SPE REPRINT SERIES

NO. 24

SURFACTANT/POLYMER CHEMICAL FLOODING—I

Published by the Society of Petroleum Engineers

SPE REPRINT SERIES NO. 24

SURFACTANT/POLYMER CHEMICAL FLOODING—I

Published by the
Society of Petroleum Engineers
Richardson, TX

SPECIAL REPRINT COMMITTEE

1-55563-012-X

Foreword

The two reprint volumes on surfactant/polymer flooding of necessity contain only a small fraction of the papers that have been published by SPE on the subject of chemical flooding. A cursory glance at the extensive Bibliography may make it clear why the subject was narrowed to include only surfactant/polymer flooding, omitting papers on closely allied subjects, such as alkaline flooding, polymer flooding, and emulsion or foam flooding. These subjects may be covered in later Reprint Series volumes.

An effort was made by the selection committee to include sufficient material that a thorough study of the papers in the volumes and closely related papers would provide a basic education in surfactant/polymer flooding for the beginner. The volumes should also serve as handy desk references for those experienced in the subject.

The publication period for surfactant/polymer flooding papers covers about 20 years. Although there were a few earlier papers and patents leading toward this process, a clear-cut and accelerating interest in the process began with the presentation of two papers by Gogarty and Tosch and by Davis and Jones at the 1967 SPE Annual Meeting in Houston and the publication of these papers in *JPT* in Dec. 1968. These papers, by Marathon Oil Co. authors, soon brought forth papers by authors from other oil companies describing different versions of surfactant/polymer flooding processes. Despite their strong historical interest, these papers are not included because later scientific and engineering studies present clearer, more complete pictures of the processes involved and were considered more essential.

The committee found it possible to cover the subject adequately using only papers published by SPE; therefore, papers from other publications are not included. Papers on field pilots and fieldwide projects also were not included because they appear in another recently published Reprint Series volume (No. 23, *EOR Field Case Histories*); seven of the papers in the volume are on surfactant/polymer floods.

Of course, as with all scientific and engineering areas, the subject of surfactant/polymer flooding is not closed, and these volumes do not contain all of the definitive studies that have been or will be performed.

E.L. Claridge
Chairman

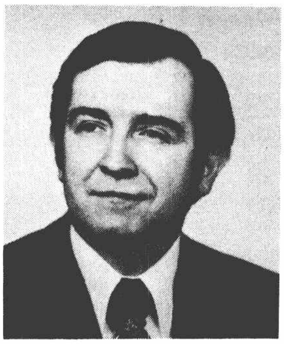
TABLE OF CONTENTS

Volume I

TABLE OF CONTENTS

Volume II

Distinguished Author Series



Enhanced Oil Recovery Through the Use of Chemicals—Part 1

by W.B. Gogarty, SPE

Since 1975 W.B. Gogarty has been associate research director of production with Marathon Oil Co.'s Denver Research Center. He holds a PhD degree in chemical engineering from the U. of Utah. Gogarty joined Marathon in 1959 as a research scientist in Denver. He became advanced research scientist in 1962, senior research scientist in 1964, and manager in 1967. In 1973 he transferred to Findlay, OH, to work in U.S. and Canadian production operations. He was adjunct associate professor in the U. of Denver Chemical Engineering and Metallurgy Dept. from 1967 until 1972. Gogarty was 1982-83 SPE Distinguished Lecturer on chemical EOR. He has chaired the Monograph, Textbook, and Lester C. Uren Award committees and served on program committees for several SPE Annual Meetings and the 1982 SPE/DOE Enhanced Oil Recovery Symposium. He holds 57 U.S. and 80 international patents and has written many technical papers.

Introduction

Chemical enhanced oil recovery (EOR) includes processes in which chemicals are injected to improve oil recovery. Chemical methods are one of three categories of EOR, the others being thermal and miscible. Table 1 shows the different processes in these categories as defined by the Crude Oil Windfall Profit Tax Act of 1980.[1] A comparison of field project activity in the three categories is shown in Table 2.[2-5] Thermal activity is the highest, followed by chemical. Note that the number of chemical projects more than doubled between 1980 and 1982. Miscible CO_2 injection accounts for most of the miscible category.

Projects in the chemical category of Table 2 are broken down further in Table 3 in terms of the three chemical EOR methods. Micellar/polymer projects are those in which surfactant is injected into the formation. Polymer projects refer to a spectrum of uses including near-wellbore treatments, complete polymer-augmented waterfloods, and a combination of both. Caustic refers to projects where alkali is injected to increase pH and to produce surfactants in situ. With all three chemical EOR methods, activity has increased significantly between 1980 and 1982.

In Part 1, each of the three chemical methods is discussed separately. The history of each method is presented along with field projects and laboratory developments. In Part 2 (to appear next month), reservoir heterogeneities are considered in relation to their effect on process performance. Next, information is presented on chemical flooding simulators, and procedures are described for their use. Then, U.S. government incentive programs and their effect on chemical EOR development are considered. Finally, the risk vs. reward associated with chemical EOR is illustrated by some economic calculations.

0149-2136/83/0091-2367$00.25

Micellar/Polymer Flooding

Two kinds of surfactant systems are being developed for this chemical method.[6,7] Work on the first system began in the late 1920's; it involves a large PV (up to 50%) of a low concentration (less than 2.5%) active surfactant solution. This development has led to the so-called low-tension waterflood process. Most often, polymer is used in the surfactant solution to increase its viscosity, thereby giving mobility control to the system. Development of the second system began in the late 1950's. Here a small PV (5 to 15%) of a high-concentration (5 to 12%) active surfactant is used. The small-PV development led to patent processes such as Maraflood™ and Uniflood.™ Both systems are followed by polymer solution for mobility control.

