar-polymer displacement efficiency and is taken to be a function of slug size (V_{ps}), surfactant retention (D_s), heterogeneity, and micellar-polymer swept zone residual oil saturation (S_{orc}) (Figure 2.3). The constant in Equation (2.10) is an empirical factor used to account for the difference between displaced oil ($E_D TO$) and produced oil (RO). In later iterations of the predictive performance model we shall attempt to give better resolution to this factor.

Figure 2.3 was developed⁹⁵ assuming a layered system and using an approach analogous to that of Stiles¹⁰⁷. The principal assumptions made to develop Figure 2.3 are:

- a) All displacement fronts have a unit mobility ratio;
- b) Crossflow, dispersion and fractional flow effects are negligible;
- c) Chemical is completely active at all saturations;

MICELLAR - POLYMER DISPLACEMENT EFFICIENCY VS. SLUG SIZE - RETENTION RATIO

FIGURE 2.3

- d) Chemical adsorption and residual oil saturations are uniform;
- e) A layer is swept completely to S_{orc} if its slug size is greater than D_s .

The measure of heterogeneity used in Figure 2.3 is the Dykstra-Parsons' coefficient, V_{DP} , which can be calculated from core data.¹⁰⁸ D_s is a measure of the surfactant retention, expressed as the size of surfactant slug (measured in pore volumes) required to satisfy all adsorption. D_s is derived by equating the total injected surfactant to the total adsorbed, which leads to

$$D_s = \left(\frac{1-\phi}{\phi} \right) \left(\frac{\rho_r^a}{\rho_s C_s} \right) \left(\frac{1}{1000} \right) \quad (2.11)$$

where a_s is the surfactant retention (in mg surfactant/g rock) and C_s is the concentration of surfactant in the injected slug (volume fraction).

The quantity $\Delta S_o/S_{orw} = (S_{orw} - S_{orc})/S_{orw}$ is the degree to which the surfactant slug can mobilize residual oil. Laboratory data⁸⁵ indicate that this quantity correlates with N_{cap} through the capillary desaturation curve (CDS). Thus, where available, the value of $\Delta S_o/S_{orw}$ should be estimated from the particular field's CDS using the previously developed relations for N_{cap} [Equations (2.4) and (2.5)] again assuming $IFT = 10^{-3}$ dynes/cm and $C_p = 0.3$ psi/ft or where the CDS is not available, using the Gupta-Trushenski⁸⁵ curves shown in Figure 2.4. Note that this incorporates into the calculation procedure one of the variables (N_{cap}) which was found to have a significant effect on micellar-polymer field tests in Section 2.3.

Table 2.6 compares oil recovery (normalized by target oil) estimated by this predictive model* to that reported for field tests. Eliminating unstable floods, the Salem test, and those in progress, the average deviation between observed and calculated recovery is 7% of target oil with the estimated recovery generally larger than the observed value. There may be several reasons for this:

*denoted $(CFR)_{ult}$

1. A σ higher than 10^{-3} dynes/cm is generated in situ;
2. Areal sweep effects for the mobility buffer lower than for water;
3. Target oil was taken to be equivalent to remaining oil in place;
4. Large uncertainties in all of the numbers making up N_{cap} , V_{DP} and, most particularly, V_{ps}/D_s .

Nevertheless, it appears that the above procedure gives hope that micellar-polymer recovery estimates adequate for screening purposes may be obtained. The principal effort of the simulation studies will be to further validate (and possibly improve) the various correlations used in estimating oil recovery in the predictive model and thus improve the accuracy of the estimated oil recovery.

(3) Surfactant Requirements. The major determinant in the quantity of surfactant required is retention, and the retention is determined primarily by adsorption on clay surfaces. Appendix I, Part III.3 contains a discussion of the effort made to correlate adsorption with clay content. This effort is very crude in that many of the variables known or believed to have a significant effect on retention (e.g., alcohol, temperature, electrolyte concentration, etc.) were not included. Nevertheless, the results obtained (Figure 2.5) are at least order-of-magnitude correct and provide a start for estimating the total surfactant requirement. Only a few of the many data points tabulated and used for the basis of the correlation are shown (see Appendix I, Part III.3). The data shown are representative averages of the laboratory values examined. The

**CAPILLARY DESATURATION CURVES,
WATER WET AND OIL WET**

FIGURE 2.4

TABLE 2.6

**Comparison of Observed and Predictive Model Estimate Ratio of
Recovered Oil (RO) to Target Oil (TO)**

Test	N _{cap}	S _{orc}		V _{ps} /D _s	V _{DP}	(CFR) _{ult} /TO		Comments
		Observed	Estimated			Observed	Estimated	
Big Muddy Pilot	4.5 × 10 ⁻³	0.12	0.11	1.15	0.6	0.35	0.36	—
Bingham 533	1.9 × 10 ⁻³	—	0.06	1.83 ¹	0.65	0.44	0.50	oil wet
Bingham Expansion	8.4 × 10 ⁻⁴	—	0.12	1.32 ¹	0.65 ²	0.43	0.37	oil wet
Borregos	1.9 × 10 ⁻²	0.09	0.04	1.44	0.7	0.204	0.46	unstable
Henry W	2.4 × 10 ⁻³	0	0.08	1.23	0.62 ³	0.63	0.56	—
Louden	2 × 10 ⁻⁴	—	0.17	2.3	0.42	0.15	0.29	—
North Burbank	4 × 10 ⁻⁴	—	0.16	0.91	0.61	0.19	0.26	in progress
Salem	6.1 × 10 ⁻⁴	—	0.11	2.97	0.34	0.17	0.51	—
219 R	8.9 × 10 ⁻⁴	—	0.13	2.68 ¹	0.62	0.30	0.50	in progress
Delaware-Childers	3.7 × 10 ⁻⁴	—	0.16	1.16	0.48	0	0.34	in progress

¹ a_s = 0.4 mg surfactant/g-rock

² V_{DP} used for Bingham 533

³ V_{DP} for 119 R used

average deviation between observed and estimated = 0.04

SULFONATE RETENTION ON SANDSTONES

FIGURE 2.5

clay adsorption data (not shown on the figure because of the scale used). The lower line is an estimate at what might be achieved using, among other things, sacrificial agents such as silicates. The upper line is an estimate at the likely, actual, historical, field retention values. It should be pointed out that, in the cases of field data, an adjustment was made for activity, since all laboratory data were on an active basis and it was assumed that these particular field data were not. But the assumed adjustment (60%) is very uncertain. Also, the field data probably include other retention mechanisms.

The 100% clay line in Figure 2.5 gives

$$a_s = 3.3 W_{\text{clay}}$$

which can be used in Equation (2.11) to estimate D_s . The actual surfactant slug used should be somewhat larger than D_s . While this value is subject to optimization, a value of $V_{PS} = 1.3 D_s$ is being used. Thus, in terms of the floodable pore volume (see Appendix II),

$$FPV = \left[\frac{1 - \frac{S'_O}{S_{oi}} \frac{B_{oi}}{B_{of}} - \frac{N_p}{OOIP}}{\frac{S_{orw} - S'_O}{B_{of}}} \right] \{OOIP\} (1-f_{bw}) (1-f_{gc}) \quad (2.12)$$

the total surfactant slug size in stb is given by

$$V_{PS} = (1.3 D_s) (FPV) \quad (2.13)$$

and the total active surfactant injected is (in stb), according to this modelling procedure:

$$C_{TS} = C_S V_{PS} = (1.3 D_s) (C_S) (FPV). \quad (2.14)$$

(4) Polymer Requirements. In Section 2.2 of this Chapter, it was found the polymer concentration and the

total volume of the mobility buffer had a large effect on oil recovery in the field tests. Further, since polymer costs are usually smaller but of the same magnitude as surfactant costs, the impact on project economics is large. A standard procedure for designing mobility buffers is to make the initial mobility of the polymer slug equal to λ_{min} , the minimum total mobility for oil and water (see Figure 2.6), and then grade the mobility buffer viscosity down to that of the chase water in some optimized manner. Unfortunately, relative permeability data (necessary for determining minimum mobility) is seldom available in the data base for oil reservoirs at this time. Furthermore, no generally accepted procedure exists for designing the grading or total volume of the mobility buffer. Therefore, a simplified procedure has been developed to estimate polymer requirements. It is hoped that this procedure can be improved as a result of insight gained from numerical simulation (see Chapter 6).

Figure 2.7 plots C_p , the polymer concentration in the initial portion of the drive, vs. the ratio of oil to water viscosity. The data are based on the field test information in Appendix I, Part II and are subdivided into two groups corresponding to the wettability of the subject reservoir. Plotting C_p vs. the viscosity ratio tends to decrease the sensitivity of polymer requirements to reservoir temperature. For both groups the correlation is quite good; however, the points for the correlation of oil-wet reservoirs are so clustered on the x-axis -- this accounts for the extremely high slope -- that it is recommended using a line of slope equal to that of the water-wet correlation but shifted upwards through the mean C_p of the oil-wet test as indicated in Figure 2.7 for oil-wet reservoirs.

Taking C_p from Figure 2.7 and assuming linear grading of concentration, the average concentration, $\bar{C}_p$, is given by

$$\bar{C}_p = \frac{1}{2} C_p V_{MB}, \text{ ppm} \quad (2.15)$$

where V_{MB} is the total volume of the mobility buffer. For the purpose of estimating economic potential, $V_{MB} = \text{FPV}$ is assumed. Therefore, the total polymer, in pounds, is

$$C_{TP} = 5.615 \times 10^{-6} (\bar{C}_p) (\text{FPV})(\bar{\rho}_{MB}) \quad (2.16)$$

where $\bar{\rho}_{MB}$ is the average density of the mobility buffer in lbm/ft^3 .

SCHEMATIC TOTAL RELATIVE MOBILITY VS. WATER SATURATION CURVE

FIGURE 2.6

INITIAL POLYMER CONCENTRATION VS. OIL - WATER VISCOSITY RATIO

FIGURE 2.7

(5) Project Life and Production Schedule. In order to include the time value of money as well as operating costs in the estimate of economic potential, a project life and production schedule are required. From Equations (2.2) and (2.3) (with $r_w = 0.3$ ft and $C_p = 0.3$ psia/ft) the project life for a line drive or 5-spot pattern is given by:

$$(t_{\text{life}})_{\text{LD}} = (31433A\phi) \frac{4.56 + \frac{1}{\pi} \ln(A)}{(kD/\mu_o)} Q_D \quad (2.17)$$

$$(t_{\text{life}})_5 = (20533A\phi) \frac{5.58 + \frac{1}{2} \ln(A)}{(kD/\mu_o)} Q_D \quad (2.18)$$

where Q_D is the total injection volume in pore volumes:

$$Q_D = V_{\text{PS}} + V_{\text{MB}} + V_{\text{CW}}$$

V_{CW} is the volume of chase water injected. A typical value for Q_D is 1.5.

As a first approximation to the production schedule, a constant oil rate of RO/t_{life} will be used. It is recognized that this may give optimistic results for DCFROR, and it is planned to develop more realistic estimates of production schedules based on the numerical simulation results.

(6) Field Development. The amount of development that would be required to implement a micellar-polymer project is based on the current number of injection/production wells in the field and an estimate of the total number of wells required. Based on the estimated floodable pore volume, Equation (2.12) the developed acres are given by:

$$DA = \frac{FPV}{7758\phi h}, \text{ acres} \quad (2.19)$$

where h is the average net pay. Assuming development on the existing spacing, the number of repeated patterns would be:

$$\text{NRP} = \frac{\text{DA}}{\text{A}}, \text{ repeated patterns} \quad (2.20)$$

For 5-spot or direct line drive patterns, there is one injector and one producer per pattern, so the number of injectors and the number of producers is equal to NRP.

Thus, from the number of existing production and injection wells, and the estimated number of wells given by Equation (2.20), the number of new wells and well conversions required can be calculated.

(7) Cost Data. The procedure described above provides the production and injection data required to evaluate a micellar-polymer project. In order to calculate an economic potential, data on oil price, chemical and operating costs, and development costs are also required.

The following relationships for oil price, $\$_O$, based on oil gravity and sulfur content, is used

$$\$_O = \{ \$_O' - 0.02 (40 - ^\circ\text{API}) \} X_S \quad (2.21)$$

where $X_S = 1.0$ if no sulfur is present in crude

$$X_S = 0.9 \text{ if crude contains significant sulfur}$$

and $\$_O'$ is a base oil price (in evaluation year dollars), and $\$_O$ is the estimated oil price for a specific reservoir. Equation (2.21) provides a \$0.02 penalty for every $^\circ\text{API}$ less than 40°API , and reduces the oil price by 10% if the crude contains significant amounts of sulfur.

The expenses associated with a micellar-polymer flood project for any given candidate reservoir fall into three main categories:

- 1) Development costs,
- 2) Operating costs,
- 3) Chemical costs.

These expenditures include expenses resulting from drilling and completing proposed injection and production wells, purchasing the additional required equipment, and working over or converting existing wells. The Office of Technology Assessment (OTA) developed the costs¹⁰⁹ (in 1976 dollars) associated with these items as a function of location within the United States and three reservoir depth ranges: (1) 0 to 2500 feet, (2) 2500 to 5000 feet, and (3) 5000 to 10,000 feet. These values, after escalating to 1980 dollars by applying an escalation rate of 12% per year since 1976, are the basis for estimating development and operating expenditures associated with the implementation of a micellar-polymer project.

Workover costs for existing wells are based on when the reservoir was discovered. As the OTA study suggests, assuming all the existing wells were present from the discovery date on, the following table is used to determine the percentage of wells requiring workover:

<u>Age, years</u>	<u>% Workover</u>
>25	100
15-25	50
10-15	25
<10	0

Operating costs on an annual-per-well basis are taken from the OTA study. The number of wells in the project is equal to twice the number of repeated patterns (Equation (2.20)).

Chemical costs are input as dollars per barrel of surfactant slug and dollars per pound of polymer in the mobility buffer.

(8) Economic Calculation. A discounted cash flow calculation will be performed, based upon the oil recovery, development, operating and chemical costs. The results of these calculations will be used to economically evaluate the reservoirs contained in the data base which pass the technical feasibility screen.

A potential optimization loop is indicated on Figure 2.2. This is intended to imply that it might be possible to maximize the potential of a particular reservoir relative to some objective function (e.g., oil recovery, direct cash flow rate of return, DCFROR, PV profit, etc.) by adjusting some of the controllable process variables (e.g., pattern size, surfactant slug size, mobility buffer size). Preliminary results with the predictive model described here suggest that some optimization may be possible. However, additional effort is required before the inclusion of such an optimization loop in the model can be justified.

Appendix III contains a simplified example of the calculation procedure described in Figure 2.2 to be used in estimating the micellar-polymer potential of a given reservoir.

Chapter 3 - Reservoir Data Bank for Micellar-Polymer Process Evaluation

One of the objectives of this study is to provide a list of reservoirs which are potential candidates for tertiary oil recovery utilizing the micellar-polymer process. Reservoir candidates are to be provided for the Mid-Continent and California regions respectively. A list of reservoirs deemed to be most suitable for micellar-polymer recovery will be provided along with values for as many critical reservoir parameters as possible at the conclusion of Phase II of the study contract for both the Mid-Continent and California.*

The first step in building the data bank was to combine the existing archival data files. By starting in this manner, it is possible not only to take advantage of the existing data, but also to acquire the associated computer logic program capable of sorting data by labels. Such a system has been developed by Information Systems Programs (ISP) group at the University of Oklahoma. Initial and subsequent funding for this effort has been provided by the United States Geological Survey. The system, which is known as Petroleum Data System (PDS), is available by computer timesharing through General Electric. The program logic associated with the data files in PDS is known as GIPSY. In addition to the many data files available to the public, ISP is recognized as the depository for other petroleum archival files. ISP also continues to develop other files which are not yet ready for public access. Under this DOE project, we were allowed to combine data from all files. However, the quality of data from some of the sources has not yet been checked for validity.

Many PDS files have as many as 300 labels associated with them, and GIPSY has the capability to sort the data on a combined logic basis -- i.e., one could construct a statement to search for all reservoirs below 5000 feet, greater than 10 feet of thickness and containing oil of a gravity greater than 30°API. A wide variety of such logic statements can be constructed utilizing GIPSY. The Petroleum Data System, which was the starting file for the data combination under this study contract, has more than 84,000 field/reservoir records.

*Mid-Continent: 100 reservoirs. California: 50 reservoirs.

3.1 Baseline Data Bank

This PDS data base was passed through the following zeroth order screen for reservoirs suitable for micellar-polymer flooding. The following criteria, as specified in the DOE contract, were used:

- a. Oil reservoirs only
- b. Sandstone lithology only
- c. Onshore only
- d. All states except the states of Illinois, Alaska, and Hawaii

Three additional criteria were used for preliminary screening of the PDS data bank. They were:

- a. API gravity greater than 20° -- a "Non-Heavy Oil" criterion
- b. Depths of less than 10,000 feet -- a "Temperature" criterion
- c. Cumulative production greater than 2,000,000 stb or annual production greater than 1,000,000 stb in any one year for Mid-Continent* -- an "Economic" criterion.

The gravity constraint was used to avoid overlap with the heavy-oil investigations; the viscosity will enter into the economic evaluation via the project life equations (2.17) and (2.18). Since polymers tend to break down at high temperatures, the depth constraint (corresponding approximately to 175°F) was used. The cumulative production figure was selected based upon the economic expectation parameter, Present Value of Production. Where the above information was not available, the record was retained. When the missing parameter was determined, it was entered. This zeroth order screen produced a data base of 2534 records, and is stored in a computer file at the University of Oklahoma, 1930 records in "Clean 5" for the Mid-Continent and 604 records in "Clean 3" for California.

*California: Cumulative production greater than 500,000 stb

3.2 Expansion of Data in Data Bank

After reviewing the 2534 records, it was apparent that a substantial amount of reservoir data was absent, preventing the application of the predictive model of Chapter 2. As a consequence, a data information task force was formed to gather data from all other archival sources and amalgamate them into the "Clean 3" and "Clean 5" records. Federal agencies, state agencies and several other data bases were surveyed. To verify specific parameter data, where there was duplication, each source was checked against the other. Table 3.1 is a partial list of sources used and/or agencies contacted to expand the reservoir record data bank.

A massive amount of data was acquired during this data gathering phase and added to the data bank. However, as the study progressed, it became apparent that a number of parameters critical to micellar flooding performance; i.e., residual oil saturation after waterflooding, reservoir heterogeneity, clay type and weight percent, wettability, etc. (see Chapter 2) were not available either in the published archival records or at state or federal agencies.

To acquire such critical data, it was determined that the owners/operators would have to be contacted. This data phase is in progress and will be a continuing effort.

3.3 Statistical Distributions of Reservoir Properties

Tables 3.2 and 3.3 are summaries of the results of the statistical distributions of reservoir properties for the Mid-Continent and for California. A feeling for completeness of data, data averages, statistical spread, etc., may be inferred from these distributions.

It is interesting to note that there is no apparent significant difference in the distribution of reservoir properties as a function of reservoir size. Also, there is no apparent significant difference between the distribution of properties in the Mid-Continent and in California. This last observation must be tempered by the caution that a large amount of California reservoir data is currently unavailable. However, both of these counter-intuitive results may stand the test of time as more data is entered into the reservoir records files.

3.4 Utilization of Data Base

The reservoir data in the data bank will be utilized in two ways: 1) in the evaluation algorithm described in Chapter 2, and 2) in numerical reservoir simulations of the micellar-polymer flooding process, Chapter 6. Information from the simulations can be used to validate the evaluation algorithm and thus substantiate the algorithm, which we call the "predictive model" (PM). The development of a good predictive model can be used in the future to estimate any reservoir's potential as a micellar-polymer flooding candidate, provided the necessary data exist.

Table 3.4 displays the data required to perform the predictive model calculations described in Chapter 2. These data are indicated by PM. Also indicated on this table is the percentage of reservoirs for which each data item is available for the Mid-Continent and California data files. This Data Availability column illustrates that numerous data required for the predictive model are not available in the databanks, "Clean 3" and "Clean 5". As an iterative solution to this problem, a simplified predictive model (called PECØN, Chapter 4) was formulated and coded for computer execution. The data required for PECØN is indicated by "E" on Table 3.4; note that a less complete list of data is required for PECØN usage. The next section describes the simplifying assumptions and operation of the PECØN program.

The point is that we will use PECØN to generate a list of several hundred reservoirs which are the most suitable for micellar-polymer flooding based upon the ordering objective function selected. Then, the owner/operator of each of these designated reservoirs will be contacted to obtain the data necessary for the application of the full predictive model of Chapter 2 and the validating numerical simulations of Chapter 6.

TABLE 3.1

**Data Sources Amalgamated Into Reservoir Files,
"Clean 3" and "Clean 5"**

1. University of Oklahoma
Information Systems Program
Energy Resources Center
 - a. OILY
 - b. TEXS
 - c. BRINE ANALYSES
 - d. OIL ANALYSES
 - e. Texas Secondary Recovery
 - f. Kansas Secondary Recovery

PDS 84,000 Reservoir Records
2. Gulf Universities Research Consortium
Report No. 153
3. Lewin and Associates
"Big Fields File"
Final Report to ERDA, 1976
4. Department of Energy
Energy Information Administration
Office of Applied Analysts
Dallas Field Office
5. Various State Oil and Gas Commission Publications
(Texas, Oklahoma, Louisiana, Wyoming, Kansas)
6. Professional Society Libraries
7. Bureau of Mines Waterflooding Reports of Investigation by States
8. State Geological Societies and Surveys

TABLE 3.2

MCM/EOR Reservoir Distribution of Properties by Reservoir Size

	>20 mil Bbls SUBSET I			2-5 mil Bbls SUBSET II			5-20 mil Bbls SUBSET IV			"Clean 5" File TOTALS		
1 Std. Dev.	16%	50%	84%	16%	50%	84%	16%	50%	84%	16%	50%	84%
	L	M	H	L	M	H	L	M	H	L	M	H
Viscosity	1.4	4.3	14.5	1.75	3.5	7.0	.6	2.2	6.2	1.4	3.6	9.0
Scw	17.5	27.5	39.5	23.5	33	43.5	20	30	41	20	30.5	42
Porosity	12.75	20.75	30	13	19	28.5	13.75	19.75	28.75	13.25	19.75	29
Spacing	12	26	46	15	26	44	12	22	37	13	25	40
Net Pay	11	30	90	6.8	14	33	8.8	18	42	8	18	49
Spacing/Net Pay	.36	1.0	3.7	.94	2.4	5.7	.6	1.5	4.2	.58	1.7	4.8
API Gravity	27.5	35.5	40.5	30.5	37	41.5	29	36.5	41	29.5	36.5	41
Permeability	26	185	1200	10	110	740	12.5	140	960	11.5	140	960
Depth	2500	4800	8200	2300	4400	6600	2400	4500	7000	2400	4500	7100
Salinity		62000	96000	7400	30000	64000				5900	50000	78000
TDS	13000	82000	162000	10000	76000	180000	5000	50000	190000	8000	66000	180000
Sor	14	27.5	38.5				17.5	28.5	38.5	16	28	38.5
Boi (FVF)	1.095	1.2	1.37	1.09	1.22	1.38	1.075	1.18	1.41	1.08	1.2	1.39

TABLE 3.3

Distribution of Reservoir Properties

	SAMPLE SIZE	<u>MID-CONTINENT</u> 1977 Reservoirs			SAMPLE SIZE	<u>CALIFORNIA</u> 604 Reservoirs		
		<u>16%</u>	<u>50%</u>	<u>84%</u>		<u>16%</u>	<u>50%</u>	<u>84%</u>
1 Std. Dev.								
SCW (percent)	44%	19.5	30	39.7	19%	25	33	40
API Gravity	94%	29	36.5	41	99%	24.5	30.5	36.5
Viscosity (CP@60°F)	30%	1.3	3.8	11.0	12%	2.1	4.7	31.5
Depth (feet)	96%	2300	4700	7100	97%	3000	5500	8300 ^{*4}
Permeability (md)	58%	28	235	980	31%	81	310	1000
Net Pay (feet)	86%	8	18	50.5	75%	40	135	330 ^{*5}
Porosity (percent)	66%	14.2	21.5	29.7	57%	20	25	30
Spacing (acres)	40%	11.5	22	39	N/A	N/A	N/A	N/A
Spacing/Net Pay (acres/ft)	38%	.59	1.75	4.8	N/A	N/A	N/A	N/A
Salinity (ppm)	2%	5000	41000	90000 ^{*1}	N/A	N/A	N/A	N/A
TDS (ppm)	23%	7000	70000	173000 ^{*2}	N/A	N/A	N/A	N/A
SOR (percent)	5%	15	27.5	39.5 ^{*3}	N/A	N/A	N/A	N/A
B _{oi} (FVF) (RB/STB)	29%	1.08	1.2	1.38	N/A	N/A	N/A	N/A

*See comments on next page.

TABLE 3.3 (Cont.)

COMMENTS

- 1) Mid-Continent salinity has very few samples and is subject to change.
- 2) TDS is weighted high due to about one-third of the samples being in Oklahoma.
- 3) Mid-Continent Sor has very few samples, most of which are from Texas, and are subject to change. The information we have is remaining oil saturation and what we need is residual oil saturation after water flood.
- 4) California depth is subject to error due to excessive degree of dip in that state.
- 5) California net pay is probably gross interval.

TABLE 3.4

Data Requirements and Availability for Predictive Micellar-Polymer Model (PM)
and Program for Preliminary Economic Evaluation, (E)

Data Availability (percent)		Symbol	Technical Screen	Target Oil	Recov- erable Oil	Micellar Require- ments	Polymer Require- ments	Field Develop- ment	Project Life	Prices & Costs
M.C.	Calif.									
94	97	Depth	D		PM,E				PM,E	PM,E
27	7	Temperature	T	PM,E						
43	0	Pattern Size	A		PM,E			PM,E	PM,E	
NA	NA	Pattern Type	Type		PM				PM	
59	31	Permeability	k		PM,E				PM,E	
NA	NA	Vertical Perm Variation	V _{DP}		PM					
NA	NA	Clay Content	W _{clay}			PM				
33	8	Oil Viscosity	μ_o				PM		PM,E	
6	0	Residual Oil	S _{orw}	PM,E	PM,E	PM,E	PM,E	PM,E		
66	57	Porosity	ϕ					PM,E	PM,E	
23	2	Salinity	TDS	PM,E						
30	6	OOIP	—	PM	PM	PM	PM	PM		
100	100	Cum Prod	N _p	PM,E	PM,E	PM,E	PM,E	PM,E		
31	6	Initial FVF	B _{oi}	PM	PM	PM	PM	PM		
0	0	CURRENT FVF	B _{of}	PM,E	PM,E	PM,E	PM,E	PM,E		
44	19	Initial Oil Sat	S _{oi}	PM,E	PM,E	PM,E	PM,E	PM,E		
NA	NA	Capillary De-saturation Curve	CDS		PM,E					
NA	NA	Water Viscosity	μ_w				PM			
NA	NA	Wettability	WET		PM		PM			
87	75	Net Pay	h					PM,E		
100	100	Location	LOC							PM,E
82	86	Existing Wells	WELLS					PM,E		
99	99	Discovery Date	AGE					PM,E		
95	100	API Gravity	API							PM,E
36	28	Sulfur Content	SULF							PM,E
NA	NA	Fraction of Oil over bottom water	f _w	PM	PM	PM	PM	PM		
NA	NA	Fraction of Oil below gas cap	f _g	PM	PM	PM	PM	PM		

Chapter 4 - PECØN, Program for Preliminary Economic Evaluation

As discussed at the conclusion of Chapter 3, once a reservoir passes the technical feasibility screen, its economic potential is to be estimated in order to designate it for further data acquisition effort. To accomplish this preliminary evaluation, use is made of a simplified version of the full predictive model developed in Chapter 2 and shown diagrammatically in Figure 2.2. As indicated in Section 3.4, the data required for the full predictive model is usually not available in the current data bank. Therefore, the development of an intermediate predictive economic evaluation model (PECØN) necessitates additional assumptions in order to work with the present content of the data bank. Also, use must be made of default options so as to process as many of the potential reservoir candidates as possible without bias toward or against those reservoirs with insufficient data. As these reservoirs are processed through the modified predictive model, PECØN, preliminary estimates of oil recoveries and micellar-polymer project economics can be calculated. With all the assumptions and data defaults clearly in mind, the PECØN results provide a means by which the candidate reservoirs can be ordered one relative to another and a grouping of several hundred be designated as more suitable than the others. This, in turn, provides the necessary direction to future data solicitation efforts from the individual owner/operators.

The program documentation for PECØN is given in Appendix IV. Included in the PECØN Appendix is a brief explanation of the equations used, all required input variables, user default options, and cost tables.

4.1 Estimate of Target Oil

Although Equation (2.9) discounts the target oil for the fraction of the reservoir above bottom water (f_{bw}) and the fraction directly below the gas cap (f_{gc}), this information is not currently available in the data base. Therefore, both f_{bw} and f_{gc} are assumed to be zero for all reservoirs. Through future data solicitation efforts, individual owner/operators should be able to identify those reservoirs in the data base for which this assumption is not valid and hopefully to give some guidance as to the correct values for these parameters.

For the purpose of making these preliminary calculations, oil shrinkage is also assumed to be negligible.

This results in the ratio of initial to final oil formation volume factors being equal to unity ($B_{oi}/B_{of} = 1.0$). In turn, this ratio eliminates the need, at present, for an assessment of original oil-in-place (OOIP). The distinctive advantage to this assumption is an ability to order all the reservoirs without bias for or against those that still lack this information.

In addition to the above, if maximum resaturation of the unswept portion of the reservoir ($S'_o = S_{oi}$) is assumed, Equation (2.9) then reduces to

$$TO = \frac{S_{orw}}{S_{oi} - S_{orw}} N_p, \text{ stb} \quad (4.1)$$

4.2 Estimation of Micellar-Polymer Recoverable Oil

A measure of heterogeneity can be calculated from the core data once this is available. Lacking this information at present, the assumption is made that each reservoir is homogeneous (i.e., the Dykstra-Parsons' coefficient is zero, $V_{DP} = 0$). If it is also assumed that the injected slug size is sufficient to satisfy all adsorption requirements (i.e., the slug size-retention ratio is unity, $V_{ps}/D_s = 1.0$), Figure 2.3 indicates the quantity

$$\left(\frac{E_D}{\Delta S_o / S_{orw}} \right)$$

is also equal to unity. This results in a direct equality between the displacement efficiency, E_D , and the fraction of S_{orw} that is mobilized at a specific value of N_{cap} , that is

$$E_D = \frac{\Delta S_o}{S_{orw}} = 1 - \frac{S_{orc}}{S_{orw}} = E_M(N_{cap}), \text{ dimensionless} \quad (4.2)$$

It has already been noted that the degree to which the surfactant slug can mobilize residual oil ($\Delta S_o / S_{orw}$) can be predicted by its correlation with N_{cap} . Since capillary desaturation curves for the individual reservoirs are not yet available in the data base, the Gupta-Trushenski curves shown in Figure 2.4 are used to estimate recovery. Here, the assumption is made that all reservoirs behave as water-wet systems. In addition, all N_{cap} quantities are calculated assuming a 5-spot geometry pattern (Equation 2.5) where $\sigma = 10^{-3}$ dynes/cm and $C'_p = 0.3$ psi/ft.

Assuming that all displaced oil will be produced, Equation (2.10) reduces to

$$RO = (1 - \frac{S_{orc}}{S_{orw}}) TO, \text{ stb} \quad (4.3)$$

4.3 and 4.4 Surfactant and Polymer Requirements

The previous development of the Predictive Model in Chapter 2 details the need for clay content and type (of secondary importance) to determine the sulfonate retention level which is fundamental to the design of the total surfactant injection system. Equally important to chemical costs are the polymer requirements which are based on viscosities and wettabilities. At present, all of these, except viscosity, are usually unavailable reservoir parameters. Therefore, to make an approximation of the chemical costs associated with a micellar-polymer flood, surfactant and polymer requirements are calculated as a function of floodable pore volume [Equation (2.12)] where we take again, $f_{bw} = f_{gc} = 0$; $B_{oi}/B_{of} = 1.0$; and $S'_o = S_{oi}$:

$$\$_C = b(FPV), \text{ dollars} \quad (4.4)$$

where b is a constant in dollars chemical cost per barrel of reservoir pore volume to be flooded. This approach assumes the same proportionate surfactant slug and mobility buffer sizes, as well as respective surfactant and polymer concentrations, for each reservoir. This assumes there is no process advantage design capability based upon individual reservoir characteristics. When the necessary parameters mentioned above, Table 3.4, are available, chemical requirements can be assessed.

4.5 Project Life and Production Schedule

The time value of money is not accounted for in the modified predictive model, PECØN, and thus a production schedule is not calculated. However, in order to estimate the operating expenses incurred during a micellar-polymer flood, it is necessary to estimate the tertiary project life. Equation (2.16) provides a means for calculating this quantity; the assumption is again made that $C'_p = 0.3$ psi/ft. The cumulative injection (Q_D) in pore volumes is an input parameter to be assigned at user discretion. As noted before, a reasonable value would be 1.50 of the total floodable pore volume. An upper and lower

limit can be anticipated for such a tertiary project. Therefore, where project life is less than 2 years or greater than 20 years, the quantity is set to the appropriate limit.

4.6 Field Development

No additional assumptions were necessary in the use of PECØN to estimate developed acres and the number of required patterns for the implementation of a micellar-polymer flood [Equations (2.19 and (2.20) respectively].

4.7 Price and Cost Data

Recoverable oil volumes, in conjunction with the prevailing sale price for crude, determine the revenue associated with the respective micellar-polymer flooding project. A sale price of \$27.00/stb for crude is used* (and the chemical costs are indexed to that value). The oil price as adjusted for gravity and sulfur can then be estimated using Equation (2.21), where $\$'_O = \$27.00/\text{stb}$. The potential revenue (REV) generation from the tertiary flood is then calculated:

$$\text{REV} = \$_O (RO), \text{ dollars} \quad (4.5)$$

where $\$_O$ is calculated from Equation (2.21).

As discussed in Chapter 2, the expenses associated with a micellar-polymer flood project fall into three main categories:

- 1) development costs
- 2) operating costs
- 3) chemical costs.

*September 1979 Value Mid-Continent

The modified predictive model PECØN follows closely the guidelines outlined previously in Section 2.4 for estimating these costs. The only notable exception is the calculation of chemical costs. The constant "b" in Equation (4.4) is provided by the Bell Creek Pilot¹⁸. The micellar system utilized in this pilot equates to a cost of \$.88 per reservoir barrel of floodable pore volume, and a slug size of 3.8% of the floodable pore volume. The mobility buffer expenses for Bell Creek equate approximately to \$.45 per reservoir barrel of floodable pore volume assuming a fluid viscosity of 30 cp and a buffer size of 100% of the floodable pore volume. Hence, a combined micellar and mobility buffer cost yields a value for "b" of \$1.33 per stb of floodable pore volume, which reduces Equation (4.4) to

$$\$_C = 1.33(\text{FPV}), \text{ dollars} \quad (4.6)$$

4.8 Economic Calculations

As indicated above, the time value of money is not considered in the PECØN program calculations. Therefore, a straightforward ratio of revenue to expenses is used as the valuation parameter of potential project economics. Based upon the assumptions detailed above, the candidate reservoirs are then ordered, one relative to another, by means of the magnitude of this revenue to expense ratio.

Chapter 5 - Ordering of Candidate Reservoirs for Further Data Acquisition

5.1 Mid-Continent Reservoirs

The PECØN program of Chapter 4 is used here to generate a grouping of 200 Mid-Continent reservoirs which have higher Revenue to Expense (R/E) ratios under the assumptions and default options detailed below than do the other reservoirs in the Mid-Continent "Clean 5" data bank of 1970 reservoirs. This list of 200 Mid-Continent reservoirs are designated for further data solicitation efforts.

5.2 Summary of Use of PECØN

To summarize, the calculation concepts governing the use of PECØN for the preliminary ordering of the candidate reservoir are as follows:

Target Oil	-Based upon waterflood volumetrics
Recoverable Oil	-Based upon Laboratory Ncap operating in waterflood swept regions; heterogeneity not considered
Micellar Requirement	-Based upon pore volume (same % all reservoirs)
Polymer Requirement	-Based upon pore volume (same % all reservoirs)
Field Development	-Based upon transformation of current well pattern into full tertiary symmetric pattern array
Project Life	-Based upon pattern size, type, well injectivities, k and D
Costs	-Wells & Plant: location, depth, field, age, chemicals, supplies
Crude Price	-API, sulfur content
Economics	-Revenue/Expense (R/E) (no time value of money)

5.2 PECØN Input Assumptions for Mid-Continent Reservoirs

In general, these rules applied to the input variables:

Numerical Values

Core Variables: location, depth, permeability,
cumulative production

Default Variables: assume mean value of distribution,
if not available; Table 3.2

Specifically, for the Mid-Continent, the following restrictions have been placed on each of the reservoirs that appear in the summaries:

- 1) The reservoir was not considered if the location, depth, permeability, and cumulative oil production were not all known.
- 2) If S_{orw} was not available on a reservoir, it was defaulted to 0.30.
- 3) If any of the following variables were not available for a reservoir, a default value was set.

Discovery date = 1962
Well spacing = 22.0 Acres/Well
Reservoir thickness = 18.0 ft.
Connate Water Saturation = 0.30
Porosity = 0.215
Oil Viscosity = 3.8 cp
API Gravity = 36.5°.

- 4) Currently the program internally assumes $B_{of} = B_{oi}$; that is no shrinkage, regardless of what was input for B_{of} . In addition, B_{oi} is assumed to be 1.2 if unavailable.
- 5) The calculated project life cannot be less than 2 years nor more than 20 years. Otherwise, it is set to the appropriate limit.
- 6) The calculated N_{cap} number cannot exceed the limits of the Gupta-Trushenski experimental curve, Figure 2.4. Otherwise, it is set to the appropriate limit.
- 7) The price of oil has been assumed to be \$27/bbl, the September 1979 value for Market Clearing Price. There is a \$0.02/Bbl penalty for each API degree below 40; there is a 10 percent penalty to revenue for oil with sulfur present, Equation 2.

