DOE/BC/14880-5
(DE94000113)

First Annual Technical Progress Report

IMPROVED TECHNIQUES FOR FLUID DIVERSION IN OIL RECOVERY

Contract Number: DE-AC22-92BC14880

New Mexico Petroleum Recovery Research Center
New Mexico Institute of Mining and Technology
Socorro, New Mexico

Principal Investigator: Randall S. Seright

Reporting Period: September 17, 1992 through September 30, 1993

December 1993

ABSTRACT

This report describes work performed during the first year of the project, "Improved Techniques for Fluid Diversion in Oil Recovery." This three-year project has two general objectives. The first objective is to compare the effectiveness of gels in fluid diversion with those of other types of processes. Several different types of fluid-diversion processes are being compared, including those using gels, foams, emulsions, and particulates. The second objective of the project is to identify the mechanisms by which materials (particularly gels) selectively reduce permeability to water more than to oil.

To establish a baseline for the applicability of gel treatments, previously published field results were examined to determine if they reveal usable guidelines for the selection of candidates for gel treatments. Views of seven gel vendors and experts from eight major oil companies were also surveyed concerning the selection and implementation of gel treatments. After analyzing the literature and the survey responses, we proposed criteria for candidate selection, both for injection wells and production wells. These criteria are listed in the Executive Summary.

In our theoretical work, we examined whether gravity and density differences can be exploited to optimize gel placement. During injection of aqueous gelants into fractured wells, viscous forces usually dominate over gravity forces. Thus, the position of the gelant front will not be significantly altered by gravity during gelant injection. When a well is shut in after gelant injection, the rate of equilibration of a gelant-oil interface in a vertical fracture can be very rapid. This situation can be exploited during gel placement in oil wells where water channels (or "cones") through a fracture to the well from an underlying aquifer.

Experimentally, we investigated the importance of gelant viscosity and the presence of partially gelled material on gelant placement in fractures. Flow visualization studies in beadpacks demonstrated that for a given volume of fluid injected, viscous injectants leakoff from a fracture into the matrix to a greater extent than low-viscosity injectants. We also performed corefloods with Cr^{3+}(acetate)-HPAM and resorcinol-formaldehyde gelants and gels, where various delays were used between gelant preparation and gelant injection into fractured and unfractured cores. Tracer studies coupled with permeability reduction measurements were made to assess sweep improvements before and after gelant or gel placement. Injection of pre-formed gels was shown to improve sweep efficiency (in effect, by healing the fractures) much more effectively than injection of gelants that formed gels in situ. Our results suggest two possible methods to minimize gelant leakoff in fractured systems. One method is to design the gel treatment so that before the gelant leaves the wellbore, sufficient gelation occurs so that the gelant will not penetrate into the rock matrix. For this approach to succeed, the gel must remain pumpable for some period after gelation. The second method involves adding gelled material or some other particulate matter to the gelant. Both methods deserve further investigation.

We conducted several corefloods to explore why gels can reduce water permeability more than oil permeability. Many gels have this property, including Cr^{3+}(acetate)-HPAM, Cr^{3+}(acetate)-PAM-AMPS, Cr^{3+}(chloride)-xanthan, glyoxal-CPAM, and resorcinol-formaldehyde. The disproportionate permeability reduction was observed for both "weak" and "strong" gels. In previous work, we showed that the phenomenon was not caused simply by hysteresis of relative permeabilities or by gel breakdown. We also showed that the effect occurs both in cores of intermediate wettability as well as in strongly water-wet cores. In the present work, we demonstrate that the disproportionate permeability reduction is not sensitive to (1) core orientation, (2) oil viscosity (from 1 cp to 31 cp), and (3) system pressure (from 0 to 1,500 psi). Experiments to determine the nature and cause of the phenomenon are continuing.

TABLE OF CONTENTS

ABSTRACT . . . iii

LIST OF FIGURES . . . ix

LIST OF TABLES . . . xiii

ACKNOWLEDGEMENTS . . . xvi

EXECUTIVE SUMMARY . . . xvii

1. INTRODUCTION . . . 1
    Project Objectives . . . 1
    Report Content . . . 1

2. A SURVEY OF FIELD ACTIVITY FOR GEL TREATMENTS IN INJECTION WELLS: 1980-1992 . . . 2
    Cumulative Frequency Plots . . . 3
        Reservoir Permeability and Lithology . . . 3
        Reservoir Temperature . . . 16
        Oil/Water Viscosity Ratio . . . 16
        Oil Present at Project Startup . . . 16
        Producing Water/Oil Ratio at Project Startup . . . 16
        Polymer Concentration . . . 16
        Quantity of Polymer Injected . . . 17
        Projected Incremental Oil Recovery . . . 17
    Correlation of Properties and Predicted Performance . . . 18
        Producing Water/Oil Ratio vs. Oil Produced Before Project Startup . . . 18
        Producing Water/Oil Ratio vs. Oil/Water Viscosity Ratio . . . 18
        Projected Oil Recovery vs. Quantity of Polymer Injected . . . 18
        Projected Oil Recovery vs. Oil Produced Before Project Startup . . . 18
    Discussion . . . 27
    Conclusions . . . 28

3. A SURVEY OF FIELD ACTIVITY FOR POLYMER AND GEL TREATMENTS IN PRODUCTION WELLS: 1970-1991 . . . 30
    Survey of Field Activities . . . 30
        Formation . . . 30
        Lithology . . . 30
        Presence of Fractures . . . 32
        Producing Mechanism . . . 32
        Treatment Type . . . 32
        Zone Isolation . . . 32
    Cumulative Frequency Plots . . . 32
        Producing Water/Oil Ratios . . . 32
        Oil Productivities . . . 35

Discussion 35
Conclusions 38

4. A SURVEY OF VENDORS CONCERNING THE SELECTION OF CANDIDATES FOR GEL TREATMENTS IN INJECTION AND PRODUCTION WELLS 39
Gel Systems Used 39
Breakdown of Applications 39
Criteria for Candidate Selection 44
Injection Wells 44
Production Wells 47
Treatment Procedures 48
Stimulation Before Gelant Injection 49
Gelant Volumes 50
Injectivity Changes and Hall Plots 50
Postflush 51
Conclusions 52

5. A SURVEY OF EIGHT MAJOR OIL COMPANIES CONCERNING THE SELECTION OF CANDIDATES FOR GEL TREATMENTS IN INJECTION AND PRODUCTION WELLS 53
Gelant Systems Used 53
Breakdown of Applications 54
Success Rates 55
Lithology 55
Fractures 58
Flow Behind Pipe 58
Oil Viscosity 58
Candidate Selection 59
Injection Wells 60
Production Wells 63
Treatment Design and Application 64
Volumes of Gelant Injected 64
Stimulation Before Gelant Injection 70
Injectivity Changes and Hall Plots 71
Conclusions 72

6. DO HALL PLOTS INDICATE SELECTIVITY DURING GEL PLACEMENT? 73
What is a Hall Plot? 73
What Does a Hall Plot Reveal? 73
Hall Plots for Analysis of Treatments with Buoyant Ball Sealers 75
Hall Plots for Analysis of Gel Treatments in Unfractured Injection Wells 75
Hall Plots for Analysis of Gel Treatments in Fractured Injection Wells 77
Injectivity Increases During Gelant Injection 79
Conclusions 79

7. GEL TREATMENTS IN PRODUCTION WELLS WITH WATER-CONING PROBLEMS . 81
Gel Placement . . . 81
Effect of Gel on the Critical Rate in Unfractured Wells . . . 85
Muskat Model . . . 85
Schols Model . . . 85
Abass and Bass Model . . . 86
Meyer and Garder Model . . . 86
Chappelear and Hirasaki Model . . . 87
Other Models . . . 87
Comparison of Model Predictions . . . 87
Effect of Gel on the Critical Rate in Fractured Wells . . . 88
Conclusions . . . 91

8. EXPLOITING DENSITY DIFFERENCES DURING GELANT PLACEMENT . . . 95
Gel Placement in Fractured Wells . . . 96
Gel Placement in Unfractured Wells . . . 99
Conclusions . . . 99

9. AN EXPERIMENTAL INVESTIGATION OF GELANT PLACEMENT IN FRACTURED SYSTEMS . . . 101
Effects of Gelant Viscosity . . . 101
Dyed Water Displacing Clear Water . . . 103
Dyed Polymer Solutions Displacing Clear Water . . . 108
Relevance to Fractured Wells . . . 111
Channeling While Injecting a Water Postflush . . . 112
Gelant and Gel Propagation Through Sandstone . . . 112
Gels and Gelants in Fractured Cores . . . 115
Experiments with a Resorcinol-Formaldehyde Gelant . . . 118
Experiments with a Cr^{3+}(acetate)-HPAM Gelant . . . 122
Injection of Cr^{3+}(acetate)-HPAM Gels . . . 125
Injection of a Resorcinol-Formaldehyde Gel . . . 138
Conclusions . . . 140

10. AN INVESTIGATION OF THE MECHANISMS FOR DISPROPORTIONATE PERMEABILITY REDUCTION . . . 141
Experimental Procedures . . . 141
Gelants Studied . . . 141
Rock Used . . . 141
Fluids Used . . . 142
Coreflood Sequence . . . 143
End-Point Permeabilities Before Gel Treatments . . . 145
Gelant Placement in Cores . . . 146
Permeability Reduction Using Gels . . . 149
Cr^{3+}(acetate)-HPAM . . . 149
Resorcinol-Formaldehyde . . . 155
Glyoxal-CPAM . . . 155
Cr^{3+}(acetate)-PAM-AMPS . . . 156
Results From Tracer Studies . . . 156

Cr^{3+}(acetate)-HPAM 156
Resorcinol-Formaldehyde 156
Glyoxal-CPAM 158
Cr^{3+}(acetate)-PAM-AMPS 158
Possible Mechanisms for Disproportionate Permeability Reduction 158
Gravity Effect 158
Lubrication Effect 159
Shrinking and Swelling Effects 161
Dangling-Polymer Effect 162
Conclusions 164

11. A PRELIMINARY INVESTIGATION OF THE USE OF PRECIPITATES AS BLOCKING AGENTS 166
Sequential Injection 166
Sequential Injection with Spacers 167
Use of Stabilizing Agents to Prevent Precipitation in Oil Zones 169
Aqueous Dispersion of Inorganic Compounds in Polymeric Solutions 169
Use of Precipitation Inhibitors for Deep Placement 170
Temperature Triggered Precipitation 170
Use of Surfactant-Alcohol Blends for In-Depth Profile Modification 170
Formation of Plastic-Like Solid by In-Situ Polymerization 171
Conclusions 171

NOMENCLATURE 172

REFERENCES 174

APPENDIXES

A - BIBLIOGRAPHY FOR CHAPTER 2 182

B - BIBLIOGRAPHY FOR CHAPTER 3 212

C - OIL AND WATER COREFLOOD DATA (SUPPLEMENT TO CHAPTER 10) 215

LIST OF FIGURES

Figure 1. Cumulative frequency plot of permeability 6

Figure 2. Cumulative frequency plot of temperature 7

Figure 3. Cumulative frequency plot of oil/water viscosity ratio 8

Figure 4. Cumulative frequency plot of % OOIP present 9

Figure 5. Cumulative frequency plot of WOR values 10

Figure 6. Cumulative frequency plot of polymer concentration 11

Figure 7. Cumulative frequency plot of polymer injected in lbs/ac-ft 12

Figure 8. Cumulative frequency plot of EOR in % OOIP 13

Figure 9. Cumulative frequency plot of projected EOR in bbl oil/ac-ft 14

Figure 10. Cumulative frequency plot of projected EOR in bbl oil/lb of polymer 15

Figure 11. WOR vs. % OOIP produced before startup for gel projects 19

Figure 12. WOR vs. % OOIP produced before startup for polymer floods 20

Figure 13. WOR vs. oil/water viscosity ratio for gel projects 21

Figure 14. WOR vs. oil/water viscosity ratio for polymer floods 22

Figure 15. Projected EOR vs. lbs of polymer for gel projects 23

Figure 16. Projected EOR vs. lbs of polymer for polymer floods 24

Figure 17. Projected EOR vs. % OOIP produced before startup for gel projects 25

Figure 18. Projected EOR vs. % OOIP produced before startup for polymer projects 26

Figure 19. Cumulative frequency plot of producing WOR before and after treatments (polymer and gel cases) 33

Figure 20. Cumulative frequency plot of producing WOR before and after treatments (gel cases) 34

Figure 21. Cumulative frequency plot of oil productivity ratios before and after treatments (polymer and gel cases) 36

Figure 22. Cumulative frequency plot of oil productivity ratios before and after treatments (gel cases) 37

Figure 23. Hall plot illustrating an injectivity decrease after 5,000 bbl cumulative injection 74

Figure 24. Use of buoyant ball sealers for diversion in perforated casing 76

Figure 25. Gelant placement in radial flow 78

Figure 26. Hall plot with both injectivity increases and decreases 80

Figure 27. Reduction of water coning using idea from Karp *et al.* 82

Figure 28. Incorrect view of gel placement. (Gelant only enters zones with high water saturations.) 83

Figure 29. Correct view of gel placement. (Gelant enters all open zones.) 83

Figure 30. Effect of water cone height outside of the gel-treated region 84

Figure 31. Effect of gel treatments on critical rate in unfractured production wells 89

Figure 32. Effect of gel treatments on critical rate (Abass Model) 90

Figure 33. Reduced coning by healing a fracture 92

Figure 34. Gel restricting water entry into a fracture 93

Figure 35. Reduced coning by partly healing a fracture 94

Figure 36. Vertical velocity vs. k/μ and density difference 97

Figure 37. "Fractured" beadpack 102

Figure 38. Dyed water displacing clear water. Pack with 2-layer-mesh fracture 104

Figure 39. Dyed water displacing clear water. Pack with 8-layer-mesh fracture 105

Figure 40. Characterization of beadpacks by displacing clear water with dyed water 106

Figure 41. Injection of dyed polymer into beadpack with the 2-layer fracture 109

Figure 42. Injection of dyed polymer into beadpack with the 8-layer fracture 110

Figure 43. Viscosity vs. time during gelation 113

Figure 44. Plugging in the first core segment for different delay times between gelant mixing and gelant injection (41°C) 114

Figure 45. Schematic of a fractured core 117

Figure 46. Tracer results in fractured vs. unfractured Berea sandstone cores. Cores are saturated with water only 119

Figure 47. Tracer results before and after placement of a resorcinol-formaldehyde gel in fractured Core 1 (fracture outlet open) 120

Figure 48. Permeability reduction in fractured Core 1 after placement of a resorcinol-formaldehyde gel (fracture outlet open) 121

Figure 49. Permeability reduction in fractured Core 2 after placement of a resorcinol-formaldehyde gel (fracture outlet sealed) 123

Figure 50. Tracer results before and after placement of a resorcinol-formaldehyde gel in fractured Core 2 (fracture outlet sealed) 124

Figure 51. Permeability reduction in fractured Cores 3 and 4 after placement of 0.3 PV of a Cr(III)-acetate-HPAM gel 126

Figure 52. Tracer results before and after placement of a Cr(III)-acetate-HPAM gel in fractured Core 3 (fracture outlet open) 127

Figure 53. Tracer results before and after placement of a Cr(III)-acetate-HPAM gel in fractured Core 4 (fracture outlet sealed) 128

Figure 54. Tracer results before and after placement of a Cr(III)-acetate-HPAM gel (24-hr delay before gel injection) in fractured Core 5 129

Figure 55. Tracer results before and after placement of a Cr(III)-acetate-HPAM gel (24-hr delay before gel injection) in fractured Core 6 130

Figure 56. Permeability reduction in the fracture vs. brine throughput after placement of a Cr(III)-acetate-HPAM gel (24-hr delay before gel injection) 131

Figure 57. Permeability reduction in the fracture vs. pressure gradient after placement of a Cr(III)-acetate-HPAM gel (24-hr delay before gel injection) 133

Figure 58. Effect of brine and gel throughput on apparent mobility in fractured Core 7 134

Figure 59. Tracer results before and after placement of a Cr(III)-acetate-HPAM gel (24-hr delay before gel injection) in fractured Core 7 135

Figure 60. Resistance factor in the fracture vs. injection rate during placement of a Cr(III)-acetate-HPAM gel in fractured Core 8 136

Figure 61. Pressure gradient vs. gel injection rate during placement of a Cr(III)-acetate-HPAM gel in fractured Core 8 137

Figure 62. Effect of brine and gel throughput on apparent mobility in fractured Core 9 139

Figure 63. Effluent pH during gelant injection 147

Figure 64. Effluent chromium concentration during gelant injection 148

Figure 65. Resistance factors in the short core segment during gelant injection 151

Figure 66. Resistance factors in the long core segment during gelant injection 152

Figure 67. Effect of injection order and multiple water-oil injection cycles 154

Figure 68. The dangling-polymer model 163

Figure 69. Change of residual resistance factors for water caused by core shut-in and injection of brine containing Cr^{3+} 165

LIST OF TABLES

Table 1. Summary of Gel Projects: 1980-1992 4

Table 2. Summary of Polymer Floods: 1980-1992 5

Table 3. Summary of Field Activity for Polymer and Gel Treatments in Production Wells: 1970-1991 31

Table 4. Most Frequent Operating Locations 39

Table 5. Gelant Systems Used Most Often 40

Table 6. Percentages of Producer/Injector Applications: 1990-1992 40

Table 7. Distribution of Producing-Well Applications 41

Table 8. Claimed Success Rates of Producing-Well Applications 42

Table 9. Lithology of Applications 42

Table 10. Does Lithology Have an Important Impact on Treatment Performance? 43

Table 11. Percentage of Wells Thought to be Fractured 43

Table 12. Does Oil Viscosity Have an Important Impact on Treatment Performance? 44

Table 13. Selection of Injector Candidates 45

Table 14. How Often are Tracer Studies Performed to Diagnose Channeling Before Injector Treatments? 45

Table 15. Selection of Producer Candidates 48

Table 16. How Long are You Usually on a Well During a Treatment (Days)? 49

Table 17. Do You Normally Acidize Your Wells Before Gelant Injection? 49

Table 18. Injected Gelant Volumes 50

Table 19. Do Hall Plots Indicate Selectivity During Gel Placement? 51

Table 20. How Much Postflush is Injected After the Gelant? 51

Table 21. Locations Where Operators Applied Gel Treatments 53

Table 22. Gelant Systems Used 54

Table 23. Percentages of Producer/Injector Applications: 1990-1992 55

Table 24. Distribution of Producing-Well Applications 56

Table 25. Technical Success Rates of Producing-Well Applications 56

Table 26. Economic Success Rates of Producing-Well Applications 56

Table 27. Success Rates of Injection-Well Applications 57

Table 28. Lithology of Applications 57

Table 29. Does Lithology Have an Important Impact on Treatment Performance? 57

Table 30. Treated Wells Thought to be Fractured 58

Table 31. Treated Production Wells Thought to Have Casing Leaks or Flow Behind Pipe 58

Table 32. Does Oil Viscosity Have an Important Impact on Treatment Performance? 59

Table 33. Who Participates in the Selection of Candidate Wells? 59

Table 34. Selection Criteria for Injection Wells 60

Table 35. Consolidated Selection Criteria for Injection Wells 61

Table 36. Use of Interwell Tracers to Diagnose Channeling in Injectors 62

Table 37. Selection Criteria for Production Wells 63

Table 38. Consolidated Selection Criteria for Production Wells 64

Table 39. Who Designs Your Gel Treatments? 65

Table 40. Gelant Volumes Injected (Barrels) 65

Table 41. How Much Gelant Should Be Injected into Injection Wells 66

Table 42. How Much Gelant Should Be Injected into Production Wells? 67

Table 43. Are Your Wells Normally Acidized Before Gelant Injection? 70

Table 44. For Treatments in Unfractured Wells, How Often Are Zones Isolated During Injection? 71

Table 45. Do Hall Plots Indicate Selectivity During Gel Placement? 72

Table 46. Properties of "Fractures" Made from 1,000-μm Mesh 103

Table 47. Predicted vs. Experimental Effluent Dye Concentrations (Plateau Region) for the Beadpack with the 2-Layer-Mesh Fracture 111

Table 48. Predicted vs. Experimental Effluent Dye Concentrations (Plateau Region) for the Beadpack with the 8-Layer-Mesh Fracture 111

Table 49. Core and Fracture Permeabilities 116

Table 50. Gelant Compositions and Properties (at 41°C) 142

Table 51. Rock and Fluid Properties 142

Table 52. Sequence Followed During Oil/Water Core Experiments 144

Table 53. Summary of Residual Saturations and End-Point Permeabilities Obtained before Gel Treatment (Cores SSH36, 38, 43 and 44) 145

Table 54. Residual Saturations and End-Point Permeabilities Obtained before Gel Treatment (Core SSHM1) 145

Table 55. Effect of System Pressure on End-Point Mobilities before Gel Treatment 146

Table 56. Gelant Placement Data (41°C) 150

Table 57. Summary of Residual Resistance Factors for Water (F_{rrw}) and for Oil (F_{rro}) 153

Table 58. Summary of Gel Saturations (S_{gel}) and Residual Oil Saturations Trapped by Gel ($S_{o(trap)}$) 157

Table 59. Effect of Core Orientation and Flow Direction on Residual Resistance Factors (Core SSH-43) 159

Table 60. Effect of Core Orientation and Flow Direction on Residual Resistance Factors (Core SSH-44) 159

Table 61. Effect of Oil Viscosity (μ_o) on End-Point Oil Permeabilities Before Gel Treatment . . 160

Table 62. Effect of Oil Viscosity (μ_o) on Oil Residual Resistance Factors (F_{rro}) 161

Table 63. Effect of System Pressure on Residual Resistance Factors 162

Table 64. Effect of System Pressure on Residual Resistance Factors at Constant Flow Rate . . . 162

ACKNOWLEDGEMENTS

This work was financially supported by the United States Department of Energy, the State of New Mexico, Arco Exploration and Production Technology Co., Chevron Petroleum Technology Co., Conoco Inc., Exxon Production Research Company, Marathon Oil Co., Mobil Research and Development Corp., Phillips Petroleum Co., and Unocal. This support is gratefully acknowledged. I greatly appreciate the efforts of those individuals who contributed to this project. For the experimental work described in Chapter 9, Richard Schrader performed the corefloods, and John Hagstrom performed the flow visualization experiments. Dr. Jenn-Tai Liang played the major role in the work described in Chapters 3, 7 and 11. Haiwang Sun was principally responsible for performing and reporting the experimental work in Chapter 10, with help from Dr. Jenn-Tai Liang. I also thank Yingli He and Martin Bartosek for their help during the experiments described in Chapter 10; Cathy Lambert for her help in preparing many of the figures and for copying and binding the report; and K. Stanley and her staff for reviewing the report. I especially appreciate the thorough review of the manuscript by Julie Ruff.

EXECUTIVE SUMMARY

This report describes work performed during the first year of the project, "Improved Techniques for Fluid Diversion in Oil Recovery." This three-year project has two general objectives. The first objective is to compare the effectiveness of gels in fluid diversion with those of other types of processes. Several different types of fluid-diversion processes are being compared, including those using gels, foams, emulsions, and particulates. The second objective of the project is to identify the mechanisms by which materials (particularly gels) selectively reduce permeability to water more than to oil.

Survey of Field Activity for Gel Treatments in Injection Wells: 1980-1992. Previously published field results were examined to determine if they reveal usable guidelines for the selection of injection wells as candidates for gel treatments. This study demonstrated that gel treatments and polymer floods have been applied over a remarkably wide range of conditions. Our analysis indicated that the producing water/oil ratio was the primary technical criterion that was used to select candidates for gel treatments. Some factors that did not play a major role in candidate selection included the percent original oil in place (%OOIP) produced before project startup, the oil/water viscosity ratio (i.e., the mobility ratio), and lithology. Surprisingly, no correlation exists between the %OOIP produced before project startup and the incremental oil projected by the operator. The projected volume of enhanced oil recovery (EOR) correlates only with the number of lbs of polymer (or gel) injected. The validity of many of the EOR projections is questionable. To improve the success rate for future gel applications, several factors are suggested that should be considered during candidate selection. In addition to the producing water/oil ratio, these factors include (1) the %OOIP produced before the project, (2) comparison with the performance of other patterns and wells in the field, (3) results from tracer studies, and (4) injectivity and productivity calculations.

Survey of Field Activity for Gel Treatments in Production Wells: 1970-1991. We conducted a literature survey of 274 field applications of polymer and gel treatments in production wells. Most of the treatments were applied in fractured carbonate reservoirs that were produced by bottom-water-drive. Fifty percent of the projects were applied in either the Arbuckle or the Ellenberger formations. For the gel projects, the median producing water/oil ratio was 101 before the treatment, 5 immediately after the treatment, and 14 one year after the treatment.

Surveys of Vendors and Operators Concerning the Selection of Candidates for Gel Treatments. Views of seven gel vendors and experts from eight major oil companies were examined concerning the selection and implementation of gel treatments in injection and production wells. These surveys focused on activity from 1990 through 1992. In most cases, vendors will treat virtually any well that the operator chooses, so <u>the operator has responsibility for the proper selection of candidates</u>.

After analyzing the survey responses, we proposed the following as criteria for selection of injection-well candidates:

1. Reservoir and production data indicates low sweep efficiency during waterflooding.
    a. Water breakthrough occurs much earlier than expected (i.e., from standard calculations or simulations or from comparison with the performance of other patterns in the field).
    b. Water/oil ratios (WOR) at offset producers are much higher than expected.
    c. Recovery calculations indicate that considerable mobile oil remains that could be recovered more cost-effectively if a blocking agent could be realistically placed in the proper location.

2. In unfractured wells,
   a. Poor injection profiles are correlatable from well to well.
   b. Effective barriers to crossflow exist (very low k_v/k_h, no flow behind pipe, no vertical fractures).
   c. Gel can be placed in the offending channel without damaging oil zones (e.g., using zone isolation).

3. If barriers to crossflow do not exist, then interwell tracers must show very rapid transit times (probably indicating that fractures or formation parting cause the channeling problem).

4. Reduced injectivity (caused by the gel) can be tolerated.

5. The well to be treated is in good mechanical condition.

We also propose the following as criteria for selection of production-well candidates:

1. Recovery calculations indicate that considerable mobile oil remains that could be recovered more cost-effectively if a blocking agent could be realistically placed in the proper location.

2. High WOR values are observed.

3. The source of the excess water production is identified (e.g., using profiles, logs, or tracers).

4. The candidate well exhibits high productivity.

5. The gelant can be placed without damaging oil zones (e.g., using zone isolation).

Chapters 4 and 5 of this report summarize and compare (1) the distribution of recent applications in producers and injectors, (2) technical and economic success rates, and (3) views on the importance of lithology, oil viscosity and fracturing. We also compare views and practices concerning treatment design and application, including (1) well stimulation before gelant injection, (2) types of gelants employed, (3) volumes of gelant injected, (4) zone isolation during gelant placement, and (5) the use of Hall plots.

Use of Hall Plots to Indicate Selectivity During Gel Placement. Chapter 6 demonstrates that by themselves, Hall plots do not indicate selectivity during gel placement. Hall plots may be a useful indicator that the injected gel is doing something, but it does not indicate whether the gel is being placed in a beneficial or harmful manner.

Gel Treatments in Production Wells with Water-Coning Problems. In Chapter 7, we discuss some of the reservoir conditions, gel properties, and placement problems that influence how effectively gel treatments reduce water coning. For gel treatments in unfractured production wells, analysis using different theoretical coning models suggests that the desired production rate should be less than 1.5 to 5 times the pretreatment critical rate. Calculations also suggest that under ideal conditions, gel treatments in fractured wells could increase the critical rate by two orders of magnitude. For gels applied to reduce water coning, an essential property is an ability to reduce water permeability much more than oil permeability.

Exploiting Density Differences during Gelant Placement. In Chapter 8, we examine whether gravity and density differences can be exploited to optimize gel placement. Several conclusions are reached concerning gel treatments in wells where oil and water are the primary reservoir fluids of interest. During injection of aqueous gelants into fractured wells, viscous forces usually dominate over gravity forces. Thus, the position of the gelant front will not be significantly altered by gravity during gelant injection. When a well is shut in after gelant injection, the rate of equilibration of a gelant-oil interface in a vertical fracture can be very rapid. This situation can be exploited during gel placement in oil wells where water channels (or "cones") through a fracture to the well from an underlying aquifer.

During injection of aqueous gelants into unfractured wells, viscous forces usually dominate over gravity forces near the wellbore, but gravity becomes more important deeper in the formation. In concept, gravity could be exploited during gelant placement if the offending channel or aquifer is located below oil-productive zones. However, in view of the low settling rate in unfractured porous rock, relatively long gelation times will be needed.

Experimental Investigation of Gelant Placement in Fractured Systems. Chapter 9 discusses two factors that can have an important effect on gelant placement in fractures. These factors are gelant viscosity and the presence of partially gelled material in the gelant. Flow visualization studies in beadpacks demonstrate that for a given volume of fluid injected, viscous injectants leakoff from a fracture into the matrix to a greater extent than low-viscosity injectants. This observation may explain field results where the interwell transit times for viscous gelants are much greater than that for a low-viscosity water tracer.

We performed corefloods with a Cr^{3+}(acetate)-HPAM gelant, where various delays were used between gelant preparation and gelant injection into the core. Our experiments confirmed that the Cr^{3+}(acetate)-HPAM gelant and gel performed in a similar manner to that for other gelants and gels that were described in the literature. Specifically, before gelation, gelants can penetrate readily into the rock matrix, but after gelation, gel propagation is extremely slow or negligible. These observations suggest two possible methods to minimize gelant leakoff in fractured systems. One method is to design the gel treatment so that before the gelant leaves the wellbore, sufficient gelation occurs so that the gelant will not penetrate into the rock matrix. For this approach to succeed, the gel must remain pumpable for some period after gelation. The second method involves adding gelled material or some other particulate matter to the gelant. Both methods deserve further investigation.

Finally, several experiments were conducted using fractured cores. Tracer studies coupled with permeability reduction measurements were made to assess sweep improvements before and after gel placement. Injection of pre-formed gels was shown to improve sweep efficiency (in effect, by healing the fractures) much more effectively than injection of gelants that formed gels in situ. Several experiments were performed to assess whether pre-formed gels can propagate effectively through fractures. Twenty-four hours after gelant preparation, a Cr^{3+}(acetate)-HPAM gel was found to propagate through fractured cores without "screening out" or plugging. The experimental results suggested that some minimum pressure gradient was needed to keep the gel mobilized in a fracture. Twenty-four hours after gelant preparation, this pressure gradient was between 60 and 75 psi/ft. At later times, a higher pressure gradient was needed. During brine injection after a shut-in period, washout of gels from fractured cores was much less for gels that were formed before injection than for gels that were formed in situ from gelants. For a Cr^{3+}(acetate)-HPAM gel in fractured cores, Newtonian behavior was observed during brine injection after gelation. More work will be needed to establish the best circumstances for propagation of the various gels in fractures.

Investigation of the Mechanisms for Disproportionate Permeability Reduction. We conducted several corefloods to explore why gels can reduce water permeability more than oil permeability. Many gels have this property, including Cr^{3+}(acetate)-HPAM, Cr^{3+}(acetate)-PAM-AMPS, Cr^{3+}(chloride)-xanthan, glyoxal-CPAM, and resorcinol-formaldehyde. The disproportionate permeability reduction was observed for both "weak" and "strong" gels. In previous work, we showed that the phenomenon was not caused simply by hysteresis of relative permeabilities or by gel breakdown. We also showed that the effect occurs both in cores of intermediate wettability as well as in strongly water-wet cores. In the present work, we demonstrate that the disproportionate permeability reduction is not sensitive to (1) core orientation, (2) oil viscosity (from 1 cp to 31 cp), and (3) system pressure (from 0 to 1,500 psi). Experiments to determine the nature and cause of the phenomenon are continuing.

A Preliminary Investigation of the Use of Precipitates as Blocking Agents. The petroleum and patent literatures were surveyed to investigate whether precipitates formed in situ in a reservoir have potential advantages over gels for use as blocking agents. Most of this literature makes unsubstantiated claims that the blocking materials will selectively enter and block high-permeability watered-out zones in preference to less-permeable oil-productive zones. Critical analyses of these claims reveals that most (if not all) of the proposed schemes suffer from the same placement limitations that gels experience.

Additional work will be required to determine whether in situ precipitates can be superior blocking agents compared with gels or other materials. One possible area of study, in this regard, is whether precipitates can reduce water permeability more than oil permeability. In the future, we will examine whether precipitates can show a disproportionate permeability reduction, and we will compare this ability with that for gels.

1. INTRODUCTION

In any oil recovery process, fractures and high-permeability streaks can cause early breakthrough of injected fluid and reduce oil recovery efficiency. They can also aggravate production of excess water or gas in reservoirs with water-drive or gas-drive recovery mechanisms. Several different types of processes have been proposed to reduce channeling of fluids through fractures and streaks of very high permeability. Processes that use crosslinked polymers or other types of gels have been most common. However, processes using emulsions, foams, suspended solids, precipitates, and microorganisms have also been proposed or tested. Although many of these fluid-diversion (or water or gas shutoff) projects have been very successful, many other projects have been technical failures. At present, there is no consensus on where or how the various treatments should be applied.

Project Objectives

This three-year project has two general objectives. The first objective is to compare the effectiveness of gels in fluid diversion with those of other types of processes. Several different types of fluid-diversion processes are being compared, including those using gels, foams, emulsions, and particulates. The ultimate goals of these comparisons are to (1) establish which of these processes are most effective in a given application, and (2) determine whether aspects of one process can be combined with those of other processes to improve performance. Analyses and experiments are being performed to verify which materials are the most effective in entering and blocking high-permeability zones. Another objective of the project is to identify the mechanisms by which materials (particularly gels) selectively reduce permeability to water more than to oil.

Report Content

This report describes work performed during the first year of the project. The next four chapters present several surveys concerning field applications of gel treatments. Chapter 2 surveys the literature involving field applications of gel treatments in injection wells for the period from 1980 through 1992. Chapter 3 provides a similar survey of field applications of gel treatments in production wells for the period from 1970 through 1991. Chapter 4 is a survey of the beliefs of seven gel vendors concerning candidate selection and field application of gel treatments. Chapter 5 describes a similar survey of experts from eight major oil companies. Based on the results of the surveys, guidelines are proposed in Chapter 5 for the selection of candidates for gel treatments (both injection wells and production wells).

Chapters 6, 7, 8, and 11 discuss theoretical work that was performed during the project. Chapter 6 examines whether Hall plots indicated selectivity during gelant placement. Chapter 7 discusses several important theoretical aspects of gel treatments in production wells with water-coning problems. Chapter 8 considers exploitation of density differences during gelant placement. Chapter 11 presents a preliminary consideration of the use of precipitates as blocking agents. We are also actively investigating the use of foams and emulsions as blocking agents.

Chapters 9 and 10 detail the experimental work for the project. Chapter 9 describes an experimental investigation of gelant placement in fractured systems. Chapter 10 describes experiments that probe the mechanisms for disproportionate permeability reduction by gels.

2. A SURVEY OF FIELD ACTIVITY FOR GEL TREATMENTS IN INJECTION WELLS: 1980-1992

A large number of polymer floods and gel treatments have been applied with the objective of improving reservoir sweep efficiency.[1,2] With this extensive field experience, one might expect conditions where these technologies do and do not work to be fairly well defined. Earlier studies,[1,2] revealed that agreement is not unanimous about where polymer floods work best. However, the success of several well-planned and well-documented field projects[3-7] creates optimism that the best reservoirs for polymer flooding can be identified.

At present, there is considerable uncertainty concerning how and where gel treatments are best applied. While many projects have been very successful,[8-11] many other projects have been technical failures. One study revealed that less than 45% of near-wellbore gel treatments were successful.[12]

The objective of this study is to determine if previously published field results reveal usable guidelines for the selection of injection wells as candidates for gel treatments. In pursuit of this objective, we performed a literature survey of field applications of gel treatments in injection wells. During the course of conducting this survey, we performed a parallel survey of traditional polymer floods. To explain why this was done, we first point out that a gel treatment should have a very different objective from that for a traditional polymer flood. Certainly, both processes are ultimately intended to improve reservoir sweep efficiency; however, in a traditional polymer flood, we want the injected polymer solution to penetrate as far as possible into the zones that were swept poorly before the polymer flood (e.g., the less-permeable zones). In contrast, in a gel treatment, we want gelant penetration to be maximized in the high-permeability channels and minimized in the less-permeable, oil-productive zones. Gel that forms in the oil-productive zones acts to reduce sweep efficiency.[13-18]

Some organizations have not made a distinction between gel treatments and traditional polymer floods. For example, in their biennial reports,[19-23] the *Oil & Gas Journal* has not distinguished between the two technologies. For political and taxation purposes, both technologies were often lumped under the term, "polymer-augmented waterflood." Thus, when sorting through the literature, it was necessary to decide in which category a given project belonged. Usually, this distinction was easily made because most gel treatments involved the use of a crosslinker and small gelant volumes. In contrast, most polymer floods involved injection of relatively large (on a pore-volume basis) banks of uncrosslinked polymer solutions. However, in some cases, the distinction was less obvious. In particular, several projects involved injection of (1) a relatively small volume of a cationic polyacrylamide solution, (2) small volumes of an aluminum citrate solution, and (3) relatively large volumes of an anionic polyacrylamide solution.[24,25] In an earlier survey,[2] these projects were classified as gel projects because a crosslinker was used. However, in the present survey, we classified them as polymer floods because of (1) the large size of the anionic polymer banks compared with the other chemical banks, and (2) the approach taken during the design and reporting of these projects.[24,25]

This review included 114 gel projects and 171 polymer floods that were planned and/or implemented from 1980 until 1992. The literature that provided the information for this survey is listed in the bibliography in Appendix A. The information was obtained from over 600 articles and reports from *Enhanced Recovery Week, Oil & Gas Journal, Texas State House Reporter, Western Oil Reporter, Petroleum Engineer International, Journal of Petroleum Technology, Well Servicing, Drill Bit, Journal of Canadian Petroleum Technology, American Oil & Gas Reporter, Southwest Oil World, Western Oil World, North Eastern Oil Reporter, Ocean Industry, Petroleum Engineer,* DOE reports, vendor literature, and proceedings from various conferences of the Society of Petroleum Engineers, the Petroleum Society of CIM, AIChE, the American Chemical Society, and others. Parameters that were correlated included %OOIP present at project startup, producing water/oil ratio at project startup, oil/water viscosity ratio at reservoir temperature, reservoir permeability, reservoir temperature, lithology, gel used, injected polymer concentration, pounds of polymer injected per acre-ft, and three values for projected enhanced oil recovery (EOR) or incremental oil recovery (%OOIP, bbl oil/ac-ft, and bbl oil/lb polymer).

Tables 1 and 2 summarize the results of the surveys of gel projects and polymer floods, respectively. The tables list median, minimum and maximum values for many of the properties of interest. For each property, Tables 1 and 2 also list the number of data points that were available for analysis. Some of the desired information was not available for many of the projects. However, at least 40 data points were available for each property in the survey of gel projects, and at least 92 data points were available for each property in the survey of polymer floods.

Cumulative Frequency Plots

The distribution of data points for the different properties are shown in Figs. 1 through 10. In each figure, the distribution of data points from the survey of gel projects is compared with that from the survey of polymer floods. The y-axis in each figure is labeled "cumulative frequency," which is the percentage of the data points associated with a property value less than or equal to that indicated on the x-axis. For example, in Fig. 1, 40% of the gel projects were associated with reservoirs that had an average permeability that was less than or equal to 100 md. By subtraction, 60% of the gel projects were applied in reservoirs that had an average permeability that was greater than 100 md. In another example, 90% of the gel projects were performed in reservoirs with an average permeability that was less than or equal to 1,000 md.

Reservoir Permeability and Lithology. Fig. 1 compares the distributions of average reservoir permeabilities for the gel projects and polymer floods. The median permeability was 100 md for the gel projects and 75 md for the polymer floods. For both types of projects, the distribution of values was very wide, ranging from 4.1 md to 5,000 md for the gel projects and from 0.6 md to 15,000 md for the polymer floods. It is interesting that 18% of the polymer floods were applied in reservoirs with permeabilities that averaged less than 10 md. Laboratory data indicates that high-molecular-weight polymers do not propagate very readily through low-permeability rock.[26-28]

Table 1 indicates that gel treatments were applied in sandstone reservoirs 2.6 times more frequently than in carbonate reservoirs. For comparison, Table 2 reveals that polymer floods were applied in sandstone reservoirs 3.8 times more frequently than in carbonate reservoirs.

Table 1. Summary of Gel Projects: 1980-1992 (114 Projects in Database)

Property	Median value	Minimum value	Maximum value	Number of data points
Permeability, md	100	4.1	5,000	111
Temperature, °F	110	64	240	95
Oil/water relative viscosity at reservoir temperature	6.6	0.65	280	91
%OOIP present at project startup	75.0	27.4	98.9	60
Water/oil ratio at project startup	11.5	0.1	160	40
Polymer concentration, ppm	2,500	300	70,000	50
Polymer injected, lbs/ac-ft	1.6	0.006	35	50
Projected EOR, %OOIP	1.3	0	18	62
Projected EOR, bbl/lb polymer	2.4	0	560	57
Projected EOR, bbl/ac-ft	5.9	0	169	66
Lithology, sandstone/carbonate	81/31 = 2.6			112
Polymer type, HPAM/xanthan	48/29 = 1.7			87*

* Ten gel projects used materials other than HPAM or xanthan.

Table 2. Summary of Polymer Floods: 1980-1992 (171 Projects in Database)

Property	Median value	Minimum value	Maximum value	Number of data points
Permeability, md	75	0.6	15,000	153
Temperature, °F	120	60	230	155
Oil/water relative viscosity at reservoir temperature	9.4	0.96	187	149
%OOIP present at project startup	76.2	36	97.1	125
Water/oil ratio at project startup	3.0	0	99	92
Polymer concentration, ppm	460	35	2,000	122
Polymer injected, lbs/ac-ft	25	0.77	535	101
Projected EOR, %OOIP	4.9	0.78	25	128
Projected EOR, bbl/lb polymer	1.1	0.04	28.6	107
Projected EOR, bbl/ac-ft	27.1	0.84	493	117
Lithology, sandstone/carbonate	132/35 = 3.8			167
Polymer type, HPAM/xanthan	149/7 = 21			156

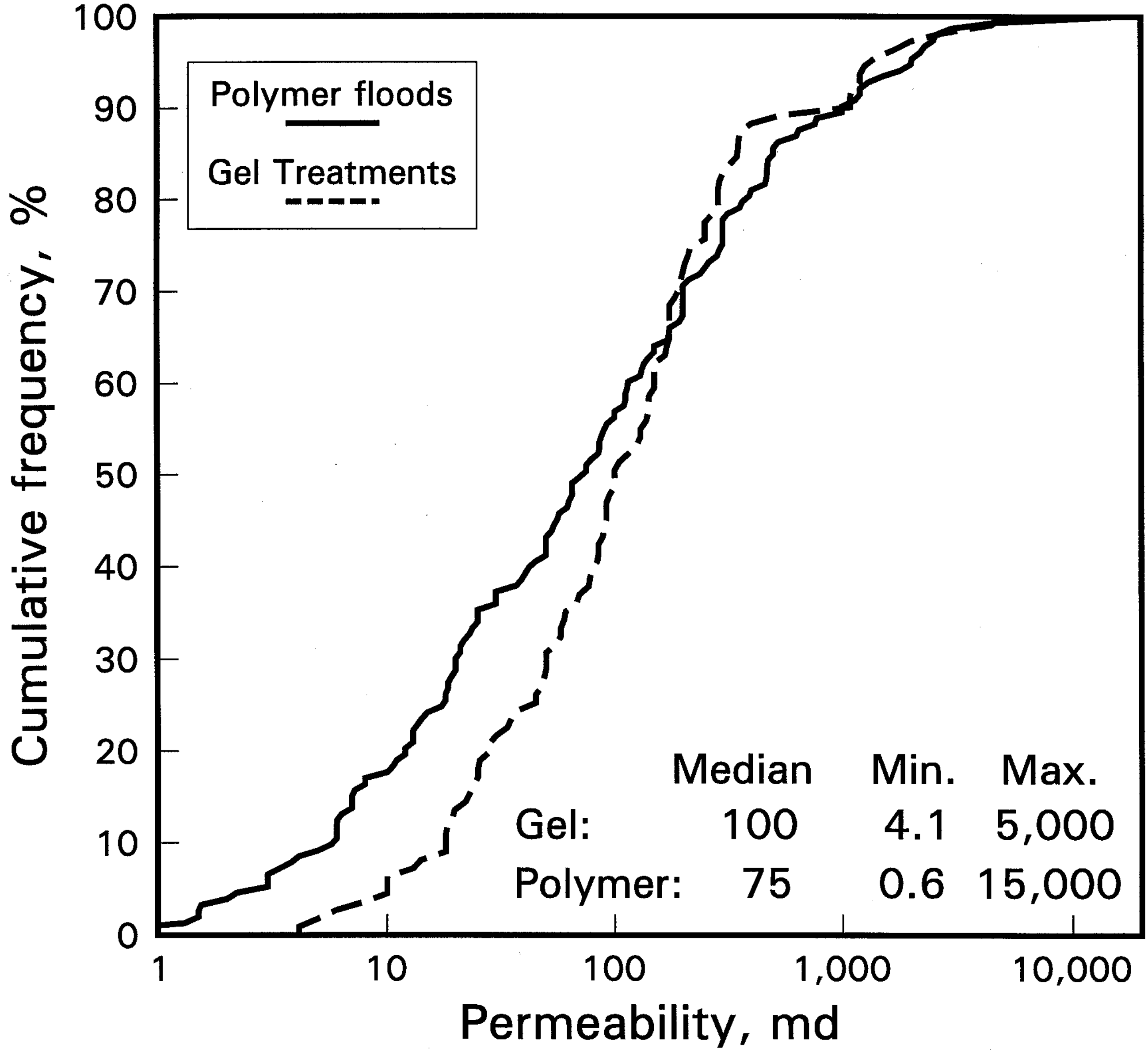


Fig. 1. Cumulative frequency plot of permeability.

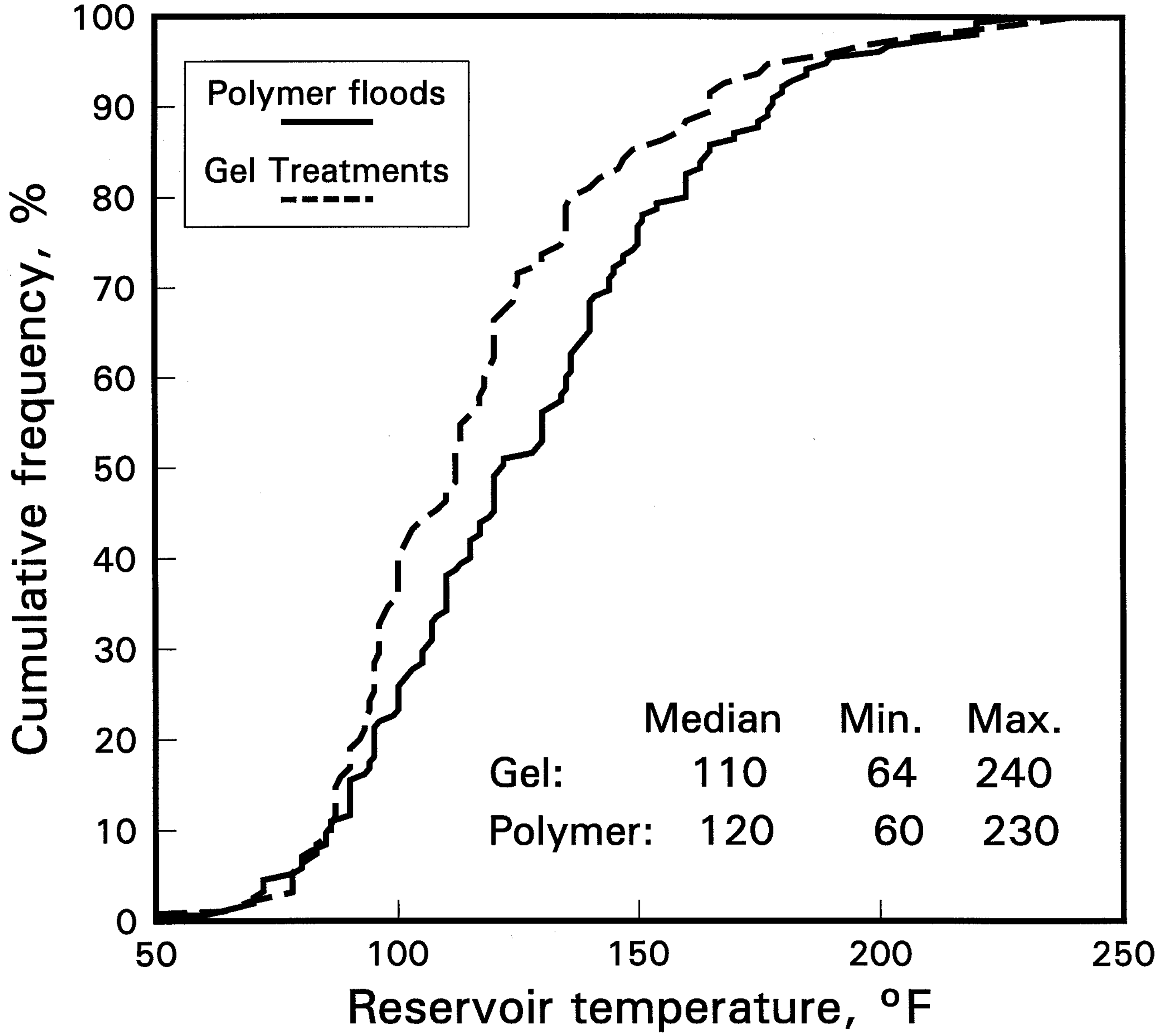


Fig. 2. Cumulative frequency plot of temperature.

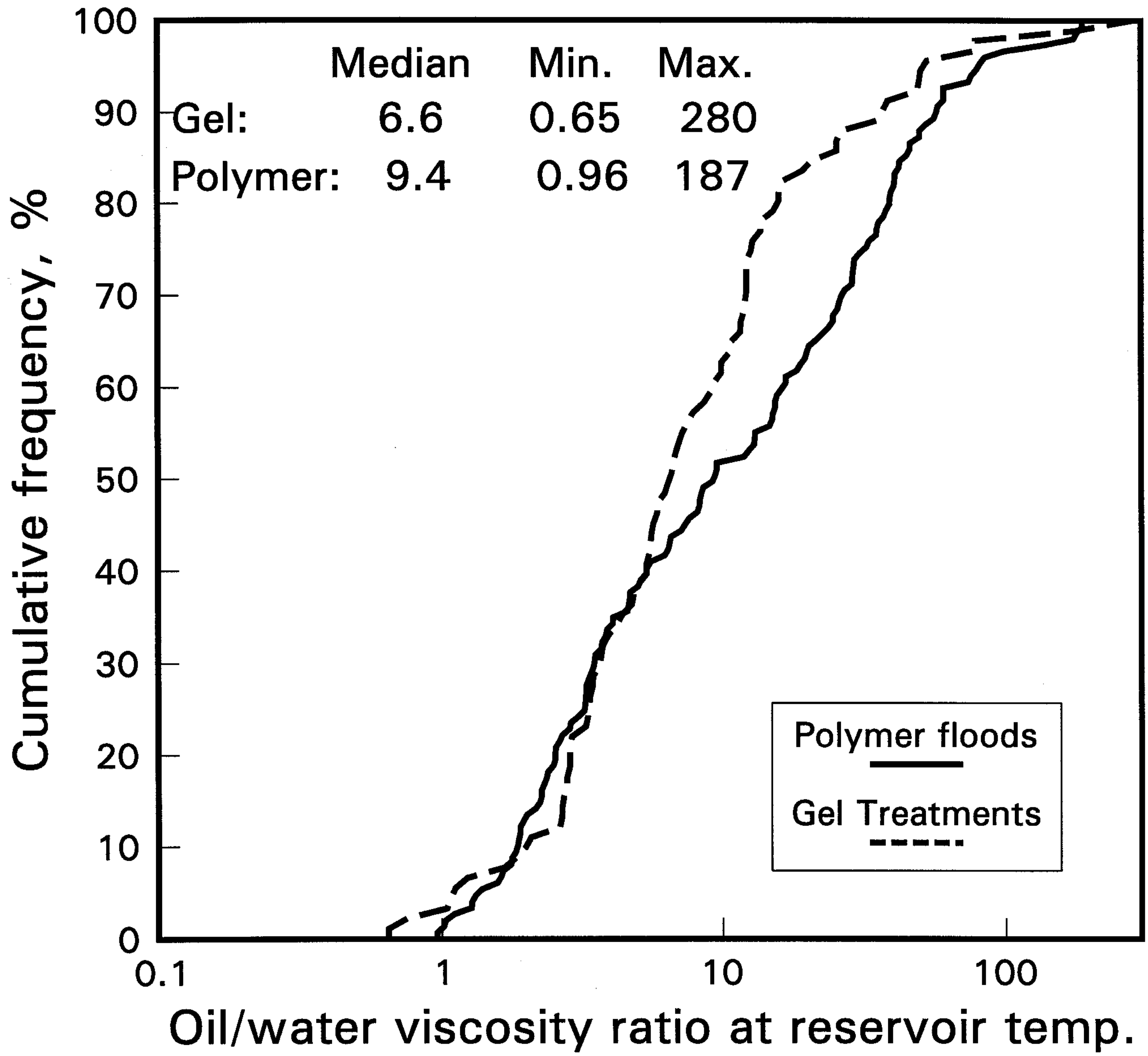


Fig. 3. Cumulative frequency plot of oil/water viscosity ratio.

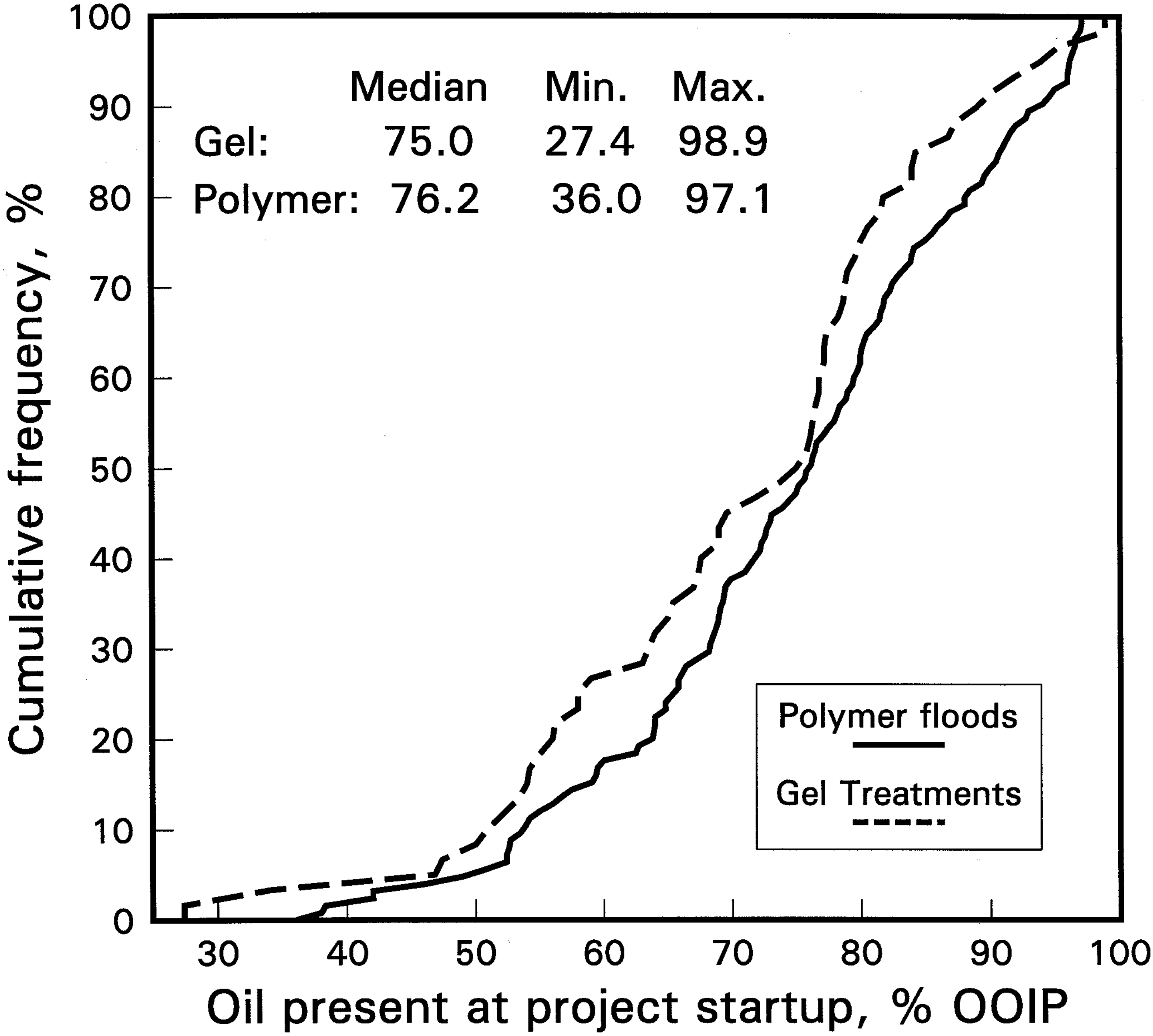


Fig. 4. Cumulative frequency plot of % OOIP present.

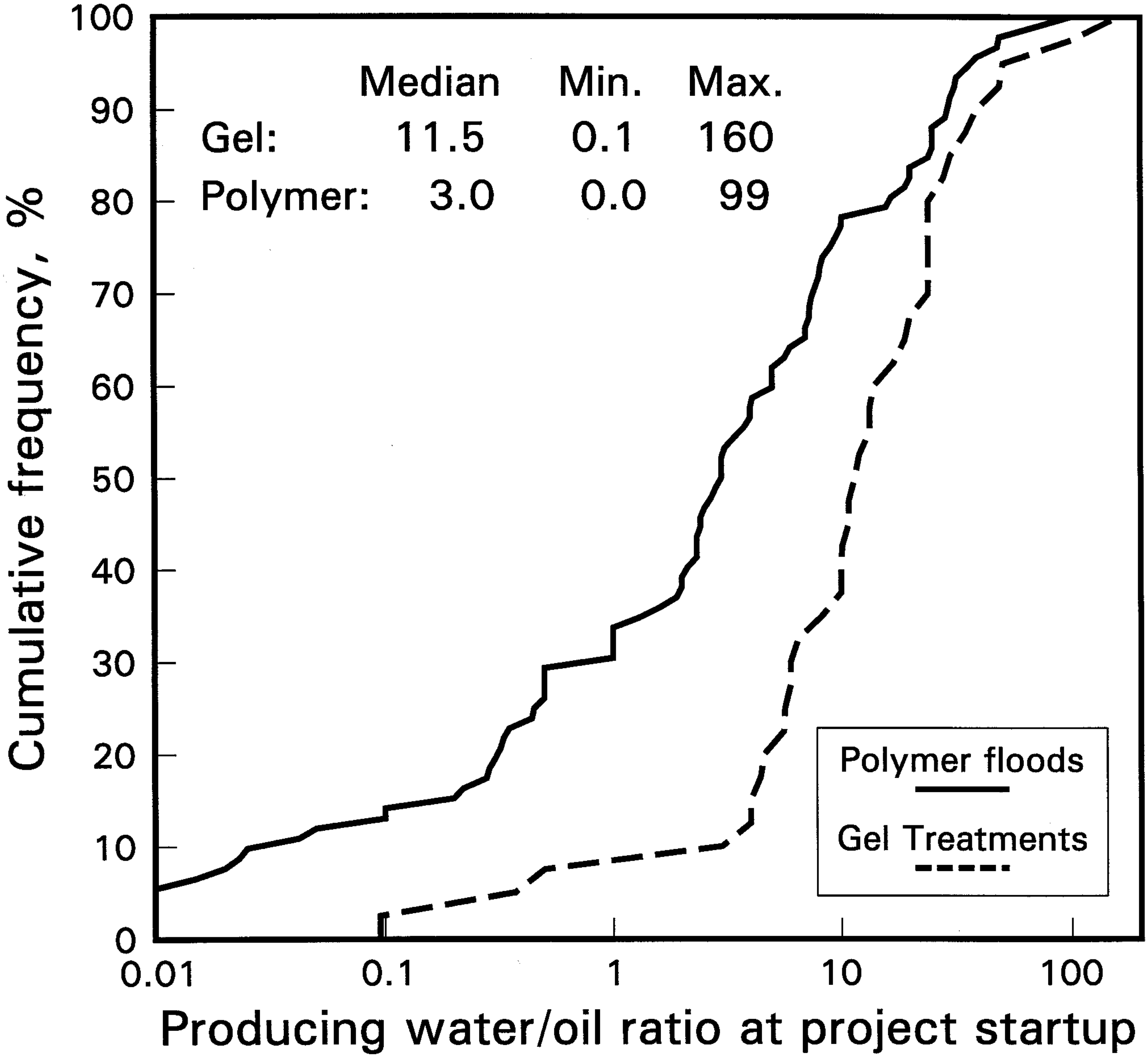


Fig. 5. Cumulative frequency plot of WOR values.

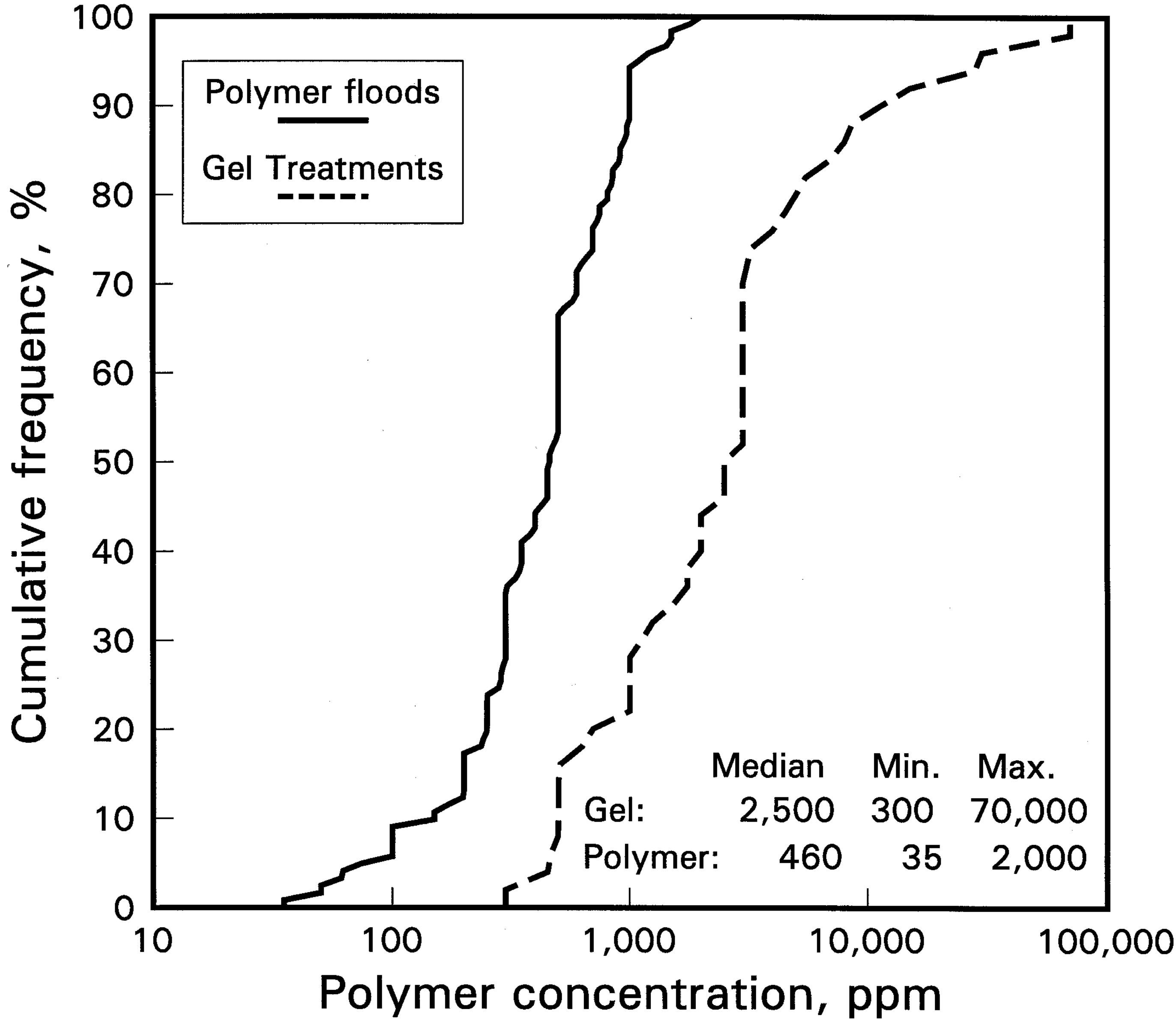


Fig. 6. Cumulative frequency plot of polymer concentration.