During the 1960's and early 1970's, surfactant/polymer field tests in the U.S. mostly used single-pattern well configurations.[8] The area covered in these projects was relatively small. For example, ¾-acre pilot tests with one injector and four producers were not uncommon.[9] In the middle to late 1970's, the

TABLE 1—WINDFALL PROFIT TAX TERTIARY RECOVERY METHODS

Chemical
- Microemulsion or micellar emulsion flooding
- Polymer-Augmented waterflooding
- Alkaline flooding

Thermal
- Steamdrive injection
- In-Situ combustion
- Cyclic steam injection

Miscible
- Miscible fluid displacement
- CO_2 augmented waterflooding
- Immiscible CO_2 displacement
- Other methods approved by the U.S. Internal Revenue Service

TABLE 2—ACTIVE U.S. EOR PROJECTS

	1976	1978	1980	1982
Thermal	106	115	150	139
Miscible	25	45	34	50
Chemical	28	46	42	85
Total	159	206	226	274

TABLE 3—ACTIVE U.S. CHEMICAL EOR PROJECTS

	1976	1978	1980	1982
Micellar/Polymer	13	22	14	24
Polymer	14	21	22	48
Caustic	1	3	6	13
Total	28	46	42	85

seven micellar/polymer field tests shown in Table 4 were initiated. Most of these projects covered a large area and contained repeated patterns. Detailed information on all these projects is available through the quarterly and annual U.S. Department of Energy (DOE) reports.[10] Each of these projects was undertaken with the idea of exploring one or more new ideas related to surfactant flooding. The goals of these projects give an indication of the direction that surfactant flooding was going in the middle to late 1970's.

The El Dorado project compared performance of a high-concentration Uniflood type system with a low-concentration Shell system. The overall objective was to compare performance of these two systems under similar reservoir conditions. To date, only the pattern containing the high-concentration system has shown a response.

The Lawry project was designed to determine the performance of a surfactant/polymer system in a low-permeability (about 8 md) Bradford sand reservoir of Pennsylvania. A high-concentration Maraflood type system was used in this test. The project recovered only a small amount of oil and was not successful. Apparently, surfactant systems are not capable of mobilizing and producing significant amounts of oil in reservoirs with low permeability.

The Phillips project in the North Burbank field tested surfactant flooding performance in an oil-wet reservoir. This project used a system containing about 5% active surfactant. This is on the low end of the range for a high-concentration surfactant system. The project recovered about half the oil anticipated before the test started.

The Bell Creek project was developed to determine economic feasibility of a surfactant flood after an extremely successful waterflood. A high-surfactant-concentration Uniflood slug was used in the test. One of the purposes was to evaluate the sensitivity to reservoir heterogeneities. Different evaluations have been made of this project. The people who designed the slug deemed the project a success. The operators of the project have indicated that they have not felt the project was a success.

The Wilmington project used a Maraflood type high-concentration surfactant system. The objective was to evaluate surfactant flooding performance in an unconsolidated reservoir containing a high-viscosity aromatic crude. This project has been deemed a success and recovered 43% of the oil remaining in place after waterflooding. The temperature of the reservoir is 145°F and the viscosity of the crude is about 35 cp in place. These temperature and viscosity conditions are the highest of any successful micellar/polymer flood in the U.S.

The M-1 project is the largest surfactant flooding project in the world. This project was designed to compare performance on a commercial scale of identical surfactant systems in the same reservoir with different pattern spacing. A Maraflood high-concentration surfactant system was used in this project. The project was developed on 2.5- and 5-acre spacing. Presently, the 5-acre portion of the project is performing better than the 2.5-acre portion.

The Big Muddy project used a low-concentration surfactant system developed by Conoco. The goal is to demonstrate the feasibility of a low-tension process in a low-permeability (40 md) reservoir on a commercial-scale field basis. This project is in the early stages but has begun to respond.

The DOE cost-sharing micellar/polymer floods represent a significant expenditure to develop this technology. These projects range in cost from about $5 to $45 million.[10] For most of the projects, the government provided about one-third of the funds. Companies have provided results on performance of these projects. Reports include the development of production and injection equipment, fluid treatment problems, etc. Those interested in surfactant/polymer flooding should consult these reports.

TABLE 4—MICELLAR/POLYMER PROJECTS UNDER U.S. DOE COST SHARING

Project	Initiation Date	Project Area (acres)	Spacing (acres)	Operator
El Dorado (KS)	1974	25.6	6.4	Cities Service Oil Co.
		25.6	6.4	
Lawry (PA)	1975	13.5	1.5	Penn Grade Crude Producers Assn.
North Burbank (OK)	1975	90	10	Phillips Petroleum Co.
Bell Creek (MT)	1976	160	40	Gary Energy Corp.
Wilmington (CA)	1976	10	2.5	City of Long Beach, CA
M-1 (IL)	1977	248	2.5	Marathon Oil Co.
		159	5.0	
Big Muddy (WY)	1978	90	10	Conoco

TABLE 5—FACTORS AFFECTING SURFACTANT/POLYMER FLOODING PERFORMANCE

Fluid system design
- Phase behavior
- Coreflooding

Improved surfactants and additives
Improved cosurfactants
Vertical conformance
Polymer preflush
Effective mobility buffers (polymers)
Pattern type and spacing

Table 5 shows factors affecting surfactant/polymer flooding performance. In the past 20 years, a great deal of R&D has gone into these factors. Our understanding about some has increased significantly; with others, we have barely scratched the surface.

Phase behavior remains one of the mainstays in designing fluid systems for surfactant/polymer flooding.[11-16] Both industrial and university research have contributed to this effort. Industrial laboratories have developed their own procedures as an aid to designing surfactant flooding systems. To be as effective as possible, actual reservoir fluids, along with fluids being injected, should be used in these studies. A significant amount of literature is available on such topics as optimal salinity, salinity gradient, and the use of phase volumes.

Laboratory corefloods are important to augment phase study screening procedures. In fact, corefloods probably represent the ultimate laboratory tool necessary for fluid system designs. Results in the literature indicate the need for using actual reservoir rock and fluids in these corefloods. For some surfactant systems, recoveries in Berea corefloods will be significantly higher than those in reservoir cores.[17] In our laboratory, we have observed that recoveries can vary by a factor of three when an identical surfactant/polymer flooding system in different sandstone cores is used. The objective of the laboratory coreflood design is to modify the micellar/polymer system continually to maximize recovery in the actual reservoir rock.

The historical development of sulfonates for EOR is shown in Table 6. In the early 1960's, sulfonates used in surfactant flooding came as a byproduct from lube-oil manufacturing. Lube oil stocks were sulfonated to remove aromatic components. Because of the limited demand for lube oil stocks, the sulfonate supply was small. A low-cost method of mass-producing sulfonate was needed. A first attempt was made by sulfonating gas-oil fractions with sulfuric acid. Sludge disposal was a problem. Next, the gas-oil fractions were sulfonated with SO_3 to eliminate the sludge. The process was expensive. Finally, crude oil was sulfonated with SO_3 to give a cost-effective process. In the mid-1970's, Marathon built an 80-million-lbm/yr plant in Illinois that used the crude-oil sulfonation process. Products from this plant have been used in various Illinois and Pennsylvania projects.