- 8) Chemical cost was assumed to be \$1.33/Bbl of floodable pore volume. This is the September 1979 value based upon the Bell Creek Field Demonstration Project, Ref. 18.
- 9) Drilling, production and injection equipment, workover and operating costs reflect 1980 prices, Ref. 109, as inflated.
- 10) Workover costs were based on reservoir age

<u>Years</u>	<u>Percent</u>
25+	100
15-25	50
10-15	25
10-	0

5.4 Mid-Continent Reservoirs Designated for Further Data Acquisition

The Mid-Continent Data Bank, "Clean 5" was passed through the PECØN program with the restrictions and assumptions of Section 5.3. This generates a list of reservoirs ordered by R/E ratios. This list of 200 reservoirs are the ones which are expected to be more amenable to micellar-polymer flooding technology than the other candidate reservoirs in the "Clean 5" Mid-Continent Data Bank Reservoir file.

These 200 suitable Mid-Continent reservoirs are listed alphabetically by state in Table 5.1. During the next contract year, the owner/operators of the first 100 reservoirs will be contacted in order to complete the data file required for the Predictive Model, Table 3.4. Also during the next contract year the file will be edited to eliminate duplicate entries, if any, and to further identify the specific field or area designated.

The point to be made with respect to Table 5.1 is that these Mid-Continent reservoirs are expected to be more suitable for micellar flooding than the reservoirs not in Table 5.1. As more data is gathered for each reservoir, some of the first hundred reservoirs will have R/E ratios which will drop them below those of the reservoirs not currently in the first 100 group in Table 5.1. Specifically, the acquisition of TDS and/or salinity values will force some of the candidate reservoirs out of the group based upon technical feasibility, TDS 80,000 ppm. Then reservoirs

in Table 5.1 from the second 100 file will be moved up into the first 100 grouping of reservoirs deserving further data acquisition efforts.

However, it is not expected that there will be a significant changing of reservoirs in the first 100 candidate list. At the end of the next contract year, it is expected that the project will produce an ordered list of 100 Mid-Continent reservoirs most amenable to the micellar-polymer technology.

5.5 Mid-Continent Summary

The PECØN program has been used to determine the 200 reservoir candidates most amenable to micellar-polymer flooding. The owner/operators of the first 100 are being contacted to obtain the missing data. If the owner/operators are unresponsive, the reservoir will be dropped and the next best reservoir in the second 100 reservoirs will be included in the contact list. Should new data reduce the ranking of the reservoir to below the 200th best candidate, it will be dropped; otherwise it will be reinserted in the list where it properly belongs based upon the R/E ratio.

In this manner a list of the 100 Mid-Continent reservoirs most amenable to micellar flooding will be generated, where the data required for the Predictive Model (PM) will be complete. The reservoirs on this final list can then be ranked in a number of ways using the final version of the Predictive Model, which in turn will be validated by the numerical simulation, Chapter 6.

TABLE 5.1

Two Hundred Mid-Continent Reservoirs Designated for Further Verification*

<u>Field</u>	<u>First Hundred</u> <u>Producing Formation</u>	<u>Depth</u>
ARKANSAS		
Buckner	Travis Peak	4640
Fouke	Paluxy	3400
Stephens	Hogg	3190
Wesson	Hogg	2590
LOUISIANA		
Bayou Segnette	Celotex	9000
Dog Lake	CC Reservoir "J"	4700
Fausse Point	5000 Reservoir "A"	4600
Garden Island Bay	177 Reservoir "A"	8700
Leeville	7900 Reservoir "A-B"	7652
Sweet Lake	Miocene	4457
MISSISSIPPI		
Clear Springs	4600 Wilcox	4650
Heidelberg, East	Christmas	4630
Kingston	Wilcox-Harmon	6587
Lake Mary, North	Tew Lake	6730
Quitman Bayou	4600 Wilcox	3918
MONTANA		
Fred-George Creek	Sunburst	2600
OKLAHOMA		
Cache Creek	Pontotoc	1302
Healdton	Hoxbar	1050
Maud	Misener	2950
TEXAS		
Aviators	Jackson	1525
Bay City	7500 Frio	7406
Beaumont	Heterostegina	5640
Berclair	2200 Frio	2223
Big Hill	Marginulina	8398
Bloomington	4600 Greta	4608
Bonnie View	Greta	4575
Brayton	Perry-Frio	7196
Cayuga	Woodbine	4030
Chapel Hill	Paluxy	5680
Clear Lake	Frio	6184
Cleveland, North	Yegua	5785
Coke	Paluxy	6310
Cold Springs	Cockfield	7960
Coletto Creek	Catahoula	2776

*Alphabetically by State and Reservoir Name

TABLE 5.1 (Cont'd)
First Hundred

<u>Field</u>	<u>Producing Formation</u>	<u>Depth</u>
TEXAS (Cont'd)		
Cottonwood	Frio	8205
Dayton, North	Jackson	4993
Dirks	Pettus	3925
Eastland County	Pennsylvanian	2850
Fargo	3900 Canyon	3900
Fig Ridge	Sea Breeze	8468
Ganado, West	Marginulina	4730
Gatewood	Strawn	1585
Greta	Frio	4400
Greta	Frio	4400
Guerra	Jackson	2245
Hankamer, South	Frio	6482
Hastings, West	Frio	6200
High Island	Miocene	9000
Hobson	Reklaw	4002
Hoffman	Loma Novia	2733
Houston, South	Yegua	4800
Hull	Frio	2740
Humble	Miocene	3400
Jacksonville, North	Woodbine	4376
Jackson-Doty	Yegua	6444
Johns	Hockley	3954
Karon	Wilcox	7270
Kelsey, South	Zone 19-B Frio	5980
Lake Pasture	H-440 Greta	4450
Lake Pasture	FS-527 Frio	5309
Lake Pasture	FS-523 Frio	5269
London Gin	Doughter	4496
Long Lake	Woodbine	5121
Manvel	Oligocene	5000
Mary Ellen Oconnor	FQ-40 Frio	5856
Mirando City	Jackson	1540
Neches	Woodbine	4704
Pettus	Pettus	3900
Pierce Junction	Frio	5000
Port Neches, West	Miocene	6000
Powell	Woodbine	3000
Prado	Loma Novia 3	3705
Rankin	Cockfield	8252
Seeligson	Frio	6583
Seventy-Six, South	Jackson	1710
Sour Lake	Miocene	4400
Spindletop	Frio	5900
Stewart	Frio	5000
Sugarland	Marginulina	3400
Sulphur Bluff	Paluxy	4450
Taft	Catahoula	4000
Taft, East	Frio	5604
Thompson	3600 Frio	3600
Thompson, South	Miocene	5400

TABLE 5.1 (Cont'd)
First Hundred

<u>Field</u>	<u>Producing Formation</u>	<u>Depth</u>
TEXAS (Cont'd)		
Thompson, South	Miocene	4400
Thompson, South	Upper Frio	5062
Tom O'Connor	5500 Frio	5500
Webb	Oil Creek	7156
Webster	Marginulina	5750
Weigang	Carrizo	3921
West Columbia	Miocene	4000
West Columbia New	Frio	5400
West Ranch	Greta	5100
Winnie, North	Sullivan	8445
Woodsboro	Frio	5900
Yougeen	Lower Vicksburg	3831
WYOMING		
Bonanza	Tensleep	2900
Grass Creek	Madison	4380
Lance Creek	Leo	5300
Tisdale, East	Tensleep	2244
<u>Second Hundred</u>		
ARKANSAS		
Smackover	Travis Peak	3020
COLORADO		
Adena	Dakota "J"	5650
Plum Bush Creek	Dakota "J"	4984
LOUISIANA		
Avondale	Upper Miocene	5430
Black Bayou	T2 Reservoir "B"	7100
Bonnet Carre	Operculinaides	10400
Delhi	Holt Bryant	3135
Egan	Egan-Hayes	10600
Iberia	Garlino "A" Reservoir "B-C"	6100
Little Creek	Cruse	2360
Port Barre	Futrel Reservoir "A"	5886
Saturday Island	Miocene	10350
Southeast Pass	"L" Reservoir "C"	8040
MISSISSIPPI		
Junction City	Eutaw	3570
Kingston	Wilcox-Harmon	6580
LaGrange	4600 Wilcox	4250
Natchez, North	Wilcox	4301
Tinsley	Selma-Eutaw	4800
Tinsley	Perry-Woodruff	4366

TABLE 5.1 (Cont'd)
Second Hundred

<u>Field</u>	<u>Producing Formation</u>	<u>Depth</u>
MONTANA		
Sumatra	Tyler	4500
NEBRASKA		
Huntsman	Graneros "J" & "D"	4742
Sleepy Hollow	Pennsylvanian "B"	3418
OKLAHOMA		
Bowlegs	2nd Wilcox	4280
TEXAS		
Bay City, North	Frio-Stray	7874
Baylor County R	Gunsight	1400
Big Caesar, South	Pfleuger	7562
Buffalo	Woodbine	5720
Burnell	Reklaw	6778
Caplen	Miocene	7516
Clodine	Yegua	7700
Coletto Creek	Catahoula	2840
Conroe	1st Cockfield	4930
Cordele	Catahoula	2755
Cottonwood Creek, South	Wilcox	7647
Credo	Wolfcamp	7334
Credo	Wolfcamp Lower "B"	7430
Danbury Dome	Frio	5655
Durkee	Yegua	7052
Dyersdale	Miocene	4915
Escobas	Jackson	1500
Fairbanks	Yegua	6785
Fuller	Strawn	5147
Ganado	Frio	5808
Ganado Deep	Hultquist	6483
Gillock	Frio	9365
Gillock, South	Frio	9082
Gist	Hackberry	7200
Government Wells, North	Jackson	2300
Ham Gossett, East	Woodbine	3253
Handy	Strawn	1665
Handy, Southeast	Strawn	3652
Hankamer	Frio	4207
Heyser	5400 Frio	5400
Hitchcock	Frio	6555
Houston, South	Oligocene	4616
Jay Simmons	C-1 Frio	6110
Katy	Yegua	6596
Kelsey	M-2 Frio	4730
Kelsey Deep	Zone 20-A Frio	6114
Kelsey Deep	Zone 19-K Frio	6079
La Belle	Frio	8217

TABLE 5.1 (Cont'd)
Second Hundred

<u>Field</u>	<u>Producing Formation</u>	<u>Depth</u>
TEXAS (Cont'd)		
LochrIDGE	Frio	7000
Lolita Deep	4-Way Zone Frio	6330
Lopez	Mirando	2300
Magnet Withers	5500 Frio	5550
Manvel	Frio	4200
Markham, North -		
Bay City, North	Cayce	7800
Mary Ellen Oconnor	TS-96 Frio	5428
Mayo	Rodesney	5407
Muldoon, Southwest	Arnim	2317
Needville	Frio	6690
Ohern	Yegua	2800
Oilton	Jackson	2025
Palm Blanno	Vicksburg	4612
Petronilla	Frio	7308
Placedo, East	Frio	4750
Plymouth	Greta	4660
Quien Sabe	Mirando	2332
Quitman	Paluxy	6200
Raccoon Bend	Upper Cockfield	3970
Raccoon Bend	Lower Cockfield	4177
Rose City, South	Frio	8102
Sandusky	Oil Creek	7187
Sarita	5-KLM	4664
Saxet	McAllen	6919
Seeligson	Zone 19-D-1 Frio	6129
Seeligson	Zone 10 Frio	4592
Swan Lake	Frio	6000
Thompson	Frio	5300
Tomball	Cockfield	5500
Tomball	Yegua	5500
Wst	Strawn	4260
West Ranch	41-A Frio	5753
West Ranch	98-A Frio	6145
West Ranch	Yenado Zone	5800
Withers, North	Frio	5295
WYOMING		
Dead Horse Creek	Parkman	6924
Happy Springs	Dakota	4600
Semlek	Minnelusa "B"	7198
Wertz	Tensleep	5800

Chapter 6 - Validation of Predictive Model by Numerical Simulation

In 1979, a number of 1-D and 2-D simulations with Intercomp's Chemical Flood model were run in a simple linear "core" geometry. The purpose was to understand the basic rudiments of micellar-polymer process sensitivity and the effects of layering on oil recovery. The results of the 1-D and 2-D simulations are detailed in Appendices V and VI, respectively. In 1-D, increased surfactant retention was found to have the most adverse effect on oil recovery; the 2-D results suggested that the optimal surfactant slug size may decrease with increasing vertical layering. However, the results of the first year work cannot be generalized because the input data (from the micellar-polymer process for the Bell Creek¹⁸ project) used a low salinity environment, with resultant simplified constant phase equilibria and two-phase relative permeability. Furthermore, the Bell Creek data does not allow for trapping of the surfactant-rich micellar phase, which as simulation work on the El Dorado micellar-polymer project has shown, may be a significant component of surfactant retention when large salinity gradients are present. In addition, further 2-D and 3-D simulations are required to understand the apparently significant relationship between heterogeneity and micellar-polymer process performance in more realistic geometries. The 2-D and 3-D results can then be incorporated into the simulator-based Predictive Model (PM).

6.1 Proposed Work

The proposed work consists of three phases: 1-D, 2-D, and 3-D simulations. 1-D simulations will be calculated to assess micellar-polymer process sensitivity to more realistic phase behavior and three-phase relative permeability. Oil-brine-surfactant phase diagrams and three-phase relative permeabilities will be generated by the methods presented in Ref. 119.

Once the 1-D process sensitivity is completed, 2-D simulations will be initiated in order to verify and possibly improve the correlations using a predictive model: E_D as a function of V_{DP} , surfactant retention/slug size ratio, etc. There will likely be some carryover between the 1-D and 2-D runs. For example, the E_D function for high water-content micellar systems may differ from that for "soluble oil" type systems. Finally, 3-D simulations will be used to verify the oil recovery calculated on the Predictive Model. In 3-D, all of the significant 1-D and 2-D variables will be simulated in combination with field parameters such as pattern type, areal heterogeneity and the like.

The proposed simulations are outlined below:

1. 1-D Simulations

Objective - Assess micellar-polymer process sensitivity to phase behavior and slug design.

- A. Sensitivity to phase package parameters;
- B. Sensitivity to process parameters (surfactant concentration, polymer concentration in micellar slug, slug oil content, salinity gradient);
- C. Verification of design procedure in 1-D.

2. 2-D Simulations

Objective - Generate predictive model.

- A. Sensitivity to parameters not present in 1-D (V_{DP} , L/h , transverse dispersion, k_v/k , S_{orw} distribution, number and order of layers);
- B. Sensitivity to parameters found important in 1-D (slug size, mobility buffer size, salinity, surfactant retention, S_{orw} are anticipated);
- C. Verification of design procedure in 2-D.

3. 3-D Simulations

Objective - Estimate project life with production function validated for Predictive Model.

- A. Sensitivity to parameters not present in 1-D or 2-D (areal heterogeneity, pattern type, capture, N_{cap});
- B. Sensitivity to parameters important in 2-D;
- C. Sensitivity to parameters important to 1-D, 2-D, 3-D (N_{cap} , crossflow, S_{or} , V_{DP} , etc.).

Chapter 7 - Work Forecast

The iterative Technical Approach for this study has the following component tasks:

1. Assessment of Available Test Data
2. Development of a Full Predictive Model for Economic Evaluation of a Reservoir
3. Reservoir Data Bank for Micellar Recovery Evaluation
4. Program for Preliminary Economic Evaluation of Reservoirs (PECØN)
5. Ordering of Candidate Reservoirs
6. Validation of Predictive Model by Numerical Simulation.

The first contract year involved the first iteration of proceeding down the Technical Approach component tasks 1 through 5. The work done under each of these tasks for the first iteration was detailed in Chapters 2 to 5 of this First Annual Report. (Component Tasks 1 and 2 were both discussed in Chapter 2).

Thus, the first iterative ordering of candidate reservoirs, Chapter 5, was only for the purpose of identifying those 200 candidate reservoirs in the Mid-Continent (100 in California) which qualify under the terms of the Work Statement and thus require a detailed reservoir specific data acquisition effort in order to provide the technical input conditions for the second ranking iteration during the second contract year. With all of the reservoir specific data in place for the second evaluation iteration, the full Predictive Model of Chapter 2 will be used to provide the prioritized list of 100 Mid-Continent reservoirs (50, California) based upon their potential contribution to the DOE incremental production goals.

Statement of Work Task II, "Assessment of Available Test Data", has been completed and is represented by Appendix I to this First Annual Report.

During the second contract year, the Chemical Flood Simulation work of Chapter 6 will be used for the purpose of checking the validity of the reservoir parameter and recovery predictions given by the Predictive Model, Chapter 2, Equations (2.1) to (2.21). This validation

will be done for three reservoir categories: (i) actual reservoirs in Table 5.1; (ii) the reservoir with the mean characteristics of the reservoirs in Table 5.1; e.g., see Table 3.2; and (iii) reservoirs with characteristics which are one standard deviation from that of the mean reservoir.

Based upon this simulation validation work, the Predictive Model will be adjusted accordingly so that it correctly represents the critical micellar flooding phenomena; and thus produces accurate predictions of recovery under micellar flooding with an accurate value for the revenue and expenses for the respective micellar flood project.

Additionally, by working with the mean and the one-standard deviation reservoirs, the Chemical Flood Simulator will build up a set of Sensitivity or Influence Coefficients for the critical micellar flooding parameters, which will be helpful with Project Work Task III, "Design Recommendations". Task III will be addressed in the third contract year. The design recommendations will follow, in a technical sense, directly from the "Predictive Model for Economic Evaluation of Reservoirs", Chapter 2, as modified by the simulation validation work.

Figure 7.1 displays the Project Time Line. The intent of the DOE and the contractors was to do the Mid-Continent "survey" first; and then, after the structure of the tasks, procedures and algorithms were in place, to follow with the California work. Thus, the accomplishment of the respective California work tasks always follow by several months the completion of the Mid-Continent work tasks.

SELECTION OF RESERVOIRS AMENABLE TO MICELLAR FLOODING *

Assess Data

Develop
Predictive Model

Develop
Data Bank

Preliminary
Econ. Program

Prioritized
List

Validation By
Simulation

Design
Recommendation
for DOE, Owner / Operator

* MID-CONTINENT.

CALIFORNIA FOLLOWS BY 1 QUARTER.

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Selection of Reservoirs Amenable to Micellar Flooding

**First Annual Report
(October 1978 — December 1979)**

Appendix I

Identification of Micellar-Polymer Candidate Reservoirs

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**Work Performed Under DOE Contract Nos.
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**Gary Energy and Intercomp
Contractors**

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Prologue

This report is intended to partially satisfy the objectives of Federal Contracts DE-AC19-78BC-00048, Selection of Mid-Continent Reservoirs Amenable to Micellar Flooding, and DE-AC19-78BC-00051, Selection of California Reservoirs Amenable to Micellar Flooding. As discussed below, the procedure followed has been:

- I. Identify critical reservoir and micellar quantities (CRMQ's).
- II. Assess current and on-going field tests.
- III. Develop a screening procedure to identify micellar flooding (MCM/EOR) candidates.

The remainder of this report divides into sections as listed above, wherein more description of each is provided. The underlying feature of all the work is that it is based entirely on public literature sources. That is, no simulation or laboratory work has been done, nor has there been recourse to proprietary sources. In addition, the results presented here are based predominantly on field tests of the MCM/EOR process, although lab-derived data are frequently used when important field data are absent. The work, therefore, serves as a technical review of the MCM/EOR process as well as satisfying the objectives of the above-mentioned contracts.

Referring to the original Request for Proposal (RFP No. ET-78-R-03-2032), this work specifically addresses section 2.1 (*Selection of Target Reservoirs*) through the development of a screening procedure in Part III; section 2.2 (*Assessment of Available Test Data*) in Part II; and section 2.3 (*Analysis of Test Data for Design Recommendations*) in Parts I and II.

Part I

Identification of Critical Reservoir and Micellar Quantities

I.1 Introduction

This section identifies and supports the twenty or so quantities most important to the commercial success of the MCM/EOR process. We use the term "quantities" throughout rather than the less general "parameters" as several important determinating factors to the success of the MCM/EOR process are more properly classified as functional relationships (such as low IFT relative permeabilities) rather than single parameters. The quantities so derived are the "Critical Reservoir and Micellar" Quantities (CRMQ).

The procedure used to accomplish this goal is nearly as important as the CRMQ's themselves because the worth of the final list will be greatest if the selection procedure is rigorous and technically sound. Also, such a procedure would be useful in determining the value and frequency distribution of test data parameters discussed in Part II, and would make the work have greater intrinsic value. Correspondingly, we used the following detailed procedure to attain the above objective.

I.2 Stepwise Procedure for Identification

Step 1. Amass and review an extensive collection of literature references on MCM/EOR field tests. Such a collection was needed for at least two reasons:

- (a) It was the primary source for ranking and selecting the CRMQ's (see steps 2-4 below).
- (b) It enables us to technically evaluate the MCM/EOR field tests in Part II.

We concentrated on pilot tests and commercial field floods, but included whatever supporting references are necessary to adequately characterize the test data and identify the CRMQ's. The references used to execute this step are listed in the References of this report.

Step 2. Prepare an exhaustive list of quantities that affect the MCM/EOR process however remotely.

Table I is the product of this step, a list of 106 separate entities identified from this brainstorming approach. Even though it proved fairly difficult to reduce many variables to their smallest constituent parts, the list is surprisingly unredundant, indicating the well-acknowledged complexity of the MCM/EOR process. Table I also divides the quantities into parameter groups (rock property, etc.), a non-trivial task itself, and one that introduces a certain arbitrariness into the list as a few seemingly related quantities are in different categories (permeability and permeability distribution, for example). Also on table I, we've indicated the relative importance of each parameter to the four criteria of a successful MCM/EOR flood (see Part III) where L means large, S small, SL means that the effect varies from small to large depending on the exact circumstances, and no entry means no effect or effect unknown. These indications are meant to apply to direct relations only; for example, many quantities indirectly affect the *in situ* capillary number (ionic environment, for example), but only those quantities which directly affect IFT, viscosity, or fluid velocity have an entry in the capillary number column. On the right of the table is a comments column which attempts to expand on the terse judgements of the preceding columns.

TABLE 1
Exhaustive List of Variables Affecting MCM/EOR Processes

	Mobilizing Trapped Oil			Sweep Efficiencies			Propagate Large Distances in Sufficient Quantity							Economic Criteria				Comment	How Eliminated
	Capillary No.	Solubilization	Swelling	Local	Vertical	Areal	Retention			Mixing				Target Oil	Chemical Cost	Drilling Cost	Project Life		
							Mechanical	Adsorption	Trapped Phase	Fingering	Dispersion	Viscous Crossflow	Gravity						
Rock Property																			
Cation Exchange Cap.								L										depends on clay type and composition, usually lab-derived	
Cation Exch. Consts																		depends on clay type and composition	unimportant
Clay Mineralogy								L										—	
Clay Composition								L										—	
Dispersivity Param. α_L				S						S	L	S	S					depends on tortuosity, particle size, etc.	unable to measure
Dispersivity Param. α_t				S	S					L	L							depends on tortuosity, particle size, etc.	unable to measure
Heterogeneity, local				L			L			S	L	S	S					incorporated in relative permeabilities	redundant
Mineral solubility							SL											influences electrolyte environment	BAT
Permeability							L						L				L	depends on rock type, clays, compaction, etc.	
Porosity								S						L	L			—	
Rock mineralogy								L										influences electrolyte environment	
Rock composition								L										influences electrolyte environment	
Fluid Property																			
Resident brine visc.				S	S	S											S		BAT
Resident brine density													S					not considered important	unimportant
Resident brine salinity	SL	SL	SL	S	S	S		L	S						S			—	
Resident brine hardness	L	L	L					L	L						L			influences design criteria, influences electrolyte env.	
Crude oil viscosity				L	L	L				L		L	L		SL			a function of depth and temp., influences design	
Crude oil composition	L	L	L						L						S			design tailored to particular comp.	BAT
Crude oil density													L					gravity not considered important in MCM/EOR process	redundant
Preslug viscosity				SL	SL	SL									S		S	important only if polymer added	BAT
Preslug density													S					not considered important	unimportant
Preslug salinity	L	L	L					L	L						S			design variable, influences electrolyte environment	BAT
Preslug hardness	L	L	L					L	L						L			design variable, influences electrolyte environment	BAT

TABLE 1 (cont.)

	Mobilizing Trapped Oil			Sweep Efficiencies			Propagate Large Distances in Sufficient Quantity							Economic Criteria				Comment	How Eliminated
	Capillary No.	Solubilization	Swelling	Local	Vertical	Areal	Retention			Mixing				Target Oil	Chemical Cost	Drilling Cost	Project Life		
							Mechanical	Adsorption	Trapped Phase	Fingering	Dispersion	Viscous Crossflow	Gravity						
Fluid Property (cont.)																			
Preslug sac. agent typ.								L							SL			design variable, influences electrolyte environment	BAT
Preslug sac. agent comp.								L							SL			design variable, influences electrolyte environment	BAT
Slug viscosity	SL			L	L	L	S		S	L		L	L		SL		L	design variable, affected by slug comp.	BAT
Slug density													L					gravity not considered important in MCM/EOR process	unimportant
Slug salinity	L	L	L					L	L						S			design variable, influences electrolyte environment	BAT
Slug hardness	L	L	L					L	L						S			design variable, influences electrolyte environment	BAT
Slug surf. type	L	L	L					L	L						L			choice tailored to usage	BAT
Slug surf. conc.	L	L	L					L	L						S			design variable	BAT
Slug co-surf. type	L	L	L	SL	SL	SL		L	L						L			design variable	BAT
Slug co-surf. conc.	L	L	L	SL	SL	SL		L	L						S			design variable	BAT
Slug polymer type		S	S	L	L	L			S			SL	SL	S	L			design variable	BAT
Slug polymer conc.	L	S	S	L	L	L	S		S			SL	SL	S	S		L	design variable	BAT
Slug perm. red.	SL			L	L	L	S					S		S	S		S	depends on polymer, rock type & polymer conc.	BAT
Slug non-Newt. behavior				S	SL	S						SL						depends on polymer, rock type & polymer conc.	BAT
Slug phase behavior	L	L	L	L					L	L	SL							depends on surf. conc., electrolyte, etc.	BAT
Slug excluded pore vol.																			effect uncertain
Mobility Buf. visc.				L	L	L				L		L	L		L		L	design variable, depends on polymer conc.	BAT
M B perm. red.				SL	SL	SL				L		L	L		S		L	depends on polymer type, comp., etc.	BAT
M B non-Newt. behavior				S	SL	S				S		S						depends on polymer type, comp., etc.	BAT
M B density													L					gravity not considered important in MCM/EOR process	unimportant
M B pol. type															L			design variable	BAT
M B pol. conc.				L	L	L				L		L	L		S		L	affects sweep efficiencies	BAT
M B salinity	L	L	L	S	S	S		L										affects surf. environment & M B visc., design	BAT
M B excluded pore vol.																			effect uncertain
M B hardness	L	L	L	S	S	S		L	L						L		S	affects surf. environment & M B visc., design	BAT

TABLE 1 (cont.)

	Mobilizing Trapped Oil			Sweep Efficiencies			Propagate Large Distances in Sufficient Quantity							Economic Criteria				Comment	How Eliminated	
	Capillary No.	Solubilization	Swelling	Local	Vertical	Areal	Retention			Mixing				Target Oil	Chemical Cost	Drilling Cost	Project Life			
							Mechanical	Adsorption	Trapped Phase	Fingering	Dispersion	Viscous Crossflow	Gravity							Imbibition
<u>Fluid Property (cont.)</u>																				
Chase water visc.				S	S	S					L		SL					S	usually fixed	unimportant
C W density														S					—	unimportant
C W salinity	S	S	S																—	BAT
C W hardness	S	S	S																—	BAT
Gas viscosity																			usually not present	unimportant
Gas density																			usually not present	unimportant
Diffusion coeffs.																			unimportant at high rates	effect uncertain
IFT's, all phases	L			L															incorporate into capillary number	
<u>Fluid/Rock Property</u>																				
Cap. desat. curves				L															relates N_{cap} to S_{orc}	
Cap. pressure																			may control flow in oil bank	effect unknown
Relative perms	S			L	L	S					L	L		SL		S		SL	used to design M B	
Resid. oil chem., S_{orc}			S	L					L		S								laboratory derived quantity or correlation	redundant
S_{orc} distribution			S	L	L				L										poorly known	inability to measure
Wettability				S				S	S							S			affects k_r 's, P_c 's, S_{orc} , etc.	
Polymer shear deg.			L	L	L														function of rock, injection rates, etc.	BAT
<u>Reservoir Condition and History</u>																				
Pressure																			MCM/EOR process generally insensitive to pressure	unimportant
Pressure distribution						L													drift velocity important	BAT
Temperature distrib.	SL	SL	SL													S			affects stability of M B, efficiency of surfactant	

TABLE 1 (cont.)

	Mobilizing Trapped Oil			Sweep Efficiencies			Propagate Large Distances in Sufficient Quantity							Economic Criteria				Comment	How Eliminated	
	Capillary No.	Solubilization	Swelling	Local	Vertical	Areal	Retention			Mixing				Target Oil	Chemical Cost	Drilling Cost	Project Life			
							Mechanical	Adsorption	Trapped Phase	Fingering	Dispersion	Viscous Crossflow	Gravity							Imbibition
<u>Reservoir Condition and History (cont.)</u>																				
Depth	L												L	L		S	L	L	affects injectivities	
Thickness																				unimportant
Net to gross pay ratio																				effect unknown
Pattern type	S					S													affects velocity distribution, sweep efficiency	BAT
Well spacing	L										L	L	L	L			L	L	affects fluid velocity	BAT
Confinement, areal						L										L			problems exacerbated by isolated patterns	redundant
Confinement, vertical					L						L					L				
Communication					L	L									L					
Fracture limit	S																	S	determines injection rate	unimportant
Fractures, induced					S	S												L	involves trade-off between sweep & project life	
Fractures, natural					L	L														
Faults																				effect unknown
Perm., vertical distr.					L						L	L		L		S			affects sweep efficiency	
Perm., areal dist.						L														
Perm., anisotropy						L														redundant
Vertical permeability					L					S	S	L	L	L					affects flow from adjacent layers	unable to measure
Porosity, dist.					S															unimportant
Original gas																			deduce existence of gas cap	unimportant
Remaining gas															L				deduce existence of gas cap	
Cumulative gas															L				deduce existence of gas cap	
Original oil in place															L				used in target oil calculation	
Original oil sat.															L				used in target oil calculation	
Remaining oil in place															L				used in target oil calculation	
Cumulative oil prod.															L				used in target oil calculation	

TABLE 1 (cont.)

	Mobilizing Trapped Oil			Sweep Efficiencies			Propagate Large Distances in Sufficient Quantity								Economic Criteria				Comment	How Eliminated	
	Capillary No.	Solubilization	Swelling	Local	Vertical	Areal	Retention			Mixing					Target Oil	Chemical Cost	Drilling Cost	Project Life			
							Mechanical	Adsorption	Trapped Phase	Fingering	Dispersion	Viscous Crossflow	Gravity	Imbibition							
<u>Reservoir Condition and History (cont.)</u>																					
Res. oil sat.															L					used in target oil calculation	
Res. oil sat. dist.																				potential problem if high K contains less oil	effect unknown
Waterflood sweep															L					used in target oil calculation	
Resat. by waterflood															L					important if reservoir pressure is below original BP	effect unknown
Distribution, CEC																					
Distribution, electrolyte																					
Distribution, minerals																					
<u>Operating Variable</u>																					
Injectivities	L																	L		a function of viscosities, k, etc.	redundant
Productivities	L																	L		a function of viscosities, k, etc.	redundant
Preflush size								S										L			BAT
Slug size					L	L		S								S					BAT
M B size					L	L		S								S		L			BAT
M B grading					L	L		S								S		S			BAT
Chase water size					S	S															

Step 3. Eliminate quantities from the exhaustive list on the basis of

(a) Redundancy. A quantity is redundant if it depends directly on one or more of the other quantities on the list. When redundancy exists, we eliminated the quantity with the least direct influence on the MCM/EOR process.

(b) Inability to measure. There were several of these (vertical permeability, for example.)

(c) Unable to ascertain effect on MCM/EOR process. Despite over twenty years of MCM/EOR research, there are still many poorly understood or characterized aspects of the process. Since we are not engaging in original research, we eliminated such quantities rather than trying to ascertain their effect. This could, however, provide useful insight into where MCM/EOR research should go in the future.

(d) Best available technology (BAT). BAT is an assumption which says that the MCM/EOR process will be exposed to the best technology available to the entire industry. We used it here to eliminate those quantities whose affect on the MCM/EOR process can be minimized by good formulation and process design. The effect of BAT was to eliminate most laboratory and test tube quantities from table 1, as well as those whose effects can be estimated from correlations or laboratory data.

The last column in table 1 indicates how each quantity was eliminated; the remaining list has only 29 entries.

Step 4. Group, evaluate, discuss, and rank the remaining quantities. In this step, the 29 remaining quantities of table 1 are grouped into 14 groups, ranked and discussed in order of importance to the MCM/EOR process. This list comprises the Critical Reservoir and Micellar Quantities alluded to throughout this report.

I.3 The Critical Reservoir and Micellar Quantity List

1. *Residual oil saturation, distribution* - If we had to choose only one quantity upon which to select a MCM/EOR candidate it would be residual oil saturation. By "residual oil saturation" we mean that oil saturation that would be left behind by a piston-like water front in the regions contacted by the water. Residual oil saturation is the single most important determinant of MCM/EOR target oil and also greatly affects volumetric displacement efficiency. The best values of this parameter are derived from cores, laboratory displacements, or the Exxon tracer test. A "best case" parameter set would contain some indication of residual oil saturation distribution as the possibility exists that high permeability zones contain low residual oil saturations, with corresponding decrease in MCM/EOR target.

2. *Confinement, areal, vertical and communication* - These are easily the most difficult to quantitatively define for a given reservoir. We are including them as a concession to MCM/EOR projects which have failed because of lack of one or more of the above. Perhaps a reconstruction of the waterflood history would pin this down. Also, geological interpretation maps showing the nature and location of reservoir boundaries (faults, aquifers, gas caps, etc.) would aid in determining communication and confinement. In the design phase of a project, of course, these variables are determined through well, interference, and tracer tests.

3. *Fractures, natural and induced* - Likewise it has been that fractures have contributed to MCM/EOR failures. The consensus on this, however, is by no means universal, as several oil-recovering tests have deliberately fractured injectors to improve injectivity. Again, this quantity defies exact definition, but should be included in a "best case" set.

4. *Temperature, depth* - A very important quantity, as the MCM/EOR phase behavior and IFT, improve at elevated temperatures while the mobility agent tends to degrade. Depth is in some ways redundant with temperature, and is important in determining injectivities, as most

operations operate below the formation parting pressure. Injectivities, in turn, determine the project life and *in situ* capillary number. It seems the most complete information would be from a subsurface elevation map.

5. *Permeability, areal and vertical distribution, anisotropy* - Permeability is usually a primary quantity, commonly available. The areal and vertical distribution of permeability is usually less well known, but is equally as important as the permeability itself owing the small slug nature of the MCM/EOR process. The permeability distribution ought to be available on many surfactant flooding candidates because these reservoirs, being older, have been extensively cored at one time or another. It is, however, a non-trivial task to extract quantitative information from core data although it is worth the effort. The vertical distribution is nicely characterized by the Dykstra-Parsons coefficient which, if properly applied, conveys more information than the Lorenz coefficient. Areal distribution is not so neatly quantified, but we could infer it from permeability maps. Anisotropy must come from pulse tests or something similar.

6. *PVT analysis of reservoir crude* - The most important single quantity in this group is crude viscosity at reservoir temperature and pressure. It's entirely conceivable, however, that future technology will be able to relate surfactant design properties to crude oil composition; hence, a "best case" parameter set would contain the entire PVT analysis. At the least, reconstructing the waterflood history would require formation volume factors, solution gas-oil ratios, etc.

7. *Make-up water composition* - (mg/l of the following cations: calcium, magnesium, sodium, barium, iron, etc., and of the anions: chloride, sulfate, bicarbonate, etc., plus pH). The electrolyte composition of the mobility buffer is the most important salinity need of the MCM/EOR process; hence, we rank make-up water composition ahead of resident brine salinity. If full analysis is not available, mg/l total dissolved solids and mg/l total cations would be useful. The designation of make-up water as "fresh" is insufficient.

8. *Resident brine composition* - Historically one of the most important MCM/EOR determinants, we've downgraded resident brine composition to this position because of

- Increased understanding of the mechanisms operating in a preflood (such as cation exchange and sodium silicate adsorption) which will improve preflood designs.
- Increasingly tolerant surfactant formulations.
- Increased understanding of surfactant process mechanisms in general which will result in improved flooding strategies (the salinity gradient).
- A rapidly developing ability to simulate all of the above.

Again, if complete analysis is not available, information on total dissolved solids and total cations would be useful.

9. *Wettability (relative permeabilities)* - This quantity affects mobility requirements nearly as much as crude oil viscosity. We suggest using relative permeabilities as a measure of wettability only because it directly relates to fluid flow, although there is a need for a quick, reliable test for this quantity.

10. *Pattern type and spacing* - There is some impreciseness here as what we are after is the type and spacing of a potential MCM/EOR process, quantities which might not be the same as what currently exist. These quantities are, however, among the easiest to obtain and should be included for completeness.

11. *Clay mineralogy composition* (% illite, montmorillonite, kaolinite, etc.) - It's been long known that reservoir clays are probably the most important determinant to surfactant adsorption. Unfortunately, the direct link or exact physical mechanism for this dependence is not definitely known, although such a link might be established empirically. (See Part III).