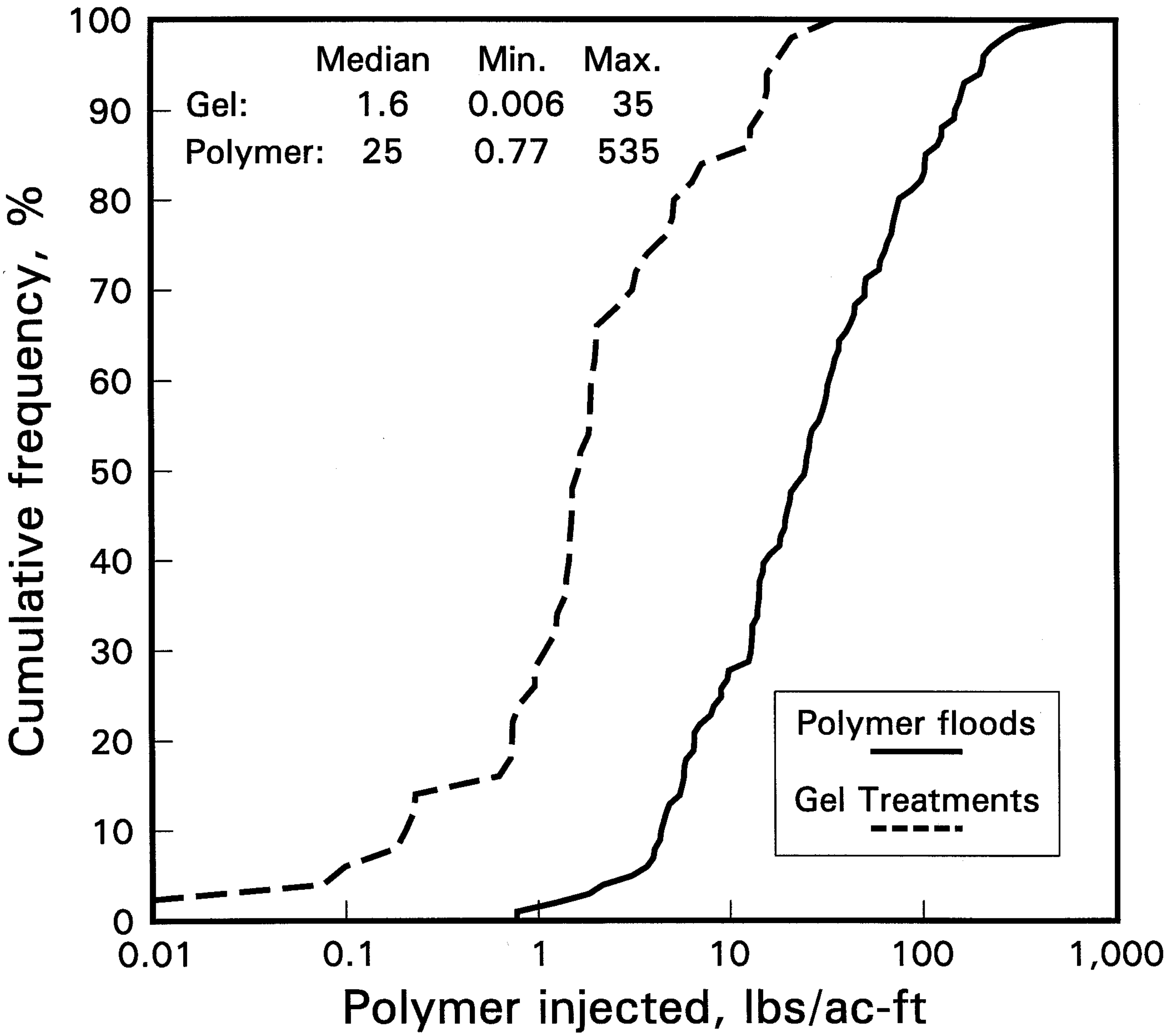


Fig. 7. Cumulative frequency plot of polymer injected in lbs/ac-ft.

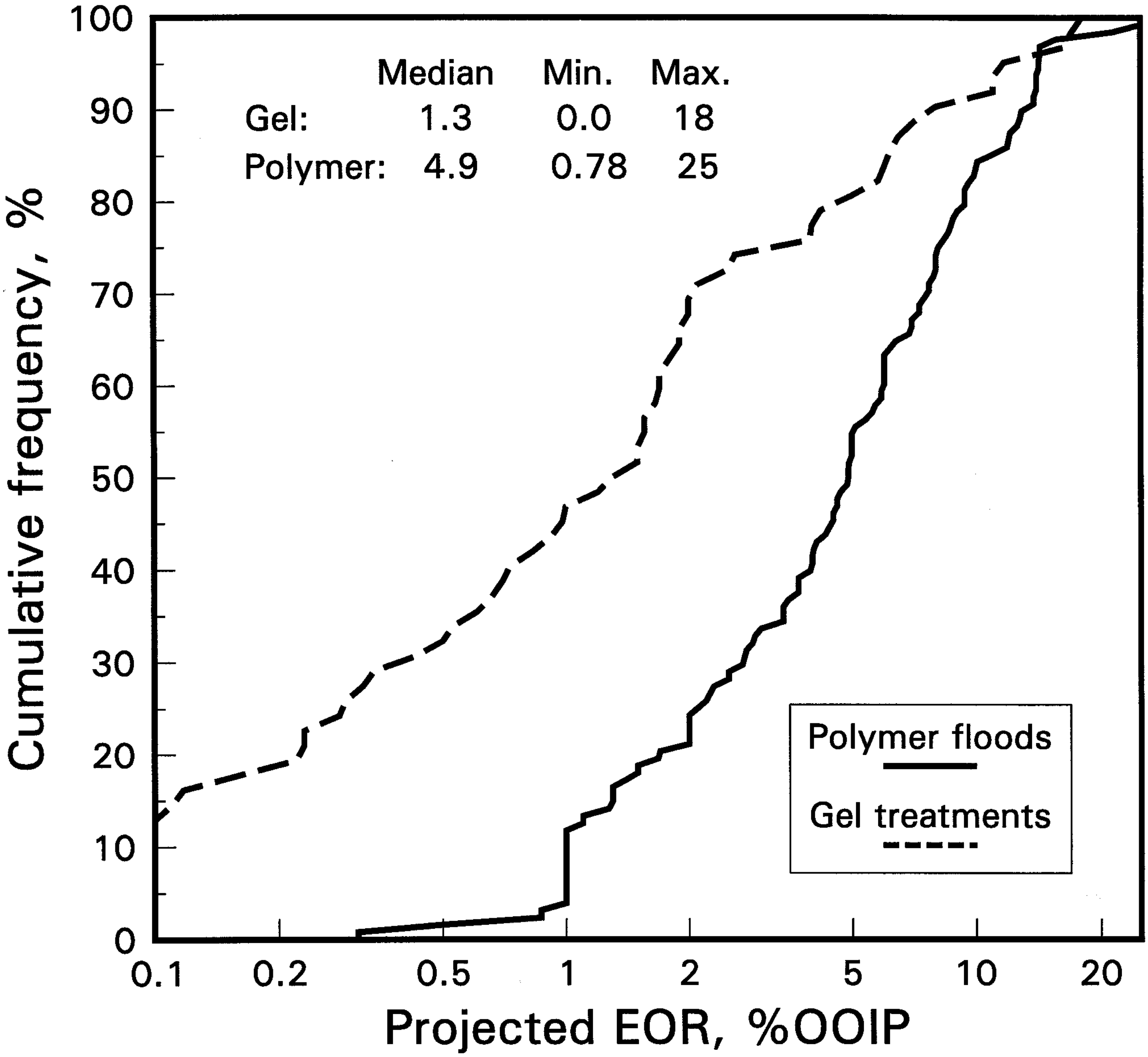


Fig. 8. Cumulative frequency plot of EOR in % OOIP.

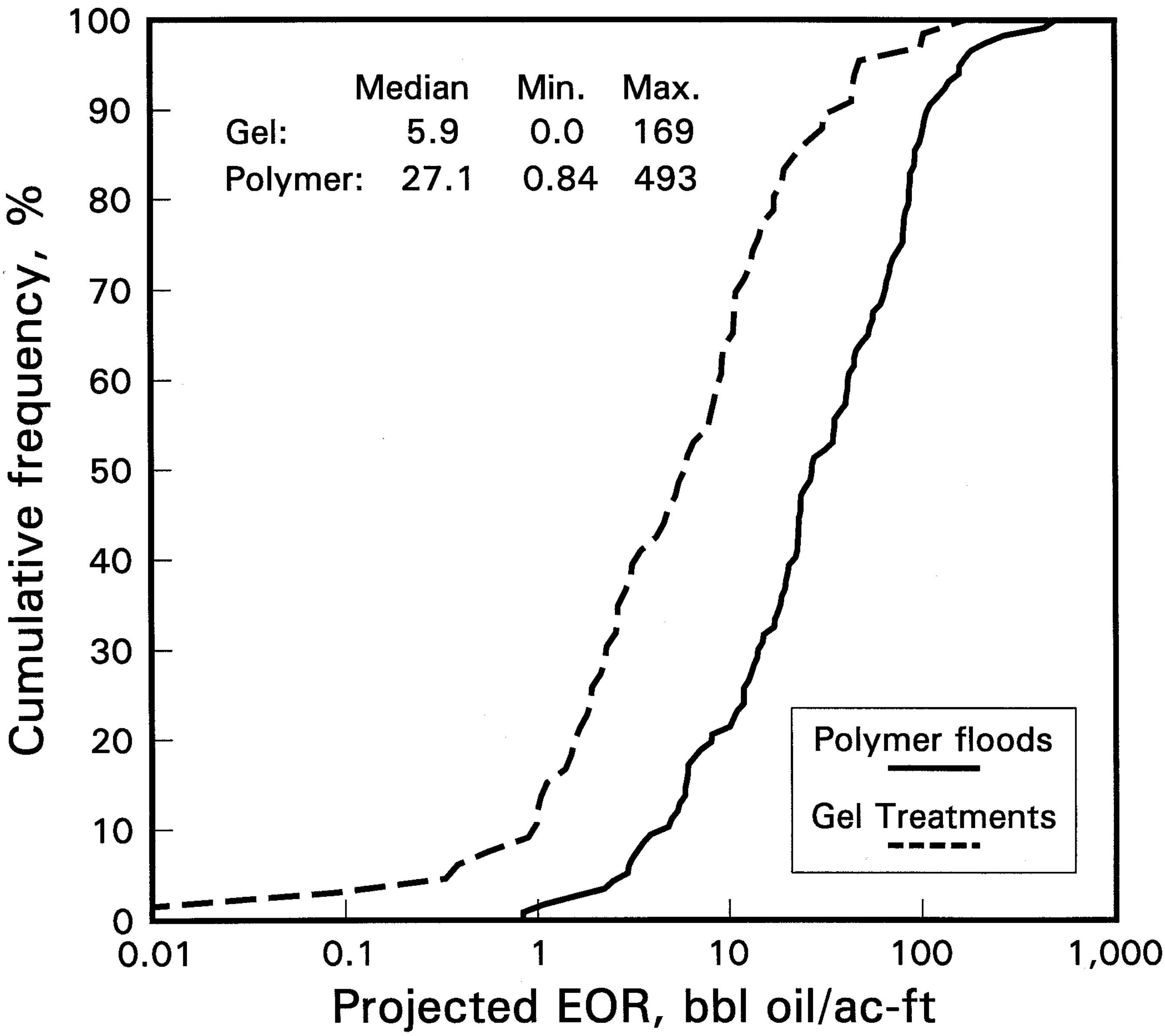


Fig. 9. Cumulative frequency plot of projected EOR in bbl oil/ac-ft.

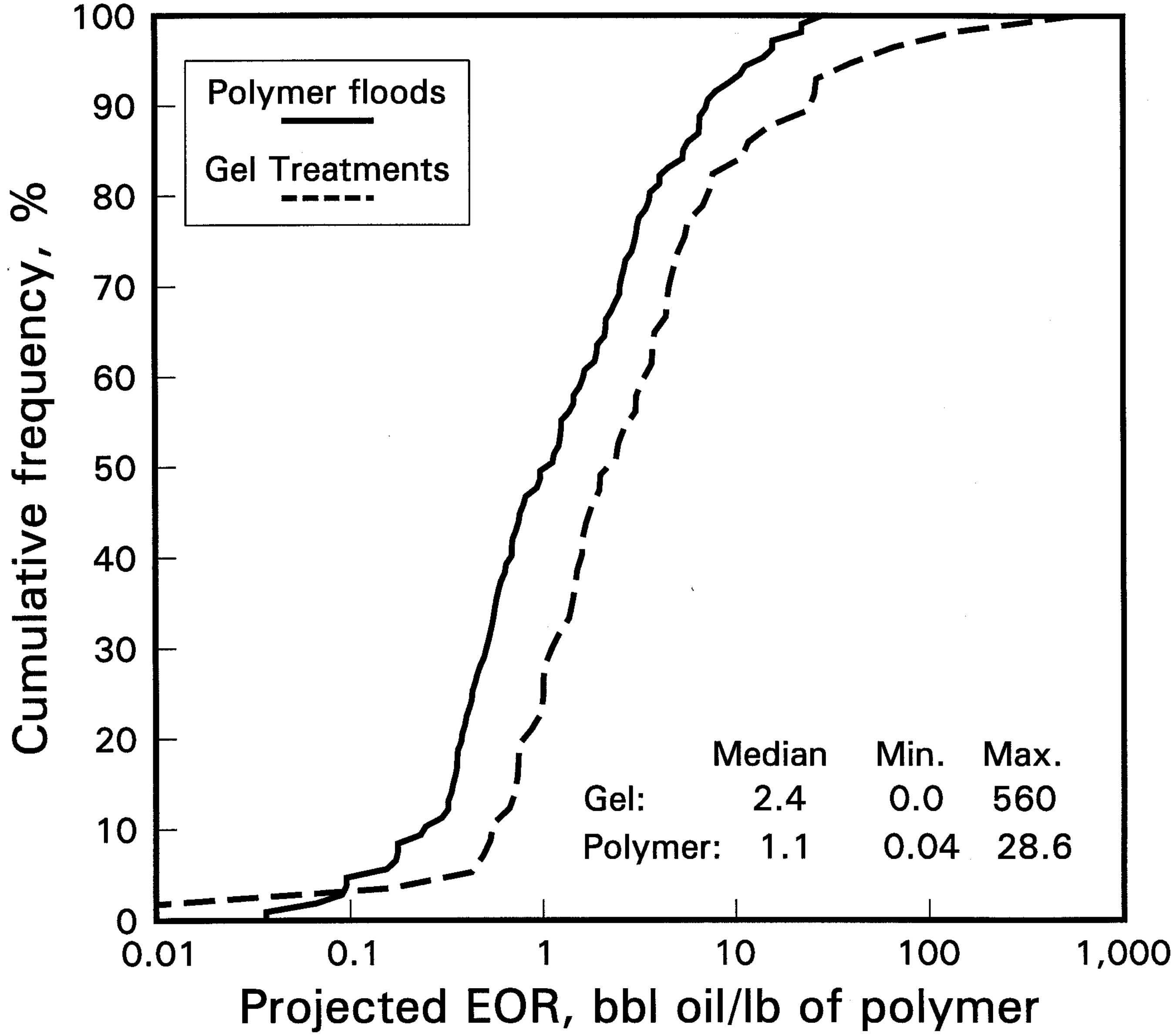


Fig. 10. Cumulative frequency plot of projected EOR in bbl oil/lb of polymer.

Reservoir Temperature. The distributions of reservoir temperatures are compared in Fig. 2 for the two types of projects. The median reservoir temperature was 110°F for the gel projects and 120°F for the polymer floods. The minimum and maximum values for the two distributions were about the same ($\approx$60°F to $\approx$240°F). For both types of projects, 95% of the projects were applied in reservoirs with temperatures below 200°F, reflecting a general concern that most polymers and gels may not be sufficiently stable at high temperatures. However, it is curious that reservoir temperatures were generally lower for gel treatments than for polymer floods. Because gel projects usually were small volume, near-wellbore treatments, one would expect the temperature limitations for gel projects to be less stringent than those for polymer floods. A gel in a near-wellbore injection-well treatment will experience cooler temperatures (because of the cool temperature of the injection fluids) than a polymer that has penetrated far from the wellbore. Also, if the gel in a near-wellbore treatment degrades after one year, retreating the well may not present a difficult technical or economic burden. However, if the polymer in a traditional polymer flood degrades after one year, most or all of the expensive polymer bank may be destroyed before any benefit can be realized.

Oil/Water Viscosity Ratio. Fig. 3 compares the distributions of oil/water viscosity ratios for the gel projects and polymer floods. Both distributions had a wide range of values. The median oil/water viscosity ratio, μ_o/μ_w, was 6.6 for gel treatments and 9.4 for polymer floods. If we assume that the ratio of endpoint permeabilities, k_o/k_w, is between 5 and 10, then the median endpoint mobility ratio, $(k_w/\mu_w)/(k_o/\mu_o)$, is approximately equal to one for both types of projects. Thus, roughly 50% of the reservoirs had a favorable mobility ratio during waterflood operations, suggesting that in at least half of the cases, channeling was more caused by reservoir heterogeneity (e.g., fractures and high-permeability streaks) rather than an adverse mobility ratio.

Oil Present at Project Startup. For the different types of projects, Fig. 4 compares the percent of original oil in place (%OOIP) at project startup. Again, both data sets have very wide distributions. The median value was 75.0% for the gel projects and 76.2% for the polymer floods. One would expect both types of projects to be most effective in reservoirs with a high %OOIP present at project startup. A low recovery efficiency during primary and waterflooding operations indicates that severe channeling may have occurred and that a large volume of mobile oil exists as a target for a gel treatment or polymer flood. In contrast, a high recovery efficiency before project startup suggests that gel treatments and polymer floods may not have been the most appropriate technology to apply (e.g., no serious channeling problem existed and little mobile oil remained as a target for the process).

Producing Water/Oil Ratio at Project Startup. Fig. 5 shows the distributions of producing water/oil ratios (WOR) at project startup. The median value for the gel projects (11.5) was almost four times greater than that for the polymer floods (3.0). Fig. 5 reveals that the water/oil ratios for the gel treatments are significantly greater than those for the polymer floods at most cumulative-frequency values. For a given %OOIP present at project startup, more severe channeling is associated with higher WOR values. Thus, as expected, the channeling problems treated by gel projects have generally been more severe than those treated by polymer floods. Also, polymer floods are thought to work best when applied early in the life of a waterflood (or even in place of a waterflood), when the WOR value is low.

Polymer Concentration. The distributions of average polymer concentrations are compared in Fig. 6. For the polymer floods, the median polymer concentration was 460 ppm, and the concentration values ranged from 35 ppm to 2,000 ppm. For the gel projects, the median concentration of polymer (or active gelant) was 2,500 ppm. In general, polymer concentrations were much greater for the gel treatments than for the polymer floods. This was anticipated since relatively high polymer concentrations are needed in order for gelation to occur. For the gel treatments, the distribution is especially broad because different types of formulations are used. For example, high-molecular-weight polymers can be crosslinked to form gels at relatively low concentrations, but low-molecular-weight polymers require higher concentrations in order to gel. Monomer based gels usually require even higher chemical concentrations.

About 95% of the polymer floods used partially hydrolyzed polyacrylamides (HPAM). The remaining 5% of the floods used xanthan. Approximately 55% of the gel treatments used polyacrylamides. In most of these treatments, the polyacrylamide was crosslinked using the chromium(VI)-redox process. However, in some treatments, acrylamide monomer solutions were injected and polymerized in situ. Also, in a number of cases, chromium(III), aluminum, or zirconium were used as crosslinkers. About 33% of the gel projects used chromium crosslinked xanthan. The remaining gel projects used other gel technologies.

Quantity of Polymer Injected. Fig. 7 compares the quantities of polymer injected, expressed as pounds of polymer injected per ac-ft of reservoir. The median value for the polymer floods (25 lbs/ac-ft) was over 15 times that for the gel treatments (1.6 lbs/ac-ft). This fact is not surprising since most polymer floods involved injection of a polymer bank that was between 5% and 50% of one pore volume, while most gel projects were designed so that the gelant penetrated a short distance into the reservoir. For both gel treatments and polymer floods, the distributions are very broad. For the gel projects, the values ranged from 0.006 to 35 lbs/ac-ft, while the values ranged from 0.77 to 535 lbs/ac-ft for the polymer floods.

Projected Incremental Oil Recovery. Figs. 8, 9, and 10 show the distributions of values for the projected incremental oil recovery. In these figures, "projected EOR" means the oil that was projected to be produced by the gel project or polymer flood, incremental over a waterflood. These projections are expressed in three different ways: (1) as %OOIP in Fig. 8, (2) as barrels of oil per ac-ft of reservoir in Fig. 9, and (3) as barrels of oil per pound of polymer injected in Fig. 10. We emphasize that the values shown in these figures are projections. Usually, these projections were published near the start of the project. In many cases, the method used to estimate incremental oil provided only a crude guess. For example, a fixed %OOIP was sometimes chosen as an incremental oil value, regardless of variations in reservoir conditions. Other operators chose a fixed number of barrels of incremental oil per pound of polymer injected for a given process. In other cases, the projections were based on simulation of a polymer flood, when in reality, a near-wellbore gel treatment was applied. Thus, the validity of many of these projections is questionable. Unfortunately, oil-recovery values were usually not provided after the projects were completed. Thus, the projections shown here should be viewed with caution.

When expressed as %OOIP (Fig. 8), the median values for the projected EOR were 4.9 %OOIP for the polymer floods and 1.3 %OOIP for the gel treatments. When expressed as bbl oil/ac-ft (Fig. 9), the median values for the projected EOR were 27.1 bbl oil/ac-ft for the polymer floods and 5.9 bbl oil/ac-ft for the gel treatments. Thus, for a given project, a polymer flood was generally expected to recover much more incremental oil than a gel treatment. However, when expressed as bbl oil/lb of polymer (Fig. 10), the gel projects appear more favorable. The median values for the projected EOR were 2.4 bbl oil/lb of polymer for the gel treatments and 1.1 bbl oil/lb of polymer for the polymer floods. For all cases shown in Figs. 8, 9, and 10, the distributions were very broad.

Correlation of Properties and Predicted Performance

In an effort to establish where gel treatments and polymer floods were most effective, we attempted to correlate various parameters for the different projects.

Producing Water/Oil Ratio vs. Oil Produced Before Project Startup. One would expect the best candidate reservoirs for gel treatments to have a low recovery efficiency and a high WOR value. For the gel projects, Fig. 11 plots producing water/oil ratio vs. oil produced before project startup. This figure indicates that most WOR values (at project startup) were in the range from 3 to 100. No correlation is evident with the %OOIP produced before the project. The figure suggests that in many (perhaps most) previous field applications, the primary criterion for candidate selection was a high water cut in offset production wells. Apparently, the mobile oil saturation was often not given much consideration. Perhaps the success rate from gel treatments in injection wells can be improved significantly if more consideration is given to the magnitude of the remaining mobile oil saturation.

For the polymer floods, Fig. 12 plots producing water/oil ratio vs. oil produced before project startup. Again, no correlation is evident. A comparison with Fig. 11 reveals that polymer floods were initiated with a broader range of water/oil ratios. This observation is not particularly surprising. Many EOR experts advocate that polymer floods should be implemented early in the life of a waterflood, when the WOR is low. On the other hand, many polymer floods in the United States were implemented when waterfloods were relatively mature simply because polymer-flood technology had not been developed or accepted at the time the waterfloods were initiated.

Producing Water/Oil Ratio vs. Oil/Water Viscosity Ratio. Figs. 13 and 14 plot WOR vs. the oil/water viscosity ratio for the gel projects and polymer floods, respectively. Other factors being equal, water channeling (i.e., the WOR) is expected to increase in severity with increased mobility ratio (and oil/water viscosity ratio). Thus, a greater number of gel treatments and polymer floods might have been expected in reservoirs with high oil/water viscosity ratios. Obviously, Figs. 13 and 14 do not support these expectations. No technical explanation is apparent.

Projected Oil Recovery vs. Quantity of Polymer Injected. Of the various parameters that were examined during this study, only two appeared to correlate. As shown in Figs. 15 and 16, the projected EOR (in bbl) increased with increased quantity of chemical injected (in lbs). This trend was evident for both the gel projects and the polymer floods. However, both Fig. 15 and 16 show substantial data scatter. As the figures show, this scatter is not reduced by grouping the projects by lithology.

Projected Oil Recovery vs. Oil Produced Before Project Startup. Figs. 17 and 18 plot projected EOR vs. oil produced before project startup for gel projects and polymer floods, respectively. In both figures, a large degree of data scatter is observed. This scatter is not reduced by grouping the projects by lithology. Contrary to our expectations, no correlation is evident between projected EOR and oil produced before project startup. In fact, except for the quantity of polymer injected, no correlation was found between the projected EOR and any other variable. This observation raises doubt about the validity of many of the EOR projections.

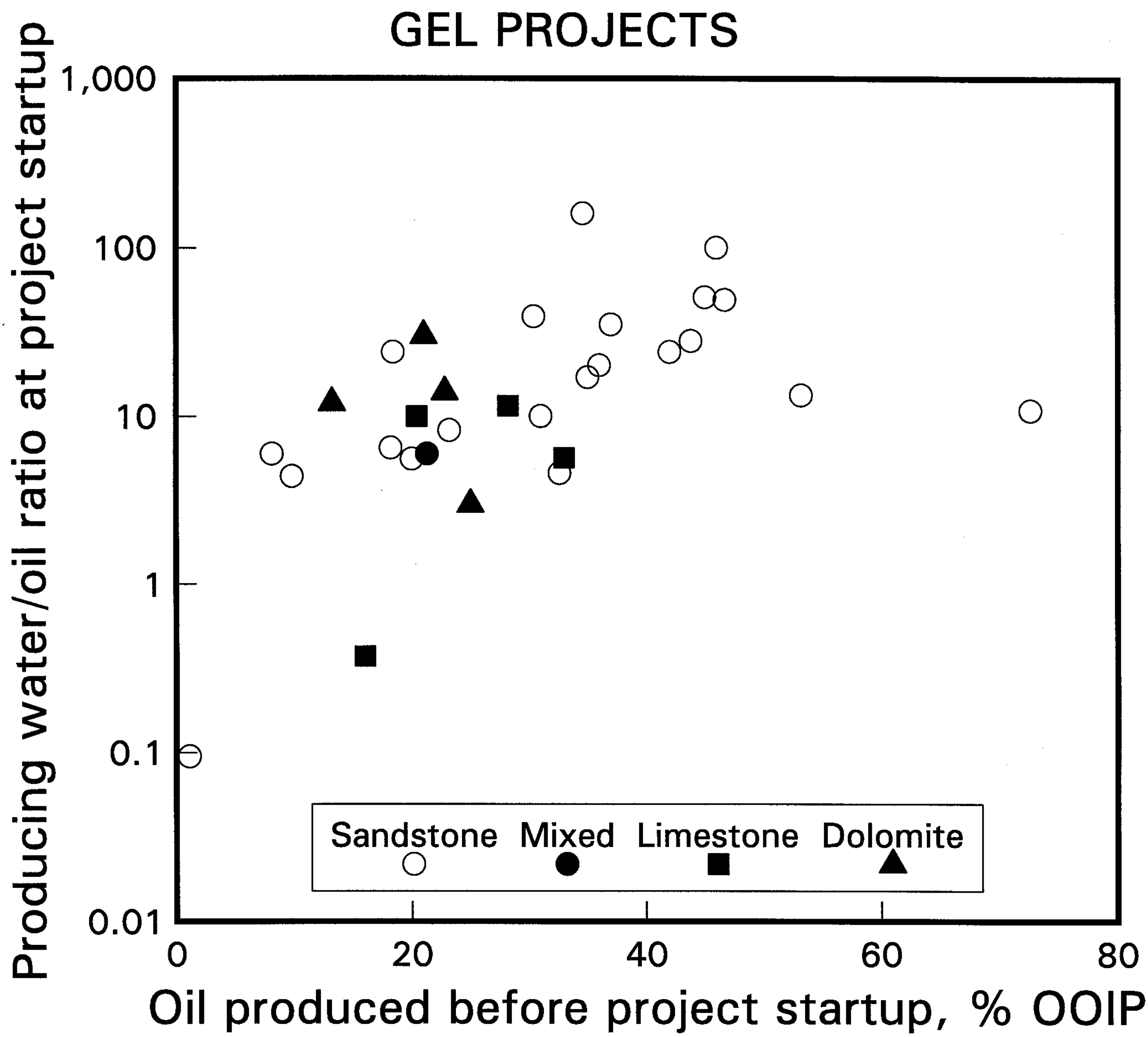


Fig. 11. WOR vs. % OOIP produced before startup for gel projects.

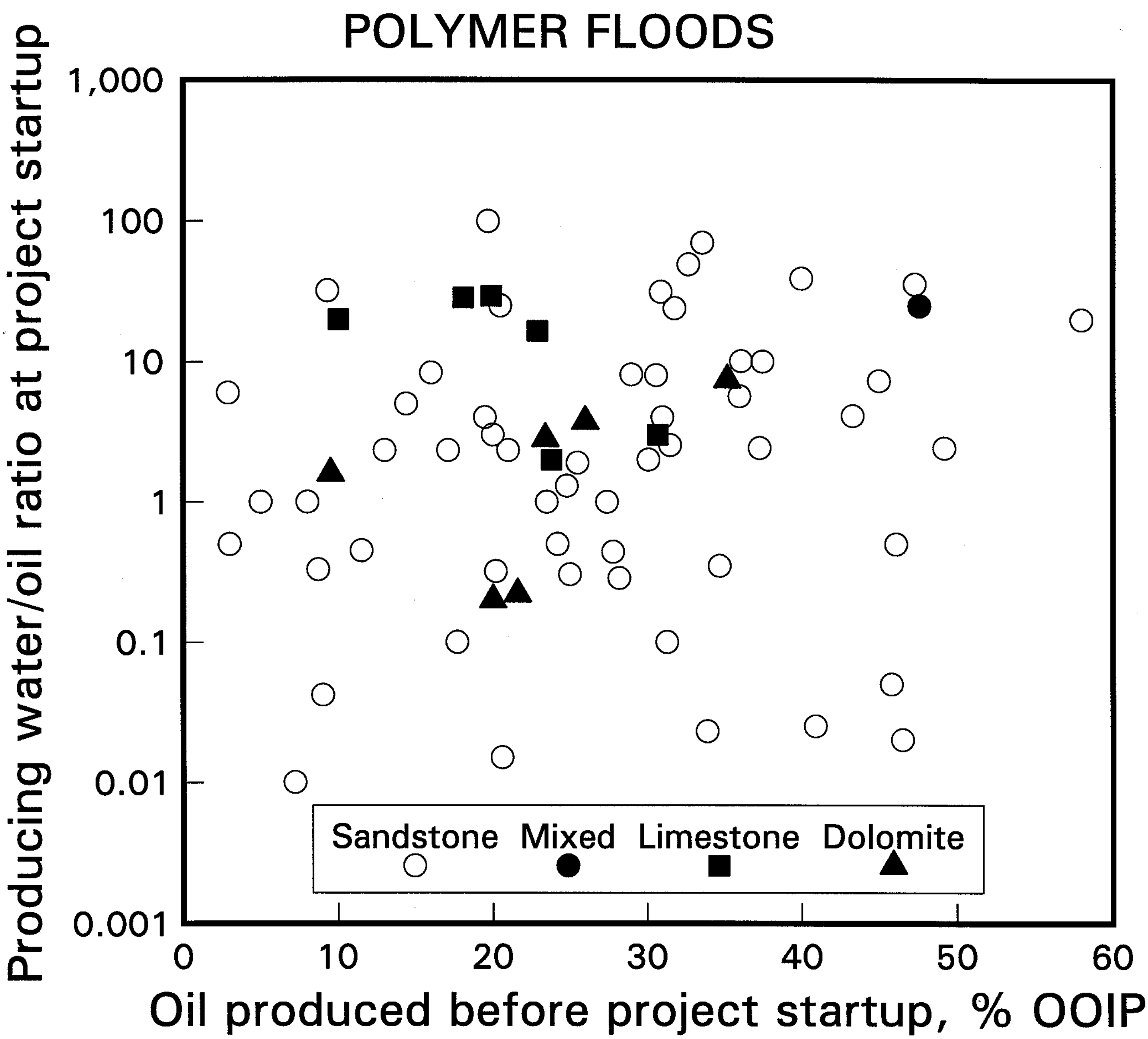


Fig. 12. WOR vs. % OOIP produced before startup for polymer floods.

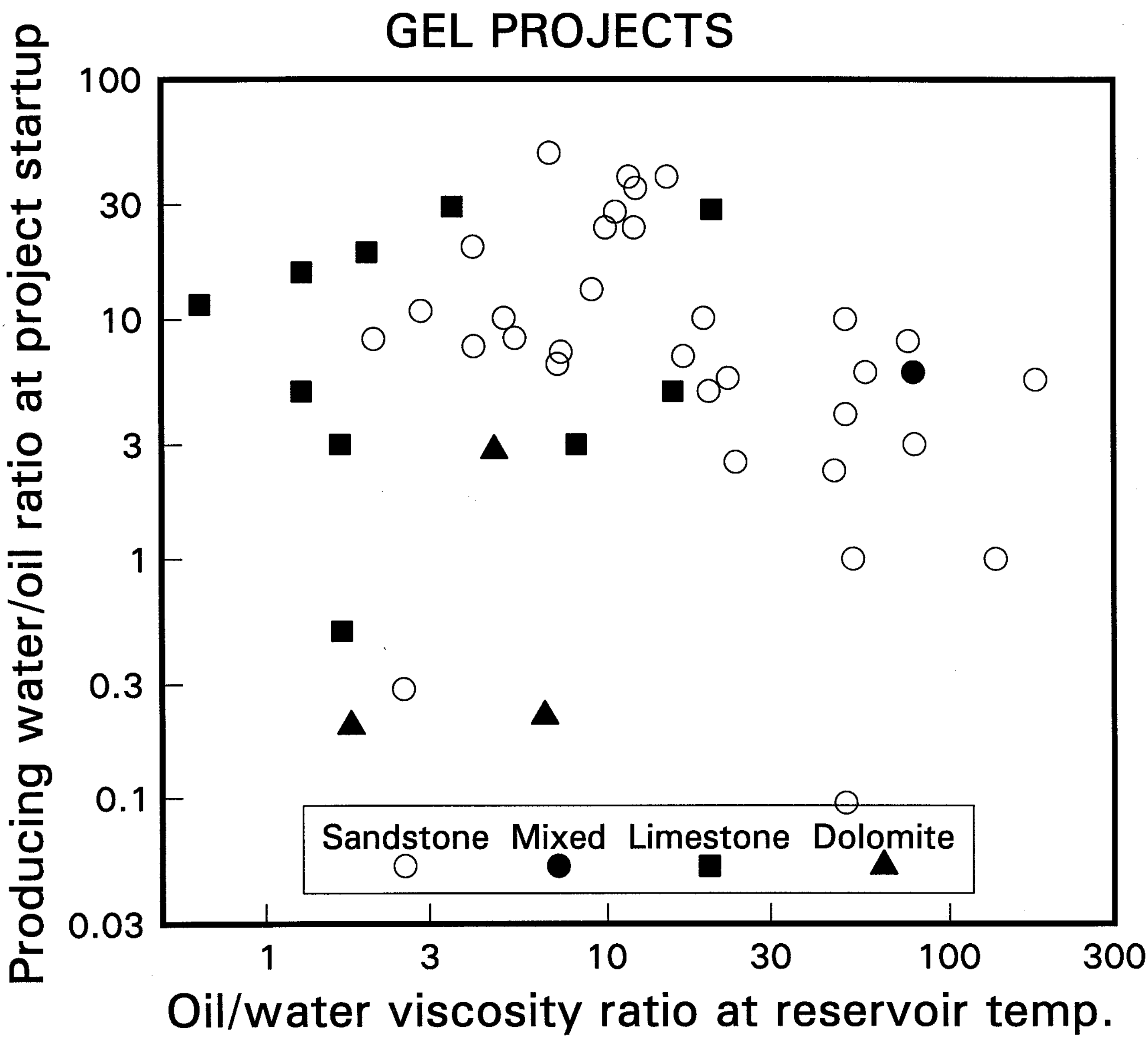


Fig. 13. WOR vs. oil/water viscosity ratio for gel projects.

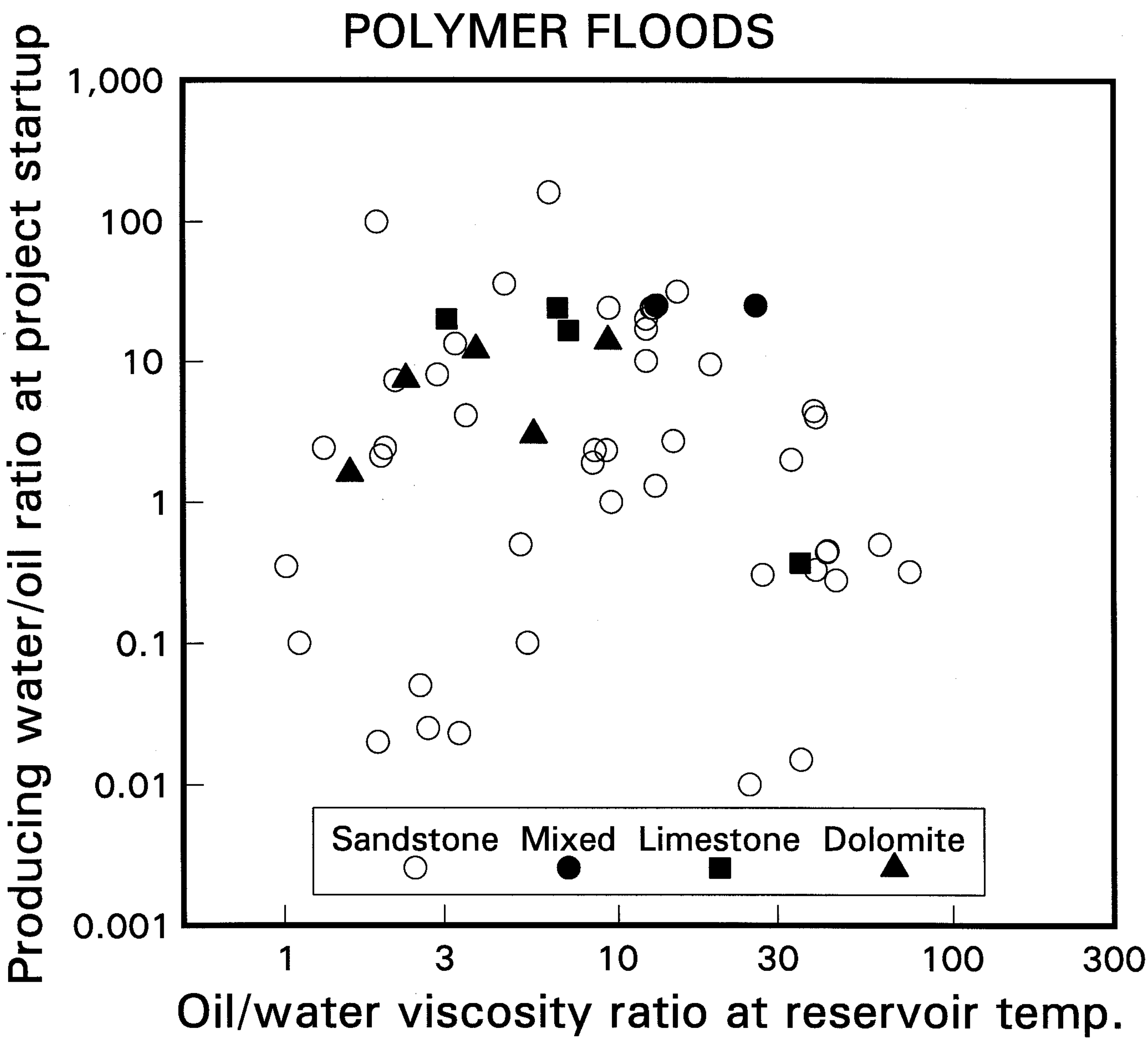


Fig. 14. WOR vs. oil/water viscosity ratio for polymer floods.

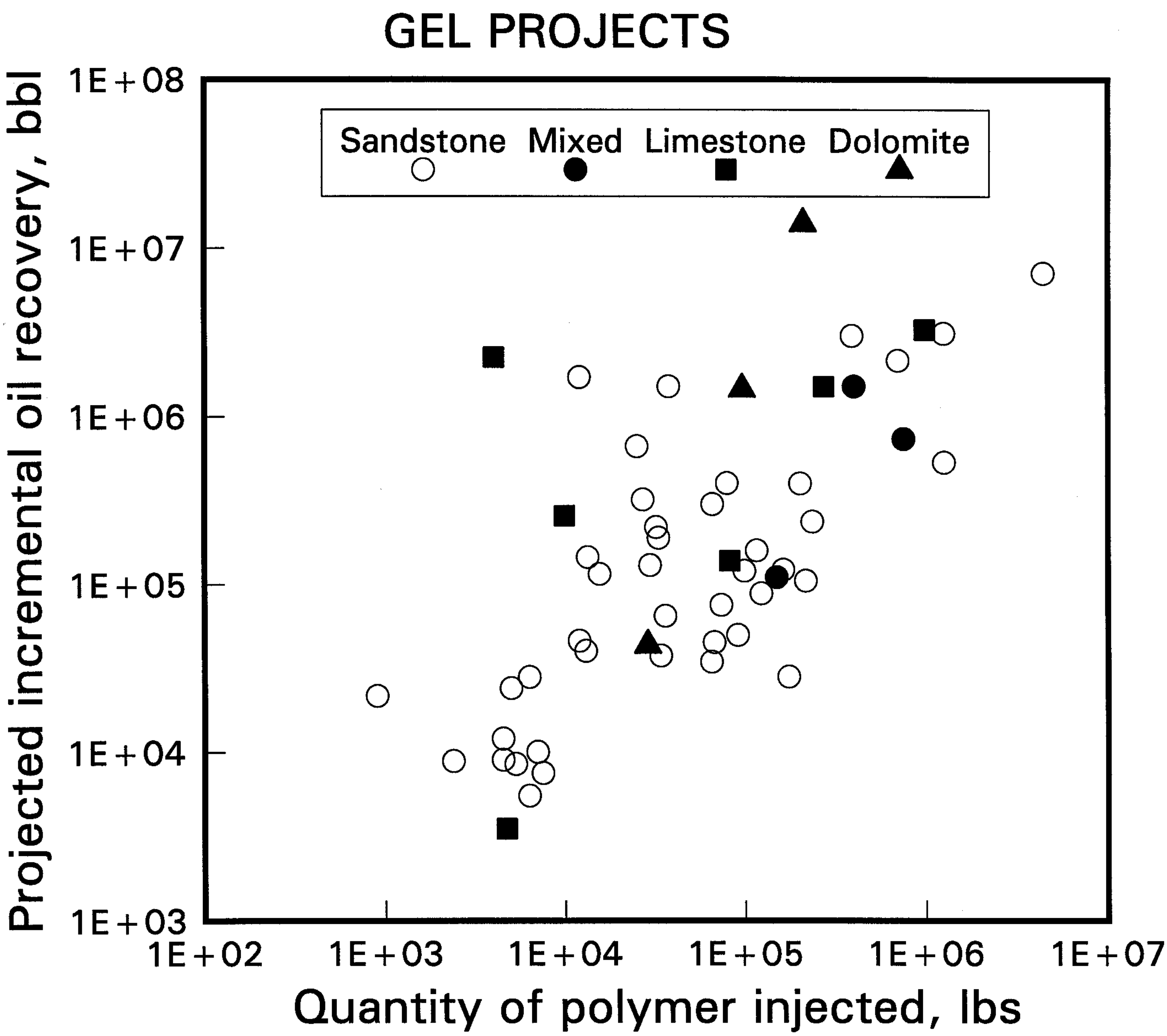


Fig. 15. Projected EOR vs. lbs of polymer for gel projects.

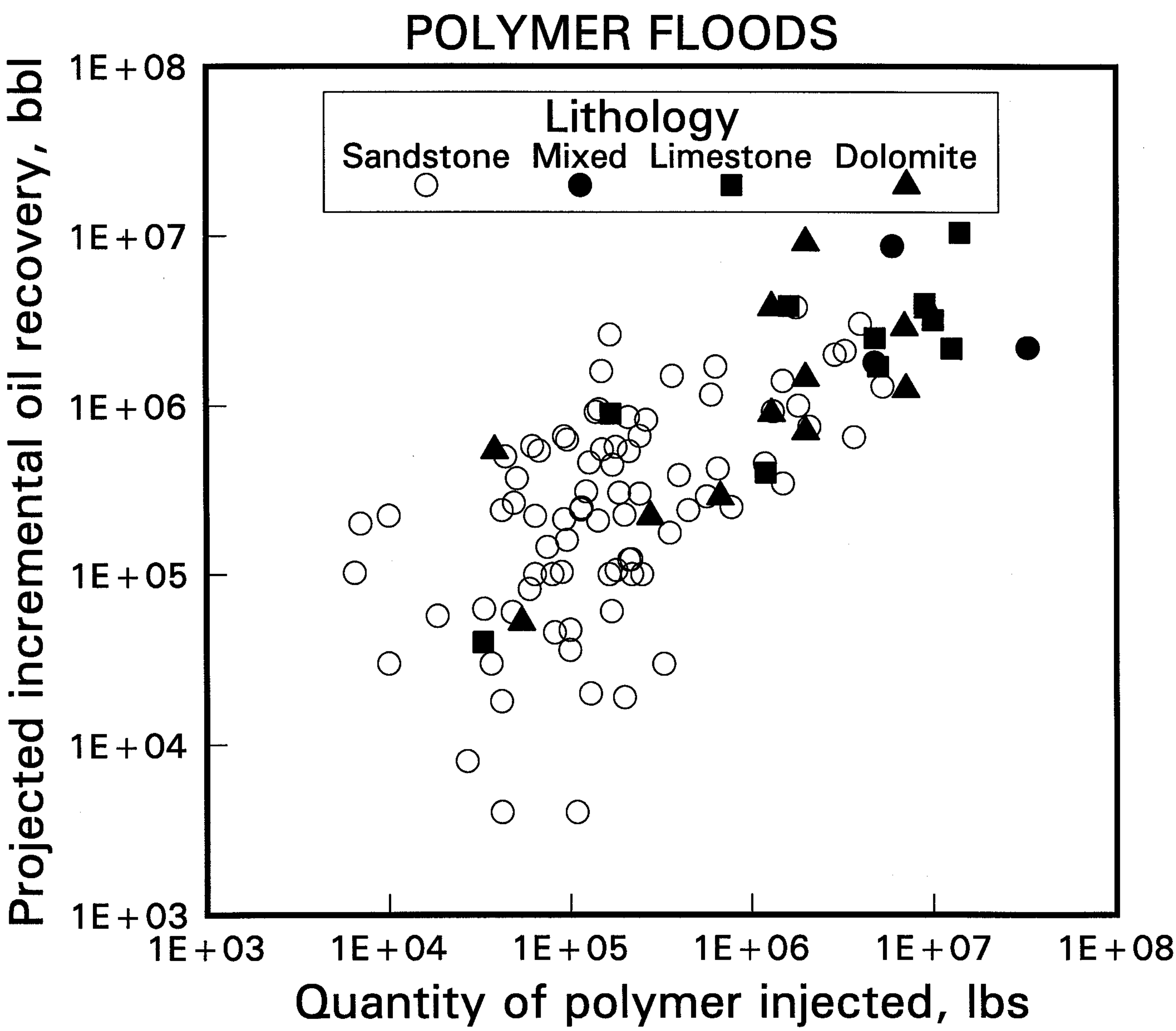


Fig. 16. Projected EOR vs. lbs of polymer for polymer floods.

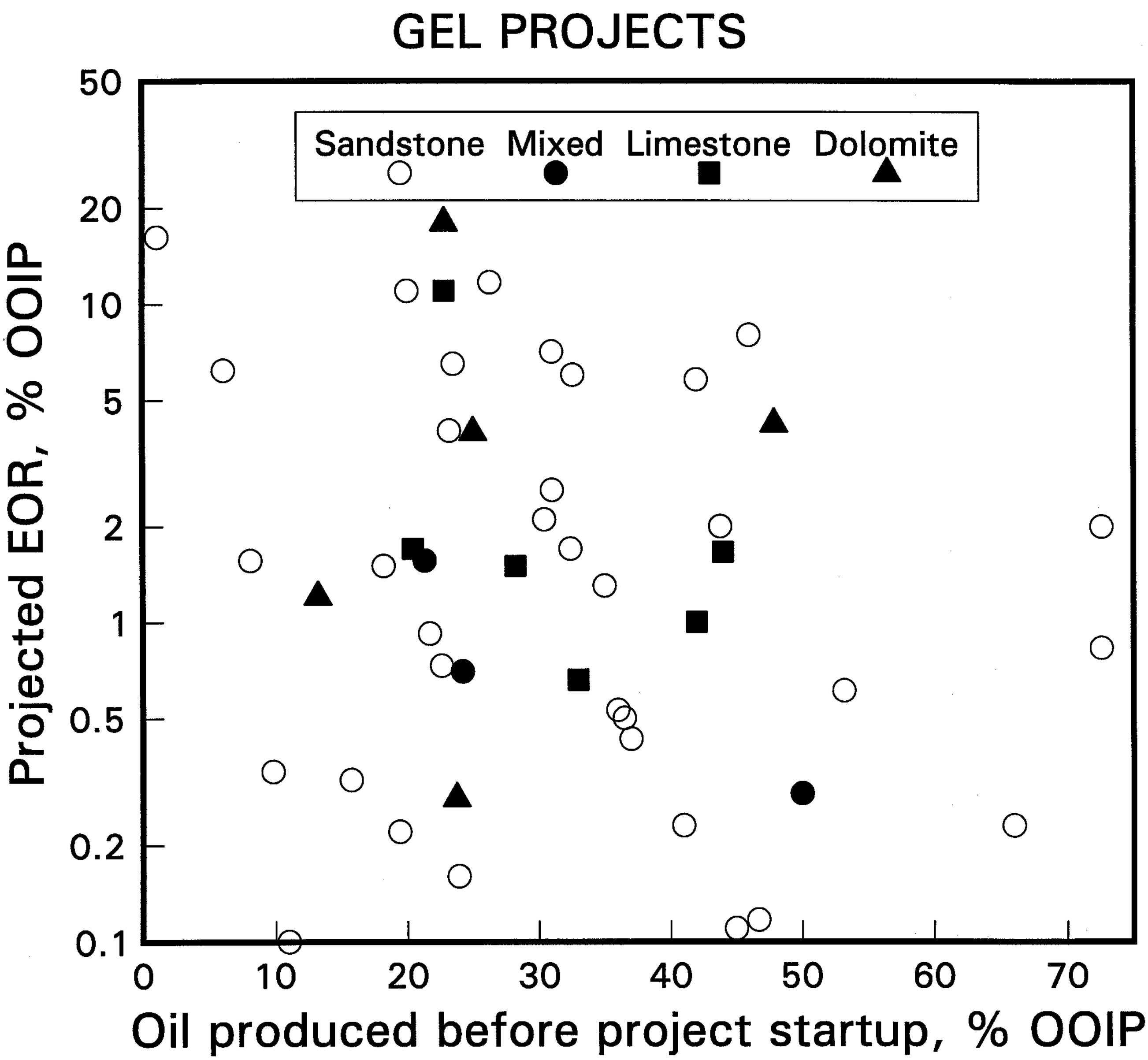


Fig. 17. Projected EOR vs. % OOIP produced before startup for gel projects.

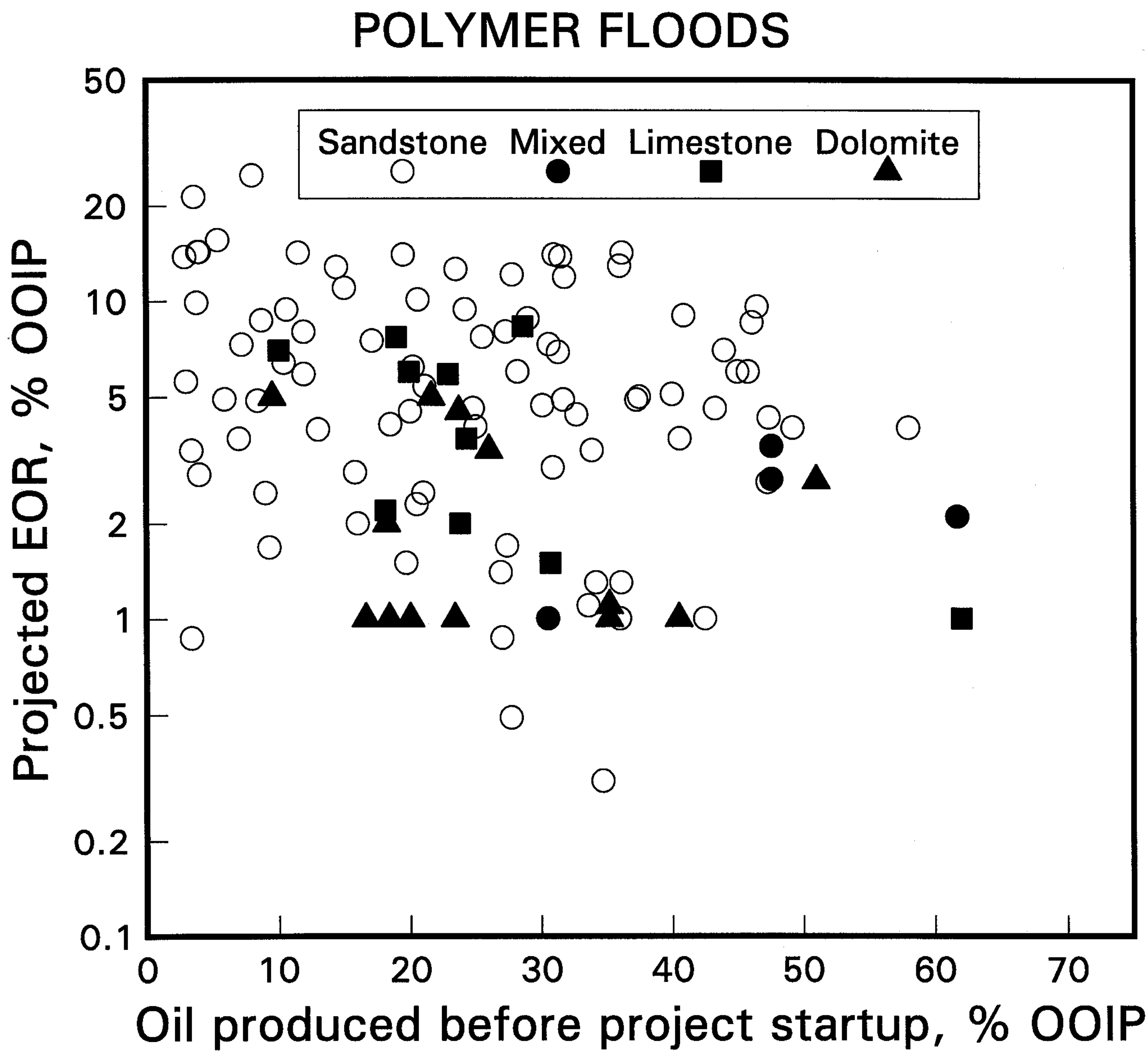


Fig. 18. Projected EOR vs. % OOIP produced before startup for polymer projects.

Discussion

One fact becomes evident when viewing the figures and tables in this chapter—polymer floods and gel treatments have been applied over a remarkably wide range of conditions. Another point becomes clear upon detailed examination of the field data; that is, many important factors were not considered when selecting candidates or projecting EOR for the gel projects. Apparently, a high producing water/oil ratio was the only criterion that was commonly used when selecting candidates for gel treatment. In view of the sporadic success rate for gel treatments, questions about the validity of many EOR projections and the sketchy reporting of the field data, published field data by itself is insufficient to establish guidelines for where or how to best apply gel treatments.

During our analysis, several factors were identified that could have improved the process of candidate selection for past gel treatments. First, consideration should be given to the %OOIP produced prior to the project. Unless a large mobile-oil saturation remains in the target area, a gel treatment or polymer flood is unlikely to be effective.

Second, in many previous gel projects, all injection wells in the field or unit were treated. The success rate could have been improved by identifying and treating only those wells where severe channeling was noted. For wells that were not associated with severe channeling, gel injection could reduce water injectivity and oil productivity without reducing the WOR. Of course, we recognize that the US tax code from 1980 to 1986 encouraged application of gel treatments in all injectors in a unit, regardless of whether a channeling problem existed. Hopefully, future tax incentives will encourage more sound technical decisions.

Third, some effort should be made to characterize the channeling problem before applying a gel treatment. This effort need not be unacceptably expensive. For example, a simple comparative analysis of %OOIP produced, WOR values, and water injection volumes for the patterns and wells in the field could aid considerably in candidate selection. Also, an inexpensive tracer test could be crucial in identifying whether a channel exists that is amenable to correction by a gel treatment. If a tracer experiences a very short transit time (e.g., less than one week) between a pair of widely separated wells, then a gel treatment may be a good choice to treat this channel (which is probably a fracture or a formation parting problem). If the tracer transit time or breakthrough pore volume is not very small, then perhaps gel injection is not the best choice of treatment.

An important prediction from our previous theoretical work is that gel treatments should be most effective if fractures (or formation parting) are the source of the channeling problem.[13-17] Results from some of the most successful field projects support this prediction.[8-11] However, to fully test the theory, the success rate should be examined for gel treatments in injection wells where channeling was not caused by fractures or formation parting.

Our theoretical studies predict that conventional gel treatments are unlikely to be effective in unfractured injection wells unless the gelant is prevented from entering the oil-productive zones. On the surface, these predictions seem very amenable to field testing. Unfortunately, in virtually all the published field applications, either the reports state that fractures were the source of the problem or they do not indicate if fractures were present. Without a direct comparison with cases where formation parting is not a factor, the theory cannot be adequately tested.

During discussions with some vendors and operators, general agreement was found that the best injection-well candidates are those where an injected tracer shows a very short transit time (0.001 PV or less) between the injector and a nearby producer. In several cases, the vendor or operator was unwilling to label the channel as a fracture or formation part. Some individuals suggest that relative permeability effects or rock dissolution are responsible for these extremely small-volume and high-permeability channels. However, except under one circumstance, these explanations do not appear plausible in view of accepted reservoir engineering calculations.[14-16] (It is possible that these channels could develop from viscous fingering of water or another high-mobility fluid through a very viscous oil.)

Another explanation that some vendors and operators offer is that an extremely short transit time is due to a geologic structure other than a fracture. This explanation requires that a very small-volume pathway connect an injector-producer pair. Such a structure must have a very small cross-section, a very high aspect ratio (length to width), and an extremely unfortunate orientation. It seems improbable that two widely separated wells with an 8" to 12" cross-section would be drilled into the same small-cross-section porous-rock deposit. A fracture, fracture system, or formation part seems much more likely.

For reservoirs where formation parting is clearly not present and channeling still exists, it is important to identify discrete zones that are separated by impermeable barriers. Under these conditions, gel treatments can be effective in injection wells, but only if the gel is prevented from entering the oil-productive zones.[13-17] Incidently, we note that BP has developed an interesting concept for gel placement in heterogeneous reservoirs with crossflow[29] (where zone isolation would be of little value during gelant injection). This concept involves injection of a low-viscosity gelant into a well where the temperature increases with distance from the wellbore. The thermal gradient is exploited to delay gelation until deep penetration is achieved. Hopefully, this technology will be effective under some circumstances in unfractured wells.

Reservoir heterogeneity has been suggested as a possible screening device for gel treatments. Measures of reservoir heterogeneity (e.g., the Dykstra-Parsons coefficient or Lorenz coefficient[30]) are usually based on the vertical variation of matrix permeabilities in a well. We have previously demonstrated that these measures are of little or no value in determining the applicability of gel treatments in injection wells.[17] Basically, the reason is that these coefficients of permeability variation do not indicate whether the offending channel causes linear or radial flow from the wellbore. An assessment of whether flow is linear or radial in the channel is crucial in determining how the channeling problem should be attacked.[13-17]

Conclusions

The following conclusions were reached after an extensive review of published field activity for polymer floods and applications of gel treatments in injection wells:

1. Gel treatments and polymer floods have been applied over a remarkably wide range of conditions.

2. Producing water/oil ratio was the primary technical criterion that was used to select candidates for gel treatments. At project startup, the median producing water/oil ratio for gel treatments was almost four times that for polymer floods (11.5 vs. 3.0).

3. Some factors that did not play a major role in candidate selection included the %OOIP produced before project startup, the oil/water viscosity ratio (i.e., the mobility ratio), and lithology.

4. No correlation exists between the %OOIP produced before project startup and the incremental oil projected by the operator. In fact, no correlation was found between projected EOR and any variable except the amount of polymer injected.

5. The median projected EOR was 2.4 bbl per lb of polymer for gel treatments and 1.1 bbl/lb for polymer floods. For both gel treatments and polymer floods, the projected volume of EOR correlates with the number of lbs of polymer (or gel) injected.

6. The validity of many of the EOR projections is questionable.

7. Published field data is insufficient to establish guidelines for where or how to best apply gel treatments.

8. To improve the success rate for future gel applications, several factors are suggested that should be considered during candidate selection. These include (1) the %OOIP produced before the project, (2) comparison with the performance of other patterns and wells in the field, (3) results from tracer studies, and (4) injectivity and productivity calculations.

3. A SURVEY OF FIELD ACTIVITY FOR POLYMER AND GEL TREATMENTS IN PRODUCTION WELLS: 1970-1991

Coping with excess water production is always a challenging task for field operators. The cost of handling and disposing produced water can significantly shorten the economic life of a well. The hydrostatic pressure created by high fluid levels is also detrimental to oil production.

The two major sources of excess water production are coning and channeling. Water coning is a common problem encountered when a reservoir is produced by bottom-water-drive. Fractures and high-permeability streaks are the common causes of premature water breakthrough (channeling) during waterfloods. Gels have been applied to many production wells to control excess water production. Some field results suggest that gels can be effective in reducing water production without adversely affecting oil production. However, in many cases, gel treatments have not been so successful. A key goal of our work is to establish where and how gel treatments are best applied.

In previous theoretical studies[14,17], we made some specific predictions as to where gel treatments are/are not effective in reducing water production. This study was undertaken to determine whether field results confirm or contradict our predictions. Our analysis included 274 field cases that were reported between 1970 and 1991. The sources for these field results are listed in the bibliography in Appendix B. More than 75% of the cases were reported by various vendors. Since they tend to focus on successful cases, the results of our analysis must be viewed as somewhat optimistic. In particular, the results shown in the figures of this chapter may not reflect most of the industry's failures.

The parameters examined in this study included formation, lithology, presence of fractures, producing mechanism, treatment type (uncrosslinked or crosslinked polymers or gels), and whether zones were isolated during the placement process. Also included in our analysis were producing water-oil-ratios (WOR) and oil productivities before and after treatments.

Survey of Field Activities

Results of the survey of field activity for polymer and gel treatments in production wells are summarized in Table 3. In this study, each parameter was subdivided into a number of elements. Table 3 lists the actual number of projects associated with each individual element and its percentage of the total projects involved.

Formation. Table 3 shows that 38.3% of the treatments surveyed were applied in the Arbuckle formation and 11.7% of the treatments were applied in the Ellenberger formation. In other words, 50% of the total projects were found in either the Arbuckle or the Ellenberger formations. About one-quarter of the projects (24.8%) were applied in 40 other different formations. For 25.2% of the projects, the formation was not reported.

Lithology. If the applications are grouped according to lithology, 54.7% of the cases were applied in dolomite reservoirs, and 6.6% of the cases were applied in limestone reservoirs. Since limestone and dolomite reservoirs can both be classified as carbonate reservoirs, 61.3% of the projects were found in carbonate reservoirs. Our survey also revealed that 21.5% of the cases were applied in sandstone reservoirs. Thus, production-well treatments were applied in carbonate reservoirs 2.85 times more frequently than in sandstone reservoirs.

Table 3. Summary of Field Activity for Polymer and Gel Treatments in Production Wells: 1970-1991 (274 cases in database)

	No. of Cases	%
Formation		
Arbuckle	105	38.3
Ellenberger	32	11.7
Other known	68	24.8
Unknown	69	25.2
Lithology		
Dolomite	150	54.7
Sandstone	59	21.5
Limestone	18	6.6
Unknown	47	17.2
Fracture Status		
Fractured	149	54.4
Unfractured	9	3.3
Unknown	116	42.3
Producing Mechanism		
Bottom-water-drive	160	58.4
Other known	6	2.2
Unknown	108	39.4
Treatment Type		
Gel	168	61.3
Polymer	106	38.7
Gel Type		
Cr^{3+}-HPAM	129	76.8
Glyoxal-CPAM	13	7.7
Al^{3+}-HPAM	6	3.6
Inorganic	5	3.0
Unknown	15	8.9
Polymer Type		
HPAM	84	79.2
Unknown	22	20.8
Zones isolated during placement?		
No	202	73.7
Yes	14	5.1
Unknown	58	21.2
Zone Isolation: No		
Fractured	131	64.9
Unfractured	8	4.0
Unknown	63	31.2
Zone Isolation: Yes		
Fractured	11	78.6
Unknown	3	21.4

Presence of Fractures. Our theoretical studies suggested that gel treatments are more likely to be effective in fractured reservoirs than in unfractured reservoirs.[14] Our survey found that 54.4% of the treated wells were stated to be fractured; only 3.3% of the cases were applied in wells that were stated to be unfractured. Thus, the majority of the treatments were applied in fractured reservoirs.

Producing Mechanism. Water coning is a common problem encountered when a reservoir is produced via bottom-water-drive. An important prediction from our theoretical studies is that gel treatments are most effective in suppressing water coning when fractures provide the conduit for excess water.[14] Table 3 shows that the producing mechanism was bottom-water-drive for 58.4% of the cases surveyed. Our survey also revealed that, among the cases with bottom-water-drive mechanism, 90% were found in reservoirs stated to be fractured.