Improvements are under way throughout the industry to use gas-oil sulfonate as a feedstock. In surfactant development, the process engineers must work closely with the users. Phase studies and corefloods are needed to improve the sulfonation process. Synthetic surfactants may lead to further improvements in surfactants for EOR; they are more costly but are reported more effective in displacing oil. Exxon's Loudon test used a synthetic surfactant.[18] Apparently Shell is considering the use of a synthetic surfactant for a micellar/polymer flood in Indonesia.[19] The more expensive synthetic surfactant also is being used as an additive. Here, part of the gas-oil or crude-oil sulfonate is replaced with the synthetic surfactant material.

Improved cosurfactants help surfactant/polymer flood performance. In the earlier system designs, simple alcohols such as isopropyl, butyl, and amyl alcohols were used in system formulation. Ethoxylated alcohol use, pioneered by Texaco, shows much promise as an improved cosurfactant.[20] These chemicals have resulted in improved oil recovery and allow slugs to be tailored for higher salinity and temperature. They also lend a greater flexibility to fluid system design because the chain length and/or degree of ethoxylation may be varied to adjust slug viscosity. Other functionality groups may be added with these cosurfactants.

TABLE 6—HISTORICAL DEVELOPMENT OF SULFONATES FOR EOR

Feedstock	Sulfonating Agent	Solvent	Extraction Step	Comments
Gas-oil fractions	H_2SO_4	chlorinated	generally yes, either feed or product	sludge disposal problem
Gas-oil fractions	SO_3	chlorinated	generally yes, either feed or product	eliminates sludge, but solvent and extraction steps make process expensive
Crude oil (whole or topped)	SO_3	none or hydrocarbon diluent	no	inexpensive product containing undesirable materials
Gas-oil fractions	SO_3	none or hydrocarbon diluent	generally yes, either feed or product	promising but untested process
Synthetics (polybutenes and alkylated aromatics)	SO_3	none or hydrocarbon diluent	no	possible wave of future

Vertical conformance, probably the most significant factor affecting surfactant/polymer flooding performance in the field, depends on reservoir heterogeneities. Poor vertical conformance must be improved if surfactant/polymer flooding recovery is to be increased. The laboratory data in Fig. 1 show that oil recovery is increased by polymer preflushes. Apparently the polymer preflush improves the vertical conformance of the surfactant solution so that recovery is increased.

Continued development of improved mobility buffers is needed to ensure better surfactant flooding performance. The mobility-control problem at the surfactant/polymer interface is demonstrated by the increasing injectivity of polymer solution following slug injection. Fig. 2 shows the results of a micellar/polymer injectivity test in the Bradford sand. This test was performed at a constant injection pressure of 1,000 psi. Slug injection remained constant at about 95 B/D. As polymer injection started, the rate increased to about 105 B/D and then began to decrease. This increase in polymer rate indicates the unfavorable mobility conditions at the slug/polymer interface.

Pattern type and spacing, including size, are important factors affecting surfactant/polymer flooding performance. The effect of pattern type on oil recovery is demonstrated in Fig. 3. Laboratory disk floods for the 119-R and 219-R projects with the same slugs and volumes as used in the field recovered about the same amount of oil. Both projects were conducted in the same reservoir with about the same spacings. The difference in field recoveries appeared to have been caused by pattern types. Results indicate that line-drive patterns are superior to five-spot patterns. In developing the fields, well locations, injectivity, and pattern type should be given careful consideration.

Normally pilot-flood recoveries are used to predict full-field recoveries for determining economics. Selection of pattern size to predict full-field performance is a difficult problem. Table 7 compares the results of the Henry pilot and 119-R field projects in which essentially the same Maraflood fluid system was used in the same reservoir. Note that 63% of the oil in place was recovered in the 0.75-acre pattern of the Henry test.[9] In the 40-acre 119-R project, the recovery was only 38% of the oil in place.[21] These results indicate the need for large projects with repeated patterns to determine full-scale recoveries. Conoco is using this philosophy in going from their successful 1.25-acre project[22] to the 90-acre project with repeated 10-acre patterns. Exxon, in reporting results for the Loudon test, indicated its confidence in projecting directly the small pilot-test results to a full-scale pilot development.[18]

Alkaline Flooding

Alkaline or caustic flooding began in 1925 with the injection of a sodium carbonate solution in the Bradford area of Pennsylvania.[23] Work on this process has continued since then. Fig. 4 shows the location of all of the alkaline flood field tests conducted in North America.

Fig. 5 shows the details of the Whittier field test conducted by Chevron.[24] Water injection began in 1964 and caustic began in 1966. They injected 23% PV of 0.2% sodium hydroxide in soft water. On the basis of waterflood extrapolations, recovery was 350,000 to 470,000 stock-tank bbl of incremental oil. This project is typical of the state of the art for caustic flooding in the late 1960's and early 1970's.

The highlights of three caustic field tests now in progress are given in Table 8. These are the largest of the 13 active projects in the U.S. in 1982.[5] The projects represent the state of the art in caustic flooding for the late 1970's. Two of the projects used sodium orthosilicate as the caustic agent. The slug size for these projects is two to three times greater than in the Chevron project of the 1960's. Concentration of the caustic agent is two to five times greater. Apparently, the direction of caustic flooding in the field has been toward the use of larger amounts of the

TABLE 7—PILOT AND FIELD RECOVERIES

Operator	Pilot/Field Project	Size (acres)	Tertiary Oil Recovery (%)
Marathon	Henry	0.75	63
	119-R	40	38
Conoco	Big Muddy	1.25	50
	Big Muddy	90	—
Exxon	Loudon	0.68	60
	Loudon	—	—

alkaline flooding agent.[25] Caustic is used up in the reservoir by interaction with the rock and clay minerals. Quantifying and designing for caustic consumption to inject sufficient chemical for effective recovery is one of the major problems to be solved in the 1980's. For the three tests shown in Table 8, the oil response is behind schedule. Even with the large amounts of caustic injected in these tests, the amount of chemical may be insufficient for effective recovery because of the loss caused by reaction with the reservoir.