Also, the cation exchange capacity (in meq/g rock), a quantity determined by the clay mineralogy and composition, is important in determining the surfactant's electrolyte environment. A "best case" parameter set would contain both the clay composition and C.E.C.

12. *Rock mineralogy composition* (% quartz, feldspar, calcite, etc.) - At least two recent studies have indicated that the rock matrix composition, particularly the level of carbonate minerals, affect the surfactant's electrolyte environment. Although this is not a conventionally-measured quantity, a "best case" parameter set would include this. Certainly the designation of a reservoir as sandstone or carbonate is needed.

13. *Volumetric waterflood quantities* - There are several variables which would help isolate the MCM/EOR target oil (Part III).

- Original oil, gas, and water in place is useful because reservoirs with large original bottom water or free gas zones are poor MCM/EOR candidates as these zones contain greatly reduced oil saturations.
- Cumulative oil, gas, and water produced are needed to calculate target oil and might also indicate continuity problems.
- Remaining oil, gas and water in-place are useful if some indication of distribution is also given. The most useful measures of this distribution are waterflood sweep efficiency and swept zone residual oil saturation. The latter quantity is so important that we have placed it at the top of the list in a category by itself.

Part II

Assessment of Available Test Data

II.1 Literature Search for Available Test Data

Appendix A gives the data summarized on the 44 proposed, completed and ongoing field tests based on the literature¹⁻⁸² collected in Part I. Appendix C contains the results of a similar effort¹ by Gulf Universities Research Consortium. In this section we briefly summarize important features of these tests to provide insight to the MCM/EOR process, and to the screening procedures of Part II. Appendix A is an expanded version of the data set given in a prior publication⁸³, along with additions and corrections suggested by L.W. Holm⁸⁴.

II.2 Observations and Statistics on Available Test Data

Table 2 lists maximums, minimums, means, and standard derivations for several process variables based on the data in Appendix A. The summaries were based on reservoir averages on those variables where multiple tests in the same reservoir, the Robinson sand for example, would distort the statistics. Those variables, mainly process variables, keyed more closely to individual tests are based on test averages.

Important observations center around the extreme variability of most variables as standard deviations are nearly always the same size as population means. Many variables exhibit 1-2 factors of ten increase between their extreme values (resident hardness, for example). Such extreme variability, taken as a whole, implies that the MCM/EOR process may be more widely applicable than is commonly supposed — note the extremes on oil viscosity, permeability, and residual oil saturation.

Another interesting observation in table 2 is that the standard deviation of the surfactant slug size-concentration product (the total surfactant injected on an active basis) is less than the standard deviation of either the slug size or surfactant concentration alone, expressed as a fraction of their respective mean values. This implies less variability in how much surfactant was used than in the manner in which it was injected, hence, the controversy between large diluted and small concentrated slugs.

Table 2 also shows the comparative information for Gary/DOE's Bell Creek Unit A flood. Bell Creek exhibits extreme parameter value for spacing, permeability, and resident salinity and near extreme parameter values for permeability variation, resident hardness, and slug size-concentration product.

Of the 44 tests included in the literature search, 20 have had oil recovery results published in sufficient detail to allow statistical interpretation. These are listed in table 3 along with several important variables whose effect on oil recovery is to be analyzed. The first column on table 3 refers to the numbered points on the following figures.

Of the 20 projects with reported recoveries, three (Borregos, Batesville, and the Benton Pilot) were viscously unstable;* Batesville, being the oldest reported MCM/EOR flood, was such a primitive effort that its results are omitted from table 3 and the following discussion. By "viscously unstable" we mean that the mobility of the mobility buffer was greater than that of the fluids it was to displace. The unstable floods are also not considered in the following, except where noted.

*there could be others we have not identified due to insufficient information

II.3 Performance Recovery as a Function of Critical Quantities

Frequently we attempt to fit the oil recovery data to various independent variables using least square line fitting techniques. Such techniques are available in standard statistics texts⁸⁵, and are meant to indicate general correlations rather than physical relationships. In this regard, we use a correlation coefficient r to indicate "goodness" of fit; $r = 1$ is perfect correlation; $r = 0$ is no correlation. Between these extremes the goodness of fit or confidence level is determined from standard tables⁸⁵ depending on sample size. The confidence level (CL) is the probability that a given set of data is better correlated by the least square straight line than by a normal distribution about a mean E_R . There are, therefore, two aspects to each correlation: the confidence level, and the slope or trend of the correlation. The latter item indicates the importance of the given variable to E_R , and, strictly speaking, has relevance only if r is large. (Of course, if an observable trend is absent the correlation coefficient is less valid also.)

TABLE 2
Summary of Several Important Variables in Proposed,
Completed and Ongoing MCM/EOR Field Tests

<u>Variables</u>	<u>No.</u> <u>Sample</u>	<u>Min.</u>	<u>Max.</u>	<u>S.D.</u>	<u>Mean</u>	<u>Bell</u> <u>Creek</u>
Depth, ft.	33	600	6256	1447	2850	4550
Temperature, °F	27	60	200	39	103	110
Acres/pattern*	37	0.625	40	7.0	5.0	40
Net pay, ft.*	32	3.8	76	19.2	24.6	8
Permeability, md	28	4	2500	496	319	1050
Perm. variation, V_{DP}	14	0.26	0.85	0.148	0.6	0.7
Clay fraction	14	0.0	0.21	0.042	0.093	0.18
C.E.C., meq/g	3	0.004	0.035	0.014	0.015	—
Oil viscosity, cp	28	0.36	40	8.83	7.03	4.6
Residual oil saturation, fr.	24	0.2	0.465	0.15	0.31	0.28
Resident salinity, mg/l	23	2690	160,000 TDS	43,400	36,600	2690
Resident hardness, mg/l	15	23	7260	2108	1936	27
Slug size, fr.*	35	0.02	1.14	0.258	0.173	0.035
Surfactant conc., fr.*	25	0.00025	0.13	0.193	0.054	0.081
Slug size x concentration*	24	0.000114	0.0108	0.0034	0.0059	0.0028

*Average for test

TABLE 3

Data Summary of Field Tests with Reported Oil Recovery

Point #	Test	V_{ps}	C_s	V_{MB}	C_p , ppm	C_{rs} , mg/l	A, acres	k, md	Depth	N_{cap}	E_R
1	Benton Pilot	1.11	0.013	3.30	275 ⁴	41,000	1	90	2120	—	0.29
2	Big Muddy Pilot	0.25	0.025	0.30	200	3050	1.25	52	3050	$(4.3 \times 10^{-4})^1$	0.35
3	Bingham 533	0.064	0.13	1.4	1700	2800	0.75	82	1860	1.9×10^{-3}	0.57
4	Bingham Expansion	0.05	0.12	1.2	1500	2800	2.9	82	1866	8.4×10^{-4}	0.43
5	Borregos	0.47	0.023	0.51	0 ⁴	19,600	1.25	434	4998	1.9×10^{-2}	0.20
6	118 K	0.085	0.09	0.87	—	—	2.4	90	1500	8.3×10^{-4}	0.48 ²
7	Delaware-Childers	0.085	0.054	0.40	1350	5200	2.5	100	620	3.7×10^{-4}	0.0 ³
8	Henry W	0.09	0.10	1.91	1200 ⁵	10,000	0.75	200	1000	2.4×10^{-3}	0.63
9	Henry E (I)	0.40	—	0.44	—	10,000	0.75	200	1000	2.4×10^{-3}	0.27
10	Henry E (II)	0.20	—	0.83	—	10,000	1.5	200	1000	1.6×10^{-3}	0.33
11	Henry E (III)	0.10	—	0.55	—	10,000	3	200	1000	1.1×10^{-3}	0.26
12	Jones City Regular	0.028	0.09	0.34	650	54,000	8.2	500	1870	—	0.19
13	Louden	0.40	0.023	0.32	558	13,000	0.625	103	1460	$(2.0 \times 10^{-4})^1$	0.15
14	North Burbank	0.06	0.038	0.47	2500	53,400	10	52	2900	4×10^{-4}	0.19 ³
15	Salem	0.285	0.016	0.30	700	40,000	5	87	1750	6.1×10^{-4}	0.17
16	Sloss	0.155	0.044	1.0	800	—	9	93	6256	1.7×10^{-3}	0.29 ³
17	Wilkin	0.025	0.072	0.068	—	3700	2.5	200	1000	1.2×10^{-3}	0.14
18	119 R	0.07	0.11	1.0	1200	10,000	2.5	211	1000	3.6×10^{-3}	0.38
19	219 R	0.102	0.10	1.05	1156	9400	3	165	1000	8.9×10^{-4}	0.30 ³
20	Wichita County Regular	0.15	0.015	0.3	500	—	20	53	1700	1.6×10^{-4}	<0.1 ³

Footnotes

¹ Based on experimental interfacial tensions² Upper limit of recovery used³ Test in progress⁴ Unstable displacement⁵ Not graded

One final point is that the results and conclusions presented here are based on historical results, mainly pilot tests, rather than on currently-available technology. This fact must remain an important qualification to the results of Part II, and is the main reason why an alternative screening procedure, using the BAT, is proposed in Part III.

II.3.i Surfactant Quantities

Figures 1-3 show E_R vs. slug size V_{ps} , injected surfactant concentration C_s , and the total surfactant injected $C_s V_{ps}$, respectively. In these figures and throughout, filled symbols refer to projects where crude oil was injected with the slug, boxes refer to projects in progress. These figures show a trend of increasing E_R with increasing C_s , of $V_{ps} C_s$, but decreasing E_R with increasing V_{ps} . More importantly, Figure 1 shows no correlation with V_{ps} , while Figures 2 and 3 show some degree of correlation with C_s (CL = 0.99) and $V_{ps} C_s$ (CL = 0.9). If one excludes the aqueous slugs from the correlations of Figures 2 and 3 both correlations are improved. Thus, it appears that increasing C_s does indeed improve oil recovery; however, this conclusion must be tempered by the remarks in the next section about the effect of mobility buffer size. We note, further, that Holm⁸⁴ has suggested that the inclusion of cosurfactant in the surfactant concentration of C_s would improve the correlations.

Figure 1. Recovery Efficiency vs. Slug Size

Figure 2. Recovery Efficiency vs. Surfactant Concentration

II.3.ii The Mobility Buffer Quantities

The next logical variables to investigate are those associated with the mobility buffer. Figure 4 shows E_R plotted against mobility buffer size V_{MB} . As noted in Appendix A, V_{MB} is the total polymer-water slug size, including taper, based on the pore volume associated with the respective test. Figure 4 shows a definite trend of increasing E_R with increasing V_{MB} . An r -value of 0.83 based on a sample size of 18 (note that we include the viscously unstable Borregos test, no. 5, in Figure 4) yields a confidence limit in excess of 0.999. That is, one can be more than 99.9% certain that the data show a correlation between E_R and V_{MB} . Such a high degree of correlation is remarkable given the complexity of the MCM/EOR process. The presence of a correlation with V_{MB} is also not a little unsettling as MCM/EOR design has concentrated on making the mobility buffer viscosity large enough so as to effect a stable displacement between it and the MCM/EOR slug. Hence, E_R should correlate with mobility buffer viscosity, or, at the least, mobility buffer concentration. There's not enough published data to indicate whether E_R would, in fact, correlate with mobility buffer viscosity, but the strong correlation in figure 4 suggests two conclusions:

- (1) MCM/EOR designers have done a good job in designing viscously stable mobility buffers, and
- (2) The amount of viscously stable mobility buffer injected is highly important to MCM/EOR success. It further follows from this, and the fact that polymer costs generally consume about half of the total chemical costs, that a truly significant impact on the commercial effectiveness of the MCM/EOR process could be realized by research into techniques, such as polymer grading, to minimize the amount of polymer required in a given application.

Figure 3. Recovery Efficiency vs. Slug Size - Surfactant Concentration Product

At this point, one is tempted to conclude that, based on Figures 2 and 4, both C_s and V_{MB} correlate well with E_R . However, these two variables themselves show a considerable correlation (see Table 3) which indicates that it is not statistically proper to consider them independently as is done in Figures 2 and 4. There is, of course, no physical basis for a dependence of C_s on V_{MB} , but the data do indicate that, on the whole, tests that have used large surfactant slug concentrations have also used large mobility buffers. To separate these effects would require more statistical analysis than is given in this report. Here we merely conjecture that the largest effect is that due to V_{MB} because of the higher degree of correlation. Holm⁸⁴ agrees with the Figure 4 correlation and suggests that the viscous stability of the micellar slug could also be important.

It's difficult to make a similar plot of E_R against total polymer injected — as was done for surfactant in figure 3 — because nearly all mobility buffers were tapered (the Henry W test is an exception). Crudely, one can make an estimation of how much polymer was used in each test by assuming the tapering to be linear over V_{MB} . That is,

$$\bar{C}_p = \frac{1}{2} C_p V_{MB}, \text{ ppm} \quad (1)$$

where $\bar{C}_p$ = average polymer concentration in mobility buffer

C_p = polymer concentration in initial portion of mobility buffer.

C_p is given for 14 of the reported field tests (see table 3 and Appendix A). Note that multiplying $\bar{C}_p$ by the test pore volume should give the total polymer used in mass units. Figure 5 plots E_R vs. $\bar{C}_p$. Again, a trend of increasing E_R with increasing $\bar{C}_p$ is noted with an

Figure 4. Recovery Efficiency vs. Mobility Buffer Size

r-value of 0.7. With the indicated number of points this correlation is significant at the 0.99 confidence level. Given the approximations in equation 1, the small decrease in confidence level from 0.999 to 0.99 between figures 4 and 5 is something of a surprise.

II.3.iii The Resident Salinity Quantity

As was discussed in Part I, considerable MCM/EOR research has gone into formulating processes that are insensitive to high salinity reservoir brines. Figure 6 shows a plot of E_R vs. resident brine salinity C_{RS} , defined here as resident chloride concentration in mg/l. A trend of decreasing E_R with increasing C_{RS} is apparent in figure 6, but it is weaker than either trend in figures 4 and 5. The r-value indicates no significant correlation. By plotting E_R vs. resident salinity defined as total dissolved solids, Holm⁸⁴ has indicated a correlation that is significant at the 0.99 confidence level. Although neither C_{RS} nor TDS are entirely adequate measures of the effect of salinity on the MCM/EOR process, the existence of some correlation justifies the research being done on salinity tolerant micellar processes.

II.3.iv The Capillary Number Parameters

The MCM/EOR literature contains occasional references to a pattern size sensitivity. Since the rate sensitivity of the MCM/EOR process has been well verified in the laboratory^{55, 86-89} it is possible that rate sensitivity and pattern size sensitivity are essentially the same observation. In order to investigate this we must calculate a field capillary number. The definition for capillary number used here is

$$N_{cap} = u\mu/\sigma, \quad (2)$$

which is the dimensionless number used in most laboratory studies, and represents a ratio of viscous forces to capillary forces on the trapped phase saturations in a porous medium.

To calculate N_{cap} we need an expression for u , the superficial velocity, which we abstract from the steady-state production/injection rates given by Muskat⁹⁰

$$Q_{LD} = \frac{0.002254kh\Delta P/\mu}{\frac{d}{a} - 1.17 + \frac{2}{\pi} \ln\left(\frac{a}{r_w}\right)}, \text{ bbl/day} \quad (3)$$

for a line drive, and

$$Q_5 = \frac{0.003541 kh\Delta P/\mu}{\ln\left(\frac{d}{r_w}\right) - 0.619}, \text{ bbl/day} \quad (4)$$

for a 5-spot. Equations 3 and 4 are very approximate for an MCM/EOR flood, mainly because *in situ* mobilities are not constant as required in the steady-state derivation. The use of these equations, however, can provide relative information about MCM/EOR projects, and may even approximate actual conditions as economics usually dictate near-unity mobility ratios between injected fluid banks. In equations 3 and 4, a and d are injector-injector and injector-producer distances, respectively; all other quantities are in standard units. In equation 3 we take $d = 2a$, which corresponds to the way 5-spots are usually infilled to make line drives.

Some other necessary assumptions are $r_w = 0.3$ feet and

$$\frac{\Delta P}{\mu} \equiv C_p D / \mu_o \quad (5)$$

Figure 5. Recovery Efficiency vs. Average Polymer Concentration

Figure 6. Recovery Efficiency vs. Resident Salinity

If $\mu_o \approx \mu$ the coefficient C_p' can be as high as 0.7 psia/ft, if the injectors are injecting at their fracture limit (fracture gradient ≈ 0.7 psia/ft) and the producers are completely pumped off, or as low as 0.27 psia/ft, if the producers have a water head. Equations 3 and 4 now become

$$Q_{LD} = \frac{0.002254 C_p' k h D}{\mu_o \left(4.56 + \frac{1}{\pi} \ln(A) \right)}, \text{ bbl/day} \quad (6)$$

$$Q_5 = \frac{0.003541 C_p' k h D}{\mu_o \left(5.58 + \frac{1}{2} \ln(A) \right)}, \text{ bbl/day} \quad (7)$$

where A = area/injection well (spacing) in acres. The superficial velocity for the line drive is $2Q_{LD}/h\sqrt{A}$ or

$$u_{LD} = \frac{0.00012 C_p' k D}{\mu_o \sqrt{A} \left(4.56 + \frac{1}{\pi} \ln(A) \right)}, \text{ ft/day} \quad (8)$$

and for the 5-spot using Parsons⁹¹ results for median velocity

$$u_5 = \frac{0.000055 C_p' k D}{\mu_o \sqrt{A} \left(5.58 + \frac{1}{2} \ln(A) \right)}, \text{ ft/day} \quad (9)$$

From equations 8 and 9 the line drive has about twice the fluid velocity as the 5-spot for equivalent parameter values. Taking $\mu \approx \mu_o$, we have from equation 2

$$(N_{cap})_{LD} = \frac{(4.3 \times 10^{-7})C_p'kD}{\sqrt{A} \left(4.56 + \frac{1}{\pi} \ln A\right)} \quad (10)$$

$$(N_{cap})_5 = \frac{(1.9 \times 10^{-7})C_p'kD}{\sqrt{A} \left(5.58 + \frac{1}{2} \ln A\right)} \quad (11)$$

where we have taken $\sigma = 10^{-3}$ dynes/cm. Now, it is certainly true that all MCM/EOR projects have not generated this low σ *in situ*; in fact, in all but two cases in table 3 the laboratory measured σ 's are not reported. Even when laboratory σ 's are reported, the application of these to *in situ* conditions is anything but clear. Nevertheless, taking σ to be the same in all projects (except for the two — the Big Muddy Pilot and Loudon — where the σ 's are given) will again provide a relative comparison between projects and address the question of rate and pattern size sensitivity.

N_{cap} can be easily calculated given k , D , and A if C_p' were known. Table 4 shows injection/production data for 16 field tests from which, using equations 6 and 7 with the appropriate parameters, C_p' may be derived. The Q 's in table 4 are based on average rates beginning at the onset of surfactant injection in these floods. C_p' 's in table 4 range from 0.13 to 3.63 psia/ft with an average of 0.54 ± 0.85 . Eliminating from the average those tests with injectivity/productivity irregularities (along with Salem which is treated as an aberrant data point), yields an average of 0.3 ± 0.08 . Correspondingly, $C_p' = 0.3$ psia/ft is used to calculate N_{cap} . Note that this agrees with the producer with water head limit mentioned above.

Using $C_p' = 0.3$ psia/ft, and either of equations 10 or 11, it is possible to calculate N_{cap} for 17 of the field tests of Table 3. Figure 7 shows a semi-log plot of E_R vs. N_{cap} from which two observations follow:

- There is a definite trend of increasing E_R with increasing N_{cap} . The correlation is significant at the 0.99 confidence level. Given the extremely crude assumptions used to develop N_{cap} , especially taking $\sigma = 10^{-3}$ dynes/cm for every test but two, the positive indication of a correlation is remarkable.
- All test data fall below typical laboratory data⁸⁷ also shown on figure 7. The difference between the laboratory and field data are due to adsorption, poor sweep efficiency, and/or the near certainty that many tests did not generate $\sigma = 10^{-3}$ dynes/cm *in situ*. Presumably, using the correct σ for each test would reduce the data scatter.

The E_R - N_{cap} plot of figure 7 incorporates three important reservoir variables - k , A and D - into a single number and does a better job of correlating E_R than each of them individually. This is apparent from Figures 8-10 which Plot E_R vs. depth, permeability, and spacing, respectively, on semi-log plots. The correlations with k and D are particularly poor, while that with A is moderate (confidence level = 0.95) certainly much less than the correlation with N_{cap} in figure 7.

TABLE 4

Data Used to Estimate C_p

<u>Test</u>	<u>Project</u>	<u>Production (P) or Injection (I) Rate, BPD</u>	<u>C_p, psia/ft</u>	<u>Comments</u>
Big Muddy	Pilot	130 (P)	0.13*	Fractured injectors
Bradford	Bingham 533	106 (I)	0.23	—
Bradford	Bingham expansion	83 (I)	0.21	—
Bradford	Lawry	19 (I)	0.24	—
El Dorado	Chesney	438 (I)	0.34	Oil wet
El Dorado	Hegberg	378 (I)	0.36	Oil wet
Louden	—	30 (I)	0.28	—
North Burbank	—	730 (I)	0.60*	Oil wet fractured
Henry W	—	70 (I)	0.39	—
Henry E	—	66 (I)	0.39	—
119 R	—	68 (I)	0.19	—
219 R	—	81 (I)	0.37	—
M-1	—	67 (I)	0.25	Based on average pattern size
Salem	—	600 (P)	1.01*	—
Sloss	—	400 (P)	0.087*	Productivity problems
Wichita County Regular	—	900 (I)	3.63*	Injection pressure above fracture gradient

average = 0.54 ± 0.85 average without* = 0.30 ± 0.08

Figure 7. Recovery Efficiency vs. Capillary Number

II.3.v Cross Correlations of N_{cap} and Mobility Buffer

If single variable correlations of V_{MB} , $\bar{C}_p$, and N_{cap} indicate significant correlations with E_R , then two variable correlations should be even better. Once again, using linear regression we fitted the E_R data to the combination of V_{MB} and N_{cap} , and then to $\bar{C}_p$ and N_{cap} (the V_{MB} - $\bar{C}_p$ combination is not independent). Figure 11 plots actual E_R (y-axis) vs. estimated E_R (x-axis) where the estimated E_R is from regression analysis and is given by the equation below the x-axis. If there were perfect correlation all data would fall on a 45° line. As is shown in Figure 11, the E_R estimated from a linear combination of V_{MB} and $\text{Log}(N_{cap})$ is very significant at a confidence level of 0.999 and has a mean deviation of 9 recovery efficiency percent. The correlation of E_R vs. $\bar{C}_p$ - $\text{log}(N_{cap})$ - Figure 12 - is slightly worse with a confidence level of 0.99 and a mean deviation of 10%.

II.3.vi Conclusions on the Critical Quantities

One point not emphasized by this discussion but still observable in figures 1-12 concerns the relative merits of oleic (oil containing) and aqueous MCM/EOR slugs. In figure 1, there is no discernible difference between oleic and aqueous slugs; in figures 2 and 3, the correlations with C_s and the V_{ps} - C_s product, there appears to be a greater trend within the oleic group than for the whole group if point 19 (the 219 R) is excluded. In figure 4, again focusing only on the oleic slugs, the correlation with V_{MB} is improved to a confidence level much greater than 0.999. Note further that the oleic process, as a rule, has been used with larger mobility buffers than the aqueous slug process. These same comments hold to a lesser extent, in figure 5 also. In the remaining figures there is no apparent difference between the two types of slugs.

In summary for Part II, we conclude based upon the historical data of 20 reported MCM/EOR field tests:

1. The MCM/EOR process has been tried in a large variety of reservoirs.
2. Oil recovery correlates with both the amount of surfactant injected, $C_S V_{PS}$ and the injected surfactant concentration, C_S . These variables are probably not independent as the large C_S slugs tend to have been used with the larger V_{MB} 's.
3. Oil recovery correlates, on the other hand, with concentration and volume of mobility buffer agent. This indicates that, on the whole, MCM/EOR designers have been able to achieve viscously stable displacements *in situ*.
4. Likewise does oil recovery correlate with capillary number, though not quite as well as mobility buffer concentration and volume.
5. Although isolation upon oleic slugs only does tend to improve correlations with C_S and V_{MB} , the difference between the performance of oleic and aqueous slugs is not great, and may be attributed to the fact that the oleic process has been used with larger polymer drives.

Figure 8. Recovery Efficiency vs. Depth

Figure 9. Recovery Efficiency vs. Permeability

Figure 10. Recovery Efficiency vs. Spacing

Figure 11. Actual vs. Estimated Recovery Efficiency

Figure 12. Actual vs. Estimated Recovery Efficiency

Part III

Development of a Screening and Evaluation Procedure

III.1 Background of Screening Procedures

The usual screening procedures for MCM/EOR flooding is to assign a collection of about 15 parameter values above or below which an MCM/EOR project will not be conducted in a particular reservoir. Table 5 summarizes some of the previous parameter values for MCM/EOR screens. Although it is succinct, table 5 does not rigorously reflect the previous work. (Gogarty's review⁷ probably does a better job.) For example, the NPC study⁹⁵ actually used a sliding scale on some parameters, and Geffen's criteria⁹² on water purity is actually on make-up water, not on formation water. The intent in compiling table 5 was to see how the criteria has changed over the 7+ years the MCM/EOR process has been screened. The blanks in Table 5 indicate the parameter was not considered in the designated screen. It is apparent that there has been little evolution of the screening parameters, certainly no systematic changes. The consensus seems to be that a given reservoir will be a MCM/EOR candidate if it is sandstone, has a temperature less than about 200° F, a permeability greater than 20 md, a salinity of less than 50,000 ppm TDS, etc.

Since it seems unlikely that we could contribute much to the goals of Part I by merely repeating the already established criteria, we propose a somewhat different approach. Our approach deals with why the values of table 5 were chosen, and, as such, comes near to a "combination of criteria" approach that rests on the field test assessment of Part II.

A given reservoir will be a MCM/EOR candidate if an affirmative answer can be given to both of the following questions:

Will the MCM/EOR process recover the tertiary oil (technical success)?

Will it make money (economic success)?

Of course, it's not as clear-cut as all that, but for screening purposes the distinctions are probably good enough and, in any event, provide a logical framework for the following discussion (see Figure 13).

III.2 Technical Success with the Best Available Technology

To be a technical success the MCM/EOR process is highly dependent upon the formulation chemistry. As in Part I, we will assume that the candidate reservoir will be exposed to the best available technology (BAT) of the industry. Although this technology may not be available to a given operator, the consequence of this assumption is that we will relax any of the conventional criteria (table 5) to a less stringent level if any field tests have been reported in the literature in a reservoir at the lower level. Correspondingly, we do not believe that the MCM/EOR screen should, as is usually the case, exclude carbonate reservoirs because of at least one currently ongoing polymer flood reported in the literature⁹⁸. To be sure, the remainder of the screening procedure will eliminate most carbonate reservoirs anyhow, but we do not see any serious reason to eliminate them a priori.

For a process to be a technical success, two further questions must have affirmative answers.

Can an adequate mobility control be generated and maintained in situ?

Will the MCM/EOR process lower waterflood residual oil saturation S_{or} ? We deal with each question in the following paragraphs.

The BAT assumption says that an adequate mobility can be generated in situ just by adding more polymers, or whatever mobility control agent is used. (Of course, there is an economic limit on this — see the discussion below.) Maintaining the generated mobility is another question, however, as polymers have a tendency to chemically degrade at high temperatures.

TABLE 5

Summary of Previously Used Screening Criteria

<u>Parameter</u>	<u>Geffen⁹² (1973)</u>	<u>Lewin^{93,94} (1976)</u>	<u>NPC⁹⁵ (1976)</u>	<u>GURC⁹⁶ (1977)</u>	<u>Lake et al⁹⁷ (1978)</u>	<u>OTA/109 INTERCOMP (1978)</u>
Formation	—	sandstone	sandstone	—	sandstone	sandstone
Temperature, °F	≤ 200	< 200	< 250	< 175	≤ 200	< 275
Residual oil saturation, %	> 25	> 25	≥ 20	> 20	≥ 20	> 30
Permeability, md	> 20-50	> 20	≥ 20	> 20	> 100	> 10
Oil viscosity, cp	< 10	< 20	≤ 30	—	< 10	< 20
Gravity, °API	—	> 28	≥ 25	> 25	—	20-35
Waterflood sweep efficiency	> 50%	> 50%	—	—	> 50%	> 50%
Salinity, ppm Cl ⁻	—	—	—	—	—	< 20,000
Divalent, ppm Ca ⁺⁺ + Mg ⁺⁺	< 500	< 1000	—	< 500	—	< 500
Total dissolved solids, ppm	< 5000	< 50,000	≤ 200,000	< 75,000	—	< 50,000
Producing interval, ft	—	—	—	—	—	> 10
Remaining oil, MM bbls	—	—	—	—	> 1	—
Waterdrive	—	weak	—	—	—	—
Bottom water/gas cap	—	small	—	—	small	—

Figure 13. Schematic of Proposed Screening and Evaluation Procedure

Since no breakthrough has been reported on reducing this degradation substantially, we will impose an upper temperature limit on the screen (note that this is the only variable carried over by itself from table 5). However, BAT says that this limit should be a rather high $T_{crit} = 229^{\circ}F$, because of a reported polymer flood at this temperature⁹⁸. A limitation on temperature is essentially a limitation on depth, a quantity which is included explicitly below.

With regards to whether S_{Or} can be lowered the best available guide is whether the capillary number $N_{cap} = u\mu/\sigma$ exceeds a certain critical value $(N_{cap})_{crit}$. There have, of course, been numerous studies on this phenomenon, and the most recent summary is that of Gupta and Trushenski⁸⁷ from which we extract the following

$$(N_{cap})_{crit} = \begin{cases} 10^{-5}, & \text{water wetting} \\ 10^{-4}, & \text{oil wetting} \end{cases} \quad (12)$$

These numbers were picked so that S_{OrC} , the swept-zone MCM/EOR residual oil saturation, is about 90% of S_{Or} . Equation 12 can be made into a usable expression if we had some measure of the wettability of the reservoir. (It's not shown on table 5, but wettability is occasionally a screening parameter alone.) The wettability measure related most directly to flow in porous media is the ratio of brine relative permeability at S_{Or} (k_{rw}^o) to oil relative permeability at S_{cw} (k_{ro}^o) — that is, $R = k_{rw}^o/k_{ro}^o$. Using Berea sandstone as a standard of water wetness ($R = 0.10$), and taking a strongly oil wet reservoir to be $R = 10$, we can now make equation 12 into a linear function of R .

$$\text{Log } ((N_{cap})_{crit}) = \frac{1}{2} \text{Log}(R) - 9/2 \quad (13)$$

We elect the logarithm form to decrease the sensitivity of $(N_{cap})_{crit}$ to R , and because most $S_{OrC} - N_{cap}$ correlations have been done on semi-log plots.

Now a reservoir will be an MCM/EOR candidate if its characteristic capillary number, calculated by equations 10 or 11, is greater than $(N_{cap})_{crit}$. If wettability data are not available, the $(N_{cap})_{crit}$ for water wet media should be used. Use of N_{cap} to reject a candidate reservoir is probably the weakest part of the Figure 13 procedure, mainly because of the coarseness of the assumptions used in its development (part 2). Moreover, Figure 7 would seem to suggest that N_{cap} could be readily incorporated into the economic feasibility portion of the screen. In later work, we shall attempt such an incorporation as well as substantiating the use of N_{cap} through numerical simulation.

Another conventional screen for the MCM/EOR technical feasibility question is salinity. We are disinclined to use a salinity screen because of several recent advances in this branch of MCM/EOR technology (see Part I). We, therefore, feel that the BAT assumption will eliminate a salinity/divalent screen, or, at most, cause it to be very loose ($<200,000$ ppm TDS). Moreover, we feel that a stricter salinity requirement, if it is used, should be on the make-up water rather than on the formation water.

Here we conclude our discussion of technical feasibility screens and begin the economic feasibility screens. Note that there are only three screening parameters (temperature, N_{cap} , and salinity) in this section. (See figure 13).

III.3 Economic Evaluation

In contrast to the technical screen, the economic screen has several parameters. This fact indicates the prevailing belief that the hold-up MCM/EOR processes is economic, not technical. The economic screen part of figure 13 indicates that the economic screen divides into a cost path and a revenue path. The former is to answer the question "How much will it

cost?" and the latter the question "What will be the gross revenue?". The answer to each question should be quantitatively used to reject, accept, or rank the reservoir according to profitability. In the following, we discuss the cost path first.

Surfactant and polymer costs, on the whole, contribute equally to the overall chemical costs. The major determinant in surfactant cost is retention, and the major component of retention is adsorption, primarily on clay surfaces. Hence, for a screening estimate of surfactant costs, it is necessary to relate retention, a_s in mg active surfactant/g rock, to clay fraction, W_{clay} .

Since only a few field retention results were available (Appendix A) and they are of highly uncertain interpretation; most of the data used to correlate adsorption were laboratory data. Further discussion of the laboratory data is in Appendix C.

The following types of laboratory surfactant adsorption (retention) data^{34,37,52,99-105} were examined: (1) static adsorption on pure clays (kaolinite, montmorillonite); (2) static adsorption on disaggregated rocks (Berea, reservoir sandstones, limestone); (3) dynamic (core flood) retention on Berea sandstone; and (4) dynamic retention of a few reservoir rocks. In all cases, only adsorption data for sulfonates were considered* (as opposed to sulfates, alcohols), and include (1) several petroleum sulfonates; (2) several isomerically pure synthetic sulfonates; and (3) several mixtures of synthetic sulfonates. Other variables besides amounts and types of substrate and type of sulfonate included (1) alcohol, (2) temperature, (3) electrolyte, (4) pH, (5) sulfonate concentration, (6) sulfonate molecular weight, (7) operating variables for the dynamic tests, such as flow rate, slug size, measurement technique, etc. and (8) other chemical ingredients such as polymer, sacrificial adsorbates, cosurfactants, etc. All of these variables can and usually do make a difference of roughly two to ten fold, taken one at a time, and much more, of course, taken together. Nevertheless, a single correlation of adsorption versus amount of clay (without regard to type, deposition, etc.) was attempted. This was done in part by putting more weight on the range of these variables expected to prevail in actual field tests using the BAT. For example, a low salinity (relative to the surfactant's optimum salinity) polymer drive, the use of alcohol or some other co-agent, a pH above 7, etc., was assumed. Also, fortunately, the type of clay seemed to make little difference relative to most of the other variables. That is, the range of reported values for adsorption on a substrate of given clay content was much larger (over five times) than the variation for the same system with differing clay types (the data of Malmberg⁹⁹, Lawson¹⁰⁰, and Gale and Sandvik³⁷ were relied on very heavily here). The approach also assumes that the adsorption on other minerals such as silica minerals (quartz, feldspar, etc.), is negligible compared to the loss on the clays. This may not be true for limestones or any rock containing large fractions of calcium minerals such as calcite, dolomite, etc.

The result for sandstones is shown on Figure 14. Only a very few of the many data points tabulated and used for the basis of the correlation are shown (see Appendix C). The data shown are, however, representative averages of the laboratory values examined. The central "best guess" line is simply a straight line passing through the origin and the average of many 100% clay adsorption data (not shown on the figure because of the scale used). The lower line is a guess at what might be achieved with BAT using, among other things, sacrificial agents such as the silicates. The upper line is a guess at the likely actual, historical, field retention values. It should be pointed out that, in the cases of field data, an adjustment was made for activity, since all lab data were on an active basis and it was assumed that these particular field data were not. But the assumed adjustment (60%) is very uncertain. Also, the field data probably include other retention mechanisms (as they should since all actual retention values in the field floods will to some degree).

*Some other data are listed, however, in Appendix C.

Figure 14. Sulfonate Retention on Sandstones

One final point is that, even given the scatter of figure 14, the adsorption data seems to correlate better with total clay fraction rather than with a particular clay species. This became apparent when we tried to effect a correlation with cation exchange capacity, a strong indicator of montmorillonite content. The adsorption-cation exchange capacity correlation was worse than that of figure 14.

Despite all the above, and even though the absolute values mean little and probably are too optimistic even for future BAT, we believe the *trend* with increasing clay content is at least order of magnitude correct and represents a necessary and useful screening device because of the large importance of sulfonate retention. Finally, although sulfonate adsorption data are reported^{100,102} for three limestones, and are surprisingly of comparable magnitude to the sandstones, since no mineral analysis was given for the limestones, no correlation can be made. In the absence of other information, values on the order of 0.4 mg/g may be used for an order of magnitude guess. Using a rock bulk density of 2.2 g/cm³ and 1 m³ = 10⁶ cm³ the "typical" retention value of 0.4 mg/g is about 2 lbs. of active sulfonate per cubic meter of rock.

The "best" line in figure 14 is $a_s = 3.3 W_{\text{clay}}$, a quantity which may be used to calculate the surfactant retention expressed in pore volumes, D_s

$$D_s = \left(\frac{1 - \phi}{\phi} \right) \left(\frac{\rho_r a_s}{\rho_s C_s} \right) \frac{1}{1000}, \text{ dimensionless} \quad (14)$$

Now the surfactant slug size should be fractionally greater than D_s ; the optimum value for this proportionality can be found by the methods below. Usually this turns out to be about $V_{ps} = 1.3 D_s$; hence, the total surfactant required C_{TS} is in volume units

$$C_{TS} = V_{ps} C_s V_p = \left(\frac{1 - \phi}{\phi} \right) \left(\frac{\rho_r}{\rho_s} \right) (3.3 W_{\text{clay}}) (1.3 V_p), V_p \text{ units} \quad (15)$$

here V_p is the floodable reservoir pore volume, and C_{TS} is the total active surfactant required to meet the retention demands of the candidate reservoir. Given surfactant cost on a dollar per unit volume basis, it should be easy to estimate surfactant cost from equation 15.