Treatment Type. Our survey indicated that 38.7% of the projects used uncrosslinked polymers. At the first glance, this number seems surprisingly high. However, these treatments with uncrosslinked polymers were all applied before 1980. Actually, most of these treatments were applied in the early 70's when gel technology was in its infancy. For the cases where uncrosslinked polymers were injected to shut off excess water, 79.2% of the projects stated that polyacrylamides were used. For the cases where gels were injected, 76.8% of the treatments used partially hydrolyzed polyacrylamide polymers (HPAM) crosslinked with chromium ions (Cr^{3+}-HPAM). In these cases, the gelation reaction was often delayed by using a redox system where Cr^{6+} was mixed with a reducing agent before injection. The gelation occurred in-situ when Cr^{6+} was reduced to Cr^{3+}. Our survey also showed that 7.7% of the treatments used cationic polyacrylamide polymers (CPAM) crosslinked with the organic crosslinker, glyoxal. Al^{3+}-HPAM was used in 6% of the projects, and 3% of the cases used inorganic gels.

Zone Isolation. For 73.7% of the projects, we know that zones were not isolated during gelant placement (Table 3). For the cases without zone isolation, 64.9% were applied in reservoirs that are known to be fractured. This finding is not surprising since zone isolation will usually not be effective in vertically fractured wells. Table 3 shows that only 5.1% of the cases surveyed exercised zone isolation during the placement process. However, it is somewhat surprising that when zones were isolated, 78.6% of the cases occurred in fractured reservoirs. For 21.2% of the projects, we do not know if zones were isolated.

Cumulative Frequency Plots

We used cumulative frequency plots to compare producing water/oil ratios (WOR) and oil productivities before and after treatments. The y-axis in each figure is labeled "cumulative frequency," which is the percentage of the data points associated with a property value less than or equal to that indicated on the x-axis. For example, Fig. 19 shows that 60% of the cases had WOR values that were less than or equal to 100 before treatment, while the other 40% had WOR values that were greater than 100 before treatment.

Producing Water/Oil Ratios. The distribution of WOR values at various times before and after treatment are shown in Fig. 19. (This figure includes results from both polymer and gel treatments.) Fig. 19 shows that, at most cumulative frequency values, the producing water/oil ratios were reduced significantly immediately after treatment. However, WOR values gradually increased as time elapsed. Fig. 19 also shows that the median WOR value was reduced from 82 to 7 immediately after treatment. However, after one year, the median WOR was 20. If we consider gel cases only, Fig. 20 shows that

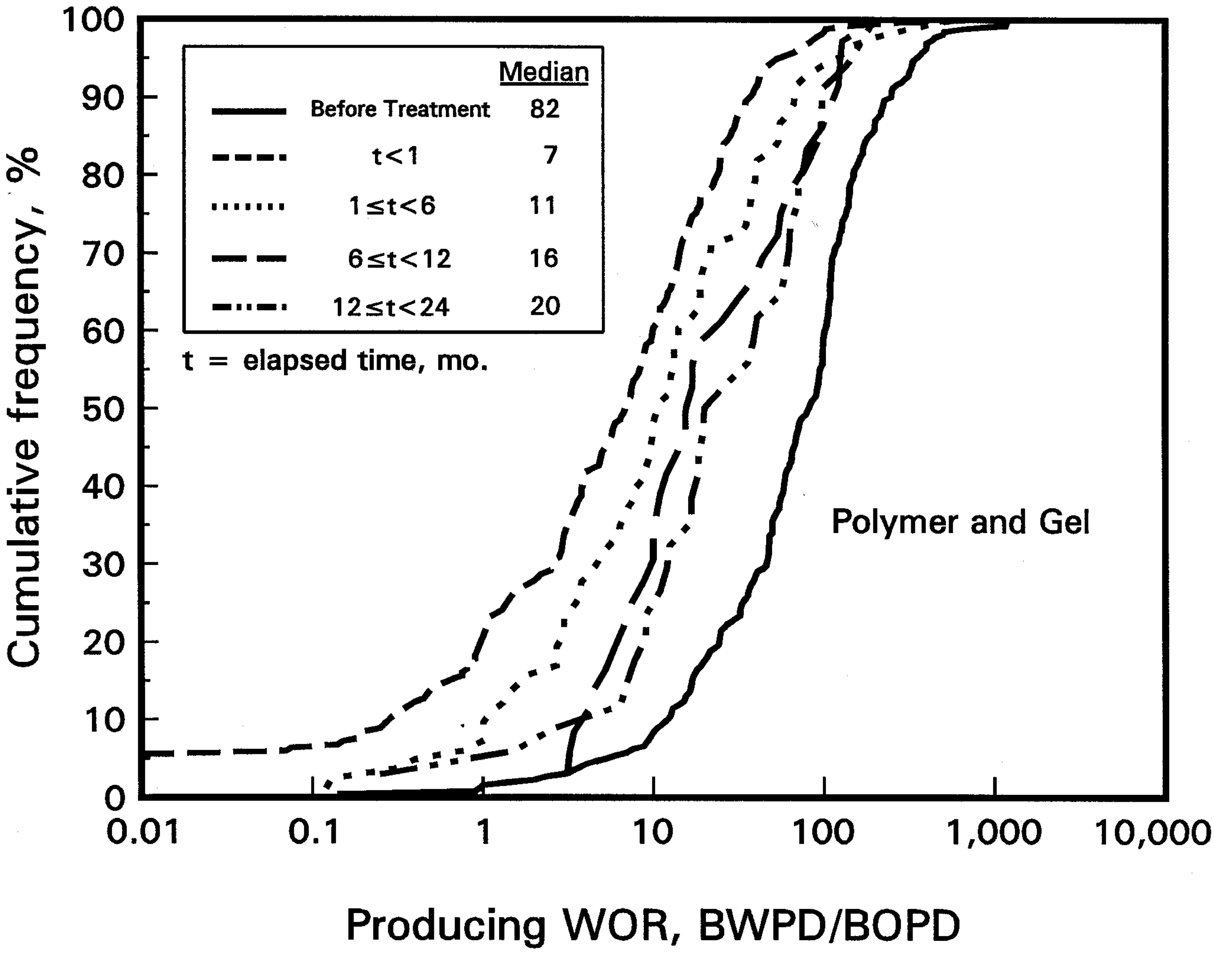


Fig. 19. Cumulative frequency plot of producing WOR before and after treatments (polymer and gel cases).

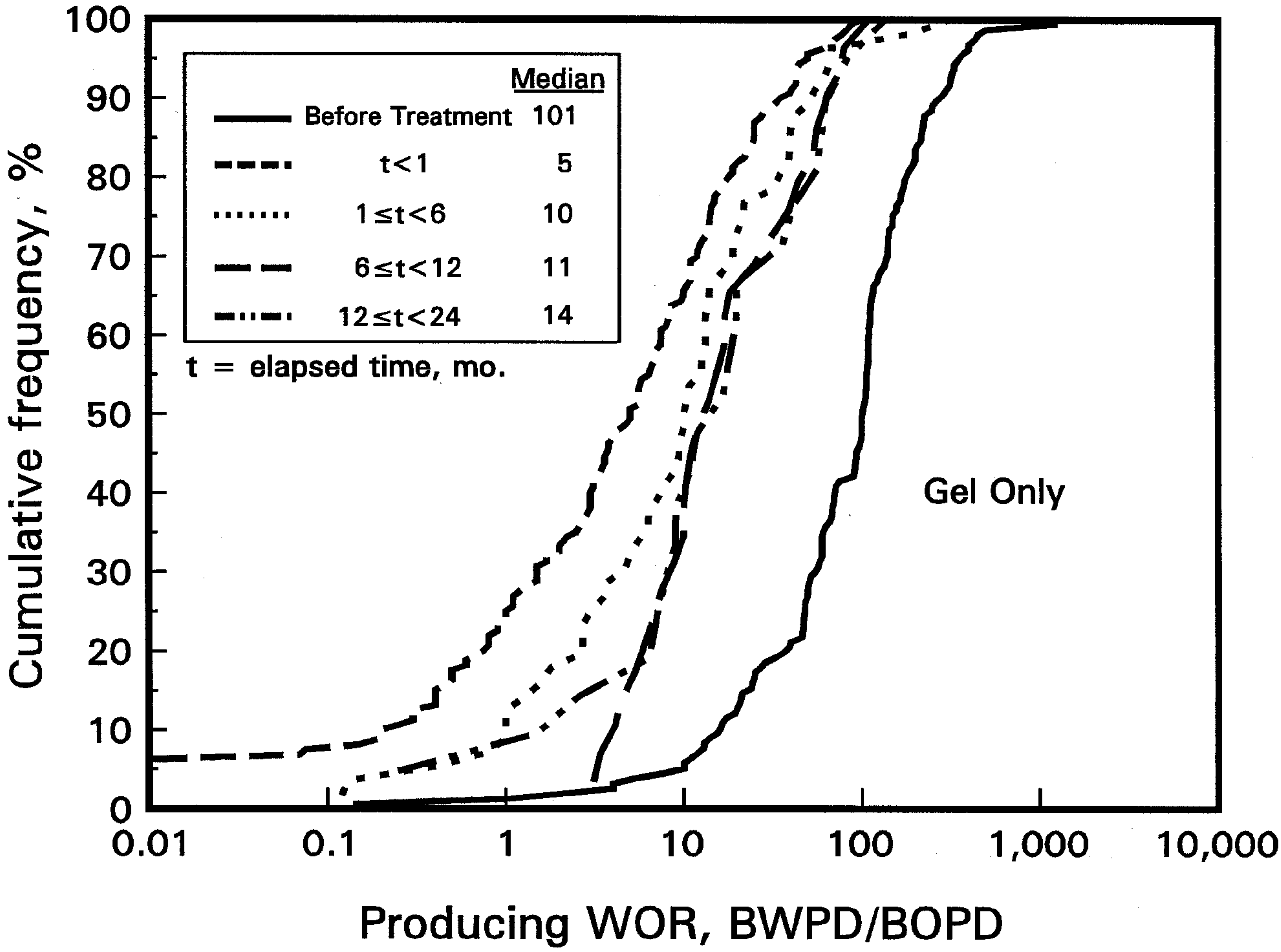


Fig. 20. Cumulative frequency plot of producing WOR before and after treatments (gel cases).

the median WOR value experienced a reduction from 101 to 5 immediately after treatment. After one year, the median WOR was 14. A comparison of Figs. 19 and 20 indicates that gels are more effective not only in reducing producing WOR but also in maintaining the level of reduction in producing WOR after treatments.

Oil Productivities. Fig. 21 is a cumulative frequency plot of oil productivity ratios at various times after treatment. The oil productivity ratio is defined as the oil productivity after treatment divided by the oil productivity before treatment. Thus, an oil productivity ratio below one indicates that the oil productivity was damaged by the treatment. Results from both the polymer cases and the gel cases are shown in Fig. 21. The median value of oil productivity was increased by a factor of three immediately after treatment. However, this increase was lost after one year (as indicated by the median value of oil productivity ratio being reduced to one).

The objective of water-shutoff treatments is to reduce water production without sacrificing oil production. Although reduction of the WOR is desirable, the effectiveness of a treatment should be judged also by whether the oil productivity was damaged during the process. Fig. 21 shows that, immediately after treatments, the oil productivity of about 15% of the cases was damaged, and this number increased to about 50% one year later. Similar results were observed for the gel cases by themselves (Fig. 22).

Discussion

Our theoretical study[14] predicted that gel treatments are most effective in suppressing water coning when fractures provide the conduit for excess water. Findings from our survey of field activities support this prediction.

Our theoretical study[14] showed that, without zone isolation, gelants can penetrate to a significant degree into all open zones—not just those water-source zones. To minimize damage to oil-productive zones in production wells when zones are not isolated during gelant placement, the gel must be able to reduce water permeability much more than oil permeability and the productive zones must have high oil saturations. In a separate study,[17] we found that during unconfined gelant placement in field applications, capillary pressure and relative permeability effects will not prevent aqueous gelants from penetrating significant distances into zones with high oil saturations. Our analysis of field projects did not confirm or contradict the results of these theoretical findings.

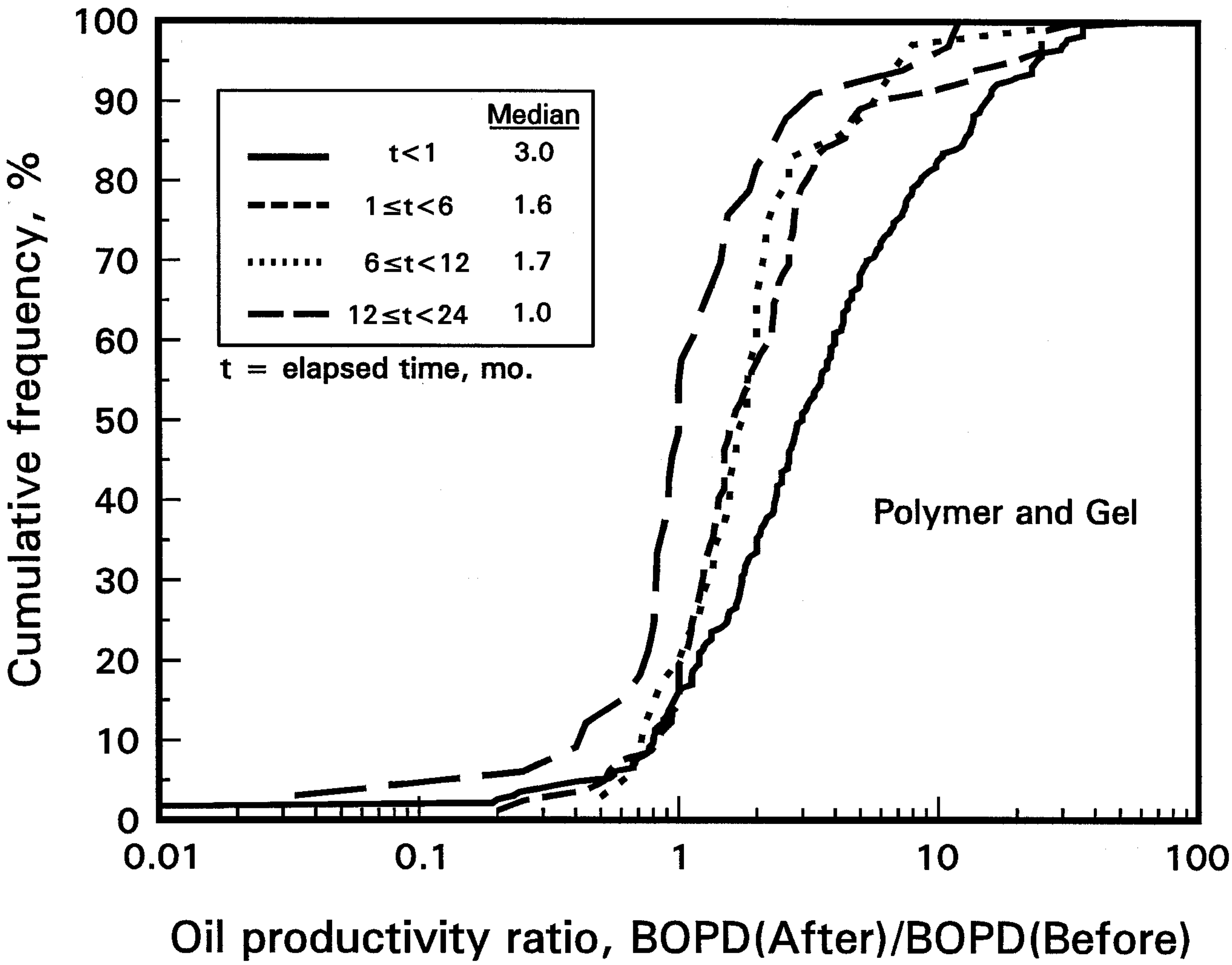


Fig. 21. Cumulative frequency plot of oil productivity ratios before and after treatments (polymer and gel cases).

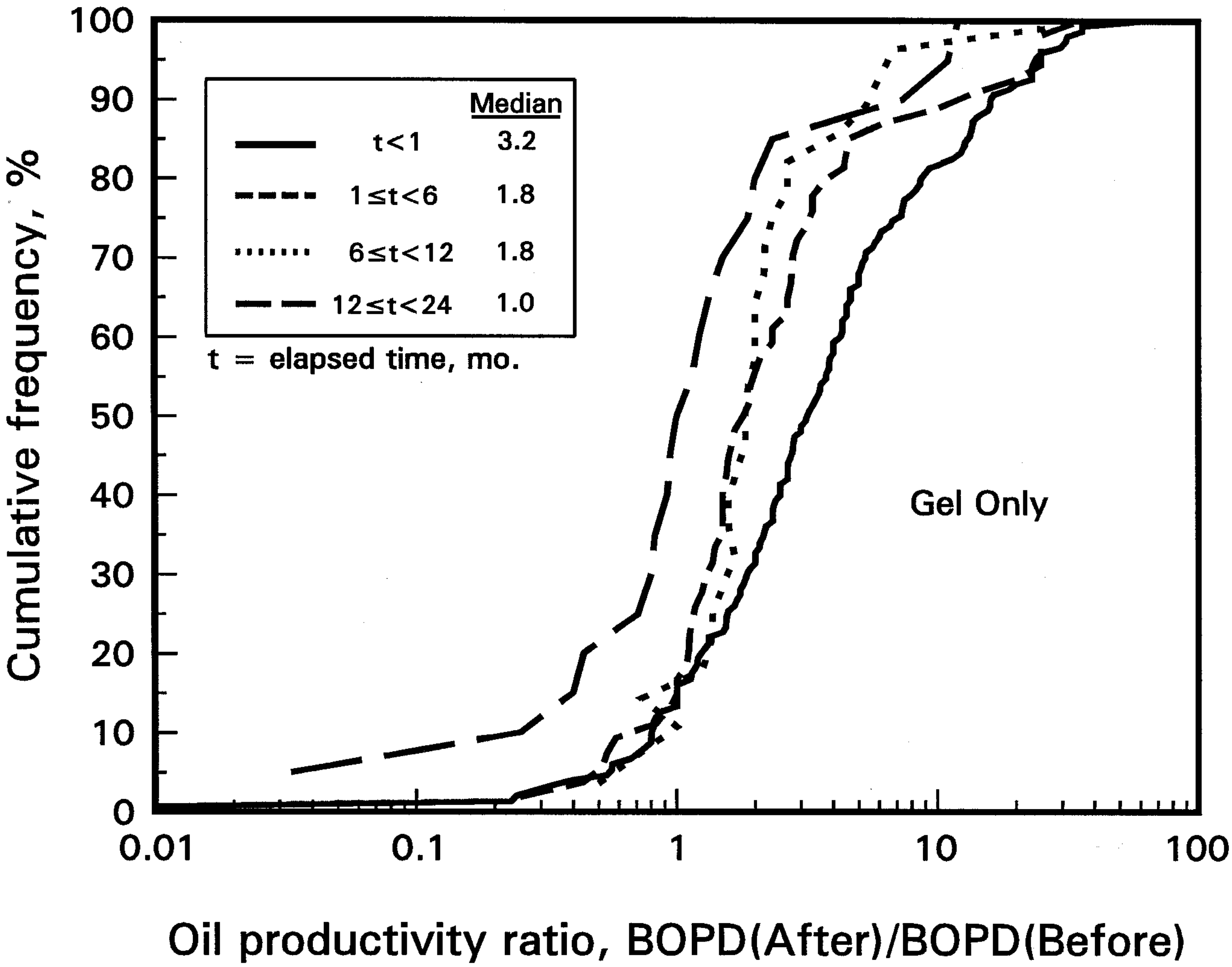


Fig. 22. Cumulative frequency plot of oil productivity ratios before and after treatments (gel cases).

Conclusions

The following is the summary of a survey of 274 field cases for polymer and gel treatments in production wells:

1. Fifty percent of the total projects and 67% of the projects with known formation were found in Arbuckle and Ellenberger formations.

2. Sixty-one percent of the total projects and 74% of the projects with known lithology were applied in carbonate reservoirs.

3. Fifty-four percent of the total treatments and 94% of the treatments with known fracture status were applied in wells that were stated to be fractured.

4. The producing mechanism was bottom-water-drive for 58% of the total cases surveyed and 96% of the cases with known producing mechanism. Among the cases with bottom-water-drive mechanism, 90% were found in reservoirs stated to be fractured.

5. For at least 74% of the projects, zones were not isolated during gelant placement. This percentage might actually be higher, since we do not know if zones were isolated in 21% of the cases.

6. For the projects in this survey, the median WOR value was 82 before the treatment, 7 immediately after the treatment, and 20 one year after the treatment.

7. For the gel cases alone, the median WOR value experienced a reduction from 101 to 5 immediately after treatment. After one year, the median WOR was about 15% of the original value.

8. Results from both polymer and gel cases indicate that the median value of oil productivity was increased by a factor of 3 immediately after treatment. However, this increase was lost after one year.

4. A SURVEY OF VENDORS CONCERNING THE SELECTION OF CANDIDATES FOR GEL TREATMENTS IN INJECTION AND PRODUCTION WELLS

This chapter examines the views of gel vendors about the selection and implementation of gel treatments in injection and production wells. The information presented here was obtained through interviews with seven companies, including Allied Colloids (Steve Harris, Suffolk, VA), Enhanced Petroleum Technology (Rod Eson, Bakersfield, CA), Halliburton (Jeff Dahl, Duncan, OK), Oil/Water Ratio Control (Bharat Mody, Midland, TX), Pfizer Oil Field Products (Marc Gruenenfelder, Groton, CT), Profile Control Services (Ken Goltz, John Lambillotte, Mahmoud Osman, Midland, TX), and Tiorco (Jim Mack, Englewood, CO). The locations where these companies operate most frequently are listed in Table 4.

Table 4. Most Frequent Operating Locations

Vendor	Region
Allied Colloids	Wyoming, Nebraska
EPT	Overseas, California, Midcontinent
Halliburton	Midcontinent
Oil/Water Ratio Control	West Texas, Canada
Pfizer	Midcontinent, Gulf Coast
Profile Control Services	Texas, New Mexico
Tiorco	Wyoming, West Texas

Gelant Systems Used

The gelant systems used most often are listed in Table 5. In this table, HPAM is an abbreviation for partially hydrolyzed (or anionic) polyacrylamide, and CPAM is an abbreviation for cationic polyacrylamide. During the past 15 years, the chromium-redox-HPAM process[9] has been used most frequently in both injection wells and production wells. Other gelants that were often used in injection wells included aluminum-citrate-HPAM/CPAM[9,31] (by EPT and Tiorco), silicate,[32] acrylamide monomer[33] (by Halliburton), and Cr^{3+}-xanthan[34] (by Pfizer). In recent years, glyoxal-CPAM gels[35] have been applied frequently in production wells (by Pfizer), and Cr^{3+}(acetate)-HPAM gels[36] have recently become popular for injector applications. Many other gelants have been used to a lesser extent.

Breakdown of Applications

From 1990 through 1992, about 80% of the gel treatments were applied in production wells. Table 6 lists the percentages of injector and producer applications for each of the seven gel vendors. Six to

Table 5. Gelant Systems Used Most Often

Vendor	Gelant
Allied Colloids	Cr^{3+}(acetate)-HPAM: 75%, Cr-redox-HPAM: 25%
EPT	Cr-redox-HPAM: 40% of water injectors, 90% of non-steam oil producers, 67% of gas producers. Al-citrate-HPAM-CPAM: 45% of injectors. Resorcinol-HCHO-PAM/AMPS: 100% of steam wells. Sodium aluminate: 33% of gas wells.
Halliburton	Cr-redox-HPAM: 40%, Silicate: 30%, Acrylamide monomer, cement
Oil/Water Ratio Control	Cr-redox-HPAM
Pfizer	glyoxal-CPAM: 80-90% of producers, Cr^{3+}-xanthan: most injectors (matrix), Cr^{3+}(acetate)-HPAM: fractured injectors, many other gelants used.
Profile Control Services	Cr-redox-HPAM usually
Tiorco	Al-citrate-HPAM-CPAM, Cr^{3+}(acetate)-HPAM

Table 6. Percentages of Producer/Injector Applications: 1990-1992

Vendor	Producers	Injectors
Allied Colloids	80%	20%
EPT	80%	20%
Halliburton	80%	20%
Oil/Water Ratio Control	70%	30%
Pfizer	90%	10%
Profile Control Services	85%	15%
Tiorco	50%	50%

ten years ago, applications in injection wells were much more popular than those in production wells. The shift in preference can be attributed to two factors. First, after 1985, low oil prices eliminated tax incentives that favored applications in injectors. Second, the effectiveness of gel treatments in production wells usually can be judged more quickly and definitively than that in injection wells. In the current economic environment, aspirations for a short payout period favor producer applications.

For gel treatments in production wells, Table 7 provides a breakdown of the applications according to the probable source of water. The table shows that the mix of applications in bottom-water-drive reservoirs vs. waterfloods varies considerably, depending on the vendor. We were somewhat surprised that more applications were not reported in the category of "unknown water source."

Although not reflected in our tables, many of the vendors have applied gels to repair casing leaks or as a substitute for cement in cement squeezes.

Table 7. Distribution of Producing-Well Applications

Vendor	Bottom-water drive	Waterflood	Unknown water source
Allied Colloids	25%	75%	
EPT	75%	20%	5%
Halliburton	65%	20%	15%
Oil/Water Ratio Control	10-20%	80-90%	
Pfizer	50%	30%	20%
Profile Control Services	35-50%	50-65%	
Tiorco	20%	80%	

Table 8 lists the success rates claimed by the vendors for producing-well applications. In this case, "success" means the project was said to be economically profitable. In concept, this should mean that the project was also successful from a technical viewpoint—that is, that the producing water/oil ratio was reduced substantially without significantly reducing oil productivity. The success rates given by the vendors were usually quite high. Interestingly, operators are more inclined to put the success rate for gel treatments below 50%.[37] Thus, a discrepancy needs to be resolved between many of the success rates quoted by vendors and those of the operators. Examination of Table 8 generally does not allow one to conclude that gel treatments work best in one type of application vs. another (e.g., bottom-water-drive vs. waterflood).

For applications in injection wells, differences of opinion about the definition of "success" did not allow meaningful comparisons to be made.

Table 8. Claimed Success Rates of Producing-Well Applications

Vendor	Bottom-water drive	Waterflood	Unknown water source
Allied Colloids	75%	50%	
EPT	90%	75-90%	50%
Halliburton	80%	90%	80-90%
Oil/Water Ratio Control	90%	90%	
Pfizer	60%C, 40%S	50%	60%
Profile Control Services	90%	90%	
Tiorco	90%	60-70%	

C = carbonate. S = sandstone.

Table 9 shows the lithology (sandstone or carbonate) of gel applications in production wells and injection wells from 1990 through 1992. In production wells, most of the vendors applied the treatments significantly more often in carbonates than in sandstones. In injection wells, the frequency of application in sandstones vs. carbonates varied greatly with the vendor. Overall, injection well treatments are equally likely to be applied in sandstone and carbonate reservoirs.

Table 9. Lithology of Applications

Vendor	Producers		Injectors	
	Sandstone	Carbonate	Sandstone	Carbonate
Allied Colloids	50%	50%	80%	20%
EPT	50%	50%	70%	30%
Halliburton	40%	60%	50%	50%
Oil/Water Ratio Control	5%	95%	5%	95%
Pfizer	30%	70%	70%	30%
Profile Control Services	10%	90%	10%	90%
Tiorco	25%	75%	25%	75%

The vendors had mixed opinions about whether lithology had an important impact on treatment performance (Table 10). Three companies felt that better success was achieved in carbonates than in sandstones. Pfizer also thought that their gel treatments in production wells generally worked better in carbonates than in sandstones. In particular, Pfizer reported that in bottom-water-drive reservoirs, their success rate was somewhat greater in carbonate reservoirs than in sandstone reservoirs (see Table 8). However, in injection wells, Pfizer has had better success with Cr^{3+}-xanthan gels in sandstones than in carbonates. They felt that the Cr^{3+}(acetate)-HPAM technology should be less sensitive to lithology in injectors. Three companies felt either that lithology was not particularly important or that other factors about individual formations (such as fracturing or heterogeneity) were much more important.

Table 10. Does Lithology Have an Important Impact on Treatment Performance?

Vendor	Response	Which is best?
Allied Colloids	yes	carbonates
EPT	maybe	more dependent on the formation
Halliburton	no	--
Oil/Water Ratio Control	yes	carbonates
Pfizer	yes	sandstones for injectors, carbonates for producers
Profile Control Services	maybe	more dependent on the formation
Tiorco	yes	carbonates

With one exception, the vendors thought that most of their injection and production wells were fractured or experienced a formation parting problem (Table 11). The exception, Pfizer, felt that only about 30% of their injectors were fractured.

Table 11. Percentage of Wells Thought to be Fractured

Vendor	Producers	Injectors
Allied Colloids	75%	90-100%
EPT	80%	60%
Halliburton	70%	70%
Oil/Water Ratio Control	90%	90%
Pfizer	60-70%	30%
Profile Control Services	100%	100%
Tiorco	80%	80%

The vendors were split in their opinions about whether oil viscosity was important to treatment performance (Table 12). For those who felt that it was important, moderately viscous oils were preferred.

Table 12. Does Oil Viscosity Have an Important Impact on Treatment Performance?

Vendor	Response	Which is best?
Allied Colloids	maybe	moderately high
EPT	no	--
Halliburton	no	--
Oil/Water Ratio Control	yes	moderately high
Pfizer	yes	moderately high
Profile Control Services	no	--
Tiorco	yes	moderately high

Criteria for Candidate Selection

Analyses of field projects over the past 20 years reveal that a high producing water/oil ratio (WOR) was the primary criterion (and often the only criterion) used during the selection of candidate wells for gel treatments (see Chapters 2 and 3). These surveys suggest that if a high WOR is the only criterion applied during candidate selection, then the success rate is likely to remain sporadic. Thus, additional factors must be considered to improve the selection process.

Injection Wells. Table 13 lists the criteria that individual vendors felt were most important in the selection of injector candidates. For both injectors and producers, most vendors indicated that the operator usually selected the candidate wells. Only one vendor said that he usually played the primary role in determining which wells would be treated. Another vendor stated that he had actually declined to treat certain wells for technical reasons. However, in most cases, the vendors will treat virtually any well that the operator chooses, so the operator has responsibility for the proper selection of candidates.

Five of the seven vendors felt that clear evidence of severe channeling was an important criterion for selection of injector candidates. Early tracer breakthrough in producers was often stated as a good way to diagnose severe channeling. In most cases, "early breakthrough" meant that a water-soluble tracer travelled from an injector to a producer in less than one week. Ironically, only two vendors routinely recommend the use of well-to-well tracers (Table 14). Added cost was the primary reason given for not performing tracer studies. This reason is somewhat paradoxical. On the one hand, most vendors feel obligated to keep the cost of their treatments below a certain level (e.g., $20,000 per well). On the other hand, a tracer study that increases the cost of a treatment by 20% to 100% might double the success rate and have an even more dramatic effect on incremental oil recovery.

Table 13. Selection of Injector Candidates

Vendor	Criteria
Allied Colloids	1. High mobile oil saturation remaining. 2. Early tracer breakthrough in producers. 3. High injectivity compared to other wells.
EPT	1. High mobile oil saturation remaining. 2. Well in good mechanical condition. 3. Clear evidence of a channeling problem.
Halliburton	1. Early tracer breakthrough in producers. 2. Poor injection profile. 3. Pressure communication with producers.
Oil/Water Ratio Control	1. Evidence of severe channeling. 2. High injectivity. 3. Adverse fluid-in to fluid-out ratio.
Pfizer	1. Operator usually chooses the well. 2. Temperature (to select gelant). 3. Fracture status. 4. Injection profiles (for matrix treatments).
Profile Control Services	1. Poor injection profile. 2. Low injection pressure (high injectivity).
Tiorco	1. Operator usually chooses the well. 2. High mobile oil saturation remaining. 3. Well in good mechanical condition. 4. Early tracer breakthrough in producers.

Table 14. How Often are Tracer Studies Performed to Diagnose Channeling Before Injector Treatments?

Vendor	Response
Allied Colloids	90-100%
EPT	40%
Halliburton	70-80%
Oil/Water Ratio Control	< 5%
Pfizer	10-20%
Profile Control Services	1%
Tiorco	25%

Increased use of small volumes of relatively inexpensive tracers may be one of the best ways to improve the success rate for water-shutoff treatments in injection wells. Tracer studies can be useful (1) in diagnosing the severity of the channeling problem, (2) in determining whether a gel treatment should be attempted, (3) in designing the volume of gelant to be injected, (4) in assessing whether zones should be isolated during gelant placement, and (5) in estimating the ultimate effectiveness of the treatment. An important challenge is to convince operators that tracer studies are cost-effective.

Three vendors indicated that pre-treatment injectivities (injection rate divided by injection pressure drop) should be high. This requirement recognizes that gel treatments are expected to reduce injectivity. Thus, if the operator plans to maintain the same injection rate after the gel treatment, the injection pressure must be allowed to increase and yet remain below the formation parting pressure.

Simple injectivity or productivity calculations also can aid in establishing the nature of a channeling problem. Estimates of net pay and average permeability are usually available from logs, core data, or pressure transient analyses. Static fluid levels and flowing well pressures (either surface or downhole) are also commonly available. This information, along with Eq. 1, can be used to predict injectivity (or productivity), I.

$$I = \frac{q}{\Delta p} = \frac{kh}{141.2 \mu \ln(r_e/r_w)} \tag{1}$$

where
h = formation thickness, ft
k = permeability, md
Δp = difference between flowing and static bottomhole pressures, psi
q = injection rate, bbl/D
r_e = external radius, ft
r_w = wellbore radius, ft
μ = viscosity, cp

If the injectivity (or productivity) calculated by the right side of Eq. 1 is substantially less than the actual injectivity, $q/\Delta p$, then a fracture or formation part may be present.

Several vendors state that a high mobile oil saturation should be present before treating a well. On the surface, this seems very logical. If the reservoir is completely watered out, then no incremental oil can be expected. However, vendors are reluctant to quantify how low the oil saturation must be in order for a gel treatment to be precluded. This quantification is needed to make oil saturation a useful screening criterion. Perhaps, the best way to apply this criterion is by comparison. In particular, the pre-treatment oil recovery efficiency for the pattern of interest should be dramatically lower than predicted from waterflooding calculations, or it should be much lower than that in other patterns in the field. These comparisons would then provide another means of identifying a severe channeling problem.

Three vendors said that injection profiles were often used to select injector candidates. This can be a good method, but it has often been used badly in the past. If a vertical fracture extends through all open zones, if flow can occur behind pipe, or if crossflow can occur between strata, then injection profiles are of little value. For injection profiles to be useful, the zones of interest must be separated by laterally-extensive impermeable barriers. Also, when interpreting changes in injection profiles, one must recognize the limitations of the tools and techniques, especially the resolution of flow rates and vertical positions.

An interesting irony exists concerning the use of injection profiles. Their use usually implies a belief that vertical fractures are not present and that fluid crossflow and flow behind pipe do not occur. If this belief is valid, then precautions (e.g., zone isolation) must be taken to prevent gelant from entering and damaging oil-productive zones.[13-16] These precautions are rarely used by the vendors that commonly rely on injection profiles. The reason given is that zone isolation is impractical or too expensive. The flaw in this argument is that the gel treatment will probably do more harm than good if precautions are not taken to protect oil-productive zones. Thus, there is a need to convince both vendors and operators that zone isolation is necessary during applications in unfractured injection wells in reservoirs with non-communicating zones.

Pressure communication between wells was listed by one vendor as an important criterion. This is another factor that can easily be misused. By itself, pressure communication between wells does not mean that a channel exists. In fact, pressure communication must exist between injectors and producers in order for a waterflood to work. To be valuable, the time frame of the pressure communication should be very short. Ideally, the information should be interpreted using accepted pressure-transient methods.

In summary, to select candidates for gel treatments in injection wells, the most important criteria include (1) clear evidence of severe channeling (e.g., tracer breakthrough in less than one week), (2) high injectivity, and (3) a recovery efficiency that is dramatically less than anticipated (based on comparison with flood performance in other patterns or with simulated flood performance). Additional criteria, such as mechanical condition of the well, poor injection profiles, etc., can also be of value.

Production Wells. Selection criteria for production wells are listed in Table 15. High water cut is a criterion for virtually all vendors. However, since all production wells in waterfloods and in bottom-water-drive reservoirs will eventually reach a high water cut, this cannot be the only criterion for candidate selection.

Most vendors also look for a high dynamic fluid level (high productivity) in the producers. This requirement makes sense because a gel treatment is expected to reduce the total fluid productivity and the dynamic fluid level in the producer. A reduced fluid level in the well, in turn, provides a greater pressure drop to stimulate oil production.

A high fluid level also increases the probability that high-conductivity fractures are the source of the excess water production. Theoretical analyses reveal that gel treatments are most likely to be effective in production wells if fractures are the source of the water.[14,38] These observations apply to wells both in waterfloods and in bottom-water-drive reservoirs.

Many vendors prefer wells that had high oil productivity and low water cut early in their life, but that experienced a dramatic increase in the WOR much earlier than anticipated. Possibly, the increase in WOR was due to channeling through fractures or to flow behind pipe after well stimulation. Under the right circumstances, these conditions should be amenable to treatment by gels.

Taken as a whole, the criteria for candidate selection listed in Table 15 appear reasonable. It is important to recognize that candidate selection must involve more than simply identifying wells with a high water cut. A summary of the most important criteria might include (1) high fluid productivity (Eq. 1 can be used as a gauge to quantify what "high" means), and (2) high oil productivity and low water cut early in the well's life, followed by a dramatic increase in the WOR much earlier than anticipated.

Table 15. Selection of Producer Candidates

Vendor	Criteria
Allied Colloids	1. Dramatic change in WOR. 2. High fluid level.
EPT	1. Excess water production relative to other wells. 2. High fluid level. 3. All zones containing mobile oil are open. 4. Well in good mechanical condition.
Halliburton	1. Operator usually chooses the well. 2. High water cut.
Oil/Water Ratio Control	1. Good initial productivity with low water cut. 2. High dynamic fluid level. 3. High structural well. 4. High water cut. 5. Dramatic change in WOR due to stimulation.
Pfizer	1. Temperature (to select gelant). 2. Water cut > 90%. 3. Best wells watered out early in waterflood. 4. Best wells have high oil viscosity (up to 100 cp).
Profile Control Services	1. Good past production performance. 2. High fluid level. 3. High water cut.
Tiorco	1. Well approaching the economic limit.

Treatment Procedures

After selecting the wells that are good candidates for a gel treatment, the treatment procedures must be determined. Logically, one might expect the treatment procedures to depend on the specific nature of the channeling problem. Thus, it would seem important to identify the source of the excess water production before selecting the treatment. As discussed in the previous sections, tracer studies, injectivity and productivity calculations, and recovery efficiency calculations can aid greatly in this identification. In addition to these methods, temperature surveys and noise logs may be useful in identifying flow behind pipe. Vendors frequently said that although they knew that these procedures should be performed for proper problem diagnosis, excessive cost-sensitivity by the operators often precluded their use.

In this section, we examine the procedures that gel vendors normally use during their gel treatments. Table 16 compares the time periods that the various vendors typically spend on a well during a treatment. In most cases, this time is 1 to 2 days for production wells. However, the time ranges from 1 to 30 days for injection wells. The large range of time periods for injection wells appears to be tied to the particular gelant technologies that are used. Generally, the Cr-redox-HPAM treatments require 1 to 2 days in both injectors and producers. However, the aluminum-citrate and Cr^{3+}(acetate)-HPAM technologies can require significantly more time (partly because larger volumes of gelant are often injected).

Table 16. How Long are You Usually on a Well During a Treatment (Days)?

Vendor	Producers	Injectors
Allied Colloids	3-5	7-10
EPT	1	2 (Cr-redox), 20 (Al-citrate)
Halliburton	1	1
Oil/Water Ratio Control	2	2
Pfizer	1.5	4-5
Profile Control Services	1	1
Tiorco	2-15	5-30

Stimulation Before Gelant Injection. Both in injectors and producers, several vendors routinely acidize wells before gelant injection (Table 17). One argument given for acidizing is that by cleaning up formation damage, injectivity will be increased and oil production will be further stimulated over the contribution from the gel treatment. Other vendors do not routinely acidize before gelant injection—reasoning that formation damage may restrict gelant from entering less-permeable, oil-productive zones. One vendor also commonly stimulates injectors with organic solvents before gelant injection. The vendor uses these solvents because paraffin deposition is a common problem in the region where he operates.

Table 17. Do You Normally Acidize Your Wells Before Gelant Injection?

Vendor	Producers	Injectors
Allied Colloids	no	no
EPT	no	no
Halliburton	yes	yes
Oil/Water Ratio Control	yes	yes
Pfizer	yes	no
Profile Control Services	no	no
Tiorco	no	no

Gelant Volumes. Typical injection volumes are indicated in Table 18. In recent years, a few treatments have involved large gelant volumes (> 10,000 bbl/well). However, the vast majority of treatments have been very small—certainly less than 5,000 bbl/well, and many have been less than 1,000 bbl/well. The sizing of gelant treatments varies somewhat from vendor to vendor. For some vendors, the gelant volume is initially planned as ½ to 1 day's injection or production volume. Other vendors plan for a certain number of barrels of gelant per foot of net pay. Still others plan to inject gelant to reach a certain radius from the wellbore. The latter plan seems ironic since most treated wells are thought to be fractured, where the flow geometry is described better as linear rather than radial.

Most vendors plan an upper limit for their injection volumes. For example, a vendor that normally injects 100 bbl/ft in a 10-ft formation might inject only 10 bbl/ft in a 100-ft formation. The reason for doing this is strictly economic. Vendors fear that above a certain base cost per well, the operator will not accept their plan. Obviously, this policy means that the distance of gelant penetration into thin formations will tend to be much greater than in thick formations. Thus, improvements are needed in the methods used for sizing gel treatments.

Table 18. Injected Gelant Volumes

Vendor	Producers	Injectors
Allied Colloids	200-3,000 bbl, 1 day's production	50-150 bbl/ft
EPT	75-3,000 bbl	500-4,000 bbl
Halliburton	100-1,000 bbl, 40 ft radius	100-500 bbl, 40 ft radius
Oil/Water Ratio Control	25-40% of 1 day's production, 25-30 ft radius, 100 bbl min	25-40% of 1 day's injection, 25-30 ft radius, 100 bbl min
Pfizer	500-1,200 bbl, 25-50 ft radius	1,500-5,000 bbl, 75 ft radius
Profile Control Services	½-1 day's production, 1,000 bbl max	½-1 day's injection, 1,000 bbl max
Tiorco	50-200 bbl/ft	100-500 bbl/ft

Injectivity Changes and Hall Plots. During gelant injection, all vendors monitor the injection pressure and the injectivity. Many express this information in "Hall plots" or "modified Hall plots." Most vendors prefer a gradual decrease in injectivity during gelant injection. A sharp decrease in injectivity is interpreted as near-wellbore plugging and is usually a criterion for stopping gelant injection. An injectivity increase during gelant injection has been interpreted by some vendors as indicating that the gelant has opened new zones. However, a critical analysis reveals that Hall plots and injectivity changes measured at the wellhead do not, by themselves, indicate that the gelant is entering one zone in preference to another (see Chapter 6). Table 19 reveals that most vendors currently agree with this conclusion.

Table 19. Do Hall Plots Indicate Selectivity During Gel Placement?

Vendor	Response
Allied Colloids	no
EPT	no
Halliburton	maybe
Oil/Water Ratio Control	no
Pfizer	no
Profile Control Services	no
Tiorco	maybe

Postflush. After gelant injection but before shutting in the well, all vendors inject at least one tubing volume of water or oil to clear the gelant from the wellbore (Table 20). In injection wells, the postflush fluid is usually water (although uncrosslinked polymer has been used on occasion). In production wells, the postflush is usually oil. In some cases, up to 75 barrels of oil are injected beyond the volume needed to clear the tubing.

Table 20. How Much Postflush is Injected After the Gelant?

Vendor	Producers	Injectors
Allied Colloids	> 2 tube vol. oil	1-2 tube vol. water
EPT	1 tube vol.+ 10-40 bbl oil	1 tube vol. water
Halliburton	1 tube vol. + 5-10 bbl oil	1 tube vol. water
Oil/Water Ratio Control	1 tube vol. + 50 bbl oil	1 tube vol. water
Pfizer	50-75 bbl oil + 1 tube vol. water	1 tube vol. water
Profile Control Services	1 tube vol.+ 50 bbl oil	1 tube vol. water
Tiorco	1 tube vol. oil	1 tube vol. water

Conclusions

1. In most cases, the vendors will treat virtually any well that the operator chooses, so <u>the operator has responsibility for the proper selection of candidates</u>.

2. For selection of injector candidates, most vendors felt that clear evidence of severe channeling was an important criterion. Early tracer breakthrough in producers (e.g., tracer breakthrough in less than one week) was often stated as a good way to diagnose severe channeling. Since cost considerations make many vendors reluctant to insist on the use of tracers, an important challenge is to convince operators that tracer studies are cost-effective.

3. Several vendors stated that a high mobile oil saturation should be present before treating a well. However, a need exists to quantify what is meant by "high." Comparisons of pre-treatment recovery efficiencies with those from other patterns in the field or from modeling studies might be valuable in this regard.

4. Additional criteria, such as high injectivity and good mechanical condition of the well, can also be useful in candidate selection. Injection profiles and pressure communication between wells can be helpful in some circumstances, but caution must be exercised during their interpretation. There is a need to convince both vendors and operators that oil-productive zones must be protected during gelant placement in unfractured injection wells in reservoirs with non-communicating zones.

5. From 1990 through 1992, about 80% of the gel treatments were applied in production wells.

6. Taken as a whole, the criteria that vendors use for candidate selection in production wells (see Table 15) appear reasonable. Candidate selection must involve more than simply identifying wells with a high water cut. A summary of the most important criteria includes (1) high fluid productivity (Eq. 1 can be used as a gauge to quantify what "high" means), and (2) high oil productivity and low water cut early in the well's life, followed by a dramatic increase in the producing water/oil ratio much earlier than anticipated.

7. Vendors had mixed opinions about whether lithology and oil viscosity had an important impact on treatment performance. Several companies felt that the best results were obtained with moderately viscous oils and in carbonate reservoirs.

8. In both injectors and producers, most vendors thought that most of the treated wells were fractured or experienced a formation parting problem.

9. Improvements are needed in the methods used for sizing gel treatments.

5. A SURVEY OF EIGHT MAJOR OIL COMPANIES CONCERNING THE SELECTION OF CANDIDATES FOR GEL TREATMENTS IN INJECTION AND PRODUCTION WELLS

This chapter examines the views of experts from eight major oil companies about the selection and implementation of gel treatments in injection and production wells. Our survey covers their gel applications from 1990 through 1992. The responses from the participants are compared with those of seven gel vendors that were reported in Chapter 4.

The regions where the oil-company respondents have been most active are listed in Table 21. Over the past few years, the Permian Basin, Midcontinent USA (Oklahoma, western Kansas, Illinois Basin), and the Gulf Coast (onshore and offshore) were the areas with the most activity. However, gel treatments were applied in several other U.S. and foreign locations. For the most part, the activity indicated in Table 21 is consistent with that noted during the vendor survey in Chapter 4.

Table 21. Locations Where Operators Applied Gel Treatments

Location	Number of Respondents Active in this Area
Permian Basin	7
Midcontinent	4
Gulf Coast	4
California	3
Canada	3
Alaska	1
Wyoming	1
Australia	2
Indonesia	1
Thailand	1

Gelant Systems Used

The gelant systems used by the oil-company respondents are listed in Table 22. For the period covered by this survey, six of the respondents used Cr-redox-HPAM gelants and three companies used sodium-silicate gelants. Several other gelants were also used. Table 22 shows considerable diversity in gelant preferences. The aluminum-citrate-HPAM-CPAM gelant was the only system reported in the vendor survey that was not mentioned by the respondents for this survey. (At the request of some companies, we do not specify who provided a given response, and the ordering of companies in Table 22 is not related to that in subsequent tables. However, a given company is represented by the same letter, A through H, in Tables 23 through 45. Company H was not able to responded to many questions.)

Table 22. Gelant Systems Used

Company	Gelant Systems
1	Cr-redox-HPAM or AMPS: 100%
2	Cr-redox-HPAM: >90%
3	Cr-redox-HPAM: 80% Aluminate: 10% Phenol-formaldehyde: 10%
4	Cr-redox-HPAM: 20% Acrylamide monomer: 20% Cr^{3+}-xanthan: 20% Sodium silicate: 20% Cr^{3+}(acetate)-HPAM: 20%
5	Sodium silicate: 37% Cr^{3+}-xanthan: 19% Cr-redox-HPAM: 19% Acrylamide monomer: 19% Other: 6%
6	Phenol-formaldehyde: 47% Phenol-formaldehyde + cement: 37% Glyoxal-CPAM: 10% Cr-redox-HPAM: 3% Sodium silicate: 3%
7	Cr^{3+}(acetate)-HPAM: 100%

Breakdown of Applications

The breakdown of producer and injector applications for the respondents are listed in Table 23. Two companies applied treatments exclusively in production wells; one company applied treatments only in injectors; and four companies had a mix of applications. Table 23 suggests that applications in production wells were only slightly more frequent than those in injection wells. However, the vendor survey revealed that about 80 percent of the treatments for the 1990-1992 period were applied in production wells (Table 6). The vendor survey probably covered more projects than this survey.

For gel treatments in production wells, Table 24 provides a breakdown of the applications according to the probable source of water. The table shows that the mix of applications in bottom-water-drive reservoirs vs. waterfloods varies considerably, depending on the operator. One company had 100 percent bottom-water-drive wells; a second company had 90 percent of the treatments in waterflood producers; and the source of the water was unknown for 90 percent of a third company's applications. The vendor survey revealed that the mix of production-well applications also varied considerably from vendor to vendor (Table 7).

Table 23. Percentages of Producer/Injector Applications: 1990-1992

Company	Producers	Injectors
A	100 %	0 %
B	100 %	0 %
C	60 %	40 %
D	50 %	50 %
E	50 %	50 %
F	30 %	70 %
G	0 %	100 %

Success Rates. Tables 25 and 26 list the technical and economic success rates stated by the operators for their producing-well applications. Applications in waterflood producers appeared to have the highest success rates (60 to 100 percent). When the source of the water was unknown, success rates were low to moderate (0 to 70 percent). The widest variation in success rates (10 to 100 percent) occurred for applications in bottom-water-drive producers. Success rates claimed by vendors (typically 80 to 90 percent) were generally higher than those listed in Tables 25 and 26. Interestingly, the success rates derived from our surveys of operators and vendors are both significantly greater than the values quoted in the October 1992 issue of *Petroleum Engineer International*.[37] That publication's survey of operators indicated that the technical and economic success rates for gel treatments were 44 percent and 43 percent, respectively.

The success rates for gel applications in injection wells are listed in Table 27. Technical success rates varied from 50 to 90 percent. Four oil companies provided information on this topic. We note that in all four cases, the success rates quoted for applications in waterflood producers were at least as high as those for waterflood injectors (compare Table 27 with the middle column of Table 25). This observation is in contradiction to the beliefs of some experts. Credible information from vendors on success rates for applications in injection wells was not available for comparison.

Lithology. Table 28 shows the lithology (sandstone or carbonate) of gel applications in production wells and injection wells from 1990 through 1992. In both production wells and injection wells, the frequency of application in sandstones vs. carbonates varied greatly with the operator. Overall, treatments were applied more often in carbonates than in sandstones. For comparison, the vendor survey indicated that treatments in production wells were applied significantly more often in carbonates than in sandstones, and that injection-well treatments were equally likely to be applied in sandstone and carbonate reservoirs.

Operators had mixed opinions about whether lithology had an important impact on treatment performance (Table 29). Several companies felt that applications were more likely to be effective in carbonates than in sandstones. Many respondents felt that the heterogeneity of the formation (especially the presence or absence of fractures) was more important than the mineralogy of the rock. Higher success rates may occur in carbonate reservoirs because carbonate formations are more likely to be fractured, and gels are most effective in treating fracture problems.

Table 24. Distribution of Producing-Well Applications

Company	Bottom-water drive	Waterflood	Unknown water source
A	100 %	0 %	0 %
D	67 %	33 %	0 %
E	20 %	60 %	20 %
C	15 %	80 %	5 %
F	10 %	90 %	0 %
B	10 %	0 %	90 %

Table 25. Technical Success Rates of Producing-Well Applications

Company	Bottom-water drive	Waterflood	Unknown water source
A	100 %		
D	50 %	100 %	
E	70 %	80 %	70 %
C	70 %	75 %	
F	85 %	90 %	
B	100 %		40 %

Table 26. Economic Success Rates of Producing-Well Applications

Company	Bottom-water drive	Waterflood	Unknown water source
A	33 %		
D	50 %	100 %	
E	10 %	70 %	?
C	30 %	60 %	0 %
F	85 %	85 %	
B	100 %		30 %

Table 27. Success Rates of Injection-Well Applications

Company	Technical	Economic
F	90 %	85 %
E	80 %	50 %
C	70 %	35 %
D	50 %	50 %

Table 28. Lithology of Applications

Company	Producers		Injectors	
	Sandstone	Carbonate	Sandstone	Carbonate
B	90 %	10 %		
F	25 %	75 %	35 %	65 %
D	50 %	50 %	100 %	0 %
E	10 %	90 %	20 %	80 %
C	5 %	95 %	25 %	75 %
A	0 %	100%		
G			15 %	85 %

Table 29. Does Lithology Have an Important Impact on Treatment Performance?

Company	Response	Which is best?
A	yes	carbonate
F	possibly	carbonate
C	sometimes	carbonate
D	sometimes	carbonate
E	sometimes	
G	don't know	
B	no	

Fractures. With one or two exceptions, the respondents thought that most of their injection and production wells were fractured or experienced a formation parting problem (Table 30). In a notable exception, one company felt that only 10 percent of their producer treatments were applied in wells with a parting problem.

Table 30. Treated Wells Thought to be Fractured

Company	Producers	Injectors
F	90 %	100 %
G		100 %
D	50 %	100 %
C	90 %	80 %
E	60 %	80 %
A	67 %	
B	10 %	

Flow Behind Pipe. Table 31 lists the percent of the treated production wells that were thought to have a problem with casing leaks or flow behind pipe. The percentages ranged from 0 to 33 percent.

Table 31. Treated Production Wells Thought to Have Casing Leaks or Flow Behind Pipe

Company	Percent
A	33
D	33
B	30
F	15
C	5
E	0

Oil Viscosity. The operators were split in their opinions about whether oil viscosity was important to treatment performance (Table 32). For those who felt that it was important, more viscous oils were preferred. This finding is consistent with that from the survey of gel vendors.

Table 32. Does Oil Viscosity Have an Important Impact on Treatment Performance?

Company	Response	Which is best?
A	yes	moderate to high
B	yes	moderate to high
C	don't know	
D	don't know	
E	don't know	
G	don't know	
F	no	

Candidate Selection

Table 33 indicates who participates in candidate selection for the various oil companies. For all companies, field engineers usually play the primary role in identifying candidates for treatment. Thus, these people have the greatest need to be aware of the proper criteria for candidate selection. Table 33 suggests that gel vendors rarely, if ever, participate in candidate selection. Participation by the company's research or technical arm varies widely—from 0 to 100 percent.

Table 33. Who Participates in the Selection of Candidate Wells?

Company	Field Engineers	Gel Vendor	Research or Technical Arm
B	100 %	0 %	100 %
D	100 %	0 %	75 %
C	100 %	0 %	< 5 %
A	100 %	0 %	0 %
F	95 %	0 %	60 %
E	80 %	< 10 %	20 %
G	75 %	0 %	25 %

Analyses of field projects over the past 20 years reveal that a high producing water/oil ratio (WOR) was the primary criterion (and often the only criterion) used during the selection of candidate wells for gel treatments (see Chapters 2 and 3). These surveys suggest that if a high WOR is the only criterion applied during candidate selection, then the success rate is likely to remain sporadic. Thus, additional factors must be considered to improve the selection process.

Injection Wells. Table 34 lists the criteria for selection of injection-well candidates, as suggested by nine experts from eight major oil companies. For seven companies, only one response was received per company. However, note that Company D provided two responses. For each response, the criteria are supposed to be listed in decreasing order of importance.

Table 34. Selection Criteria for Injection Wells

Company	Criteria
A.	1. High WOR in offset producers, high fluid productivity, and low waterflood sweep efficiency.
	2. Severe channeling shown by rapid tracer breakthrough.
	3. High injectivity.
	4. Mechanical integrity of well.
	5. Oil viscosity and mobility ratio.
	6. Comparison of efficiencies of waterfloods and polymerfloods predicted by simulation.
B.	1. Poor injection profiles (similar thief zones) in several wells.
	2. Spacing $<$ 20 acres.
	3. Good mechanical condition of well.
	4. Offset producer(s) have high WOR.
	5. Temperature $<$ 200°F.
	6. $S_{or} > 0.4$.
	7. Multiple heterogeneous zones.
C.	1. Poor injection profile.
	2. Fracture or high-permeability streak connected to offset production wells.
	3. Evidence of water cycling (e.g., early tracer breakthrough).
D.	1. Rapid increase in water production rate associated with a high-rate injector.
	2. Spinner survey shows high water loss into high-permeability stringers.
D.	1. Has isolatable thief zone that can be shut off without affecting other zones.
	2. Low k_v/k_h.
E.	1. Known fracture is source of the problem. Fracture orientation is also important.
	2. Early water breakthrough in producers.
	3. Poor flow conformance documented by logs.

Table 34. Selection Criteria for Injection Wells (continued)

F.
1. Pattern and well performance.
2. Tracer studies and other evidence of severe channeling.
3. Estimates of mobile oil that can be recovered.
4. WOR.

G.
1. Recoverable reserves in target pattern.
2. Pattern performance (production well profiles and WORs).
3. Injection well profiles.
4. Tracer transit times.
5. Wellbore condition.
6. Well location.
7. Available injection pressure.

H.
1. "Good" oil target.
2. Evidence of channeling.
3. For matrix applications, post-treatment injectivity must be below the parting pressure.
4. Well in good mechanical condition.

Since wells are often (usually?) chosen for treatment without consulting the company's research or technical affiliate (see Table 33), there would be considerable value in establishing a consistent set of guidelines that field engineers could use for candidate selection. In Table 35, we have attempted to consolidate the responses in Table 34 to make a prioritized list of criteria for selecting injection-well candidates. Agreement may not be universal on a number of points in Table 35, including whether all of the most important criteria are listed and whether the criteria are prioritized properly. Even within each item there may be significant disagreement about certain points.

Table 35. Consolidated Selection Criteria for Injection Wells

1. Reservoir and production data indicates low sweep efficiency during waterflooding.
   a. Water breakthrough occurs much earlier than expected (i.e., from standard calculations or simulations or from comparison with the performance of other patterns in the field).
   b. WOR values at offset producers are much higher than expected.
   c. Recovery calculations indicate that considerable mobile oil remains that could be recovered more cost-effectively if a blocking agent could be realistically placed in the proper location.

2. In unfractured wells,
   a. Poor injection profiles are correlatable from well to well.
   b. Effective barriers to crossflow exist (very low k_v/k_h, no flow behind pipe, no vertical fractures).
   c. Gel can be placed in the offending channel without damaging oil zones (e.g., using zone isolation).

3. If barriers to crossflow do not exist, then interwell tracers must show very rapid transit times (probably indicating that fractures or formation parting cause the channeling problem).

4. Reduced injectivity (caused by the gel) can be tolerated.

5. The well to be treated is in good mechanical condition.

For the first criterion in Table 35, several qualifications were added to clarify what is meant by "low sweep efficiency." We felt that this clarification was necessary because different operators interpret this phrase in radically different ways. Cases exist where gel treatments were implemented even though more than 50 percent of the original oil in place had been recovered before the treatment (see Chapter 2). Point C in the first criterion is particularly important for applications in gray areas. One criticism of this point might be that, often, insufficient manpower or reservoir description is available to adequately predict the benefits of a gel treatment. If that is the case and if the second or third criterion in Table 35 cannot be met, then we feel that a gel treatment is unlikely to be successful.

The second criterion in Table 35 may be the most controversial. Disagreement may exist about (1) the value of injection profiles in fractured wells, (2) the necessity of barriers to crossflow, and (3) the importance of gel placement. These issues must be resolved before a consensus can be reached on selection criteria.

The third criterion in Table 35 is directed at identifying very severe channeling between injector-producer pairs. In our view, very rapid tracer transit times (less than one week) probably indicate that the channel is a fracture or a formation part. For severe channeling problems, tracer studies can be very valuable for several reasons. They can be useful in (1) diagnosing the severity of the channeling problem, (2) determining whether a gel treatment should be attempted, (3) designing the volume of gelant to be injected, (4) assessing whether zones should be isolated during gelant placement, and (5) estimating the ultimate effectiveness of the treatment.

Table 36 provides responses from the oil companies about how often interwell tracer studies are performed. The table indicates that the frequency of tracer application varies widely—from 0 to 60 percent of the treatments—depending on the operator. The vendor survey also indicated that the use of tracers varies widely. Although tracer studies are performed for less than half of the injection-well treatments, most of the respondents felt that they should be used before implementing at least 80 percent of the applications. However, both vendors and operators expressed concern about the added cost of tracer studies.

Table 36. Use of Interwell Tracers
to Diagnose Channeling in Injectors

Company	How often are they used?	How often should they be used?
F	60 %	95 %
C	50 %	90 %
A	30 %	100 %
E	< 20 %	?
B	5 %	100 %
D	0 %	80 %
G	0 %	25 %

Production Wells. Table 37 lists the criteria for selection of production-well candidates, as suggested by nine experts from major oil companies. Again, note that Company D provided two responses.

Table 37. Selection Criteria for Production Wells

Company		Criteria
A.	1.	High WOR.
	2.	High fluid productivity.
	3.	Structural position.
	4.	Wells in fields where polymer treatments have been successful previously.
	5.	Wells producing at the economic limit.
	6.	High remaining oil saturation.
	7.	Wells produced at high oil rates early but then showed a dramatic decrease in oil rate.
B.	1.	Significant reserves remaining.
	2.	Water entry source identified.
	3.	Well in good mechanical condition.
	4.	Zonal isolation possible.
	5.	Reducing water production can allow increased oil/gas production.
C.	1.	Production log shows high percent of water production comes from a small interval.
	2.	Overall high water production volumes with low hydrocarbon cut.
D.	1.	Decreasing oil production rate relative to offset producers.
	2.	Onset of high water production rates.
D.	1.	Cement squeeze likely to be unsuccessful.
	2.	Not likely to have large voids behind pipe.
	3.	Zone isolation can be used to avoid damage to oil-productive zones.
	4.	Acceptable injectivity into isolated treatment zone (>1.5 BPM).
E.	1.	Production logs identify the water source.
	2.	Economic evaluation via single-well reservoir simulation.
	3.	High WOR and high disposal costs/environmental regulations.
F.	1.	Estimates and source of excessive water production.
	2.	Pattern and well performance.
	3.	Is the high-WOR well pumped off?
G.	1.	Available reserves.
	2.	WOR.
	3.	Well pumped off?
	4.	Profiles.
	5.	Thief zone location (depth).
	6.	Water source (injection well vs. coning).
	7.	Well condition.

Table 37. Selection Criteria for Production Wells (continued)

H.
1. "Good" oil target.
2. High WOR compared to other pattern wells.
3. High fluid level.
4. Well in good mechanical condition.

In Table 38, we have attempted to consolidate the responses from Table 37 to make a prioritized list of criteria for selecting production-well candidates. As is the case for Table 35, Table 38 will require additional discussion to determine its utility in candidate selection.

Table 38. Consolidated Selection Criteria for Production Wells

1. Recovery calculations indicate that considerable mobile oil remains that could be recovered more cost-effectively if a blocking agent could be realistically placed in the proper location.

2. High WOR values are observed.

3. The source of the excess water production is identified (e.g., using profiles, logs, or tracers).

4. The candidate well exhibits high productivity.

5. The gelant can be placed without damaging oil zones (e.g., using zone isolation).

Treatment Design and Application

In this section, we consider the design and application of gel treatments from the viewpoint of the oil company experts. A similar study from the viewpoint of gel vendors is reported in Chapter 4. Table 39 shows the breakdown of who designs the treatments for the various oil companies. For two companies, the operator's local engineers play the primary role in treatment design. For four companies, gel vendors usually design the treatments, while only one company had the operator's research or technical arm provide the design.

Volumes of Gelant Injected. Table 40 lists the minimum, median and maximum volumes of gelant that the operators injected during their injector and producer treatments. In this table, median gelant volumes range from 200 to 250 bbl in injectors and from 300 to 500 bbl in producers. Thus, the treatments have generally been very small. Interestingly, the producer treatments were normally larger than the injector treatments.

One company, not listed in Table 40, characterized both their injector and producer treatments as "large." Generally, their treatment volumes were substantially greater than those listed in Table 40. For this company, gelant volumes for injectors were usually larger than those for producers.

Table 39. Who Designs Your Gel Treatments?