Factors influencing alkaline flooding are shown in Table 9. Much research has been done on various aspects of the first four factors. The last two factors are on the leading edge of caustic flooding technology.[26,27]

Five different agents have been used in field trials, including sodium hydroxide, ammonium hydroxide, sodium orthosilicate, sodium carbonate, and ammonium carbonate. Cost effectiveness is the most important consideration in selecting any caustic agent. Most field projects to date have used sodium hydroxide. Sodium orthosilicate is used because it forms very insoluble products with divalent ions such as calcium and magnesium. These divalent ions reduce the degree to which interfacial tension (IFT) is lowered.[28,29]

Perhaps the most important of the fluid/fluid interaction factors is the lowering of IFT. Natural acids associated with some crude oils are neutralized with the injected caustic and become surfactants. These surfactants concentrate at the oil/water interface and lower the IFT. With time, the surfactant will migrate into the water phase. This migration is speeded up as the concentration of surfactant in the brine is lowered. This will take place if the oil/water bank does not move through the reservoir in a piston-like manner. In other words, the surfactant loss at the interface will be more rapid if fresh brine replaces brine containing surfactant. Because of this migration of surfactant between oil and water, IFT reduction under reservoir conditions is difficult to predict. Much research is going on in this area. Experimental data obtained in the laboratory show that IFT increases with time.[30] Results show that, for a given time, IFT decreases with increases in pH. Mathematical models

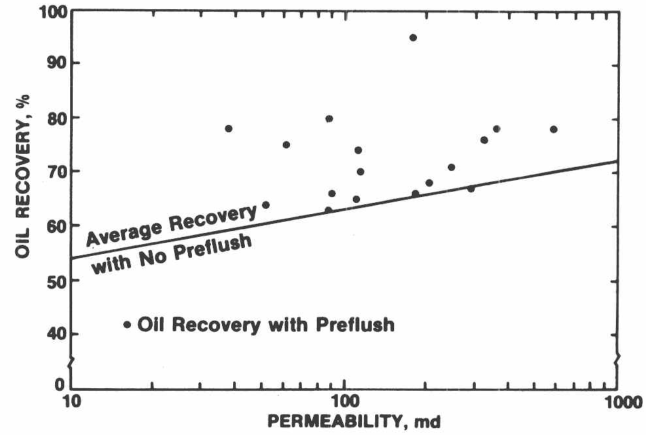


Fig. 1—Micellar/polymer disk flooding results.

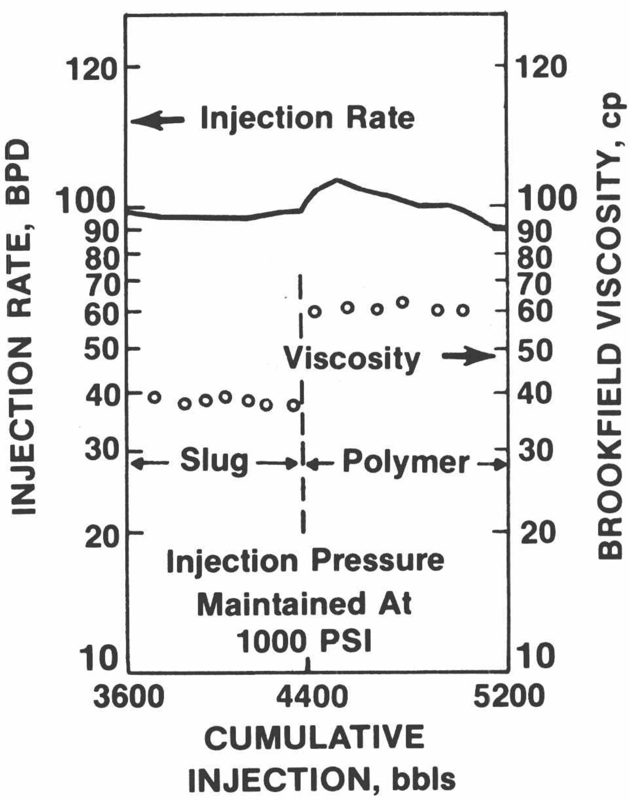


Fig. 2—Micellar/polymer injectivity test (Bradford sand).

TABLE 8—CAUSTIC FIELD TESTS IN PROGRESS

	Caustic Agent			
Field Location (Operator)	Type	Concentration (wt%)	Slug Size (% PV)	Project Size (PV in million bbl)
Wilmington, CA (THUMS)	Na_4SiO_4	0.4	60	100
Huntington Beach, CA (Aminoil)	Na_4SiO_4	1.0	40	32
Bison basin, WY (Gulf)	NaOH	0.5	50	5

TABLE 9—FACTORS INFLUENCING ALKALINE FLOODING

Types of caustic
Fluid/fluid interactions
  Emulsification
  Oil swelling
  Precipitation
  Low IFT
Fluid/rock interaction
  Ion exchange
  Dissolution
  Wettability alteration
Reservoir rock properties
Caustic consumption
Use of polymer

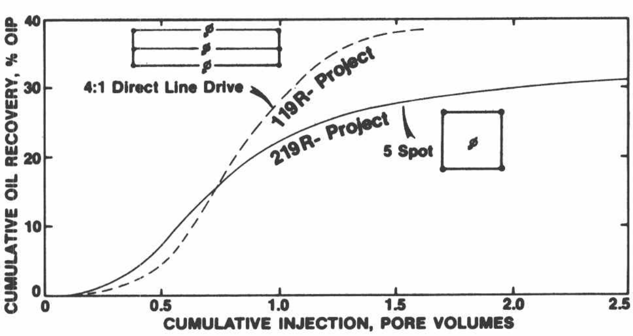


Fig. 3—Effect of pattern type on oil recovery.

Fig. 4—North American alkaline flood field tests.

have been developed that match the laboratory IFT changes with time.[31,32] These changes indicate surfactant migration from oil to the water phase. IFT decreases to a minimum in a very short time as surfactant concentration increases at the interface. As mass transfer takes place from the interface to the water phase, IFT increases.

Wettability alteration is one of the important fluid/rock interaction factors.[33-36] Natural surfactant is attached to the rock and makes the reservoir oil-wet. Caustic removes surfactant from the rock and changes it from oil-wet to water-wet. Oil is moved into the water phase where flow occurs.