Estimating polymer costs is rather more tenuous as polymer requirements depend more directly on viscosities, wettabilities and heterogeneities than on adsorption. There are at least three approaches one can take to estimate polymer requirements. The first is to take polymer costs equal to surfactant costs given by equation 15. This alternative is easiest to use but denies reservoir specificity (except that originating from the surfactant cost estimate). The second approach is to use figures 4 or 12 to calculate an "optimum" average polymer concentration $\bar{C}_p$ — this is the $\bar{C}_p$ where a plot of E_R vs. $\bar{C}_p$ would have zero slope. The total polymer required in mass units would then be

$$C_{TP} = \bar{C}_p V_p \quad (16)$$

This approach tends to violate the BAT by using historical data. The third approach restores some reservoir specificity while at the same time not requiring total dependence on correlations. Figure 15 plots C_p , the polymer concentration in the initial portion of the drive vs. the ratio of oil to water viscosity. The data are again based on the Appendix A information and are subdivided into two groups corresponding to the wettability of the subject reservoir. Plotting C_p vs. the viscosity ratio tends to decrease the sensitivity of polymer requirements to reservoir temperature. For both groups the correlation is quite good; however, the points for the correlation of oil wet reservoirs are so clustered on the x-axis — this accounts for the extremely high slope — that we recommend using a line of slope equal to that of the water-wet correlation but shifted upwards through the average C_p of the oil wet reservoirs as indicated in figure 15.

Figure 15. Initial Polymer Concentration vs. Oil-water Viscosity Ratio

Given C_p from figure 15, it is straightforward to calculate C_{TP} from equations 1 and 16 if V_{MB} were known. V_{MB} ought to be fairly specific to the backside mobility ratio and degree of heterogeneity of the candidate reservoir. Unfortunately, the science of designing graded polymer drives has not progressed to where a simple calculation of V_{MB} can be made. Correspondingly, and particularly in view of the success of the larger polymer drives in figure 4, we suggest using $V_{MB} = 1.0$ in equations 1 and 16 to estimate C_{TP} .

As far as drilling and operating costs, royalties and taxes, we suggest the approach used in the National Petroleum Council study⁹³.

On the revenue path of figure 13, the first step is to estimate the MCM/EOR target oil TO. Assuming, among other things⁹⁵, that the MCM/EOR volumetric sweep efficiency will be the same as in the preceding water flood, the target oil is

$$TO = \left(\frac{S_{or}}{S_{oi} - S_{or}} \right) \left(N_p^\infty - OOIP \left(1 - \frac{B_i}{B_f} \right) \right) (1 - f_{bw})(1 - f_{gc}), Stb \quad (17)$$

Equation 17 reintroduces several parameters from table 5, S_{or} , waterflood sweep efficiency, remaining oil, and discounts for bottom water (f_{bw}) and gas caps (f_{gc}). See the original work⁹⁵ for details on how equation 17 was derived. The essential assumption behind it is that, the volumetric sweep efficiencies in the MCM/EOR flood and the waterflood being the same, it already contains corrections for areal sweep efficiency to some extent.

The next step on the revenue path is to estimate MCM/EOR ultimate recovery $(CFR)_{ult}$.

$$(CFR)_{ult} = 0.8 E_R (TO) \quad (18)$$

where E_R is the MCM/EOR displacement efficiency (volume oil displaced/volume target oil), and the 0.8 factor is to account for displaced, but unproduced oil. The latter is an empirical factor introduced to account for differences observed between this procedure and E_R 's calculated from numerical simulation⁹⁵. E_R is dependent on slug size, retention, and heterogeneity as shown in Figure 16 where $E_R S_{or} / \Delta S_o$ — a vertical sweep efficiency for MCM/EOR flooding — is plotted vs. these quantities. The quantity ΔS_o is

$$\Delta S_o = S_{or} - S_{orc} \quad (19)$$

where S_{orc} is the swept-zone MCM/EOR oil saturation. This very important quantity obtains from the data of Gupta and Trushenski using the N_{cap} of equations 10 or 11. If V_{DP} for the candidate reservoir is not available, use $V_{DP} = 0.6$ which is close to the average (table 2) of the completed MCM/EOR tests.

III.4 Recovery Prediction and Pilot Results

Columns 7 and 8 of table 6 compare $(CFR)_{ult}$, (normalized by TO) calculated by the method proposed above with reported recoveries (Appendix A). Eliminating unstable floods, the Salem test, and those in progress, the average deviation between observed and calculated is 0.07 with the estimated $(CFR)_{ult}$ generally larger than the observed. There are several reasons for this:

1. A σ higher than 10^{-3} dynes/cm generated *in situ*;
2. Areal sweep effects;
3. Target oil was taken to be equivalent to remaining oil in place;
4. Large uncertainties in all number making up N_{cap} , V_{DP} and, most particularly, V_{ps}/D_s .

Nevertheless, it appears that the above procedure gives $(CFR)_{ult}$, that are adequate for screening purposes.

Figure 16. MCM/EOR Recovery Efficiency vs. Slug Size - Retention Ratio

III.5 Rate of Return Calculations

After the calculation of CFR, the cost and revenue paths of figure 13 remerge into a calculation of economic pay-back. The central feature of this calculation is an estimate of project life. Using equations 6 and 7 project life can be estimated as

$$(t_{\text{life}})_{\text{LD}} = (9430 A\phi) \left(\frac{4.56 + \frac{1}{\pi} \ln(A)}{(C_p kD/\mu_o)} \right) Q_D, \text{ years} \quad (20)$$

and

$$(t_{\text{life}})_5 = (6160 A\phi) \left(\frac{5.58 + \frac{1}{2} \ln(A)}{(C_p kD/\mu_o)} \right) Q_D, \text{ years} \quad (21)$$

where Q_D is the cumulative injection in pore volumes. A typical value for Q_D is 1.5. Note that t_{life} reintroduces many of the table 1 parameters back into the screen.

TABLE 6

Comparison of Observed and Estimated MCM/EOR Recoveries

Test	N_{cap}	S_{orc}		V_{ps}/D_s	V_{DP}	$(CFR)_{ult}/TO$		Comments
		Observed	Estimated			Observed	Estimated	
Big Muddy Pilot	4.5×10^{-3}	0.12	0.11	1.15	0.6	0.35	0.36	—
Bingham 533	1.9×10^{-3}	—	0.06	1.83 ¹	0.65	0.44	0.50	oil wet
Bingham Expansion	8.4×10^{-4}	—	0.12	1.32 ¹	0.65 ²	0.43	0.37	oil wet
Borregos	1.9×10^{-2}	0.09	0.04	1.44	0.7	0.204	0.46	unstable
Henry W	2.4×10^{-3}	0	0.08	1.23	0.62 ³	0.63	0.56	—
Louden	2×10^{-4}	—	0.17	2.3	0.42	0.15	0.29	—
North Burbank	4×10^{-4}	—	0.16	0.91	0.61	0.19	0.26	in progress
Salem	6.1×10^{-4}	—	0.11	2.97	0.34	0.17	0.51	—
219 R	8.9×10^{-4}	—	0.13	2.68 ¹	0.62	0.30	0.50	in progress
Delaware-Childers	3.7×10^{-4}	—	0.16	1.16	0.48	0	0.34	in progress

¹ $a_s = 0.4$ mg surfactant/g-rock

² V_{DP} used for Bingham 533

³ V_{DP} for 119 R used

Project life, by itself, is not useful for calculating economic pay-back (although project lives of 100 years are probably out of the question). What is also needed is some sort of recovery function. We suggest simply using a linear function between the limits of $(CFR)_{ult}$ and t_{life}

$$CFR = (CFR)_{ult} \begin{cases} t/t_{life}, & t < t_{life} \\ 1.0, & t > t_{life} \end{cases} \quad (22)$$

The best that can be said for equation 22 is that it's optimistic (will predict too early response), but this may be what is best for a baseline screen. Appendix D presents an example calculation.

Based on equations 15, 16 and 22, and knowing what other costs are associated with the MCM/EOR process, it should be possible to decide whether a given reservoir has a chance of being profitable. This, then, is the sole remaining criteria in the economic feasibility section.

In conclusion we should note that no screening procedure, particularly one as embryonic as that shown on Figure 13, should be viewed as a rigid, uncompromising path for accepting or rejecting a candidate reservoir. This, in part, is the reason for including the economic feasibility portion of the screen where a candidate will be judged on an interacting collection of several parameters rather than just one or two. Undoubtedly, some compromise will be justified as we seek to validate the procedure through numerical simulation.

Appendix A

Contemplated, Current and Completed MCM/EOR Tests

There are 44 contemplated, current and completed MCM/EOR field tests reported in the literature. The tests range in size from 0.625 acres (Louden) up to 407 acres (Marathon's M-1) with several of the larger projects being labeled "demonstration projects" rather than tests by their operators.

Here we define an MCM/EOR test as any project which injects surfactants to produce oil. This definition therefore encompasses tests (Borregos, for example) which did not use a mobility control agent, but omits tests, such as the West Ranch¹⁰⁷ or the various Marathon minitests,¹⁰⁸ which did not have a producer. Our rationale for this is that extrapolation to commercial ventures may most confidently be done from oil producing tests, as there are several potential problems associated with oil capture and production in MCM/EOR flooding. Moreover, we are aware of several minitests conducted by operators which have not been reported; thus, we feel that our survey will be more nearly complete if it is restricted to producing tests.

On the following pages we have attempted to describe the various MCM/EOR tests in terms of the "critical reservoir and micellar quantities" (CRMQ) described in the first part of this report. Necessarily, what follows is an abbreviated version of that list as most of the CRMQ are not reported in the literature. For completeness, the descriptions also include general information, such as operator identity and formation age, as well as estimates of the derived variables discussed earlier. We have relied on primary literature sources (references describing micellar-polymer field-derived results in the designated reservoir) as much as possible, but have also relied on secondary sources (laboratory studies or reports of other projects in the same reservoir) when necessary. When an item has been abstracted directly from primary sources, it appears without annotation. Otherwise, the following legend applies:

- = quantity not appropriate (e.g., the ending date of an ongoing project)
- Blank = quantity not known
- () = estimated quantity, or one derived from secondary sources
- ≈ = approximate
- / = used when multiple entries are appropriate

When the various literature sources reveal slightly different, or in some cases conflicting variable values, we have used the value given by the primary sources. When the primary sources disagree, we use the value from the most recent primary source. Where appropriate, all variables are given at reservoir conditions.

We are indebted to Mr. Chapman Cronquist of Gulf Universities Research Consortium for providing an excellent initial data base (Appendix B) as well as for several useful discussions.

The MCM/EOR field test descriptions are grouped into rough categories corresponding to variable type. The remainder of this discussion is to further amplify some of these variables.

- Partner - Several tests have been joint efforts between two or more entities (the Salem test, for example). Thus, the Partner category indicates a second party, an oil company or the Department of Energy, which has contributed substantially to the enterprise in either technology or expenses.
- Begin - Refers to the date of the initiation of surfactant injection
- End - Refers to the termination of chase water injection

- Pat. Type - Pattern type designation; uses the following legend:
- N5 - Normal 5 spot (four injectors/producer) — note that older publications refer to this as “inverted”
 - CN5 - Confined normal 5-spot
 - I5 - Inverted 5-spot (four producers/injector)
 - CI5 - Confined inverted 5-spot
 - R5 - Repeated 5-spots
 - LD - Line drive
 - SLD - Staggered line drive
 - QI9 - Quarter of an inverted 9-spot
 - IRR - Irregular
- C.E.C. - Cation exchange capacity in meq/gram rock
- Perm. - Permeability variation as defined by Dykstra-Parsons
- Var.
- Resident Salinity - The chloride concentration in mg Cl⁻/liter liquid of produced samples. When salinities are reported in total dissolved solids, the entry is designated with a (TDS)/
- Resident Hardness - The sum of the divalent cation concentrations
- PF Size - Preflush size reported as fraction pore volume (true for all slug sizes)
- Oil Content - Volume fraction oil in slug. The designation >0 is used when the slug contains oil in an unspecified amount.
- MB Visc., Conc. - Mobility buffer viscosity and concentration refers to the initial portion of the usually-tapered mobility buffer.
- MB Size - Refers to the total amount (including taper) of polymer water injected
- Surf. Ret. - Surfactant retention in mg surfactant/g-rock on an active surfactant basis. This variable represents total surfactant loss due to retention, adsorption, and phase trapping, and is frequently reported for field tests. In correcting from retention expressed per unit rock volume to retention per unit rock weight, we used a rock grain density of 2.5 g/ml. (L) indicates a lab-derived value.
- Cap. No. - Is the overall capillary number estimated by the methods described in the first part of this report. This method assumes the controlling IFT is 10⁻³ dynes/cm except where noted by * which cases use an experimentally derived IFT.
- Oil Rec. - Oil recovery reported as fraction of original oil in place before MCM/EOR flood.
- References - Sources of the above data. Secondary sources are designated with parentheses.

AUX VASES

STATE : Illinois

COUNTY :

OPERATOR/ : Marathon
(Partner)

PROJECT :

BEGIN : 5/70

END : 7/72

PROJ. AREA (acres) : 4.3

INJECTORS : 4

PRODUCERS : 1

PAT. TYPE : N5

NUM. PAT. : 1

ACRES/PAT : 4.3

DEPTH (feet) : 3000

TEMPERATURE (°F) :

FORMATION : Aux Vases

ZONE :

AGE :

DEP. ENVIR. :

CLAY FR. :

C.E.C. (meq/g) :

CLAY TYPE :

NET PAY (ft) :

PERM. (md) :

PERM. VAR. (D-P) :

POROSITY (fr.) :

OIL VIS. (cp) :

RES. OIL SAT. (fr) :

CRUDE TYPE :

WETTABILITY:

RESIDENT SALINITY (mg/l) :

RESIDENT HARDNESS (mg/l) :

pF SIZE (fr. V_p) :

pF SALINITY (mg/l) :

pF HARDNESS (mg/l) :

OTHER pF AGENT :

SLUG SIZE (fr. V_p) : 0.025

SLUG OIL CONTENT :

SLUG VISC. (cp) :

SURF. TYPE :

SURF. CONC. (fr.) :

CO-SURF TYPE :

CO-SURF CONC. (fr.) :

SLUG. POL. CONC. (ppm):

SLUG SALINITY (mg/l) :

SLUG HARDNESS (mg/l) :

MB POLY TYPE :

MB VISC. (cp) :

MB CONC. (ppm) :

MB SIZE (fr. V_p) : 0.24

MB SALINITY (mg/l) :

MB HARDNESS (mg/l) :

SURF. RET. (mg/g) :

PROJ. LIFE (mos.) : 26

CAP. NO.:

MOBILITY RATIOS -

SLUG - OIL :

MB - SLUG :

OIL REC (fr. S_{or}) :

REFERENCES : 5, 6, 9

BATESVILLE POOL

STATE	: Kansas			SURF. TYPE	: Pluroni L64
COUNTY	: Woodson	NET PAY (ft)	: 20	SURF. CONC. (fr.)	: 0.00025
OPERATOR/ (Partner)	: Bird-Hanley & Sheedy	PERM. (md)	: 55		0.00002
PROJECT	: -	PERM. VAR. (D-P)	:	CO-SURF TYPE	: -
BEGIN	: 10/56			CO-SURF CONC. (fr.)	: -
END	: 12/66	POROSITY (fr.)	: 0.19	SLUG. POL. CONC. (ppm)	: 0
PROJ. AREA (acres)	: 331	OIL VIS. (cp)	: 1	SLUG SALINITY (mg/l)	: 31,60
INJECTORS	: 22	RES. OIL SAT. (fr)	: 0.39	SLUG HARDNESS (mg/l)	: 2750
PRODUCERS	: 30	CRUDE TYPE	:	MB POLY TYPE	: -
PAT. TYPE	: IRR			MB VISC. (cp)	: -
NUM. PAT.	: -			MB CONC. (ppm)	: 0
ACRES/PAT	: -	WETTABILITY:		MB SIZE (fr. V_p)	: -
DEPTH (feet)	: 1420	RESIDENT SALINITY (mg/l)	: 31,600	MB SALINITY (mg/l)	:
TEMPERATURE (°F)	: 80	RESIDENT HARDNESS (mg/l)	: 2750	MB HARDNESS (mg/l)	:
FORMATION	: Quincy - Bartlesville Trend	pF SIZE (fr. V_p)	: -	SURF. RET. (mg/g)	: 80-160
ZONE	:	pF SALINITY (mg/l)	: -		($\mu\text{g}/\text{m}^2$)
AGE	:	pF HARDNESS (mg/l)	: -	PROJ. LIFE (mos.)	: 112
DEP. ENVIR.	:	OTHER pF AGENT	: -	CAP. NO.:	
CLAY FR.	:	SLUG SIZE (fr. V_p)	: (1.14)	MOBILITY RATIOS -	
C.E.C. (meq/g)	:	SLUG OIL CONTENT	: -	SLUG - OIL	:
CLAY TYPE	:	SLUG VISC. (cp)	:	MB - SLUG	:
				OIL REC (fr. S_{or})	: 0.09

REFERENCES : 16

BELL CREEK

STATE	: Montana			SURF. TYPE	: Petrostep 45
COUNTY	: Powder River	NET PAY (ft)	: 8.1	SURF. CONC. (fr.)	: 0.081 (pl co-surfactant)
OPERATOR/ (Partner)	: Gary/(Union)	PERM. (md)	: 1050	CO-SURF TYPE	: Butyl cellosolve
PROJECT	: Unit A	PERM. VAR. (D-P)	: 0.7	CO-SURF CONC. (fr.)	:
BEGIN	: 2/79				
END	: —	POROSITY (fr.)	: 0.29	SLUG. POL. CONC. (ppm)	: —
				SLUG SALINITY (mg/l)	: 2500
PROJ. AREA (acres)	: 40	OIL VIS. (cp)	: 4.6	SLUG HARDNESS (mg/l)	: 9
INJECTORS	: 4	RES. OIL SAT. (fr)	: 0.28		
PRODUCERS	: 1	CRUDE TYPE	:	MB POLY TYPE	: Polyacrylamide
PAT. TYPE	: CN5			MB VISC. (cp)	: 32
NUM. PAT.	: 1			MB CONC. (ppm)	: 950
ACRES/PAT	: 40	WETTABILITY: WW		MB SIZE (fr. V_p)	: 0.6
				MB SALINITY (mg/l)	: 700
DEPTH (feet)	: 4550	RESIDENT SALINITY (mg/l)	: 248-2680	MB HARDNESS (mg/l)	: 8
TEMPERATURE (°F)	: 110	RESIDENT HARDNESS (mg/l)	: 16-27		
FORMATION	: Muddy	pF SIZE (fr. V_p)	: 0.1	SURF. RET. (mg/g)	:
ZONE	: —	pF SALINITY (mg/l)	: 4200		
AGE	: Cretaceous	pF HARDNESS (mg/l)	: 9	PROJ. LIFE (mos.)	:
DEP. ENVIR.	: Interdeltaic Barrier Bar	OTHER pF AGENT	: Alkaline Silicate (pH ~ 12)	CAP. NO.: (5.8 x 10 ⁻³)	
				MOBILITY RATIOS -	
CLAY FR.	: 0.03-0.07	SLUG SIZE (fr. V_p)	: 0.035	SLUG - OIL	: 0.21
C.E.C. (meq/g)	:	SLUG OIL CONTENT	: 0.40	MB - SLUG	: 0.69
CLAY TYPE	: Illite, altered opal, montmorillonite	SLUG VISC. (cp)	: 22		
				OIL REC (fr. S_{or})	:

REFERENCES : 1, 3, 7, 11-15, 17-24

BENTON

STATE : Illinois		SURF. TYPE : Pet. Sulfonate
COUNTY : Franklin	NET PAY (ft) : 4	SURF. CONC. (fr.) : 0.013
OPERATOR/ (Partner) : Shell	PERM. (md) : 90	CO-SURF TYPE : Sodium Tripolyphosphate
PROJECT : Pilot	PERM. VAR. (D-P) : 0.42	CO-SURF CONC. (fr.) : 0.005
BEGIN : 5/68		
END : 1/69	POROSITY (fr.) : 0.17	SLUG. POL. CONC. (ppm) : 400
		SLUG SALINITY (mg/l) : 3500
PROJ. AREA (acres) : 1	OIL VIS. (cp) : 3.5	SLUG HARDNESS (mg/l) : 400
INJECTORS : 3	RES. OIL SAT. (fr) : 0.32	
PRODUCERS : 1	CRUDE TYPE : Napthenic	MB POLY TYPE : Polyacrylamide
PAT. TYPE : IRR		MB VISC. (cp) : (~4)
NUM. PAT. : 1		MB CONC. (ppm) : 275
ACRES/PAT : 1	WETTABILITY: WW	MB SIZE (fr. V_p) : (3.30)
		MB SALINITY (mg/l) : 880
DEPTH (feet) : 2120	RESIDENT SALINITY (mg/l) : (41,000)	MB HARDNESS (mg/l) :
TEMPERATURE (°F) : 95	RESIDENT HARDNESS (mg/l) : (4,800)	
FORMATION : Tar Springs	pF SIZE (fr. V_p) : (1.30)	SURF. RET. (mg/g) : 0.13
ZONE : B	pF SALINITY (mg/l) : (3500)	
AGE : Mississippian	pF HARDNESS (mg/l) : (400)	PROJ. LIFE (mos.) : 12
DEP. ENVIR. : Channel	OTHER pF AGENT : -	CAP. NO.:
		MOBILITY RATIOS -
CLAY FR. : (.05)	SLUG SIZE (fr. V_p) : (1.11)	SLUG - OIL : (2-5)
C.E.C. (meq/g) : 0.004	SLUG OIL CONTENT : 0	MB - SLUG : (~1)
CLAY TYPE : Illite, koalinite, chlorite (50% of total)	SLUG VISC. (cp) :	
		OIL REC (fr. S_{or}) : 0.29

REFERENCES : 1, 25-29.

BENTON

STATE	: Illinois			SURF. TYPE	: Pet. Sulfonate
COUNTY	: Franklin	NET PAY (ft)	: 44	SURF. CONC. (fr.)	: (0.5)
OPERATOR/	: Shell	PERM. (md)	: (55)	CO-SURF TYPE	: Neodol
(Partner)		PERM. VAR. (D-P)	: 0.42	CO-SURF CONC. (fr.)	:
PROJECT	: Stage I				
BEGIN	: 1972				
END	: —	POROSITY (fr.)	: 0.19	SLUG. POL. CONC. (ppm):	
				SLUG SALINITY (mg/l)	: 5430
PROJ. AREA (acres)	: 160	OIL VIS. (cp)	: 3.5	SLUG HARDNESS (mg/l):	: 336
INJECTORS	: 6	RES. OIL SAT. (fr)	: 0.32		
PRODUCERS	: 15	CRUDE TYPE	: Napthenic	MB POLY TYPE	: Polyacrylamide
PAT. TYPE	: IRR			MB VISC. (cp)	: (~10)
NUM. PAT.	: —			MB CONC. (ppm)	: (650)
ACRES/PAT	: —	WETTABILITY:	WW	MB SIZE (fr. V_p)	:
				MB SALINITY (mg/l)	: 880
DEPTH (feet)	: 2100	RESIDENT SALINITY (mg/l)	: (41,000)	MB HARDNESS (mg/l)	: 130
TEMPERATURE (°F)	: 95	RESIDENT HARDNESS (mg/l)	: (4880)		
FORMATION	: Tar Springs	pF SIZE (fr. V_p)	: (0.08)	SURF. RET. (mg/g)	:
ZONE	: —	pF SALINITY (mg/l)	: (3500)		
AGE	: Mississippian	pF HARDNESS (mg/l)	: (400)	PROJ. LIFE (mos.)	:
DEP. ENVIR.	: Channel	OTIIEP pF AGENT	: —	CAP. NO.:	
				MOBILITY RATIOS	:
CLAY FR.	: (0.05)	SLUG SIZE (fr. V_p)	: 0.10	SLUG - OIL	: 0.8
C.E.C. (meq/g)	: 0.004	SLUG OIL CONTENT	: 0	MB - SLUG	: 0.8
CLAY TYPE	: Illite, kaolinite, chlorite (50% of latter)	SLUG VISC. (cp)	: 15		
				OIL REC (fr. S_{or})	:

REFERENCES: 1, 2, 3, 27-30

BIG MUDDY

STATE	: Wyoming			SURF. TYPE	: Sodium Sulfonate
COUNTY	: Converse	NET PAY (ft)	: 65	SURF. CONC. (fr.)	: 0.025
OPERATOR/	: Conoco	PERM. (md)	: 52	CO-SURF TYPE	: Alcohol
(Partner)		PERM. VAR. (D-P)	: 0.6	CO-SURF CONC. (fr.)	: 0.03
PROJECT	: Pilot				
BEGIN	: 8/73				
END	: 2/78	POROSITY (fr.)	: 0.19	SLUG. POL. CONC. (ppm)	: 200
				SLUG SALINITY (mg/l)	: 4166
PROJ. AREA (acres)	: 1.25	OIL VIS. (cp)	: 4	SLUG HARDNESS (mg/l)	: 17
INJECTORS	: 4	RES. OIL SAT. (fr)	: 0.32		
PRODUCERS	: 1	CRUDE TYPE	:	MB POLY TYPE	: Biopolymer
PAT. TYPE	: CN5			MB VISC. (cp)	: 6
NUM. PAT.	: 1			MB CONC. (ppm)	: 200
ACRES/PAT	: 1.25	WETTABILITY:	WW	MB SIZE (fr. V_p)	: 0.3
				MB SALINITY (mg/l)	: (4166)
DEPTH (feet)	: 3050	RESIDENT SALINITY (mg/l)	: 3050	MB HARDNESS (mg/l)	: (17)
TEMPERATURE (°F)	: 120	RESIDENT HARDNESS (mg/l)	: 23		
FORMATION	: Frontier F	pF SIZE (fr. V_p)	: 0.8	SURF. RET. (mg/g)	: 0.34(L)
ZONE	: 2nd Wall Creek	pF SALINITY (mg/l)	: 4166		
AGE	: Cretaceous	pF HARDNESS (mg/l)	: 17	PROJ. LIFE (mos.)	: 62
DEP. ENVIR. :		OTHER pF AGENT	: —	CAP. NO.: (5 x 10 ⁻⁴)*	
				MOBILITY RATIOS -	
CLAY FR.	: (0.11)	SLUG SIZE (fr. V_p)	: 0.25	SLUG - OIL	: 1.0
C.E.C. (meq/g):		SLUG OIL CONTENT	: 0	MB - SLUG	: 1.0
CLAY TYPE	: kaolinite, illite, chlorite	SLUG VISC. (cp)	: 6		
				OIL REC (fr. S_{or})	: 0.35

REFERENCES: 1-4, 7, 11, 31-34

*using measured IFT

BIG MUDDY

STATE	: Wyoming			SURF. TYPE	:
COUNTY	: Converse	NET PAY (ft)	: 65	SURF. CONC. (fr.)	:
OPERATOR/	: Conoco/(DOE)	PERM. (md)	: 52	CO-SURF TYPE	:
(Partner)		PERM. VAR. (D-P)	: 0.61	CO-SURF CONC. (fr.)	:
PROJECT	: Demonstration				
BEGIN	: 1979				
END	:	POROSITY (fr.)	: 0.19	SLUG. POL. CONC. (ppm)	:
				SLUG SALINITY (mg/l)	:
PROJ. AREA (acres)	: 90	OIL VIS. (cp)	: 5.5	SLUG HARDNESS (mg/l)	:
INJECTORS	: 9	RES. OIL SAT. (fr)	:		
PRODUCERS	: 16	CRUDE TYPE	:	MB POLY TYPE	: Polyacrylamide
PAT. TYPE	: 15			MB VISC. (cp)	:
NUM. PAT.	: 9			MB CONC. (ppm)	:
ACRES/PAT	: 10	WETTABILITY:	WW	MB SIZE (fr. V_p)	:
				MB SALINITY (mg/l)	:
DEPTH (feet)	: 300	RESIDENT SALINITY (mg/l)	: 3050	MB HARDNESS (mg/l)	:
TEMPERATURE (°F)	: 115	RESIDENT HARDNESS (mg/l)	: 23		
FORMATION	: Frontier	pF SIZE (fr. V_p)	:	SURF. RET. (mg/g)	: (0.22) (L)
ZONE	: 2nd Wall Creek	pF SALINITY (mg/l)	:		
AGE	: Cretaceous	pF HARDNESS (mg/l)	:	PROJ. LIFE (mos.)	:
DEP. ENVIR.	:	OTHER pF AGENT	:	CAP. NO.: (4.2 x 10 ⁻⁴)	
				MOBILITY RATIOS	:
CLAY FR.	: <0.11	SLUG SIZE (fr. V_p)	:	SLUG - OIL	:
C.E.C. (meq/g)	: 0.0041	SLUG OIL CONTENT	:	MB - SLUG	:
CLAY TYPE	: Montmorillonite (<0.06), kaolinite (0.05)	SLUG VISC. (cp)	:		
				OIL REC (fr. S_{or})	:

REFERENCES : 1, 15, 35

BORREGOS

STATE	: Texas			SURF. TYPE	: Pet. sulfonate
COUNTY	: Kleberg	NET PAY (ft)	: 3.8	SURF. CONC. (fr.)	: 0.023
OPERATOR/	: Exxon	PERM. (md)	: 434	CO-SURF TYPE	: —
(Partner)		PERM. VAR. (D-P)	: (0.7)	CO-SURF CONC. (fr.)	: 0
PROJECT	: —				
BEGIN	: 1965				
END	: 1966	POROSITY (fr.)	: 0.21	SLUG. POL. CONC. (ppm)	: —
				SLUG SALINITY (mg/l)	: 1030
PROJ. AREA (acres)	: 1.25	OIL VIS. (cp)	: 0.36	SLUG HARDNESS (mg/l)	: 20
INJECTORS	: 4	RES. OIL SAT. (fr)	: 0.307		
PRODUCERS	: 1	CRUDE TYPE	:	MB POLY TYPE	: —
PAT. TYPE	: N5			MB VISC. (cp)	: 0.40
NUM. PAT.	: 1			MB CONC. (ppm)	: 0
ACRES/PAT	: 1.25	WETTABILITY:		MB SIZE (fr. V_p)	: 0
				MB SALINITY (mg/l)	: 1030
DEPTH (feet)	: 4998	RESIDENT SALINITY (mg/l)	: 19,600	MB HARDNESS (mg/l)	: 20
TEMPERATURE (°F)	: 165	RESIDENT HARDNESS (mg/l)	: 1671		
FORMATION	: Frio	pF SIZE (fr. V_p)	:	SURF. RET. (mg/g)	: 0.80
ZONE	: F-4 Sand	pF SALINITY (mg/l)	: 1030		
AGE	: Oligocene	pF HARDNESS (mg/l)	: 20	PROJ. LIFE (mos.)	:
DEP. ENVIR.	: Channel	OTHER pF AGENT	: —	CAP. NO.: (1.9 x 10 ⁻²)	
				MOBILITY RATIOS -	
CLAY FR.	: 0.085	SLUG SIZE (fr. V_p)	: 0.47	SLUG - OIL	: 4-6
C.E.C. (meq/g)	:	SLUG OIL CONTENT	: 0	MB - SLUG	: 1
CLAY TYPE	: Montmorillonite	SLUG VISC. (cp)	: 0.40		
				OIL REC (fr. S_{or})	: 0.20

REFERENCES : 1, 36, (37)

BRADFORD

STATE	: Pennsylvania			SURF. TYPE	: Pet. Sulfonate
COUNTY	: McKean	NET PAY (ft)	: 23.7	SURF. CONC. (fr.)	: 0.13
OPERATOR/ (Partner)	: Pennzoil/ (Marathon)	PERM. (md)	: 82	CO-SURF TYPE	:
PROJECT	: Bingham 533	PERM. VAR. (D-P)	: (~0.65)	CO-SURF CONC. (fr.)	: 0.02
BEGIN	: 12/68				
END	: 5/71	POROSITY (fr.)	: 0.18	SLUG. POL. CONC. (ppm)	: -
				SLUG SALINITY (mg/l)	:
PROJ. AREA (acres)	: 0.75	OIL VIS. (cp)	: 5	SLUG HARDNESS (mg/l)	:
INJECTORS	: 1	RES. OIL SAT. (fr)	: 0.308		
PRODUCERS	: 4	CRUDE TYPE	: Paraffinic	MB POLY TYPE	: Polyacrylamide
PAT. TYPE	: 15			MB VISC. (cp)	: 50
NUM. PAT.	: 1			MB CONC. (ppm)	: 1700
ACRES/PAT	: 0.75	WETTABILITY:	OW	MB SIZE (fr. V_p)	: 1.4
				MB SALINITY (mg/l)	:
DEPTH (feet)	: 1860	RESIDENT SALINITY (mg/l)	: 2800	MB HARDNESS (mg/l)	:
TEMPERATURE (°F)	: 68	RESIDENT HARDNESS (mg/l)	: 150		
FORMATION	: Bradford	pF SIZE (fr. V_p)	: -	SURF. RET. (mg/g)	:
ZONE	: 3rd Sand	pF SALINITY (mg/l)	: -		
AGE	: Devonian	pF HARDNESS (mg/l)	: -	PROJ. LIFE (mos.)	: 29
DEP. ENVIR.	:	OTHER pF AGENT	: -	CAP. NO.: (1.0 x 10 ⁻³)	
				MOBILITY RATIOS -	
CLAY FR.	:	SLUG SIZE (fr. V_p)	: 0.064	SLUG - OIL	: ~1
C.E.C. (meq/g)	:	SLUG OIL CONTENT	: 0.39	MB - SLUG	: ~0.7
CLAY TYPE	:	SLUG VISC. (cp)	: 35		
				OIL REC (fr. S_{or})	: (0.57)

REFERENCES: 5, 6, 9, 38

BRADFORD

STATE	: Pennsylvania			SURF. TYPE	: Pet. sulfonate
COUNTY	: McKean	NET PAY (ft)	: ~23	SURF. CONC. (fr.)	: 0.12
OPERATOR/ (Partner)	: Pennzoil/ (Marathon)	PERM. (md)	: 82	CO-SURF TYPE	: Amyl alcohol
PROJECT	: Bingham Expansion	PERM. VAR. (D-P)	:	CO-SURF CONC. (fr.)	: 0.01
BEGIN	: 3/23/71				
END	: 2/75	POROSITY (fr.)	: 0.18	SLUG. POL. CONC. (ppm)	: —
				SLUG SALINITY (mg/l)	:
PROJ. AREA (acres)	: 46.5	OIL VIS. (cp)	: 5	SLUG HARDNESS (mg/l)	:
INJECTORS	: 16	RES. OIL SAT. (fr)	: 0.362		
PRODUCERS	: 25	CRUDE TYPE	: Paraffinic	MB POLY TYPE	: Polyacrylamide
PAT. TYPE	: CN5			MB VISC. (cp)	: 50.
NUM. PAT.	: 16			MB CONC. (ppm)	: 1500
ACRES/PAT	: 2.9	WETTABILITY:	OW	MB SIZE (fr. V_p)	: 1.2
				MB SALINITY (mg/l)	:
DEPTH (feet)	: 1866	RESIDENT SALINITY (mg/l)	: 2800	MB HARDNESS (mg/l)	:
TEMPERATURE (°F)	: 68	RESIDENT HARDNESS (mg/l)	: 150		
FORMATION	: Bradford	pF SIZE (fr. V_p)	: —	SURF. RET. (mg/g)	:
ZONE	: 3rd Sand	pF SALINITY (mg/l)	: —		
AGE	: Devonian	pF HARDNESS (mg/l)	: —	PROJ. LIFE (mos.)	: 47
DEP. ENVIR.	:	OTHER pF AGENT	: —	CAP. NO.: (8.4×10^{-4})	
				MOBILITY RATIOS -	
CLAY FR.	:	SLUG SIZE (fr. V_p)	: 0.05	SLUG - OIL	: ~1
C.E.C. (meq/g)	:	SLUG OIL CONTENT	: 0.47	MB - SLUG	: ~0.5
CLAY TYPE	:	SLUG VISC. (cp)	: 25		

REFERENCES : 1-7, 9, 38

OIL REC (fr. S_{or}) : 0.43

BRADFORD

STATE :	Pennsylvania		SURF. TYPE :	TRS-16, TRS-40	
COUNTY :	McKean	NET PAY (ft) :	29	SURF. CONC. (fr.) :	0.09
OPERATOR/ (Partner) :	Pennzoil/ (Marathon/DOE)	PERM. (md) :	8	CO-SURF TYPE :	Amyl & Norm Butyl Alcohol
		PERM. VAR. (D-P) :	(0.65)	CO-SURF CONC. (fr.) :	0.01
PROJECT :	Lawry				
BEGIN :	5/77				
END :		POROSITY (fr.) :	0.13	SLUG. POL. CONC. (ppm) :	-
				SLUG SALINITY (mg/l) :	
PROJ. AREA (acres) :	24	OIL VIS. (cp) :	5	SLUG HARDNESS (mg/l) :	
INJECTORS :	16	RES. OIL SAT. (fr) :	0.32 (L)		
PRODUCERS :	25	CRUDE TYPE :	Paraffinic	MB POLY TYPE :	Biopolymer
PAT. TYPE :	N5			MB VISC. (cp) :	5.3-5.8
NUM. PAT. :	16			MB CONC. (ppm) :	
ACRES/PAT :	1.5	WETTABILITY:	OW	MB SIZE (fr. V_p) :	
				MB SALINITY (mg/l) :	
DEPTH (feet) :	1280	RESIDENT SALINITY (mg/l) :	3000 (TDS)	MB HARDNESS (mg/l) :	
TEMPERATURE (°F) :	64	RESIDENT HARDNESS (mg/l) :			
FORMATION :	Bradford	pF SIZE (fr. V_p) :	0.10	SURF. RET. (mg/g) :	
ZONE :	3rd Sand	pF SALINITY (mg/l) :	(31,000)		
AGE :	Devonian	pF HARDNESS (mg/l) :		PROJ. LIFE (mos.) :	
DEP. ENVIR. :		OTHER pF AGENT :	-	CAP. NO.: 8×10^{-5}	
				MOBILITY RATIOS -	
CLAY FR. :		SLUG SIZE (fr. V_p) :	0.094	SLUG - OIL :	-
C.E.C. (meq/g) :		SLUG OIL CONTENT :	0.28	MB - SLUG :	-
CLAY TYPE :		SLUG VISC. (cp) :	7.5-9		