Company	Operator's Local Engineers	Gel Vendor	Operator's Research or Technical Arm
E	90 %	0 %	10 %
F	70 %	5 %	25 %
C	35 %	60 %	5 %
D	0 %	75 %	25 %
G	0 %	75 %	25 %
A	0 %	67 %	33 %
B	0 %	0 %	100 %

Table 40. Gelant Volumes Injected (Barrels)

Company	Injectors			Producers		
	minimum	median	maximum	minimum	median	maximum
A				240	313	400
B				100	350	800
C	150	250	400	200	300	1,000
D				100		
E	24	240	715	240	480	950
G	30	200	4,000			

Our survey of gel vendors revealed that the sizing of treatment volumes had little or no technical basis other than an "experience" factor. Often "economics" was cited as a major consideration during treatment design. However, in this case, "economics" did not necessarily mean that a realistic analysis had been performed to maximize the return on investment (i.e., by estimating the incremental oil produced or the reduction in water production as a function of gelant volume). Instead, it meant that the operator was simply unwilling to consider (or for competitive reasons, the vendor was unwilling to bid) more than a certain cost per well (e.g., $20,000). Results from recent field tests suggest that larger treatments can be economically superior to small-volume treatments.[11]

In view of the empirical way in which gel treatments were designed in the past, we asked the following question of the experts from the major oil companies:

If you had total control over the design of a gel treatment, how would you decide how much gelant should be injected into (a) an injection well and (b) a production well?

The responses are listed in Table 41 for injection-well treatments and in Table 42 for production-well treatments. Again, Company D provided two responses.

Table 41. How Much Gelant Should Be Injected into Injection Wells?

Company	Suggested Procedure to Determine Gelant Volume
A.	1. Run a tracer test. 2. If tracer breakthrough is rapid, use tracer results to estimate the gelant volume to be injected. 3. If tracer breakthrough is not rapid and crossflow can occur in the reservoir, large volumes of gelant should be injected (0.2 PV slug size or larger). Actual volume can be estimated from reservoir modeling studies (i.e., history matching waterflood performance followed by simulation to optimize slug size.)
B.	1. Injected gelant volume ≤ volume from tracer breakthrough. 2. Time for gelant injection ≈ longest practical gelation time. 3. Theoretical radius for gelant ≥ 50 ft. 4. During gelant injection, injection pressure < fracture pressure.
C.	1. In radial treatment of non-fractured wells, gelant volume should allow gelant to reach 30-50 ft into the formation. 2. In fractured wells, inject 0.5 to 0.67 of the fracture volume between the injector and the producer. 3. Use results from similar (previous) treatments to improve future designs. 4. Economics dictate the final job design.
D.	1. Inject tracers to find (a) where the tracer leaves the injector and (b) where the tracer enters the producer. 2. If the tracer study indicates no crossflow, then inject a gelant volume equivalent to 1 day's normal injection volume. 3. If the tracer study indicates that crossflow occurs, then the maximum gelant volume would be the volume required to reach half way to the production well. The minimum gelant volume would allow the gelant to penetrate 100 ft radially into the formation.
D.	1. Inject gelant until a predetermined injectivity index is reached.
E.	1. Run production logs to identify the source of the unwanted water or gas. 2. If the source is a fracture, pump ≈ 200 gal/ft of a strong (plugging) gelant. Possibly follow the gelant with cement. 3. If the source is via the rock matrix, obtain laboratory core flow data to estimate changes in relative permeability from a weak gel, as well as the expected treatment lifetime. 4. Use a single-well reservoir simulator coupled with an economics program to optimize the gel volume.

Table 41. How Much Gelant Should Be Injected into Injection Wells? (continued)

F.
1. Determine the source of the channeling problem.
2. If the channel is rock matrix and crossflow is not a problem, isolate the offending zone and inject enough gelant volume so that total shutoff of flow will occur in the target zone (if it is watered out).
3. If the channel is a fracture network, inject much more (≈ 10 times) than the breakthrough volume determined from a tracer study.
4. If the channel is a single fracture, inject a volume of gelant equivalent to 0.5 to 0.7 times the breakthrough volume determined from a tracer study.
5. Where possible and reasonable, consider designs that have worked well during previous applications in the same field.

G.
1. Perform a modeling study using the following factors as input: (a) laboratory data (for permeability reduction), (b) simulation (for depth of gelant penetration), (c) fracture limit, (d) thief zone dimensions, (e) economics, and (f) field experience.

H.
1. Establish what the economic and technical volumes are. The economic volume is how much you think you can afford to inject. The technical volume is how much of the gelant you can pump at reservoir conditions before gelation occurs.
2. For severe channeling or a fractured well, use well-to-well tracer tests to determine the swept volume. Compare the swept volume to the economic and technical volumes and use the smallest of the three.
3. For a matrix well with non-communicating layers in an area where one has limited experience, use a volume required to provide a 10-20 ft radial treatment around the isolated thief zone unless the economic and technical volumes dictate otherwise. In that case, use the largest volume that is economically or technically possible.
4. In each case, experience in an area will allow one to optimize treatment volumes.

Table 42. How Much Gelant Should Be Injected into Production Wells?

Company — Suggested Procedure to Determine Gelant Volume

A.
1. Run production log or cased-hole log (e.g., TDT) to determine oil and water productive intervals.
2. Calculate gelant volumes based on production log results and fluid production rates.
3. Inject fairly large volumes of ungelled polymer (at least two times the total daily fluid production).
4. Inject 300-500 barrels of gelant.

B.
1. Volume of gelant $\approx$ 1 day's water production.
2. Volume of gelant penetrates to a theoretical radius of at least 15-35 ft from the wellbore.
3. Volume of gelant is injected during a 16-24 hour period.
4. Terminate injection once the pressure limit is reached.

Table 42. How Much Gelant Should Be Injected into Production Wells? (continued)

C.
1. In radial treatment of non-fractured wells, gelant volume should allow gelant to reach 30-50 ft into the formation.
2. In fractured wells, inject 0.5 to 0.67 of the fracture volume between the injector and the producer.
3. Use results from similar (previous) treatments to improve future designs.
4. Economics dictate the final job design.

D.
1. Isolate the target zone.
2. Inject a volume of gelant that is at least the greater of (a) 2 days production volume or (b) enough gelant to penetrate at least 5 ft radially into the formation.
3. The gelant would be designed to be very "hard," especially near the wellbore.

D.
1. Estimate the maximum void volume.
2. Calculate the volume needed for the gelant to penetrate the desired radial distance into the formation (drawdown in psi ÷ gel strength in psi/ft).
3. Allow for 20 bbl of gelant in the wellbore.
4. Calculate the volume needed for a 1-2 ft interface in the formation.
5. The total gelant volume to be injected will be the sum of items 1 through 4.

E.
1. Run production logs to identify the source of the unwanted water or gas.
2. If the source is a fracture, pump ≈ 200 gal/ft of a strong (plugging) gelant. Possibly follow the gelant with cement.
3. If the source is via the rock matrix, obtain laboratory core flow data to estimate changes in relative permeability from a weak gel, as well as the expected treatment lifetime.
4. Use a single-well reservoir simulator coupled with an economics program to optimize the gel volume.

F.
1. Determine the source of the channeling problem.
2. If the channel is rock matrix and crossflow is not a problem, isolate the offending zone and inject enough gelant volume so that total shutoff of flow will occur in the target zone (if it is watered out).
3. As much as possible, base designs on what has worked best during previous applications in the same field.

G.
1. Perform a modeling study using the following factors as input: (a) laboratory data (for permeability reduction), (b) simulation (for depth of gelant penetration), (c) fracture limit, (d) thief zone dimensions, (e) economics, and (f) field experience.

H.
1. Determine the treatment volumes required to give a nominal 10-20 ft radial treatment.
2. If the treatment volume is larger than the economic and technical treatment volumes, use the largest volume that is economically or technically possible.
3. Experience in the area may later indicate that smaller volumes can be used.

Part of the variation in responses in Tables 41 and 42 occurs because different types of channeling problems occur. For example, the "channel" could be (1) a fracture or fracture network, (2) a high-permeability rock stratum that is separated from oil-productive zones by impermeable barriers, (3) a high-permeability rock matrix that is in direct pressure communication with oil-productive zones (i.e., fluids can freely crossflow between strata), or (4) flow behind pipe occurring because of inadequate cement fill and bonding. Because different operators experience different types of channeling problems, their biases during treatment design are likely to be different.

When the channel is a fracture in a waterflooded reservoir, many of the respondents felt that interwell tracer studies could provide a useful basis to determine the volume of gelant injected. Depending on the company, the suggested volume of gelant varied from 50% to 100% of the injection volume associated with tracer breakthrough (i.e., tracer transit between injector and producer). Of course, the objective of this strategy is to fill most of the fracture with gel.

When the channel is a fracture network in a waterflooded reservoir, one company (Company F) felt the volume of gelant injected should be many times the volume associated with tracer breakthrough. In partial justification of this suggestion, injection-well applications have been found where the gelant was not detected at the production well even though the injected gelant volume was ten times greater than the volume associated with tracer breakthrough. The explanation for the delayed arrival of the gelant may be tied to the viscosity of the gelant compared with that of the tracer solution. Viscous injectants tend to penetrate farther into less-permeable pathways (either rock matrix or alternate fracture pathways) than do low-viscosity injectants.[13,15,18] (This is a basic principle of traditional polymer flooding.) Since the gelant is usually much more viscous than the aqueous tracer solution, the gelant requires much longer to propagate a given distance through a formation. Of course, chemical retention and filtration effects can also retard the movement of polymers, crosslinkers and gels. However, these phenomena are likely to be less important during propagation through fractures than through a rock matrix.

When the channel is a high-permeability rock stratum that is separated from oil-productive zones by impermeable barriers, then one need inject only enough gelant to effectively plug the high-permeability channel near the wellbore. Many companies recommended that the gelant should penetrate a certain minimum radial distance from the wellbore. This distance ranged from 10 to 100 feet, depending on the operator. Some companies specified that the gelant volume should be dictated by the injectivity loss in the channel. This method seems reasonable so long as the injectivity loss is applied specifically to the offending channel(s) and not to the overall injectivity index for all zones open to the well.

When the channel is a high-permeability rock matrix that is in direct pressure communication with oil-productive zones (i.e., fluids can freely cross flow between strata), then substantial differences of opinion exist about treatment design. One view is that this situation, for practical purposes, is not treatable by any gel technology that currently exists. An extension of this view is that a traditional polymer flood should be greatly preferred over gelant injection for treating this situation.[18,39-41] A second view is that, under the right circumstances, this condition could be successfully treated using a low-viscosity gelant that penetrates a substantial distance into the channel.[18,29] For this process, very large volumes of gelant must be injected, and some means must be available to substantially delay gelation. Although there are many challenges to the successful implementation of this technology, it has considerable merit and probably will be field tested in the near future. A third viewpoint is that reservoirs with extensive crossflow could be treated by injecting a gelant that simply acts like an enhanced polymer solution; that is, a crosslinker simply increases the viscosity of the polymer solution, and the resulting "gel" propagates through the formation like a polymer solution. Such a system would provide a truly dramatic advance in improving the cost-effectiveness of traditional polymer flooding. Unfortunately, all available evidence indicates that this type of gelant system does not yet exist. (Of course, using crosslinked polymers to plug severe channels before a traditional polymer flood is a worthwhile idea.[4]) A fourth view is that conventional gel treatments can be effective in unfractured reservoirs with extensive crossflow if the channel is a very high-permeability, small-volume pathway that allows very rapid tracer transit between wells (e.g., less than one week). The challenge for this view is to identify a real geologic structure or phenomenon that could be used to quantitatively justify (1) how the high-permeability, small-volume pathway was created and (2) why tracer propagation is so rapid. At present, the only structures that fit these requirements (as we see it) are fractures, formation parts, or possibly, very long, narrow viscous fingers (which require that the oil be extremely viscous).

When the channel occurs from flow behind pipe, one suggestion was that the gelant volume be roughly three times greater than that for a cement squeeze. Compared with a cement squeeze, a larger volume is needed for gel treatments because gelants penetrate into the rock matrix whereas cement does not.

Stimulation Before Gelant Injection. Table 43 shows whether the companies routinely acidize their wells before gelant injection. Only one operator indicated that they normally acidize their producers. Most of the operators did not acidize their wells as a standard practice before gelant injection. Results from the vendor survey are consistent with this finding; the majority of gel vendors stated that they did not routinely acidize wells. However, three vendors routinely acidized producers, and two vendors routinely acidized injectors before gel treatments. One argument given by vendors for acidizing is that by cleaning up formation damage, injectivity will be increased and oil production will be further stimulated over the contribution from the gel treatment. Other vendors do not routinely acidize before gelant injection—reasoning that formation damage may restrict gelant from entering less-permeable, oil-productive zones.

Table 43. Are Your Wells Normally Acidized Before Gelant Injection?

Company	Producers	Injectors
A	yes	
F	sometimes	sometimes
D	sometimes	no
G		no
C	no	no
E	no	no
B	no	no

For injection wells that were thought to be unfractured, Table 44 indicates how often the operators isolated zones during gelant injection. For both injectors and producers, the frequency of zone isolation varied widely—from 0 to 95 percent. For most of the operators, zone isolation was used for less than 50 percent of the applications. There are sound arguments why zone isolation is not needed or is not useful during gelant placement if the problem being treated is either a fracture or flow behind pipe. One could also argue that zone isolation is not needed in unfractured production wells if the gel proves to reduce water production without significantly reducing oil production.[14,42] Furthermore, zone isolation will be of little value if extensive crossflow can occur between strata.[18,39] However, in unfractured injection wells, all available theoretical and experimental evidence indicates that productive zones can be seriously damaged if precautions are not taken to protect them during gelant placement.[13-18] Since Table 44 indicates that zone isolation was not used for treatments in most unfractured injection wells, one must wonder whether the field experience contradicts the theoretical and experimental work. However, we have actively sought specific field cases involving gel treatments in unfractured injection wells where zone isolation was not used and (1) the injection profile definitely improved or (2) the producing water/oil ratio decreased. None have been found to date.

Table 44. For Treatments in Unfractured Wells, How Often Are Zones Isolated During Gelant Injection?

Company	Producers	Injectors
F	95 %	95 %
C	90 %	30 %
D	50 %	50 %
E	40 %	30 %
G		25 %
B	10 %	0 %
A	0 %	0 %

Injectivity Changes and Hall Plots. During gelant injection, injection pressures and injectivity changes are usually monitored. Many express this information in "Hall plots" or "modified Hall plots." Most vendors like to see a gradual decrease in injectivity during gelant injection. A sharp decrease in injectivity is interpreted as near-wellbore plugging and is usually a criterion for stopping gelant injection. An injectivity increase during gelant injection has been interpreted by some vendors as indicating that the gelant has opened new zones. However, a critical analysis reveals that Hall plots and injectivity changes measured at the wellhead do not, by themselves, indicate that the gelant is entering one zone in preference to another (see Chapter 6). In our earlier survey of gel vendors, five of the seven vendors agreed with this conclusion. Table 45 reveals that respondents from all but one of the oil companies do not believe that Hall plots indicate selectivity during gel placement. For the company that provided the "yes, maybe" response, the company's experts caution that their response needs clarification. The response is a direct quote from the company's "opco" engineers, and they may have overlooked the emphasis on selectivity.

Table 45. Do Hall Plots Indicate Selectivity During Gel Placement?

Company	Response
A	no
B	no
D	no
E	no
F	no
G	no
C	yes, maybe

Conclusions

1. Based on responses from experts from eight major oil companies and from seven vendors, criteria are proposed for the selection of candidate wells for gel treatments. These criteria are listed in Table 35 for injection wells and in Table 38 for production wells.

2. For gel treatments in injection wells, operators quoted success rates ranging from 35 to 90 percent. For gel treatments in production wells, success rates ranged from 60 to 100 percent in waterflood production wells, from 10 to 100 percent for bottom-water-drive producers, and from 0 to 70 percent in producers where the source of water was not known. Success rates claimed by vendors (typically 80 to 90 percent) were generally higher than those stated by the operators.

3. In both production wells and injection wells, the frequency of application in sandstones vs. carbonates varied greatly with the operator. Overall, treatments were applied more often in carbonates than in sandstones.

4. Most respondents from both oil companies and gel vendors thought that most of the injection and production wells that they treated were fractured or experienced a formation parting problem.

5. Responses from six oil companies indicated that the median gelant volumes ranged from 200 to 250 bbl in injectors and from 300 to 500 bbl in producers. A seventh company generally used much larger gelant volumes.

6. Because different operators experience different types of channeling problems, their biases during treatment design vary. Different channel types include (1) a fracture or fracture network, (2) a high-permeability rock stratum that is separated from oil-productive zones by impermeable barriers, (3) a high-permeability rock matrix that is in direct pressure communication with oil-productive zones (i.e., fluids can freely crossflow between strata), and (4) flow behind pipe occurring because of inadequate cement fill and bonding. More work is needed to establish gelant volumes and design procedures for each of these types of channels.

6. DO HALL PLOTS INDICATE SELECTIVITY DURING GEL PLACEMENT?

What is a Hall Plot?

The "Hall plot" was originally proposed as a method to analyze steady-state injectivity data for waterflood injection wells.[43] The method is based on integration of the steady-state radial-flow equation with time.[43-45] According to Earlougher[44] and Buell *et al.*,[45] Eq. 2 provides the basis for the Hall plot.

$$\int p_{tf}dt-(p_e-\Delta p_{tw})t = \frac{141.2\mu(\ln(r_e/r_w)+s)W_i}{kh} \tag{2}$$

where

- h = formation thickness, ft
- k = permeability, md
- p_e = external or reservoir pressure, psi
- p_{tf} = flowing wellhead pressure, psi
- Δp_{tw} = pressure difference between wellhead and bottom hole, psi
- r_e = external radius, ft
- r_w = wellbore radius, ft
- s = skin factor
- t = time, days
- W_i = cumulative injection, bbl
- μ = viscosity, cp

In the Hall plot, the integral, $\int p_{tf}dt$, or $\Sigma p_{tf}\Delta t$ is plotted vs. cumulative injection, W_i. Fig. 23 illustrates a Hall plot. In Eq. 2, if

$$\int p_{tf}dt >> (p_e-\Delta p_{tw})t, \tag{3}$$

then under steady-state conditions, the Hall plot should give a straight line with a slope,

$$m_H = \frac{141.2\mu(\ln(r_e/r_w)+s)}{kh}. \tag{4}$$

Injectivity is defined as injection rate in bbl/D divided by injection pressure drop (p_{tf}-Δp_{tw}-p_e) in psi. An decrease in injectivity results in an increase in the slope of a Hall plot (see Fig. 23).

What Does a Hall Plot Reveal?

A change in the slope of a Hall plot indicates a change in one or more of the following variables: k/μ, p_e, or s. However, it does not allow identification as to which of the three variables changed unless additional information is provided (such as results from pressure transient analyses).[44]

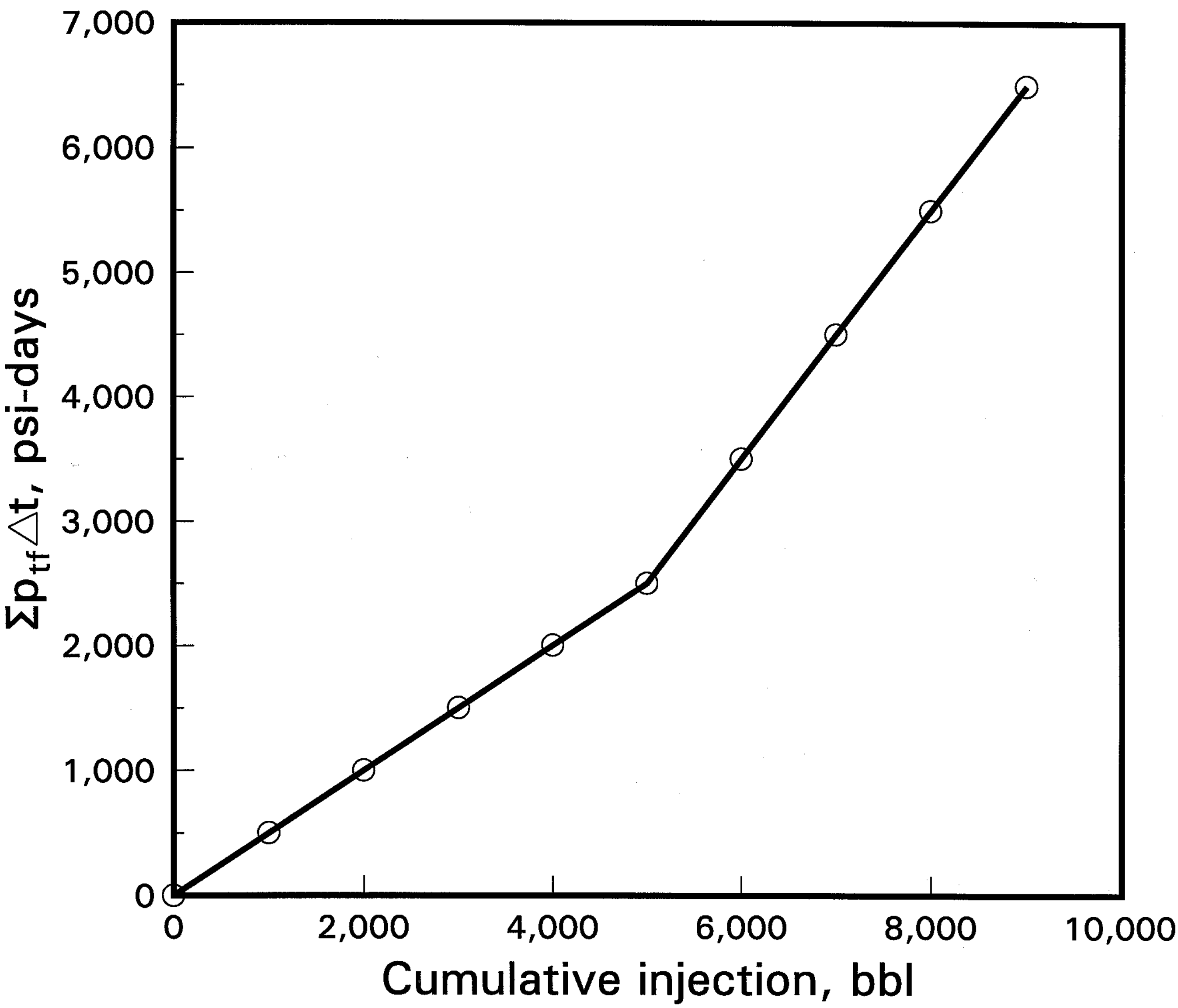


Fig. 23. Hall plot illustrating an injectivity decrease after 5,000 bbl cumulative injection.

In the development of the Hall plot, vertical stratification of the reservoir was not considered. Thus, the parameters that might be derived from a Hall plot are averaged over all open zones. This suggests that Hall plots cannot distinguish what is happening in different zones unless the analysis can be coupled with additional information. Treatments using buoyant ball sealers provide an example of how Hall plots can be coupled with other information to assess the performance of the treatment.

Hall Plots for Analysis of Treatments with Buoyant Ball Sealers. Here, we will consider the use of buoyant ball sealers to provide fluid diversion in perforated casing. Assume that a reservoir has two zones, where the upper zone is more permeable than the lower zone (see Fig. 24). By injecting the proper number of buoyant balls at an appropriate injection rate, the balls can plug the perforations in the upper zone without plugging those in the lower zone.[46,47] Our confidence that this will happen comes primarily from our knowledge of how buoyant ball sealers work. When buoyant balls flow past the upper perforations, a certain fraction of the balls will immediately enter and seal some of the perforations. The rest of the balls will overshoot the upper perforations. However, if the balls have the right density and if the injection rate is in the proper range, the fluid velocity in the casing below the upper perforations will not be sufficient to continue forcing the balls downward. Thus, the balls will rise until they enter and seal open perforations in the upper zone.

A Hall plot for treatment with buoyant ball sealers should look like Fig. 23. The point where the slope increases corresponds to the time when the balls seal the upper set of perforations. Before the treatment, the slope of the Hall plot reflects k/μ, p_e, and s values averaged over both zones. After the treatment, the slope reflects properties of the lower zone only (if enough balls were injected to seal all perforations in the upper zone). Thus, the Hall plot can indicate the selectivity of fluid diversion during injection of buoyant ball sealers, but only because the plot is complemented with information about the number and location of the perforations in the casing and knowledge of how buoyant ball sealers work.

Hall Plots for Analysis of Gel Treatments in Unfractured Injection Wells. Next, we will consider the two-layer reservoir from the previous example, but a gelant will be injected instead of ball sealers. In this case, we assume that the well is not fractured. When the gelant is injected, it will penetrate into all open zones,[13-18] For example, if the gelant penetrates to a radius of 50 ft in the high-permeability zone, then it can penetrate to a radius of at least 16 ft in a zone that is ten times less permeable.[13] Capillary pressure and relative permeability effects will not prevent aqueous gelants from penetrating significant distances into oil-productive zones.[14,17] For a given radius of gelant penetration into the high-permeability zone, the radius of penetration into the less-permeable zone will increase with increased gelant viscosity.[13,18] The non-Newtonian rheology of existing polymeric solutions will not mitigate this effect.[15]

When gelation occurs, permeability will be reduced in the gel-contacted zones. This permeability reduction is responsible for a reduced injectivity and a greater slope of the Hall plot after the gel treatment. The Hall plot reflects injectivity changes averaged over all zones. It does not indicate injectivity changes for individual zones. The injectivity loss for a given zone will depend on both the distance of gelant penetration and the degree of permeability reduction (residual resistance factor) caused by the gel in that zone.

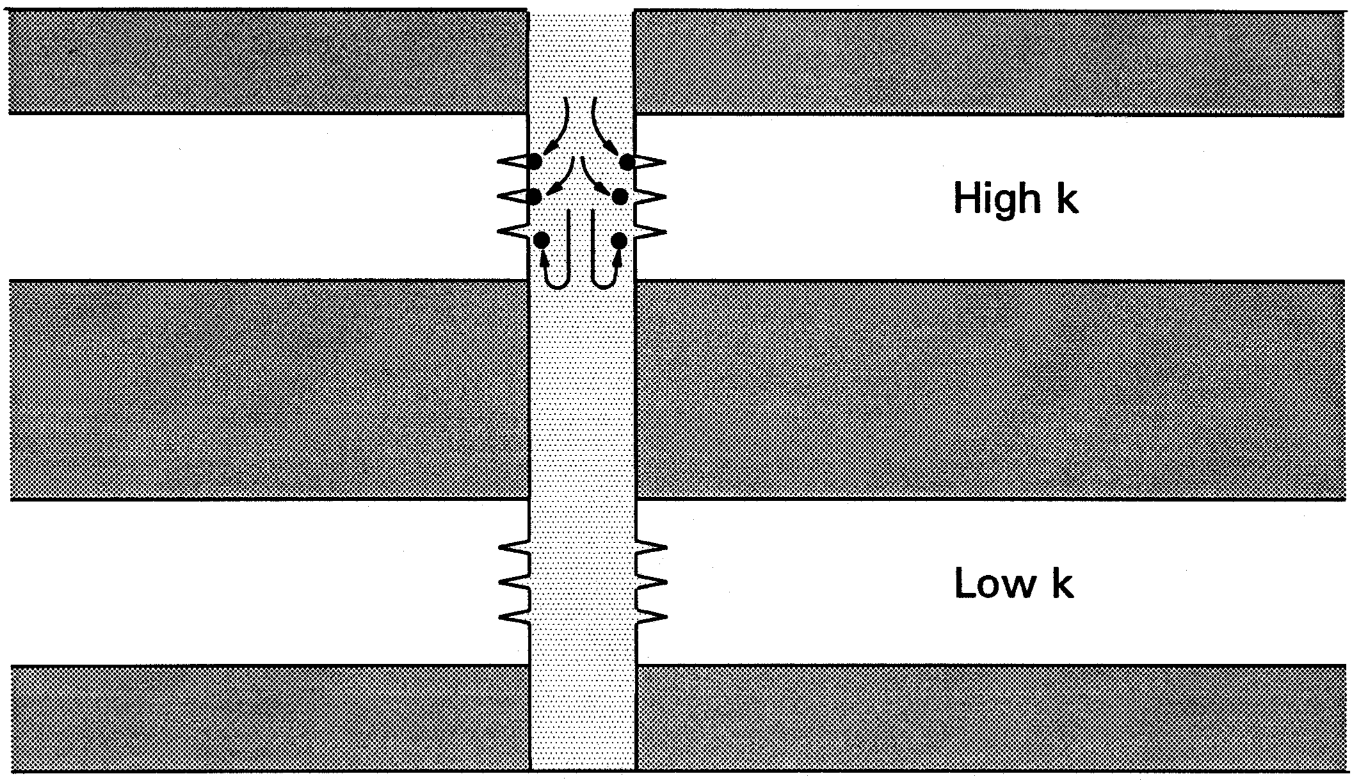


Fig. 24. Use of buoyant ball sealers for diversion in perforated casing.

Except for very "strong" gels that effectively stop all flow, most gels reduce the flow capacity of the gel-contacted portions of low-permeability rock more than in high-permeability rock.[26,27,48-51] Given this fact, straight-forward analyses[13,16,49,50] demonstrate that conventional gel treatments in unfractured injection wells will generally not significantly improve the injection profile (i.e., by reducing injectivity in high-permeability zones to a greater extent than in less-permeable zones). Thus, for applications in unfractured injection wells, injectivity changes measured at the wellhead generally reflect more or less uniform injectivity changes in all zones.

As a simple illustration of the above concept, consider a two-layer, cylindrical reservoir where both zones have an external radius of 50 ft and an internal (wellbore) radius of 0.5 ft (see Fig. 25). In this case, crossflow cannot occur between zones. Both zones have the same porosity ($\phi_1 = \phi_2$), but Layer 1 is ten times more permeable than Layer 2 ($k_1 = 10k_2$). In a unit-mobility displacement, gelant is injected to displace reservoir fluids until the gelant reaches the outer radius (r_{p1}) of Layer 1. Using Eq. 5, the radius (r_{p2}) of gelant penetration into Layer 2 is calculated to be 15.8 ft.

$$\frac{r_{p2}^2 - r_w^2}{r_{p1}^2 - r_w^2} = \frac{k_2 \phi_1}{k_1 \phi_2} \tag{5}$$

When gelation occurs, assume that the permeability is reduced by a factor of 10 ($F_{rr} = 10$) in all gel-contacted portions of the reservoir. The relative injectivity (final injectivity divided by initial injectivity, I_i/I_{i0}) in each layer can then be calculated using Eq. 6 (taken from Eq. 13 of Ref. 13).

$$\frac{I_i}{I_{i0}} = \frac{\ln(r_{p1}/r_w)}{F_{rr}\ln(r_{pi}/r_w) + \ln(r_{p1}/r_{pi})} \tag{6}$$

In this equation, the subscript, i, refers to the zone of interest (1 or 2). Calculations using Eq. 6 reveal that after gelation, brine injectivity is reduced by 90% in Layer 1 and by 87% in Layer 2. Thus, injectivity was reduced by about 90% in both zones.

Hall Plots for Analysis of Gel Treatments in Fractured Injection Wells. Previous theoretical analyses[13,16] and field results[8-11,52] indicate that with the proper gelation chemistry, gel treatments can be quite effective if fractures are the source of a severe channeling problem. Because of the high permeability contrast, injected gelant will penetrate much farther into the fracture than into the adjacent rock matrix. A Hall plot is useful because it can indicate whether the injected gelant is reducing the flow capacity of something. However, the Hall plot by itself does not indicate that the gel is plugging the fracture more than the matrix. Also, there is no way to tell from a Hall plot how far the gelant has penetrated into either the fracture or the rock matrix.

For example, consider a fractured injection well that experiences an injectivity decrease when a gelant is injected. Several possibilities could explain the reduced injectivity and the resulting increase in slope of a Hall plot. First, the gel could plug most or all of the fracture without significantly damaging the surrounding rock matrix. Second, the gelant could enter and plug both the fracture and much of the rock matrix near the wellbore. This possibility becomes more likely with increased viscosity of the injected gelant. Third, the gel could "screen out" in the fracture, thereby plugging the fracture only near the wellbore. Thus, in both fractured and unfractured wells, Hall plots do not indicate selectivity during gelant placement.

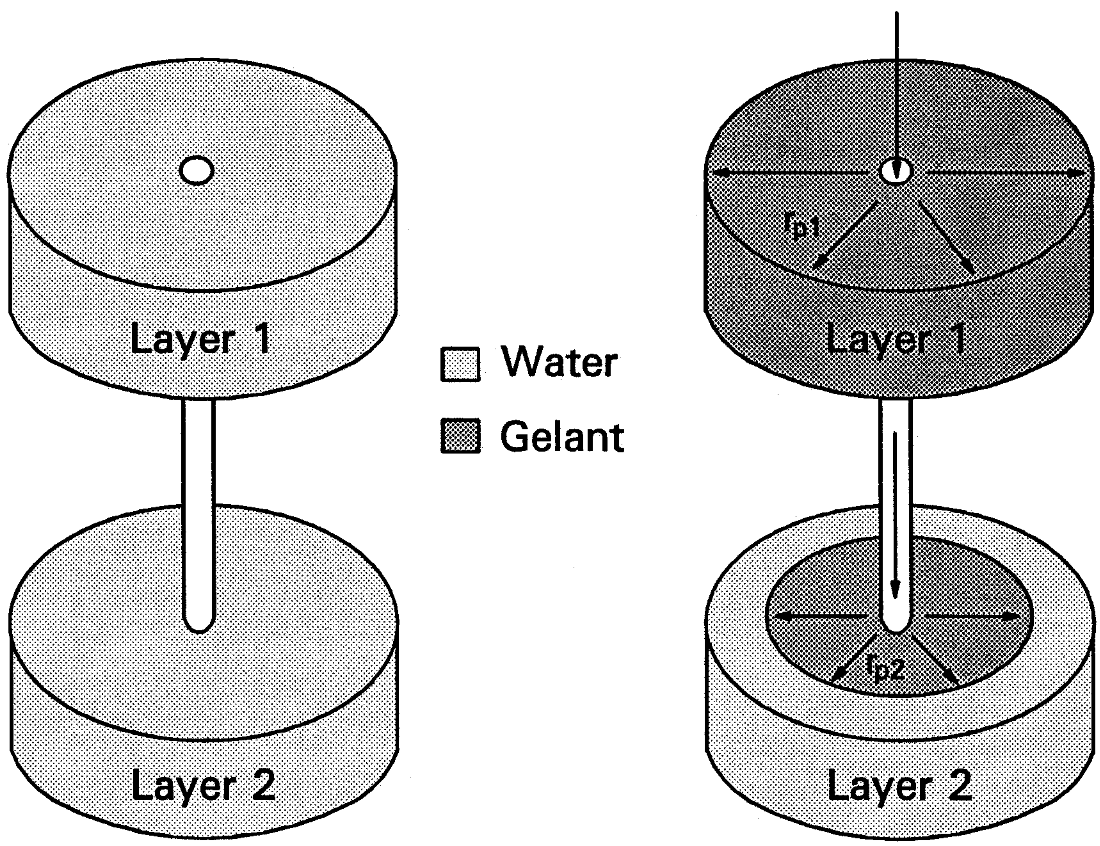


Fig. 25. Gelant placement in radial flow.

Injectivity Increases During Gelant Injection. During gelant injection, injectivity can sometimes increase. This injectivity increase is seen as a decrease in the slope of a Hall plot, as shown in Fig. 26. Some vendors interpret the injectivity increase as resulting from the opening of previously unswept or underswept zones. However, this is only one possibility. Another possibility is that a fracture has been opened. This fracture could be new or it could be an old fracture that reopened when the bottom-hole pressure was increased. The Hall plot cannot distinguish whether a fracture is opening only in one zone or in all zones. Another possibility is that gel in the near-wellbore portion of a fracture has mobilized or broken down—thus reopening the fracture. Other possibilities also exist.

Conclusions

By themselves, Hall plots do not indicate selectivity during gel placement. Hall plots may be a useful indicator that the injected gel is doing something, but it does not indicate whether the gel is being placed in a beneficial or harmful manner.

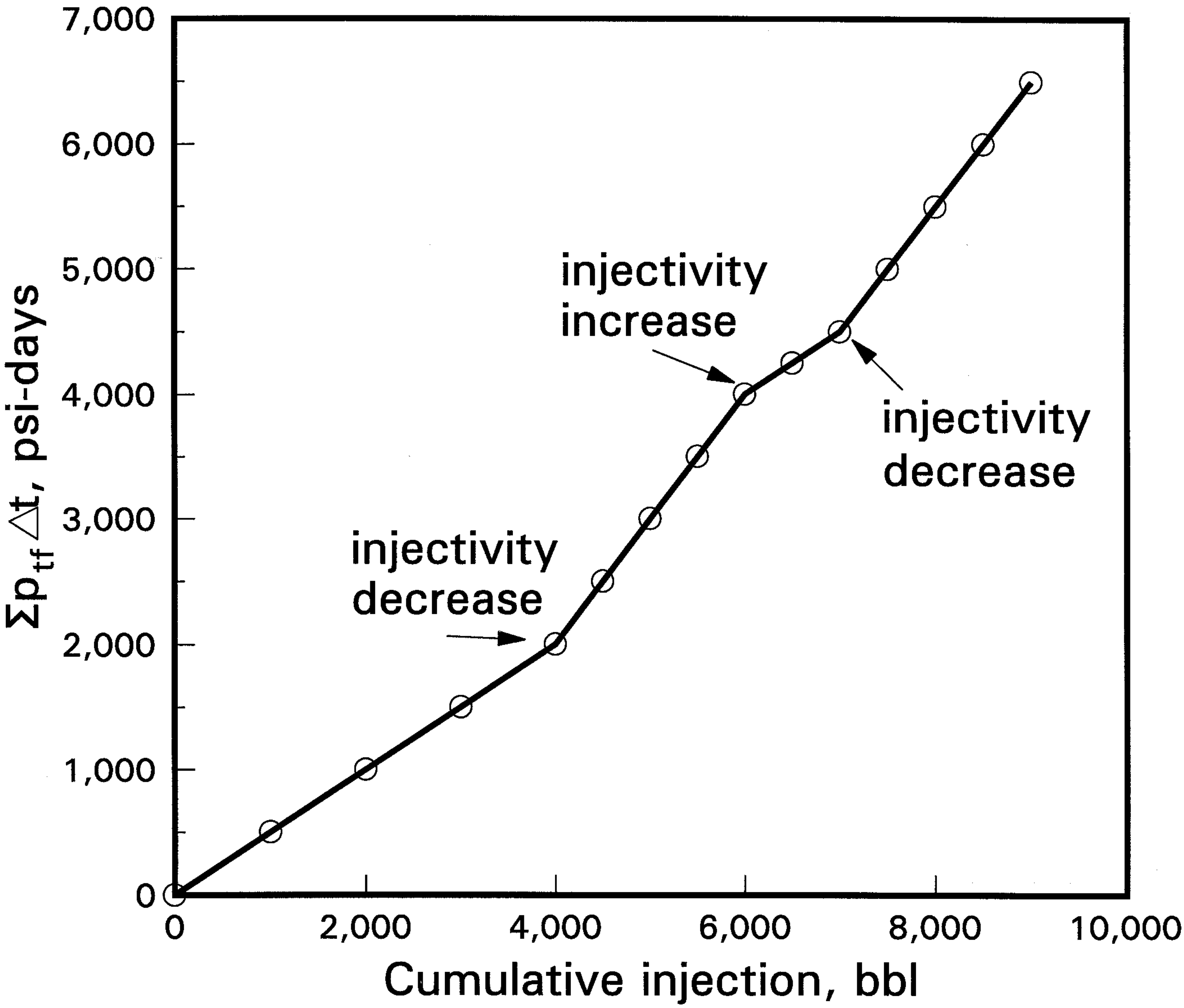


Fig. 26. Hall plot with both injectivity increases and decreases.

7. GEL TREATMENTS IN PRODUCTION WELLS WITH WATER-CONING PROBLEMS

This chapter discusses gel treatments in production wells with water-coning problems. Water coning is a common problem encountered when a reservoir is produced by bottomwater drive. The excess water production associated with this phenomenon can significantly shorten the economic producing life of a well. The hydrostatic pressure created by high fluid levels is also detrimental to oil production.

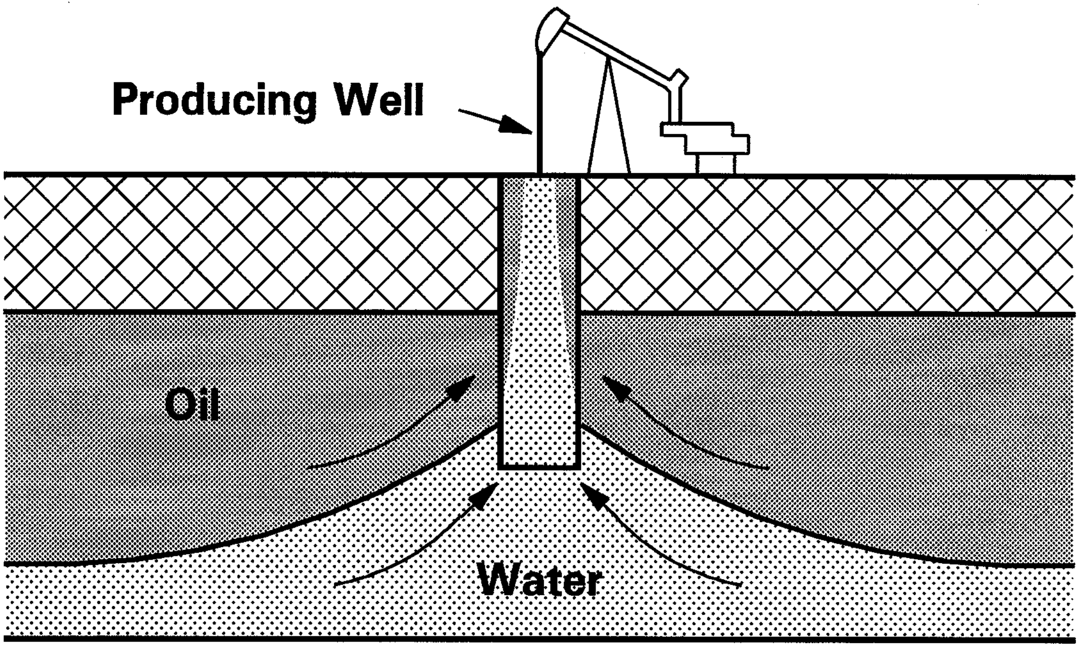
In 1934, Muskat and Wyckoff[53] first proposed that an extended shale streak at the bottom of a well can reduce water coning by preventing bottomwater from entering the well. Karp *et al.*[54] expanded this idea by proposing the placement of a horizontal barrier at the bottom of a well to reduce water coning. Specifically, they suggested inducing a horizontal fracture above the water-oil contact and then filling it with cement (see Fig. 27). A major limitation of Karp's idea is that horizontal fractures can be induced only at very shallow depths.[55] However, other methods are available for introducing a horizontal barrier. Here, we focus on the use of gels to form a horizontal barrier to reduce water coning. Using simple equations and ideas, we will consider some of the conditions, gel properties, and placement problems that influence how effectively gel treatments reduce water coning.

Gel Placement

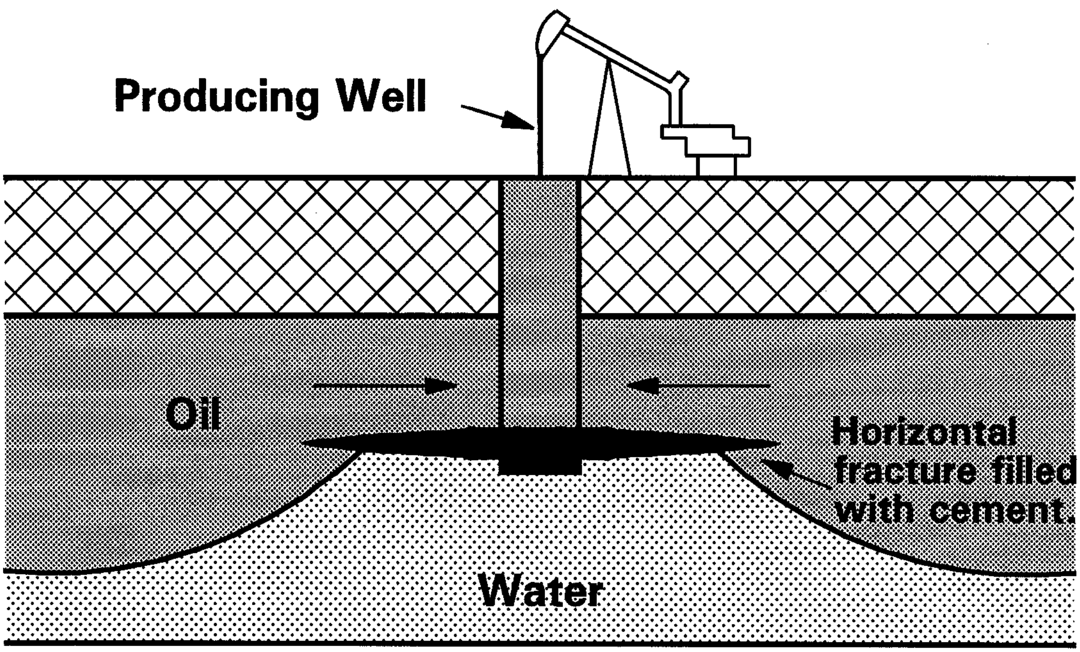
A common misconception is that aqueous gelants will not penetrate to any significant extent into zones with high oil saturations.[56] Thus, Fig. 28 illustrates a typical view of gel placement in a production well with a water-coning problem. In this view, the gelant enters only the water cone. However, this picture is correct only if the oil is extremely viscous and/or the aqueous gelant is injected at an extremely low rate (to exploit gravity during gelant placement). For the majority of field applications to date, the crude oils were not particularly viscous and gelant injection rates were relatively high (i.e., gelant injection rates were not greatly different from the fluid production rates before the gel treatment).*

Straightforward applications of the Darcy equation and fractional-flow theory demonstrate that gelants can penetrate to a significant degree into all open zones—not just those zones with high water saturations.[14] Also, in field applications, capillary effects will not prevent gelant penetration into oil-productive zones.[17] Thus, Fig. 29 is usually more representative of the gel placement process than Fig. 28. When the gel forms, oil productivity can be damaged significantly unless the gel has a special property—that is, an ability to reduce water permeability much more than oil permeability. To understand why this property is desirable, consider Fig. 29. If the gel does not significantly lower the permeability to oil, then oil can flow through the gel barrier in the upper portion of the oil zone. In contrast, when the rising water cone reaches the gel barrier, a low permeability to water impedes water influx into the well. The net effect is that the gel forms a horizontal barrier that inhibits water coning. This result does not necessarily mean that the gel will allow a higher oil production rate. If the cone height outside of the gel-treated region is high, the high water saturation can significantly restrict the rate at which oil can flow to the well (see Fig. 30).

*Based on interviews with gel vendors and service companies during 1992.



a. Before treatment.



b. After inducing a horizontal fracture
and filling with cement.

Fig. 27. Reduction of water coning using idea from Karp *et al.*[54]

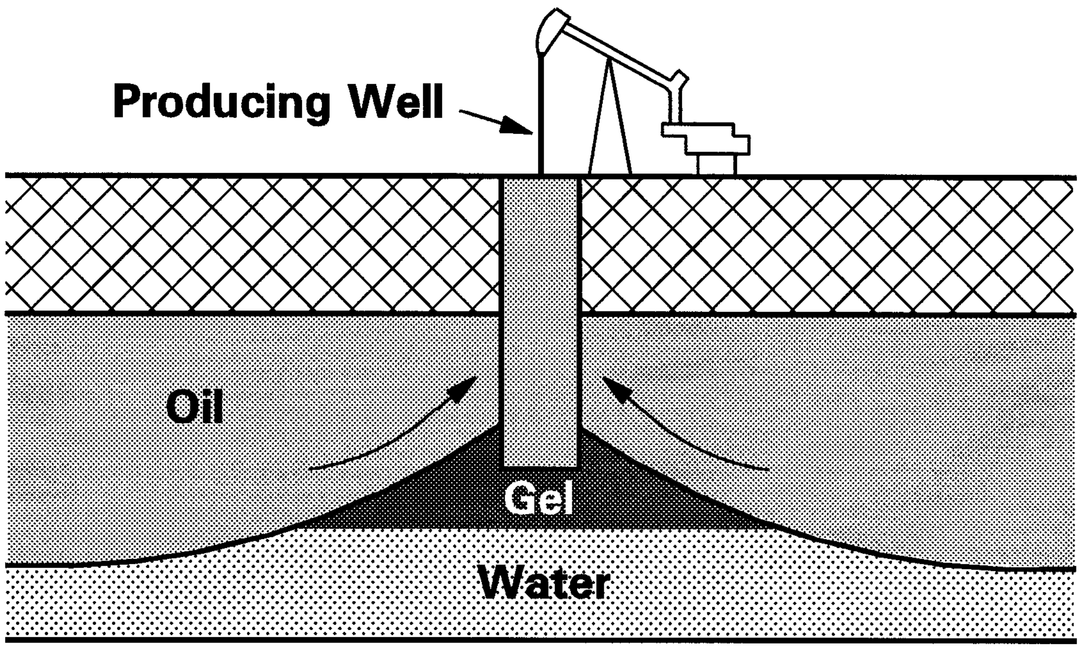


Fig. 28. Incorrect view of gel placement. (Gelant only enters zones with high water saturations.)

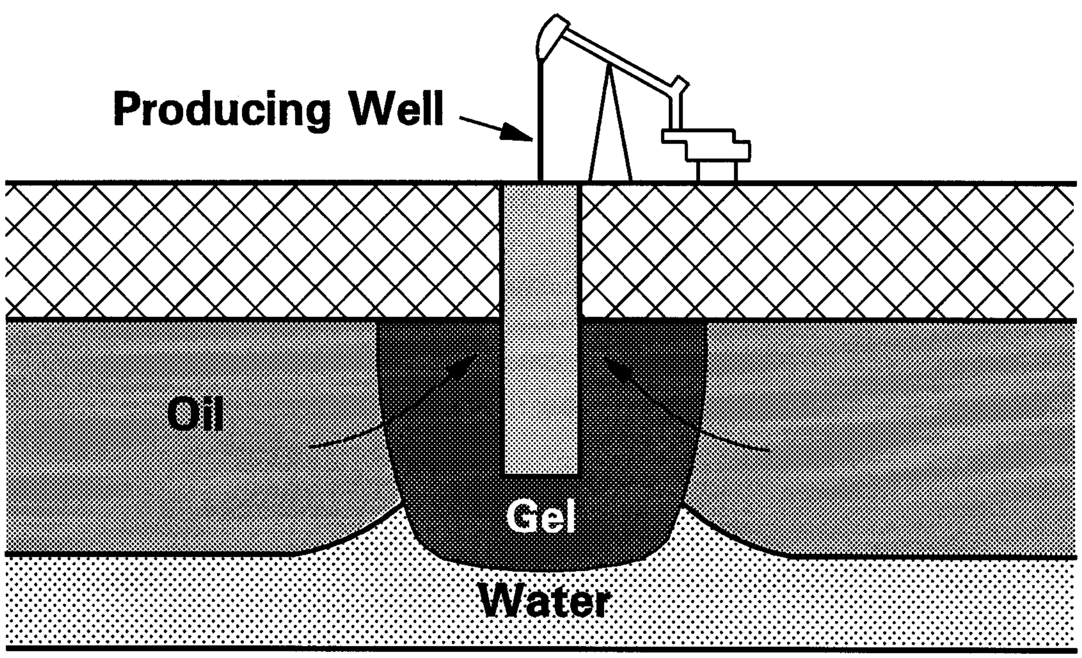
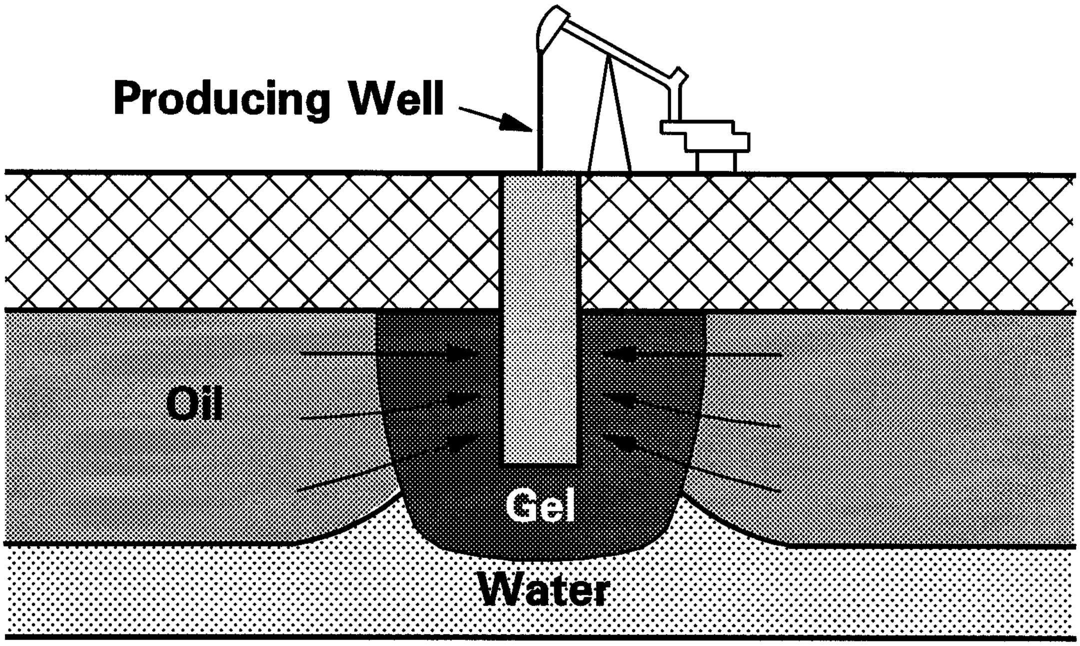
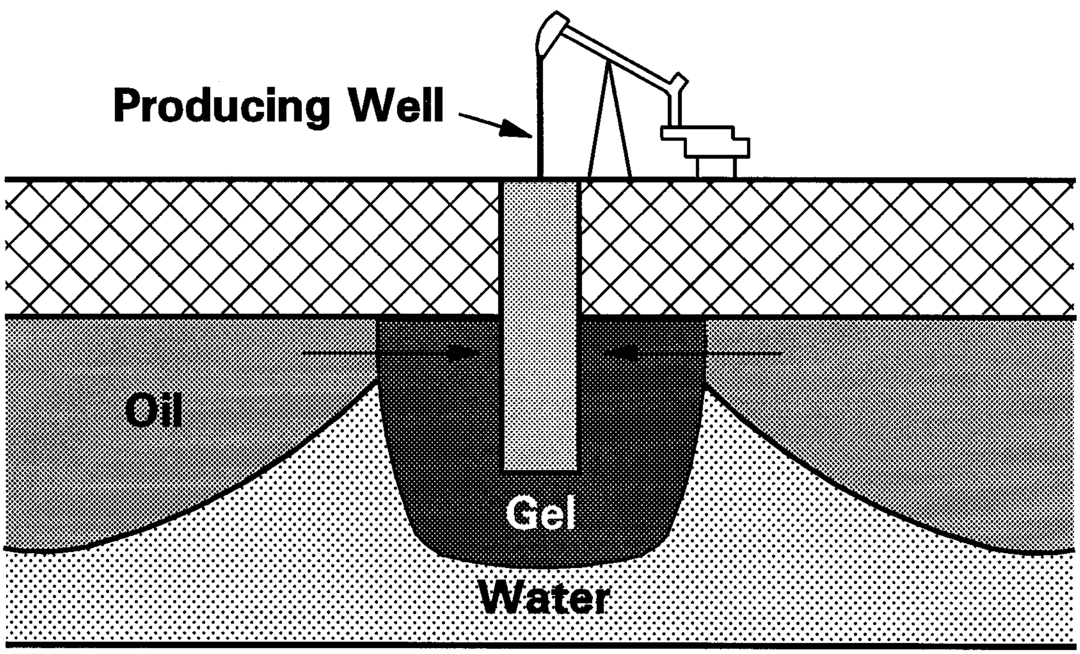


Fig. 29. Correct view of gel placement. (Gelant enters all open zones.)



a. Low cone height: oil flow is not restricted.



b. High cone height: water block restricts oil flow.

Fig. 30. Effect of water cone height outside of the gel-treated region.

Effect of Gel on the Critical Rate in Unfractured Wells

Over the years, a number of theoretical models have been developed to describe water coning.[57-68] Here, we examine several coning models to establish the effect of a horizontal barrier (e.g., a gel bank) on coning in unfractured wells. We note that different coning models can predict very different critical rates. (The critical rate is the maximum allowable production rate for water-free production.) However, the following discussion will demonstrate that, for most models, predictions are fairly similar for the effect of a horizontal barrier on the critical rate.

The following is a brief review of the theoretical coning models. Unless otherwise mentioned, all reservoirs are assumed to be homogeneous and isotropic. The fluids are assumed to be incompressible. All models presented in this study assume a steady-state flow condition.

Muskat Model. Muskat[57] proposed Eq. 7 to estimate the critical production rate for three-dimensional water coning.

$$q_c = \frac{\pi k_m g(\rho_w - \rho_o)(h_e^2 - h_w^2)}{\mu_o \ln(r_e/r_w)} \tag{7}$$

After placing a horizontal barrier near the wellbore, Karp *et al.*[54] proposed that the critical rate after treatment can be calculated by substituting the radius of the horizontal barrier, r_b, for the wellbore radius, r_w, in Eq. 7. Thus, Eq. 8 is used to estimate the critical rate, q_{cb}, after placement of the horizontal barrier.

$$q_{cb} = \frac{\pi k_m g(\rho_w - \rho_o)(h_e^2 - h_w^2)}{\mu_o \ln(r_e/r_b)} \tag{8}$$

Since r_w and r_b are the only parameters that are different before vs. after a treatment, Eq. 9 was used in our previous study[14] to estimate the effect of a gel treatment on the critical rate in an unfractured well. In the study, r_b was redefined as the horizontal radius of the gelant bank.

$$\frac{q_{cb}}{q_c} = \frac{\ln(r_e/r_w)}{\ln(r_e/r_b)} \tag{9}$$

Schols Model. Schols[58] derived an empirical formula (Eq. 10) for critical rate estimation based on experimental results.

$$q_c = \left[\frac{(\rho_w - \rho_o)k_m(h_e^2 - h_w^2)}{2049\,\mu_o}\right]\left[0.432 + \frac{\pi}{\ln(r_e/r_w)}\right]\left(\frac{h_e}{r_e}\right)^{0.14} \tag{10}$$

Following Karp's logic, we can calculate the critical rate after a gel treatment by substituting r_b for r_w (Eq. 11).

$$q_{cb} = \left[\frac{(\rho_w - \rho_o) k_m (h_e^2 - h_w^2)}{2049\,\mu_o}\right]\left[0.432 + \frac{\pi}{\ln(r_e/r_b)}\right]\left(\frac{h_e}{r_e}\right)^{0.14} \tag{11}$$

We note that the only parameters that are different before vs. after a gel treatment are r_b and r_w. Thus, the effect on the critical rate can be estimated using Eq. 12.

$$\frac{q_{cb}}{q_c} = \frac{0.432 + \dfrac{\pi}{\ln(r_e/r_b)}}{0.432 + \dfrac{\pi}{\ln(r_e/r_w)}} \tag{12}$$

Abass and Bass Model. Using a volume-averaged two-dimensional radial flow model, Abass and Bass[59] derived the following equation for critical rate calculation:

$$q_c = \frac{3.07 k_m h_w (\rho_w - \rho_o)(h_e - h_w)}{\mu_o\left[\dfrac{(h_e - h_w)^2}{(h_e - h_w)^2 - r_w^2}\ln\left(\dfrac{h_e - h_w}{r_w}\right) - 0.5\right]} \tag{13}$$

By substituting r_b for r_w in Eq. 13, Eq. 14 can be used to calculate the critical rate after a gel treatment.

$$q_{cb} = \frac{3.07 k_m h_w (\rho_w - \rho_o)(h_e - h_w)}{\mu_o\left[\dfrac{(h_e - h_w)^2}{(h_e - h_w)^2 - r_b^2}\ln\left(\dfrac{h_e - h_w}{r_b}\right) - 0.5\right]} \tag{14}$$

The effect of a gel treatment on the critical rate can be estimated by Eq. 15.

$$\frac{q_{cb}}{q_c} = \frac{\dfrac{(h_e - h_w)^2}{(h_e - h_w)^2 - r_w^2}\ln\left(\dfrac{h_e - h_w}{r_w}\right) - 0.5}{\dfrac{(h_e - h_w)^2}{(h_e - h_w)^2 - r_b^2}\ln\left(\dfrac{h_e - h_w}{r_b}\right) - 0.5} \tag{15}$$

Meyer and Garder Model. Meyer and Garder[60] derived the following equation to estimate the effect of an impermeable barrier on the critical production rate:

$$\frac{q_{cb}}{q_c} = \frac{1}{1 - \dfrac{\ln(r_b/r_w)}{\ln(r_e/r_w)}} \quad . \tag{16}$$

By redefining r_b as the horizontal radius of the gelant bank, Eq. 16 can be used to estimate the effect of a gel treatment on the critical rate.

Chappelear and Hirasaki Model. Chappelear and Hirasaki[61] derived Eq. 17 for critical rate calculations. In their derivation, they assumed vertical equilibrium and segregated flow. A correction factor, r′, was incorporated in their model to account for the departure from vertical equilibrium in the immediate vicinity of the well.

$$q_c = \frac{2\pi h_t k_m \overline{k_{ro}}(\rho_w - \rho_o) g (h_e - h_w)}{887.2\,\mu_o\left(\dfrac{\ln[r_e/(r_w + r')]}{[1 - (r_w + r')^2/r_e^2]} - 0.5\right)} \tag{17}$$

By substituting r_b for r_w in Eq. 17, the critical rate after a gel treatment can be estimated by the following equation:

$$q_{cb} = \frac{2\pi h_t k_m \overline{k_{ro}}(\rho_w - \rho_o) g (h_e - h_w)}{887.2\,\mu_o\left(\dfrac{\ln[r_e/(r_b + r')]}{[1 - (r_b + r')^2/r_e^2]} - 0.5\right)} \quad . \tag{18}$$

Thus, the effect of a gel treatment on critical rate can be estimated by Eq. 19.

$$\frac{q_{cb}}{q_c} = \frac{\dfrac{\ln[r_e/(r_w + r')]}{[1 - (r_w + r')^2/r_e^2]} - 0.5}{\dfrac{\ln[r_e/(r_b + r')]}{[1 - (r_b + r')^2/r_e^2]} - 0.5} \tag{19}$$

Other Models. Since the wellbore radius is generally very small and does not change much from one well to another, its effect on the critical rate is often considered negligible. Therefore, in several other coning models, the wellbore radius was not included.[62-68] Without the wellbore radius in the equations, we can not evaluate the effect of gelant penetration on the critical rate. Thus, in this study, we used only those models[57-61] where the wellbore radius was included in the derivations.

Comparison of Model Predictions. How much can a gel treatment be expected to affect the critical rate? The critical rate for water coning indicates the maximum production rate at which water from an underlying aquifer does not reach the wellbore. For economic reasons, the *desired* production rate is often greater than the critical rate. In order for a gel treatment to be effective, the critical rate must be increased to exceed the rate at which the well will actually be produced.

Fig. 31 illustrates the effect of gel treatments on the critical production rate, based on the coning models presented in the previous sections. In this figure, the critical rate increase is defined as the critical rate after treatment divided by the critical rate before treatment. The ratio is plotted against the radius of gelant penetration into the formation. Eqs. 9, 12, 15, 16, and 19 were used to generate the results shown in Fig. 31. The well has a drainage radius, r_e, of 372 ft (10-acre well spacing). The wellbore radius, r_w, is 0.33 ft, the oil zone thickness, h_e, is 100 ft, and the depth of well penetration into the oil zone, h_w, is 25 ft.

As shown in Fig. 31, the critical rate increase predicted by Abass' model[59] is much more sensitive to the radius of gelant penetration than that predicted by other models. In their derivations, they assumed that the thickness of the oil zone dominated by radial flow was the same as the gross perforated interval and that only the oil flow in the radial-flow region contributed to the upward movement of the cone. A volume-averaged two-dimensional radial flow model was used to calculate the pressure drawdown between the wellbore and the radial-flow region extending from the wellbore to the radius of the cone. Since this model is actually two-dimensional in nature, it is not surprising that the critical rate increase predicted by this model is much more sensitive to the radius of gelant penetration than that predicted by other three-dimensional models. Also, Fig. 32 shows that this model predicts unrealistic values when the radius of gelant penetration exceeds 45 ft.

Fig. 31 shows that, for gel treatments with a radius of gelant penetration less than 200 ft, the theoretical models predict that the critical rate after treatment should not be expected to increase by more than a factor of 5 to 15. For typical gel treatments with the radius of gelant penetration ranging from 20 to 100 ft, Fig. 31 shows that the models (excluding the Abass model) predict a factor of 1.5 to 5 increase in critical rate after treatment. In other words, the desired production rate should be less than one and one-half to five times the pretreatment rate in order for gel treatments to be effective in unfractured wells.

Effect of Gel on the Critical Rate in Fractured Wells

For gel treatments in bottomwater drive reservoirs, a recent survey revealed that more than 90 percent of the applications occurred in production wells that were known to be fractured (see Chapter 3). Thus, "coning" in fractured systems may be of greater interest than in unfractured systems. Muskat[69] presented Eq. 20 to estimate the critical rate in a two-dimensional geometry (e.g., a vertical fracture).

$$\frac{q_{cf} = k_f g w_f (\rho_w - \rho_o)(h_e^2 - h_w^2)}{2 \mu_o (L_f - r_w)} \tag{20}$$

Eqs. 7 and 20 can be used to compare the critical rates in fractured vs. unfractured wells.[14] Dividing Eq. 7 by Eq. 20 yields Eq. 21.