Reservoir rock properties have a strong effect on caustic flooding performance.[37] Some properties determine how oil is banked; others relate to oil/water flow in the reservoir. Perhaps the most important aspect of these properties is their contribution to polymer adsorption and caustic consumption. Because of these reservoir rock properties, actual reservoir rock should be used for laboratory designs of any caustic EOR project. Caustic undergoes both physical and chemical reactions with the reservoir rock. Preferably floods should be performed with virgin cores or disks so that rock character is not altered by cleaning.

Caustic consumption measured in small laboratory cores cannot be scaled directly to the field.[38,39] Field projects require much more time and involve much more rock than laboratory floods. Mass transfer between the oil and water phases and chemical reactions must be accounted for in scaling laboratory caustic flooding to field data. Rock and fluid properties from the laboratory flood must be combined to determine the chemical reaction rates. These rates are the best way to extrapolate laboratory floods to the field. Use of reaction rates for scaling represents advanced technology for caustic flooding.

The use of polymer for mobility control appears to improve caustic flooding performance in the field.[40,41] Fig. 6 demonstrates the benefit of polymer use with caustic flooding in the laboratory. The top two illustrations in this figure were run on the same virgin disk. The waterflood alone gave an oil recovery of 34%. After the waterflood, the disk was resaturated and flooded with a 25% PV caustic slug followed by 70% polymer. The recovery was increased to 45%. The two lower illustrations in the figure compare a waterflood and a caustic flood. Polymer was not used

TABLE 10—U.S. DOE COST-SHARING POLYMER FLOODING PROJECTS

Project	Initiation Date	Project Area (acres)	Spacing (acres)	Operator
Coalinga (CA)	1975	147	20	Shell Oil Co.
North Stanley (OK)	1975	1010	random	Gulf Oil Corp.
Storms (IL)	1977	60	20	Energy Resources Co.

for mobility control in the caustic flood. Here the waterflood and caustic flood recovered the same amount of oil. After 2 PV total injection, oil recovery for both was about 55%.

Polymer Flooding

Polymer flooding began in the U.S. during the late 1950's and early 1960's.[42] Work on this process has continued since then, and numerous field projects have been conducted. Polymers are added to the injection water in one application to decrease the mobility contrast between the in-place and injected fluids. Here less water is circulated through the reservoir and both vertical and areal conformances are improved. In another application, polymer is injected and crosslinked to form highly viscous gels in situ, which divert the subsequently injected water into different vertical sections of the reservoir.[43,44] This gel polymer treatment generally affects only the region of the reservoir near the wellbore. Polymer field projects have varied between the near-wellbore and full-field treatments; some have used varying combinations of both techniques.

Polysaccharides and partially hydrolyzed polyacrylamides (PHPA) currently are being studied in the laboratory and are being used extensively in field flooding.[45] Polysaccharides are biologically produced. They have higher temperature stability and are less sensitive to shear and salt. Unfortunately, they cost more and are more susceptible to bacterial degradation. The PHPA polymers are produced chemically starting with propylene. They are less expensive and are easier to manufacture. These synthetic polymers degrade at higher temperatures, are salt sensitive, and degrade by shear quite easily. A wide range of molecular weights is available with the PHPA polymers.

Table 10 shows the DOE cost-sharing polymer flooding projects.[46] Three projects were conducted in three different states. All were in sandstone reservoirs and have either been completed or terminated. These three projects provided polymer state of the art in the middle to late 1970's. The first project has been reported a technical and economic failure.[47] The second project was reported technically successful, but economics were poor.[48] The third project was terminated prematurely because no increased oil recovery was observed.[49] Apparently bacteria destroyed the polymer. The first and third projects used polysaccharides; the other used PHPA. Details of

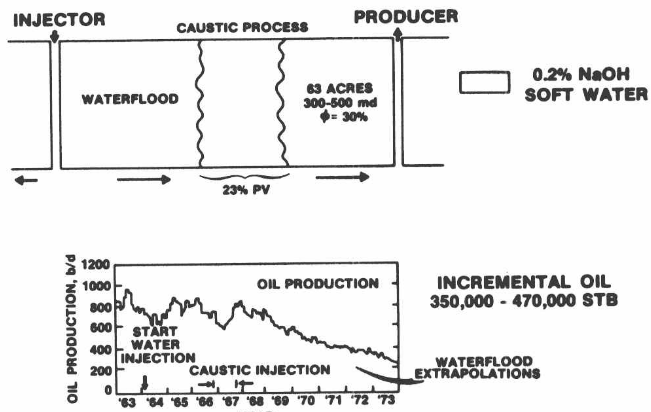


Fig. 5—Whittier field test.

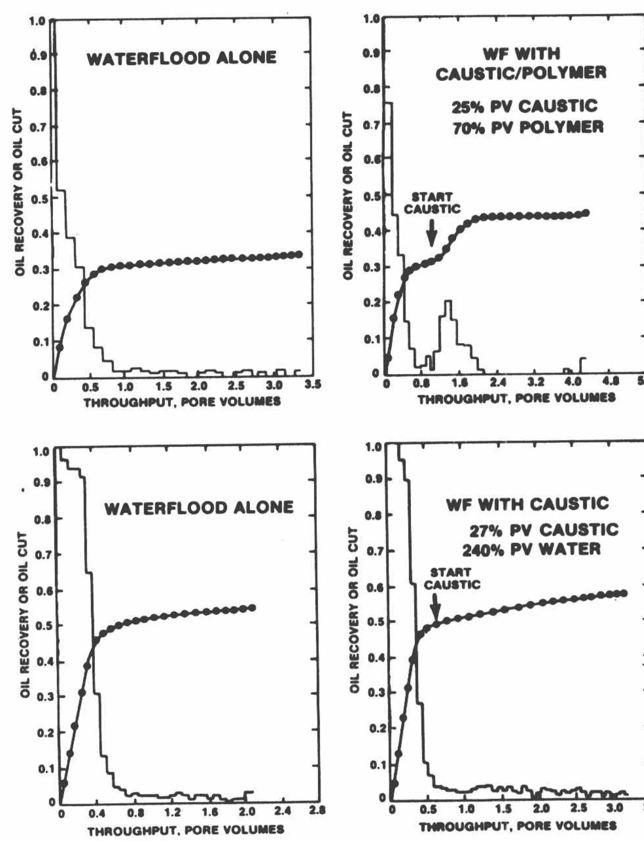


Fig. 6—Benefit of following caustic with polymer.