REFERENCES : 1, 3, 7; 12, 13, 39-41

BRIDGEPORT

STATE : Illinois
 COUNTY : Lawrence
 OPERATOR/ : Marathon
 (Partner)
 PROJECT : 118K
 BEGIN : 9/69
 END : 12/71

PROJ. AREA (acres) : 2.4
 INJECTORS : 4
 PRODUCERS : 1
 PAT. TYPE : R5
 NUM. PAT. : 1
 ACRES/PAT : 2.4

DEPTH (feet) : 1500

TEMPERATURE (°F) :

FORMATION : Kirkwood

ZONE :

AGE :

DEP. ENVIR. :

CLAY FR. :

C.E.C. (meq/g) :

CLAY TYPE :

NET PAY (ft) :
 PERM. (md) : 90
 PERM. VAR. (D-P) :

POROSITY (fr.) : 0.18

OIL VIS. (cp) : 5.5

RES. OIL SAT. (fr) : 0.3-0.45

CRUDE TYPE :

WETTABILITY:

RESIDENT SALINITY (mg/l) :

RESIDENT HARDNESS (mg/l) :

pF SIZE (fr. V_p) : -

pF SALINITY (mg/l) : -

pF HARDNESS (mg/l) : -

OTHER pF AGENT : -

SLUG SIZE (fr. V_p) : 0.085

SLUG OIL CONTENT : >0

SLUG VISC. (cp) :

SURF. TYPE :

SURF. CONC. (fr.) : 0.09

CO-SURF TYPE :

CO-SURF CONC. (fr.) :

SLUG. POL. CONC. (ppm) : -

SLUG SALINITY (mg/l) :

SLUG HARDNESS (mg/l) :

MB POLY TYPE :

MB VISC. (cp) :

MB CONC. (ppm) :

MB SIZE (fr. V_p) : 0.87

MB SALINITY (mg/l) :

MB HARDNESS (mg/l) :

SURF. RET. (mg/g) :

PROJ. LIFE (mos.) : 27

CAP. NO.: 8×10^{-4}

MOBILITY RATIOS -

SLUG - OIL :

MB - SLUG :

OIL REC (fr. S_{or}) : (0.32 - 0.48)

REFERENCES : 2, 5, 6, 9

CHATEAURENARD

STATE :	France		SURF. TYPE :	Pet. Sulfonate	
COUNTY :	—	NET PAY (ft) :	8	SURF. CONC. (fr.) :	
OPERATOR/ (Partner) :	Elf Aquitaine	PERM. (md) :	1000	CO-SURF TYPE :	Alcohol mixture
PROJECT :	—	PERM. VAR. (D-P) :	—	CO-SURF CONC. (fr.) :	
BEGIN :	2/78				
END :		POROSITY (fr.) :	0.3	SLUG. POL. CONC. (ppm) :	—
				SLUG SALINITY (mg/l) :	400(T)
PROJ. AREA (acres) :	2.5	OIL VIS. (cp) :	40	SLUG HARDNESS (mg/l) :	70
INJECTORS :	1	RES. OIL SAT. (fr) :	0.3*		
PRODUCERS :	4	CRUDE TYPE :	Paraffinic	MB POLY TYPE :	Polyacrylamides
PAT. TYPE :	15			MB VISC. (cp) :	
NUM. PAT. :	1			MB CONC. (ppm) :	1700
ACRES/PAT :	2.5	WETTABILITY:		MB SIZE (fr. V_p) :	1.25
				MB SALINITY (mg/l) :	400 (TDS)
DEPTH (feet) :	1970	RESIDENT SALINITY (mg/l) :	400 (TDS)	MB HARDNESS (mg/l) :	70
TEMPERATURE (°F) :	86	RESIDENT HARDNESS (mg/l) :	70		
FORMATION :	Neocomian	pF SIZE (fr. V_p) :	—	SURF. RET. (mg/g) :	1 (L)
ZONE :	R3	pF SALINITY (mg/l) :	—		
AGE :	Lower Cretaceous	pF HARDNESS (mg/l) :	—	PROJ. LIFE (mos.) :	—
DEP. ENVIR. :		OTHER pF AGENT :	—	CAP. NO.:	1.2×10^{-2}
				MOBILITY RATIOS:	
CLAY FR. :	0.02-0.15	SLUG SIZE (fr. V_p) :	0.10	SLUG - OIL :	
C.E.C. (meq/g) :		SLUG OIL CONTENT :	>0	MB - SLUG :	
CLAY TYPE :		SLUG VISC. (cp) :			

REFERENCES : 11, 42

OIL REC (fr. S_{or}) :

* $S_o \sim 0.55$ at start of flood

DELAWARE - CHILDERS

STATE :	Oklahoma		SURF. TYPE :	Amoco Floodaid 1	
COUNTY :	Nowata	NET PAY (ft) :	52	SURF. CONC. (fr.) :	0.054
OPERATOR/ (Partner) :	B & N Oil Co./ (DOE)	PERM. (md) :	100	CO-SURF TYPE :	Amoco 12
PROJECT :	Mary Costen Unit	PERM. VAR. (D-P) :	(0.48)	CO-SURF CONC. (fr.) :	0.018
BEGIN :	11/75				
END :		POROSITY (fr.) :	0.21	SLUG. POL. CONC. (ppm) :	0
				SLUG SALINITY (mg/l) :	5260
PROJ. AREA (acres) :	2.5	OIL VIS. (cp) :	6.9	SLUG HARDNESS (mg/l) :	28
INJECTORS :	2 (twinned)	RES. OIL SAT. (fr) :	0.34		
PRODUCERS :	4	CRUDE TYPE :		MB POLY TYPE :	Polyacrylamide
PAT. TYPE :	C15			MB VISC. (cp) :	20
NUM. PAT. :	1			MB CONC. (ppm) :	1350
ACRES/PAT :	2.5	WETTABILITY:	OW	MB SIZE (fr. V_p) :	0.4
				MB SALINITY (mg/l) :	1790
DEPTH (feet) :	620	RESIDENT SALINITY (mg/l) :	5200	MB HARDNESS (mg/l) :	28
TEMPERATURE (°F) :	86	RESIDENT HARDNESS (mg/l) :	695		
FORMATION :	Bartlesville	pF SIZE (fr. V_p) :	0.113	SURF. RET. (mg/g) :	(0.42) (L)
ZONE :	—	pF SALINITY (mg/l) :	5860		
AGE :	Pennsylvanian	pF HARDNESS (mg/l) :	29	PROJ. LIFE (mos.) :	—
DEP. ENVIR. :		OTHER pF AGENT :	—	CAP. NO.:	(3.7×10^{-4})
				MOBILITY RATIOS-	
CLAY FR. :	0.10	SLUG SIZE (fr. V_p) :	0.085	SLUG - OIL :	~1
C.E.C. (meq/g) :		SLUG OIL CONTENT :	0	MB - SLUG :	0.5
CLAY TYPE :	Kaolinite	SLUG VISC. (cp) :	10		

REFERENCES : 1, 3, 7, 11-15, 43

*as of 1/79

EL DORADO

STATE :	Kansas		SURF. TYPE :	Pet. Sulfonate	
COUNTY :	Butler	NET PAY (ft) :	18.4	SURF. CONC. (fr.) :	0.026
OPERATOR/ (Partner)	Cities Service/ (DOE) (Shell)	PERM. (md) :	265	CO-SURF TYPE :	Sec. Butanol
PROJECT :	Chesney	PERM. VAR. (D-P) :	0.78	CO-SURF CONC. (fr.) :	0.04
BEGIN :	11/76				
END :		POROSITY (fr.) :	0.243	SLUG. POL. CONC. (ppm):	900
				SLUG SALINITY (mg/l) :	425
PROJ. AREA (acres) :	25.6	OIL VIS. (cp) :	5.2	SLUG HARDNESS (mg/l) :	~0
INJECTORS :	9	RES. OIL SAT. (fr) :	0.333		
PRODUCERS :	4	CRUDE TYPE :		MB POLY TYPE :	Biopolymer
PAT. TYPE :	N5			MB VISC. (cp) :	(~80)
NUM. PAT. :	4			MB CONC. (ppm) :	(~2000)
ACRES/PAT :	6.4	WETTABILITY: OW		MB SIZE (fr. V_p) :	0.66
				MB SALINITY (mg/l) :	~50
DEPTH (feet) :	650	RESIDENT SALINITY (mg/l) :	53,000	MB HARDNESS (mg/l) :	~8
TEMPERATURE (°F) :	69	RESIDENT HARDNESS (mg/l) :	4200		
FORMATION :	Waubaussee	pF SIZE (fr. V_p) :	(0.41) (2nd preflush)	SURF. RET. (mg/g) :	(0.5)
ZONE :	Admire	pF SALINITY (mg/l) :	1750		
AGE :	Permian	pF HARDNESS (mg/l) :	~100	PROJ. LIFE (mos.) :	
DEP. ENVIR. :	Deltaic (Channel)	OTHER pF AGENT :	—	CAP. NO.: (0.0 x 10 ⁻⁴)	
				MOBILITY RATIOS -	
CLAY FR. :	0.15 - 0.21	SLUG SIZE (fr. V_p) :	0.113	SLUG - OIL :	
C.E.C. (meq/g) :	(.0022 - .0035)	SLUG OIL CONTENT :	0.00	MB - SLUG :	
CLAY TYPE :	Illite, kaolinite, chlorite	SLUG VISC. (cp) :			
				OIL REC (fr. S_{or}) :	—

REFERENCES : 1, 4, 7, 11-15, 24, 44-52

EL DORADO

STATE :	Kansas			SURF. TYPE :	Pet. Sulfonate
COUNTY :	Butler	NET PAY (ft) :	17.5	SURF. CONC. (fr.) :	~0.12
OPERATOR/ (Partner) :	Cities Service/ (DOE) (Union)	PERM. (md) :	208	CO-SURF TYPE :	ethylene glyco monobutyl ethal
PROJECT :	Hegberg	PERM. VAR. (D-P) :	0.85	CO-SURF CONC. (fr.) :	0.026
BEGIN :	6/76				
END :		POROSITY (fr.) :	0.245	SLUG. POL. CONC. (ppm) :	0
				SLUG SALINITY (mg/l) :	
PROJ. AREA (acres) :	25.6	OIL VIS. (cp) :	4.8	SLUG HARDNESS (mg/l) :	
INJECTORS :	9	RES. OIL SAT. (fr.) :	0.307		
PRODUCERS :	4	CRUDE TYPE :		MB POLY TYPE :	Polyacrylamide
PAT. TYPE :	N5			MB VISC. (cp) :	(~50)
NUM. PAT. :	4			MB CONC. (ppm) :	~1600
ACRES/PAT :	6.4	WETTABILITY:	OW	MB SIZE (fr. V_p) :	0.6
				MB SALINITY (mg/l) :	
DEPTH (feet) :	650	RESIDENT SALINITY (mg/l) :	53,000	MB HARDNESS (mg/l) :	
TEMPERATURE (°F) :	69	RESIDENT HARDNESS (mg/l) :	4200		
FORMATION :	Waubaussee	pF SIZE (fr. V_p) :	(0.16)	SURF. RET. (mg/g) :	
ZONE :	Admire	pF SALINITY (mg/l) :			
AGE :	Permian	pF HARDNESS (mg/l) :		PROJ. LIFE (mos.) :	
DEP. ENVIR. :	Deltaic (Channel)	OTHER pF AGENT :	0.281% sodium silicate	CAP. NO.: (4.7 x 10 ⁻⁴)	
				MOBILITY RATIOS -	
CLAY FR. :	0.15 - 0.21	SLUG SIZE (fr. V_p) :	0.04	SLUG - OIL :	
C.E.C. (meq/g) :	(.0022 - .0035)	SLUG OIL CONTENT :	0.67	MB - SLUG :	
CLAY TYPE :	Illite, kaolinite, chlorite	SLUG VISC. (cp) :			

REFERENCES : 1, 4, 7, 11-15, 24, 44-52

OIL REC (fr. S_{or}) :

GLENN

STATE : Oklahoma

SURF. TYPE :

SURF. CONC. (fr.) :

CO-SURF TYPE :

CO-SURF CONC. (fr.) :

SLUG. POL. CONC. (ppm):

SLUG SALINITY (mg/l) :

SLUG HARDNESS (mg/l) :

MB POLY TYPE : —

MB VISC. (cp) :

MB CONC. (ppm)

MB SIZE (fr. V_p)

MB SALINITY (mg/l)

MB HARDNESS (mg/l) :

SURF. RET. (mg/g) :

PROJ. LIFE (mos.) :

CAP. NO.:

MOBILITY RATIOS.

SLUG - OIL :

MB - SLUG :

OIL REC (fr. S_{Oij}) :

REFERENCES : 3

GOODWILL HILL

STATE :	Pennsylvania		SURF. TYPE :	
COUNTY :	Warren	NET PAY (ft) :		SURF. CONC. (fr.) :
OPERATOR/ (Partner) :	Quaker State/ (Marathon)	PERM. (md) :		CO-SURF TYPE :
PROJECT :		PERM. VAR. (D-P) :		CO-SURF CONC. (fr.) :
BEGIN :	5/71			
END :		POROSITY (fr.) :		SLUG. POL. CONC. (ppm) :
				SLUG SALINITY (mg/l) :
PROJ. AREA (acres) :	10	OIL VIS. (cp) :	~4.5	SLUG HARDNESS (mg/l) :
INJECTORS :	9	RES. OIL SAT. (fr) :		
PRODUCERS :	16	CRUDE TYPE :		MB POLY TYPE :
PAT. TYPE :	15			MB VISC. (cp) :
NUM. PAT. :	9			MB CONC. (ppm) :
ACRES/PAT :	1.11	WETTABILITY:		MB SIZE (fr. V_p) :
				0.95
				MB SALINITY (mg/l) :
DEPTH (feet) :	600	RESIDENT SALINITY (mg/l) :		MB HARDNESS (mg/l) :
TEMPERATURE (°F) :		RESIDENT HARDNESS (mg/l) :		
FORMATION :	Venago	pF SIZE (fr. V_p) :	—	SURF. RET. (mg/g) :
ZONE :	1st Sand	pF SALINITY (mg/l) :	—	
AGE :		pF HARDNESS (mg/l) :	—	PROJ. LIFE (mos.) :
DEP. ENVIR. :		OTHER pF AGENT :	—	CAP. NO.:
				MOBILITY RATIOS-
CLAY FR. :		SLUG SIZE (fr. V_p) :	0.05	SLUG - OIL :
C.E.C. (meq/g) :		SLUG OIL CONTENT :		MB - SLUG :
CLAY TYPE :		SLUG VISC. (cp) :		

REFERENCES : 2, 5, 9

OIL REC (fr. S_{or}) :

GRIFFIN CONSOLIDATED

STATE :	Indiana		SURF. TYPE :	
COUNTY :	Gibson	NET PAY (ft) :		SURF. CONC. (fr.) :
OPERATOR/ (Partner) :	Conoco	PERM. (md) :	75	CO-SURF TYPE :
PROJECT :		PERM. VAR. (D-P) :		CO-SURF CONC. (fr.) :
BEGIN :	11/73			
END :	8/77	POROSITY (fr.) :	0.2	SLUG. POL. CONC. (ppm) :
				SLUG SALINITY (mg/l) :
PROJ. AREA (acres) :	0.8	OIL VIS. (cp) :	3.6	SLUG HARDNESS (mg/l) :
INJECTORS :	1	RES. OIL SAT. (fr) :	0.30	
PRODUCERS :	4	CRUDE TYPE :		MB POLY TYPE :
PAT. TYPE :	N5			MB VISC. (cp) :
NUM. PAT. :	1			MB CONC. (ppm) :
ACRES/PAT :	0.8	WETTABILITY:		MB SIZE (fr. V_p) :
				MB SALINITY (mg/l) :
DEPTH (feet) :	2400	RESIDENT SALINITY (mg/l) :		MB HARDNESS (mg/l) :
TEMPERATURE (°F) :	85	RESIDENT HARDNESS (mg/l) :		
FORMATION :	Upper Cypress	pF SIZE (fr. V_p) :		SURF. RET. (mg/g) :
ZONE :		pF SALINITY (mg/l) :		
AGE :		pF HARDNESS (mg/l) :		PROJ. LIFE (mos.) :
DEP. ENVIR. :		OTHER pF AGENT :		CAP. NO.: (2.1×10^{-3})
				MOBILITY RATIOS -
CLAY FR. :		SLUG SIZE (fr. V_p) :		SLUG - OIL :
C.E.C. (meq/g) :		SLUG OIL CONTENT :		MB - SLUG :
CLAY TYPE :		SLUG VISC. (cp) :		

REFERENCES : 3, 4, 7

OIL REC (fr. S_{or}) :

GUERRA

STATE :	Texas			SURF. TYPE :	Coconut-oil diethanolamide
COUNTY :	Starr	NET PAY (ft) :	9	SURF. CONC. (fr.) :	0.04
OPERATOR/ (Partner) :	Sun	PERM. (md) :	2500	CO-SURF TYPE :	Ethylene diamine tetracetic acid
PROJECT :		PERM. VAR. (D-P) :		CO-SURF CONC. (fr.) :	
BEGIN :	(1970)				
END :	(1973)	POROSITY (fr.) :	0.33	SLUG. POL. CONC. (ppm) :	-
				SLUG SALINITY (mg/l) :	
PROJ. AREA (acres) :	2	OIL VIS. (cp) :	1.6	SLUG HARDNESS (mg/l) :	
INJECTORS :	4	RES. OIL SAT. (fr) :	(0.39)		
PRODUCERS :	2	CRUDE TYPE :		MB POLY TYPE :	-
PAT. TYPE :	N5			MB VISC. (cp) :	-
NUM. PAT. :	1			MB CONC. (ppm) :	0
ACRES/PAT :	2	WETTABILITY :		MB SIZE (fr. V_p) :	-
				MB SALINITY (mg/l) :	
DEPTH (feet) :	2200	RESIDENT SALINITY (mg/l) :	20,000	MB HARDNESS (mg/l) :	
TEMPERATURE (°F) :	122	RESIDENT HARDNESS (mg/l) :	300		
FORMATION :	Jackson	pF SIZE (fr. V_p) :	-	SURF. RET. (mg/g) :	.05 mg/g (L)
ZONE :		pF SALINITY (mg/l) :	-		
AGE :		pF HARDNESS (mg/l) :	-	PROJ. LIFE (mos.) :	
DEP. ENVIR. :		OTHER pF AGENT :	-	CAP. NO.: (3.8 x 10 ⁻²)	
				MOBILITY RATIOS :	
CLAY FR. :		SLUG SIZE (fr. V_p) :	0.13	SLUG - OIL :	
C.E.C. (meq/g) :		SLUG OIL CONTENT :	0	MB - SLUG :	
CLAY TYPE :		SLUG VISC. (cp) :			
				OIL REC (fr. S_{or}) :	

REFERENCES : 53

JONES CITY REGULAR

STATE : Texas

COUNTY : Jones

OPERATOR/ : Union
(Partner)

PROJECT : Higgs Unit

BEGIN : 7/69

END : 12/71

PROJ. AREA (acres) : 8.2

INJECTORS : 1

PRODUCERS : 3

PAT. TYPE : Q19

NUM. PAT. : 1

ACRES/PAT : 8.2

DEPTH (feet) : 1870

TEMPERATURE (°F) : 95

FORMATION : Bluff Creek

ZONE :

AGE : Permian

DEP. ENVIR. : —

CLAY FR. :

C.E.C. (meq/g) :

CLAY TYPE :

NET PAY (ft) : 14.25

PERM. (md) : 500

PERM. VAR. (D-P) : 0.62

POROSITY (fr.) : 0.229

OIL VIS. (cp) : 4.3

RES. OIL SAT. (fr) : 0.23

CRUDE TYPE :

WETTABILITY:

RESIDENT SALINITY (mg/l) : 54,000

RESIDENT HARDNESS (mg/l) : 6400

pF SIZE (fr. V_p) : 0.017

pF SALINITY (mg/l) :

pF HARDNESS (mg/l) :

OTHER pF AGENT : Polymer

SLUG SIZE (fr. V_p) : 0.028

SLUG OIL CONTENT : >0

SLUG VISC. (cp) :

SURF. TYPE :

SURF. CONC. (fr.) : 0.09

CO-SURF TYPE : —

CO-SURF CONC. (fr.) : 0.018

SLUG. POL. CONC. (ppm) :

SLUG SALINITY (mg/l) :

SLUG HARDNESS (mg/l) :

MB POLY TYPE :

MB VISC. (cp) :

MB CONC. (ppm) :

MB SIZE (fr. V_p) : 0.34

MB SALINITY (mg/l) :

MB HARDNESS (mg/l) :

SURF. RET. (mg/g) :

PROJ. LIFE (mos.) : 17

CAP. NO.: —

MOBILITY RATIOS :

SLUG - OIL :

MB - SLUG :

OIL REC (fr. S_{or}) : (.19)

REFERENCES : 1, 2, 54

LOMA NOVIA

STATE : Texas		SURF. TYPE :
COUNTY : Duval	NET PAY (ft) : 10-12	SURF. CONC. (fr.) : 0.019
OPERATOR/ : Mobil (Partner)	PERM. (md) :	CO-SURF TYPE : Sodium carbonate sodium tripolyphosphate
PROJECT :	PERM. VAR. (D-P) :	CO-SURF CONC. (fr.) :
BEGIN :		
END :	POROSITY (fr.) :	SLUG. POL. CONC. (ppm) : 0
		SLUG SALINITY (mg/l) : 6675
PROJ. AREA (acres) : 5	OIL VIS. (cp) :	SLUG HARDNESS (mg/l) :
INJECTORS : 4	RES. OIL SAT. (fr) : 0.2	
PRODUCERS : 1	CRUDE TYPE : Napthenic	MB POLY TYPE : -
PAT. TYPE : N5		MB VISC. (cp) : -
NUM. PAT. : 1		MB CONC. (ppm) : 0
ACRES/PAT : 5	WETTABILITY:	MB SIZE (fr. V_p) : 0.1
		MB SALINITY (mg/l) : 2000
DEPTH (feet) :	RESIDENT SALINITY (mg/l) : 6060	MB HARDNESS (mg/l) :
TEMPERATURE (°F) :	RESIDENT HARDNESS (mg/l) : 38	
FORMATION : Frio	pF SIZE (fr. V_p) : ~0.1	SURF. RET. (mg/g) :
ZONE :	pF SALINITY (mg/l) : 6000-12,000	
AGE : Oligocene	pF HARDNESS (mg/l) :	PROJ. LIFE (mos.) :
DEP. ENVIR. :	OTHER pF AGENT : $Na_5P_3O_{10}$ $NaCO_3$	CAP. NO.:
		MOBILITY RATIOS -
CLAY FR. : 0.095	SLUG SIZE (fr. V_p) : 0.12	SLUG - OIL :
C.E.C. (meq/g) :	SLUG OIL CONTENT : 0	MB - SLUG :
CLAY TYPE : Kaolinite (.055), sodium montmorillonite (.04)	SLUG VISC. (cp) :	OIL REC (fr. S_{or}) :

REFERENCES : 1, 55

LOUDEN

STATE :	Illinois		SURF. TYPE :	Pet. sulfonate	
COUNTY :	Fayette	NET PAY (ft) :	15.5	SURF. CONC. (fr.) :	0.023
OPERATOR/ (Partner) :	Exxon	PERM. (md) :	103	CO-SURF TYPE :	-
PROJECT :		PERM. VAR. (D-P) :	(0.42)	CO-SURF CONC. (fr.) :	-
BEGIN :	1969				
END :	1971	POROSITY (fr.) :	0.206	SLUG. POL. CONC. (ppm) :	242
				SLUG SALINITY (mg/l) :	(2850)
PROJ. AREA (acres) :	0.625	OIL VIS. (cp) :	14 (oil bank)	SLUG HARDNESS (mg/l) :	
INJECTORS :	4	RES. OIL SAT. (fr) :	0.291		
PRODUCERS :	1	CRUDE TYPE :		MB POLY TYPE :	Biopolymer
PAT. TYPE :	N5			MB VISC. (cp) :	10
NUM. PAT. :	1			MB CONC. (ppm) :	558
ACRES/PAT :	0.625	WETTABILITY :		MB SIZE (fr. V_p) :	0.32
				MB SALINITY (mg/l) :	(2850)
DEPTH (feet) :	1460	RESIDENT SALINITY (mg/l) :	13,000**	MB HARDNESS (mg/l) :	
TEMPERATURE (°F) :	95	RESIDENT HARDNESS (mg/l) :			
FORMATION :	Chester Cypress	pF SIZE (fr. V_p) :	.098	SURF. RET. (mg/g) :	0.42
ZONE :	Weiler sand	pF SALINITY (mg/l) :	(2850)		
AGE :	Mississippian	pF HARDNESS (mg/l) :		PROJ. LIFE (mos.) :	~24
DEP. ENVIR. :	Bar	OTHER pF AGENT :	0.0081 Na_2CO_3 0.0043 NH_3	CAP. NO. :	$(2.03 \times 10^{-4})^*$
				MOBILITY RATIOS :	
CLAY FR. :	0.09	SLUG SIZE (fr. V_p) :	0.4	SLUG - OIL :	~.7(L)
C.E.C. (meq/g) :		SLUG OIL CONTENT :	0	MB - SLUG :	~1
CLAY TYPE :	Kaolinite, montmorillonite	SLUG VISC. (cp) :	10		
				OIL REC (fr. S_{or}) :	0.153

REFERENCES : 1, (36), 56

*based on measured IFT
**produced water

MAIN CONSOLIDATED

STATE :	Illinois		SURF. TYPE :	
COUNTY :		NET PAY (ft) :		SURF. CONC. (fr.) :
OPERATOR/ (Partner) :	Getty	PERM. (md) :	200	CO-SURF TYPE :
PROJECT :		PERM. VAR. (D-P) :		CO-SURF CONC. (fr.) :
BEGIN :	1980			
END :		POROSITY (fr.) :	0.20	SLUG. POL. CONC. (ppm) :
				SLUG SALINITY (mg/l) :
PROJ. AREA (acres) :	10	OIL VIS. (cp) :	10	SLUG HARDNESS (mg/l) :
INJECTORS :	4	RES. OIL SAT. (fr) :	0.465	
PRODUCERS :	9	CRUDE TYPE :		MB POLY TYPE :
PAT. TYPE :	N5			MB VISC. (cp) :
NUM. PAT. :	9			MB CONC. (ppm) :
ACRES/PAT :	11	WETTABILITY:		MB SIZE (fr. V_p) :
				MB SALINITY (mg/l) :
DEPTH (feet) :	1000	RESIDENT SALINITY (mg/l) :		MB HARDNESS (mg/l) :
TEMPERATURE (°F) :	200 (?)	RESIDENT HARDNESS (mg/l) :		
FORMATION :	Robinson	pF SIZE (fr. V_p) :		SURF. RET. (mg/g) :
ZONE :		pF SALINITY (mg/l) :		
AGE :		pF HARDNESS (mg/l) :		PROJ. LIFE (mos.) :
DEP. ENVIR. :		OTHER pF AGENT :		CAP. NO.:
				MOBILITY RATIOS-
CLAY FR. :		SLUG SIZE (fr. V_p) :		SLUG - OIL :
C.E.C. (meq/g) :		SLUG OIL CONTENT :		MB - SLUG :
CLAY TYPE :		SLUG VISC. (cp) :		
				OIL REC (fr. S_{or}) :

REFERENCES: 3

MANVEL

STATE : Texas

COUNTY : Brazoria

OPERATOR/ : Texaco
(Partner)

PROJECT :

BEGIN : 6/77

END :

PROJ. AREA (acres) : 10

INJECTORS : 2

PRODUCERS : 3

PAT. TYPE : SLD

NUM. PAT. : 1

ACRES/PAT : 10

DEPTH (feet) : 5400

TEMPERATURE (°F) : 165

FORMATION : Frio

ZONE : A-1 (Fault block III)

AGE : Oligocene

DEP. ENVIR. : Fluvial Bar

CLAY FR. : .04-.12

C.E.C. (meq/g) :

CLAY TYPE :

NET PAY (ft) : 17

PERM. (md) : 500

PERM. VAR. (D-P) :

POROSITY (fr.) : .03

OIL VIS. (cp) : 4

RES. OIL SAT. (fr) : 0.3

CRUDE TYPE :

WETTABILITY:

RESIDENT SALINITY (mg/l) : 107,000 (TDS)

RESIDENT HARDNESS (mg/l) : 2400

pF SIZE (fr. V_p) : -

pF SALINITY (mg/l) : -

pF HARDNESS (mg/l) : -

OTHER pF AGENT : -

SLUG SIZE (fr. V_p) : 0.25

SLUG OIL CONTENT : 0

SLUG VISC. (cp) :

SURF. TYPE :

SURF. CONC. (fr.) : 0.025

CO-SURF TYPE : -

CO-SURF CONC. (fr.) : -

SLUG. POL. CONC. (ppm) : -

SLUG SALINITY (mg/l) :

SLUG HARDNESS (mg/l) :

MB POLY TYPE : Biopolymer

MB VISC. (cp) : 40

MB CONC. (ppm) : 1400

MB SIZE (fr. V_p) : 0.5

MB SALINITY (mg/l) : 21,400 (TDS)

MB HARDNESS (mg/l) : 480

SURF. RET. (mg/g) :

PROJ. LIFE (mos.) : ~24

CAP. NO.: (2.1×10^{-2})

MOBILITY RATIOS :

SLUG - OIL :

MB - SLUG :

OIL REC (fr. S_{or}) :

REFERENCES : 1, 57

MONTAGNE COUNTY REGULAR

STATE	:	Texas	SURF. TYPE	:	Pet. sulfonate
COUNTY	:	Montagne	NET PAY (ft)	:	
OPERATOR/	:	Conoco	PERM. (md)	:	
(Partner)	:		PERM. VAR. (D-P)	:	
PROJECT	:		CO-SURF TYPE	:	-
BEGIN	:		CO-SURF CONC. (fr.)	:	-
END	:		POROSITY (fr.)	:	
	:		SLUG. POL. CONC. (ppm)	:	0
PROJ. AREA (acres)	:		SLUG SALINITY (mg/l)	:	
INJECTORS	:		SLUG HARDNESS (mg/l)	:	
PRODUCERS	:		CRUDE TYPE	:	
PAT. TYPE	:		MB POLY TYPE	:	-
NUM. PAT.	:		MB VISC. (cp)	:	-
ACRES/PAT	:		MB CONC. (ppm)	:	0
	:		MB SIZE (fr. V_p)	:	-
	:		MB SALINITY (mg/l)	:	
DEPTH (feet)	:		MB HARDNESS (mg/l)	:	
TEMPERATURE (°F)	:		RESIDENT SALINITY (mg/l)	:	150,000 (TDS)
FORMATION	:		RESIDENT HARDNESS (mg/l)	:	
ZONE	:		pF SIZE (fr. V_p)	:	-
AGE	:		pF SALINITY (mg/l)	:	-
DEP. ENVIR.	:		pF HARDNESS (mg/l)	:	-
	:		OTHER pF AGENT	:	-
	:		PROJ. LIFE (mos.)	:	
CLAY FR.	:		CAP. NO.:	:	
C.E.C. (meq/g)	:		MOBILITY RATIOS -	:	
CLAY TYPE	:		SLUG - OIL	:	
	:		MB - SLUG	:	
	:		OIL REC (fr. S_{or})	:	

REFERENCES : 2, 31-33

NORTH BURBANK

STATE : Oklahoma

COUNTY : Osage

OPERATOR/ : Phillips/(DOE)
(Partner)

PROJECT : Tract 97

BEGIN : 8/2/76

END :

PROJ. AREA (acres) : 90

INJECTORS : 9

PRODUCERS : 16

PAT. TYPE : 15

NUM. PAT. : 9

ACRES/PAT : 10

DEPTH (feet) : 2900

TEMPERATURE (°F) : 120

FORMATION : Cherokee

ZONE :

AGE : Pennsylvanian

DEP. ENVIR. : Interdeltaic Bar

CLAY FR. :

C.E.C. (meq/g) :

CLAY TYPE : Chamosite

NET PAY (ft) : 47

PERM. (md) : 52

PERM. VAR. (D-P) : 0.61

POROSITY (fr.) : 0.155

OIL VIS. (cp) : 3

RES. OIL SAT. (fr) : 0.35

CRUDE TYPE :

WETTABILITY: OW

RESIDENT SALINITY (mg/l) : 53,400

RESIDENT HARDNESS (mg/l) : 7260

pF SIZE (fr. V_p) : (0.46)

pF SALINITY (mg/l) :
pF HARDNESS (mg/l) : } two preflushes

OTHER pF AGENT : =

SLUG SIZE (fr. V_p) : 0.06

SLUG OIL CONTENT : 0

SLUG VISC. (cp) :

SURF. TYPE : TRS-10-410

SURF. CONC. (fr.) : 0.038

CO-SURF TYPE : Isobutyri alcohol

CO-SURF CONC. (fr.) : .03

SLUG. POL. CONC. (ppm) : -

SLUG SALINITY (mg/l) : 5800

SLUG HARDNESS (mg/l) : 68

MB POLY TYPE : Polyacrylamide

MB VISC. (cp) : 81

MB CONC. (ppm) : 2500

MB SIZE (fr. V_p) : 0.465

MB SALINITY (mg/l) : 350

MB HARDNESS (mg/l) : 68

SURF. RET. (mg/g) : (0.29) (L)

PROJ. LIFE (mos.) :

CAP. NO.: (4×10^{-4})

MOBILITY RATIOS-

SLUG - OIL :

MB - SLUG :

OIL REC (fr. S_{or}) : 0.19

*as of 4/1/79

REFERENCES : 1, 4, 7, 11-15, 58-64

RINCON

STATE : Texas

COUNTY : Starr

OPERATOR/ : Conoco
(Partner)

PROJECT :

BEGIN :

END :

PROJ. AREA (acres) :

INJECTORS :

PRODUCERS :

PAT. TYPE :

NUM. PAT. :

ACRES/PAT :

DEPTH (feet) :

TEMPERATURE (°F) :

FORMATION :

ZONE :

AGE :

DEP. ENVIR. :

CLAY FR. :

C.E.C. (meq/g) :

CLAY TYPE :

NET PAY (ft) :

PERM. (md) :

PERM. VAR. (D-P) :

POROSITY (fr.) :

OIL VIS. (cp) :

RES. OIL SAT. (fr) :

CRUDE TYPE :

WETTABILITY :

RESIDENT SALINITY (mg/l) : 25,000 (TDS)

RESIDENT HARDNESS (mg/l) :

pF SIZE (fr. V_p) :

pF SALINITY (mg/l) :

pF HARDNESS (mg/l) :

OTHER pF AGENT :

SLUG SIZE (fr. V_p) :

SLUG OIL CONTENT : 0

SLUG VISC. (cp) :

SURF. TYPE :

SURF. CONC. (fr.) :

CO-SURF TYPE :

CO-SURF CONC. (fr.) :

SLUG. POL. CONC. (ppm): 0

SLUG SALINITY (mg/l) :

SLUG HARDNESS (mg/l) :

MB POLY TYPE : -

MB VISC. (cp) : -

MB CONC. (ppm) : 0

MB SIZE (fr. V_p) : -

MB SALINITY (mg/l) :

MB HARDNESS (mg/l) :

SURF. RET. (mg/g) :

PROJ. LIFE (mos.) :

CAP. NO.:

MOBILITY RATIOS -

SLUG - OIL :

MB - SLUG :

OIL REC (fr. S_{or}) :

REFERENCES : 31-33

ROBINSON

STATE : Illinois		SURF. TYPE : Pet. sulfonate
COUNTY : Crawford	NET PAY (ft) :	SURF. CONC. (fr.) : 0.072
OPERATOR/ (Partner) : Marathon	PERM. (md) :	CO-SURF TYPE :
PROJECT : Dedrick	PERM. VAR. (D-P) :	CO-SURF CONC. (fr.) : 0.038
BEGIN : 11/62		
END : 12/64	POROSITY (fr.) : (0.2)	SLUG. POL. CONC. (ppm) : -
		SLUG SALINITY (mg/l) :
PROJ. AREA (acres) : 2.5	OIL VIS. (cp) : 7	SLUG HARDNESS (mg/l) :
INJECTORS : 4	RES. OIL SAT. (fr) : (0.7)	
PRODUCERS : 1	CRUDE TYPE : Napthenic	MB POLY TYPE :
PAT. TYPE : N5		MB VISC. (cp) :
NUM. PAT. : 1		MB CONC. (ppm) :
ACRES/PAT : 2.5	WETTABILITY:	MB SIZE (fr. V_p) : 0.066
		MB SALINITY (mg/l) :
DEPTH (feet) : 1000	RESIDENT SALINITY (mg/l) :	MB HARDNESS (mg/l) :
TEMPERATURE (°F) :	RESIDENT HARDNESS (mg/l) :	
FORMATION : Robinson	pF SIZE (fr. V_p) : -	SURF. RET. (mg/g) :
ZONE :	pF SALINITY (mg/l) : -	
AGE :	pF HARDNESS (mg/l) : -	PROJ. LIFE (mos.) : 25
DEP. ENVIR. :	OTHER pF AGENT : -	CAP. NO.: -
		MOBILITY RATIOS-
CLAY FR. :	SLUG SIZE (fr. V_p) : 0.035	SLUG - OIL :
C.E.C. (meq/g) :	SLUG OIL CONTENT : 0.65	MB - SLUG :
CLAY TYPE :	SLUG VISC. (cp) :	