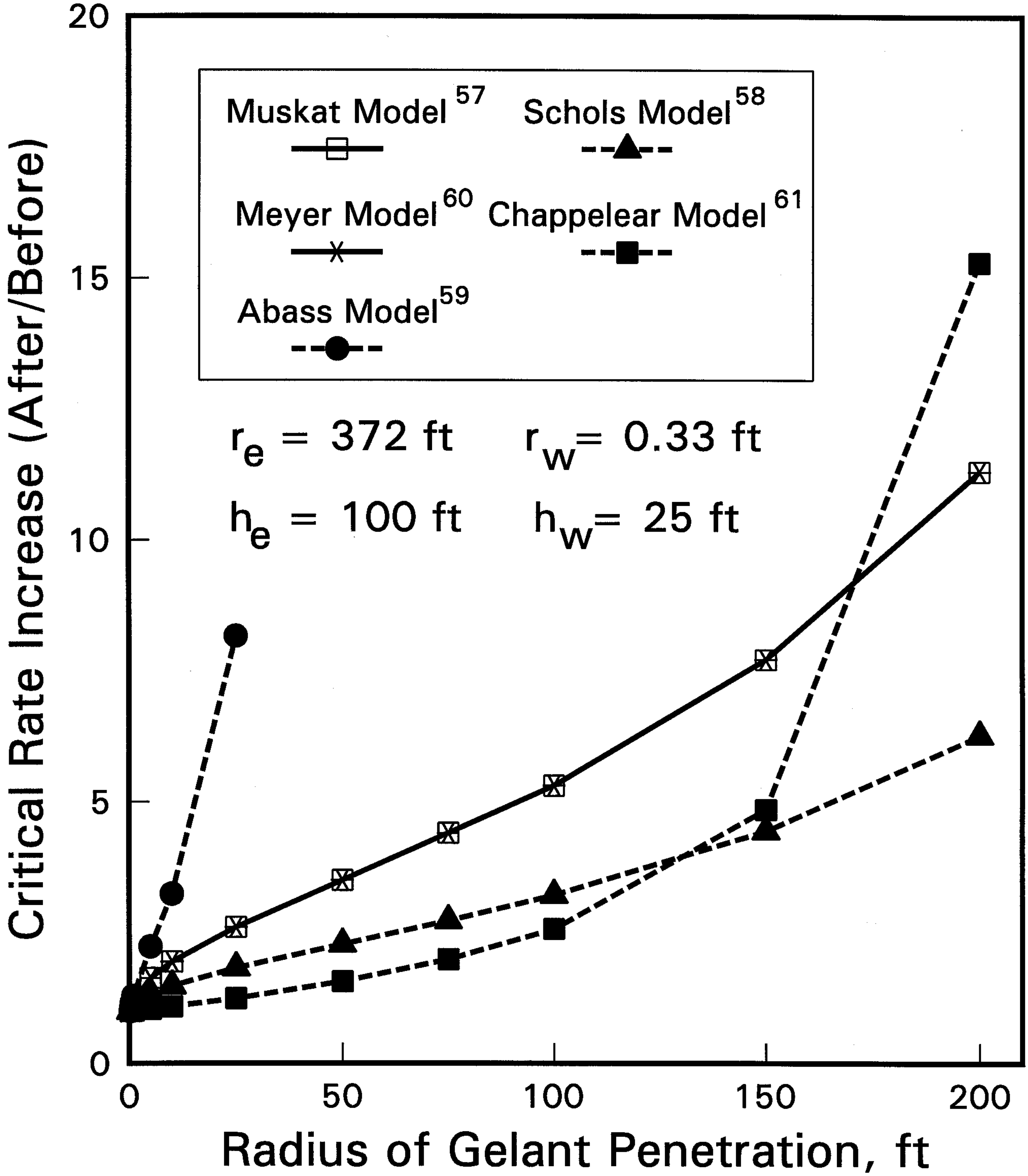


Fig. 31. Effect of gel treatments on critical rate in unfractured production wells.

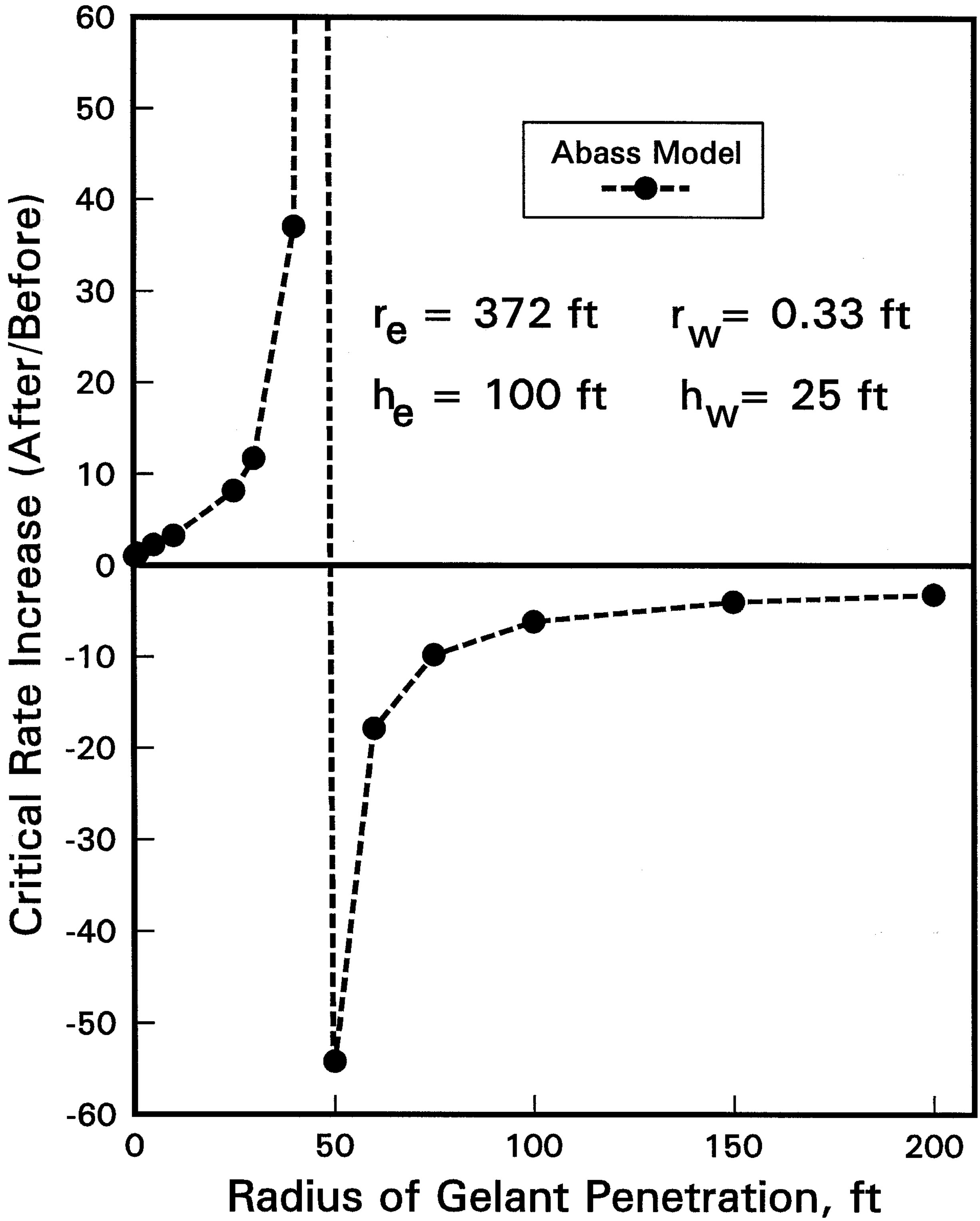


Fig. 32. Effect of gel treatments on critical rate (Abass Model).

$$\frac{q_c}{q_{cf}} = \frac{2\pi(L_f - r_w)k_m}{w_f \ln(r_e/r_w)k_f} \tag{21}$$

If $L_f=100$ ft, $r_w=0.33$ ft, $k_f/k_m=1{,}000$, $\ln(r_e/r_w)=6$, and $w_f=0.001$ ft, then $q_c/q_{cf}\approx 100$. Thus, for a typical set of parameters, the critical rate in a three-dimensional system (i.e., an unfractured well) can be two orders of magnitude greater than that in a two-dimensional system (i.e., a fractured well). In other words, if a gel treatment simply healed the fracture (see Fig. 33), it could increase the critical rate by a factor of 100.

A number of factors could prevent a gel treatment from completely healing a fracture. If a gel treatment cannot completely heal the fracture, how will the critical rate be affected by partial gelant penetration in the fracture? The logic that Karp *et al.* used for the three-dimensional coning problem should also be applicable to the two-dimensional problem. In particular, the effect of placing an impermeable material (e.g., gel) in the fracture should be to increase r_w in Eq. 20. If x_b is the distance of gelant penetration in a fracture of length, L_f, then the critical rate after gelation can be estimated using Eq. 22.

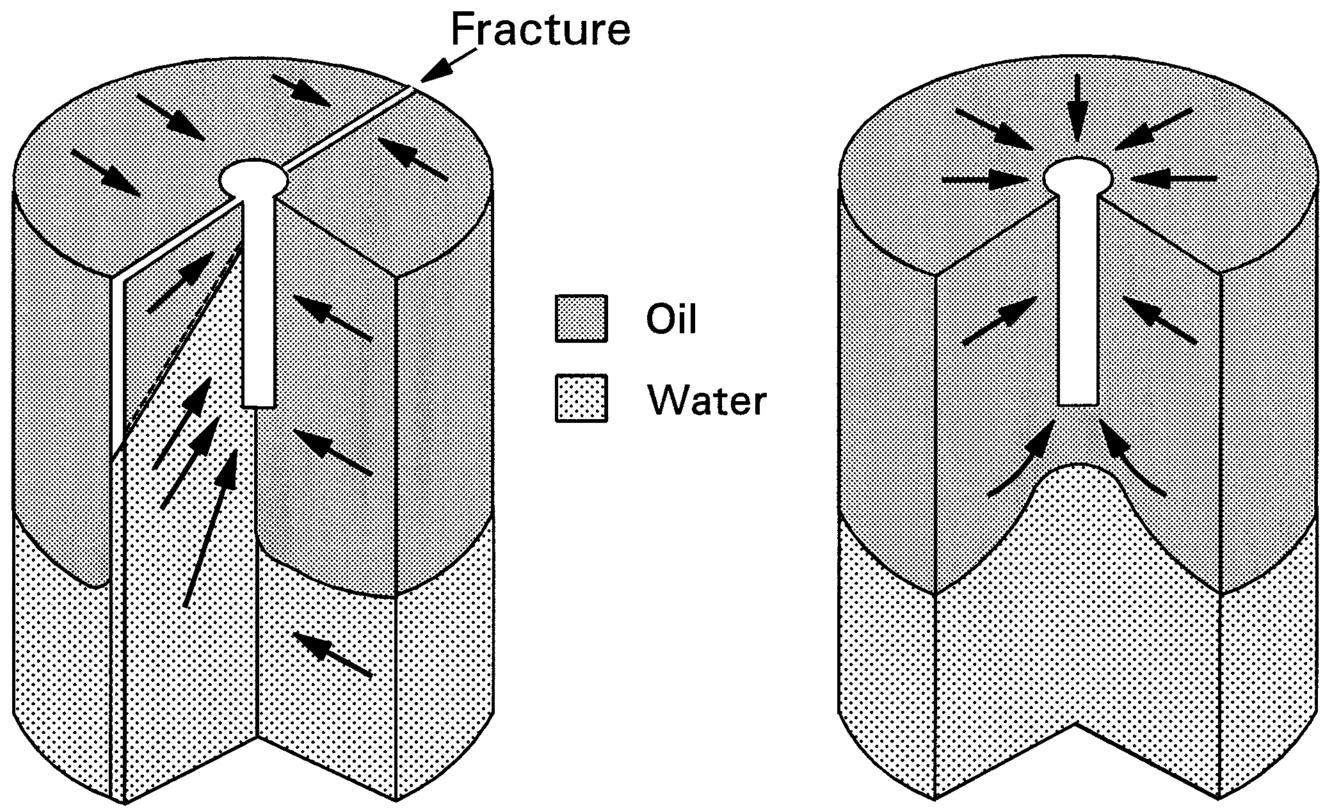
$$q_{cf} = \frac{k_f g w_f(\rho_w - \rho_o)(h_e^2 - h_w^2)}{2\mu_o(L_f - x_b)} \tag{22}$$

This equation predicts that the critical rate should vary inversely with L_f-x_b. Of course, the equation becomes invalid as x_b approaches L_f, since an infinite critical rate is predicted. In reality, the critical rate should approach that for an unfractured well as x_b approaches L_f.

Although healing a fracture could dramatically increase the critical rate, it could also significantly reduce the well's productivity. The productivity loss associated with complete healing of the fracture may not be acceptable, especially in tight formations. An alternative objective could be to place the gel some distance into the rock matrix along the fracture face, while leaving the fracture open to flow. This course of action relies, again, on an ability of the gel to reduce water permeability much more than oil permeability. Ideally, this property, in concert with gravity, would prevent water in the aquifer from entering the fracture. In contrast, oil could still enter the fracture and flow to the production well (see Fig. 34). A third objective could be to place the gel only in the lower part of the fracture, as indicated in Fig. 35. Of course, one must exploit gravity during the gelant placement process for this scheme. If this placement can be achieved, then water production could be reduced substantially while maintaining high oil productivity.

Conclusions

Analysis using different theoretical coning models suggests that in order for a gel treatment to be effective in unfractured production wells, the desired production rate should be less than one and one-half to five times the pretreatment critical rate. These calculations also suggest that under ideal conditions, gel treatments in fractured wells could increase the critical rate by two orders of magnitude. For gels applied to reduce water coning, an essential property is an ability to reduce water permeability much more than oil permeability.



a. Before gel

b. After gel:
healed fracture

Fig. 33. Reduced coning by healing a fracture.

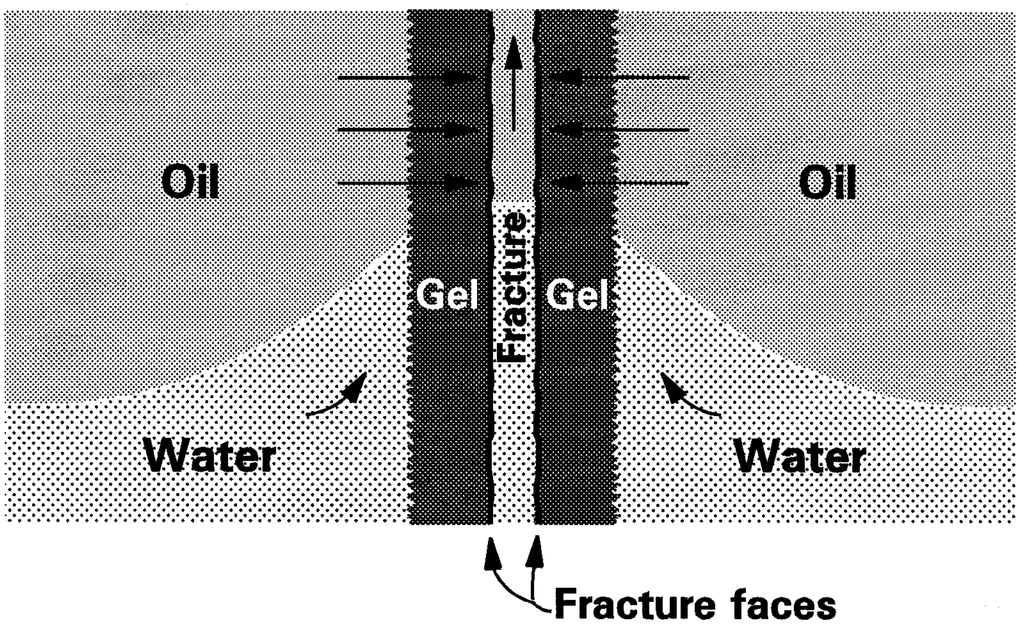


Fig. 34. Gel restricting water entry into a fracture.

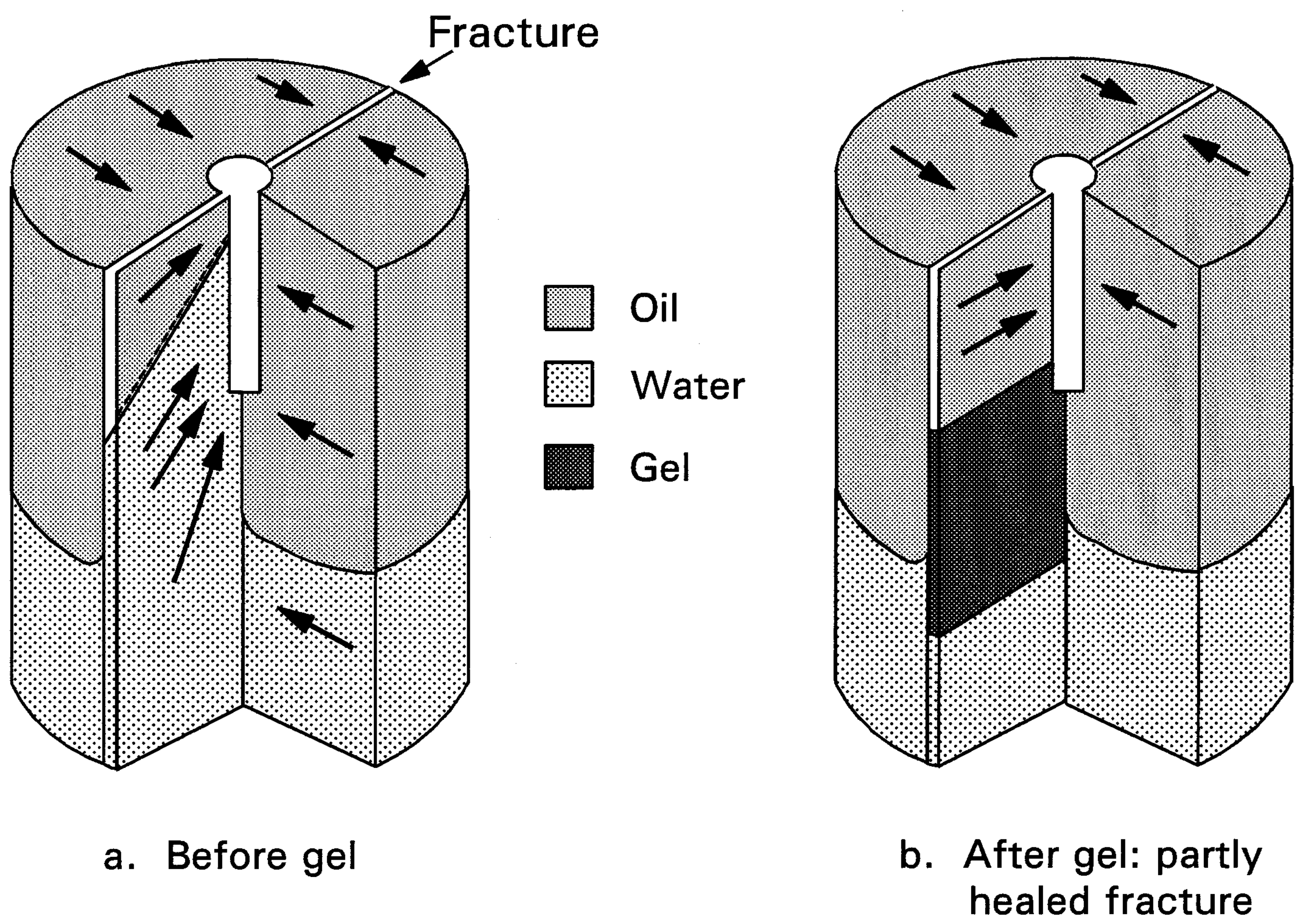


Fig. 35. Reduced coning by partly healing a fracture.

8. EXPLOITING DENSITY DIFFERENCES DURING GELANT PLACEMENT

Previously, we investigated how gel placement is affected by various factors, including rheology,[15,17,50,70] chemical retention,[13,49] pH effects,[49] dispersion,[16,17] reservoir heterogeneity,[17] crossflow,[17,18] relative-permeability effects,[14,70] capillary pressure,[17] and postflushes.[16-18,71] In this chapter, we examine whether gravity and density differences can be exploited to optimize gel placement.

Eq. 23 describes the Darcy equation, taking gravity into account.[72]

$$u = -\frac{k}{\mu}\left(\frac{dp}{dl} + \frac{\rho g}{1.0133 \times 10^6}\frac{dz}{dl}\right) \tag{23}$$

where

- dp/dl = pressure gradient in the direction of flow, atm/cm
- dz/dl = vertical gradient in the direction of flow, cm/cm
- g = acceleration due to gravity, cm/s^2
- k = permeability, darcys
- u = superficial velocity, cm/s
- μ = viscosity, cp
- ρ = density, g/cm^3

The dimensionless gravity number, G, provides a means to compare the importance of gravity forces relative to viscous forces during a displacement of oil by water.[72]

$$G = \frac{k\, k_{rw}\, \Delta\rho\, g\, \sin\Theta}{1.0133 \times 10^6\, u\, \mu_w} \tag{24}$$

where

- k_{rw} = relative permeability to water, darcys
- μ_w = water viscosity, cp
- $\Delta\rho$ = water density minus oil density, g/cm^3
- Θ = angle of inclination, degrees

If gravity alone acts as the driving force, then the vertical superficial velocity, u_z, is given by Eq. 25.

$$u_z = -\frac{k\, \Delta\rho\, g}{1.0133 \times 10^6\, \mu} \tag{25}$$

Recognizing that $g \approx 980$ cm/s^2 and that 1 cm/s = 86,400/(12 x 2.54) ft/d, Eq. 25 can be transformed into Eq. 26 if u_z is desired in units of ft/d.

$$u_z = - \frac{2.74\ k\ \Delta\rho}{\mu} \tag{26}$$

Fig. 36 illustrates u_z as a function of k/μ and $\Delta\rho$. In the following sections, Eqs. 24 and 26 and Fig. 36 will be used to illustrate several points concerning the effect of gravity on gel placement.

Gel Placement in Fractured Wells

The process of gel placement usually consists of two stages. First, the gelant is injected in a fluid form. Second, the well is shut in to allow gelation to take place. During the first stage (gelant injection) in fractured wells, viscous forces virtually always dominate over gravity forces—i.e., the gravity number is much less than one. To demonstrate this fact, first consider a fracture with an effective permeability of 100 darcys, fluids with a density difference of 0.2 g/cm^3, a viscosity of 1 cp, and $\sin \Theta = 1$,

$$G = \frac{(100)\ (0.2)\ (980)\ (1)}{(1.0133 \times 10^6)\ (1)\ u} = \frac{0.0193}{u} \tag{27}$$

where u is expressed in units of cm/s.

For gel treatments in fractured production wells, gelant injection rates are typically very high—i.e., 50 to 500 BPD/ft of pay.** Thus, for a fracture with a width of 0.01 ft, the velocity in the fracture during gelant injection typically ranges from 28,000 to 280,000 ft/d (10 to 100 cm/s). With these velocities, the G values range from 0.000193 to 0.0.00193. Note that the gravity number is substantially less than one. Even if the fracture was 100 times more permeable, the G values would still be much less than one. Thus, viscous forces dominate over gravity forces during gelant injection into fractures. This fact means that the position of the gelant front will not be significantly affected by gravity during gelant injection.

When the well is shut in after gelant injection, how rapidly will gravity equilibrate the level of the gelant-oil interface in the fracture? In performing this analysis, we assume that oil has ready access to the fracture, either from the rock matrix or from portions of the fracture beyond the gelant front. (This assumption will generally be valid for applications in production wells but not in injection wells.) We also assume that fluid displacements are piston-like (i.e., that capillary-pressure and relative-permeability effects are negligible). Given a fracture permeability of 100 darcys, a density difference of 0.2 g/cm^3, and a 1-cp fluid viscosity, u_z is -55 ft/d (from Eq. 26). Thus, the rate of interface equilibration in a fracture can be quite rapid. For example, a fracture 55 ft high could be drained of gelant in 1 day if the gelation time is long enough.

Exploiting gravity to clear a fracture of gelant before gelation could be useful for applications in production wells. By clearing the upper portion of a fracture, a high-permeability conduit remains open for oil to flow to the well. Without this conduit, oil productivity could be severely impaired.

**Based on discussions with vendors, 1992.

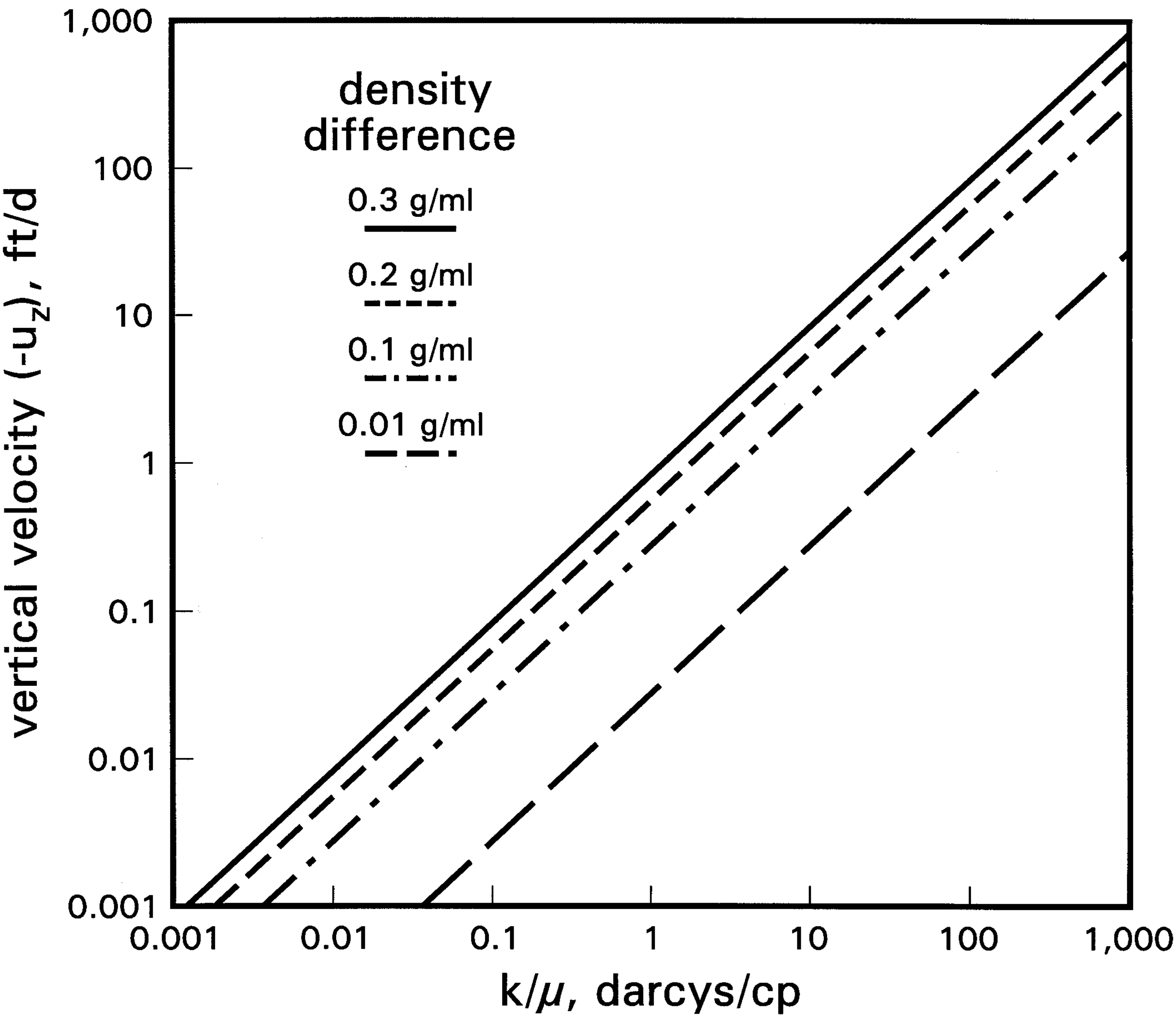


Fig. 36. Vertical velocity vs. k/μ and density difference.

After placement, the gel must effectively restrict water flow. If the source of the excess water is an underlying aquifer, then gravity would cause gelant to drain into and plug that part of the fracture located in the aquifer. If the gelant density is the same as that for the aquifer water, then gravity should prevent the final gelant-oil interface from falling below the pretreatment (static) water-oil interface.

If the gelant-oil interface does fall to the level of the pretreatment static water-oil interface, then some way must be found to prevent water from coning into the fracture. One plausible method could be realized if (1) the gel has penetrated some distance into the rock matrix and (2) the gel reduces water permeability much more than oil permeability.[42] Fig. 34 can be used to illustrate this possibility. If the product of the oil residual resistance factor and the distance of gel penetration from the fracture face (into the rock matrix) is relatively small, then the gel will not significantly impede oil from entering the fracture and flowing to the well.[71] If at the same time, the product of water residual resistance factor and the distance of gel penetration from the fracture face is large, then water entry into the fracture can be restricted considerably.

For example, consider a gel that has leaked off 0.1 ft from the fracture face in both the oil and water zones (see Fig. 34). Assume that the gel provides an oil residual resistance factor of 100 and a water residual resistance factor of 5,000. Then, in the oil zone, the gel provides a resistance to oil flow that is equivalent to only 10 feet of additional rock (0.1 x 100). In contrast, in the water zone, the gel barrier would provide a resistance to water flow that was equivalent to 500 feet of additional rock (0.1 x 5,000). Obviously, both the permeability reduction and the distance of gel penetration are important in determining the performance of a gel treatment.

In the above analysis, we assumed that oil has ready access to the fracture, either from the rock matrix or from portions of the fracture beyond the gelant front. If this assumption is not valid, then an oil postflush may be necessary (before shut in) to achieve the desired placement of gelant in the lower part of the fracture. Alternatively, oil and gelant could be injected simultaneously (e.g., oil injected into the top part of the fracture and water injected into the bottom part of the fracture). One potential problem with this idea is the oil and gelant may mix and emulsify because of turbulence created by the high velocity in the fracture. However, gravity segregation after injection could still lead to a useful gelant placement. If turbulence during injection will cause emulsification, then isolated injection of oil and water into different parts of the fracture may not be necessary.

Gravity is less likely to be exploitable in other types of fractured production wells. For example, if water channels through a fracture from an injection well to a producer, plugging the bottom portion of a vertical fracture will not prevent water from channeling through the top part of the fracture. For the same reason, gravity is not likely to be exploitable during gel placement in fractured injection wells. A preferred location for gel in a fracture in an injector (i.e., top or bottom) is not obvious. Presumably, the fracture is the offending channel, and channeling can occur in the top part of the fracture as well as in the bottom part. Also, in injection wells, very little mobile oil will be present near the wellbore or in the near-wellbore portion of the fracture. The effect of gravity will usually be small unless the gelant density is deliberately altered to be different than the density of the formation water. For fractured injection wells, a possible exception may be provided by the ideas presented in the previous paragraph. In particular, an effective gelant placement may be achievable by simultaneously injecting different liquids (e.g., aqueous gelant and oil).

Gel Placement in Unfractured Wells

Next consider an unfractured production well with a matrix permeability of 1 darcy. For the same fluid properties used in the previous examples,

$$G = \frac{(1)\ (0.2)\ (980)\ (1)}{(1.0133 \times 10^6)\ (1)\ u} = \frac{0.000193}{u} \tag{28}$$

G will be less than 1 so long as u is greater than 0.000193 cm/s. If the gelant injection rate is 10 BPD/ft, then u > 0.000193 cm/s if the gelant is within a radius of 16.3 ft from the wellbore. Thus, during gelant injection in unfractured wells, viscous forces will dominate near the wellbore, but gravity becomes more important farther from the wellbore.

When the well is shut in after gelant injection, Eq. 26 can again be used to estimate the rate of settling for a gelant-oil interface. If k = 1 darcy, $\Delta\rho = 0.2$ g/cm^3, and $\mu = 1$ cp, then $u_z = -0.55$ ft/d. Thus, even in a very permeable rock matrix, the rate of settling will be slow. The rate will be less in less-permeable rock or if a more viscous gelant is used. In concept, gravity could be exploited during gelant placement if the offending channel or aquifer is located below oil-productive zones. However, in view of the low settling rate in porous rock, relatively long gelation times (weeks, at least) will be needed.

For applications in unfractured injection wells, slow settling rates and small density contrasts (between the gelant and the formation water) make gravity difficult to exploit during gelant placement.

This analysis of settling rates in unfractured wells was based on a number of simplifying assumptions; that is, (1) that capillary and relative permeability effects are negligible (so that fluid displacements are piston-like), and (2) Eq. 26 can adequately describe the rate of settling of the gelant-oil interface at a given position. A more rigorous analysis would indicate slightly slower settling rates than those obtained above.[***]

Conclusions

The following conclusions apply to gel treatments in wells where oil and water are the primary reservoir fluids of interest:

1. During injection of aqueous gelants into fractured wells, viscous forces usually dominate over gravity forces. Thus, the position of the gelant front will not be significantly altered by gravity during gelant injection.

2. When a well is shut in after gelant injection, the rate of equilibration of a gelant-oil interface in a vertical fracture can be very rapid. This situation can be exploited during gel placement in oil wells where water channels (or "cones") through a fracture to the well from an underlying aquifer. Gravity

[***]Personal Communication with Robert L. Lee, Petroleum Engineering Dept., New Mexico Tech, January 1993.

and fluid density differences are less likely to be exploitable during gel placement in other types of fractured production wells or in fractured injection wells.

3. During injection of aqueous gelants into unfractured wells, viscous forces usually dominate over gravity forces near the wellbore, but gravity becomes more important deeper in the formation. In concept, gravity could be exploited during gelant placement if the offending channel or aquifer is located below oil-productive zones. However, in view of the low settling rate in unfractured porous rock, relatively long gelation times will be needed.

9. AN EXPERIMENTAL INVESTIGATION OF GELANT PLACEMENT IN FRACTURED SYSTEMS

Theoretical developments[13,14,17,38,71] and many field results[8-11,52] indicate that gel treatments are most effective in reservoirs where fractures constitute the source of a severe fluid channeling problem. An important factor responsible for this result is that an effective gel placement is easier to achieve in fractured wells than in unfractured wells.[13] The "permeability" of a fracture is typically 10^3 to 10^6 times greater than that of the rock matrix.[73,74] Thus, a gelant can propagate a substantial distance along the length of the fracture while penetrating a relatively short distance into the adjacent rock matrix. However, the gelant that "leaks off" into the rock matrix plays an important role in determining how well the gel treatment will improve sweep efficiency. For an effective gel treatment, the conductivity of the fracture must be reduced, <u>and</u> a viable flow path must remain open between the wellbore and mobile oil in the reservoir. This flow path should traverse gel in the rock matrix at a location near the wellbore. The viability of this flow path depends strongly on the distance of gelant penetration into the rock matrix. If the distance of gelant leakoff is too great, then both productivity and sweep efficiency could be damaged.

In order to assess the merits of a gel treatment in a fractured well, gelant "leakoff" must be quantified. This chapter discusses two factors that can have an important effect on gelant placement in fractures. These factors are gelant viscosity and the presence of partially gelled material in the gelant.

Effects of Gelant Viscosity

A basic principle of fluid displacement in porous media is that the efficiency of the displacement increases with increasing ratio of displacing fluid viscosity to displaced fluid viscosity.[18,72] This principle suggests that for a given volume of gelant injected into a fractured system, the distance of gelant leakoff will be greater for a viscous gelant than for a low-viscosity gelant (other factors being equal).

In this section, we present results from flow visualization studies in beadpacks that demonstrate the importance of gelant viscosity during placement in fractured systems. In these experiments, we used clear beadpacks with internal dimensions of 238 cm x 12.7 cm x 1.25 cm. Fig. 37 illustrates the configuration of the beadpacks. The containers were constructed of transparent polycarbonate to allow flow visualization. Before placing beads in a given pack, a "fracture" was laid along the bottom of the container. This "fracture" consisted of layers of nylon mesh with 1,000-μm openings. This nylon mesh was wrapped with one layer of nylon mesh that had 74-μm openings. The 74-μm nylon mesh was heat-sealed so that the 1,000-μm nylon mesh was completely enclosed. The 74-μm mesh was used to prevent glass beads from infiltrating the 1,000-μm mesh. The dimensions of the "fracture" (including both nylon meshes) was 236 cm x 0.15 cm x 1.2 cm.

Before placing the fractures in the bead containers, experiments were performed to determine the "permeability" of our simulated fractures. In these experiments, the fractures were covered with adhesive tape and then coated with rubber cement. After the cement was set, each end of the fracture was opened, and water was forced through the fracture to determine the permeability. Fracture permeabilities ranged from about 1,000 darcys for two layers of coarse nylon mesh to about 7,700 darcys for 8 layers of mesh (see Table 46).

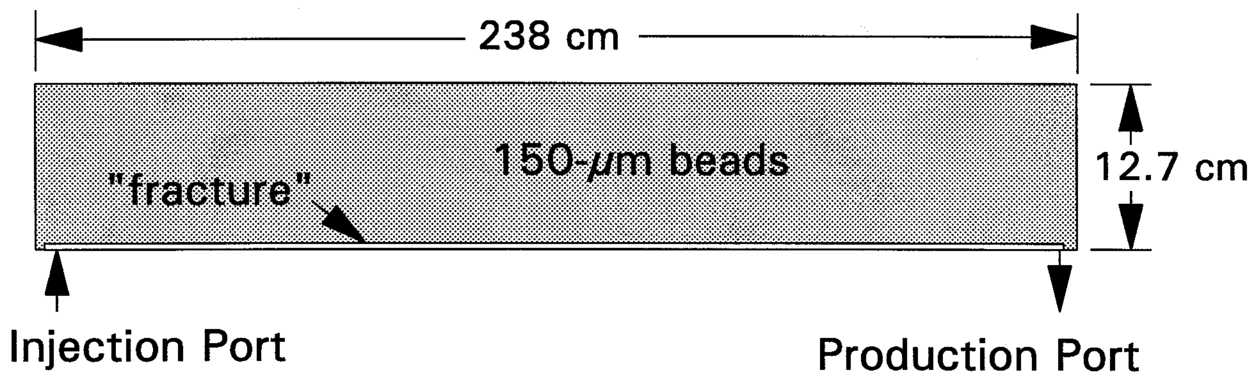


Fig. 37. "Fractured" beadpack.

Table 46. Properties of "Fractures" Made from 1,000-μm Mesh

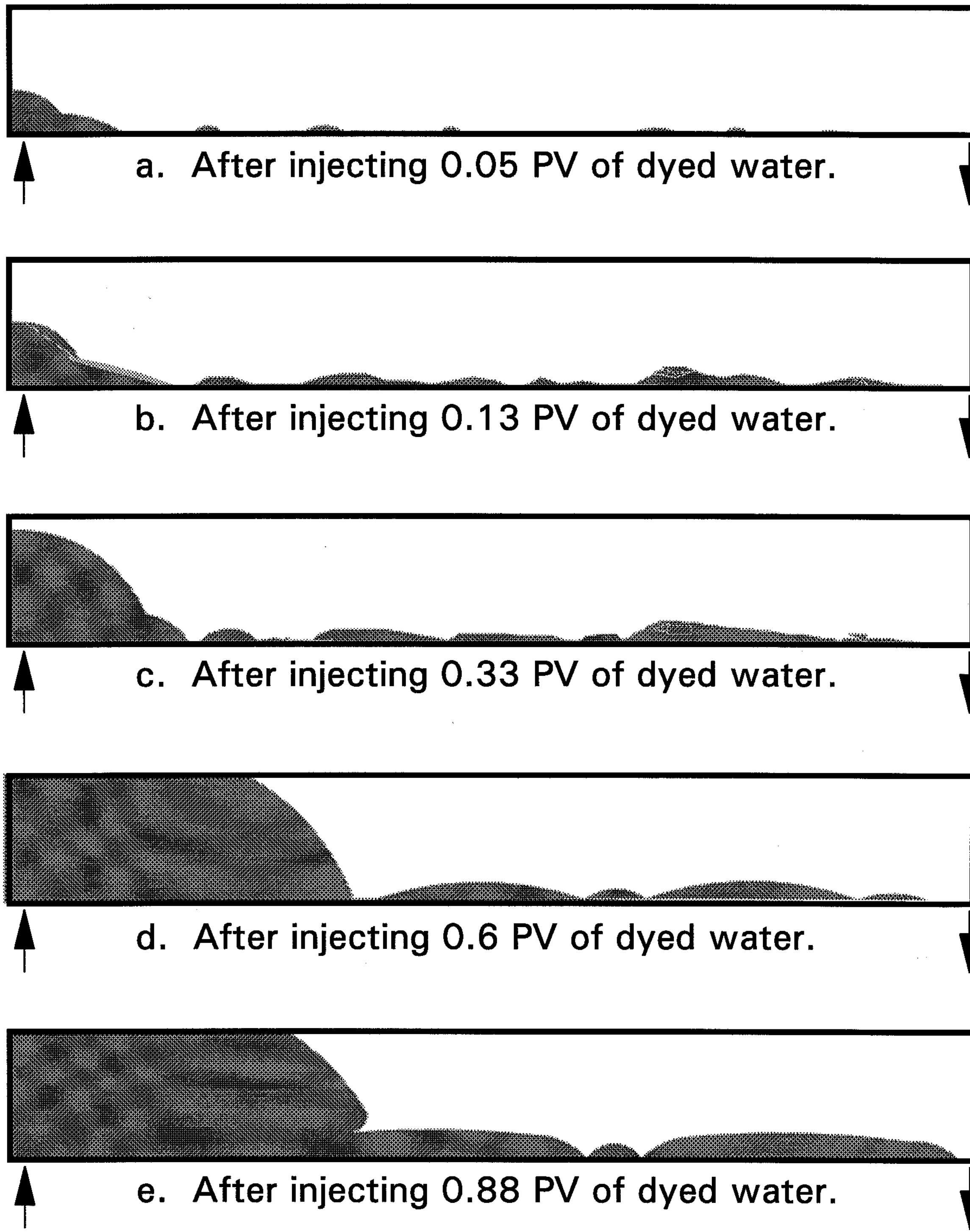
Layers of 1,000-μm mesh	"Fracture" thickness, cm	Permeability, darcys
2	0.15	1,011
3	0.23	1,845
4	0.29	2,660
6	0.39	4,190
8	0.52	7,718

After positioning the "fracture," the container was filled with 150-μm (nominal) glass beads. Without the fracture, beadpacks made from these beads had a permeability to water of about 13 darcys and a porosity of 0.38. The pore volume of the beadpack with the fracture was about 1,500 ml. In the bead container, an injection port was located next to one end of the fracture, while a production port was located next to the other end of the fracture (236 cm away). Two beadpacks were prepared using 150 μm beads. One pack contained a fracture made from two layers of 1,000-μm mesh, while the other pack had a fracture made from eight layers of mesh. All experiments described in this section were performed at room temperature. Also, a constant injection rate of 50 ml/hr was used. The experiments were recorded on VHS video tape.

Dyed Water Displacing Clear Water. To characterize the "fractured" beadpacks, dyed water was injected to displace clear water from the beadpack with the fracture. Figs. 38 and 39 illustrate the location of the dyed fluid in the beadpack at various throughput values between 0.05 and 0.88 pore volumes (PV). Fig. 38 applies to the fracture made from two layers of mesh, while Fig. 39 applies to the fracture made from eight layers of mesh. For both cases, the first dye was detected at the outlet after injecting about 75 ml or 0.05 PV of dyed water. As expected, most of the dyed injectant channeled through the fracture. However, some dyed water "leaked off" into the beadpack next to the fracture—especially near the injection port. Away from the injection port, slight variations in the fracture or the packing of the beads presumably were responsible for variations in leakoff along the fracture.

Fig. 40 shows the effluent dye concentration (relative to the injected concentration) as a function of pore volumes of solution injected. For both cases shown, the effluent dye concentration exhibited a plateau after injecting about 0.1 PV of dyed water. The plateau concentrations were 0.52 and 0.89, respectively, with the higher plateau concentration associated with the more-permeable fracture (made from eight layers of mesh).

The results shown in Fig. 40 can be rationalized using simple permeability arguments. A given beadpack effectively has two layers—the beads and the fracture. The dyed water will fill the fracture very rapidly, causing the effluent dye concentration to rise rapidly to a certain value. If dye is being injected continuously, the effluent concentration will remain fairly stable until the dye front in the beads reaches the outlet port. This reasoning qualitatively explains the plateau in dye concentration observed in Fig. 40.



a. After injecting 0.05 PV of dyed water.

b. After injecting 0.13 PV of dyed water.

c. After injecting 0.33 PV of dyed water.

d. After injecting 0.6 PV of dyed water.

e. After injecting 0.88 PV of dyed water.

Fig. 38. Dyed water displacing clear water. Pack with 2-layer-mesh fracture.

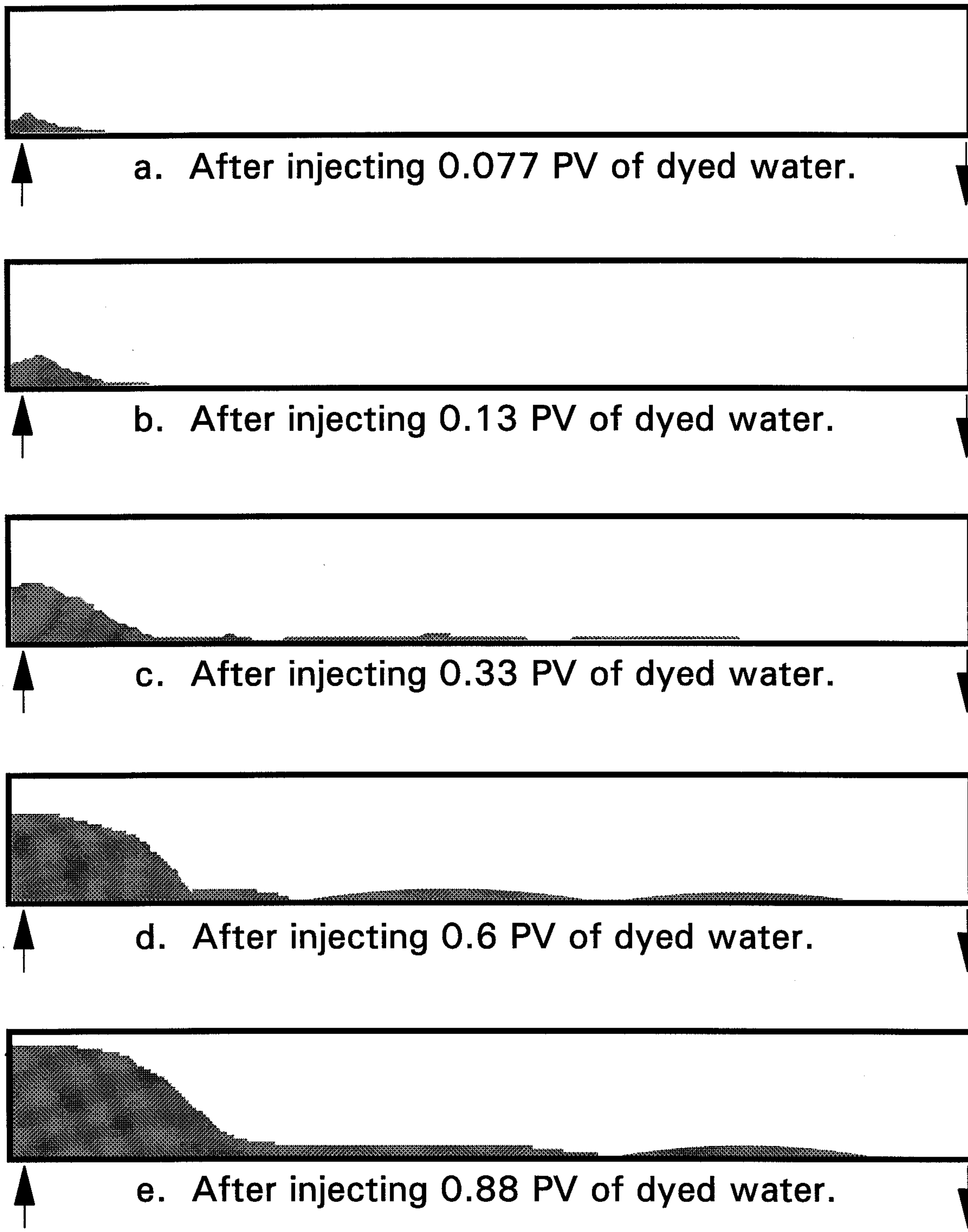


Fig. 39. Dyed water displacing clear water. Pack with 8-layer-mesh fracture.

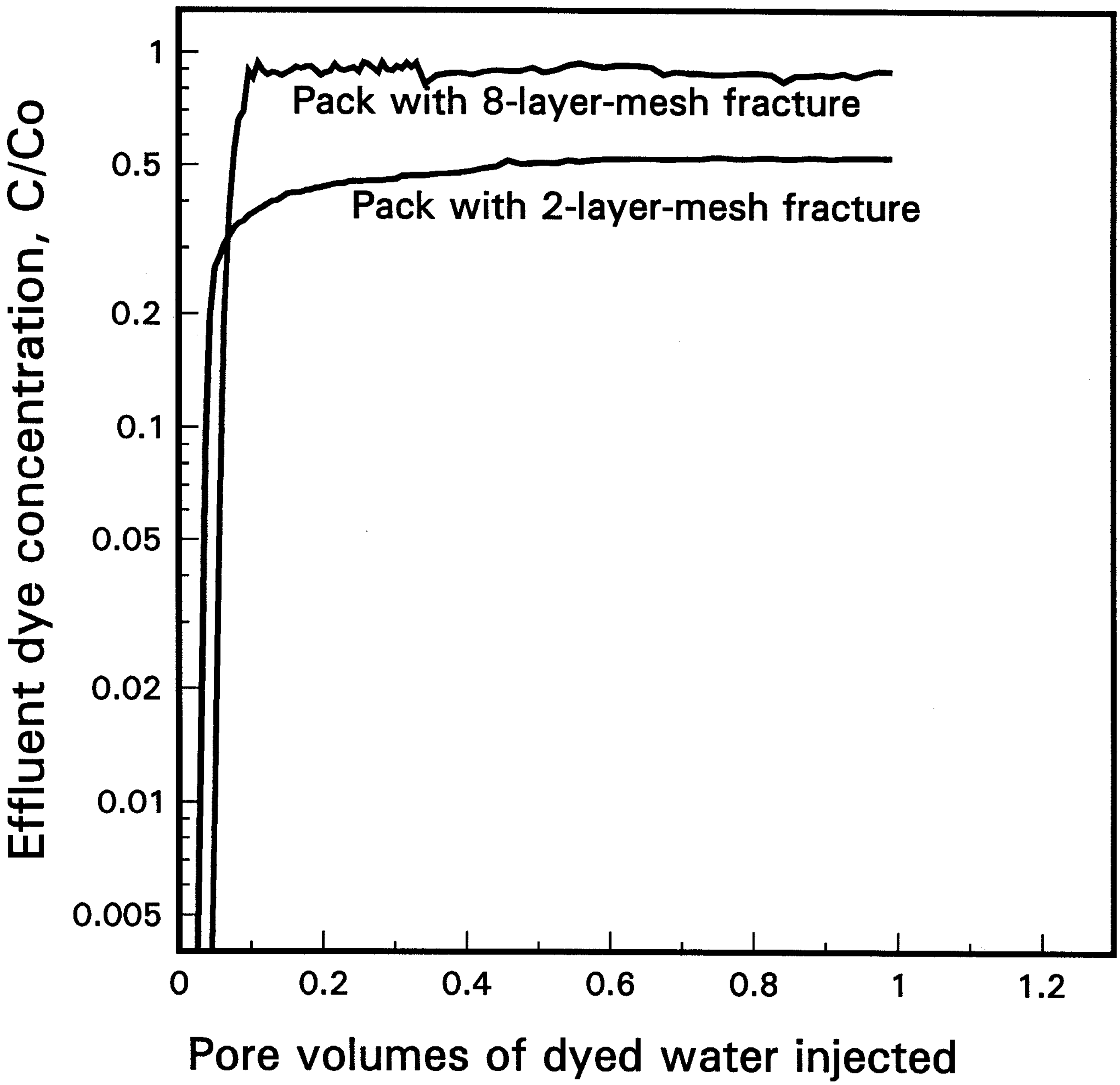


Fig. 40. Characterization of beadpacks by displacing clear water with dyed water.

Using the Darcy equation, we can predict the dye concentrations in the plateau region of Fig. 40. The total rate that fluid is produced at the outlet port is the sum of the flow rate at the end of the bead layer, q_m, and the flow rate at the end of the fracture (before mixing with the stream from the bead layer), q_f. (In our equations, the subscript, m, refers to the bead or matrix layer, and the subscript, f, refers to the fracture layer.) If the dye front has reached the outlet port in the fracture but not in the bead layer, then fluid near the end of the fracture (again, before mixing with the fluid from the bead layer) will have a dye concentration near the injected concentration ($C/C_o \approx 1$) and the fluid produced from the bead layer will have a zero dye concentration. The dye concentration obtained by combining the streams from the two layers is given by Eq. 29.

$$\frac{C}{C_o} = \frac{q_f}{q_f + q_m} \qquad (29)$$

Since the width of the beadpack is the same for the bead layer as for the fracture, Eq. 29 can be transformed to express the effluent dye concentration as a function of heights (h) and frontal velocities (v) in the two layers.

$$\frac{C}{C_o} = \frac{v_f h_f}{v_f h_f + v_m h_m} \qquad (30)$$

Since injection of dyed water to displace clear water constitutes a unit-mobility miscible displacement, these floods can be treated using the Darcy equations for flow in parallel. In particular, the rate of fluid production from each layer will be proportional to the permeability-thickness product of each layer: $k_m h_m$ for the beads or matrix and $k_f h_f$ for the fracture. Thus, the total production rate from both layers will be proportional to the sum, $k_m h_m + k_f h_f$.

$$\frac{C}{C_o} = \frac{k_f h_f}{k_f h_f + k_m h_m} \qquad (31)$$

For the beadpack with the less-permeable fracture, k_f=1,011 darcys, h_f=0.15 cm (from Table 46), k_m=13 darcys, and h_m=12.7-0.15=12.55 cm. Using these parameters, Eq. 31 predicts a value of 0.48 for the relative dye concentration (C/C_o) in the plateau region. This prediction is very close to the experimentally observed value of 0.52. Thus, the data from Fig. 40 are consistent with our input values for k_m, k_f, h_m and h_f. From another viewpoint, if the experimental C/C_o value of 0.52 is input into Eq. 31 along with k_m, h_f and h_m, then k_f is calculated to be 1,178 darcys. This value is reasonably close to that listed in Table 46 (1,011 darcys).

For the beadpack with the more-permeable fracture, k_f=7,718 darcys, h_f=0.52 cm (from Table 46), k_m=13 darcys, and h_m=12.7-0.52=12.18 cm. Using these parameters, Eq. 31 predicts a value of 0.96 for the relative dye concentration (C/C_o) in the plateau region. Upon first consideration, this prediction may seem close to the experimental value of 0.89 (from Fig. 40). However, if the experimental value of 0.89 is input into Eq. 31 along with k_m, h_f and h_m, then k_f is calculated to be 2,458 darcys—considerably lower than the value of 7,718 darcys listed in Table 46. Perhaps, the permeability of the fracture was less in the beadpack because of compression of the layers of mesh by the overlying beads or because of bead infiltration into the fracture. In subsequent experiments, we assumed that the correct values for the 2-layer and 8-layer fractures were 1,178 darcys and 2,458 darcys, respectively.

Dyed Polymer Solutions Displacing Clear Water. After characterizing the beadpacks as described above, dyed polymer solutions with different viscosities were injected into these systems to displace clear water. Polymer concentrations of 0, 100, 200, 500, 1,000, and 2,000-ppm xanthan were used. For the two beadpacks, Figs. 41 and 42 show the effluent dye concentrations while injecting the different dyed xanthan solutions. Note that in each figure the dye concentration in the plateau region decreases with increasing polymer concentration and viscosity. During these experiments, a lower dye concentration in the effluent means that a greater fraction of the injected polymer solution is flowing through the bead layer rather than through the fracture. In other words, the sweep efficiency in the pack increases with increasing viscosity of the injected fluid. The results from these beadpack floods demonstrate a basic principle of polymer flooding. That is, for a given volume of fluid injected, viscous injectants will penetrate into less-permeable zones to a greater extent than low-viscosity injectants.[13,18]

For gel treatments, the results indicate a potential problem with viscous gelants—that too much gelant may leak off from the fracture into the rock matrix. During production after a gel treatment, too much gel in the rock matrix could impede flow between the wellbore and mobile oil in the reservoir. Ideally, gelant leakoff into the rock matrix should be minimized while maximizing gel penetration into the fracture.

The results shown in Figs. 41 and 42 can be described quite well using a simple model based on ideas from paper SPE 24192.[18] The paper demonstrates that if fluids can freely crossflow between two adjacent layers, then the ratio of frontal velocities, v_m/v_f, is estimated by Eq. 32 if $k_m F_r/k_f < 1$.

$$\frac{v_m}{v_f} = \frac{k_m F_r}{k_f} \tag{32}$$

If $k_m F_r/k_f \geq 1$, then the ratio of frontal velocities is estimated by Eq. 33

$$\frac{v_m}{v_f} = 1 \tag{33}$$

In Eqs. 32 and 33, F_r is the displacing fluid resistance factor or the ratio of displacing-fluid viscosity to the displaced-fluid viscosity.

By substituting Eq. 32 into Eq. 30, Eq. 34 is obtained for the case where $k_m F_r/k_f < 1$.

$$\frac{C}{C_o} = \frac{k_f h_f}{k_f h_f + k_m h_m F_r} \tag{34}$$

Thus, Eq. 34 can be used to predict the concentration in the plateau region when viscous solutions are injected to displace water (as in Figs. 41 and 42). Tables 47 and 48 compare the predictions with the experimental values for the two beadpacks. Most of the predictions are in reasonable agreement with the experimental effluent dye concentrations. End effects in the beadpacks may be partially responsible for the differences. Although our theoretical analyses assume strictly linear flow in the fracture and matrix layers, some radial flow clear must occur near the injection and production ports.

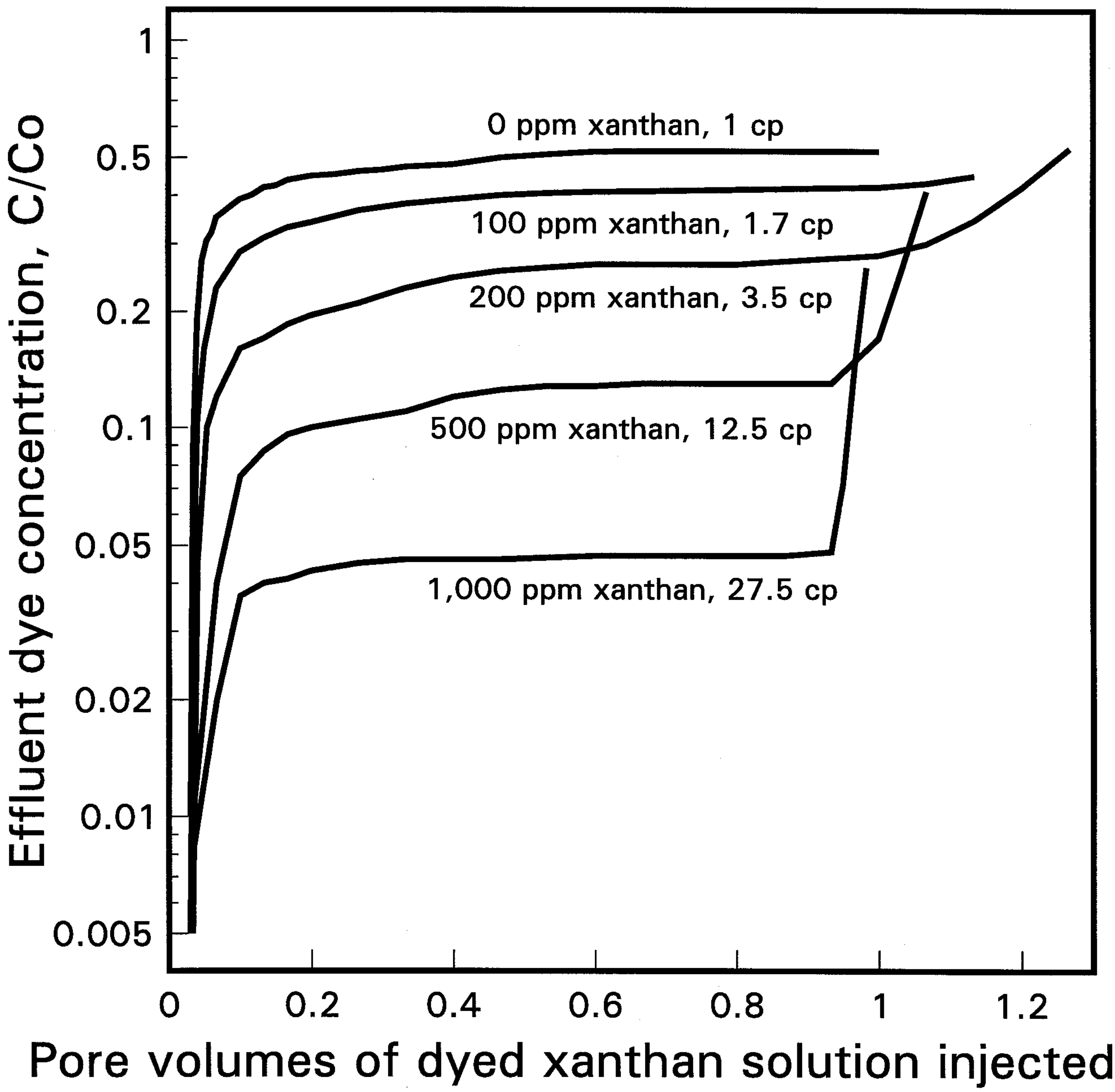


Fig. 41. Injection of dyed polymer into beadpack with the 2-layer fracture.

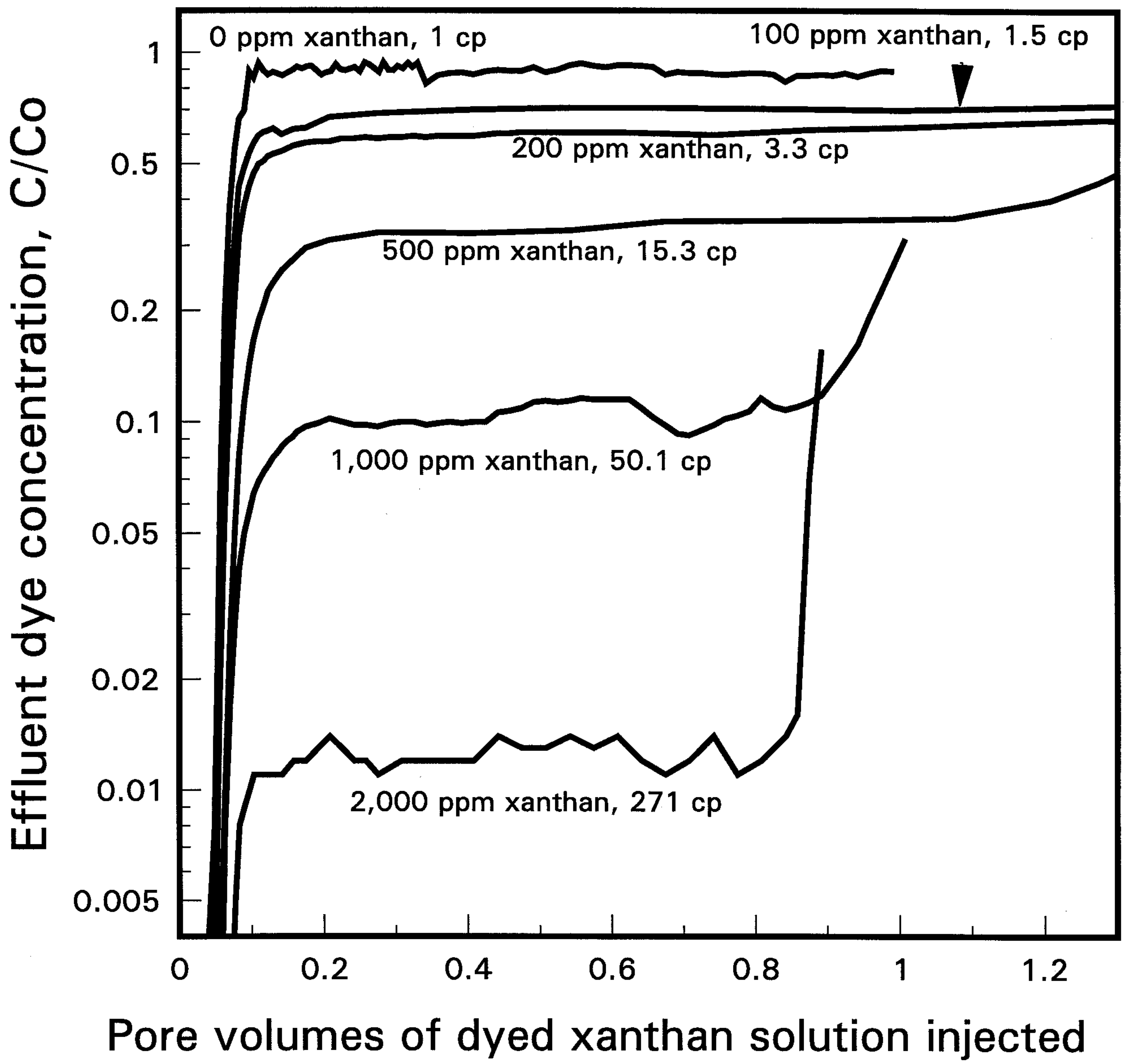


Fig. 42. Injection of dyed polymer into beadpack with the 8-layer fracture.