TABLE 11—SELECTED POLYMER FLOOD PROJECTS

Field	Operator	Initiation Date	Area (acres)	Pay Zone	Remarks
Northeast Hallsville Crane Unit (TX)	Hunt Oil	Nov. 1963	7,000	Pettit	recovery 98 bbl/acre-ft vs. expected 70 for straight waterflood
Old Lisbon (LA)	Tenneco	Jan. 1980	9,680	Pettit	using gel-forming technique to block high-permeability zones
Mabee (TX)	Texaco	Dec. 1981	13,500	San Andres	expected to yield additional 2.9 million bbl (1% of OOIP, or 11.3% OIP after waterflood)
					improve mobility ratio improve vertical conformance
Slaughter (TX)	Texaco	Dec. 1981	7,410	San Andres	expected additional 3.7 million bbl

TABLE 12—POLYMER INJECTIVITY TEST IN WYOMING

Average Rate (B/D)	Average Polymer Concentration (ppm)	Stabilized Wellhead Pressure (psi)	Normalized Injectivity
3,220	0	140	1.00
3,280	250	170	0.98
3,270	520	220	0.93
3,250	1,080	320	0.84
3,030	0	180	0.90

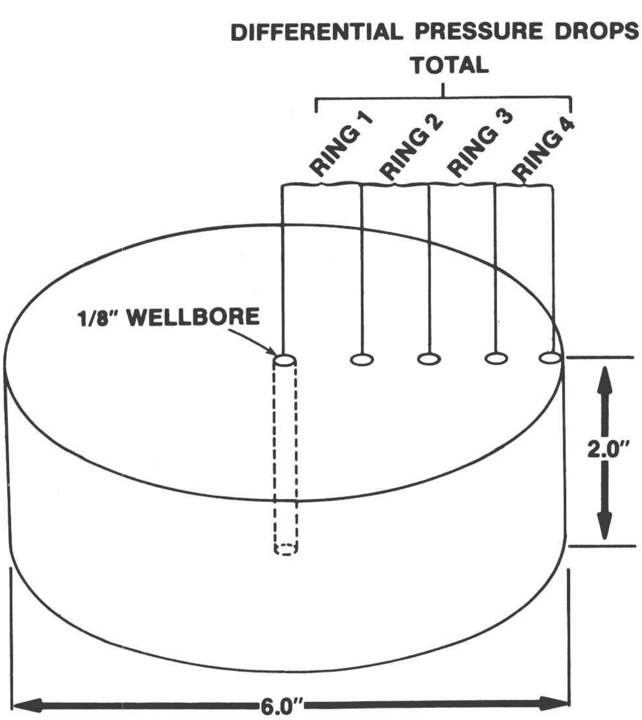


Fig. 7—Disk configuration for polymer evaluation.

these projects are given in DOE quarterly and annual reports.

Table 11 presents information on certain polymer projects selected primarily because of their size. The last three are ongoing projects and are the largest reported in the 1982 *Oil and Gas J.* survey.[5] None of the four projects in Table 11 is in a sandstone reservoir. The completed Northeast Haynesville Crane Unit project was reported to have recovered an additional 40% oil above that expected from waterflooding.[50] The other three projects are in their early stages.[51,52] All four projects use PHPA. In the old Lisbon field, Tenneco is using the near-wellbore gel-forming technique. Texaco in the Mabee field appears to be using both gel treatments and a large-PV polymer flood. The gel technique is used to plug the high-permeability zones, whereas ungelled polymer is used for mobility control.

With all three chemical EOR processes, relatively large PV's of polymer are injected. The life of any flood depends to a large degree on the polymer injection rates. For this reason, field injectivity tests are needed whenever chemical EOR processes are being considered.[53] Laboratory data usually are obtained first to see if a polymer has the potential for plugging the wellbore. Polymer injectivity then is evaluated in the field. As a part of the field injectivity test, polymer manufacturing can take place in the field to obtain appropriate design data for larger scale operations.[54] Field polymer mixing and injection procedures also can be developed as a part of the injectivity tests. Usually polymers of different molecular weights and concentrations are used as a part of the injectivity tests. Wells should be selected from those with a high, medium, and low water-injectivity rate.

Fig. 7 shows the disk configuration for evaluation of polymers prior to field injection.[55] Differential pressures are measured across the different rings of the disk. The pressure drops determined across Ring 1 serve as a measure of wellbore plugging caused by the polymer. Pressure drops across the other rings are a measure of the uniformity of permeability reduction

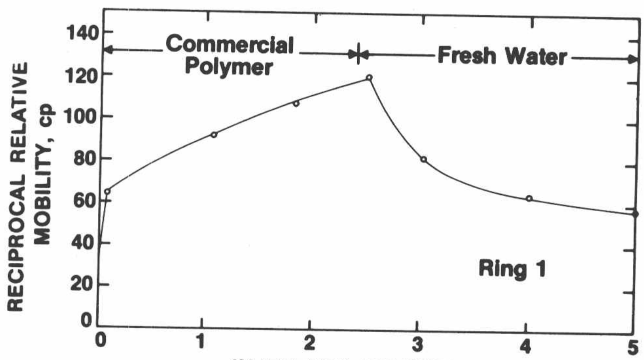


Fig. 8—Commercial polymer performance.

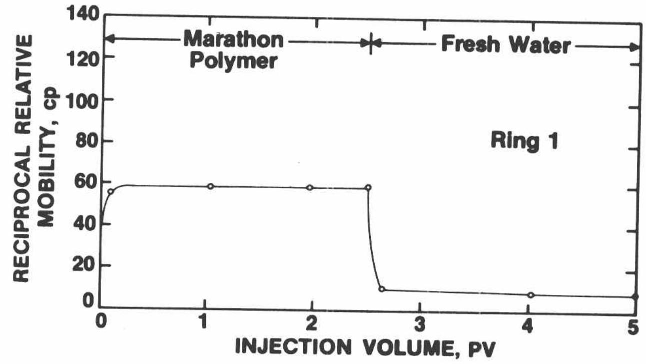


Fig. 9—Marathon polymer performance.

and viscosity within the disk. The measured pressure drops are converted into reciprocal relative mobility by means of the Darcy equation. Berea disks normally are used to determine if wellbore plugging occurs with a given polymer.