REFERENCES : 5, 6, 8-10, 65, 66

OIL REC (fr. S_{or}) : 0.35*

*based on initial oil saturation of 0.7 (secondary flood)

ROBINSON

STATE : Illinois
COUNTY : Crawford
OPERATOR/ : Marathon
(Partner)
PROJECT : Henry-W
BEGIN : 11/8/65
END : 4/17/67

NET PAY (ft) : 10
PERM. (md) : 200
PERM. VAR. (D-P) : (0.26)

POROSITY (fr.) : 0.20

PROJ. AREA (acres) : 0.75
INJECTORS : 1
PRODUCERS : 4
PAT. TYPE : 15
NUM. PAT. : 1
ACRES/PAT : 0.75

OIL VIS. (cp) : 7
RES. OIL SAT. (fr) : 0.4
CRUDE TYPE : Napthenic

WETTABILITY:

DEPTH (feet) : 1000
TEMPERATURE (°F) : 72
FORMATION : Robinson
ZONE :
AGE :
DEP. ENVIR. :

RESIDENT SALINITY (mg/l) : 10,000
RESIDENT HARDNESS (mg/l) : -
pF SIZE (fr. V_p) : -
pF SALINITY (mg/l) : -
pF HARDNESS (mg/l) : -
OTHER pF AGENT : -

CLAY FR. :
C.E.C. (meq/g):
CLAY TYPE :

SLUG SIZE (fr. V_p) : 0.09
SLUG OIL CONTENT : (~0.5)
SLUG VISC. (cp) : 30

SURF. TYPE : Pet. sulfonate
SURF. CONC. (fr.) : (0.10)
CO-SURF TYPE : Isopropyl and
nonyl alcohol
CO-SURF CONC. (fr.) : 0.018

SLUG. POL. CONC. (ppm): -

SLUG SALINITY (mg/l) : 500 (T)

SLUG HARDNESS (mg/l) :

MB POLY TYPE : Polyacrylamide

MB VISC. (cp) : 30

MB CONC. (ppm) : 1200

MB SIZE (fr. V_p) : 1.91

MB SALINITY (mg/l) : 500

MB HARDNESS (mg/l) :

SURF. RET. (mg/g) : (0.73)

PROJ. LIFE (mos.) : ~17

CAP. NO.: (2.4×10^{-3})

MOBILITY RATIOS-

SLUG - OIL : (~1)

MB - SLUG : (~1)

OIL REC (fr. S_{or}) : 0.63

REFERENCES : 5, 6, 7, 8-10, 65-67

ROBINSON

STATE : Illinois
COUNTY : Crawford
OPERATOR/ : Marathon
(Partner)
PROJECT : Henry-E(I)
BEGIN : 11/65
END : 6/66

NET PAY (ft) : 10
PERM. (md) : 200
PERM. VAR. (D-P) :

POROSITY (fr.) : 0.2

SURF. TYPE :
SURF. CONC. (fr.) :
CO-SURF TYPE :
CO-SURF CONC. (fr.) :

SLUG. POL. CONC. (ppm) : -

SLUG SALINITY (mg/l) :

SLUG HARDNESS (mg/l) :

PROJ. AREA (acres) : 0.75

OIL VIS. (cp) : 7

INJECTORS : 1

RES. OIL SAT. (fr) : 0.4

PRODUCERS : 4

CRUDE TYPE : Napthenic

MB POLY TYPE :

PAT. TYPE : 15

MB VISC. (cp) :

NUM. PAT. : 1

MB CONC. (ppm) :

ACRES/PAT : 0.75

WETTABILITY:

MB SIZE (fr. V_p) : 0.44

MB SALINITY (mg/l) :

DEPTH (feet) : 1000

RESIDENT SALINITY (mg/l) : 10,000

MB HARDNESS (mg/l) :

TEMPERATURE (°F) : 72

RESIDENT HARDNESS (mg/l) :

FORMATION : Robinson

pF SIZE (fr. V_p) : -

SURF. RET. (mg/g) :

ZONE :

pF SALINITY (mg/l) : -

AGE :

pF HARDNESS (mg/l) : -

PROJ. LIFE (mos.) : 7

DEP. ENVIR. : non-marine

OTHER pF AGENT : -

CAP. NO.: (2.4×10^{-3})

MOBILITY RATIOS -

CLAY FR. :

SLUG SIZE (fr. V_p) : 0.40

SLUG - OIL :

C.E.C. (meq/g) :

SLUG OIL CONTENT : >0

MB - SLUG :

CLAY TYPE :

SLUG VISC. (cp) :

OIL REC (fr. S_{or}) : 0.27

REFERENCES : 5, 6, 8-10, 66, 67

ROBINSON

STATE :	Illinois		SURF. TYPE :	
COUNTY :	Crawford	NET PAY (ft) :	10	SURF. CONC. (fr.) :
OPERATOR/ (Partner) :	Marathon	PERM. (md) :	200	CO-SURF TYPE :
PROJECT :	Henry-E(II)	PERM. VAR. (D-P) :		CO-SURF CONC. (fr.) :
BEGIN :	6/66 (expanded)			
END :	1/67	POROSITY (fr.) :	0.2	SLUG. POL. CONC. (ppm) : -
				SLUG SALINITY (mg/l) :
PROJ. AREA (acres) :	1.5	OIL VIS. (cp) :	7	SLUG HARDNESS (mg/l) :
INJECTORS :	1	RES. OIL SAT. (fr) :	0.4	
PRODUCERS :	4	CRUDE TYPE :	Napthenic	MB POLY TYPE :
PAT. TYPE :	I5			MB VISC. (cp) :
NUM. PAT. :	1			MB CONC. (ppm) :
ACRES/PAT :	1.5	WETTABILITY:		MB SIZE (fr. V_p) : 0.83
				MB SALINITY (mg/l) :
DEPTH (feet) :	1000	RESIDENT SALINITY (mg/l) :	10,000	MB HARDNESS (mg/l) :
TEMPERATURE (°F) :	72	RESIDENT HARDNESS (mg/l) :		
FORMATION :	Robinson	pF SIZE (fr. V_p) :	-	SURF. RET. (mg/g) :
ZONE :		pF SALINITY (mg/l) :	-	
AGE :		pF HARDNESS (mg/l) :	-	PROJ. LIFE (mos.) : 14
DEP. ENVIR. :		OTHER pF AGENT :	-	CAP. NO.: (1.6 x 10 ⁻³)
				MOBILITY RATIOS -
CLAY FR. :		SLUG SIZE (fr. V_p) :	0.20	SLUG - OIL :
C.E.C. (meq/g) :		SLUG OIL CONTENT :	>0	MB - SLUG :
CLAY TYPE :		SLUG VISC. (cp) :		
				OIL REC (fr. S_{or}) : 0.33

REFERENCES : 5, 6, 8-10, 66, 67

ROBINSON

STATE : Illinois

COUNTY : Crawford

OPERATOR/ : Marathon
(Partner)

PROJECT : Henry E (III)

BEGIN : 6/67 (expanded)

END : 6/68

PROJ. AREA (acres) : 3

INJECTORS : 1

PRODUCERS : 4

PAT. TYPE : 15

NUM. PAT. : 1

ACRES/PAT : 3

DEPTH (feet) : 1000

TEMPERATURE (°F) : 72

FORMATION : Robinson

ZONE :

AGE :

DEP. ENVIR. :

CLAY FR. :

C.E.C. (meq/g) :

CLAY TYPE :

NET PAY (ft) : 10

PERM. (md) : 200

PERM. VAR. (D-P) :

POROSITY (fr.) : 0.2

OIL VIS. (cp) : 7

RES. OIL SAT. (fr) : 0.4

CRUDE TYPE :

WETTABILITY:

RESIDENT SALINITY (mg/l) : 10,000

RESIDENT HARDNESS (mg/l) :

pF SIZE (fr. V_p) : -

pF SALINITY (mg/l) : -

pF HARDNESS (mg/l) : -

OTHER pF AGENT : -

SLUG SIZE (fr. V_p) : 0.10

SLUG OIL CONTENT : >0

SLUG VISC. (cp) :

SURF. TYPE :

SURF. CONC. (fr.) :

CO-SURF TYPE :

CO-SURF CONC. (fr.) :

SLUG. POL. CONC. (ppm) : -

SLUG SALINITY (mg/l) :

SLUG HARDNESS (mg/l) :

MB POLY TYPE :

MB VISC. (cp) :

MB CONC. (ppm) :

MB SIZE (fr. V_p) : 0.55

MB SALINITY (mg/l) :

MB HARDNESS (mg/l) :

SURF. RET. (mg/g) :

PROJ. LIFE (mos.) : 26

CAP. NO.: 1.1×10^{-3}

MOBILITY RATIOS -

SLUG - OIL :

MB - SLUG :

OIL REC (fr. S_{or}) : 0.26

REFERENCES : 5, 6, 8-10, 66, 67

ROBINSON

STATE	: Illinois			SURF. TYPE	: Pet. sulfonate
COUNTY	: Crawford	NET PAY (ft)	:	SURF. CONC. (fr.)	: 0.072
OPERATOR/ (Partner)	: Marathon	PERM. (md)	: (200)	CO-SURF TYPE	:
PROJECT	: Wilkin	PERM. VAR. (D-P)	:	CO-SURF CONC. (fr.)	: 0.038
BEGIN	: 1/64				
END	: 1/65	POROSITY (fr.)	: (0.2)	SLUG. POL. CONC. (ppm)	: -
				SLUG SALINITY (mg/l)	:
PROJ. AREA (acres)	: 2.5	OIL VIS. (cp)	: 9	SLUG HARDNESS (mg/l)	:
INJECTORS	: 4	RES. OIL SAT. (fr)	: 0.4		
PRODUCERS	: 1	CRUDE TYPE	: Napthenic	MB POLY TYPE	:
PAT. TYPE	: N5			MB VISC. (cp)	:
NUM. PAT.	: 1			MB CONC. (ppm)	:
ACRES/PAT	: 2.5	WETTABILITY:		MB SIZE (fr. V_p)	: 0.068
				MB SALINITY (mg/l)	:
DEPTH (feet)	: 1000	RESIDENT SALINITY (mg/l)	: 3700	MB HARDNESS (mg/l)	:
TEMPERATURE (°F)	:	RESIDENT HARDNESS (mg/l)	:		
FORMATION	: Robinson	pF SIZE (fr. V_p)	: -	SURF. RET. (mg/g)	:
ZONE	:	pF SALINITY (mg/l)	: -		
AGE	:	pF HARDNESS (mg/l)	: -	PROJ. LIFE (mos.)	: 24
DEP. ENVIR.	:	OTHER pF AGENT	: -	CAP. NO.: 1.2×10^{-3}	
				MOBILITY RATIOS	:
CLAY FR.	:	SLUG SIZE (fr. V_p)	: 0.025	SLUG - OIL	:
C.E.C. (meq/g)	:	SLUG OIL CONTENT	: 0.54	MB - SLUG	:
CLAY TYPE	:	SLUG VISC. (cp)	:		
				OIL REC (fr. S_{or})	: 0.14

REFERENCES: 5, 6, 8-10, 66

ROBINSON

STATE	: Illinois			SURF. TYPE	: Pet. sulfonate
COUNTY	: Crawford	NET PAY (ft)	: 25	SURF. CONC. (fr.)	: 0.11
OPERATOR/	: Marathon	PERM. (md)	: 211	CO-SURF TYPE	: Primary amyl alcohol
(Partner)		PERM. VAR. (D-P)	:	CO-SURF CONC. (fr.)	: 0.023
PROJECT	: 119R				
BEGIN	: 9/68				
END	:	POROSITY (fr.)	: 0.193	SLUG. POL. CONC. (ppm)	: -
				SLUG SALINITY (mg/l)	:
PROJ. AREA (acres)	: 40	OIL VIS. (cp)	: 7	SLUG HARDNESS (mg/l)	:
INJECTORS	: 18	RES. OIL SAT. (fr)	: 0.40		
PRODUCERS	: 27	CRUDE TYPE	:	MB POLY TYPE	: Polyacrylamide
PAT. TYPE	: LD			MB VISC. (cp)	: (~50)
NUM. PAT.	: 16			MB CONC. (ppm)	: 1200
ACRES/PAT	: 2.5	WETTABILITY:		MB SIZE (fr. V_p)	: 1.0
				MB SALINITY (mg/l)	:
DEPTH (feet)	: 1000	RESIDENT SALINITY (mg/l)	: 10,000	MB HARDNESS (mg/l)	:
TEMPERATURE (°F)	: 72	RESIDENT HARDNESS (mg/l)	:		
FORMATION	: Robinson	pF SIZE (fr. V_p)	: -	SURF. RET. (mg/g)	:
ZONE	:	pF SALINITY (mg/l)	: -		
AGE	: Pennsylvanian	pF HARDNESS (mg/l)	: -	PROJ. LIFE (mos.)	: -
DEP. ENVIR.	: Non-marine fluvial	OTHER pF AGENT	: -	CAP. NO.: (3.6 x 10 ⁻³)	
				MOBILITY RATIOS -	
CLAY FR.	:	SLUG SIZE (fr. V_p)	: 0.07	SLUG - OIL :	
C.E.C. (meq/g)	:	SLUG OIL CONTENT	: >0	MB - SLUG :	
CLAY TYPE	:	SLUG VISC. (cp)	: 30		
				OIL REC (fr. S_{or})	: 0.38*

REFERENCES : 1-6, 8-10, 65, 66

*as of 1/78

ROBINSON

STATE : Illinois
COUNTY : Crawford
OPERATOR/ : Marathon
(Partner)
PROJECT : 219R

BEGIN : 10/1/75
END : ~1980

PROJ. AREA (acres) : 113
INJECTORS : 39
PRODUCERS : 55
PAT. TYPE : C5
NUM. PAT. : ~37
ACRES/PAT : 3

DEPTH (feet) : 1000
TEMPERATURE (°F) : 72
FORMATION : Robinson
ZONE :
AGE : Pennsylvania
DEP. ENVIR. : Point bar

CLAY FR. :
C.E.C. (meq/g) :
CLAY TYPE :

NET PAY (ft) : 16.6
PERM. (md) : 165
PERM. VAR. (D-P) : 0.62

POROSITY (fr.) : 0.208

OIL VIS. (cp) : ~7
RES. OIL SAT. (fr) : 0.40
CRUDE TYPE : Napthenic

WETTABILITY:

RESIDENT SALINITY (mg/l) : 9400
RESIDENT HARDNESS (mg/l) :
pF SIZE (fr. V_p) : -
pF SALINITY (mg/l) : -
pF HARDNESS (mg/l) : -
OTHER pF AGENT : -

SLUG SIZE (fr. V_p) : 0.102
SLUG OIL CONTENT : 0.135 - 0.185
SLUG VISC. (cp) : 35

SURF. TYPE : Sulfonated crude
SURF. CONC. (fr.) : 0.10
CO-SURF TYPE : 50-50 blend of
primary amyl and normal butyl alcohol
CO-SURF CONC. (fr.) : 0.015

SLUG. POL. CONC. (ppm) : -
SLUG SALINITY (mg/l) :
SLUG HARDNESS (mg/l) :

MB POLY TYPE : Polyacrylamide
MB VISC. (cp) : (~50)
MB CONC. (ppm) : 1156
MB SIZE (fr. V_p) : 1.05
MB SALINITY (mg/l) : 200
MB HARDNESS (mg/l) : 25

SURF. RET. (mg/g) :

PROJ. LIFE (mos.) :
CAP. NO.: (8.9×10^{-4})
MOBILITY RATIOS:

SLUG - OIL :
MB - SLUG :

OIL REC (fr. S_{or}) : 0.18*

*as of 1/78

REFERENCES : 1, 4, 8, 66-68

SALEM

STATE : Illinois

COUNTY : Marion

OPERATOR/ : Texaco/(Mobil)
(Partner)

PROJECT :

BEGIN : 12/8/74

END : ~4/76

PROJ. AREA (acres) : 5

INJECTORS : 4

PRODUCERS : 1

PAT. TYPE : CN5

NUM. PAT. : 1

ACRES/PAT : 5

DEPTH (feet) : 1750

TEMPERATURE (°F) : 80

FORMATION : Upper Benoist

ZONE :

AGE : Mississippian

DEP. ENVIR. :

CLAY FR. :

C.E.C. (meq/g) :

CLAY TYPE :

NET PAY (ft) : 26

PERM. (md) : 87

PERM. VAR. (D-P) : (~0.34)

POROSITY (fr.) : 0.148

OIL VIS. (cp) : 3.6

RES. OIL SAT. (fr) : 0.3

CRUDE TYPE :

WETTABILITY:

RESIDENT SALINITY (mg/l) : 40,000

RESIDENT HARDNESS (mg/l) : 3300

pF SIZE (fr. V_p) : 0.519
freshpF SALINITY (mg/l) : fresh
3640

pF HARDNESS (mg/l) : (~0)

OTHER pF AGENT : -

SLUG SIZE (fr. V_p) : 0.285

SLUG OIL CONTENT : 0.0

SLUG VISC. (cp) :

SURF. TYPE : TRS-10-80

SURF. CONC. (fr.) : 0.016

CO-SURF TYPE : -

CO-SURF CONC. (fr.) : -

SLUG. POL. CONC. (ppm) : -

SLUG SALINITY (mg/l) : 3640

SLUG HARDNESS (mg/l) :

MB POLY TYPE : Biopolymer

MB VISC. (cp) :

MB CONC. (ppm) : 700

MB SIZE (fr. V_p) : 0.3

MB SALINITY (mg/l) : 3640

MB HARDNESS (mg/l) :

SURF. RET. (mg/g) : (0.13)

PROJ. LIFE (mos.) : ~16

CAP. NO.: (8.1×10^{-4})

MOBILITY RATIOS -

SLUG - OIL :

MB - SLUG :

OIL REC (fr. S_{or}) : 0.17

REFERENCES : 1, 3, 72-75, 84

SALES

STATE : Texas

SURF. TYPE :

COUNTY : Jones

NET PAY (ft) :

SURF. CONC. (fr.) :

OPERATOR/ : Conoco
(Partner)

PERM. (md) : 457

CO-SURF TYPE :

PROJECT : Pilot

PERM. VAR. (D-P) :

CO-SURF CONC. (fr.) :

BEGIN : 1963

END :

POROSITY (fr.) : 0.217

SLUG. POL. CONC. (ppm) :

PROJ. AREA (acres) : 2.5

OIL VIS. (cp) :

SLUG SALINITY (mg/l) :

SLUG HARDNESS (mg/l) :

INJECTORS :

RES. OIL SAT. (fr) : 0.30

PRODUCERS :

CRUDE TYPE :

MB POLY TYPE :

PAT. TYPE :

MB VISC. (cp) :

NUM. PAT. :

MB CONC. (ppm) :

ACRES/PAT :

WETTABILITY:

MB SIZE (fr. V_p) :

MB SALINITY (mg/l) :

DEPTH (feet) : 1900

RESIDENT SALINITY (mg/l) :

MB HARDNESS (mg/l) :

TEMPERATURE (°F) :

RESIDENT HARDNESS (mg/l) :

FORMATION : Flippen

pF SIZE (fr. V_p) :

SURF. RET. (mg/g) :

ZONE :

pF SALINITY (mg/l) :

AGE :

pF HARDNESS (mg/l) :

PROJ. LIFE (mos.) :

DEP. ENVIR. :

OTHER pF AGENT :

CAP. NO.:

MOBILITY RATIOS-

CLAY FR. :

SLUG SIZE (fr. V_p) :

SLUG - OIL :

C.E.C. (meq/g) :

SLUG OIL CONTENT :

MB - SLUG :

CLAY TYPE :

SLUG VISC. (cp) :

OIL REC (fr. S_{or}) :

REFERENCES : 3

SALT CREEK

STATE :	Wyoming		SURF. TYPE :	
COUNTY :	Natrona	NET PAY (ft) :	(76)	SURF. CONC. (fr.) :
OPERATOR/ (Partner) :	Amoco	PERM. (md) :	(58)	CO-SURF TYPE :
PROJECT :		PERM. VAR. (D-P) :	(0.64)	CO-SURF CONC. (fr.) :
BEGIN :	Proposed			
END :		POROSITY (fr.) :	0.18	SLUG. POL. CONC. (ppm) :
				SLUG SALINITY (mg/l) :
PROJ. AREA (acres) :	3	OIL VIS. (cp) :	3.1	SLUG HARDNESS (mg/l) :
INJECTORS :	4	RES. OIL SAT. (fr) :		
PRODUCERS :	1	CRUDE TYPE :		MB POLY TYPE :
PAT. TYPE :	N5			MB VISC. (cp) :
NUM. PAT. :	1			MB CONC. (ppm) :
ACRES/PAT :	3	WETTABILITY :		MB SIZE (fr. V_p) :
				MB SALINITY (mg/l) :
DEPTH (feet) :	2300	RESIDENT SALINITY (mg/l) :	2601 - 13,367 (TDS)	MB HARDNESS (mg/l) :
TEMPERATURE (°F) :	110	RESIDENT HARDNESS (mg/l) :	107-356	
FORMATION :	Frontier	pF SIZE (fr. V_p) :		SURF. RET. (mg/g) :
ZONE :	2nd Wall Creek	pF SALINITY (mg/l) :		
AGE :	Cretaceous	pF HARDNESS (mg/l) :		PROJ. LIFE (mos.) :
DEP. ENVIR. :		OTHER pF AGENT :		CAP. NO.: (7.2×10^{-4})
				MOBILITY RATIOS -
CLAY FR. :	0.045-0.24	SLUG SIZE (fr. V_p) :		SLUG - OIL :
C.E.C. (meq/g) :	(0.035)	SLUG OIL CONTENT :		MB - SLUG :
CLAY TYPE :	0-6% calcite, 2-7% kaolinite, 5-2% illite, 0-6% chlorite, 0-3% montmorillonite	SLUG VISC. (cp) :		OIL REC (fr. S_{or}) :
REFERENCES :	1, 3, 76, 77			

SLAUGHTER

STATE : Texas

COUNTY : Hockley

OPERATOR/ : Texaco
(Partner)

PROJECT :

BEGIN : 10/73

END :

PROJ. AREA (acres) : 4

INJECTORS : 4

PRODUCERS : 1

PAT. TYPE :

NUM. PAT. :

ACRES/PAT :

DEPTH (feet) : 5000

TEMPERATURE (°F) : 109

FORMATION : San Andres

ZONE :

AGE :

DEP. ENVIR. :

CLAY FR. :

C.E.C. (meq/g) :

CLAY TYPE :

NET PAY (ft) :

PERM. (md) : 4

PERM. VAR. (D-P) :

POROSITY (fr.) : 0.11

OIL VIS. (cp) : 1.8

RES. OIL SAT. (fr) :

CRUDE TYPE :

WETTABILITY:

RESIDENT SALINITY (mg/l) :

RESIDENT HARDNESS (mg/l) :

pF SIZE (fr. V_p) :

pF SALINITY (mg/l) :

pF HARDNESS (mg/l) :

OTHER pF AGENT :

SLUG SIZE (fr. V_p) :

SLUG OIL CONTENT :

SLUG VISC. (cp) :

SURF. TYPE :

SURF. CONC. (fr.) :

CO-SURF TYPE :

CO-SURF CONC. (fr.) :

SLUG. POL. CONC. (ppm) :

SLUG SALINITY (mg/l) :

SLUG HARDNESS (mg/l) :

MB POLY TYPE :

MB VISC. (cp) :

MB CONC. (ppm) :

MB SIZE (fr. V_p) :

MB SALINITY (mg/l) :

MB HARDNESS (mg/l) :

SURF. RET. (mg/g) :

PROJ. LIFE (mos.) :

CAP. NO.:

MOBILITY RATIOS:

SLUG - OIL :

MB - SLUG :

OIL REC (fr. S_{or}) :

REFERENCES : 3

SLOSS

STATE	: Nebraska			SURF. TYPE	: Mahogany AA
COUNTY	: Kimball	NET PAY (ft)	: 12.2	SURF. CONC. (fr.)	: 0.044
OPERATOR/ (Partner)	: Amoco	PERM. (md)	: 93	CO-SURF TYPE	: IPA
		PERM. VAR. (D-P)	: (0.45)	CO-SURF CONC. (fr.)	: 0.034
PROJECT	:				
BEGIN	: 2/26/77				
END	:	POROSITY (fr.)	: 0.17	SLUG. POL. CONC. (ppm)	: 1600
				SLUG SALINITY (mg/l)	: 7280
PROJ. AREA (acres)	: 9	OIL VIS. (cp)	: 0.8	SLUG HARDNESS (mg/l)	: 25
INJECTORS	: 4	RES. OIL SAT. (fr)	: 0.3		
PRODUCERS	: 1	CRUDE TYPE	:	MB POLY TYPE	: Polyacrylamide
PAT. TYPE	: N5			MB VISC. (cp)	: 7
NUM. PAT.	: 1			MB CONC. (ppm)	: 800
ACRES/PAT	: 9	WETTABILITY:	WW	MB SIZE (fr. V_p)	: (~1)
				MB SALINITY (mg/l)	: 260 (TDS)
DEPTH (feet)	: 6256	RESIDENT SALINITY (mg/l)	: 2500(TDS)	MB HARDNESS (mg/l)	: 25
TEMPERATURE (°F)	: 165	RESIDENT HARDNESS (mg/l)	: 50		
FORMATION	: Muddy	pF SIZE (fr. V_p)	: (~3)	SURF. RET. (mg/g)	: (0.43) (L)
ZONE	: J-sand	pF SALINITY (mg/l)	: 7280		
AGE	:	pF HARDNESS (mg/l)	: 25	PROJ. LIFE (mos.)	:
DEP. ENVIR.	: Deltaic splay	OTHER pF AGENT	: 0	CAP. NO.: (1.7×10^{-3})	:
				MOBILITY RATIOS	:
CLAY FR.	: (0.11)	SLUG SIZE (fr. V_p)	: 0.155	SLUG - OIL	: ~1
C.E.C. (meq/g)	:	SLUG OIL CONTENT	: 0	MB - SLUG	: ~1
CLAY TYPE	: Kaolinite, illite, chlorite	SLUG VISC. (cp)	: 4		
				OIL REC (fr. S_{or})	: 0.29*

REFERENCES: 1, 3, 7, 11, 34, 78, 79

*as of 1/79

WICHITA COUNTY REGULAR

STATE	: Texas			SURF. TYPE	: TRS-10-80
COUNTY	: Wichita	NET PAY (ft)	: 13	SURF. CONC. (fr.)	: 0.015
OPERATOR/ (Partner)	: Mobil	PERM. (md)	: 53	CO-SURF TYPE	:
PROJECT	: West Burk Co-op	PERM. VAR. (D-P)	: -	CO-SURF CONC. (fr.)	: -
BEGIN	: 10/75				
END	:	POROSITY (fr.)	: 0.22	SLUG. POL. CONC. (ppm)	: -
				SLUG SALINITY (mg/l)	:
PROJ. AREA (acres)	: 209	OIL VIS. (cp)	: 2.3	SLUG HARDNESS (mg/l)	:
INJECTORS	: 10	RES. OIL SAT. (fr)	: 0.30		
PRODUCERS	: 20	CRUDE TYPE	:	MB POLY TYPE	: Biopolymer
PAT. TYPE	: N5			MB VISC. (cp)	: (~20)
NUM. PAT.	: 4			MB CONC. (ppm)	: 500
ACRES/PAT	: 20	WETTABILITY:		MB SIZE (fr. V_p)	: 0.3
				MB SALINITY (mg/l)	:
DEPTH (feet)	: 1700	RESIDENT SALINITY (mg/l)	: 160,000 (TDS)	MB HARDNESS (mg/l)	:
TEMPERATURE (°F)	: 89	RESIDENT HARDNESS (mg/l)	:		
FORMATION	: Gunsight	pF SIZE (fr. V_p)	: 0.4	SURF. RET. (mg/g)	:
ZONE	:	pF SALINITY (mg/l)	:		
AGE	:	pF HARDNESS (mg/l)	:	PROJ. LIFE (mos.)	:
DEP. ENVIR.	:	OTHER pF AGENT	: 0	CAP. NO.: (1.6×10^{-4})	
				MOBILITY RATIOS -	
CLAY FR.	:	SLUG SIZE (fr. V_p)	: 0.15	SLUG - OIL	:
C.E.C. (meq/g)	:	SLUG OIL CONTENT	: 0	MB - SLUG	:
CLAY TYPE	:	SLUG VISC. (cp)	:		

REFERENCES: 1, 7, 11

OIL REC (fr. S_{or}): <.01*

*as of 1/79

WILMINGTON

STATE :	California		SURF. TYPE :	Petrostep 450,400
COUNTY :	Los Angeles	NET PAY (ft) :	56	SURF. CONC. (fr.) :
OPERATOR/ (Partner) :	Long Beach/ (Marathon) (DOE)	PERM. (md) :	180	CO-SURF TYPE :
PROJECT :		PERM. VAR. (D-P) :	(0.64)	CO-SURF CONC. (fr.) :
BEGIN :	7/77			
END :		POROSITY (fr.) :	0.27	SLUG. POL. CONC. (ppm) :
				SLUG SALINITY (mg/l) :
PROJ. AREA (acres) :	10.7	OIL VIS. (cp) :	31.7	SLUG HARDNESS (mg/l) :
INJECTORS :	4	RES. OIL SAT. (fr) :	(0.30)	
PRODUCERS :	6	CRUDE TYPE :	Aromatic	MB POLY TYPE :
PAT. TYPE :	SLD			MB VISC. (cp) :
NUM. PAT. :	2			MB CONC. (ppm) :
ACRES/PAT :	5.35	WETTABILITY:		MB SIZE (fr. V_p) :
				MB SALINITY (mg/l) :
DEPTH (feet) :	2900	RESIDENT SALINITY (mg/l) :	30,000 (TDS)	MB HARDNESS (mg/l) :
TEMPERATURE (°F) :	125	RESIDENT HARDNESS (mg/l) :		
FORMATION :	Puente	pF SIZE (fr. V_p) :	—	SURF. RET. (mg/g) :
ZONE :	Ranger, Terminal	pF SALINITY (mg/l) :	—	
AGE :	Plio-miocene	pF HARDNESS (mg/l) :	—	PROJ. LIFE (mos.) :
DEP. ENVIR. :		OTHER pF AGENT :	—	CAP. NO.: (5.7×10^{-3})
				MOBILITY RATIOS:
CLAY FR. :		SLUG SIZE (fr. V_p) :	0.07	SLUG - OIL :
C.E.C. (meq/g) :		SLUG OIL CONTENT :	>0	MB - SLUG :
CLAY TYPE :	Vermiculite, montmorillonite	SLUG VISC. (cp) :		

REFERENCES : 1, 7, 11, 13-15, 80-82

APPENDIX B
Data Set Compiled by
Gulf Universities Research Consortium

SURFACTANT-POLYMER PROJECTS

FIELD STATE	Bell Creek Montana	Benton Illinois	Benton Illinois	Big Muddy Wyoming	Big Muddy Wyoming	Borregos Texas	Bradford Pennsylvania	Bradford Pennsylvania	Delaware-Childers Oklahoma	El Dorado Kansas	El Dorado Kansas	Jones City Reg Texas	La Barge Wyoming	Loma Novia Texas	Louden Illinois	Manvel Texas	North Burbank Oklahoma	Robinson Illinois	Robinson Illinois	Robinson Illinois	Salem Illinois	Salt Creek Wyoming	Sloss Nebraska	Torchlight Wyoming	Wichita Cty Reg Texas	Wilmington California
COUNTY	Montana	Illinois	Illinois	Wyoming	Wyoming	Texas	Pennsylvania	Pennsylvania	Okklahoma	Kansas	Kansas	Texas	Wyoming	Texas	Illinois	Texas	Oklahoma	Illinois	Illinois	Illinois	Illinois	Wyoming	Nebraska	Wyoming	Texas	California
CONSDIST	Rockies	Mid Cont	Mid Cont	Rockies	Rockies	Gulf Coast	Appalachia	Appalachia	Mid Cont	Mid Cont	Mid Cont	West Texas	Rockies	Gulf Coast	Mid Cont	Gulf Coast	Mid Cont	Mid Cont	Mid Cont	Mid Cont	Mid Cont	Rockies	Mid Cont	Rockies	Mid Cont	West Coast
OPERATOR	Gary	Shell	Shell	Conoco	Conoco	Exxon	Pennzoil	Pennzoil	B.E.R.C.	Citgo	Citgo	Union	Texaco	Mobil	Exxon	Texaco	Phillips	Marathon	Marathon	Marathon	Texaco	Amoco	Amoco	Amoco	Mobil	Long Beach
PARTNER	Union	—	—	—	—	—	Bingham	Marathon	—	Shell	Union	—	—	—	—	—	—	—	—	—	—	—	—	—	—	
PROJECT	—	—	—	—	—	—	—	—	—	Chesney	Hegberg	Higgs Un	—	—	—	—	—	—	—	—	—	—	—	—	—	
PROJID	1	g1	g2	a1	a2	b	f1	f2	m	i1	i2	h	t	p	c	Q	j	d1	d2	d3	e	s	n	r	k	
DOE	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	
YRBGN	7700	6700	7200	7400	7900	6500	7100	7500	7500	7400	7400	6900	7500	—	6900	7700	7500	6800	7500	7700	7400	7200	7500	7600	7300	
YREND	—	6800	—	7700	8700	6600	—	—	—	—	7100	—	—	—	7000	—	—	—	—	—	7600	—	—	7800	—	
FORMATION	Muddy	Tar Springs	Tar Springs	Frontier	Frontier	Frio	Bradford	Bradford	Bartlesville	Waubunsee	Waubunsee	Bluff Creek	Almy	Frio	Weiler	Frio	Cherokee	Robinson	Robinson	Robinson	Benoist	Frontier	Muddy	Tensleep	Gunsight	
ZONE	—	—	—	2nd Wall Creek	2nd Wall Creek	F-4 Sand	3rd Sand	3rd Sand	Pennsylvanian	Permian	Permian	Permian	Tertiary	Oligocene	Mississippian	Oligocene	Pennsylvanian	Pennsylvanian	Pennsylvanian	Pennsylvanian	Mississippian	Cretaceous	Cretaceous	Pennsylvanian	—	
AGE	Cretaceous	Mississippian	Mississippian	Cretaceous	Cretaceous	Oligocene	Devonian	Devonian	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	
RESERV	Unit A	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	
LITHOLOGY	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	
ENVIRON	Interdeltaic	Prodelta	Prodelta	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	
DEPUNIT	Bar	Fringe	Fringe	—	—	—	—	—	—	—	—	—	—	—	Bar	Bar	Bar	Channel	Channel	Channel	—	Fractures	—	—	—	
HETEROG	—	—	—	Fractures	Fractures	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	
CLAYPCT	—	—	—	—	—	0.5	—	—	—	21	21	—	—	10	9	—	—	—	—	8.5	—	—	—	—	—	
CLAYTYP	—	—	—	—	—	Montmorillonite	—	—	—	—	—	—	—	Kaolinite, Montmorillonite	Kaolinite, Montmorillonite	—	Chamosite	—	—	—	—	—	—	—	—	
DEPTH	4300	2120	2100	3050	3000	5100	1860	1300	620	650	650	1870	700	—	1460	5400	2900	1000	1000	1000	1950	2300	6256	3200	1700	
TEMP	110	95	95	120	115	165	68	64	86	69	69	95	—	—	95	165	120	72	72	72	80	100	200	100	89	
PROJAREA	40	1	160	1	90	1.25	47	24	2.5	25.6	25.6	8.2	1.7	5	.625	10	90	40	116	407	5	3	9	5.2	209	
INJ	4	4	6	4	8	4	16	16	2	9	9	6	4	4	4	2	9	18	38	114	4	4	4	4	10	
PROD	1	1	1	1	16	1	25	25	—	4	4	4	—	4	12	1	12	1	3	—	16	18	55	132	1	
PATACRES	40	1	—	1	10	1.25	2.9	1.5	2.5	2.5	6.4	6.4	1.0	.8	8.2	1.7	5	.625	10	2.5	10	10	3	3.75	2.5	
NUMPAT	S	S	—	S	M	S	M	M	S	M	M	S	S	S	S	L	M	L	—	M	S	S	S	S	—	
PTYPE	CN5	N5	—	CN5	15	N5	CN5	N5	C15	N5	N5	Q15	N5	N5	N5	SLD	15	LD	25	15	CN5	N5	N5	N5	—	
NETPAY	7	22	—	65	65	3.8	23.7	29	52	18.4	17.5	14.2	—	—	15.5	17	43	25	29	27.8	26	12	12	13	56	
GROSSPAY	—	—	—	—	—	8	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	
PERM	1000	73	165	52	52	434	82	14	80	265	208	500	450	—	103	500	52	200	—	102	87	58	93	81	53	
PERMVAR	—	—	—	—	—	.6	—	—	—	.78	.85	—	—	—	—	—	—	—	—	.44	—	0.64	—	—	—	
VARCODE	—	—	—	—	—	L	—	—	—	DP	DP	—	—	—	—	—	—	—	—	L	—	—	—	—	—	
POROS	.261	.17	.19	.19	—	.21	.18	—	.21	.243	.245	.229	.26	—	.206	.3	.165	.2	—	.19	.148	.18	.17	.14	.22	
SWINIT	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	
API	32	38	38	35	35	42	45	45	33	37	37	37	26	—	38	28	39	35	35	36	38	37	38	34	42	
WET	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	OW	—	—	—	—	—	—	—	—	
CRUDETYPE	—	Naphthenic	Naphthenic	—	—	—	Paraffinic	Paraffinic	—	—	—	—	—	Naphthenic	—	—	—	Naphthenic	Naphthenic	Naphthenic	—	—	—	—	—	
OILVISC	5	3.5	3.5	4	5.5	.36	5	4	6.9	5.2	4.8	4.3	—	—	—	4	3	7	7	6	3.6	3.1	.8	3.4	2.3	
PREVPROD	WF	WF	WF	WF	WF	WF	—	—	—	—	—	—	—	—	—	WD	—	WF	WF	WF	—	WF	—	WF	—	
OILSAT	.38	.325	.55	.3	—	.307	.362	—	.35	.333	.307	.23	—	.2	.291	.3	.35	—	—	.4	.3	—	.3	—	.3	
OILSATYP	—	—	—	—	—	ROS	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	
SLUGSIZE	.03	.22	—	.25	—	.47	.05	.09	.085	.12	.04	.028	—	.12	.4	.25	.06	.07	—	.1	.285	—	.25	—	.15	
SLUGVISC	—	—	—	6	—	.4	25	8.4	10	—	—	—	—	—	10	—	—	—	—	27	—	—	5	—	.07	
SLUGTYPE	MOE	LTWF	LTWF	LTWF	LTWF	LTWF	MWE	MWE	—	LTWF	MOE	MOE	LTWF	LTWF	LTWF	LTWF	—	MWE	MWE	MWE	LTWF	—	—	LTWF	—	
SURFCONC	.076	.027	—	.025	—	.023	.12	.11	.054	.03	.12	.09	—	.019	.023	.025	.038	.11	—	.11	.044	—	.044	—	.015	
SURFMW	440	440	—	427	—	380	—	—	450	430	425	—	—	—	—	—	—	—	—	420	—	—	—	—	—	
SMANUF	Stepan	Shell	Witco	Conoco	—	Exxon	Witco	Witco	Amoco	Witco	Witco	—	—	—	Exxon	Texaco	Witco	Marathon	—	Marathon	Witco	—	Amoco	—	Witco	
SURFACTA	Petroleum	M-380, M-470	—	Proprietary	—	Petroleum	TRS-16	TRS 16, TRS 40	Sulfonate 151	—	—	—	—	—	—	Proprietary	TRS 10-410	—	—	Proprietary</						

REMARKS

a* (1) Sodium silicate preflush planned

b* (1) Only 3 inj effective (oper prob)

c*

d* (1) ROS from SWTT (2) kh (CBUT) = 109 md-ft (3) Used blend of petroleum and synthetic sulfonates

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Appendix C

Notes on Adsorption Data

1. Not all reported adsorption data were reviewed. Of that reviewed, not all of these data are summarized below due to time limitations.
2. The data are reported in many different units ($\mu\text{m/g}$, $\mu\text{m/m}^2$, meq/100g, mg/g, lbs/ac-ft, lbs/Bbl, mg/m², etc.). These were converted to active mg/g using molecular weight, surface area, activity, etc., as needed. In a few cases some uncertainty exists in this conversion.
3. In many cases the clay content of Berea was not reported, yet it varies considerably from sample to sample. For lack of anything better, a standard value of 8.6% wt. (Malmberg's value) was used for all data plotted as adsorption vs. clay content for Berea. One advantage of using the 100% clay data is that no significant uncertainty exists in the amount or type of clay for those data. Thus, one can compare the Berea and 100% clay data by multiplying the 100% clay data shown below by 0.086.
4. Three types of nonionics have been included now, but these data should be used with extreme caution. There are several reasons. For one, no low molecular weight alcohol was included in these experiments. For another, the adsorption mechanisms are quite different than for the sulfonates. In particular, surface area rather than clay content and type is more likely to be the dominant factor.
5. For the sulfonates, no clear-cut case could be made for correlating the adsorption with clay content versus surface area versus CEC *until* the data for kaolinite and montmorillonite were examined. The CEC's are roughly 5.5 and 110 meq/100 g respectively, a 20-fold difference, but the adsorption of the same sulfonate under the same conditions was virtually the same. Surface areas also differ greatly, although the uncertainty in the surface areas of these two clays is itself quite large.
6. When establishing the adsorption correlation, more weight was given to the data at low salinity since it is assumed BAT will be used, to the data with alcohol included for the same reason, to the data with other agents included if these are agents actually used, and to the dynamic results since they more closely represent total retention values, etc., and because at least some calcium and other minerals will usually be present in a core rather than just NaCl as in many of the static tests.