Table 47. Predicted vs. Experimental Effluent Dye Concentrations (Plateau Region) for the Beadpack with the 2-Layer-Mesh Fracture. For the predictions, k_f=1,178 D, h_f=0.15 cm. k_m=13 D and h_m=12.55 cm.

Xanthan concentration, ppm	Injectant viscosity, cp @ 1.7 s^{-1}	Predicted dye C/C_o	Experimental dye C/C_o
0	1.0	0.52	0.52
100	1.7	0.39	0.41
200	3.5	0.24	0.26
500	12.5	0.08	0.12
1,000	27.5	0.04	0.04

Table 48. Predicted vs. Experimental Effluent Dye Concentrations (Plateau Region) for the Beadpack with the 8-Layer-Mesh Fracture. For the predictions, k_f=2,458 D, h_f=0.52 cm. k_m=13 D and h_m=12.18 cm.

Xanthan concentration, ppm	Injectant viscosity, cp @ 1.7 s^{-1}	Predicted dye C/C_o	Experimental dye C/C_o
0	1.0	0.89	0.89
100	1.5	0.84	0.74
200	3.3	0.71	0.65
500	15.3	0.35	0.34
1,000	50.1	0.14	0.12
2,000	271	0.00	0.01

Relevance to Fractured Wells. The results presented above may help to explain one aspect of some recent field experiences. The field results were brought to our attention by Steve Harris of Allied Colloids (Suffolk, VA) and Tim Busing of Beard Oil Co. (McCook, NB). They described injection-well treatments where tracer studies were first performed to determine interwell transit times for tracers in water. Very rapid transit times were observed, confirming fractures as the cause of the channeling. When a viscous Cr^{3+}(acetate)-HPAM gelant was injected, no gelant was detected at the offset producers, even though the gelant volume was ten times greater than the volume associated with transit of the water tracer between the wells. Our theoretical and laboratory results provide a possible explanation for the field result. That is, leakoff (into the rock matrix) was substantially greater for the viscous gelant than for the low-viscosity tracer solution. Thus, the volume of injected water tracer required to transit from an injector to a producer is much less than that for a viscous injectant.

Channeling While Injecting a Water Postflush. In most of our beadpack studies, we injected water after completing injection of the dyed polymer solutions. In all cases, the water postflush channeled through the fracture directly from the injection port to the production port. This result was expected based on previous work.[18,71] The result indicates that when viscous gelants are used, water from a postflush (before gelation) will remain almost exclusively in the fracture.

Gelant and Gel Propagation Through Sandstone

Use of suspended particulate matter is one of the most common and effective methods to reduce leakoff during hydraulic fracturing.[75,76] Logically, suspended particulate matter might be effective in minimizing gelant leakoff during gel treatments.[17,71] One experimental investigation suggested that crosslinked polymers can effectively minimize gelant leakoff into rock matrix.[36] Thus, we are interested in exploiting partially gelled material as a means to reduce gelant leakoff.

A number of studies have been reported that discuss the flow of gelants and gels in porous media.[15,48-51,77-80] Early in the gelation process, many gelants behave like clean fluids that do not contain suspended particulate matter.[15,48-51,77] For example, early in the gelation process, the rheology in porous media is the same for a Cr^{3+}-xanthan gelant as for a xanthan solution without a crosslinker.[50] However, after gel aggregates form and grow to the size of pore throats, gel filtration can radically increase the resistance to flow.[48,77-79] The literature indicates that gelants can penetrate a significant distance into rock matrix before gelation and that after gelation, gel propagation is extremely slow or negligible.

We performed several experiments to confirm these concepts for a Cr^{3+}(acetate)-HPAM gelant. The gelant contained 5000-ppm HPAM (Allied Colloids Alcoflood 935®), 417-ppm chromium triacetate (Sargent-Welch) and 1% NaCl (pH=6). All experiments were performed at 41°C. The viscosity was 18 cp (at 1.3 s^{-1}, 41°C) for a freshly prepared gelant. Fig. 43 plots viscosity vs. time for the gelant. From 0 to 4 hours after gel preparation, the viscosity gradually increased. Thereafter, the viscosity rapidly rose to very large values. Fig. 43 suggests that the gelation time is from 4 to 6 hours at 41°C.

The Cr^{3+}(acetate)-HPAM gelant was examined during several corefloods with various delays between the time that the gelant was prepared and the time that the gelant was injected into the core. We used high-permeability Berea sandstone cores (brine permeability averaged 650 md and porosity averaged 0.21). With one exception, the cores were 14-cm long with a cross-sectional area of 10 cm^2. Each of these cores had one internal pressure tap that was located approximately 2 cm from the inlet rock face. The first core segment was treated as a filter, while the second core segment (12-cm length) was used to measure mobilities and residual resistance factors. As an exception, one core was only 2.67 cm in length and had no internal pressure tap. All cores were cast in epoxy and were not fired.

One coreflood was conducted using the minimum delay (0.1 hr) between gelant preparation and gelant injection. Slightly more than two hours were required to inject 14 PV of gelant using a Darcy velocity of 15.7 ft/d. The bottom curve in Fig. 44 (solid circles) shows the gelant resistance factor in the first core segment as a function of gelant throughput. The residual resistance factor rose gradually from 20 at 1 PV to 76 at 14 PV. For comparison, the residual resistance factor in the second segment (not shown) rose to 43 after 14 PV of gelant throughput. Although some face plugging was observed during this experiment, most of the gelant passed readily through the core. After the first few pore volumes, the effluent from the core had about the same properties (viscosity, appearance, gelation time) as the gelant that was injected. During this experiment, the maximum pressure drop across the core was 78 psi.

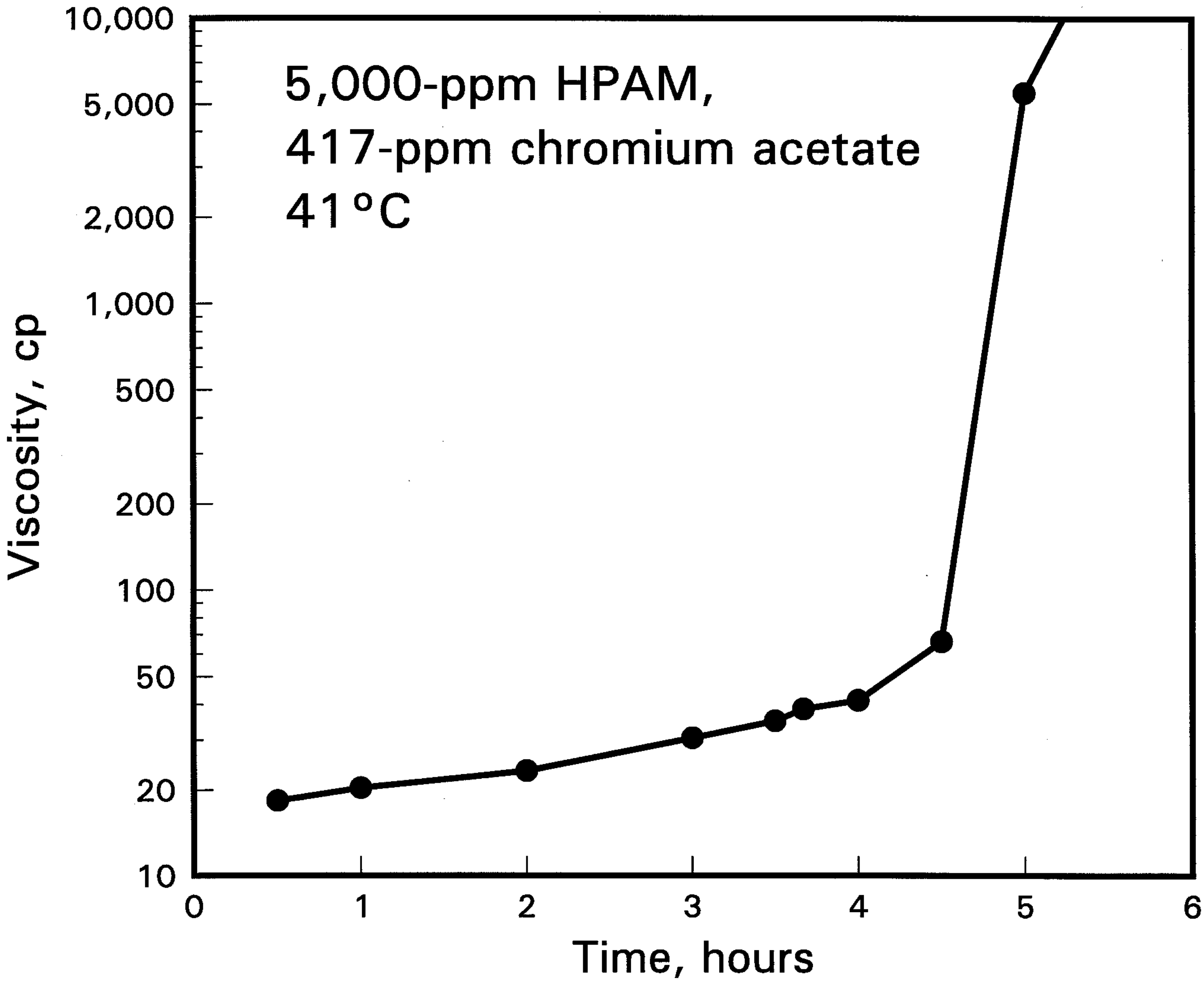


Fig. 43. Viscosity vs. time during gelation.

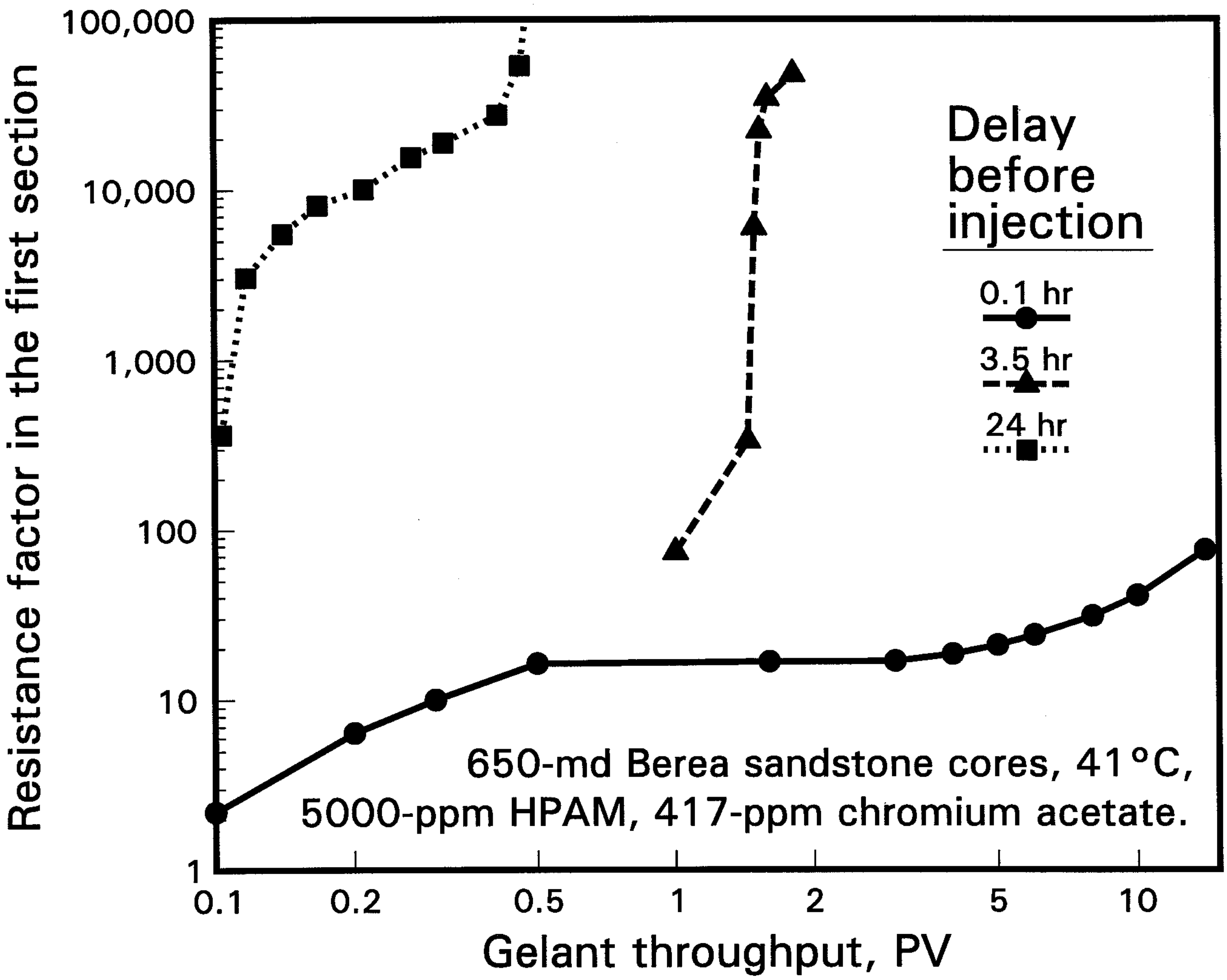


Fig. 44. Plugging in the first core segment for different delay times between gelant mixing and gelant injection (41 °C).

A second coreflood was conducted using a 3.5-hr delay between gelant preparation and gelant injection. In this experiment, the pump was set to maintain a constant pressure drop of 100 psi across the core. In Fig. 44, the solid triangles represent residual resistance factors in the first core segment as a function of gelant throughput. During the first half hour of injection, about 1 PV of gelant was injected. The viscosity and appearance of the effluent suggested that the gelant had propagated through the 14-cm core. After injecting the first pore volume of gelant, the residual resistance factor increased sharply. With the application of a 100-psi pressure drop, less than 2 PV had been injected after 24 hours. Also, after the first 3 hours of gelant injection, the viscosity of the effluent was near that for water. Thus, 6.5 hours after gelant preparation (3.5 hrs of delay plus 3 hrs of injection), no more gelant appeared to propagate through the core.

A third coreflood was performed using a 24-hr delay between gelant preparation and gelant injection. After 24 hours, the gelant had formed a highly deformable, nonflowing gel (i.e., the Sydansk gel code[36] was F). In this experiment, the pump was again set to maintain a constant pressure drop of 100 psi across the core. In Fig. 44, the solid squares represent residual resistance factors in the first core segment as a function of gelant throughput. Severe face plugging was observed immediately. Over the course of 24 hours, about 0.5 PV of gel appeared to be injected. We say "appeared" because of the possibility that the polymer may have been largely filtered out at the sandface, with only water propagating through the core. We noted that all effluent from the core had the same viscosity as water. The injected gel contained a blue dye (food coloring). So, after the experiment, the core was cut in half to estimate how far the dye (and possibly the gel) propagated through the core. The dye was visible up to one-third of the distance through the core.

To determine whether the gel actually propagated through the sandstone during the third coreflood, a fourth coreflood was conducted using a Berea core whose length was 2.67 cm rather than 14 cm. Again, a 24-hr delay occurred between gelant preparation and gelant injection. This gel also contained a blue dye that acted as a tracer. Also, the pump was set to maintain a constant pressure drop of 100 psi across the core. As was noted during the third coreflood, residual resistance factors immediately rose to very large values (up to 200,000) when gel was injected. The blue dye was first detected in the effluent after injecting 1.5 PV. However, the viscosity of the effluent remained near that for water throughout injection of 6.5 PV of dyed gel. Also, no chromium was detected in the effluent. Thus, although the dye propagated through the core, the gel did not.

In summary, our experiments confirmed that the Cr^{3+}(acetate)-HPAM gelant and gel performed in a similar manner to that for other gelants and gels that were described in the literature. Specifically, before gelation, gelants can penetrate readily into rock matrix, but after gelation, gel propagation is extremely slow or negligible. These observations suggest two possible methods to minimize gelant leakoff in fractured systems. One method is to design the gel treatment so that before the gelant leaves the wellbore, sufficient gelation occurs so that the gelant will not penetrate into the rock matrix. For this approach to succeed, the gel must remain pumpable for some period after gelation. The second method involves adding gelled material or some other particulate matter to the gelant. Both methods deserve further investigation.

Gels and Gelants in Fractured Cores

Several experiments were conducted using fractured Berea sandstone cores. The nominal permeability for most of these cores was 650 md. However, one core had a brine permeability of 66 md.

Core porosities were typically 0.21. All of these experiments were performed at 41°C. Before fracturing, the cores were identical to those described in the previous section. The cylindrical cores were 14-cm long with a cross-sectional area of 10 cm^2. These cores were fractured lengthwise using a core splitter (Park Industries Hydrasplit®). The two halves of the core were repositioned as shown in Fig. 45 and cast in epoxy. Two internal pressure taps were drilled 2 cm from the inlet sandface. One tap was located 90° from the fracture to measure pressure in the rock matrix, while the other tap was drilled to measure pressure in the fracture. During our corefloods, the fracture was always oriented vertically.

After casting the core in epoxy and saturating the core with brine, the permeability to brine was determined. The third column in Table 49 lists brine permeabilities for several fractured cores. These permeabilities average the effects of flow through the fracture and the rock matrix. When brine is the only mobile fluid, the conductivity of the fracture can be estimated using the Darcy equation for flow in parallel. In particular, the total flow rate is the sum of the flow rate through the rock matrix, q_m, and the flow rate through the fracture, q_f. The flow rate through the rock matrix is given by Eq. 35,

$$q_m = \frac{k_m A \Delta p}{\mu_w L} \tag{35}$$

where
A = core cross-sectional area, cm^2
L = core length, cm
Δp = pressure drop, psi [Pa]
μ_w = water viscosity, cp [mPa-s].

Table 49. Core and Fracture Permeabilities

Core	Nominal k_m, darcys	k_{av}, darcys	$k_f w_f$ from Eq. 37, darcy-cm	Relative flow capacity, $k_f w_f h_f / A k_m$	Fracture outlet sealed?
1	0.65	4.1	9.6	5.3	no
2	0.65	6.0	14.9	8.3	yes
3	0.65	31	84	46.5	no
4	0.65	7.4	18.8	10.4	yes
5	0.65	18.4	49.7	27.3	no
6	0.066	17.0	47.2	256	no
7	0.65	19.9	53.8	29.6	no
8	0.65	67.7	187	103	no
9	0.65	70.6	196	108	no

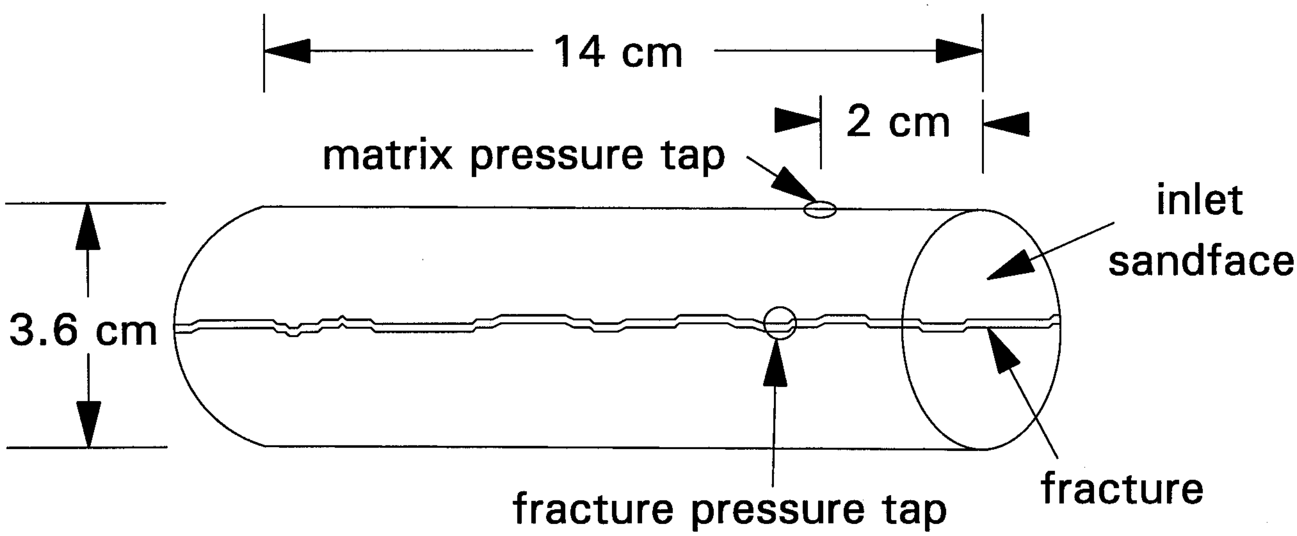


Fig. 45. Schematic of a fractured core.

The flow rate through the fracture is given by Eq. 36,

$$q_f = \frac{k_f w_f h_f \Delta p}{\mu_w L} \tag{36}$$

where w_f is the width of the fracture.

Eqs. 35 and 36 can be combined to relate the average permeability of the fractured core, k_{av}, to the matrix permeability, k_m, and the fracture conductivity, $k_f w_f$.

$$k_{av} = k_m + k_f w_f h_f / A \tag{37}$$

Since k_{av} can be determined from the Darcy equation and since the parameters, A, h_f and k_m, can be measured separately, Eq. 37 can be used to determine fracture conductivity. The fourth column in Table 49 lists these calculated fracture conductivities. If the fracture width is about 0.01 cm, then the permeabilities for these fractures range from 900 to 20,000 darcys.

The flow capacity of the fracture relative to that of the rock matrix is given by the ratio, $k_f w_f h_f / A k_m$. This ratio is listed in the fifth column of Table 49. The flow capacity of the fracture ranged from 5 to 256 times greater than the flow capacity of the rock matrix. For two cores listed in Table 49 (Cores 2 and 4), the outlet end of the fracture was blocked with epoxy. This block was placed to prevent gel from washing out of the fracture.

We routinely performed water-tracer studies before and after gel placement during our experiments. These tracer studies were used to characterize pore volumes and dispersivities of the cores. These studies involved injecting a brine bank that contained potassium iodide as a tracer. The tracer concentration in the effluent was monitored spectrophotometrically at a wavelength of 230 nm. In Fig. 46, the curve with the solid circles illustrates the results from a tracer study for an unfractured Berea core that was saturated with brine. Tracer curves for unfractured cores could be described very well using the error-function solution. Dispersivities of unfractured Berea sandstone cores were typically 0.1 cm, and the effluent tracer concentration reached 50% of the injected concentration after injecting 1 PV of tracer solution.

The solid triangles in Fig. 46 show the tracer results from a fractured Berea core (Core 1 from Table 49). For this fractured core, the first tracer was detected in the effluent after injecting 0.04 PV of tracer solution. In contrast, for the unfractured core, the first tracer was detected after injecting 0.8 PV of tracer solution.

Experiments with a Resorcinol-Formaldehyde Gelant. Using fractured Core 1, 0.3 PV (10 ml) of a resorcinol-formaldehyde gelant were injected using an injection rate of 200 ml/hr. The gelant contained 3% resorcinol, 3% formaldehyde, 0.5% KCl, and 0.42% $NaHCO_3$ at pH=9. The gelation time for this gelant was 4 to 6 hours and a clear rigid gel was formed (Sydansk gel code I[36]). After injecting the gelant, the core was shut in for 3 days at 41°C. After the shut-in period, brine was injected to determine permeability reduction values (residual resistance factors), and tracer studies were conducted to assess whether the gel treatment resulted in fluid diversion. Fig. 47 illustrates the tracer results, while Fig. 48 shows permeability reduction values as a function of pore volumes of brine injected after gelation. In Fig. 48, the fracture-tap curves were determined using the pressure drop between the internal fracture tap (shown in Fig. 45) and a pressure tap located just beyond the outlet of the core. These fracture-tap curves indicate the effectiveness of the gel in blocking the fracture. The matrix-tap curves were

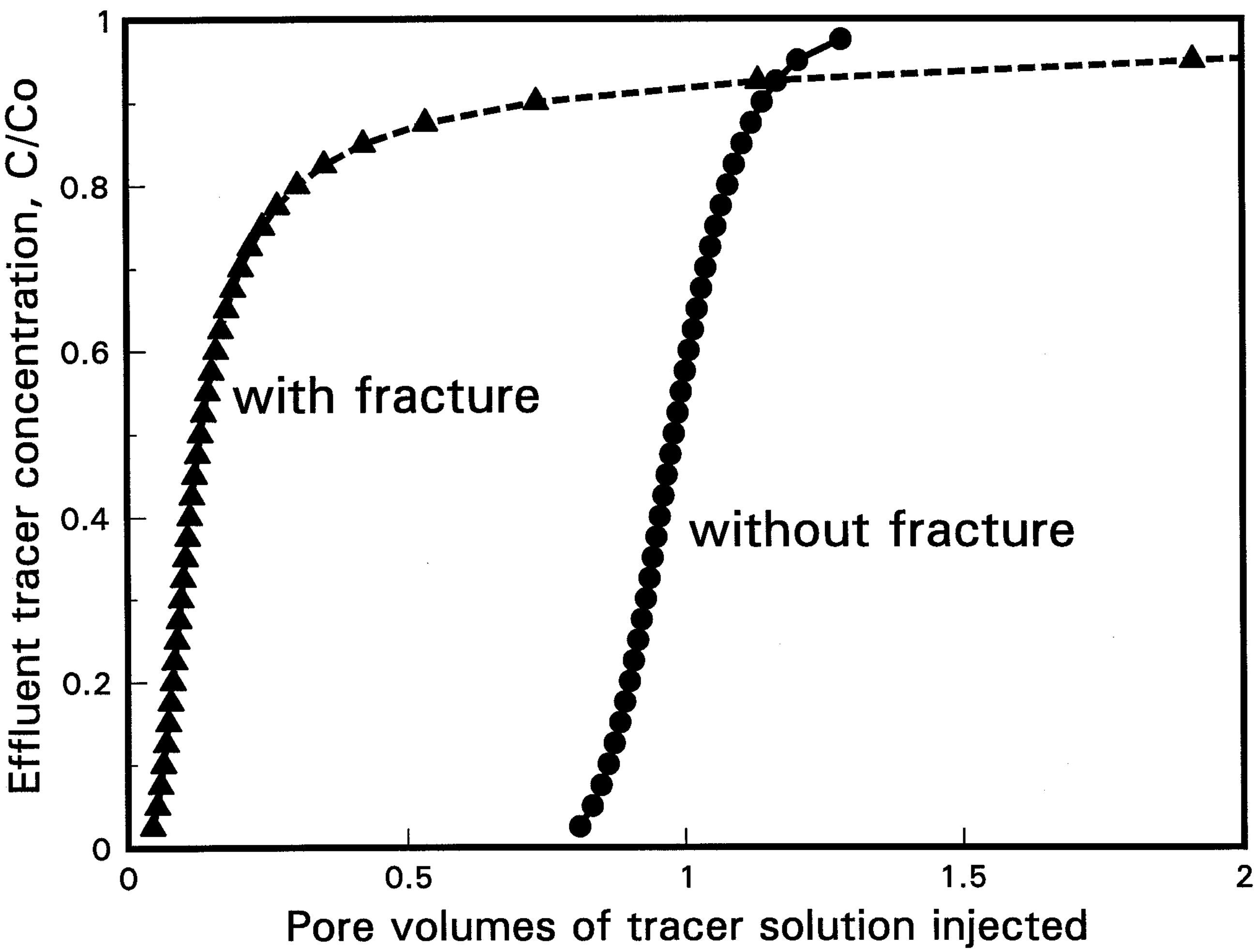


Fig. 46. Tracer results in fractured vs. unfractured Berea sandstone cores. Cores are saturated with water only.

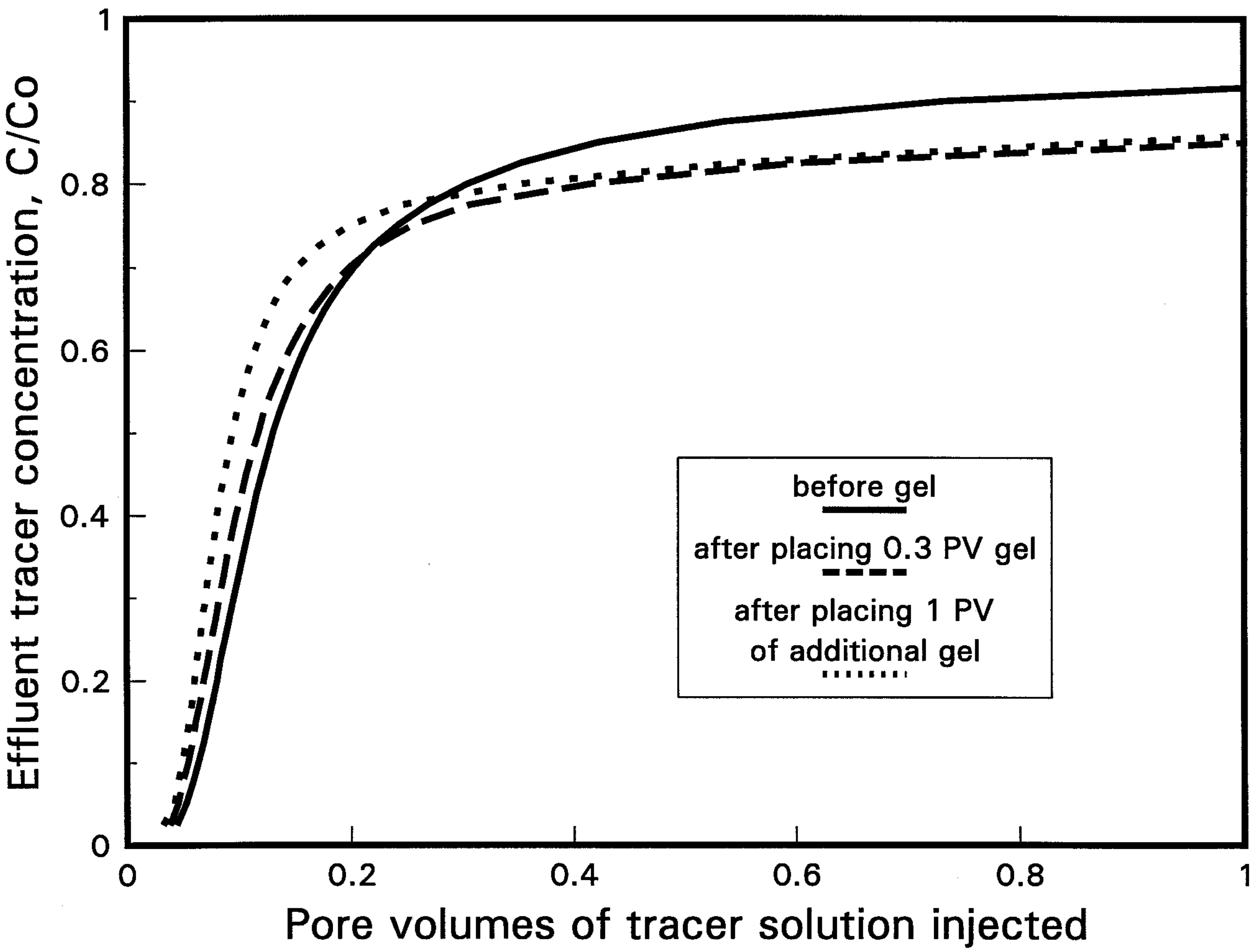


Fig. 47. Tracer results before and after placement of a resorcinol-formaldehyde gel in fractured Core 1 (fracture outlet open).

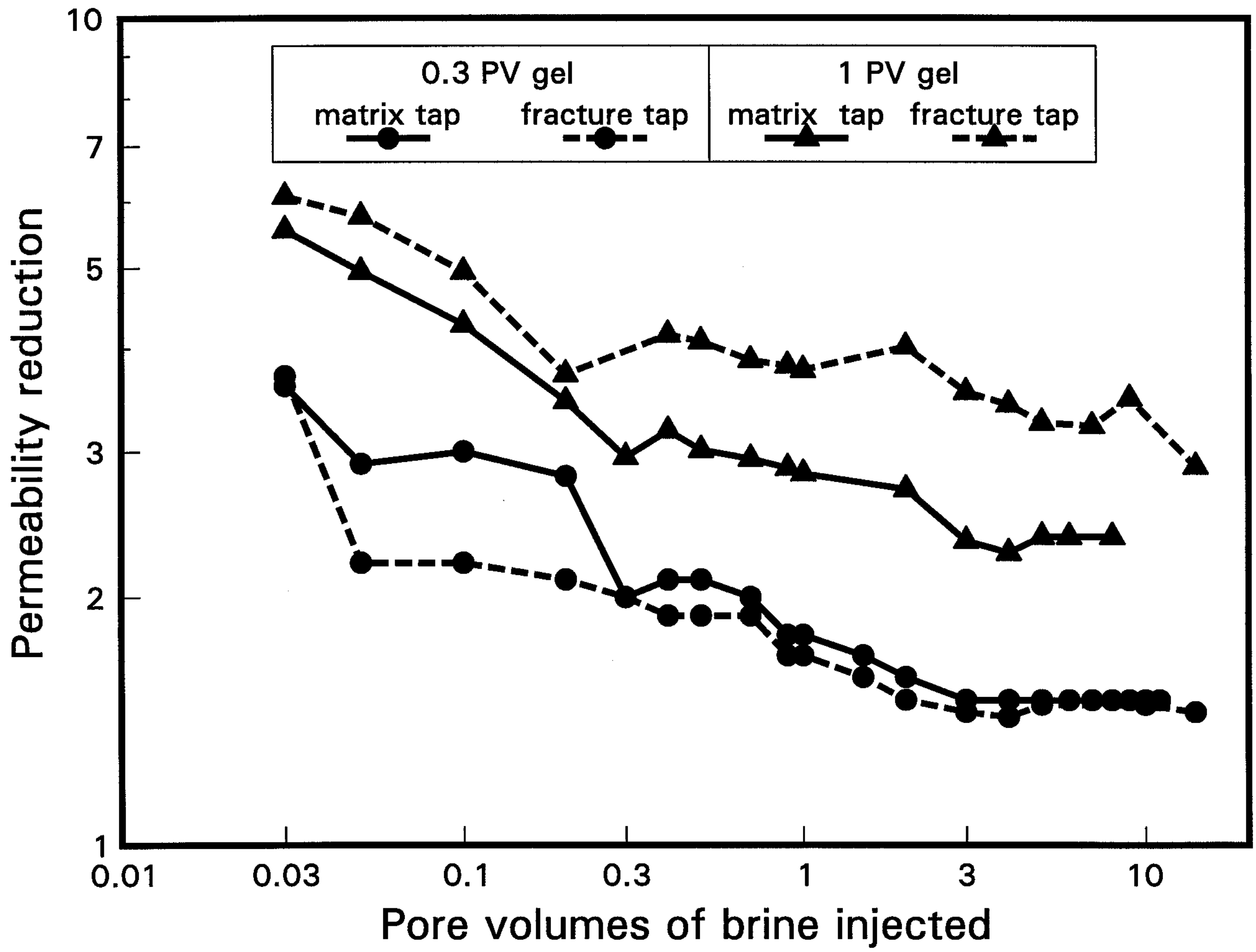


Fig. 48. Permeability reduction in fractured Core 1 after placement of a resorcinol-formaldehyde gel (fracture outlet open).

determined using the pressure drop between the internal matrix tap (located 90° from the fracture as shown in Fig. 45) and the outlet pressure tap. Thus, these curves indicate whether gel has penetrated extensively into the rock matrix.

In Fig. 47, a comparison of the dashed curve with the solid curve shows that placement of 0.3 PV of the resorcinol-formaldehyde gel resulted in only minor changes in sweep efficiency. The tracer still arrived at the core outlet after injecting less than 0.05 PV of tracer solution. The lower two curves in Fig. 48 reveal that the gel provided small permeability reductions, both in the fracture and the matrix. The permeability-reduction values decreased from about 3 to 1.5 during injection of 10 PV of brine. The low permeability-reduction values for the fracture were somewhat surprising since the fracture should have been completely filled with a strong gel. (The fracture volume was less than 0.05 PV, while 0.3 PV of gelant was injected.)

Using the same core (Core 1), another 1 PV of resorcinol-formaldehyde gelant was injected (using an injection rate of 200 ml/hr). After a 3-day shut-in period, brine was injected to determine permeability-reduction values. The top two curves in Fig. 48 show that the flow capacity of the core and the fracture were reduced a relatively small amount by the additional pore volume of gel. The permeability-reduction values decreased from about 6 to 3 during injection of 10 PV of brine. Tracer results (the dotted curve in Fig. 47) indicated that the additional pore volume of gel did not significantly change the sweep efficiency.

We wondered whether the low permeability-reduction values resulted because gel was easily being washed from the fracture. To test this idea, a new fractured core (Core 2 in Table 49) was prepared, and an epoxy block was placed in the fracture at the core outlet. We injected 0.3 PV of resorcinol-formaldehyde gelant and then shut the core in for 3 days. Fig. 49 shows permeability-reduction values for the experiment. When brine was first injected after gelation, the conductivity of the fracture was reduced by a factor of 200. This value was ten times greater than that for the matrix. However, after injecting 10 PV of brine, the fracture and matrix permeability-reduction values had decreased to about the same value—8. Thus, some washout of the gel still appeared to occur, but since the fracture outlet was blocked with epoxy, we are uncertain about where the gel went.

After determining the permeability-reduction values described in Fig. 49, a tracer study was performed. The results are shown in Fig. 50. Tracer breakthrough was delayed slightly after placement of 0.3 PV of gel—indicating a minor improvement in sweep efficiency. However, we clearly have not achieved our objective, i.e., a large improvement in sweep efficiency by substantially reducing the conductivity of the fracture.

When the fractured cores were disassembled, we noted that the red resorcinol-formaldehyde gelant had settled to the lower part of the core. Apparently, density differences between the brine and the gelant allowed this settling during the shut-in period before gelation. Although the gelant is only 1% more dense than the brine, this difference was enough to allow the gelant to drain from the upper part of the fracture. Thus, gravity can play a very important role during gelant placement.

Experiments with a Cr^{3+}(acetate)-HPAM Gelant. A second set of experiments was conducted in fractured cores using a Cr^{3+}(acetate)-HPAM gel. This gelant contained 5,000-ppm HPAM (Allied Colloids Alcoflood 935), 417-ppm chromium triacetate, and 1% NaCl at pH=6. Fig. 43 shows viscosity vs. time for this gelant. One experiment was performed in a fractured core with an epoxy block at the

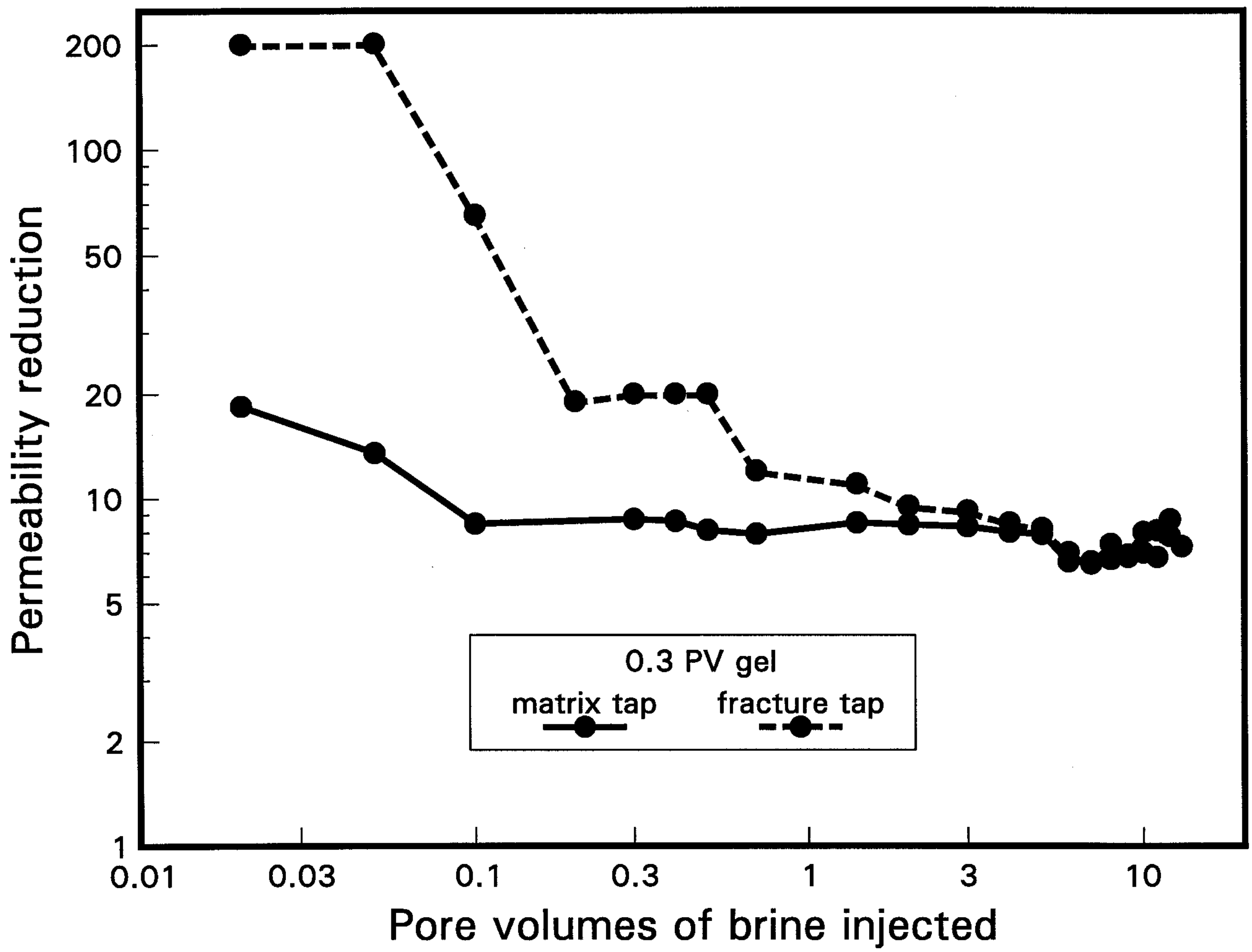


Fig. 49. Permeability reduction in fractured Core 2 after placement of a resorcinol-formaldehyde gel (fracture outlet sealed).

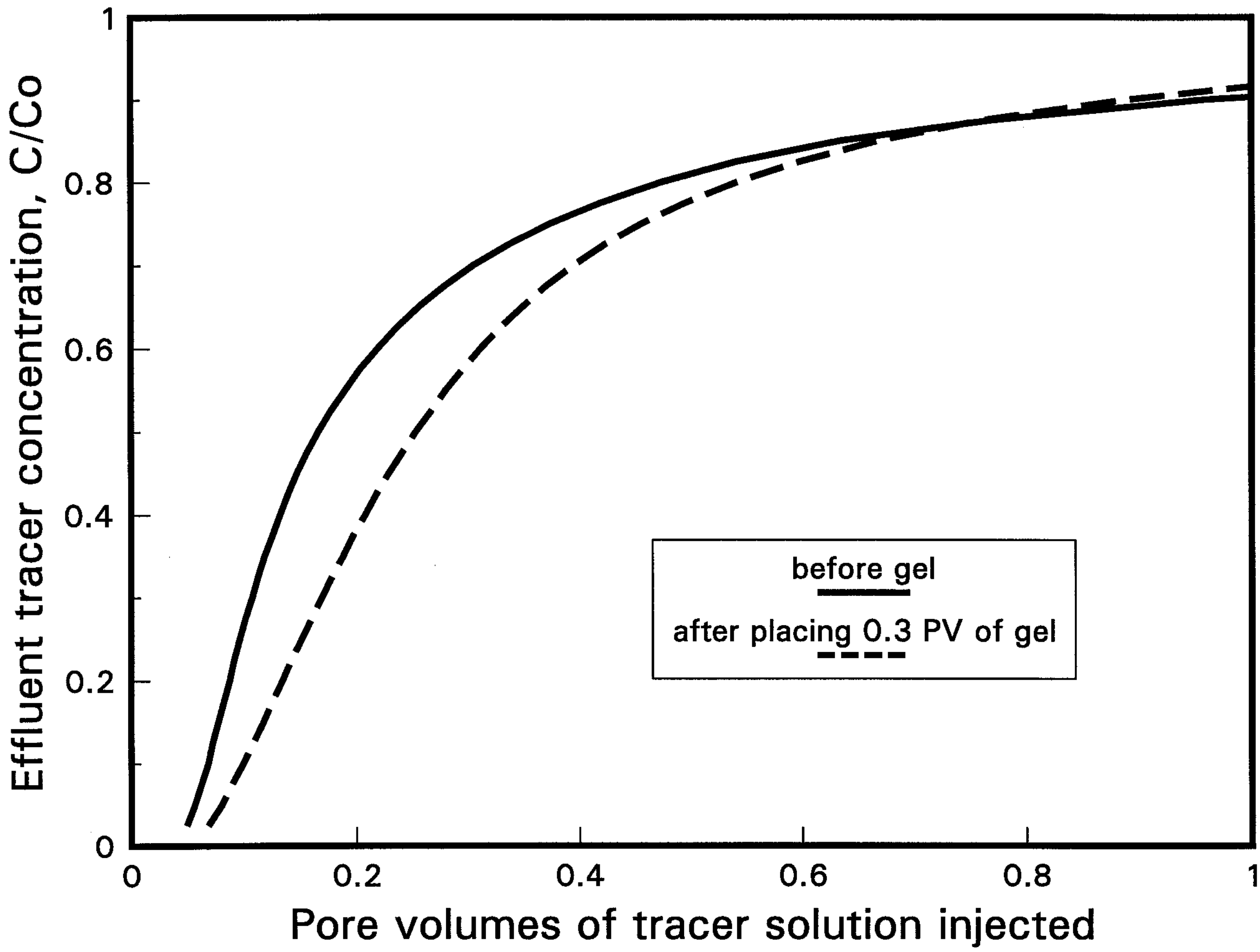


Fig. 50. Tracer results before and after placement of a resorcinol-formaldehyde gel in fractured Core 2 (fracture outlet sealed).

outlet end of the fracture (Core 4 in Table 49), while another experiment used a fractured core with no epoxy block (Core 3 in Table 49). In both experiments, 0.3 PV of gelant were injected using an injection rate of 200 ml/hr. After injecting the gelant, the cores were shut in for 6 days.

Fig. 51 compares the permeability-reduction results from the two experiments. For the core with the open fracture, the permeability reduction values were initially extremely high for both the fracture and the matrix. However, after 0.4 PV of brine injection, these values dropped sharply. For the fracture, the decline can be attributed to gel washing out of the fracture. We suspect that the dramatic decrease associated with the matrix pressure tap was an experimental artifact that occurred because gel entered and plugged the pressure tap. Tracer studies (Fig. 52) indicated that this gel treatment did not improve sweep efficiency.

For the core with the epoxy seal that blocked the fracture outlet, the initial permeability-reduction values were much lower than those for the previous experiment (Fig. 51). However, after injecting 14 PV of brine, the permeability-reduction values for the core with the sealed fracture were greater than those for the core with the open fracture. Thus, less gel appeared to wash out from the core with the sealed fracture.

For the core with the sealed fracture, the tracer studies (Fig. 53) revealed that the gel significantly delayed tracer breakthrough in the core—indicating that the gel treatment significantly increased sweep efficiency.

Injection of Cr^{3+}(acetate)-HPAM Gels. Several experiments were performed where gels (rather than gelants) were injected into fractured cores. Properties of these cores are given by listings 5 through 9 in Table 49. Note that Core 6 had a matrix permeability of 66 md rather than 650 md. The fracture outlets for these cores were not sealed.

For Cores 5, 6, 7 and 8, the gel contained 5,000-ppm HPAM (Allied Colloids Alcoflood 935), 417-ppm chromium triacetate, and 1% NaCl at pH=6. For Core 9, the gel contained 3% resorcinol, 3% formaldehyde, 0.5% KCl, and 0.42% $NaHCO_3$ at pH=9. To allow gelation to occur, a 24-hr delay occurred between gelant preparation and gel injection into the fractured cores. For Cores 5 and 6, between 0.4 and 0.6 PV of gel (12-16 ml) were injected. Of course, this volume was more than enough to fill the fractures. After the gel was injected, the cores were shut in for four days. Then, the inlet and outlet endcaps were removed from the core holder, and gel was scraped from flow lines and the inlet and outlet rock faces. The endcaps were then repositioned, and brine injection was commenced.

Figs. 54 and 55 show tracer results before and after gel placement for Cores 5 and 6, respectively. Both figures indicate that the gel has substantially improved sweep efficiency. Particularly in Fig. 55, the post-gel tracer curve suggests that the fracture is almost completely healed. For this curve, the first tracer was detected in the effluent at 0.73 PV; the 50% concentration level was reached at 0.96 PV; and the dispersivity associated with the tracer curve was 0.2 cm. For comparison, in an unfractured core with no gel, the first tracer was detected in the effluent at 0.80 PV; the 50% concentration level was reached at 1.0 PV; and the dispersivity associated with the tracer curve was 0.1 cm.

Fig. 56 shows how the permeability-reduction values varied with brine throughput. For both Cores 5 and 6, the permeability-reduction values were fairly constant during injection of 35 PV of brine. Thus, the gel did not appear to wash out as easily as the gels and gelants discussed earlier.

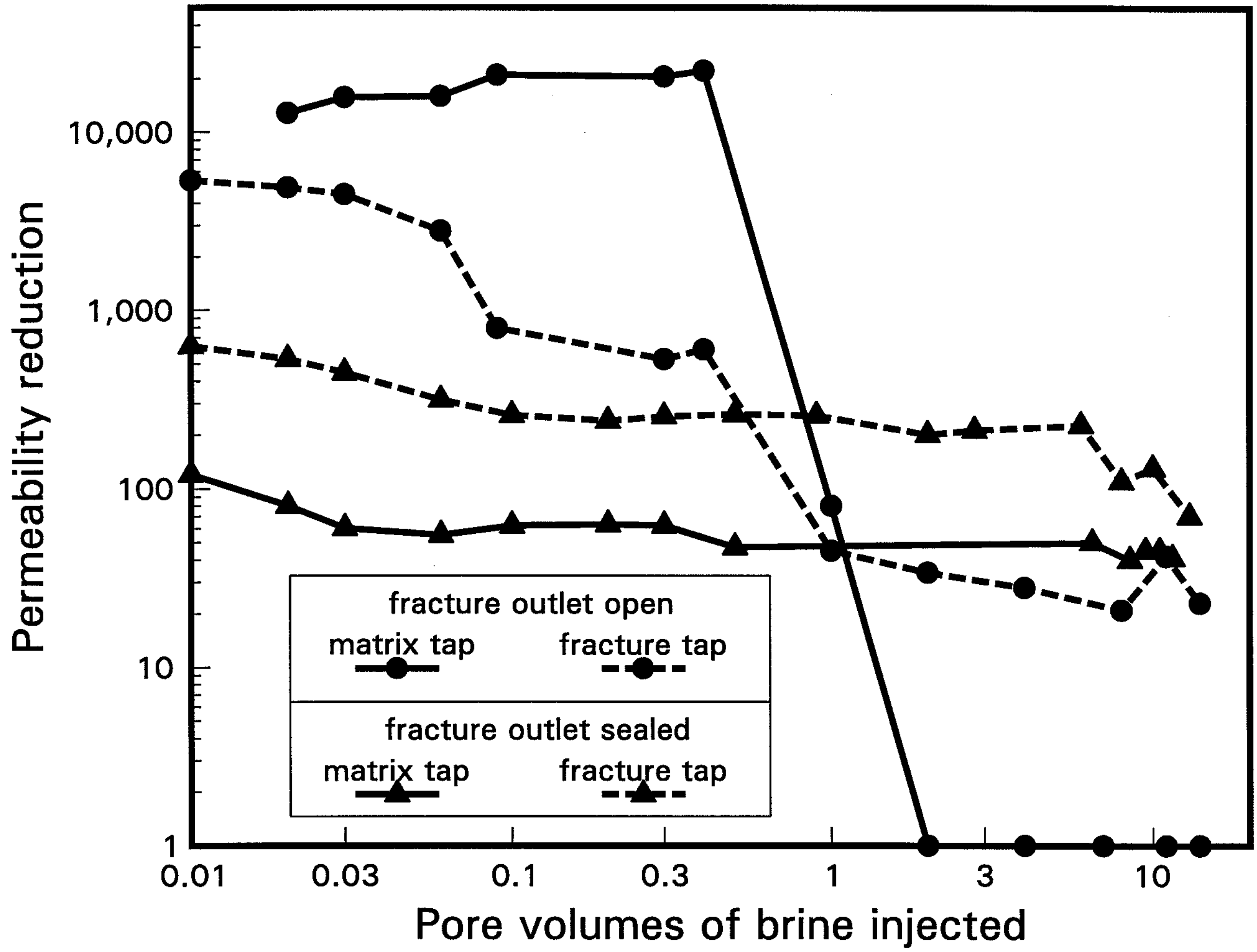


Fig. 51. Permeability reduction in fractured Cores 3 and 4 after placement of 0.3 PV of a Cr(III)-acetate-HPAM gel.

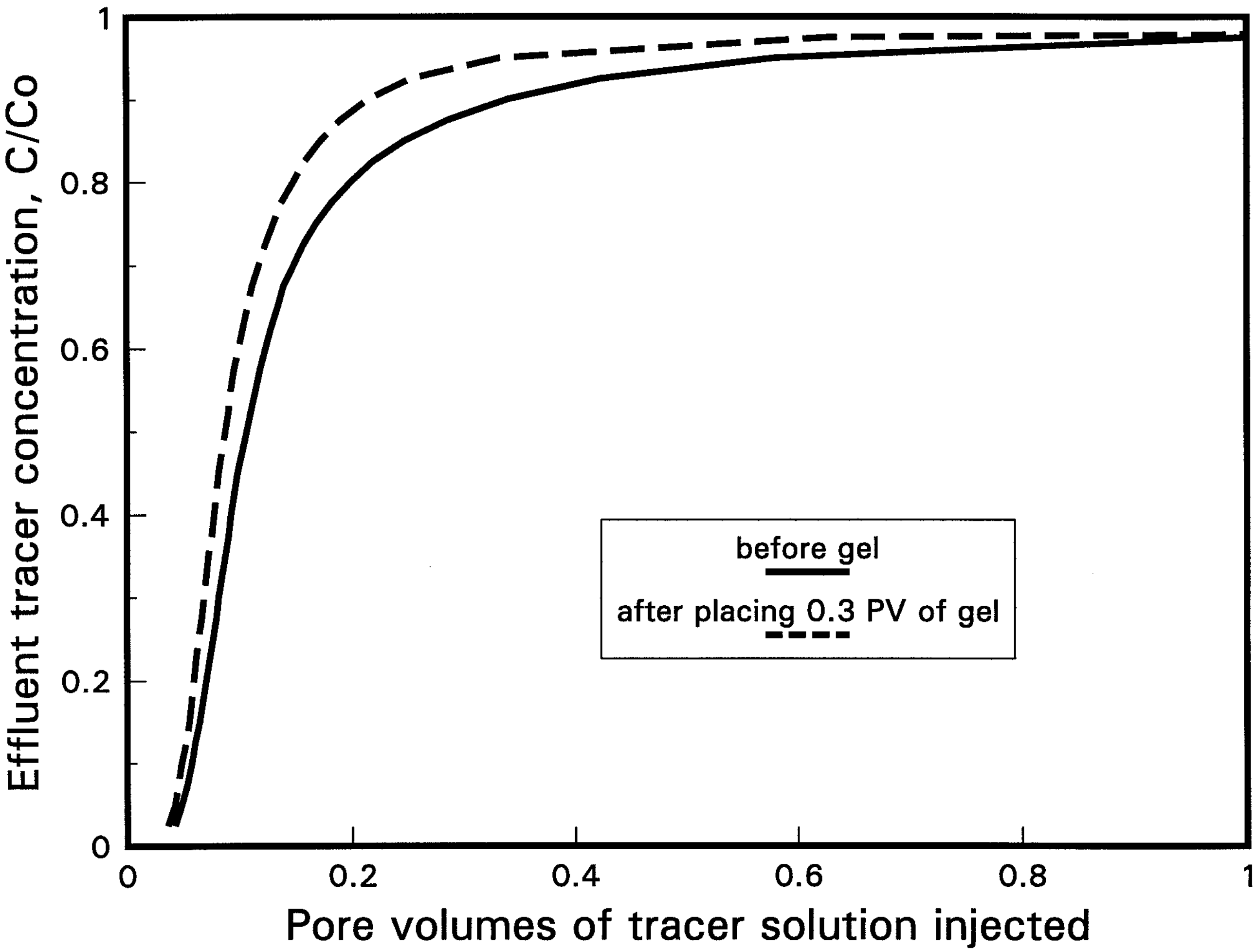


Fig. 52. Tracer results before and after placement of a Cr(III)-acetate-HPAM gel in fractured Core 3 (fracture outlet open).

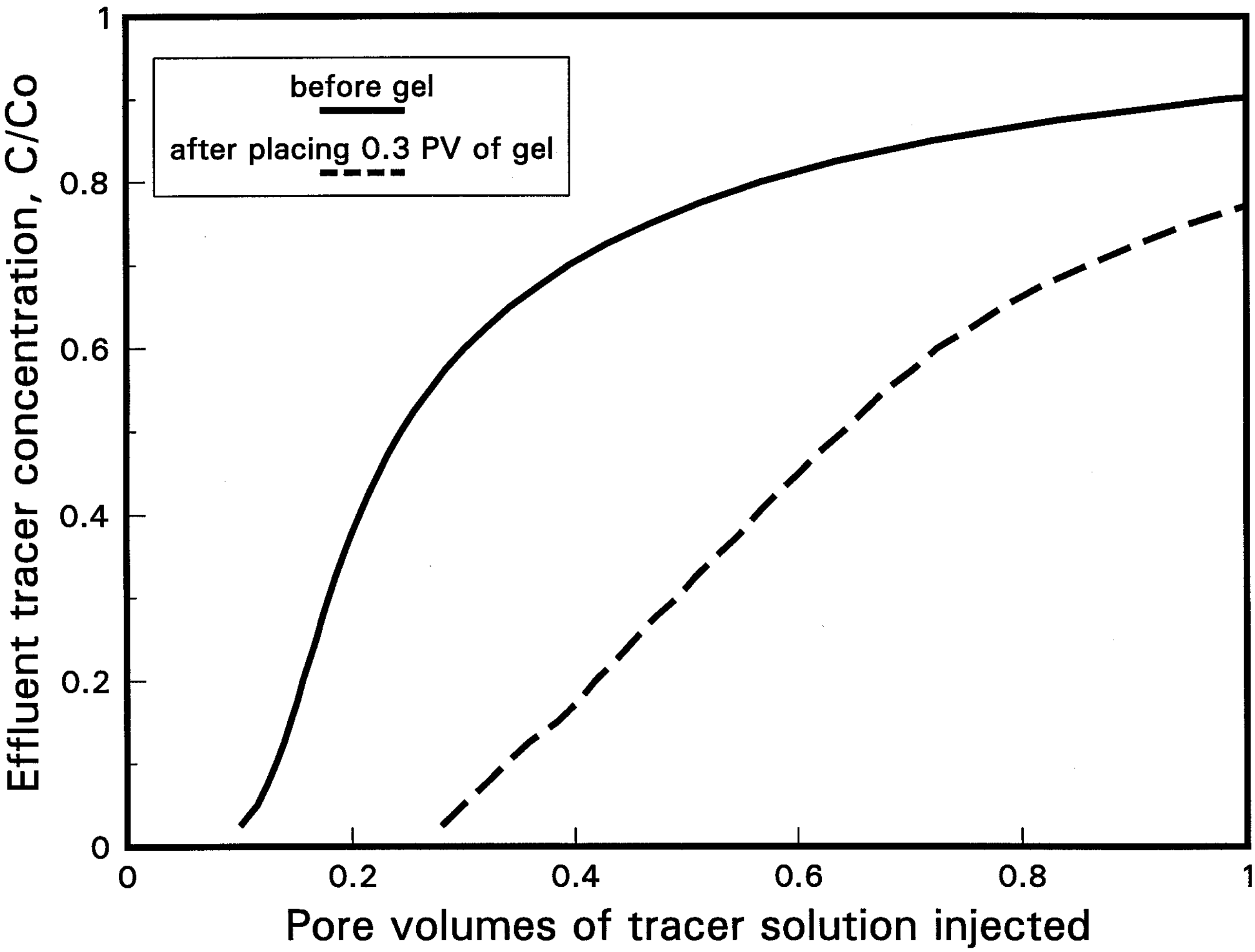


Fig. 53. Tracer results before and after placement of a Cr(III)-acetate-HPAM gel in fractured Core 4 (fracture outlet sealed).

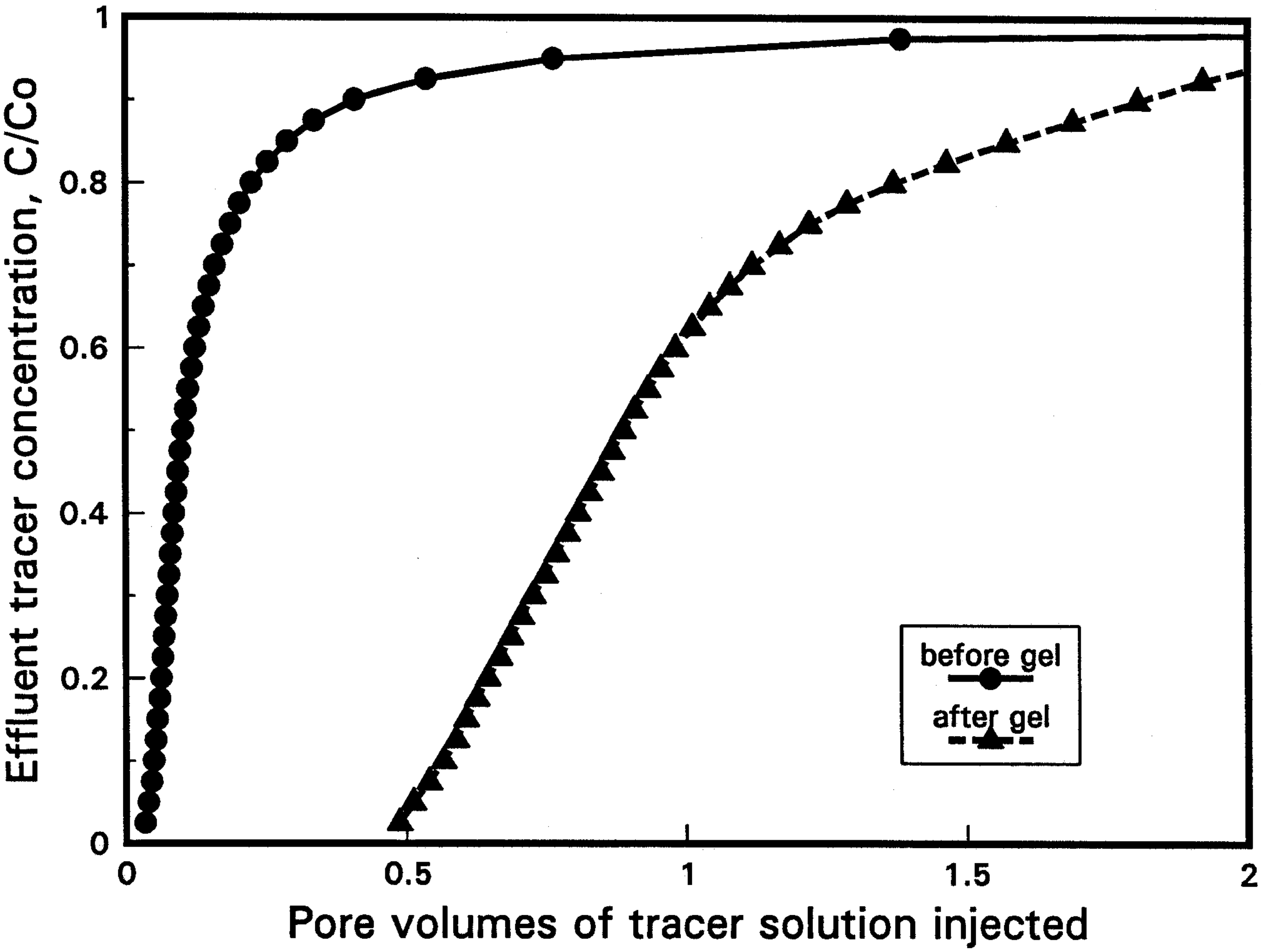


Fig. 54. Tracer results before and after placement of a Cr(III)-acetate-HPAM gel (24-hr delay before gel injection) in fractured Core 5 (650-md Berea; fracture outlet open).