Performance of a commercial polymer in a disk is shown in Fig. 8.[54] The reciprocal relative mobilities as determined from pressure drops at Ring 1 are plotted as a function of injection volume. About 2.5 PV of polymer solution were injected first, after which fresh water was injected. With polymer injection, the reciprocal relative mobility increased rapidly to about 60 cp, then continued to increase to more than 120 cp. These results indicate that this polymer is plugging the wellbore continually. With water injection, the reciprocal relative mobility decreased slowly but remained high at about 60 cp. The conditions for water injection show that the wellbore has suffered permanent skin damage.

Fig. 9 shows results from an identical experiment with a Marathon polymer.[54] The constant reciprocal relative mobility during polymer injection indicates the absence of wellbore plugging. The rapid decrease in and low concentration value of reciprocal relative mobility during water injection shows that the wellbore is clean.

Results of an injectivity test in Wyoming with a Marathon polymer are shown in Table 12. This test was conducted in a well completed in the Tensleep formation. The objectives were to determine injection rates in the field at different polymer concentrations and to see if polymer caused any skin damage or plugging of the wellbore. This injectivity test and others in the Tensleep formation were conducted to obtain field data for a fieldwide polymer food.[53,56] The average flow rate and the pressure drop between the sandface and reservoir were used to calculate the injectivities. These injectivities were normalized with the value for water obtained before polymer injection. Normalized injectivities decreased with polymer injection as would be expected when the higher-viscosity polymer solution is injected. If the normalized injectivities had remained at 1 as polymer solution was being injected, the results would have indicated that polymer was being sheared while passing through the perforations into formation. In some cases, increasing the perforation density in the casing will correct this problem. With water injection, the normalized injectivities increased. These results indicate that polymer injection did not plug the wellbore.

Part 2 (to appear next month) deals with reservoir heterogeneities and chemical flooding simulators as related to chemical EOR. Economics also are considered from the standpoint of government incentive programs and risk vs. reward.

References

1. Sullivan, B.R.: "Jurisdictional Agency Certification of Tertiary Oil Recovery Projects Under the Windfall Profit Tax—The Texas Approach," paper SPE 9771 presented at the 1981 SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, April 5-8.
2. Noran, D. and Franco, A.: "Enhanced Recovery Action Is Worldwide," *Oil & Gas J.* (April 5, 1976) 107-38.
3. Noran, D.: "Growth Marks Enhanced Oil Recovery," *Oil & Gas J.* (March 27, 1978) 113-40.
4. Matheny, S.L. Jr.: "EOR Methods Help Ultimate Recovery," *Oil & Gas J.* (March 31, 1980) 79-124.
5. Leonard, J.: "Steam Dominates Enhanced Oil Recovery," *Oil & Gas J.* (April 5, 1982) 139-59.
6. Gogarty, W.B.: "Status of Surfactant or Micellar Methods," *J. Pet. Tech.* (Jan. 1976) 93-102.
7. "Improved Oil Recovery," Exxon Corp., New York City (Dec. 1982).
8. Gogarty, W.B. and Davis, J.A. Jr.: "Field Experience With the Maraflood Process," paper SPE 3806.
9. Gogarty, W.B. and Surkalo, H.: "A Field Test of Micellar Solution Flooding," *J. Pet. Tech.* (Sept. 1972) 1161-69.
10. "Enhanced Oil Recovery and Improved Drilling Technology," DOE/BETC-81/1 Quarterly Report, Dec. 31, 1980.
11. Gogarty, W.B. and Tosch, W.C.: "Miscible Type Waterflooding: Oil Recovery with Micellar Solutions," *J. Pet. Tech.* (Dec. 1968) 1407-14.
12. Healy, R.N. and Reed, R.L.: "Immiscible Microemulsion Flooding," *Soc. Pet. Eng. J.* (April 1977) 129-39.
13. Nelson, R.C. and Pope, G.A.: "Phase Relationships in Chemical Flooding," *Soc. Pet. Eng. J.* (Oct. 1978) 325-38.
14. Nelson, R.C.: "The Salinity Requirement Diagram—A Useful Tool in Chemical Flooding Research and Development," *Soc. Pet. Eng. J.* (April 1982) 259-70.
15. Nelson, R.C.: "Phase Relationships in Chemical Flooding," *Surface Phenomena in Enhanced Oil Recovery,* D.O. Shah (ed.),