Summary of Results of the Adsorption of Active Sulfonates

Ref.	Ads. range (mg/g)	Comment
Static Kaolinite		
102	2.7 to 5.4	2.7n at pH = 10
37	3.7 to 10.8	3.7 for EW = 233
101	-6.3 to 11.8	3.1 at 0.05% NaCl
Static Berea		
102	0 to 0.68	0 at 19 g/l sulfonate
37	0.15 to 0.4	
101	0.365	
99	0.5 to 0.6	Field brine containing Ca ⁺⁺
100	0.43 to 1.29	0.43 for 0.1 N NaCl

Summary of Results of the Adsorption of Active Sulfonates (continued)

Ref.	Ads. range (mg/g)	Comment
Dynamic Berea		
99	0.17 to 0.8	0.17 for small slug
100	0.40	
52	0.15 to 0.25	0.1 at 0% NaCl
104	0 to 0.7	
103	0.1 to 0.4	
105	0.05 to 0.76	Values increase with Ca++
29	0.06 to 0.35	
26	0.08 to 0.50	
Dynamic reservoir cores		
99, 26	0.13 to 0.28	
Limestones		
102, 100	0 to 1.0	
Field tests		
See Appendix A	0.13 to 0.48	

Sulfonates (anionic)

Variable	Adsorption Multiple*
Temperature	2
Alcohol	5
NaCl	8
pH	8
Sulfonate	15
wt % clay (5 to 100%)	100

*number of times adsorption increased as variable changed from one extreme to the other extreme for a given data set from a given reference.

Ethoxylated nonylphenols (nonionic)

	Ads. range (mg/g)
Static Kaolinite	11 to 23
Static Berea	2.8

Ref. 102 (Somasundaran and Hanna)

1. *Effect of pH*

NaDBS (dodecylbenzene sulfonate)

$I = 10^{-2}$ M NaCl

Na Kaolinite ($9.8 \text{ m}^2/\text{g}$)

30°C

<i>pH</i>	<i>Adsorption</i>	
	$(\mu\text{m}/\text{m}^2)$	(mg/g)
4.5	5.0	17.5
6.8	1.2	4.2
10.2	0.6	2.1

2. *Effect of Substrate*

Mahogany Sulfonate AA (12.6 g/l active)

$I = 10^{-2}$ M NaCl

$\text{pH} = 8$ to 10

30°C

<i>Substrate</i>	<i>Adsorption</i>	
	(mg/m^2)	(mg/g)
Berea	0.20	0.20
Agricultural Limestone	0.0 to 0.38	0 to 1.62
Bedford Limestone	0.21 to 1.0	0.20 to 0.96

3. *Effect of Ionic Strength (I)*

Mahogany Sulfonate (12.6 g/l active)

$\text{pH} = 8.1$

30°C

Berea Sandstone

<i>I (M NaCl)</i>	<i>Adsorption</i>	
	(mg/M^2)	(mg/g)
Distilled Water	0.1	
10^{-2}	0.2	
2.5×10^{-2}	0.6	
5.0×10^{-2}	0.8	

4. *Effect of Temperature*

Same as above No. 3 (except for temperature)

Temperature ($^\circ \text{C}$) Adsorption (mg/g)

30	0.2
50	0.3
70	0.4

Ref. 103 (Glover et al.)

1. *Effect of Salinity (NaCl)*

63/37 mixture of 3% weight
MEAC120XS (orthoxylenesulfonate) &
TAA (tertiary amyl alcohol)

Dynamic displacement in Berea cores

% NaCl	Adsorption (mg/g)
0	0.1
1	0.2
2	0.3
3	0.4

Ref. 101 (Fernandez et al.)

1. *Effect of Salinity*

4-4' dodecylbenzene sulfonate

Na Kaolinite (15.1 m²/g)

30°C

% NaCl	Adsorption	
	(μm/g)	(mg/g)
0	-18	-6.3
0.05	9	3.1
0.10	13	4.5
0.50	26	9.0
1.0	34	11.8

2. *Effect of Alcohol*

Same as above at 1% NaCl

% TBA	Adsorption (mg/g)
0	11.8
2	8.7
5	5.6
7	5.2
10	2.4

3. *Effect of Substrate*

Same system as above at 1% NaCl

Berea rock 0.36 mg/g

Reference 37 (Gale and Sandvik)

1. Effect of Substrate

~342 EW sulfonate (0.5% wt)

2% Na₂SO₄

Substrate (clay)	Adsorption (mg/g)
Kaolinite	9.2
Ca Montmorillonite	8.2
Berea	0.44

2. Effect of Equivalent Weight (EW)

Substrate Ca Montmorillonite

2.7% Na₂SO₄

0.5% wt sulfonate

EW	Adsorption (mg/g)
300	1.0
350	8.0
400	15.

Reference 105 (Trogus)

Effect of Sulfonate

Berea Sandstone cores

1% wt NaCl

25° C

Sulfonate	Adsorption (mg/g)
348 M.W. C ₁₂ ABS	0.052
391 M.W. C ₁₅ ABS	0.117
C ₁₂ OXS	0.760

Reference 99 (Malmberg and Smith)

1. Effect of Substrate

1.3% petroleum sulfonate

1.0% alcohol

1.3% NaCl

10% P.V. slugs in various cores

Substrate (core)	Adsorption (mg/g)	wt% clay	Q _v (meq/100g)
Berea	0.17	8.62	0.83
Seeligson	0.31	9.36	7.61
S. Texas B	0.25	7.63	4.60
Cottage Grove	0.20	13.29	2.64

Reference 100 (Lawson)

1. *Effect of Substrate*

Dynamic core tests

7:3 mixture of Bryton 430 (sulfonate) and Neodol 25-3S (sulfate)

0.03 meq/g total surfactant

0.4 N NaCl

<i>Substrate</i>	<i>Adsorption (mg/g)</i>
Berea (1.4 m ² /g)	0.39
Bahama Oolite	0.43

2. *Effect of Salinity*

Static tests

Same system as above on Berea

<i>N NaCl</i>	<i>Adsorption (mg/g)</i>
0.1	0.43
0.4	0.60
0.6	0.77
0.8	1.29
1.0	0.99

Nonionics

Reference 100 (Lawson)

Plateau adsorption values

Triton (ethoxylated octylphenol)

75° F (24° C)

1 N NaCl

Static Berea

1. *Effect of EO content*

<i>Triton</i>	<i>EO's</i>	<i>Adsorption (mg/g)</i>
X-305	30.0	0.55
X-165	16.0	0.80
X-102	12.5	1.1
X-100	9.5	1.7

Reference 100 (Lawson) (continued)

2. *Effect of structure*

Neodols (ethoxylated alcohols)

75° F

0.2 N NaCl

Static Berea

<i>Surfactant</i>	<i>EO's</i>	<i>Adsorption (mg/g)</i>
Neodol 2-9	9	1.3
Neodol 25-3S*	3	0.6
Neodol 3-9	9	1.3
Neodol 5-9	9	1.5

*sulfated (anionic included for comparison)

Nonionics

Reference 106 (Sophany)

Adsorption of ethoxylated nonylphenols

Static tests at 30° C

Plateau values above CMC

1. *Effect of Substrate*

Igepal CO-630 (9 EO's) MW = 616

0% NaCl

pH = 7

<i>Substrate</i>	<i>Adsorption (mg/g)</i>
Kaolinite	14.2
Silica	2.3
Berea	2.8

2. *Effect of EO Content*

Kaolinite

0% NaCl pH = 7

<i>EO's</i>	<i>Adsorption (mg/g)</i>
9	18
15	11
20	11

3. *Effect of Salinity*

	<i>% NaCl</i>	<i>Adsorption (mg/g)</i>
Igepal CO-630	0	18
Kaolinite	1.5	19
pH = 7	3.0	23

Appendix D

Example Calculation

This Appendix illustrates the screening procedure of Part III using the Bell Creek Unit A field as an example. The following data were abstracted from the references.

OOIP	=	122 MM Stb	T	=	110°F
N_p^∞	=	57.8 MM Stb	μ_o	=	4.6 cp
B_i	=	1.112 RB/Stb	μ_w	=	0.61 cp (from correlations)
B_f	=	1.047 RB/Stb	ϕ	=	0.29
S_{or}	=	0.28	K	=	1050 md
S_{oi}	=	0.80	D	=	4550'
V_{DP}	=	0.7	C_{rs}	=	4200 mg/l
A	=	40 acres/pattern	f_{bw}	=	$f_{gc} = 0$

By assuming $f_{gc} = 0$, we are neglecting the gas-oil contact located at the western boundary of Unit A. In addition, we assume the following data:

$$a_s = 0.4 \text{ mg surf./g rock} \quad V_{ps} = 1.3 D_s$$

This a_s value corresponds to the "typical" value we recommended in the absence of clay fraction information. Note, also, the difference between this value and the lab-derived value of 0.184 mg/g (Appendix A). Presumably, this difference is caused by the sacrificial agent employed in the determination of the latter quantity. In the following we follow the outline of figure 13.

Technical screen

- $T = 110^\circ\text{F}$ is less than 229°F
- $C_{rs} = 4200 \text{ mg/l}$ is much less than 200,000 TDS
- from reference 6 $R \sim 0.22/0.38 = 0.58$, hence
- $(N_{cap})_{crit} = 2.41 \times 10^{-3}$ from equation 13
- $(N_{cap})_5 = 5.8 \times 10^{-3}$ from equation 11
- hence $(N_{cap})_5 > (N_{cap})_{crit}$

The candidate reservoir thus passes the technical screen.

Economic screen

Revenue path:

TO = 35.2 MM Stb from equation 16. This TO value implies a swept

$$V_p = 35.2/0.28 = 125.7 \text{ MM Stb}$$

$S_{orc} = 0.03$ from equation 20, figure 7, and $(N_{cap})_5 = 5.8 \times 10^{-3}$

$ER S_{or}/\Delta S_o = 0.63$ from figure 16, and $V_{DP} = 0.7$

$$E_R = 0.56$$

$(CFR)_{ult} = 15.7 \text{ MM Stb}$ from equation 18. This number compares with 28.5 MM Stb given in reference 26. The difference between these values lies in the different S_{or} 's used.

$t_{life} = 2\text{-}1/2$ years from equation 20

Cost path:

$$C_{TS} = \left(\frac{1 - .29}{.29} \right) \frac{\text{ml rock}}{\text{ml } V_p} \left(\frac{2.5 \text{ g rock/ml rock}}{1 \text{ g surf/ml surf}} \right) \left(.0004 \frac{\text{g surf}}{\text{g rock}} \right)$$

$$(125.7 \times 10^6 \text{ Stb } V_p) \times \frac{350.9 \text{ lb}_m \text{ surf}}{\text{Stb surf}} \times 1.3 = 140 \text{ MM lbm surfactant from equation 15}$$

From figure 15 with $\mu_o/\mu_w = 7.54$, $C_p = 1180$ ppm. Then

$$C_{TP} = \frac{1}{2} C_p V_{MB} V_p = (\frac{1}{2})(1180) \frac{\text{lbm polymer}}{10^6 \text{ lbm MB}} \left(1 \frac{\text{Stb MB}}{\text{Stb } V_p} \right)$$

$$(125.7 \times 10^6 \text{ Stb } V_p)$$

$$C_{TP} = 26.02 \text{ MM lbm polymer}$$

surfactant required = 8.92 lbm surfactant/Stb oil produced

polymer required = 1.66 lbm polymer/Stb oil produced

These numbers compare with the NPC values of 7-9.33 lbm surfactant and 0.52-0.70 lbm polymer per Stb oil produced for "good" reservoirs having S_{or} 's from 0.25-0.30. Using unit costs of 0.43\$/lbm surfactant and 2\$/lbm polymer yields

$$\text{Total chemical costs} = 3.83 + 3.32 = 7.15 \text{ \$ chemical cost/Stb oil}$$

Again, numbers in rough agreement with the NPC study. Note that, as predicted above, surfactant and polymer costs are about equal.

Nomenclature

a_s	Surfactant retention in mg surfactant/g rock
a	Injector-injector or producer-producer distance, L
BAT	Acronym for Best Available Technology
B_i, B_f	Initial (discovery) and final (end of waterflood) formation volume factors
$(CFR)_{ult}$	Ultimate MCM/EOR recoverable oil, Stb
CL	Confidence level
C_p	Polymer concentration initial phase of mobility buffer, ppm
$\bar{C}_p$	Average mobility buffer polymer concentration defined by equation 1, ppm
C_p	Constant in equation 5, psia/ft
C_s	Injected surfactant concentration, volume fraction
CRMQ	Acronym for Critical Reservoir and Micellar Quantities
CTP	Total polymer required to satisfy mobility requirements, mass units
CTS	Total surfactant required to satisfy retention, mass units
D	Subsurface depth, ft
d	Injector-producer distance, L
E_R	MCM/EOR recovery efficiency, Stb oil recovered/Stb target oil
f_{bw}, f_{gc}	Fraction OOIP underlain by bottom water, or covered by gas cap
h	Net interval thickness, ft
IFT	Interfacial tension, dynes/cm
k	Permeability, md
k^o_{rw}, k^o_{ro}	End point water/oil relative permeabilities
MCM/EOR	Acronym for Mid-Continent Micellar (flooding) Enhanced Oil Recovery
N_{cap}	Capillary number defined by equation 2
$N_{\infty p}$	Ultimate primary + secondary oil production, Stb
OOIP	Original oil in place before waterflood
ΔP	Injector-producer pressure drop, psia
Q	Injection or production rate, Stb/day
Q_D	Cumulative injection in pore volumes
R	Ratio of k^o_{rw} to k^o_{ro}
r	Correlation coefficient
r_w	Well radius, ft
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation in waterflood-swept regions
S_{orc}	MCM/EOR swept zone residual oil saturation
ΔS_o	$S_{or} - S_{orc}$
TDS	Acronym for Total Dissolved Solids
t_{life}	Project life, years

u	Superficial velocity, ft/day
V_{MB}	Mobility buffer slug size, fraction V_p
V_p	Waterflood-swept reservoir pore volume, Stb
V_{ps}	MCM/EOR slug size, fraction V_p
W_{clay}	Clay fraction
σ	Interfacial tension, dynes/cm
μ	Viscosity, cp
μ_o	Oil viscosity, cp
ϕ	Porosity, fraction
ρ_r	Rock grain density, g/ml
ρ_s	Surfactant slug density, g/ml

Subscripts

5	Five spot
LD	Line drive
crit	Critical value

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SELECTION OF RESERVOIRS
AMENABLE TO MICELLAR FLOODING

FIRST ANNUAL REPORT

(October 1978 - December 1979)

Appendices II - VI

Work Performed Under DOE Contracts
DE-AC19-78BC00048/DE-AC19-78BC00051

Gary Energy Corporation and Intercomp
Contractors

APPENDIX II

DEVELOPMENT OF EXPRESSION FOR MICELLAR-POLYMER TARGET OIL

In stock tank barrels, a material balance at the end of a waterflood gives:

$$OOIP = ROIP + N_p \quad (1)$$

where OOIP is the original oil in place, ROIP is the remaining oil in place, and N_p is cumulative production. If we define E_v as the fraction of the entire reservoir volume which has been thoroughly swept by water, S_{orw} as the average oil saturation in this swept zone, and S'_o as the average oil saturation in the unswept portion, then (1) becomes:

$$V_p \frac{S_{oi}}{B_{oi}} = V_p (1 - E_v) \frac{S'_o}{B_{of}} + V_p E_v \frac{S_{orw}}{B_{of}} + N_p \quad (2)$$

expressing V_p in terms of OOIP

$$V_p = \frac{OOIP}{S_{oi}/B_{oi}} \quad (3)$$

and solving (2) for E_v gives

$$E_v = \frac{\left[1 - \frac{S'_o}{S_{oi}} \frac{B_{oi}}{B_{of}} - \frac{N_p}{OOIP} \right]}{\frac{B_{oi}}{B_{of}} \left[\frac{S_{orw}}{S_{oi}} - \frac{S'_o}{S_{oi}} \right]} \quad (4)$$

If we define M-P*target oil, TO, as the oil remaining in the waterswept portion of the reservoir, and further reduce this by the fraction of the reservoir above bottom water (f_{bw}) and below a gas cap (f_{gc}), then the expression for TO is

$$TO = V_p \frac{S_{orw} E_v}{B_{of}} = OOIP \frac{S_{orw}}{S_{oi}} \frac{B_{oi}}{B_{of}} E_v (1 - f_{bw}) (1 - f_{gc}) \quad (5)$$

Substituting (4) into (5)

$$TO = OOIP \left\{ \frac{1 - \frac{S'_o}{S_{oi}} \frac{B_{oi}}{B_{of}} - \frac{N_p}{OOIP}}{\frac{B_{oi}}{B_{of}} \left[\frac{S_{orw}}{S_{oi}} - \frac{S'_o}{S_{oi}} \right]} \right\} \frac{S_{orw}}{S_{oi}} \frac{B_{oi}}{B_{of}} (1 - f_{bw}) (1 - f_{gc}) \quad (6)$$

Limits on S'_o can be obtained by assuming zero resaturation of the unswept portion of the reservoir, or complete resaturation. For zero resaturation, the oil remaining in the unswept volume is equal to that remaining at the end of primary:

$$(1 - E_v) \frac{S'_o}{B_{of}} = (1 - E_v) \frac{S_{op}}{B_{op}} \quad (7)$$

A material balance at the end of primary gives:

$$V_p \frac{S_{oi}}{B_{oi}} = V_p \frac{S_{op}}{B_{op}} + (N_p)_{prim} \quad (8)$$

From (3), (7) and (8),

$$(S'_o)_{zero} = S_{oi} \frac{B_{of}}{B_{oi}} \left(1 - \frac{(N_p)_{prim}}{OOIP}\right) \quad (9)$$

If we define

$$E_R = \frac{N_p}{OOIP} \quad \text{and} \quad E_{RP} = \frac{(N_p)_{prim}}{OOIP} \quad (10)$$

and substitute (9) into (6)

$$(TO)_{zero \text{ resat}} = OOIP \left\{ \frac{E_R - E_{RP}}{1 - E_{RP} - \frac{B_{oi}}{B_{of}} \frac{S_{orw}}{S_{oi}}} \right\} \frac{S_{orw}}{S_{oi}} \frac{B_{oi}}{B_{of}} (1 - f_{bw})(1 - f_{gc}) \quad (11)$$

For the case of maximum resaturation, $S'_o = S_{oi}$ and (6) becomes

$$(TO)_{max \text{ resat}} = OOIP \left\{ \frac{E_R + \frac{B_{oi}}{B_{of}} - 1}{1 - \frac{S_{orw}}{S_{oi}}} \right\} \frac{S_{orw}}{S_{oi}} (1 - f_{bw})(1 - f_{gc}) \quad (12)$$

The pore volume of the reservoir associated with the target oil (floodable pore volume, FPV) is given by

$$FPV = E_v V_p (1 - f_{bw})(1 - f_{gc}) = \left[\frac{1 - \frac{S'_o}{S_{oi}} \frac{B_{oi}}{B_{of}} - \frac{N_p}{OOIP}}{\frac{S_{orw} - S'_o}{B_{of}}} \right] OOIP (1 - f_{bw})(1 - f_{gc}) \quad (13)$$

APPENDIX III

EXAMPLE OF ECONOMIC POTENTIAL CALCULATION

This appendix illustrates the method described in Chapter 2 for calculating the micellar-polymer potential of a Mid-Continent example using the following data.

OOIP = 122×10^6 STB	$h = 8$ feet
$N_p = 57.8 \times 10^6$ STB	$T = 110^\circ\text{F}$
$B_{oi} = 1.112$ RB/STB	$\mu_o = 4.6$ cp
$B_{of} = 1.047$ RB/STB	$\mu_w = 0.61$ cp (from correlations)
$S_{oi} = 0.80$	$\phi = 0.29$
$S_{orw} = 0.28$	$k = 1050$ md
$V_{DP} = 0.70$	$D = 4550$ feet
$A = 40$ acres/pattern	$C_{rs} = 4200$ mg/l
$API = 32^\circ API$	$X_s = 0$
$\rho_r = 156.3$ lbm/ft ³	$\rho_s = 62.5$ lbm/ft ³
$w_{clay} = 0.07$	

Following the outline of Figure 2.2, both the temperature and salinity of the reservoir are below the feasibility screen limits so the reservoir can be considered a micellar-polymer candidate. Below, the potential of the reservoir is calculated.

1. Target Oil

- from Eqn. (2.9) assuming $S'_o = S_{oi}$ (maximum resaturation)

$$TO = (122 \times 10^6) \left\{ \frac{1 - \frac{1.112}{1.047} - \frac{57.8 \times 10^6}{122 \times 10^6}}{\frac{1.112}{1.047} \left[\frac{0.28}{0.80} - 1 \right]} \right\} \left(\frac{0.28}{0.80} \right) \left(\frac{1.112}{1.047} \right)$$

$$TO = 35.2 \times 10^6 \text{ stb}$$

2. Recoverable Oil

- from Eqn. (2.7)

$$N_{cap} = 5.8 \times 10^{-3}$$

- from Figure 2.4 for a water-wet rock

$$\frac{S_{orw} - S_{orc}}{S_{orw}} = 0.89$$

- from Fig. 2.3 with $V_{PS}/D_s = 1.3$, $V_{DP} = 0.7$

$$\frac{E_D}{\Delta S_o / S_{orw}} = 0.63$$

$$\text{so } E_D = (0.63)(0.89) = 0.56$$

- from Eqn. (2.10)

$$RO = (0.8)(0.56)(35.2 \times 10^6)$$

$$RO = 15.8 \times 10^6 \text{ stb}$$

3. Surfactant Requirement

- from Eqn. (2.12)

$$FPV = \left[\frac{1 - \frac{1.112}{1.047} - \frac{57.8 \times 10^6}{112 \times 10^6}}{\frac{0.28 - 0.80}{1.047}} \right] (122 \times 10^6)$$

$$FPV = 131.6 \times 10^6 \text{ stb}$$

- from Fig. 2.5 with $W_{\text{clay}} = 0.07$,

$$a_s = 0.22 \text{ mg surf/g rock}$$

- from Eqn. (2.11)

$$D_S \cdot C_S = \left(\frac{1 - .29}{.29} \right) \left(\frac{156.3}{62.5} \right) (0.22) (10^{-3})$$

$$D_S \cdot C_S = 0.00134$$

- from Eqn. (2.14)

$$C_{TS} = (1.3)(.00134)(131.6 \times 10^6)$$

$$C_{TS} = 0.230 \times 10^6 \text{ stb surfactant}$$

4. Polymer Requirement

- from Fig. 2.7 with $\mu_o/\mu_w = 7.54$

$$C_{MB} = 1180 \text{ ppm}$$

- from Eqn. (2.15)

$$\bar{C}_{MB} = 1/2 (1180)(1.0) = 590 \text{ ppm}$$

- from Eqn. (2.16) with $\bar{\rho}_{MB} = 62.5 \text{ lb/ft}^3$

$$C_{TP} = (5.615 \times 10^{-6})(590)(62.5)(131.6 \times 10^6)$$

$$C_{TP} = 27.2 \times 10^6 \text{ lb polymer}$$

5. Project Life

- from Eqn. (2.18) with $C_p' = 0.3$, $Q_D = 1.5$,

$$t_{\text{life}} = (6160)(40)(.29) \left[\frac{5.58 + 1/2 \ln(40)}{(0.3)(1050)(4550)/4.6} \right] (1.5)$$

$$t_{\text{life}} = 2.6 \text{ years}$$

6. Field Development

- from Eqn. (2.19)

$$DA = \frac{131.6 \times 10^6}{(7758)(.29)(8)} = 7312 \text{ acres}$$

- from Eqn. (2.20)

$$NRP = \frac{7312}{40} = 183 \text{ repeated patterns}$$

- for illustrative purposes, it is assumed that there currently are 190 producing wells and 80 injections wells. Therefore, the required development is:

well conversions	7
well workovers (25% of existing wells)	66
new injection wells	96
new production wells	0

7. Cost Data

- from Eqn. (2.21) with $\$'_O = \38.00

$$\$_O = [38.00 - 0.02(40-32)](1.0)$$

$$\$_O = \$37.84/\text{stb}$$

- based on depth and location, we have the following development cost data

drilling	\$ 69.99/ft
equipping new injectors	\$63,637.00
workovers and conversions	\$75,678.00
operating expenses	\$35,683/pattern/year

- will assume that surfactant and polymer costs are
\$151/bbl surfactant
\$2/lb polymer

8. Economic Calculations

For the purposes of this example, the time value of money will be ignored, so the economics can be treated simply.

- Development Costs are
 - Drilling injectors - $(96) [(4550)(69.99) + 63637] = 36.7 \times 10^6$
 - Workovers and conversions - $(66 + 7)(75678) = 5.5 \times 10^6$
 - Total development costs = $\$42.2 \times 10^6$
- Surfactant and polymer costs are
 - Surfactant costs = $(0.230 \times 10^6)(151) = \34.7×10^6
 - Polymer costs = $(27.2 \times 10^6)(2) = \54.4×10^6
 - Total chemical costs = $\$89.1 \times 10^6$
- Operating Costs are
 - Operating Costs = $(2.6)(183)(35683) = \$17.0 \times 10^6$
- Total Expenses are
 - $10^6 \times (42.2 + 89.1 + 17.0) = \148.3×10^6
- Total Revenue is
 - $(15.8 \times 10^6)(37.84) = \597.9×10^6
- For this example, the revenue to expense ratio is
$$R/E = \frac{597.9 \times 10^6}{148.3 \times 10^6} = 4.03$$

APPENDIX IV

A PRELIMINARY ECONOMIC EVALUATION PROGRAM

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I. PROGRAM DESCRIPTION

The PECØN program was developed as a preliminary attempt at selecting the more economically attractive micellar-polymer candidates. The method used for this selection is largely based on the results presented in Appendix I. Simplifications have been necessary to accomodate the characteristics of the data base in its present stage of development. The cost information needed to calculate revenue and expenses was provided by Gary Energy Corporation. These cost tables are based on the results of the Office of Technology Assessment (OTA) 1978 study, after adjustment to 1980 dollars.

As so often is the case, some of the parameters necessary to accurately assess the economic potential of a reservoir are not available. The program provides for considerable flexibility in dealing with this problem. The user has the option of comparing only those reservoirs which have all the necessary data available or selecting "best guess" values where needed and looking at the results.

There are several features incorporated in the program for user convenience.

- 1) The cost tables are internal to the program. Only the state code and reservoir depth are necessary to reference the appropriate costs for calculation of project expenses.
- 2) An estimate of recovery can be made internally by the program through correlation with the Gupta-Trushenski experimental curve for capillary number versus recovery.
- 3) All assumptions made and data restrictions exercised are fully explained on the first page of the output for easy reference.
- 4) Any reservoir parameter which is set to a default value is flagged as such in the program output.
- 5) Checks on data and intermediate calculations have been used liberally. A summary of errors has been included as part of the output.
- 6) If the user desires, the output can be sorted on the ratio of revenue to expenses. Both the input and output variables are listed with the ratio in descending order corresponding to the more economically desirable reservoirs appearing first.

- 7) The program is also compatible with the alphabetized input data where the sort on the ratio is overridden. The program output, therefore, appears in the same order as the original input data. Included in this type of listing is a "rank" value which indicates where the reservoirs would have fallen in an output listing sorted on the ratio.

II. EQUATIONS AND ASSUMPTIONS

A. Recoverable Target Oil (RTØ)

From a material balance on the oil, neglecting primary production, the floodable pore volume can be expressed as:

$$FPV = V_p E_v = \frac{\left[C_{oil} - OOIP \left(1 - \frac{B_{oi}}{B_{of}} \right) \right] B_{oi}}{\frac{B_{oi}}{B_{of}} (S_{oi} - S_{orw})} \quad (1)$$

The target oil can then be written as:

$$TØ = FPV \frac{S_{orw}}{B_{of}} \quad (2)$$

At present, the program assumes no oil shrinkage:

$$\frac{B_{oi}}{B_{of}} = 1.0$$

which results in the ØØIP term dropping out of Equation (1).

The capillary number for a five-spot pattern is calculated using Equation (11) from Appendix I:

$$(N_{cap})_5 = \frac{(1.9 \times 10^{-7}) C_p' k D}{\sqrt{A} (5.58 + \frac{1}{2} \ln A)} \quad (3)$$

where C_p' is assumed to be a constant 0.3 psia/ft.

This, in turn, is entered into the Gupta-Trushenski experimental curve, shown on Figure IV-1*, to determine recovery ($E_R = REC$). If the capillary number exceeds the limits of this curve, N_{cap} is assumed to equal the appropriate limiting value.

The recoverable target oil can then be expressed as:

$$RTØ = TØ * REC \quad (4)$$

*page IV-25.

B. Expenses (TEXP)

The developed acres can be calculated by:

$$DA = \frac{FPV}{7758\phi H} \quad (5)$$

By use of the well spacing, the required number of repeated five-spot patterns for the project can be calculated:

$$NRP = \frac{DA}{A} + 1 \quad (6)$$

Given one injection and one production well per repeated five-spot pattern, the development costs can be calculated as follows:

Drilling costs,

$$DEV1 = (NRP - NPR) (DRILL(J, JJ) * D) + PEQ(J, JJ) \quad (7)$$

$$DEV2 = (NRP - INJ) (DRILL(J, JJ) * D) + IEQ(J, JJ) \quad (8)$$

Workover costs,

$$DEV3 = ((EPW - PC\emptyset N) + (EIW - INC\emptyset N)) * W\emptyset(J, JJ) * FAC \quad (9)$$

Well conversion costs,

$$DEV4 = (PC\emptyset N + INC\emptyset N) * W\emptyset(J, JJ) \quad (10)$$

where

$$NPR = EPW - PC\emptyset N + INC\emptyset N$$

$$INJ = EIW - INC\emptyset N + PC\emptyset N$$

The project life is defined as:

$$PL = \frac{6160\phi A\mu_o(Q_D)(5.58 + 0.5 \ln A)}{C_p' kD} \quad (11)$$

where the restriction is:

$$2 \leq PL \leq 20 \text{ years}$$

If either limit is exceeded, project life is set to the appropriate limiting value.

The operating expenses can then be calculated by:

$$\emptyset PEXP = PL * NRP * \emptyset EP(J, JJ) \quad (12)$$

remembering that there are two wells per repeated five-spot pattern.

The chemical expenses are calculated assuming \$1.33 per barrel floodable pore volume,

$$\text{CHEMEXP} = 1.33(\text{FPV}) \quad (13)$$

The total expense is then just the sum of Equations (7), (8), (9), (10), (12) and (13).

C. Revenue (REV)

The calculation of revenue assumes \$27.00 per stb and includes a penalty of \$0.02/API° below 40° API per stb recoverable oil:

$$\text{REV} = \text{RT}\emptyset(27.0 - 0.02\text{DELT}) \quad (14)$$

where:

$$\text{DELT} = 40.0 - \text{API}$$

If sulfur is present, the revenue is subsequently reduced by 10%:

$$\text{REV} = 0.9\text{REV} \quad (15)$$

D. Nomenclature

Note that there are some differences with the Nomenclature in the body of this report.

CHEMEXP	=	chemical expenses
C_p	=	pressure gradient
DA	=	developed acres
DEV1	=	production drilling costs
DEV2	=	injection drilling costs
DEV3	=	workover costs of existing wells
DEV4	=	well conversion costs
E_v	=	volumetric sweep of waterflood
FPV	=	floodable pore volume
INJ	=	existing injection wells corrected for well conversions
$(N_{\text{cap}})_5$	=	capillary number for a five-spot pattern
NPR	=	existing production wells corrected for well conversions
NRP	=	required five-spot patterns for project
$\emptyset\text{PEXP}$	=	operating expenses
PL	=	project life
REV	=	revenue
RT $\emptyset$	=	recoverable target oil
S_{oi}	=	initial oil saturation
TEXP	=	total expenses
T $\emptyset$	=	target oil
V_p	=	total reservoir pore volume

For a description of the following variables, see the Data Card Description section.

A
API
B_{oi} (see BØI)
B_{of} (see BØF)
C_{oil} (see CØIL)
D
EIW
EPW
FAC (see IDD)
H
INCØN
k (see PERM)
ØØIP
PCØN
QD
REC
S_{orw} (see SØRW)
φ (see PHI)
μ_o (see VIS)

Cost Tables:

DRILL(J,JJ)	=	drilling
PEQ(J,JJ)	=	production equipment
IEQ(J,JJ)	=	injection equipment
WØ(J,JJ)	=	workover and well conversion
ØEP(J,JJ)	=	operating equipment

where:

J	=	location (state)
JJ	=	refers to depth

III. DATA CARD DESCRIPTION

Card 1 (one card)

LIST: K1, K2, FDRILL, DEFQD, DEFSØRW, LØCDEF, IALPHA
FORMAT: (2I5, 3F5.0, 2I5)

K1 Control on residual oil saturation at completion of secondary waterflood.

-1 The reservoir will not be processed if S_{orw} is not available.

0 If S_{orw} is not available for a given reservoir, it will be set to the default value specified by DEFSØRW.

1 S_{orw} will be set to the default value specified by DEFSØRW, regardless of what is available.

K2 Control on critical parameters

0 If any of the following parameters are not available for a given reservoir, it will not be processed.

Discovery date
Well spacing
Reservoir thickness
Connate water saturation
Porosity
Oil viscosity
API gravity

1 If any of the parameters mentioned above are not available, the appropriate default values specified on Card 2 will be used.

FDRILL If the number of existing production or injection wells is unknown for a given reservoir, this fraction is multiplied times the number of wells required for micellar-polymer flooding. This fraction of the required wells is then assumed to be the number of existing wells.