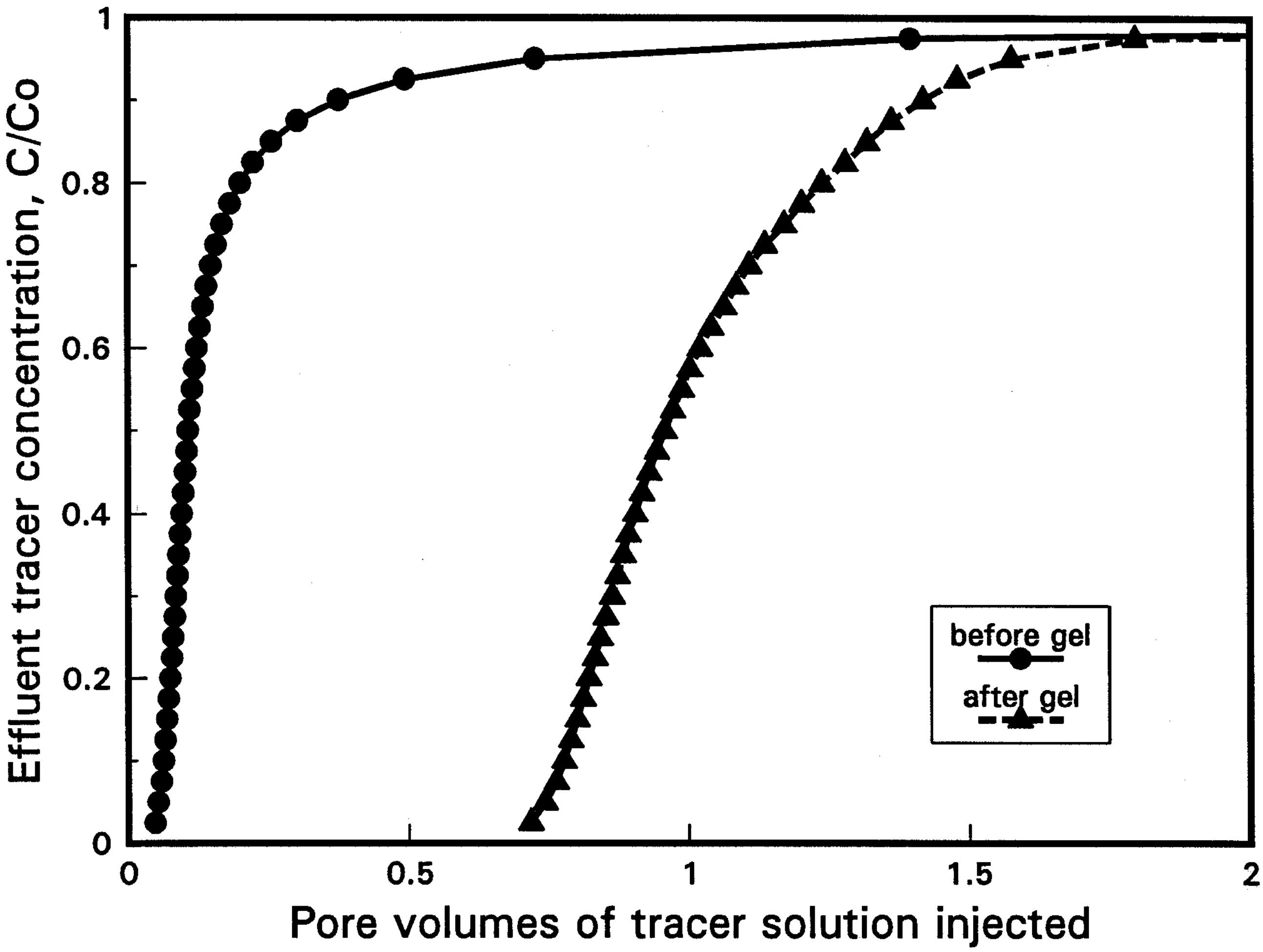


Fig. 55. Tracer results before and after placement of a Cr(III)-acetate-HPAM gel (24-hr delay before gel injection) in fractured Core 6 (66-md Berea; fracture outlet open).

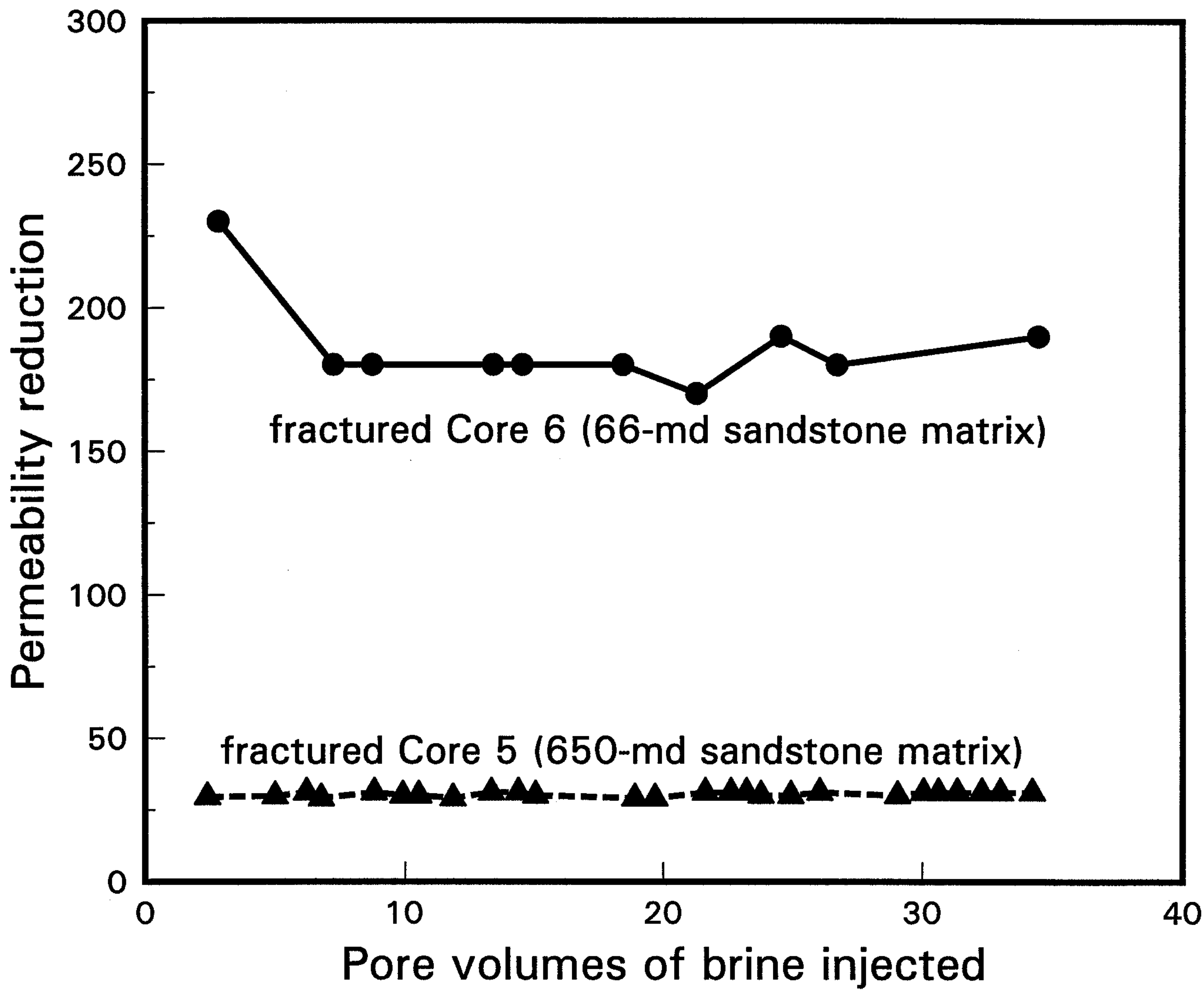


Fig. 56. Permeability reduction in the fracture vs. brine throughput after placement of a Cr(III)-acetate-HPAM gel (24-hr delay before gel injection; fracture outlets open).

For Cores 5 and 6, the gels provided permeability-reduction values that averaged 30 and 180, respectively (see Fig. 56). Before the gels were injected, we note that the flow capacities of the fracture relative to those of the rock matrix were 27.3 and 256 for Cores 5 and 6, respectively (Table 49). The similarity of these values to the corresponding permeability reduction values is consistent with the idea that the gels, in effect, healed the fractures.

The effect of pressure gradient on the permeability reduction values during brine injection is shown in Fig. 57. In both the 650-md core (Core 5) and the 66-md core (Core 6), the permeability reduction values are insensitive to pressure gradient over the ranges examined. In contrast, our previous work demonstrated that Cr^{3+}(acetate)-HPAM gels in unfractured cores (i.e., in rock matrix) exhibit a strong apparent shear-thinning behavior during brine injection.[51]

When the cores were disassembled after the experiments, the gel appeared to be well dispersed in the fractures. Thus, gravity segregation did not appear to be important during gel placement.

The above results suggest that in fractured systems, superior diversion may be obtained by injecting gels rather than gelants. However, before accepting this suggestion, we must determine whether gels can be injected into fractures without "screening out" or developing excessive pressure gradients. To test this ability, we conducted several experiments where larger volumes of gels were injected into fractured Berea cores. The cores that were used are described in Listings 7 through 9 of Table 49.

Using fractured Core 7, we injected 17 PV of brine, followed by 17 PV of Cr^{3+}(acetate)-HPAM gel (24 hrs after preparation), followed by 17 PV of brine (see Fig. 58). These steps were performed using an injection rate of 200 ml/hr. During the first brine injection, the apparent brine mobility was stable at 30 darcys/cp. During the subsequent injection of gel, the apparent gel mobility was stable at 0.01 darcys/cp. Thus, the gel was injected without plugging or "screening out" in the fracture. Also, since the apparent brine and gel mobilities are known (30 and 0.01 darcys/cp, respectively) and since these values are associated almost exclusively with flow through the fracture, we can calculate a resistance factor for gel in the fracture. This value is 3,000. Thus, the gel has an effective viscosity in the fracture that is 3,000 times greater than that for water.

After injecting the gel, the core was shut in for several days, and gel was removed from the flow lines and the inlet and outlet core faces. Then, 17 PV of brine were injected (Fig. 58). The apparent brine mobility was stable at 0.85 darcys/cp. This value was close to that expected for an unfractured core. Tracer results confirmed that the gel effectively healed the fracture (Fig. 59).

Using fractured Core 8, we examined the apparent rheology of the Cr^{3+}(acetate)-HPAM gel in a fracture. One day after the gelant was prepared, gel was injected into the fractured core at a rate of 400 ml/hr. During gel injection at this rate, the pressure gradient stabilized at about 75 psi/ft, and the resistance factor in the fracture was 1,500. After obtaining this data, the injection rate was decreased in stages. The results are shown by the solid curve and the solid circles in Figs. 60 and 61. At each successively lower rate down to 40 ml/hr, stabilized pressure drops were achieved and the resistance factors increased with decreasing flow rate (Fig. 60). Also, the pressure gradient remained fairly constant between 60 and 75 psi/ft (Fig. 61). This result suggests that some minimum pressure gradient is needed to keep the gel mobilized.

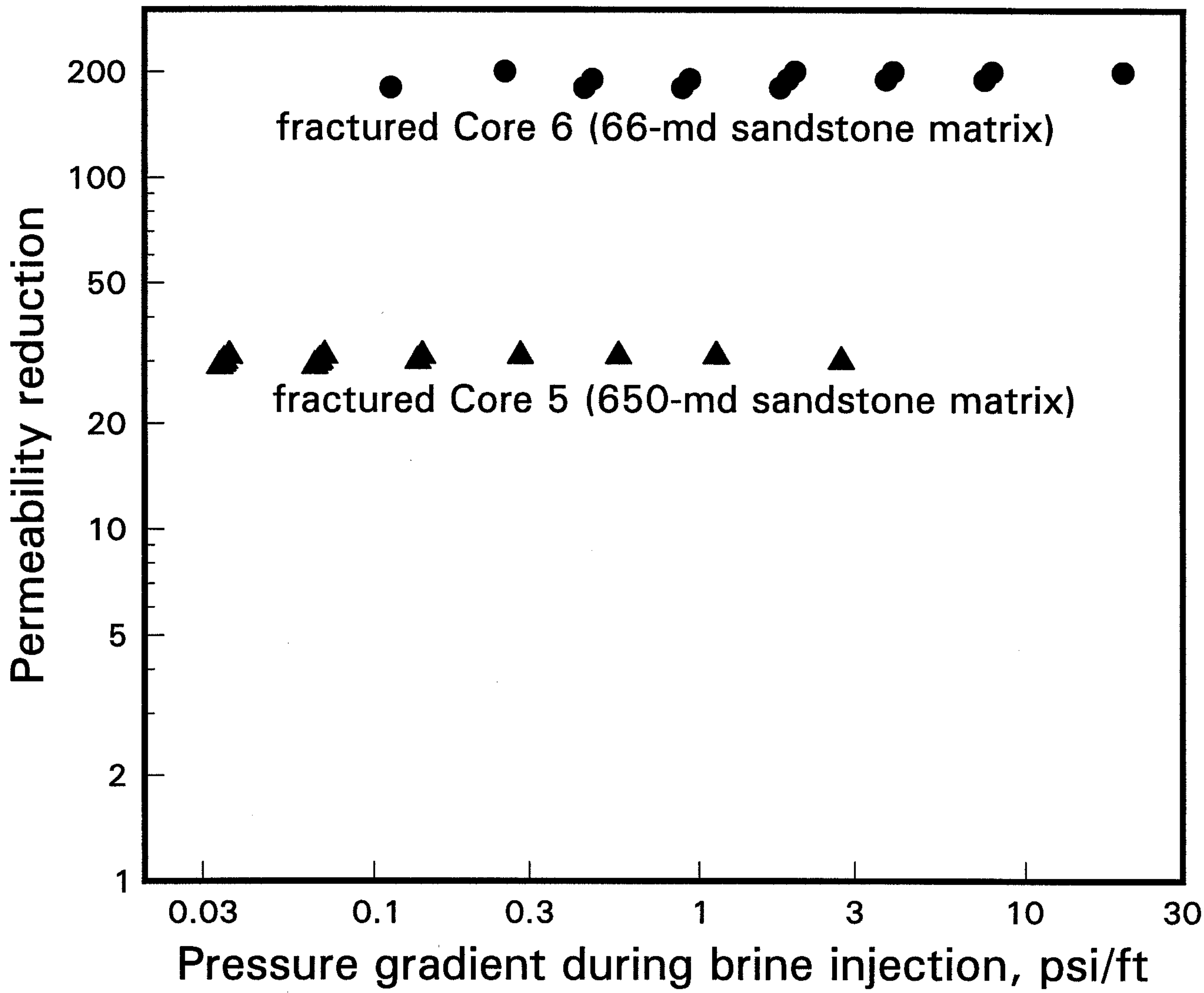


Fig. 57. Permeability reduction in the fracture vs. pressure gradient after placement of a Cr(III)-acetate-HPAM gel (24-hr delay before gel injection; fracture outlets open).

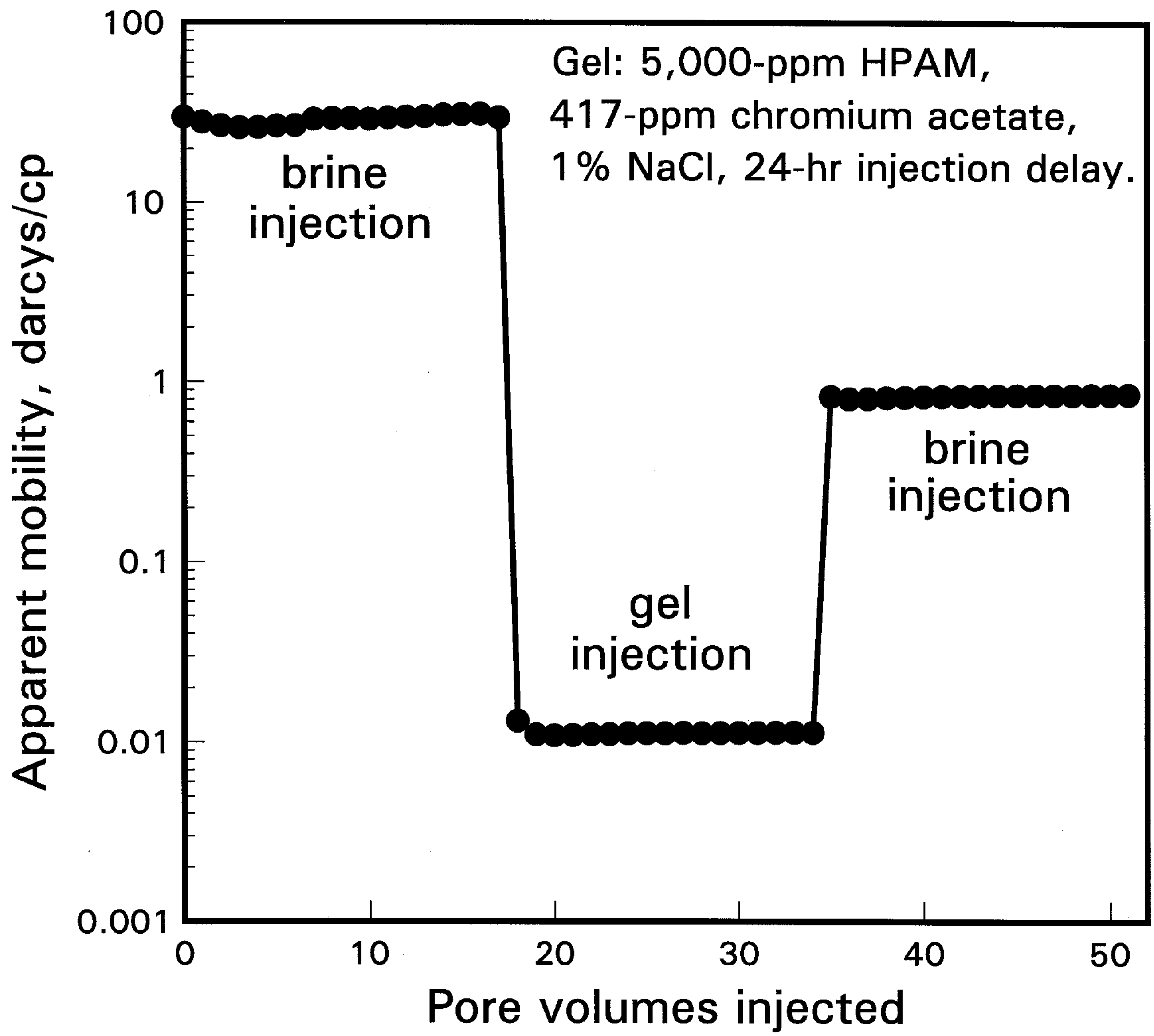


Fig. 58. Effect of brine and gel throughput on apparent mobility in fractured Core 7.

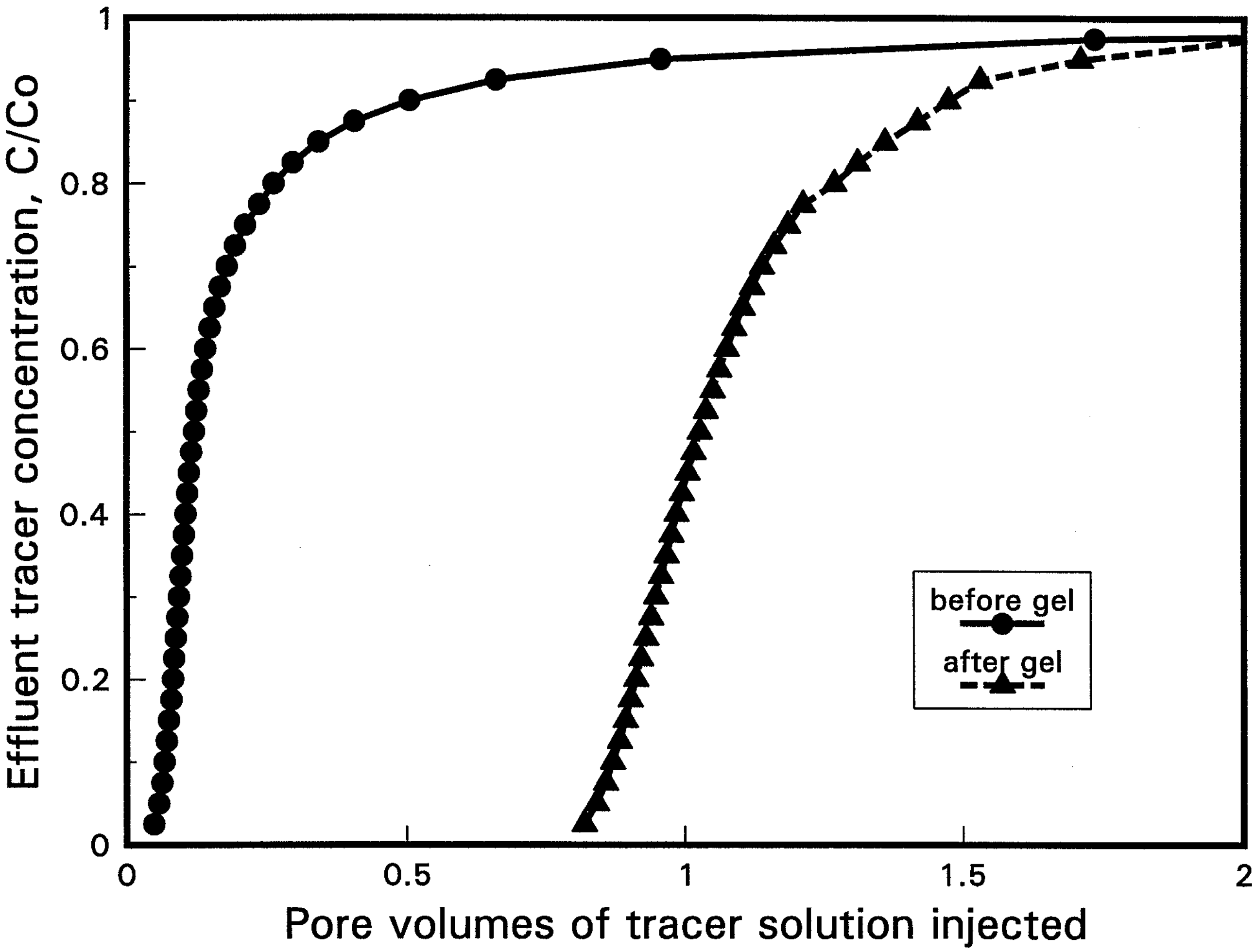


Fig. 59. Tracer results before and after placement of a Cr(III)-acetate-HPAM gel (24-hr delay before gel injection) in fractured Core 7 (650-md Berea; fracture outlet open).

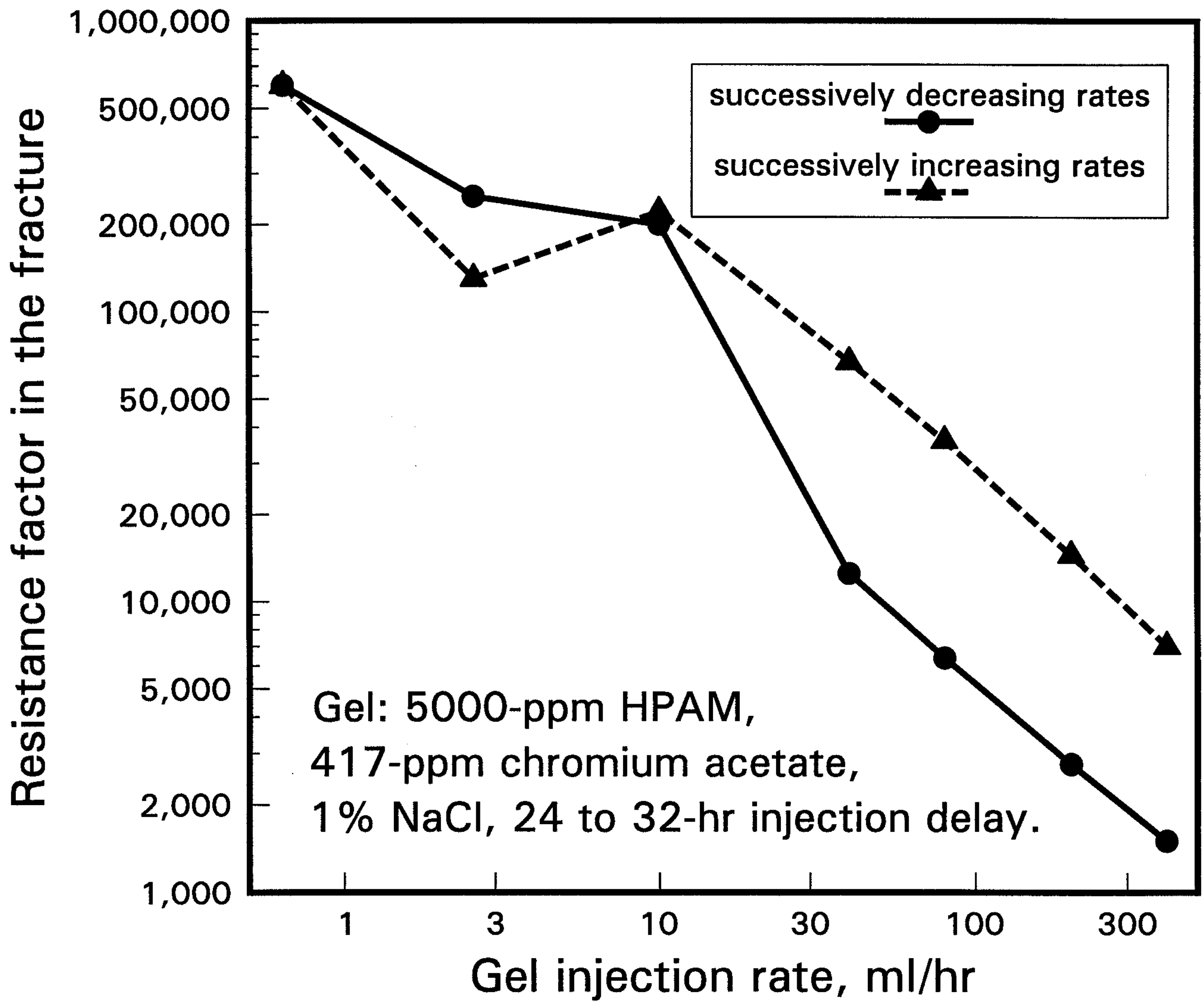


Fig. 60. Resistance factor in the fracture vs. injection rate during placement of a Cr(III)-acetate-HPAM gel (24 to 32-hr delay before gel injection, fractured Core 8).

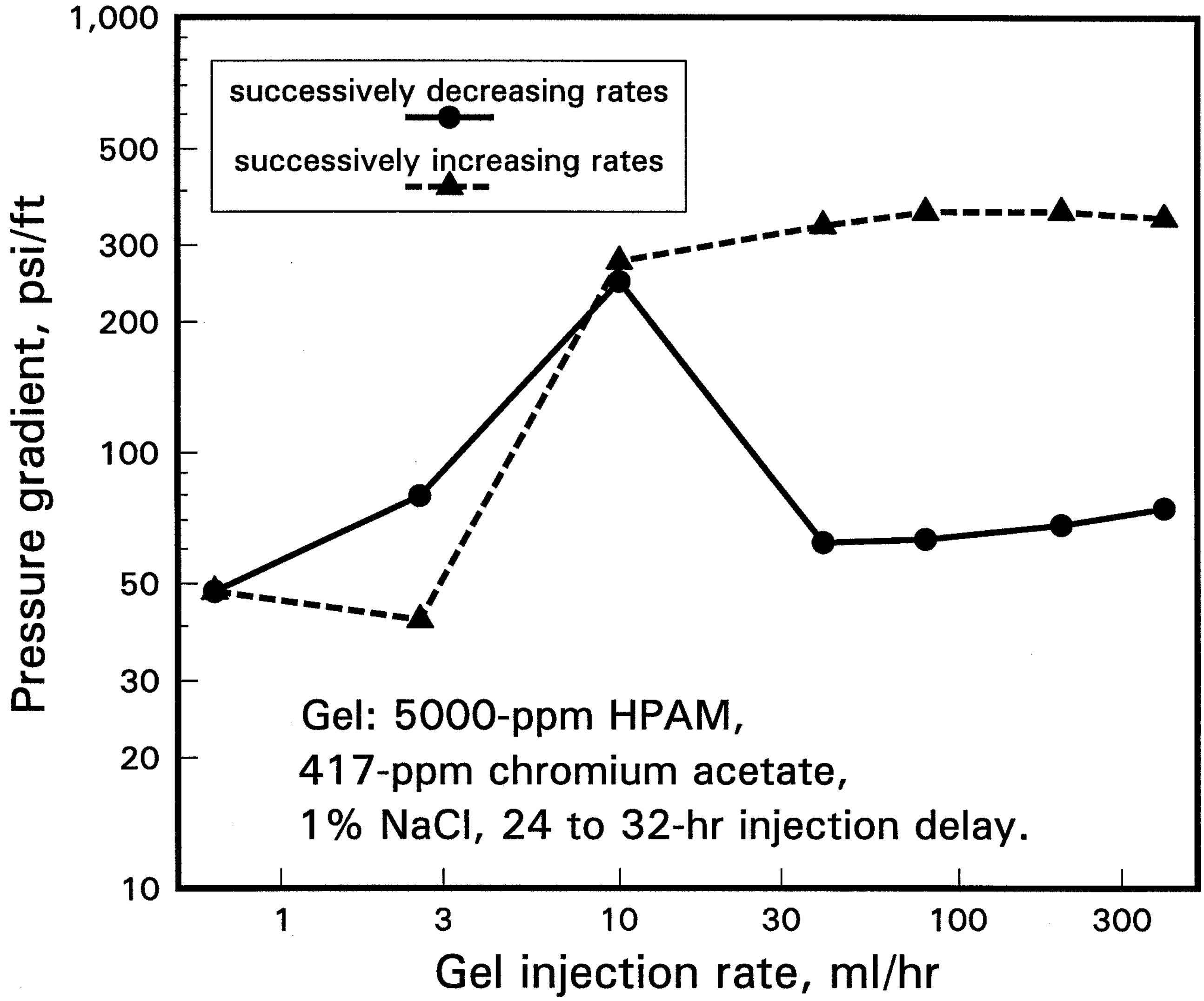


Fig. 61. Pressure gradient vs. gel injection rate during placement of a Cr(III)-acetate-HPAM gel (24 to 32-hr delay before gel injection, fractured Core 8).

When the gel injection rate was reduced to 10 ml/hr (2 hours after gel injection started and 26 hours after the gelant was prepared), the resistance factor increased to 200,000, and the pressure gradient increased to 250 psi/ft (Figs. 60 and 61). This deviation from the previous trend may have resulted from an increased degree of gelation, from the decreased injection rate, or from a combination of both effects. At lower injection rates, the average pressure gradients were lower, and the resistance factors were somewhat erratic. The low-injection-rate data points in Figs. 60 and 61 represent averages of these erratic values.

After reaching a low gel injection rate of 0.64 ml/hr, the injection rate was increased in stages. Results from this portion of the experiment are illustrated by the dashed curves and the solid triangles in Figs. 60 and 61. When the gel injection rate was increased to 10 m/hr (6 hours after gel injection started and 30 hours after the gelant was prepared), the resistance factor was 222,000, and the pressure gradient was 280 psi/ft. These values are very similar to those mentioned in the previous paragraph (associated with an injection rate of 10 ml/hr).

At higher injection rates, the resistance factors quickly stabilized at each new rate, and the pressure gradients were fairly constant around 300 psi/ft (Fig. 61). Again, this behavior suggests that some minimum pressure gradient is needed to keep the gel mobilized. However, at this point, this pressure gradient is 4 to 6 times greater than that noted earlier in the experiment. This experiment was completed 8 hours after gel injection started and 32 hours after the gelant was prepared.

Injection of a Resorcinol-Formaldehyde Gel. Using fractured Core 9, a set of experiments were performed using the resorcinol-formaldehyde gel (again, aged 24 hrs before injection). Fig. 62 shows the results. During the first brine injection, the apparent brine mobility was stable at 105 darcys/cp. During the subsequent injection of gel (at a rate of 200 ml/hr), the apparent gel mobility dropped sharply to 0.003 darcys/cp after injecting less than 1 PV of gel. No stabilization was evident. Thus, severe plugging was apparent during gel injection. After a shut-in period, 17 PV of brine was injected. The apparent brine mobility was stable at 1.5 darcys/cp.

After completion of the experiment, the core was disassembled to reveal that the gel had only penetrated 7 cm into the fracture (total length was 14 cm). This observation confirmed that the gel was "screening out" during injection into the fracture. We suspect that the ability of a given gel to propagate effectively through a fracture depends on (1) the composition of the gelant, (2) the fluid velocity (or pressure gradient) in the fracture, (3) the conductivity and tortuosity of the fracture, and (4) the degree of gelation or gel "curing." Thus, at this point, we are not suggesting that resorcinol-formaldehyde gels are necessarily better or worse than Cr^{3+}(acetate)-HPAM gels or other gels for fracture applications. More work will be needed to establish the best circumstances for propagation of gels in fractures.

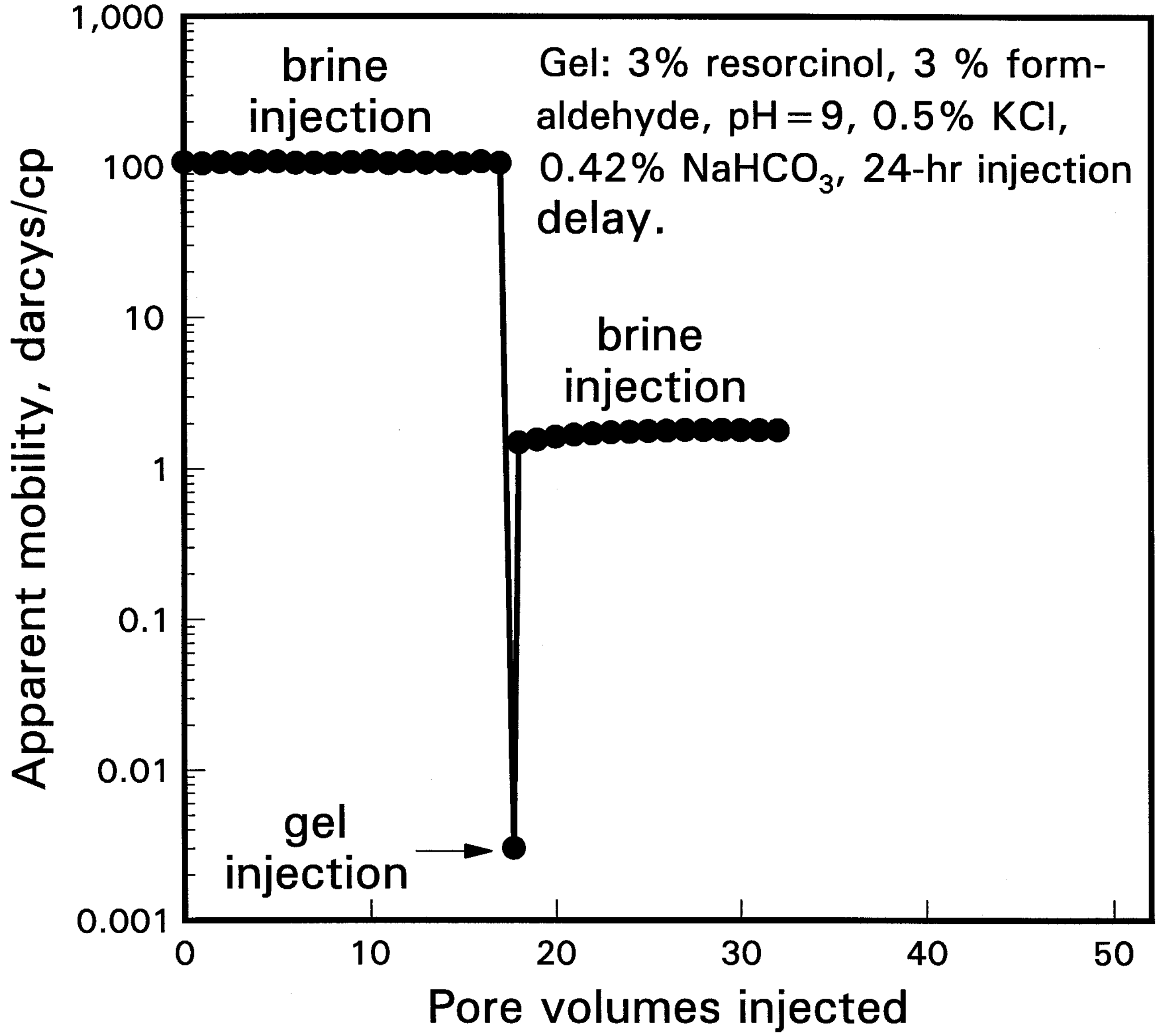


Fig. 62. Effect of brine and gel throughput on apparent mobility in fractured Core 9.

Conclusions

1. Flow visualization studies in beadpacks demonstrated that for a given volume of fluid injected, viscous injectants leakoff from a fracture into the matrix to a greater extent than low-viscosity injectants. This observation may explain field results where the interwell transit times for viscous gelants are much greater than those for a low-viscosity water tracer.

2. Coreflood experiments confirmed that a Cr^{3+}(acetate)-HPAM gelant and gel performed in a similar manner to that for other gelants and gels that were described in the literature. Specifically, before gelation, gelants can penetrate readily into the rock matrix, but after gelation, gel propagation is extremely slow or negligible. These observations suggest two possible methods to minimize gelant leakoff in fractured systems. One method is to design the gel treatment so that before the gelant leaves the wellbore, sufficient gelation occurs so that the gelant will not penetrate into the rock matrix. For this approach to succeed, the gel must remain pumpable for some period after gelation. The second method involves adding gelled material or some other particulate matter to the gelant. Both methods deserve further investigation.

3. Several experiments were conducted using fractured cores. Tracer studies coupled with permeability reduction measurements were used to assess sweep improvements before and after gel placement. Injection of pre-formed gels was shown to improve sweep efficiency (in effect, by healing the fractures) much more effectively than injection of gelants that formed gels in situ.

4. Several experiments were performed to assess whether pre-formed gels can propagate effectively through fractures. Twenty-four hours after gelant preparation, a Cr^{3+}(acetate)-HPAM gel was found to propagate through fractured cores without "screening out" or plugging. The experimental results suggested that some minimum pressure gradient was needed to keep the gel mobilized in a fracture. Twenty-four hours after gelant preparation, this pressure gradient was between 60 and 75 psi/ft. At later times, a higher pressure gradient was needed.

5. During brine injection after a shut-in period, washout of gels from fractured cores was much less for gels that were formed before injection than for gels that were formed in situ from gelants. For a Cr^{3+}(acetate)-HPAM gel in fractured cores, Newtonian behavior was observed during brine injection after gelation.

6. More work will be needed to establish the best circumstances for propagation of the various gels in fractures.

10. AN INVESTIGATION OF THE MECHANISMS FOR DISPROPORTIONATE PERMEABILITY REDUCTION

Applications of near-wellbore gel treatments in production wells are intended to reduce water production without sacrificing oil production. Several researchers[31,35,83-88] reported that polymers or gels can reduce permeability to water much more than to oil. This property is critical to the success of gel treatments in production wells if zones cannot be isolated during gel placement.[14] However, a plausible explanation for the phenomenon is not yet available. The ultimate objectives of our research in this area are to determine the reason why the disproportionate permeability reduction occurs and to identify conditions that maximize this phenomenon.

In a previous study,[71] we examined how different types of gels reduced oil and water permeabilities in Berea sandstone. Four types of gels were tested in the study: (1) resorcinol-formaldehyde, (2) Cr^{3+}(chloride)-xanthan, (3) Cr^{3+}(acetate)-HPAM, and (4) colloidal silica. Several experiments were performed to obtain a better understanding of why gels can reduce permeability to water more than to oil. Before gel placement in cores, multiple imbibition and drainage cycles were performed. Results from these studies established that hysteresis of oil and water relative permeabilities was not responsible for the behavior observed during our subsequent gel studies. Several gels clearly reduced water permeability significantly more than oil permeability. Whereas previous literature reported this phenomenon for polymers and "weak" polymer-based gels, we also observed the disproportionate permeability reduction with resorcinol-formaldehyde (a monomer-based gel) as well as with both weak Cr^{3+}(chloride)-xanthan and relatively strong Cr^{3+}(acetate)-HPAM gels. In contrast, a colloidal-silica gel reduced water and oil permeabilities by about the same factor. Residual resistance factors for several gels decreased during multiple cycles of oil and water injection. In spite of this degradation, the disproportionate permeability reduction persisted through the cycles for most of the gels. Oil- and water-tracer studies were coupled with material-balance calculations to provide insight into the fraction of the pore volume occupied by gel. The strongest gels appeared to encapsulate the original residual oil—thus rendering the residual oil inaccessible during subsequent oil flooding.

A number of different mechanisms for the disproportionate permeability reduction have been suggested. The main objective of this study is to test the validity of these mechanisms.

Experimental Procedures

Gelants Studied. Four types of gels were examined during the past one-year period: (1) resorcinol-formaldehyde, (2) Cr^{3+}(acetate)-HPAM (Marathon's MARCIT®), (3) glyoxal-CPAM (Pfizer's Floperm 500®), and (4) Cr^{3+}(acetate)-PAM-AMPS (using Drilling Specialties' HE 100® polymer). For the glyoxal-CPAM gel, two formulations were examined. Table 50 lists the compositions of these gelants. Pfizer provided the cationic polyacrylamide (CPAM), Marathon supplied the partially-hydrolyzed polyacrylamide (HPAM), and Drilling Specialties provided the PAM-AMPS copolymer. The other chemicals used in this study were reagent grade.

Rock Used. High-permeability Berea sandstone cores were used in all core experiments. All cores were strongly water-wet and were not fired. They were cast in a metal alloy (Cerrotru®). Typically, each core was about 14-cm long and 3.6 cm in diameter. The rock and fluid properties are summarized in Table 51. The first five cores in the table had one internal pressure tap located approximately 2 cm from the inlet rock face, while the other two cores had two internal pressure taps, one located approximately 2 cm from the inlet rock face, and the other located about the same distance from the outlet rock face. The first core segment was treated as a filter; whereas, the second core segment was used to measure mobilities and residual resistance factors.

Table 50. Gelant Compositions and Properties (at 41°C)

Gelant Composition	pH	μ at 11 s^{-1}, cp
3% resorcinol, 3% formaldehyde, 0.5% KCl, 0.42% $NaHCO_3$	6.5	0.67
1.39% polyacrylamide (HPAM), 212-ppm Cr^{3+} (as acetate), 1% NaCl	6.0	33
0.4% cationic polyacrylamide (CPAM), 1,520-ppm glyoxal, 2% KCl	7.3	9.3
0.3% cationic polyacrylamide (CPAM), 1,140-ppm glyoxal, 2% KCl	7.3	5.4
0.3% PAM-AMPS, 100-ppm Cr^{3+}(as acetate), 2% KCl	5.0	16

Table 51. Rock and Fluid Properties

Core ID	Length, cm	k_w, md	Gelant	Brine
SSH-36	13.52	603	3% resorcinol, 3% formaldehyde	0.5% KCl, 0.42% $NaHCO_3$
SSH-38	13.82	611	1.39% HPAM, 212-ppm Cr^{3+}(as acetate)	1% NaCl
SSH-43	13.85	710	0.4% CPAM, 1,520-ppm glyoxal	2% KCl
SSH-44	13.60	539	0.3% CPAM, 1,140-ppm glyoxal	2% KCl
SSHM1	13.33	671	0.3% PAM-AMPS, 100-ppm Cr^{3+}(as acetate)	2% KCl
SSH-51	13.35	617	1.39% HPAM, 212-ppm Cr^{3+}(as acetate)	1% NaCl
SSH-60	14.7	645	1.39% HPAM, 212-ppm Cr^{3+}(as acetate)	1% NaCl

Fluids Used. A refined oil (Soltrol-130®) with a viscosity of 1.05 cp at 41°C was usually used as the oil phase. Banco® IC46980 paraffin oil with a viscosity of 31.6 cp at 41°C was used as the viscous oil in conjunction with Soltrol-130 in core SSH-51. For a given core experiment, the brine used to saturate the core had the same composition as that used for gelant preparation. Table 51 also summarizes the gelants and brines used in each core experiment. The viscosity of all brines was about 0.67 cp at 41°C.

Coreflood Sequence. Table 52 summarizes the sequence that was usually followed during our core experiments. In each of the corefloods, the core was first saturated with brine, and the porosity was determined at ambient conditions. All subsequent steps were performed at 41°C. The core went through a cycle of oilflooding followed by waterflooding (flow direction #1). The end-point oil and water permeabilities were determined at the irreducible water saturation after the oilflood and at the irreducible oil saturation after the waterflood, respectively. To verify that the results were reproducible, each step in the procedure was repeated. Then, the flow direction was reversed (flow direction #2) and the above procedure was repeated to determine the effect of hysteresis. A constant pressure drop was maintained across the core during the process. (The pressure drop was maintained at 30 psi when the gelant to be injected was resorcinol-formaldehyde. For other more viscous gelants, the pressure drop was maintained at 100 psi to avoid mobilizing residual oil during gelant injection.)

Results from our previous study[71] showed no significant hysteresis of end-point permeabilities either from the flow-direction reversal or from the multiple imbibition and drainage cycles. Therefore, unless otherwise indicated, steps 8 through 10 in Table 52 were not performed in this study.

Water- and oil-tracer studies were routinely performed to characterize pore volumes and dispersivities. Water-tracer studies were performed after the core was first saturated with brine and after each waterflood. These studies involved injecting a brine bank that contained 20-ppm potassium iodide as a tracer. The tracer concentration in the effluent was monitored spectrophotometrically at a wavelength of 230 nm. Oil-tracer studies were performed after each oilflood. These studies involved injecting an oil bank that contained 20-ppm trans-stilbene as a tracer. The tracer concentration in the effluent was monitored spectrophotometrically at a wavelength of 300 nm. Usually, four replicates were performed for each tracer study. Also, the replicates included studies performed at different injection rates (3.1 and 15.6 ft/d). Retention of trans-stilbene in Berea sandstone was found to be negligible (less than 0.01 μg/g of rock).

To simulate the "pump-in, pump-out" sequence during gel treatments in production wells, the gelant was injected into the core from one direction (flow direction #1) and residual resistance factors were measured in the opposite direction (flow direction #2). The residual resistance factor, F_{rr}, is defined in this study as the mobility before gel treatment divided by the mobility after gelation. Resistance factors and effluent pH were monitored continuously during gelant injection. In this study, the resistance factor, F_r, is defined as the brine mobility before gel placement divided by mobility during gelant injection. Effluent samples were collected and monitored to determine whether the gelation characteristics of the effluent differed from those of gelant that had not been injected. After injecting the gelant, the core was shut in for five days (at 41°C). After shut-in, brine was injected from the opposite direction (flow direction #2) to determine residual resistance factors to water (F_{rrw}). To determine the apparent rheology of the gel in porous media and whether gel mobilization occurred at a given flow rate, residual resistance factors were determined as a function of injection rate. Measurements of residual resistance factors were first made at a very low injection rate. After stabilization, the measurements were repeated at a higher injection rate. Then, the rate of brine injection was lowered to the previous injection rate to determine whether the F_{rrw} value at that injection rate had changed. This cycle was repeated several times using successively higher injection rates until the pressure drop across the core approached the pressure constraint used in the process of establishing residual saturations.

Table 52. Sequence Followed During Oil/Water Core Experiments

Step

1. Saturate core with brine and determine porosity.
2. Determine absolute brine permeability and mobility.
3. Perform water-tracer study to confirm the pore volume (V_{po}) and to determine core dispersivity (α_0).
4. Inject oil (flow direction #1) to displace brine at a constant pressure drop of 100 psi* across the core and to determine oil mobility at residual water saturation, S_{wr}.
5. Perform oil-tracer study (flow direction #1) to determine the fraction of the original pore volume remaining (V_p/V_{po}) and the relative dispersivity (α/α_0).
6. Inject brine (flow direction #1) to displace oil at a constant pressure drop of 100 psi* across the core and to determine brine mobility at residual oil saturation, S_{or}.
7. Perform water-tracer study (flow direction #1) to determine V_p/V_{po} and α/α_0.
8. Repeat Steps 4 through 7 (flow direction #1) to verify that the results are reproducible.
9. Reverse the flow direction (flow direction #2), and repeat Steps 4 through 7 to determine the effect of hysteresis.
10. Repeat Step 9 (flow direction #2) to verify that the results are reproducible.
11. Inject gelant using the highest possible injection rate without exceeding the pressure constraint (flow direction #1).
12. Shut in core to allow gelation.
13. Inject brine (flow direction #2) to determine the residual resistance factors to water (F_{rrw}).
14. Perform water-tracer study to determine V_p/V_{po} and α/α_0 (flow direction #2).

15a. Inject oil (flow direction #2) to determine the residual resistance factor to oil (F_{rro}).
15b. Perform oil-tracer study to determine V_p/V_{po} and α/α_0 (flow direction #2).
15c. Inject brine (flow direction #2) to determine F_{rrw}.
15d. Perform water-tracer study to determine V_p/V_{po} and α/α_0 (flow direction #2).

16. Repeat Steps 15a through 15d (second oil-water injection cycle after shut-in).
17. Repeat Steps 15a through 15d (third oil-water injection cycle after shut-in).
18. Repeat Steps 15a through 15d (fourth oil-water injection cycle after shut-in).

* 30 psi if gelant was resorcinol-formaldehyde.

A water-tracer study was then performed to determine the final pore volume that was occupied by the gel and the effect of the gel treatment on the dispersivity of the core. After the tracer study, oil was injected at a pressure equal to the pressure constraint (typically 100 psi) until no more water was produced. F_{rro} values were then determined at a number of fluid velocities. These values were measured at successively decreasing flow rates. Then, an oil-tracer study was performed. Next, water was injected at a pressure equal to the pressure constraint until no more oil was produced. F_{rrw} values were then determined using successively decreasing flow rates. The purpose of this procedure was to determine whether the gels exhibited non-Newtonian behavior during water or oil injection. The gels were exposed to multiple cycles of water and oil injection. Tracer studies were also repeated.

Most corefloods were performed at ambient pressure. However, to study the effect of changing system pressure on the residual resistance factors, core experiment SSH-60 was conducted using different back pressures (0, 500, 1,000, and 1,500 psi).

End-Point Permeabilities Before Gel Treatments

The results from end-point oil and water permeability measurements before gel treatments are summarized in Tables 53 and 54. The residual saturations (S_{wr} and S_{or}) listed in these tables were obtained from material balance calculations. Since results from our previous study[71] showed no significant hysteresis of end-point permeabilities (either for water or oil) from the flow-direction reversal and the multiple imbibition and drainage cycles, steps 8 through 10 in Table 52 were not performed in this study except for corefloods SSH-38, SSHM1, SSH-51 and SSH-60. For core experimentS SSH-38 and SSH-60, Steps 4 and 5 were repeated once after the first oil-water injection cycle, so the gelant could be injected at residual water saturation (S_{wr}). For core experiment SSHM1, all steps outlined in Table 52 were performed. As shown in Table 54, no hysteresis of end-point permeabilities (either for water or oil) was observed as a result of flow-direction reversal and multiple imbibition and drainage cycles. (Core SSH-51 will be discussed later.)

Table 53. Summary of Residual Saturations (S_{wr}, S_{or}) and End-Point Permeabilities (k_o^o, k_w^o) Obtained before Gel Treatment (Berea Sandstone Cores, Strongly Water-Wet, 41°C)

Core ID	S_{wr}	k_o^o, md	S_{or}	k_w^o, md
SSH-36	0.27	515	0.34	124
SSH-38	0.28±0.02†	497±2†	0.30	201
SSH-43	0.27	568	0.28	237
SSH-44	0.28	405	0.26	167

† The average of the results from two measurements in flow direction #1.

Table 54. Residual Saturations (S_{wr}, S_{or}) and End-Point Permeabilities (k_o^o, k_w^o) Obtained before Gel Treatment (Core SSHM1, Berea Sandstone, Strongly Water-Wet, 41°C)

Stage	S_{wr}	k_o^o
1st oilflood before gel (Step 4)	0.30	547
2nd oilflood before gel (Step 8)	0.30	562
3rd oilflood before gel* (Step 9)	0.31	484
4th oilflood before gel* (Step 10)	0.32	484
Stage	**S_{or}**	**k_w^o**
1st waterflood before gel (Step 6)	0.35	107
2nd waterflood before gel (Step 8)	0.35	93
3rd waterflood before gel* (Step 9)	0.34	99
4th waterflood before gel* (Step 10)	0.33	100

* Flow-direction reversed.

To establish baselines for the effect of changing system pressure on the residual resistance factors, end-point mobility measurements for core SSH-60 were performed using different back pressures (0, 500, 1,000, and 1,500 psi). As shown in Table 55, brine and oil mobilities were essentially independent of system pressure.

Table 55. Effect of System Pressure on End-Point Mobilities before Gel Treatment (Core SSH-60, Berea Sandstone, Strongly Water-Wet, 41°C)

Back pressure (psi)	Brine mobility (md/cp) (at $S_w=1.0$)	Oil mobility (md/cp) (at $S_{wr}=0.24$)	Brine mobility (md/cp) (at $S_{or}=0.31$)
0	1,150	573	212
500	1,154	559	232
1,000	1,146	549	257
1,500	1,142	528	257
1,500	1,142	520	266
1,000	1,148	523	263
500	1,141	540	258
0	1,130	571	245

Gelant Placement in Cores

Effluent samples were collected continuously throughout the gelant injection process at one-pore-volume intervals. The samples were allowed to gel, and the final gel strength was compared with gelant that had not been injected into the core. Effluent pH and resistance factors were also routinely monitored during the injection process. For the gelants that contained chromium, effluent samples were analyzed for chromium concentration using atomic absorption spectrometry. For the resorcinol-formaldehyde gel (Core SSH-36) and the Cr^{3+}(acetate)-HPAM gel (Cores SSH-38, SSH-51, and SSH-60), the behavior observed during the gelant injection process was very similar to that reported in our previous study.[71]

Fig. 63 plots the effluent pH against the number of pore volumes injected for the glyoxal-CPAM and Cr^{3+}(acetate)-PAM-AMPS gelants. Fig. 64 is a plot of the chromium concentration in the effluent relative to the injected chromium concentration vs. the number of effective pore volumes injected for the Cr^{3+}(acetate)-PAM-AMPS gel. The effective pore volume is the pore space that remains accessible to the water phase at the residual oil saturation. For comparison, the results from a Cr^{3+}(acetate)-HPAM gelant (Core SSH-31) examined in a previous study[71] are also included in Fig. 64. The slower rate of chromium propagation for the Cr^{3+}(acetate)-PAM-AMPS gelant may be largely due to the lower concentration of chromium in the gelant.

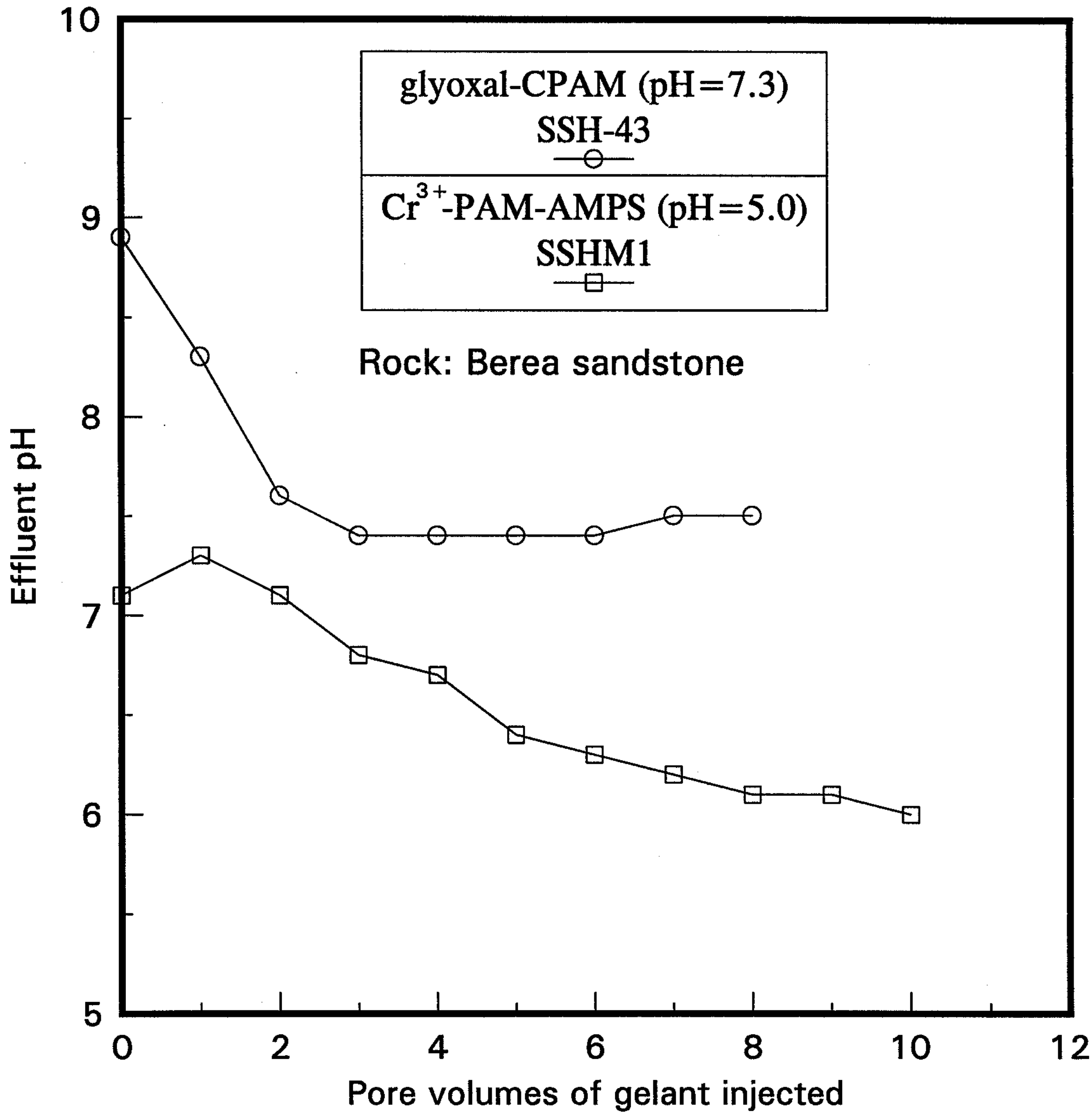


Fig. 63. Effluent pH during gelant injection.

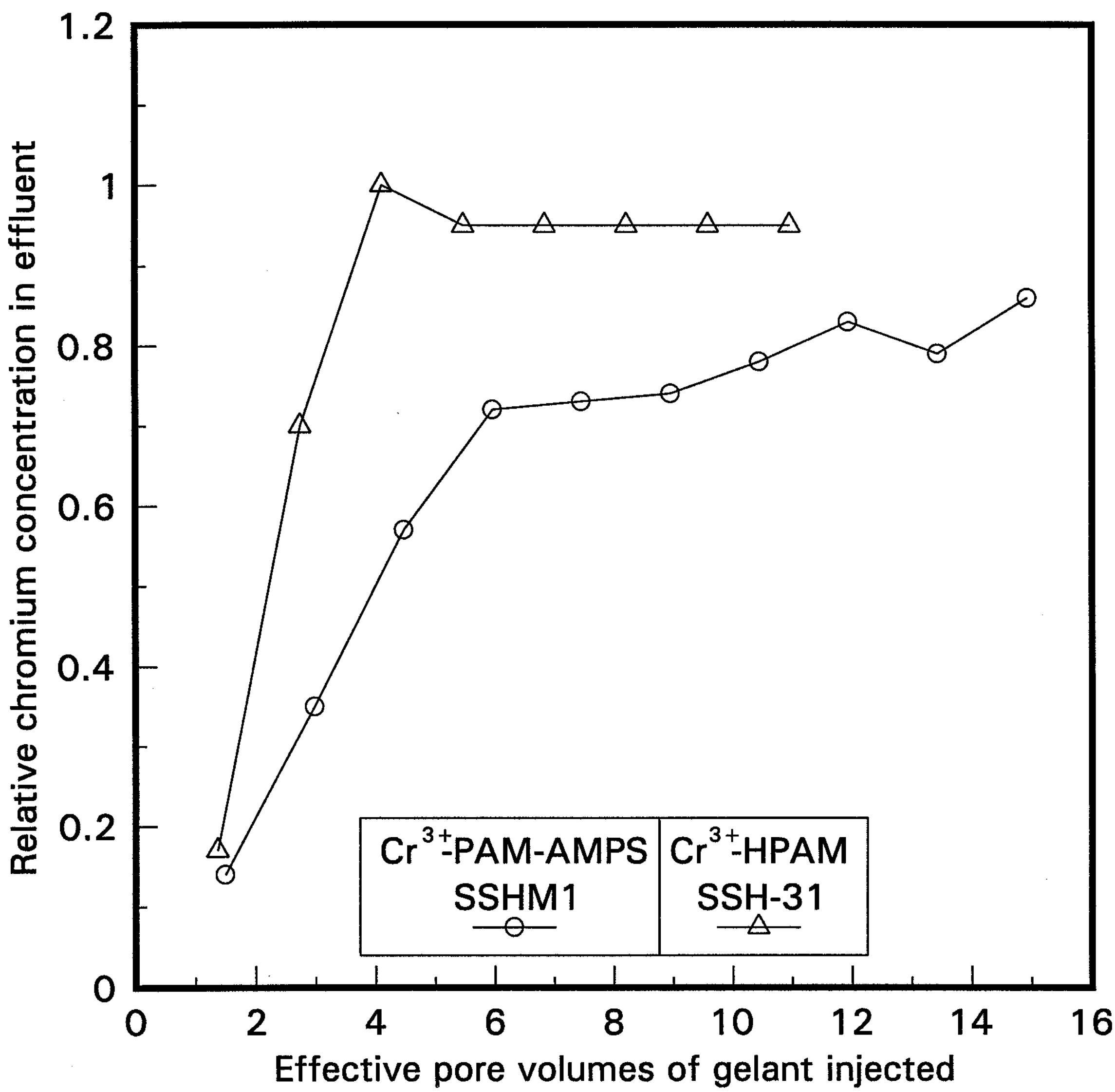


Fig. 64. Effluent chromium concentration during gelant injection.

For the Cr^{3+}(acetate)-PAM-AMPS gelant, the injected and noninjected gelant samples exhibited similar gelation times and final gel strengths. In contrast, the glyoxal-CPAM gelants showed behavior that was opposite to that expected during the gelation process. Specifically, gelant viscosities decreased instead of increased. The initial viscosity was 9.3 cp for the glyoxal-CPAM gelant with 0.4% CPAM and 1,520-ppm glyoxal. However, the viscosity dropped to 3.1 cp after six days. A similar behavior was observed for the glyoxal-CPAM gelant with 0.3% CPAM and 1,140-ppm glyoxal—the bulk viscosity dropped from 5.4 cp initially to 1.9 cp after six days.

The gelant placement data are summarized in Table 56, including approximate gelation times and the number of pore volumes injected for the gelants investigated in this study and a previous study.[71] Gelation times were estimated by observing the fluidity of gelant in bottles. For the glyoxal-CPAM gels, the gelation times were not available because the bulk viscosities actually decreased during gelation.

During a given gelant injection process, a constant pressure drop (100 psi in most cases) was maintained across the core. In most cases, we tried to inject 10 PV of gelant. We successfully injected 10 PV of gelant for eight corefloods. However, for several other cases, pressure increases during the placement process limited injection to less than 10 PV. For the resorcinol-formaldehyde gelant, retention studies[71] in Berea sandstone cores revealed no significant loss of gelant components, either by adsorption or by partitioning into the oil phase. Therefore, in one case, only three pore volumes of the gelant were injected (Core SSH-36).

Figs. 65 and 66 present a summary of the resistance-factor measurements during the placement process for seven gelant formulations. Fig. 65 summarizes the resistance-factor measurements in the short core segments (2-cm lengths). The results from the resistance-factor measurements in the long core segments (12-cm lengths) are presented in Fig. 66.

As can be seen in Figs. 65 and 66, the resistance factors for most of the gelants were relatively low and stable during the placement process, indicating good injectivities for these gelants in high-permeability Berea sandstone. The resistance factors for the glyoxal-CPAM gelant increased significantly in the short (inlet) segment of the core toward the end of the injection process (Fig. 65). For the Cr^{3+}(acetate)-HPAM gelant with the higher polymer concentration (1.39%), the resistance factors in both core segments increased significantly during the later stage of gelant injection (Figs. 65 and 66).

Permeability Reduction Using Gels

Four gelant formulations were tested during the past one-year period: (1) Cr^{3+}(acetate)-HPAM, (2) resorcinol-formaldehyde, (3) glyoxal-CPAM, and (4) Cr^{3+}(acetate)-PAM-AMPS. The gelant compositions can be found in Table 50. For easier comparison, results from core experiments both in this study and in a previous study[71] are summarized in Table 57. The detailed results of the core experiments can be found in Appendix C.

Cr^{3+}(acetate)-HPAM. In our standard coreflood sequence (Table 52), the residual resistance factors for water were determined before those for oil. In other words, after gelation, water was injected first, then oil was injected. To test whether the process of switching from water to oil injection affected gel performance, multiple cycles of water and oil were injected after gelation. Fig. 67 shows the results from two core experiments that were performed using a gel that contained 1.39% polyacrylamide (HPAM) and 212-ppm Cr^{3+} (as acetate). In one set of experiments from Ref. 71 (represented by the circles in Fig.