Plenum Press, New York City, 1981.
16. Vinatieri, J.E.: "Correlation of Emulsion Stability With Phase Behavior in Surfactant Systems for Tertiary Oil Recovery," *Soc. Pet. Eng. J.* (Oct. 1980) 402-06.
17. Goldburg, A.: "Selection Methodology as Between Competing Micellar/Polymer Designs," paper SPE 6729 presented at the 1977 SPE Annual Technical Conference and Exhibition, Denver, Oct. 9-12.
18. Bragg, J.R. *et al.*: "Loudon Surfactant Flood Pilot Test," paper SPE 10862 presented at the 1982 SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, April 4-7.
19. "Shell to Start Micellar Test in Brunei," *Enhanced Recovery Week* (March 8, 1982).
20. "Three Texaco EOR Projects Seek Improved Recovery," *Pet. Eng. Intl.* (Nov. 1981) 22-50.
21. Gogarty, W.B.: "Micellar/Polymer Flooding—An Overview," *J. Pet. Tech.* (Aug. 1978) 1089-1101.
22. Gilliland, H.E. and Conley, F.R.: "Pilot Flood Mobilizes Residual Oil," *Oil & Gas J.* (Jan. 19, 1976) 43-48.
23. Nutting, P.G.: "Soda Process for Petroleum Recovery," *Oil & Gas J.* (1927) **25**, Nos. 45, 76, and 150.
24. Graue, D.J. and Johnson, C.E. Jr.: "Field Trial of the Caustic Flooding Process," *J. Pet. Tech.* (Dec. 1974) 1353-58.
25. "Chevron Aims Caustics at Two California Fields," *Enhanced Recovery Week* (Jan. 18, 1982).
26. Johnson, C.E. Jr.: "Status of Caustic and Emulsion Methods," *J. Pet. Tech.* (Jan. 1976) 85-92.
27. Mayer, E.H. *et al.*: "Alkaline Injection for Enhanced Oil Recovery—A Status Report," *J. Pet. Tech.* (Jan. 1983) 209-21.
28. Jennings, H.Y. Jr.: "Studies of Caustic Solution/Crude Oil Interfacial Tensions," *Soc. Pet. Eng. J.* (June 1975) 197-202.
29. Jennings, H.Y. Jr., Johnson, C.E. Jr., and McAuliffe, C.D.: "A Caustic Waterflooding Process for Heavy Oils," *J. Pet. Tech.* (Dec. 1974) 1344-52.
30. McCafferty, F.G.: "Interfacial Tensions and Aging Behavior of Some Crude Oils Against Caustic Solutions," Petroleum Recovery Inst. Research Note RN-3, Calgary (Sept. 29, 1975).
31. England, D.C. and Berg, J.C.: "Transfer of Surface-Active Agents Across a Liquid-Liquid Interface," *AIChE J.* (March 1971) 313-22.
32. Radke, C.J. and Somerton, W.H.: "Enhanced Recovery With Mobility and Reactive Tension Agents," *Enhanced Oil and Gas Recovery and Improved Drilling Methods,* Vol. 1A-Oil, Fourth Annual U.S. DOE Symposium (Aug. 29-31, 1978), B-2.
33. Mungan, N.: "Certain Wettability Effects in Laboratory Waterfloods," *J. Pet. Tech.* (Feb. 1966) 247-52.
34. Emery, L.W., Mungan, N., and Nicholson, R.W.: "Caustic Slug Injection in the Singleton Field," *J. Pet. Tech.* (Dec. 1970) 1569-76.
35. Ehrlich, R., Hasiba, H.H., and Raimondi, P.: "Alkaline Waterflooding for Wettability Alteration—Evaluating a Potential Field Application," *J. Pet. Tech.* (Dec. 1974) 1335-43.
36. Ban, A. *et al.*: "The Sorption of an Inorganic Compound Increases Oil Production," *Proc.*, Intl. Hydrocarbon Exploration, Drilling, and Production Technology Symposium (Dec. 10-12, 1975) 55-77 (in French).
37. Katsanis, E.P., Krumrine, P.H., and Falcone, J.S. Jr.: "Chemical Interactions in an Alkaline Flood," paper presented at American Chemical Soc. 184th National Meeting, Kansas City, Sept. 12-17, 1982.
38. Bunge, A.C. and Radke, C.J.: "Migration of Alkaline Pulses in Reservoir Sands," *Soc. Pet. Eng. J.* (Dec. 1982) 998-1012.
39. Somerton, W.H. and Radke, C.J.: "Role of Clays in Enhanced Recovery of Petroleum," paper D-7 presented at the 1979 U.S. DOE Symposium, Tulsa, Aug. 22-24.
40. "Mitchell Plans Polymers for Jacksboro Field," *Enhanced Recovery Week* (March 15, 1982).
41. Sloat, B. and Zlomke, D.: "The Isenhour Unit—A Unique Polymer-Augmented Alkaline Flood," paper SPE 10719 presented at the 1982 SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, April 4-7.
42. Pye, D.J.: "Improved Secondary Recovery by Control of Water Mobility," *J. Pet. Tech.* (Aug. 1964) 911-16.
43. Routson, W.G., Neale, M., and Penton, J.R.: "A New Blocking Agent for Waterflood Channeling," paper SPE 3992 presented at the 1972 SPE Annual Meeting, San Antonio, Oct. 8-11.
44. Needham, R.B., Threlkeld, C.B., and Gall, J.W.: "Control of Water Mobility Using Polymers and Multivalent Cations," paper SPE 4747 presented at the 1974 SPE Improved Oil Recovery Symposium, Tulsa, April 22-24.
45. Chang, H.L.: "Polymer Flooding Technology—Yesterday, Today, and Tomorrow," *J. Pet. Tech.* (Aug. 1978) 1113-28.
46. "Enhanced Oil and Gas Recovery and Improved Drilling Methods," U.S. DOE Quarterly Report (June 30, 1978), No. 15.
47. Peterson, J.E. *et al.*: "Coalinga Polymer Demonstration Project," Final Report, DOE/SAN/1556-5, July 1976-Dec. 1980.
48. DuBois, B.M.: "North Stanley Polymer Demonstration Project," Third Annual and Final Report, DOE BETC/R1-78/19, Nov. 1978.
49. "Storms Pool Effort is Over and Out," *Enhanced Recovery Week* (Feb. 14, 1983).
50. Moore, J.K.: "Reservoir Barrier and Polymer Waterflood: Northeast Hallsville Crane Unit," *J. Pet. Tech.* (Sept. 1969) 1130-36.
51. "Tenneco Sets Louisiana Field for Huge Polymer Project," *Enhanced Recovery Week* (Oct. 13, 1980).
52. "Mabee, Slaughter to Get Polymers From Texaco," *Enhanced Recovery Week* (Nov. 2, 1981).
53. Milton, H.W. Jr., Argabright, P.A., and Gogarty, W.B.: "EOR Prospect Evaluation Using Field Manufactured Polymer," paper SPE 11720 presented at the 1983 California Regional Meeting, Ventura, March 23-25.
54. Argabright, P.A., Rhudy, J.S., and Phillips, B.L.: "Partially Hydrolyzed Polyacrylamides With Superior Flooding and Injection Properties," paper SPE 11208 presented at the 1982 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 26-29.
55. Earlougher, R.C. Jr., O'Neal, J.E., and Surkalo, H.: "Micellar Solution Flooding—Field Test Results and Process Improvements," *J. Cdn. Pet. Tech.* (Jan.-March 1976) 1-8.
56. Gill, D.: "Byron Field Polymer Waterflood Will Achieve Two Important Firsts," *Western Oil Reporter* (Sept. 1982) 131-33.

SI Metric Conversion Factors

acre	× 4.046 873	E+03	=	m^2
B/D	× 1.589 873	E−01	=	m^3/d
cp	× 1.000*	E−03	=	Pa·s
°F	(°F−32)/1.8		=	°C
lbm	× 4.535 924	E−01	=	kg
psi	× 6.894 757	E−03	=	MPa

*Conversion factor is exact.

Distinguished Author Series articles are general, descriptive presentations that summarize the state of the art in an area of technology by describing recent developments for readers who are not specialists in the topics discussed. Written by individuals recognized as experts in the areas, these articles provide key references to more definitive work and present specific details only to illustrate the technology. **Purpose:** To inform the general readership of recent advances in various areas of petroleum engineering. The series is a project of the Technical Coverage Committee.