No default.

DEFQD If the total pore volumes injected during the project is unknown for a given reservoir, this value is used as a default in calculating project life.

 No default.

DEFSØRW Default value for S_{orw} . Omit if $K_1 = -1$.

 If $K_1 = 0$ or 1 , S_{orw} will be assumed to be zero when unavailable if a default is not provided.

LØDEF Location sorting option. If it is desired to consider only the reservoirs in a given state, the appropriate two digit state code described on Card 3 (ID) can be specified here.

 All states will be considered for processing if this field is left blank.

IALPHA Control on format of output listing.

 0 The output will be sorted in descending order of the ratio of revenue to expenses.

 1 The output will appear in the same order as the original input data. This will include a "rank" value to indicate the order in which the reservoirs would appear if they had been sorted on the ratio.

Card 2 (one card)

Default values for critical parameters. Omit
if K2 $\neq$ 1.

LIST:	IDEFDD, DEFA, DEFH, DEFPHI, DEFSCW, DEFVIS, DEFAPI
FORMAT:	(I5, 5X, 6F10.0)
IDEFDD	Discovery date of reservoir, in whole years.
DEFA	Well spacing, in acres per well.
DEFH	Reservoir thickness, in feet.
DEFPHI	Average reservoir porosity, as a fraction.
DEFSCW	Connate water saturation as a fraction.
DEFVIS	Oil viscosity, in cp.
DEFAPI	Oil gravity, in API ^o .

Card 3 (repeat as needed)

LIST: ID, (NAME(I), I=1,3), IDD, A, EPW, EIW, PCØN,
INCØN

FORMAT: (I9, 1X, 3A5, I5, F10.0, 4I5)

ID Unique identification number for the
reservoir. The first two digits are used
as a location code and are critical to the
calculation of the expenses. The following
two digit combinations are permissible:

<u>LØC</u>	<u>State</u>	<u>J</u>
01	Alabama	16
02	Arizona	17
03	Arkansas	1
04	California	18
05	Colorado	2
09	Florida	19
13	Indiana	20
15	Kansas	3
16	Kentucky	21
17	Louisiana	5
19	Maryland	22
21	Michigan	23
23	Mississippi	6
24	Missouri	24
25	Montana	7
26	Nebraska	8
27	Nevada	25
30	New Mexico	9
31	New York	26
33	No. Dakota	27
34	Ohio	28
35	Oklahoma	10
37	Pennsylvania	11
40	So. Dakota	29
41	Tennessee	30
42	Texas	13
43	Utah	31
45	Virginia	32
47	W. Virginia	33
49	Wyoming	15

The reservoir will not be processed if the LØC
code is not available. No default.

NAME Reservoir name.

IDD

Discovery date of reservoir, in whole years. This is used to calculate the percentage of existing wells requiring workover.

<u>Age, years</u>	<u>% Workover</u>
>25	100
15-25	50
10-15	25
<10	0

The reservoir will not be processed if this is not available. Default option on Card 2.

A

Well spacing, in acres per well. This is used in the calculation of the capillary number, required wells for project and project life.

The reservoir will not be processed if this is not available. Default option on Card 2.

EPW

Existing number of production wells prior to micellar-polymer flooding. This is used in the calculation of expenses.

If not available, FDRILL on Card 1 is used to calculate a default.

EIW

Existing number of injection wells prior to micellar-polymer flooding. This is used in the calculation of expenses.

If not available, FDRILL on Card 1 is used to calculate a default.

PCØN

Number of existing production wells to be converted to injection wells for micellar-polymer flooding.

If not available, this workover costs for conversion will not be included.

INCØN

Number of existing injection wells to be converted to production wells for micellar-polymer flooding.

If not available, the workover costs for conversion will not be included.

Card 4 (repeat as needed)

LIST: D, H, PERM, PHI, SCW, SØRW, VIS, API, SULF
FORMAT: (4F10.0, 2F5.0, 3F10.0)

D Depth to top of reservoir, in feet. This is used in the calculation of the capillary number and expenses.

The reservoir will not be processed if this is not available. No default.

H Reservoir thickness, in feet. This is used in the calculation of developed acres.

The reservoir will not be processed if this is not available. Default option on Card 2.

PERM Average reservoir permeability, in md. This is used in the calculation of the capillary number and project life.

The reservoir will not be processed if this is not available. No default.

PHI Average reservoir porosity, as a fraction. This is used in the calculation of developed acres and project life.

The reservoir will not be processed if this is not available. Default option on Card 2.

SCW Connate water saturation, as a fraction. This is used in the calculation of the initial oil saturation which is necessary for recoverable target oil.

The reservoir will not be processed if this is not available. Default option on Card 2.

SØRW Residual oil saturation at completion of secondary waterflood, as a fraction. This is used in the calculation of recoverable target oil.

The default option is determined by K1 on Card 1.

VIS Oil viscosity, in cp. This is used in the calculation of project life.

The reservoir will not be processed if this is not available. Default option on Card 2.

API

Oil gravity, in API[°]. This is used to calculate a penalty to revenue to \$0.02/[°] API below 40 per stb recoverable oil.

The reservoir will not be processed if this is not available. Default option on Card 2.

SULF

Sulfur content of crude, as a fraction of the total weight. If any sulfur is present, a 10% penalty to revenue is incurred.

If not available, the revenue will not include this penalty.

Card 5 (repeat as needed)

LIST: BØI, BØF, ØØIP, CØIL, QD, REC
FORMAT: (6F10.0)

BØI Initial oil formation volume factor, as res. bbls/stb. This is used in the calculation of recoverable target oil.

If not available, BØI is assumed to be 1.0.

BØF Oil formation volume factor at completion of secondary waterflood, as res. bbls/stb. This is used in the calculation of recoverable target oil.

Due to the lack of availability of BØF at this time, it will be set to the value of BØI (i.e., no oil shrinkage) regardless of what may have been input. BØF should definitely be read when available.

ØØIP Original oil-in-place, in MMSTB. This is used in the calculation of recoverable target oil.

With the assumption of no oil shrinkage, the ØØIP term drops out of the RTØ equation. But ØØIP should definitely be read when available for future work done utilizing BØF data.

CØIL Cumulative oil production at completion of secondary waterflood, in MMSTB. This is used in the calculation of recoverable target oil.

The reservoir will not be processed if this is not available. No default.

QD Total pore volumes injected during project, as a fraction. This is used in the calculation of project life.

If not available, DEFQD on Card 1 is used as default.

REC Expected oil recovery from micellar-polymer flooding project, as a fraction. This is used in the calculation of recoverable target oil.

If not available, the anticipated recovery will be determined from the calculation of the capillary number and subsequent correlation with the Gupta-Trushenski experimental curve, Fig. IV-1.

The 3, 4 and 5 card series should be repeated until all the reservoirs have been read.

Card 6 (one card)

LIST: NAME(1)
FORMAT: (10X, I5)

NAME(1) The word 'STØP should be used to terminate
the data.

No default.

Note: The program is presently dimensioned to handle 1000 reservoirs per run. If it is desired to process more than this, several runs will be necessary.

IV. COST TABLES

The tables that follow summarize the costs used in calculating project expenses. The costs have been subdivided into three categories based on well depth.

<u>JJ</u>	<u>Depth, ft.</u>
1	<2500
2	2500-500
3	>5000

These base figures were estimated from the Office of Technology Assessment study published in 1978. Since the original work was done in 1976 dollars, an escalation rate of 12% was applied annually to estimate 1980 values.

In Table A, Drilling, Cost/Foot/Well, it may be noted that in some instances the variation with depth is not monotonic. The reason may be related to the variation in the amortization of site preparation over more ft./well and the increased cost of a drilling rig to go to deeper pay.

A. Drilling

Cost/Foot/Well

<u>State</u>	<u>1</u>	<u>2</u>	<u>3</u>
Alabama	\$42.02	\$41.54	\$59.47
Arizona	\$52.26	\$46.46	\$50.55
Arkansas	\$26.38	\$29.80	\$39.37
California	\$63.35	\$63.49	\$67.43
Colorado	\$64.47	\$33.56	\$37.57
Florida	\$42.02	\$41.54	\$59.47
Indiana	\$36.37	\$39.30	\$48.68
Kansas	\$23.37	\$29.84	\$34.24
Kentucky	\$36.37	\$39.30	\$48.68
Louisiana	\$90.68	\$78.80	\$69.81
Maryland	\$22.87	\$28.38	\$26.97
Michigan	\$36.37	\$39.30	\$48.68
Mississippi	\$34.67	\$34.67	\$35.22
Missouri	\$30.58	\$37.32	\$45.48
Montana	\$23.76	\$44.68	\$54.72
Nebraska	\$30.29	\$37.32	\$45.48
Nevada	\$58.25	\$62.45	\$67.10
New Mexico	\$52.26	\$46.46	\$50.55
New York	\$22.87	\$28.38	\$26.97
North Dakota	\$38.66	\$46.17	\$56.31
Ohio	\$36.37	\$39.30	\$48.68
Oklahoma	\$30.29	\$37.32	\$45.48
Pennsylvania	\$22.87	\$28.38	\$26.97
South Dakota	\$38.66	\$46.17	\$56.31
Tennessee	\$36.37	\$39.30	\$48.68
Texas	\$40.00	\$35.00	\$40.00
Utah	\$58.25	\$62.45	\$67.10
Virginia	\$22.87	\$28.38	\$26.97
West Virginia	\$22.87	\$28.38	\$26.97
Wyoming	\$62.80	\$69.99	\$51.76

B. Production Equipment

Cost/Well

<u>State</u>	<u>1</u>	<u>2</u>	<u>3</u>
Alabama	\$34,940	\$67,800	\$ 75,085
Arizona	\$34,346	\$48,917	\$ 77,910
Arkansas	\$37,022	\$55,162	\$ 73,004
California	\$49,512	\$77,167	\$ 70,179
Colorado	\$52,931	\$67,502	\$114,338
Florida	\$34,940	\$67,800	\$ 75,085
Indiana	\$37,022	\$55,162	\$ 73,004
Kansas	\$37,022	\$55,162	\$ 73,004
Kentucky	\$37,022	\$55,162	\$ 73,004
Louisiana	\$36,725	\$70,327	\$ 78,654
Maryland	\$12,489	\$25,276	\$ 25,276
Michigan	\$37,022	\$55,162	\$ 73,004
Mississippi	\$34,941	\$67,800	\$ 75,085
Missouri	\$37,022	\$55,162	\$ 73,004
Montana	\$59,931	\$67,502	\$114,338
Nebraska	\$37,022	\$55,162	\$ 73,004
Nevada	\$52,931	\$67,502	\$114,338
New Mexico	\$34,346	\$48,917	\$ 77,910
New York	\$12,489	\$25,276	\$ 25,276
North Dakota	\$52,931	\$67,502	\$114,338
Ohio	\$37,022	\$55,162	\$ 73,004
Oklahoma	\$37,022	\$55,162	\$ 73,004
Pennsylvania	\$12,489	\$25,276	\$ 25,276
South Dakota	\$52,931	\$67,502	\$114,338
Tennessee	\$37,022	\$55,162	\$ 55,162
Texas	\$34,346	\$48,917	\$ 77,910
Utah	\$52,931	\$67,502	\$114,338
Virginia	\$12,489	\$25,276	\$ 25,276
West Virginia	\$12,489	\$25,276	\$ 25,276
Wyoming	\$59,931	\$67,502	\$114,338

C. Injection Equipment

Cost/Well

<u>State</u>	<u>1</u>	<u>2</u>	<u>3</u>
Alabama	\$42,375	\$42,375	\$ 67,354
Arizona	\$41,185	\$41,185	\$ 65,569
Arkansas	\$44,605	\$44,605	\$ 95,306
California	\$45,348	\$45,348	\$ 72,112
Colorado	\$63,637	\$63,637	\$111,067
Florida	\$42,375	\$42,375	\$ 67,354
Indiana	\$44,605	\$44,605	\$ 95,306
Kansas	\$44,605	\$44,605	\$ 95,306
Kentucky	\$44,605	\$44,605	\$ 44,605
Louisiana	\$46,241	\$46,241	\$ 77,762
Maryland	\$18,139	\$18,139	\$ 18,139
Michigan	\$44,605	\$44,605	\$ 95,306
Mississippi	\$42,375	\$42,375	\$ 67,354
Missouri	\$44,605	\$44,605	\$ 95,306
Montana	\$63,637	\$63,637	\$111,067
Nebraska	\$44,605	\$44,605	\$ 95,306
Nevada	\$63,637	\$63,637	\$111,067
New Mexico	\$41,185	\$41,185	\$ 65,659
New York	\$18,139	\$18,139	\$ 18,139
North Dakota	\$63,637	\$63,637	\$111,067
Ohio	\$44,605	\$44,605	\$ 95,306
Oklahoma	\$44,605	\$44,605	\$ 95,306
Pennsylvania	\$18,139	\$18,139	\$ 18,139
South Dakota	\$63,637	\$63,637	\$111,067
Tennessee	\$44,605	\$44,605	\$ 44,605
Texas	\$41,185	\$41,185	\$ 65,659
Utah	\$63,637	\$63,637	\$111,067
Virginia	\$18,139	\$18,139	\$ 18,139
West Virginia	\$18,139	\$18,139	\$ 18,139
Wyoming	\$63,637	\$63,637	\$111,067

D. Workover and Well Conversion

Cost/Well

<u>State</u>	<u>1</u>	<u>2</u>	<u>3</u>
Alabama	\$32,264	\$ 56,797	\$ 95,306
Arizona	\$25,128	\$ 40,739	\$ 85,493
Arkansas	\$25,870	\$ 44,158	\$ 88,911
California	\$30,331	\$ 74,639	\$153,739
Colorado	\$51,592	\$ 75,678	\$114,335
Florida	\$32,264	\$ 56,797	\$ 95,306
Indiana	\$25,870	\$ 44,159	\$ 88,913
Kansas	\$25,870	\$ 44,158	\$ 88,911
Kentucky	\$25,870	\$ 44,159	\$ 44,159
Louisiana	\$52,632	\$102,589	\$139,759
Maryland	\$13,233	\$ 43,862	\$ 43,862
Michigan	\$25,870	\$ 44,159	\$ 88,913
Mississippi	\$32,264	\$ 56,796	\$ 95,304
Missouri	\$25,871	\$ 44,159	\$ 88,913
Montana	\$51,592	\$ 75,672	\$114,335
Nebraska	\$25,870	\$ 44,158	\$ 88,911
Nevada	\$51,593	\$ 75,680	\$114,338
New Mexico	\$25,127	\$ 40,738	\$ 85,491
New York	\$13,233	\$ 43,862	\$ 43,862
North Dakota	\$57,593	\$75,680	\$114,338
Ohio	\$25,870	\$ 44,159	\$ 88,913
Oklahoma	\$25,870	\$ 44,158	\$ 88,911
Pennsylvania	\$13,233	\$ 43,861	\$ 43,861
South Dakota	\$57,593	\$ 75,680	\$114,338
Tennessee	\$25,870	\$ 44,159	\$ 44,159
Texas	\$25,127	\$ 40,738	\$ 85,491
Utah	\$51,593	\$ 75,680	\$114,338
Virginia	\$13,233	\$ 43,861	\$ 43,862
West Virginia	\$13,233	\$ 43,862	\$ 43,862
Wyoming	\$51,592	\$ 75,678	\$114,335

E. Operating Cost

Cost/Well Pair

<u>State</u>	<u>1</u>	<u>2</u>	<u>3</u>
Alabama	\$24,531	\$34,493	\$40,887
Arizona	\$19,923	\$21,409	\$28,993
Arkansas	\$24,830	\$27,505	\$38,359
California	\$28,695	\$33,602	\$42,266
Colorado	\$21,558	\$35,683	\$63,189
Florida	\$24,532	\$34,494	\$40,886
Indiana	\$14,876	\$16,504	\$23,937
Kansas	\$24,830	\$27,505	\$38,359
Kentucky	\$14,867	\$16,504	\$23,937
Louisiana	\$22,004	\$30,182	\$37,616
Maryland	\$ 5,799	\$ 6,542	\$ 6,542
Michigan	\$14,867	\$16,504	\$23,937
Mississippi	\$24,532	\$34,494	\$40,886
Missouri	\$24,830	\$27,505	\$38,359
Montana	\$21,558	\$35,683	\$63,189
Nebraska	\$24,830	\$27,505	\$38,359
Nevada	\$21,558	\$35,683	\$63,189
New Mexico	\$19,923	\$21,409	\$28,993
New York	\$ 5,799	\$ 6,542	\$ 6,542
North Dakota	\$21,558	\$35,683	\$63,189
Ohio	\$14,867	\$16,504	\$23,937
Oklahoma	\$24,830	\$27,505	\$38,359
Pennsylvania	\$ 5,799	\$ 6,542	\$ 6,542
South Dakota	\$21,558	\$35,683	\$63,189
Tennessee	\$14,867	\$16,504	\$23,937
Texas	\$19,923	\$21,409	\$28,993
Utah	\$21,558	\$35,683	\$63,189
Virginia	\$ 5,799	\$ 6,542	\$ 6,542
West Virginia	\$ 5,799	\$ 6,542	\$ 6,542
Wyoming	\$21,558	\$35,683	\$63,189

V. DIAGNOSTIC STATEMENTS

A series of checks on intermediate calculations have been built into the program for diagnostic purposes. A summary of the first error incurred per reservoir is included as part of the program output. It should be noted, though, that if a reservoir appears in this summary, it should have also been included in the summary of output variables but was omitted due to the error.

The following is a list of all the possible diagnostic errors:

- (1) $SCW \geq 1.0$
- (2) $SØI > SØRW$
- (3) Target oil ($TØ$) ≤ 0.0
- (4) $EPW < PCØN$
- (5) $EIW < INCØN$
- (6) Revenue/Expenses ($RATIØ$) ≤ 0.0

Figure IV.1: Gupta-Trushenski Experimental Curve

APPENDIX V

CHEMICAL FLOODING PROCESS SENSITIVITY 1-D SIMULATIONS

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1. Summary and Conclusions

Intercomp's Chemical Flooding Ternary Equilibrium (CFTE) simulator was used to study the sensitivity of micellar-polymer flooding to a number of process variables. Oil recovery efficiency and interactions among the injected fluids were studied for variable surfactant slug size and retention, and with and without preflush, mobility buffer, polymer inaccessible pore volume or physical dispersion. Bell Creek phase equilibria, relative permeability and physical property data were used in all simulations, References 17 and 18.

Increased surfactant retention was found to have the most adverse effect on oil recovery. A positive correlation was found between surfactant slug size/retention ratio and tertiary oil recovery. The process was not as sensitive to preflush. The results reflect that, for the Bell Creek data, interfacial tension is a stronger function of surfactant concentration than of preflush concentration.

Oil recovery was reduced significantly in the absence of a mobility buffer. Absence of physical dispersion from the model improved recovery slightly as did the presence of polymer inaccessible pore volume.

The simulator was tested with data from the Lake-Pope models for phase equilibria and three-phase relative permeability. Successful runs were made when the simulator was forced to traverse phase environments, move through the three-phase region and undergo severe salinity gradients.

The results indicate that with adequate process design information, micellar-polymer flooding for the candidate reservoirs from the technical and economic screens can be simulated with a high degree of confidence.

2. Simulator Input Data

Simulations were conducted in a one-layer, linear reservoir of uniform permeability ($k = 1075$ md) with 30 grid blocks in the direction (x) of flow. Grid block dimensions were 32 ft. (x), 85 ft. (y) and 6 ft. (z). With $\phi = .27$, pore volume was about $132,000 \text{ ft}^3$. An injection well and a production well were completed in grid blocks 1 and 30, respectively. Floods were run at a rate of $155 \text{ ft}^3/\text{day}$. The initial conditions were $S_{orw} = .25$, $S_{cw} = .75$ and $P = 950$ psi.

The Bell Creek phase behavior (Figure V.1) input is type II(-) with all tie-lines terminating in the oil corner. Figures V.2 and V.3 show the two-phase relative permeability curves as a function of capillary number (N_{cap}). The program determined relative permeability by a linear interpolation on $\ln N_{cap}$. Thus, negative values for the low tension oleic phase curve are input for oil saturations below residual.

Surfactant adsorption (retention) isotherms for various runs are shown in Figure V.4. Surfactant adsorption was irreversible in all runs. There was no polymer adsorption. IFT as a function of surfactant, preflush and co-surfactant concentration is shown in Figure V.5. Shear dependence of the micellar or polymer slugs was not considered in these runs.

3. Results and Discussion

The results are summarized in Table V.1 and Figures V.6 - V.15.

Run 1 - Base Case

The injection sequence was: .16 pv preflush, .038 pv micellar slug, .6 pv mobility buffer (polymer) and .71 pv chase water. The injection composition of the micellar slug was: .06 (vol. %) surfactant, .53 water and .41 oil, with a trace amount of co-surfactant. Physical dispersion was input as $\alpha_L = 12$ ft. for all phases. Surfactant retention was .27 mg surfactant/gm rock.

Figure V.6 shows normalized concentration profiles, $\log_{10} N_{cap}$ and oil saturation in grid block 15 as a function of pore volumes injected. Oil production (f_o and cumulative) data were taken from grid block 30 (production well). Formation of an oil bank ahead of the micellar slug is apparent as is the non-adsorbing character of polymer ($C/C_o = 1$). There is some invasion of the micellar slug by the mobility buffer. The higher values of N_{cap} (low IFT) occur at the rear of the oil bank and in the zone of high surfactant concentration. After 1.5 pv injection (Figure V.7), the remaining S_o is highest at the core outlet reflecting some micellar slug breakdown with distance. Tertiary oil recovery in Run 1 was 90.3%.

Run 2 - No Preflush

Run 1 was repeated without preflush. Tertiary recovery dropped to 77%. IFT was not as low (Figure V.5) in the absence of preflush. Run 2 data are shown in

Figure V.8. Overall behavior is not remarkably different from Run 1.

Run 3 - Mobility Buffer

Base case recovery dropped to 63.5% without mobility buffer (zero polymer concentration). Figure V.9 shows the dispersion of surfactant by invasion of high mobility chase water, with consequent reduction of N_{cap} in the dispersed zone and lower fractional flow of oil. Figure V.10 shows good displacement efficiency near the injection well but S_o 's of greater than 10%, due to micellar slug dilution, in grid blocks 15-30.

Run 4 - Polymer Inaccessible Pore Volume = .2

Base case recovery increased to 95.7%. Inaccessible pore volume is thought to result from the inability of swollen polymer molecules to traverse narrow pore throats. The net result is a reduction in the effective permeability to polymer. The reduced permeability in turn results in a lower mobility for the polymer slug and thus higher oil recovery.

Run 5 - No Physical Dispersion

The CFTE simulator assumes a two parameter model (D^*, α) for the effective physical dispersion coefficient

$$D_e = D^* + v\alpha_L$$

where D^* is the effective binary molecular diffusion coefficient, v is the interstitial velocity (Darcy velocity/ ϕ) and α_L is the dispersion coefficient. D^* was set equal to zero for all runs, and $\alpha_L = 12$ ft. for all runs except Run 5. The value of 12 ft. was obtained from scale-up of corefloods in which salinity gradients were tracked. 12 ft. may be an unusually high value for physical dispersion. With $\alpha_L = 0$, base case recovery increased to 98.6%. The sharpening of all concentration profiles is apparent from Figure V.11. The remaining dispersion, which is attributed to numerical truncation error, was estimated to be about 3 ft. In order to judge the influence of a more realistic imposed physical dispersion, the numerical dispersion can be reduced by control of time-step size and grid block dimensions.

Run 6 - Inject Micellar Slug in One-Phase Region

The idea here was to inject the micellar slug in the one-phase region of the ternary equilibrium diagram, whereupon dilution would force the slug into the two-phase region. Figure V.12 shows that this was the case, where the front of the slug tracks to a stabilized oil-water bank and the rear to the (miscible) polymer bank (water corner). Figure V.12 is the triangular diagram of Figure V.1 plotted on right rectangular coordinates with the two-phase region greatly expanded. The injection concentration (.7 surfactant, .15 water, .15 oil) is off the plot. Oil recovery was 100%.

Figure V.12 also shows that the micellar slug tracks into an oil bank of roughly the same magnitude when surfactant concentration in the injected slug is reduced to .062 (point A, Run 7). Run 7, as well as Runs 1-5 in which the micellar slug was injected in the two-phase region, are examples of so-called immiscible microemulsion flooding.

Run 8 - High Surfactant Retention

Base case recovery fell to 59.3% when surfactant retention was doubled. Figure V.13 shows a more dispersed and diluted surfactant profile. Figure V.14 shows that the slug broke down and no tertiary oil was recovered beyond about grid block 21.

Runs 9-13 - Variable Surfactant Retention and Slug Size

Runs 9-13 as well as Runs 1, 7 and 8 are all variations on slug size, retention, and/or the slope of the adsorption isotherms (Figure V.4). A convenient way to correlate these runs is to plot tertiary oil recovery vs. V_{ps}/D_s , where V_{ps} is the micellar slug pore volume and D_s is the retention expressed in pore volumes:

$$D_s = \left(\frac{1 - \phi}{\phi} \right) \left(\frac{\rho_r a_s}{\rho_s C_s} \right)$$

where

ρ_r = rock density

ρ_s = surfactant density

a_s = surfactant retention

C_s = surfactant concentration in slug

ϕ = porosity

For $V_{ps}/D_s = 1$, the micellar slug would be "used up" right at the production well if there were no dilution effects. Figure V.15 shows that the optimum V_{ps}/D_s ratio is about 1.3, a typical value for lab corefloods. The ratio will increase as a function of heterogeneity. The significance of the curve in Figure V.15 is that the simulator appears to realistically account for the interactions between slug size, adsorption and oil recovery.

Simulator Testing with Lake-Pope Models for Phase Equilibria and Three-Phase Relative Permeability

The Lake-Pope phase equilibria model is described elsewhere.¹¹⁹ The model calculates idealized phase diagrams and physical properties for a typical micellar fluid. The phase behavior is represented using the three pseudo components brine, oil and chemical. Seven parameters are input to the model from which the phase diagrams are computed as a function of salinity. The parameters are the maximum height of the binodal curve in the type II(-), III and II(+) regions, the left and right plait points and lower (CSEL) and upper (CSEU) critical salinities. CSEL is the salinity at which the phase environment switches from type II(-) to type III; CSEU is the salinity at which the system switches from type III to type II(+).

The set of parameters chosen was for "Run 2" of the table in Reference 119. With these parameters, a suite of phase diagrams was calculated from which five were selected for input to the simulator: one type II(-), three III and one II(-).

The Lake-Pope model for high capillary number three-phase relative permeability is also described in Reference 119. Using the Bell Creek oil-water relative permeability curves as input data, three-phase relative permeability was calculated for three capillary numbers: waterflood case, $N_{cap} = 10^{-3}$, and miscible displacement of non-wetting (oil) phase. A set of capillary desaturation curves for Berea sandstone was used to generate the phase residuals as a function of capillary number.

The CFTE simulator was tested with the three-phase relative permeability data and suite of five equilibrium diagrams. Runs were made with salinity gradients such that the overall system composition would pass among the various phase diagrams and across phase boundaries on the same diagram. The simulator appears to handle all test problems run to date.

TABLE V.1

Summary of Process Sensitivity Runs

I-D, linear, NX = 30 grid blocks
 Micellar slug followed by 0.60 pv polymer (except #3)
 $\alpha_L = 12$ ft. (except #5)
 $da_S/dc_S = .27 \times 10^2$ (except #12, 13)

Run No.	Description	pv Micellar Slug	Retention, $a_S, \text{mg}_S/\text{gm}_r$	Tertiary Rec, % OIP aft. WF
1.	Base Case	0.038	0.27	90.3
2.	No Preflush	0.038	0.27	77.0
3.	No Polymer	0.038	0.27	63.5
4.	IPV Polymer = 0.2	0.038	0.27	95.7
5.	Low Dispersion ($\alpha_L = 0$)	0.038	0.27	98.6
6.	Injection Slug in 1 ϕ Region*	0.038	0.27	100.0
7.	2X Micellar Slug pv	0.076	0.27	97.9
8.	2X Retention	0.038	0.54	59.3
9.	2X Retn, 2X Slug pv	0.076	0.54	96.3
10.	2X Retn, 0.060 pv Slug	0.060	0.54	93.5
11.	2X Retn, 0.050 pv Slug	0.050	0.54	80.5
12.	Steep Adsorp. Isotherm**	0.038	0.27	72.1
13.	Steep Adsorp. Isotherm ⁺	0.038	0.18	91.3

*Miscible Displacement

** $da_S/dc_S = .27 \times 10^5$

⁺ $da_S/dc_S = .18 \times 10^5$

BELL CREEK TERNARY EQUILIBRIUM

FIGURE V.1

FIGURE V.2

OLEIC PHASE RELATIVE PERMEABILITY

ADSORPTION ISOTHERMS

FIGURE V.4

INTERFACIAL TENSION

FIGURE V.5

RUN I — BASE CASE

1-D BASE CASE

FIGURE V.6

RUN 1-BASE CASE

FIGURE V.7

RUN 2

NO PREFLUSH

FIGURE V.8

RUN 3

NO POLYMER

FIGURE V.9

RUN 3 DATA AFTER 1.5PV INJECTION

NO POLYMER

GRID BLOCK No.

FIGURE V.10

RUN 5

LOW DISPERSION

FIGURE V.11

COMPOSITION PATH

AFTER .75 PV INJECTION FOR RUNS 6 AND 7

FIGURE V.12

RUN 8

HIGH ADSORPTION

FIGURE V.13

RUN 8 DATA AFTER 1.5PV INJECTION

HIGH ADSORPTION

FIGURE V.14

RATIO OF PV SURFACTANT SLUG TO SURFACTANT RETENTION LOSS (INPV) VS. TERTIARY OIL RECOVERY FOR 8 RUNS

FIGURE V.15

APPENDIX VI

CHEMICAL FLOODING PROCESS SENSITIVITY RUNS TWO-LAYERED SIMULATIONS

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Summary and Conclusions

Preliminary results from simulations in a linear two-layered cross-sectional model indicate that reservoir stratification can have a very deleterious effect on oil recovery and that cross flow between layers has a marked effect on recovery. The results indicate that oil recovery in a layered system can be increased by increasing surfactant slug size and/or mobility buffer size. However, as the permeability contrast increases, the sensitivity of oil recovery to surfactant slug size decreases, suggesting that optimum surfactant slug size may decrease with increasing vertical heterogeneity.

The reservoir model utilized in this portion of the study was quite simple, and the very large length-to-thickness ratio used (960 ft/6 ft) would tend to accentuate the effect of cross flow. However, these preliminary results indicate that the effect of vertical heterogeneity is great enough to warrant additional study using more representative reservoir geometries.

The purpose of this study was to estimate the effect of stratification on recovery in a chemical flood. The study utilized very simplified geometry and phase behavior and was intended to indicate gross behavior. Work to be completed in 1980 will involve more realistic reservoir descriptions and a variety of phase behaviors.

Simulator Input Data

Bell Creek fluid and rock properties described in Appendix V were used. A linear system made up of two equal-thickness, equal-porosity layers was modelled using a 15 x 1 x 2 grid. The permeabilities of the two layers were varied to study the effect of stratification. The base case reservoir geometry is given in Table VI.1. The reservoir was initialized at waterflood residual oil (25%) for both layers.

In all runs the surfactant slug was followed by a mobility buffer. The viscosity of the mobility buffer was graded linearly from that of the slug to that of the chase water in five equal volume increments as shown in Figure VI.1. Chase water was injected following the mobility buffer until essentially a zero oil cut was achieved.

Results and Discussion

Table VI.2 summarizes the individual runs made. Figure VI.2 shows the effect of permeability ratio on recovery for a 3.8% pv surfactant slug followed by a 30% pv mobility buffer. As expected, recovery drops with increasing permeability contrast. Also shown in this figure is the recovery from the individual layers. Note that the recovery from the high permeability layer (layer 2) is relatively insensitive to the permeability contrast, with the recovery at $k_2/k_1 = 5$ actually being higher in this layer than that obtained in the homogeneous case. However, significant resaturation of the low permeability layer has occurred, as evidenced by the negative recovery for layer 1. Thus, a significant amount of the oil mobilized in layer 2 is lost into layer 1 and not recovered. Figure VI.3 shows the recovery versus k_2/k_1 for a 3.8% pv surfactant slug followed by a 120% pv mobility buffer. At all permeability levels, the total recovery has been increased by the larger mobility buffer. The individual layer recoveries show that the recovery from the low permeability layer has increased the most, but the fact that the high permeability layer's recovery has decreased as a result of the larger mobility buffer indicates that much of the oil displaced from the low permeability layer was pushed back into the high permeability layer behind the surfactant slug and hence not recoverable.

Figures VI. 4 - VI.7 show the oil recovery as a function of surfactant slug size for various permeability contrasts and mobility buffer sizes. From these figures, it can be seen that for all permeability contrasts investigated, the oil recovery increases with increasing slug size and with increasing mobility buffer size. However, as the degree of heterogeneity increases, the effect of increased slug size on recovery is diminished. This suggests that as reservoir heterogeneity increases, the optimum surfactant slug size may decrease.

TABLE VI.1

Grid Description

Grid	15 x 1 x 2
Lenth	960 ft.
Width	85.18 ft.
Thickness	6 ft.
Porosity	0.27
k_v/k	0.10
Pore Volume	132,471 ft ³
Injection Rate	155 ft ³ /day
S_{orw}	25%
Longitudinal Dispersion (α_L)	12 ft.
Transverse Dispersion (α_T)	0.005 ft.

TABLE VI.2

Summary of Two-Layered Simulation Runs

SLUG SIZE (% pv)	K_2/K_1	MOBILITY BUFFER SIZE (% pv)	RECOVERY (% S_{orw})		
			Layer 1	Layer 2	TOTAL
1.9	1.0	30.0	47.17	47.17	47.17
1.9	1.0	60.0	51.90	51.90	51.90
1.9	1.0	90.0	-	-	-
1.9	1.0	120.0	-	-	-
1.9	2.0	30.0	16.18	44.15	30.17
1.9	2.0	60.0	27.63	45.85	36.74
1.9	2.0	90.0	29.71	47.08	38.39
1.9	2.0	120.0	30.82	47.36	39.09
1.9	3.0	30.0	-6.84	59.37	26.27
1.9	3.0	60.0	7.74	57.18	32.46
1.9	3.0	90.0	9.73	55.59	32.69
1.9	3.0	120.0	10.53	53.42	31.97
1.9	5.0	30.0	-26.90	68.91	21.01
1.9	5.0	60.0	-10.83	69.65	29.41
1.9	5.0	90.0	-3.13	69.28	33.08
1.9	5.0	120.0	0.89	68.53	34.71
3.8	1.0	30.0	79.87	79.87	79.87
3.8	1.0	60.0	86.00	86.00	86.00
3.8	1.0	90.0	87.51	87.51	87.51
3.8	1.0	120.00	88.03	88.03	88.03
3.8	2.0	30.0	27.79	72.98	50.38
3.8	2.0	60.0	52.56	71.08	61.82
3.8	2.0	90.0	56.38	71.78	64.08
3.8	2.0	120.0	57.92	72.18	65.05
3.8	3.0	30.0	3.76	73.67	38.71
3.8	3.0	60.0	29.59	68.98	49.28
3.8	3.0	90.0	35.18	66.60	50.89
3.8	3.0	120.0	36.37	67.74	52.05
3.8	5.0	30.0	-23.36	80.51	28.58
3.8	5.0	60.0	5.12	69.24	37.18
3.8	5.0	90.0	14.32	66.65	40.43
3.8	5.0	120.0	16.36	66.54	41.45
7.6	1.0	30.0	89.98	89.98	89.98
7.6	1.0	60.0	95.83	95.83	95.83
7.6	1.0	90.0	97.09	97.09	97.09
7.6	1.0	120.0	97.66	97.66	97.66
7.6	2.0	30.0	43.74	81.58	62.66
7.6	2.0	60.0	77.67	91.40	84.54
7.6	2.0	90.0	82.37	94.17	88.27
7.6	2.0	120.0	84.68	94.93	89.81
7.6	3.0	30.0	16.50	81.85	49.17
7.6	3.0	60.0	53.97	75.14	64.56

TABLE VI.2

(continued)

SLUG SIZE (% pv)	K_2/K_1	MOBILITY BUFFER SIZE (% pv)	RECOVERY (% S_{orw})		
			Layer 1	Layer 2	TOTAL
7.6	3.0	90.0	62.30	77.07	69.69
7.6	3.0	120.0	67.07	78.28	72.67
7.6	5.0	30.0	-13.13	84.02	35.45
7.6	5.0	60.0	17.01	74.66	45.83
7.6	5.0	90.0	29.27	73.60	51.44
7.6	5.0	120.0	33.76	72.89	53.33

LINEAR GRADING OF MOBILITY BUFFER

FIGURE VI.1

RECOVERY VS. PERMEABILITY CONTRAST FOR
3.8% SURFACTANT SLUG
FOLLOWED BY 30% MOBILITY BUFFER

FIGURE VI.2

**RECOVERY VS. PERMEABILITY CONTRAST FOR
3.8% SURFACTANT SLUG
FOLLOWED BY 120% MOBILITY BUFFER**

FIGURE VI.3

OIL RECOVERY VS. SURFACTANT SLUG SIZE WITH 30% PV MOBILITY BUFFER

FIGURE VI.4

OIL RECOVERY VS. SURFACTANT SLUG SIZE WITH 60% PV MOBILITY BUFFER

FIGURE VI.5

OIL RECOVERY VS. SURFACTANT SLUG SIZE WITH 90% PV MOBILITY BUFFER

FIGURE VI.6

OIL RECOVERY VS. SURFACTANT SLUG SIZE WITH 120% PV MOBILITY BUFFER

FIGURE VI.7

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