Table 56. Gelant Placement Data (41°C)

Core ID	Gelant	Gelation time, days	Pore volumes injected
SSH-15	3% resorcinol, 3% formaldehyde	0.25	10
SSH-17	3% resorcinol, 3% formaldehyde	0.25	10
SSH-36*	3% resorcinol, 3% formaldehyde	0.25	3
SSH-22	0.4% xanthan, 154-ppm Cr^{3+} (as chloride)	0.42	10
SSH-23	0.4% xanthan, 154-ppm Cr^{3+} (as chloride)	0.42	10
SSH-32	10% colloidal silica	0.21	10
SSH-33	10% colloidal silica	0.21	10
SSH-26	1.39% HPAM, 636-ppm Cr^{3+} (as acetate)	0.15	4
SSH-27	0.7% HPAM, 318-ppm Cr^{3+} (as acetate)	0.45	10
SSH-31	1.39% HPAM, 212-ppm Cr^{3+} (as acetate)	0.63	8
SSH-38*	1.39% HPAM, 212-ppm Cr^{3+} (as acetate)	0.63	6
SSH-51*	1.39% HPAM, 212-ppm Cr^{3+} (as acetate)	0.63	6
SSH-60*	1.39% HPAM, 212-ppm Cr^{3+} (as acetate)	0.63	5
SSH-43*	0.4% CPAM, 1,520-ppm glyoxal	--	6
SSH-44*	0.3% CPAM, 1,140-ppm glyoxal	--	6
SSHM1*	0.3% PAM-AMPS, 100-ppm Cr^{3+} (as acetate)	--	10

* The core experiments with the starred IDs were performed in this study. The other experiments were performed during a previous study.[71]

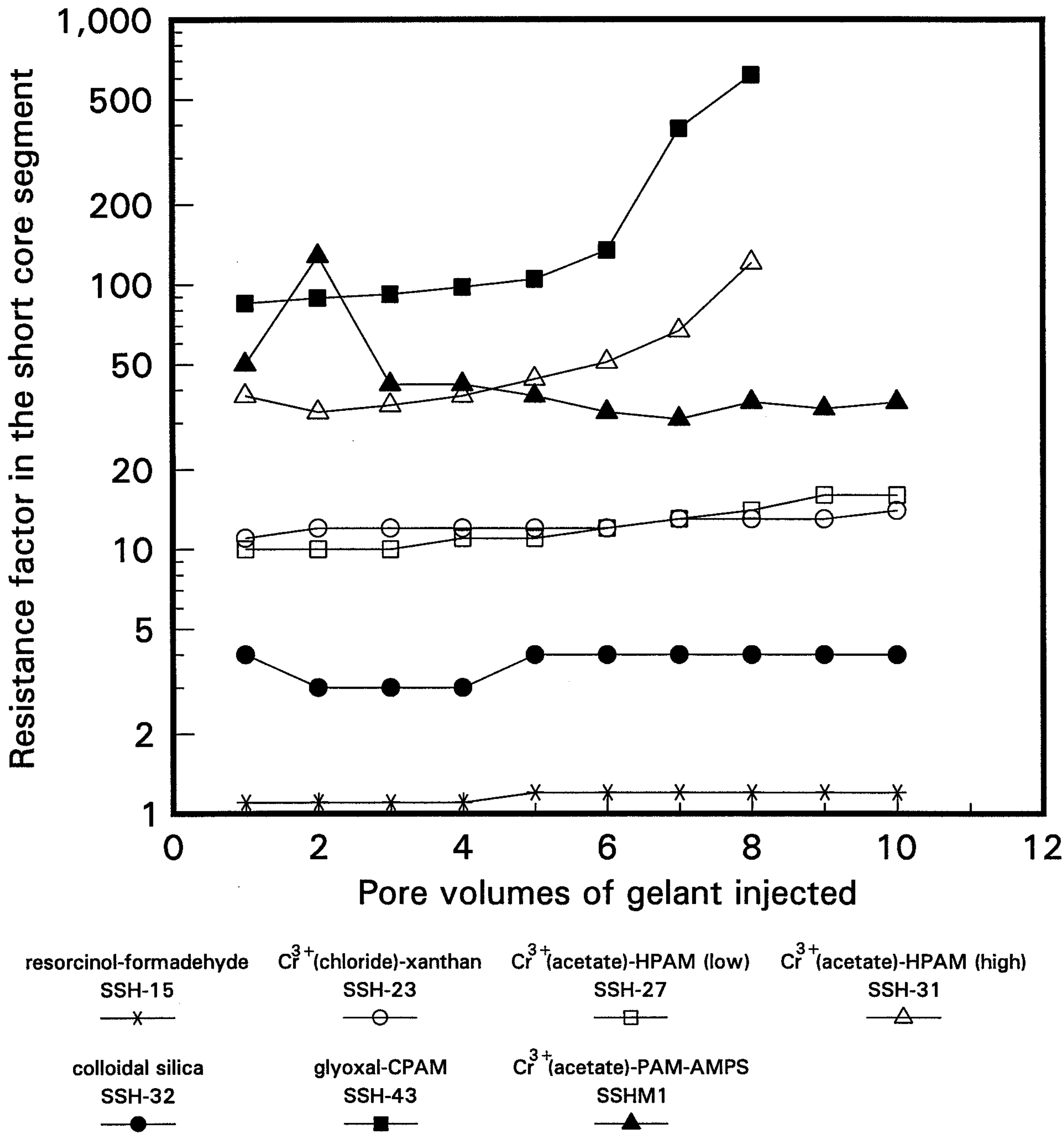


Fig. 65. Resistance factors in the short core segment during gelant injection.

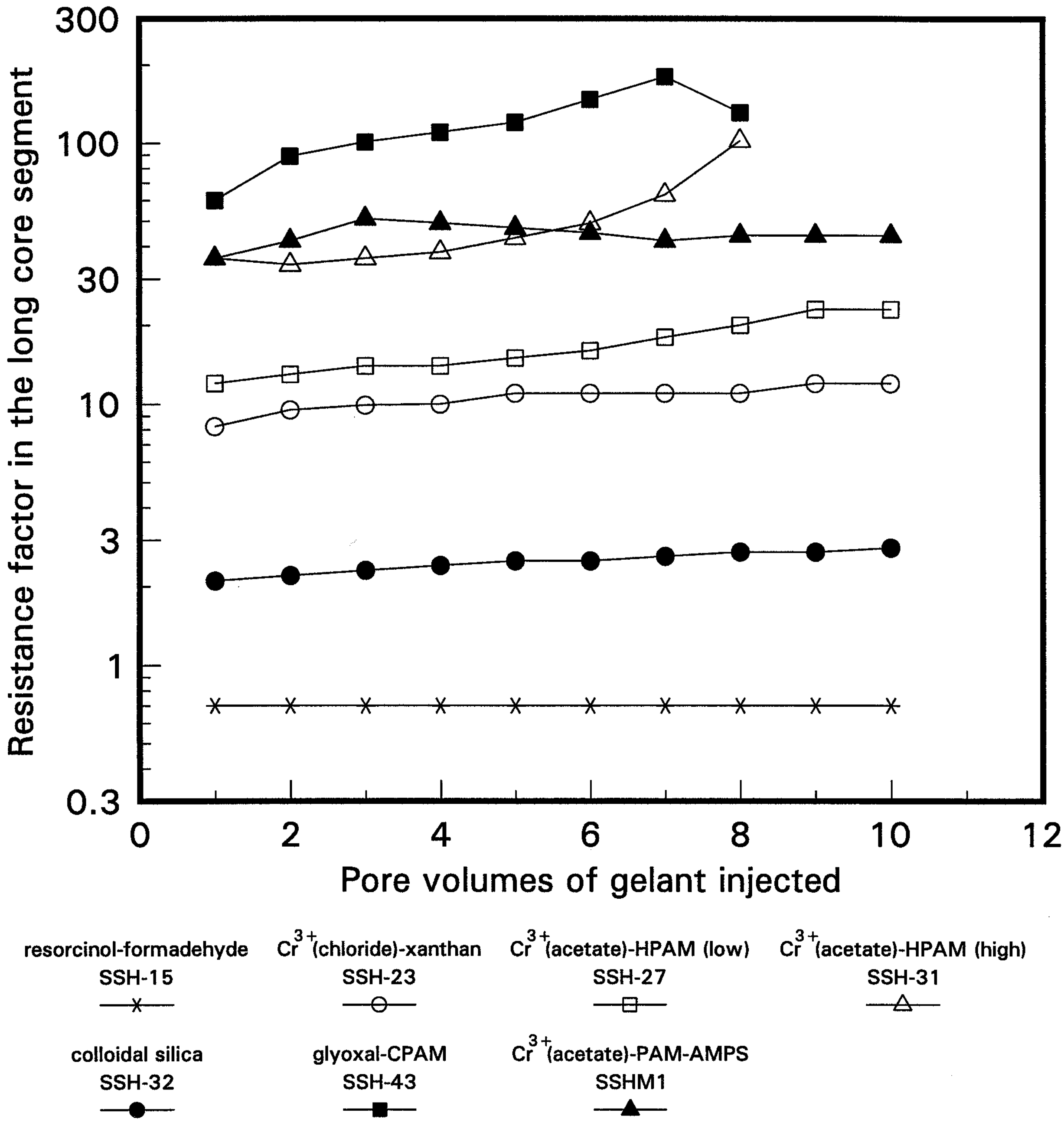


Fig. 66. Resistance factors in the long core segment during gelant injection.

Table 57. Summary of Residual Resistance Factors for Water (F_{rrw}) and for Oil (F_{rro})

Core ID	Wettability	Gel type	F_{rrw} (13)†	F_{rro} (15a)	F_{rrw} (15c)	F_{rro} (16a)	F_{rrw} (16c)	F_{rro} (17a)	F_{rrw} (17c)	F_{rro} (18a)	F_{rrw} (18c)
SSH-15	Intermediate	3% resorcinol, 3% formaldehyde	510	26	180	29	241				
SSH-17	Strongly water-wet		49	11	40	12	41				
SSH-36*	Strongly water-wet		170	23	123	14	62				
SSH-22	Strongly water-wet	0.4 % xanthan, 154-ppm Cr^{3+}(chloride)	8	5	12	4	8				
SSH-23	Intermediate		22	14	31	16	42				
SSH-26	Strongly water-wet	1.39% HPAM, 636-ppm Cr^{3+}	>40,000	1,020	12,300	148	2,180	100	$409\ u^{-0.43}$	67	
SSH-27	Strongly water-wet	0.7% HPAM, 318-ppm Cr^{3+}	$829\ u^{-0.45}$	20	$117\ u^{-0.29}$	15	$33\ u^{-0.33}$	5	$9\ u^{-0.17}$		
SSH-31	Strongly water-wet	1.39% HPAM, 212-ppm Cr^{3+}	>53,000	50	$972\ u^{-0.50}$	25	$357\ u^{-0.49}$	14	$105\ u^{-0.55}$	5	$9\ u^{-0.20}$
SSH-38*	Strongly water-wet			$133\ u^{-0.35}$	$1,290\ u^{-0.33}$	$63\ u^{-0.28}$	$476\ u^{-0.57}$	$27\ u^{-0.13}$	$87\ u^{-0.52}$	12	
SSH-51*	Strongly water-wet		>35,300	49	$1,430\ u^{-0.44}$	28	$818\ u^{-0.40}$				
SSH-60*	Strongly water-wet			9	$18\ u^{-0.18}$	2					
SSH-32	Strongly water-wet	10% colloidal silica	26	23	14	9	12	6	8		
SSH-33	Strongly water-wet		8	16	14	6	10				
SSH-43*	Strongly water-wet	0.4% CPAM, 1,520-ppm glyoxal	$2,090\ u^{-0.32}$	23	$84\ u^{-0.59}$	2	8				
SSH-44*	Strongly water-wet	0.3% CPAM, 1,140-ppm glyoxal	$849\ u^{-0.35}$	7	$38\ u^{-0.42}$	4	9	3	7		
SSHM1*	Strongly water-wet	0.3% PAM-AMPS, 100-ppm Cr^{3+}	44	4	7	2	4				

* The core experiments with their IDs starred were performed in this study, while the other results were originally presented in an earlier report.[71]

† The numbers in parentheses represent the steps outlined in Table 52, and u is superficial velocity (in ft/d).

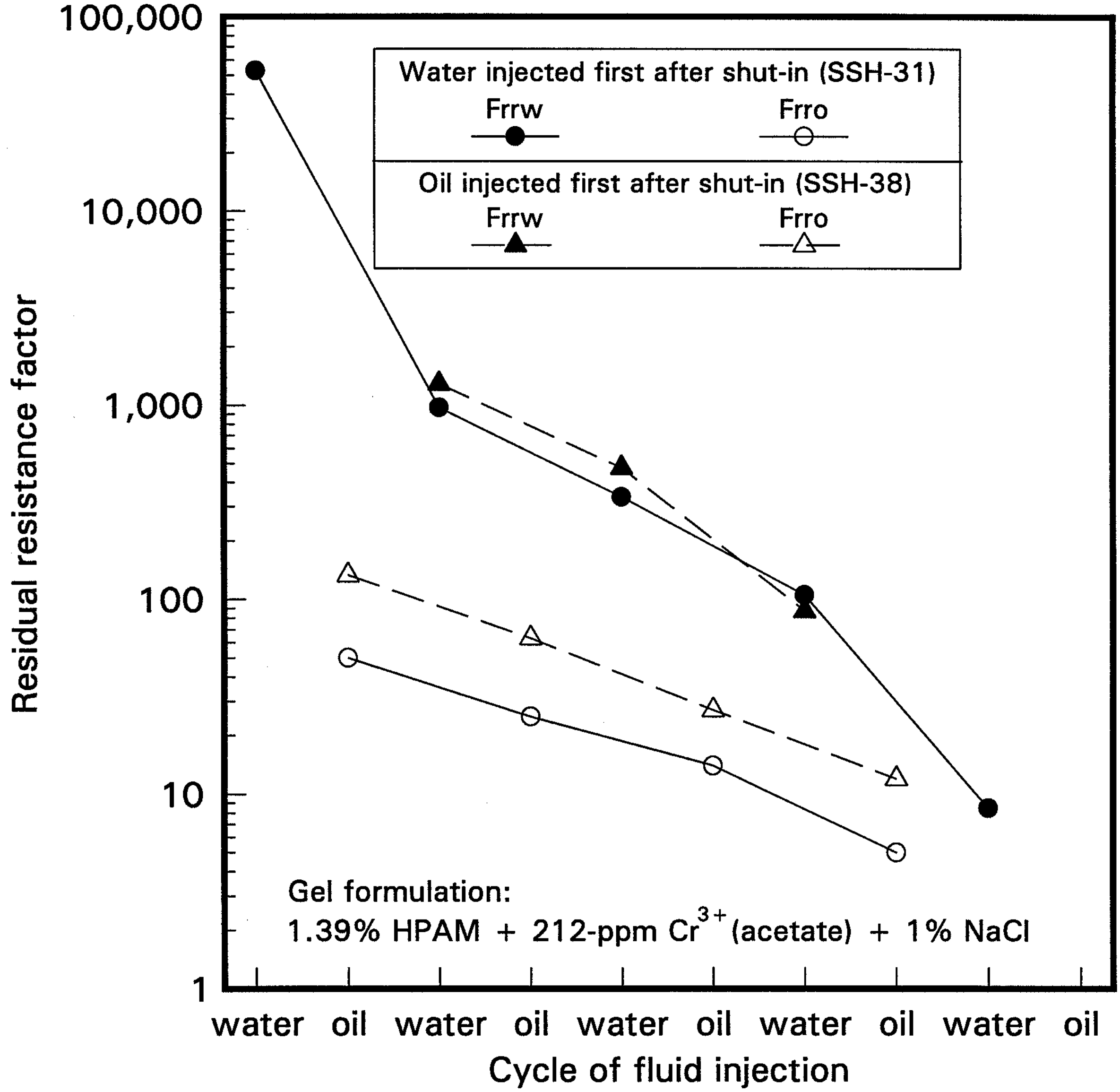


Fig. 67. Effect of injection order and multiple water-oil injection cycles on gel performance in Berea sandstone.

67), water was the first fluid injected after gelation, while in the other set (represented by the triangles), oil was injected first after gelation. The solid symbols show values during water injection, and the open symbols show values during oil injection.

Note for the case where water was injected first after gelation (the first solid circle in Fig. 67), the residual resistance factor was extremely high—53,000. During the subsequent injection of oil, the residual resistance factor was only 50. When water was injected after the oil, the residual resistance factor was 970. Thus, the oil residual resistance factor was substantially less than the water residual resistance factors that were determined immediately before and immediately after oil injection.

Fig. 67 shows that with each successive cycle of water and oil injection, the residual resistance factors decreased for both water and oil. The reduction was particularly large for the water residual resistance factor during the first cycle (i.e., a drop from 53,000 to 970). This erosion suggests that the gel physically breaks down during the water-oil injection cycles. In spite of this erosion during the various cycles, residual resistance factors for oil were consistently much less than those for water.

For the core experiment where oil was injected first after gelation, the first oil residual resistance factor was 135. This value is more than twice the corresponding value from the experiment where water was injected first after gelation (see Fig. 67). For the subsequent cycles of oil injection, the oil residual resistance factors from the second experiment (the open triangles) were consistently between two and three times greater than the corresponding values from the first experiment (the open circles). In contrast, for a given cycle, the water residual resistance factors were fairly similar for the two experiments. The main value of these experiments is in demonstrating that the disproportionate oil/water permeability reduction is real and not an experimental artifact that depends on which fluid was injected first after gelation.

Two data points in Fig. 67 would be relevant to a field application—the first solid circle and the first open triangle. For this gel, 53,000 is the residual resistance factor experienced in zones with high water saturations. In contrast, 135 is the residual resistance factor in zones with high oil saturations. Therefore, in the gel-contacted portions of the rock, the permeability reduction for water would be about 400 times greater than that for oil. This large difference would be very desirable for applications in production wells. However, since the permeability reduction for oil is fairly large (135), the gel would be most useful in fractured wells where the gelant leaks off only a short distance into the rock matrix.

Resorcinol-Formaldehyde. As shown in Table 57, the resorcinol-formaldehyde gel (SSH-36) reduced water permeability more than oil permeability. Gel breakdown was observed during the water-oil injection cycles as indicated by the decreasing residual resistance factors. However, the disproportionate permeability reduction persisted throughout the oil-water injection cycles. The residual resistance factors were Newtonian (velocity independent) during continuous injection of either water or oil. For the same gelant formulation, the first F_{rrw} value measured in this study (SSH-36) was more than three times higher than that in our previous study (SSH-17). The F_{rro} values were also higher during the first water-oil injection cycle. The discrepancy probably occurred because the gelation reaction is extremely sensitive to pH for this gelant.[49]

Glyoxal-CPAM. Two glyoxal-CPAM formulations were tested in this study in cores SSH-43 and SSH-44. Table 57 shows that, immediately after shut-in, both formulations provided significantly higher F_{rrw} values than some gels tested in this study. In both cases, an apparent shear-thinning behavior was observed for the F_{rrw} values during the first two cycles of water injection, while the flow of oil remained

Newtonian. As indicated in Table 57, the relationship between F_{rrw} and superficial velocity, u, could be described using power law equations. Both formulations reduced water permeability significantly more than oil permeability during the first water-oil injection cycle. However, the residual resistance factors decreased during the subsequent water-oil injection cycles. Table 57 also shows that the permeability-reduction properties of these gels are analogous to those of other gels (e.g., Cr^{3+}(acetate)-HPAM).

Cr^{3+}(acetate)-PAM-AMPS. Table 57 shows that this gel reduced permeability to water more than to oil. When the brine was first injected after shut-in, the F_{rrw} exhibited a shear-thinning behavior and could be described by a power-law equation ($F_{rrw}=244\ u^{-0.36}$). However, during continued water injection, gel breakdown occurred until F_{rrw} was reduced to 44. Relatively small F_{rrw} and F_{rro} values were measured during subsequent oil and water injection cycles.

Results From Tracer Studies

Water- and oil-tracer studies were conducted to determine pore volumes and the dispersivities of the cores. Detailed results from our tracer studies are summarized in Tables C-2a through C-2n and Tables C-3a through C-3n in Appendix C. The ratio, V_p/V_{po}, represents the fraction of the original pore volume that was sampled by the tracer during a given tracer study. The difference, $1-V_p/V_{po}$, represents the fraction of the original pore volume that was occupied by the immobile phase and/or gel. The quantity, α, refers to the dispersivity during a given tracer study. The α values were obtained using a mixing zone that extends from 10% to 90% of the injected tracer concentration.[89] (α values based on 20%-50% concentrations are also available in Appendix C.)

Tables C-2a through C-2n show that before gel placement, the S_{wr} and S_{or} values obtained from material-balance calculations generally agreed with the results from the oil- and water-tracer studies ($1-V_p/V_{po}$). After the gel treatments, results from water- and oil-tracer studies were coupled with material-balance calculations to determine the fraction of the original pore volume occupied by gel and the amount of oil, if any, trapped by gel. These results are summarized in Table 58.

Cr^{3+}(acetate)-HPAM. For the Cr^{3+}(acetate)-HPAM gel tested in Cores SSH-38, SSH-51, and SSH-60, results from water- and oil-tracer studies are consistent with those obtained in our previous study[71] (Core SSH-31). As shown in Table 58, the gel tested in Core SSH-38 occupied 57% of the original pore volume during the fourth waterflood after shut-in. This value is very close to the percentage (52%) obtained at the same stage in Core SSH-31. Table 58 also shows that the gel encapsulated most of the residual oil and render it immobile after treatment.

Resorcinol-Formaldehyde. For the resorcinol-formaldehyde gel (Core SSH-36), Table 58 shows that the gel occupied 13% to 27% of the pore space. During our previous study,[71] the same gel formulation (SSH-17) occupied only 3% of the pore space. We attributed the difference to the sensitivity of the gelant pH, as discussed earlier.[49]

Table 58. Summary of Gel Saturations (S_{gel}) and Residual Oil Saturations Trapped by Gel ($S_{o(trap)}$)

Core ID	Gel type	S_{gel} (determined after a waterflood)					$S_{o(trap)}$ (determined after an oilflood)				S_{or} just after gel treatment
		1st (14)†	2nd (15d)	3rd (16d)	4th (17d)	5th (18d)	1st (15b)	2nd (16b)	3rd (17b)	4th (18b)	
SSH-17	3% resorcinol, 3% formaldehyde	0.03									0.34
SSH-36*		0.13	0.27	0.18			0.04	0.02			0.34
SSH-26	1.39% HPAM, 636-ppm Cr^{3+}				0.53		0.27	0.31	0.33	0.35	0.29
SSH-27	0.7% HPAM, 318-ppm Cr^{3+}		0.11	0.08	0.04		0.14	0.12	0.00		0.30
SSH-31	1.39% HPAM, 212-ppm Cr^{3+}			0.52	0.52	0.44	0.29	0.29	0.25	0.11	0.27
SSH-38*					0.57		0.30	0.27	0.26	0.26	0.31
SSH-51*							0.39				0.35
SSH-60*		0.56					0.24				0.24
SSH-32	10% colloidal silica	0.70	0.63	0.58	0.56		0.35	0.26	0.25		0.28
SSH-33		0.66	0.64	0.61			0.30	0.30			0.34
SSH-43*	0.4% CPAM, 1,520-ppm glyoxal		0.26	0.02			0.13	0.03	0.11		0.28
SSH-44*	0.3% CPAM, 1,140-ppm glyoxal		0.07	0.00	0.00		0.07	0.07	0.07		0.26
SSHM1*	0.3% PAM-AMPS, 100-ppm Cr^{3+}	0.27	0.24	0.22			0.00	0.04			0.33

* The core experiments with starred IDs were performed in this study.
† The numbers in parentheses represent the steps outlined in Table 52.

Glyoxal-CPAM. For the glyoxal-CPAM gel with 0.4% CPAM and 1,520-ppm glyoxal, water-tracer studies and material-balance calculations indicated that the gel occupied 26% of the pore volume during the second water injection after shut-in (Table 58). By the third cycle of water injection, this number had dropped to 2%. The trapped residual oil saturations were between 3% and 13% during the various cycles of oil injection.

For the glyoxal-CPAM gel with 0.3% CPAM and 1,140-ppm glyoxal, Table 58 shows that this gel occupied a small fraction of the pore space after treatment.

Cr^{3+}(acetate)-PAM-AMPS. The Cr^{3+}(acetate)-PAM-AMPS gel apparently occupied 22% to 27% of the pore space after treatment (Table 58). However, very little oil was trapped by this gel.

Possible Mechanisms for Disproportionate Permeability Reduction

An important objective of our research is to identify the mechanisms by which materials (particularly gels) selectively reduce permeability to water more than to oil. In addition to establishing why this occurs, our research will attempt to identify materials and conditions that maximize this phenomenon. In this study, we examined four possible mechanisms for the disproportionate permeability reduction. Specially designed core experiments were performed to test these mechanisms.

Gravity Effect. We wondered whether the disproportionate permeability reduction could be caused by a gravity effect. Perhaps gravity can influence the location of gel particles in pores. For a water-based gel, the density of the gel particles inside the pore bodies is similar to that of the brine. During the waterflooding process, the gel particles floating freely in the water phase can easily be caught in the pore throats, thereby causing significant permeability reduction for water. However, during the oil flooding process (if the fluid velocity is low enough), the density difference between the water-based gel particles and the oil phase could theoretically cause the gel particles to settle at the bottom of the pore bodies, thereby causing less permeability reduction for oil.

We recognize that this theory is unlikely to provide a valid explanation of the disproportionate permeability-reduction effect simply because each core contains a large number of pores with random orientations. However, we proceeded to test this concept in spite of our reservations. According to this theory, the disproportionate permeability reduction might be sensitive to the changes in core orientation and flow direction. Therefore, oil/water experiments with different combinations of core orientation and flow direction were performed in high-permeability Berea sandstone cores to study this mechanism.

Results shown in Tables 59 and 60 are from core experiments SSH-43 and SSH-44. Glyoxal-CPAM gels with 0.4% CPAM, 1,520-ppm glyoxal (Core SSH-43) and 0.3% CPAM, 1,140-ppm glyoxal (Core SSH-44) were used in these core experiments. As shown in Tables 59 and 60, core experiments were performed with three different combinations of core orientation and flow direction. The residual resistance factors were first measured with the core oriented horizontally by injecting water or oil into the core horizontally. Then the core orientation was changed ninety degrees to a vertical position and water or oil was injected into the core both from the top and from the bottom of the core. In experiment SSH-43, the mechanism was tested after the second oilflood (Step 16a) and the third waterflood (Step 16c) after gel treatment. Results from tracer studies indicated that the gel occupied only a very small fraction of the original pore volume ($S_{gel}=0.02$, Table 58). In experiment SSH-44, the mechanism was tested during the first water injection after shut-in (Step 13) and after the first oilflood (Step 15a). During the water injection (Step 13), the extremely high residual resistance factors precluded water-tracer studies after the first waterflood. However, we believe that a large portion of the original pore volume was occupied by the gel at that stage.

Tables 59 and 60 show that the F_{rrw} and F_{rro} values were not sensitive to flow direction or core orientation. Through the water-oil injection cycles, the gel consistently reduced water permeability substantially more than oil permeability (Table 57). These observations do not support the idea that the disproportionate permeability reduction was caused by a gravity effect.

Table 59. Effect of Core Orientation and Flow Direction on Residual Resistance Factors (Core SSH-43, Berea sandstone, Gelant: 0.4% CPAM, 1,520-ppm glyoxal)

Core Orientation	Flow Direction	F_{rro} after 2nd oilflood (Step 16a)	F_{rrw} after 3rd waterflood (Step 16c)
Horizontal	Horizontal	2	8
Vertical	Up	2	8
Vertical	Down	2	8

Table 60. Effect of Core Orientation and Flow Direction on Residual Resistance Factors (Core SSH-44, Berea sandstone, Gelant: 0.3% CPAM, 1,140-ppm glyoxal)

Core Orientation	Flow Direction	F_{rro} after 1st oilflood (Step 15a)	F_{rrw}^{*} at 0.187 ft/d during 1st waterflood (Step 13)
Horizontal	Horizontal	7	5,090
Vertical	Up	7	4,870
Vertical	Down	7	5,000

* The F_{rrw} exhibited a shear-thinning behavior and could be described by the equation, $F_{rrw}=849\ u^{-0.35}$, where u is the superficial velocity in units of ft/d (Table 57).

Lubrication Effect. Two concepts that have some elements in common are the "hydrophilic film theory," proposed by Sparlin and Hagen[91], and the "lubrication effect," proposed by Zaitoun and Kohler.[87] Both concepts apply to strongly water-wet cores where a layer of polymer or gel is adsorbed onto pore walls. For different reasons, the two theories suggest that the presence of the hydrocarbon/adsorbed-polymer interface effectively "lubricates" the flow of oil or gas through the center of pores. These ideas appear to be an extension of the theory that Odeh proposed for the effect of oil/water viscosity ratio on relative permeabilities.[90]

Based on the ideas of Zaitoun and Kohler[87] and Odeh,[90] we expect residual resistance factors to vary with oil viscosity during core experiments with gels present. Therefore, using two oils with different viscosities, we investigated the lubrication effect in a strongly water-wet Berea sandstone core. At 41°C, the oils, Soltrol 130® and Banco® IC46980 paraffin oil, had viscosities of 1.05 cp and 31.6 cp, respectively. After saturating the core with brine, Soltrol 130® was injected to determine oil permeability at the residual water saturation. Then, the Soltrol was displaced by the paraffin oil, and oil permeability was again measured. The paraffin oil was then displaced by Soltrol, and oil permeability was determined once more. Next, brine was injected to determine water permeability at the residual oil saturation. This procedure was repeated three times. Two sets of measurements were performed using the original flow direction, and two sets were obtained using flow through the core in the reverse direction. As shown in Table 61, this experiment provided four Soltrol permeabilities before paraffin-oil injection (averaging 522 ± 17 md), four paraffin-oil permeabilities (averaging 588 ± 16 md), four Soltrol permeabilities after paraffin-oil injection (averaging 561 ± 19 md), and four water permeabilities (averaging 124 ± 1 md). If the lubrication effect was important, the apparent oil permeability should have been much greater for the paraffin oil than for the Soltrol oil.[90] Given the similarity of the Soltrol and paraffin oil permeabilities, no significant lubrication effect was evident before placing gel in the core.

Table 61. Effect of Oil Viscosity (μ_o) on End-Point Oil Permeabilities Before Gel Treatment (Core SSH-51, Berea Sandstone, Strongly Water-Wet, 41°C)

Oil type	μ_o, cp	S_{wr}	k_o^o, md	S_{wr} *	k_o^o, md*
Soltrol	1.05	0.28±0.02	503±5	0.26±0.00	522±17
Paraffin	31.6	0.24±0.02	561±5	0.23±0.01	588±16
Soltrol	1.05	0.24±0.02	537±9	0.23±0.01	561±19
Water type	μ_w, cp	S_{or}	k_w^o, md	S_{or} *	k_w^o, md*
1.0% NaCl	0.67	0.34±0.01	112±3	0.35±0.00	124±1

* Flow-direction reversed.

Next, six pore volumes of Cr^{3+}-HPAM gelant were injected into the core. The gelant contained 1.39% HPAM, 212-ppm Cr^{3+}(acetate), and 1% NaCl. After the core was saturated with the gelant and shut in for five days, water was injected. Residual resistance factors for water were found to be over 35,000. Then, the core was oilflooded to establish a residual water saturation, and residual resistance factors for both oils were determined. These factors ranged from 10 to 19 (see Table 62). The core was waterflooded, and residual resistance factors for water were redetermined. The latter values could be described by the equation, $F_{rrw} = 1{,}430\ u^{-0.44}$, where u is superficial velocity in units of ft/d. Finally, the core was oilflooded again to verify the results.

Table 62 shows that the residual resistance factors for both oils were measured at two residual water-plus-gel saturations after each oilflood. At a given saturation, the residual resistance factors for the two oils were essentially the same. Thus, no lubrication effect was apparent. Through the water-oil injection cycles, the gel reduced water permeability substantially more than oil permeability. These observations suggest that the disproportionate permeability reduction was not caused by a lubrication effect.

Table 62. Effect of Oil Viscosity (μ_o) on Oil Residual Resistance Factors (F_{rro}) (Core SSH-51, Berea Sandstone, Strongly Water-Wet, 41°C)

Stage	Oil injected	Oil viscosity (cp)	Residual water-plus-gel saturation	F_{rro}
1st oilflood after gel (15a)	Soltrol	1.05	0.50	49
	Paraffin	31.6	0.46	19
	Soltrol	1.05	0.46	19
	Paraffin	31.6	0.43	11
	Soltrol	1.05	0.43	10
2nd oilflood after gel (16a)	Soltrol	1.05	0.48	28
	Paraffin	31.6	0.41	11
	Soltrol	1.05	0.41	9

Shrinking and Swelling Effects. Sparlin and Hagen[91] proposed that water-based gels swell in water and shrink in oil. This property should result in constricted pathways for water and more open pathways for oil in the porous media. Thus, the permeability reduction for water is greater than that for oil. If this concept is correct, an increase in system pressure should favor a more compressed (smaller volume) state for the gel—causing the residual resistance factors both for water and for oil to decrease. Since the gel is more compressible in its swollen state (in water), increased system pressure should cause the residual resistance factor for water to decrease more than that for oil. To investigate this theory, oil/water experiments were performed in a high-permeability Berea sandstone core (SSH-60) at different back pressures. A Cr^{3+}(acetate)-HPAM gel with 1.39% HPAM and 212-ppm Cr^{3+}(as acetate) was used.

Five pore volumes of the gelant was injected into the core at residual water saturation. After gelant injection, the core was shut in for five days. After shut-in, oil was injected first and residual resistance factors were measured at the four back pressures (0, 500, 1,000, and 1,500 psi). During the process, water- and oil-tracer studies were routinely performed at 0 and 1,500 psi. Table 63 shows that the F_{rro} values were Newtonian and insensitive to system pressure. The core was then waterflooded and residual resistance factors for water were measured. As shown in Table 63, the F_{rrw} values exhibited a strong apparent shear-thinning behavior where the relationship between F_{rrw} and superficial velocity, u, can be described using a power-law equation. Table 63 shows that the F_{rrw} values were also insensitive to system pressure. Gel breakdown was observed during the early stage of oil injection and during the water- and oil-tracer studies (Table C-1f). To determine whether the gel breakdown or the changes in system pressure actually caused the decrease in residual resistance factors, residual resistance factors were measured again at different back pressures (0, 500, 1,000, 1,500 psi) using a constant flow velocity. No tracer studies were performed during the process. Table 64 shows that, at a constant flow velocity of 3.15 ft/d, both F_{rro} and F_{rrw} were insensitive to system pressure. The lower F_{rro} values shown in Table 64 were caused by the gel breakdown which occurred during the oilflooding process after the F_{rrw} measurements. During the oil-water injection cycles, the gel reduced water permeability significantly more than oil permeability. Our results suggest that shrinking and swelling effects are not an important mechanism behind the disproportionate permeability reduction.

Table 63. Effect of System Pressure on Residual Resistance Factors
(Core SSH-60, Berea Sandstone, Strongly Water-wet, 41°C)

Back pressure, psi	F_{rro}	F_{rrw}
0	9	$18\ u^{-0.18}$
500	9	$16\ u^{-0.26}$
1,000	11	$18\ u^{-0.31}$
1,500	11	$15\ u^{-0.24}$

* u is the superficial velocity in ft/d.

Table 64. Effect of System Pressure on Residual Resistance Factors at Constant Flow Rate
(Core SSH-60, Berea Sandstone, Strongly Water-wet, 41°C)

Back pressure, psi	Flux, ft/d	F_{rro}	F_{rrw}
0	3.15	2	8
500	3.15	2	8
1,000	3.15	2	8
1,500	3.15	2	7
1,000	3.15	2	7
500	3.15	2	8
0	3.15	2	7

Dangling-Polymer Effect. In a strongly water-wet rock pore with an adsorbed gel layer, some polymer molecules could dangle freely from the gel surface. When water flows by these dangling hydrophilic polymer molecules, the drag may significantly increase the resistance to water flow. If oil causes these polymer molecules to shrink or dehydrate, the resistance to oil flow should be less. This idea is illustrated in Fig. 68. If dangling polymer molecules exist on the gel surface, the injection of additional crosslinking agents may cause further crosslinking and an increase in residual resistance factors.

We tried to test this idea in Core SSH-51 with the Cr^{3+}(acetate)-HPAM gel [1.39% HPAM, 212-ppm Cr^{3+}(as acetate)]. Additional crosslinker (212-ppm Cr^{3+}(as acetate) in 1% NaCl) was injected after the second and the third waterfloods after gel treatment (Steps 15c and 16c). At Step 16c, the following sequence was followed:

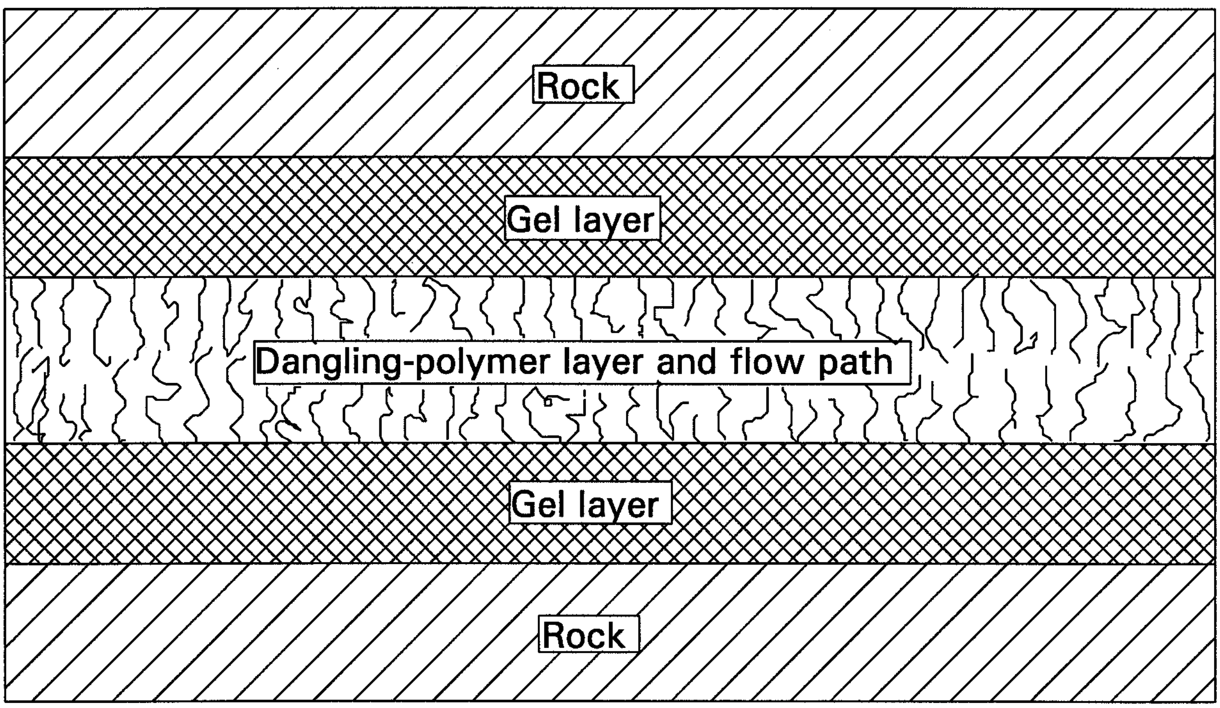


Fig. 68. The dangling-polymer model.

1. Inject 1% NaCl at 100-psi constant pressure across the core.
2. Determine F_{rrw} while injecting 1% NaCl at different flow rates.
3. Shut in core for 2 days.
4. Determine F_{rrw}.
5. Shut in core for 1 day.
6. Determine F_{rrw}.
7. Inject a solution containing 212-ppm Cr^{3+} (as acetate), 1% NaCl while monitoring F_{rrw}.
8. Shut in core for 2 days.
9. Determine F_{rrw}.

The F_{rrw} values obtained by following the above sequence are summarized in Table C-1e (page 239). The F_{rrw} values obtained at different stages of the above procedure are presented in Fig. 69. This figure suggests that the injection of additional crosslinker did cause the F_{rrw} values to increase. However, the available evidence is not clear enough to definitively attribute these increases to additional crosslinking reactions or to the dangling-polymer effect. Therefore, additional research is needed to test the validity of this mechanism.

Conclusions

Several corefloods were conducted to explore why gels can reduce permeability to water more than to oil. Many gels have this property, including Cr^{3+}(acetate)-HPAM, Cr^{3+}(acetate)-PAM-AMPS, Cr^{3+}(chloride)-xanthan, glyoxal-CPAM, and resorcinol-formaldehyde. The disproportionate permeability reduction was observed for both "weak" and "strong" gels. In previous work,[71] we showed that the phenomenon was not caused simply by hysteresis of relative permeabilities or by gel breakdown. We also showed that the effect occurs both in cores of intermediate wettability as well as in strongly water-wet cores. In the present work, we demonstrated that the disproportionate permeability reduction is not sensitive to (1) core orientation, (2) oil viscosity (from 1 cp to 31 cp), and (3) system pressure (from 0 to 1500 psi). Experiments to determine the nature and cause of the phenomenon are continuing.

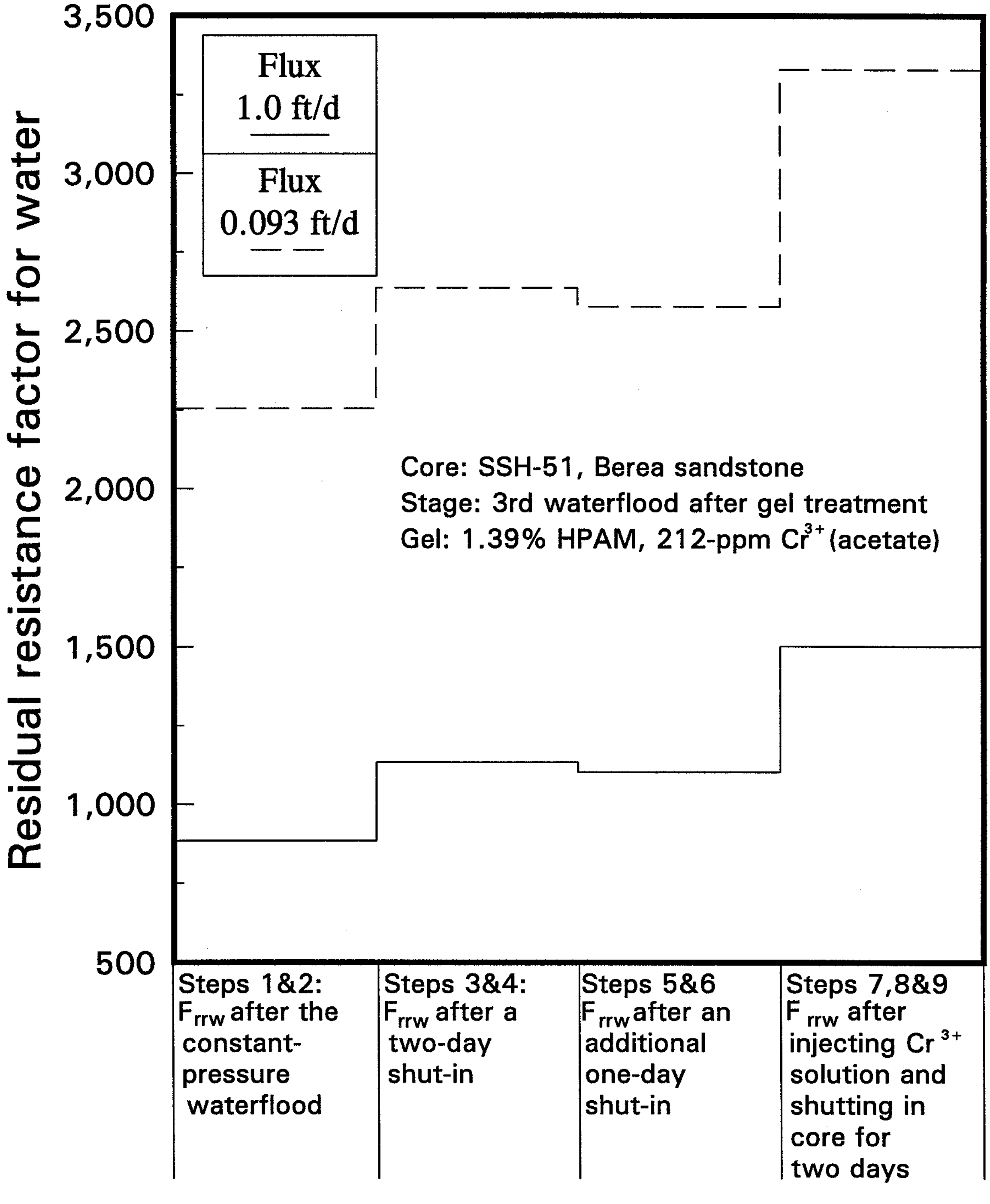


Fig. 69. Change of residual resistance factors for water caused by core shut-in and injection of brine containing Cr^{3+}.

11. A PRELIMINARY INVESTIGATION OF THE USE OF PRECIPITATES AS BLOCKING AGENTS

Several investigators[92-107] proposed the use of precipitates as blocking agents for fluid diversion in oil recovery processes. These processes involve forming precipitates in situ by bringing two incompatible chemical solutions into contact with each other in the formation. The following is a literature review of precipitates as blocking agents. Our objective is to determine from the published information whether precipitates can be effective in blocking fractures and high-permeability streaks without damaging the oil-producing zones.

Sequential Injection

Nathan and Perry[92] proposed the use of metal sulfide precipitates to reduce water production. In their method, a water-soluble metal ion is first introduced into the formation followed by a solution of thioamide. The thioamide hydrolyses in situ to yield hydrogen sulfide. The metal ion then reacts with the hydrogen sulfide to form a water-insoluble sulfide. However, if zones cannot be isolated during the placement process, the chemicals can penetrate into all open zones.[14,18] The precipitates formed in the oil zones can severely damage the oil productivity after treatment.

A two-stage process was proposed by Bond and O'Brien[93] to stop the crossflow between two contiguous zones of different permeabilities. In their technique, one of the chemicals is injected into the high-permeability zone first. After the production of the first chemical is observed from the high-permeability zone, the second chemical is injected into the low-permeability zone. The authors claimed that a narrow band of precipitate would form at the interface between the two contiguous zones, thereby stopping crossflow between the two zones.

Bond and O'Brien recommended zone isolation during the placement process. However, the vertical communication between the two zones would cause the injected fluid to crossflow into the other zone as soon as it leaves the wellbore.[18] Therefore, instead of forming a narrow band of precipitate along the interface, precipitation would occur in both zones. Also, the coreflood data that the authors provided did not necessarily support their claims.

Holm[94] proposed the use of aqueous plugging agents to improve the volumetric sweep efficiency of the micellar flooding process. In Holm's method, an aqueous plugging agent is first injected into the heterogeneous formation to modify the permeability contrast before the injection of micellar solutions. The author did not give any specific information regarding the plugging agents other than that they contain polyvalent cations. The author suggested that the aqueous plugging agents would penetrate preferentially into high-permeability water-bearing zones without entering low-permeability oil-productive zones. Hence, the sweep efficiency during the subsequent micellar injection could be improved.

As mentioned previously, if zones cannot be isolated during the placement process, aqueous plugging agents can penetrate to a significant degree into all open zones—not just those high-permeability watered-out zones.[14,18] Therefore, the plugging agents can cause significant permeability reduction in both oil and water zones. This can result in severe injectivity loss after treatment. Holm did not provide any coreflood or field data to support the claim of selective plugging.

Megyeri *et al.*[95] proposed the use of inorganic salt crystals formed in situ to increase sweep efficiency. In their method, an aqueous solution of inorganic salt (e.g., NaCl, KCl, etc.) is first injected into the formation. Then a gas (e.g., natural gas, CO_2, etc.) is injected into the formation to remove the water so that the salt crystallizes in situ at the formation temperature. The authors suggested that, if desired, the salt crystals could be redissolved by injecting additional solvent into the formation. However, the authors did not provide any laboratory or field data to support their claims. Also, the authors did not mention the selectivity of the process.

Sequential Injection with Spacers

Hower *et al.*[96] proposed a two-stage treatment procedure to partially block offending formations. Their method involves first injecting one chemical capable of strongly adsorbing on the rock surface into the formation. Following a small water spacer, a second chemical solution is injected into the formation. A water-insoluble gelatinous precipitate is formed in the formation after the two incompatible chemicals react with each other in situ. No specifics about the chemicals were described in the paper. They claimed that, if desired, the precipitate could be removed by using hydrochloric acid.

Using radioactive chemicals, the placement process is continuously monitored by a radioactive logging tool. During the placement process, the radioactive chemicals are pumped down the tubing while water is pumped down the annular space. By adjusting the flow rates, the interface of the two fluids, in concept, could be adjusted and maintained at a predetermined point so that the chemicals could be confined in the offending zone.

A potential problem with this technique is that it is very difficult to control the flow rates from the wellhead to maintain the position of the fluid interface. Also, if crossflow can occur, water can crossflow into the oil zones from behind the treated region, thereby rendering the treatments ineffective.[16,18]

King and Fallgatter[97] proposed a method that they professed can selectively plug the thief zones without damaging the oil-producing zones. Their method involves injecting two incompatible chemical solution slugs into the formation with a small brine spacer in between. Conceptually, for a radial-flow geometry, under ideal conditions, the chemical slugs and the brine spacer would form concentric circular bands around the injection well. The circular bands should become thinner as they are displaced outwardly from the injection well. King and Fallgatter proposed that when the spacer slug becomes thin enough, dispersion and diffusion could bring the two incompatible chemicals (e.g., NaOH and $Al_2(SO_4)_3$) into contact with each other, thereby forming precipitates in situ. They also suggested that they could control the radial distance from the wellbore where precipitation occurs by adjusting the size of the brine spacer. However, if zones cannot be isolated during the placement process, the chemicals can penetrate into all open zones—not just the thief zones.[14,18] The precipitates formed in the oil zones can significantly damage the oil productivity, even if a brine spacer or postflush is used.[16] The coreflood data provided by the authors did not support their claim of selective plugging.

Bernard[98] modified King and Fallgatter's process[97] by injecting multiple cycles of chemicals with an increasing volume of brine spacers. Bernard claimed that the modified process could place the plugging agents even deeper into the formation. However, the modification does not prevent the chemicals from entering low-permeability oil zones. Again, the precipitates formed in the oil zones can significantly damage the oil productivity. In addition, the oil recovery data from their coreflood experiments did not provide proof of selective plugging.

Sydansk[99] proposed a process for improving conformance and flow profiles in a subterranean formation. In the process, an aqueous caustic solution and an aqueous solution containing a polyvalent cation are sequentially injected into the formation interposed by a hydrocarbon spacer. The author claimed that a water-insoluble precipitate can be formed in the near-wellbore region. The author speculated that, during the injection process, a portion of the first aqueous slug might be trapped by the hydrocarbon spacer within the residual water phase. During the subsequent injection of the second aqueous slug, the mixing of the residual water phase and the second aqueous slug could result in the formation of the water-insoluble precipitate in the near-wellbore region.

Sydansk proposed that, with zone isolation, the process should be most efficient in improving the vertical conformance and flow profiles in reservoirs without vertical communication between zones. The author also suggested that, even without zone isolation, the process could still improve the vertical conformance by reducing the permeability contrast between zones. Results from parallel linear coreflood experiments provided by the author showed a substantial decrease in the ratio of the permeability of the high-permeability core to that of the low-permeability core after treatment. However, the results also indicated significant permeability reduction in both the high-permeability and low-permeability cores. Therefore, if zones cannot be isolated, this process can cause significant damage to the oil-producing zones. Also, results from parallel linear coreflood experiments are poor indicators of the selectivity of a treatment process.[51]

Sydansk[100] proposed a similar process using an aqueous spacer instead of a hydrocarbon spacer. The aqueous spacer is placed between an aqueous caustic solution and an aqueous solution containing a polyvalent cation. The aqueous caustic solution is first injected into the formation. The well is then shut in for a period of time to allow the caustic solution to react with the sandstone formation. The author asserted that, during the shut-in period, a portion of the caustic chemicals are retained in the formation. The retained caustic chemicals then react with the subsequently injected polyvalent cation to form a water-insoluble precipitate in the near-wellbore region. The author recommended zone isolation during the treatment process. However, as discussed previously, if zones cannot be isolated, this process can also cause significant damage to the oil-producing zones.

Harwell and Scamehorn[101] proposed injecting two surfactants with different chromatographic velocities into the formation interposed by an aqueous fluid spacer. In their method, the surfactant with a slower chromatographic velocity (e.g., an anionic surfactant) is first injected into the formation. The surfactant slug is then displaced to a predetermined distance from the wellbore by a sufficient amount of aqueous spacer. After injecting the aqueous spacer, the second surfactant slug with a higher chromatographic velocity (e.g., a cationic surfactant) is injected. The authors claimed that when the front edge of the second surfactant overtakes the rear edge of the first surfactant slug, a phase change occurs. The phase change results in the formation of a water-insoluble precipitate, thereby reducing the permeability of the contacted region. The authors used parallel linear coreflood experiments to demonstrate the selective plugging of the high-permeability water-bearing zones. However, as mentioned previously, results from parallel linear coreflood experiments are not always good indicators of the selectivity of a treatment process.[51] Without zone isolation, the surfactants can penetrate to a significant degree into all open zones—not just the high-permeability water-bearing zones.[14,18] The precipitates formed in the low-permeability oil zones can severely damage the oil productivity.

Use of Stabilizing Agents to Prevent Precipitation in Oil Zones

Chamberlain and Robinson[102] proposed the use of metal salts (e.g., $BiCl_3$, $Fe(NO_3)_3$, etc.) that are incompatible with alkaline materials to form precipitates in situ. In their process, stabilizing agents (e.g., lactic acid, ammonium acetate, etc.) are used in conjunction with the metal ions to achieve deep placement in the formation. The authors indicated that the stabilizing agents can delay the precipitation by raising the pH value at which precipitation occurs. The metal ions and stabilizing agents are both dissolved in non-aqueous solvents (e.g., methyl and ethyl alcohol, acetone, ether, glycol, etc.).

In Chamberlain and Robinson's method, the formation is first flooded with an aqueous solution of the stabilizing agent. During the process, the stabilizing agent penetrates into both the water zones and the oil zones. The well is then returned to production long enough to flush the solution of the stabilizing agent completely out of the water zones. After the back flush, the authors suggested that the connate water remaining in the oil-productive zones is replaced by a solution of the stabilizing agent. Then the non-aqueous solution of the metal ion is injected into the formation. The non-aqueous solution of the metal ion is diluted in the water zones, thereby forming water-insoluble precipitates. However, because of the presence of the stabilizing agent in the connate water, they speculated that no precipitate is formed when the non-aqueous metal-ion solution is brought into contact with the connate water in the oil-productive zones.

This technique might work when no crossflow exists between adjacent zones. If crossflow can occur, however, water can still crossflow between zones from behind the treated region, thereby rendering the treatments ineffective. Also, Chamberlain and Robinson did not provide any coreflood or field data to support their claims.

Aqueous Dispersion of Inorganic Compounds in Polymeric Solutions

Routson[103] proposed the use of aqueous plugging agents comprised of an aqueous dispersion of a colloidal, water-insoluble, inorganic compound. The plugging agents are formed by reacting the sulfides of iron (or copper, nickel, etc.) with the hydroxides of aluminum (or chromium, iron, etc.) in a dilute solution of a polymeric polyelectrolyte (e.g., high-molecular-weight hydrolyzed polyacrylamides).

Routson claimed that the injection of a more viscous polymeric fluid would help the injection fluid to flow preferentially into high-permeability water-bearing zones. However, a basic principle in polymer flooding is that the injection profile can be improved by injecting a more viscous fluid into the formation. Therefore, a more viscous injection fluid should penetrate even deeper into the low-permeability oil-productive zones.[14,15,18]

To achieve selective placement, the author also suggested a technique involving first pressurizing the formation, then releasing the pressure and producing the well for a short period of time before injection. The author speculated that, during the transient period, the pressure required to inject into the more-permeable water zones is less than that for the less-permeable oil zones. Therefore, the plugging agents can be injected selectively into the more-permeable water zones. A potential problem with this technique is that the transient period is usually too short to achieve deep placement. Also, the injection-pressure difference between the more-permeable and the less-permeable zones during the transient period must be large enough to ensure selective placement of the viscous plugging agents.

Routson also proposed the use of an acid postflush to remove the plugging agents in the less-permeable oil-productive zones. However, because of the unfavorable mobility ratio, the less-viscous, water-like acid solution would finger through the plugging agent in the more-permeable water zones long before it could reach the plugging agent-oil interface in the less-permeable zones.[16,18] No coreflood or field data were provided by the author to support the claim of selective plugging.

Use of Precipitation Inhibitors for Deep Placement

Mohnot *et al.*[104] proposed the use of precipitation inhibitors (e.g., polyacrylic acid, a copolymer of acrylic acid and a hydroxyalkyl acrylate, etc.) in the alkaline flooding process to improve the flow profile of the reservoir. During an alkaline flooding process, the alkaline injection water can precipitate the multivalent cations, especially the divalent cations, commonly found in the formation brine. The authors proposed that the addition of a precipitation inhibitor into the alkaline injection water can prevent the precipitation from occurring in the near-wellbore region. The authors also suggested that the alkaline injection water flows preferentially into the high-permeability water-bearing zones without entering the low-permeability oil zones. However, as discussed previously, the injection water will penetrate to a significant degree into all open zones—not just the high-permeability water-bearing zones.[14,18] The precipitates formed in the oil zones can significantly damage the oil productivity. Also, the authors did not provide any coreflood or field data to support their claims.

Temperature Triggered Precipitation

Paul[105] proposed the use of polysulfides to improve the vertical sweep efficiency of formations having a temperature in excess of 250°F. The author professed that polysulfides (e.g., ammonium polysulfide, ethylamine polysulfide, etc.) form a precipitate of elemental sulfur at 250°F. In this method, a polysulfide solution is injected into a subterranean formation having a temperature in excess of 250°F. The precipitation of elemental sulfur causes a significant reduction in formation permeability. The author also asserted that the polysulfide solution flows preferentially into high-permeability water-bearing zones. However, the author did not provide any coreflood or field data to support his claim of selective plugging. Again, as mentioned before, without zone isolation, the polysulfide solution can penetrate into all open zones—not just the high-permeability water-bearing zones.[14] Therefore, if zones cannot be isolated, the precipitates formed in the oil zones can significantly damage the oil productivity.

Use of Surfactant-Alcohol Blends for In-Depth Profile Modification

Llave *et al.*[106] proposed a method to achieve in-depth permeability modification using surfactant-alcohol blends. The authors argued that the injection of surfactant-alcohol blends can cause significant permeability reduction in sandstone cores. Akzo Chemical's Armostim® PF-series of surfactants were used in conjunction with different alcohols (e.g., methanol, ethanol, isopropanol, etc.) in their experimental studies. Their slim-tube and linear-coreflooding experiments demonstrated that the surfactant-alcohol blends caused significant permeability reduction in the porous media. The authors also claimed that the results from their parallel linear coreflooding experiment showed selective plugging of the high-permeability core without significantly damaging the injectivity of the low-permeability core. However, as mentioned before, results from parallel linear coreflood experiments are not always good indicators of the selectivity of a treatment process.[51] If zones cannot be isolated, the chemicals can penetrate into all open zones, thereby causing significant damage to the oil-producing zones.[14]

Formation of Plastic-Like Solid by In-Situ Polymerization

Phelps *et al.*[107] proposed the use of a plastic-like solid formed in situ to plug fractures or thief zones in formations with an extremely high flow rate or high pressure. In their process, an oil-in-water emulsion consisting of a monomer (e.g., ethylene, styrene, etc.), a cross-linker (e.g., divinylbenzene), a free-radical initiator (e.g., sodium persulfate), a retarder (e.g., potassium ferricyanide), and a surfactant (e.g., sodium dodecylsulfate) is injected into the more permeable zones. The polymerization then occurs in situ to form a plastic-like solid (e.g., polystyrene, polyethylene, etc.). The authors proposed that because of a very high elastic limit and a bimodal size distribution, the process is effective in plugging fractures. This process might work in fractured wells if the chemicals leak off only a short distance into the rock matrix[38] during the placement process. However, the authors did not furnish any laboratory or field results regarding the effectiveness of this process.

Conclusions

The petroleum and patent literatures were surveyed to investigate whether precipitates formed in situ in a reservoir have potential advantages over gels for use as blocking agents. Most of this literature makes unsubstantiated claims that the blocking materials will selectively enter and block high-permeability watered-out zones in preference to less-permeable oil-productive zones. Critical analyses of these claims reveals that most (if not all) of the proposed schemes suffer from the same placement limitations that gels experience.

Additional work will be required to determine whether in situ precipitates can be superior blocking agents compared with gels or other materials. One possible area of study, in this regard, is whether precipitates can reduce water permeability more than oil permeability. In the future, we will examine whether precipitates can show a disproportionate permeability reduction, and we will compare this ability with that for gels.

NOMENCLATURE

A	=	core cross-sectional area, cm^2
C	=	dye concentration in the effluent, g/cm^3
C_o	=	injected dye concentration, g/cm^3
dp/dl	=	pressure gradient in the direction of flow, atm/cm
dz/dl	=	vertical gradient in the direction of flow, cm/cm
F_r	=	resistance factor (brine mobility prior to gel placement divided by gelant mobility prior to gelation)
F_{rr}	=	residual resistance factor (mobility prior to gel placement divided by mobility after gel placement)
F_{rro}	=	oil residual resistance factor (oil mobility prior to gel placement divided by oil mobility after gel placement)
F_{rrw}	=	brine residual resistance factor (brine mobility prior to gel placement divided by brine mobility after gel placement)
G	=	dimensionless gravity number defined by Eq. 24
g	=	acceleration of gravity, ft/s^2 [m/s^2]
h	=	formation thickness, ft [m]
h_e	=	thickness of the oil zone, ft [m]
h_f	=	fracture height, ft [m]
h_m	=	height of the matrix zone, ft [m]
h_t	=	total zone thickness, ft [m]
h_w	=	depth of well penetration in the oil zone, ft [m]
I_i	=	injectivity in Zone i, bbl/D-psi [m^3/s-Pa]
I_{i0}	=	initial injectivity in Zone i, bbl/D-psi [m^3/s-Pa]
k	=	permeability, md [μm^2]
k_f	=	effective fracture permeability, md [μm^2]
k_i	=	effective permeability to water in Zone i, md [μm^2]
k_m	=	effective matrix permeability, md [μm^2]
k_o^o	=	end-point permeability to oil, md [μm^2]
$\overline{k_{ro}}$	=	depth-averaged relative oil permeability, md [μm^2]
k_{rw}	=	relative permeability to water, md [μm^2]
k_w	=	permeability to water, md [μm^2]
k_w^o	=	end-point permeability to water, md [μm^2]
L	=	core length, cm
L_f	=	fracture length, ft [m]
m_H	=	slope of Hall plot given by Eq. 4
PV	=	pore volume
Δp	=	pressure drop, psi [Pa]
p_e	=	external or reservoir pressure, psi [Pa]
p_{tf}	=	flowing wellhead pressure, psi [Pa]
Δp_{tw}	=	pressure difference between wellhead and bottom hole, psi [Pa]
q_c	=	critical rate for coning before barrier placement, bbl/D [m^3/s]
q_{cb}	=	critical rate for coning after barrier placement, bbl/D [m^3/s]
q_f	=	volumetric flow rate in the fracture, bbl/D [cm^3/s]
q_m	=	volumetric flow rate in the matrix zone, bbl/D [cm^3/s]
r	=	correlation coefficient

r' = $4h_e(|\frac{h_e - h_w}{h_e}|\frac{h_e}{h_e + h_w})^{\frac{h_e}{2h_w}}$, ft [m]

r_b = barrier radius, ft [m]

r_e = external radius, ft [m]

r_{pi} = radius of gelant penetration in Zone i, ft [m]

r_w = wellbore radius, ft [m]

S_{gel} = gel saturation or fraction of pore volume occupied by gel

$S_{o(trap)}$ = residual oil saturation trapped by gel

S_{or} = irreducible oil saturation from material-balance calculations

S_{wr} = irreducible water saturation from material-balance calculations

s = skin factor

t = time, days

u = superficial or Darcy velocity or flux, ft/D [m/s]

u_z = superficial velocity in the vertical direction, ft/D [m/s]

V_p = apparent remaining pore volume, cm^3

V_{po} = initial pore volume of the core, cm^3

v_f = frontal velocity in the fracture, ft/D [m/s]

v_m = frontal velocity in the matrix, ft/D [m/s]

W_i = cumulative injection, bbl [m^3]

w_f = fracture width, ft [m]

x_b = barrier length in the fracture, ft [m]

α = dispersivity at the given stage in the experiment, cm

α_o = initial dispersivity of the core, cm

Θ = angle of inclination, degrees

μ = viscosity, cp [mPa-s]

μ_o = oil viscosity, cp [mPa-s]

μ_w = water viscosity, cp [mPa-s]

ρ = density, g/cm^3

ρ_o = oil density, g/cm^3

ρ_w = water density, g/cm^3

$\Delta\rho$ = water density minus oil density, g/cm^3

ϕ = porosity

ϕ_i = effective aqueous-phase porosity in Zone i

REFERENCES

1. Manning, R.K. *et al.*: "A Technical Survey of Polymer Flooding Projects," DOE report DOE/BC/10327-19, U.S. DOE, (Sept. 1983).

2. Schurz, G.F., Martin, F.D., Seright, R.S., and Weiss, W.W.: "Polymer-Augmented Waterflooding and Control of Reservoir Heterogeneity," paper NMT890029, *Proc.* Petroleum Technology into the Second Century, Socorro, NM, Oct. 16-19, 1989.

3. Koning, E.J.L., Mentzer, E., and Heemskerk, J.: "Evaluation of a Pilot Polymer Flood in the Marmul Field, Oman," paper SPE 18092 presented at the 1988 SPE Annual Technical Conference and Exhibition, Houston, Oct. 2-5.

4. Moffitt, P.D. *et al.*: "Application of Freshwater and Brine Polymerflooding in the North Burbank Unit," *SPE Reservoir Engineering* (May 1993) 128-134.

5. Maitin, B.K.: "Performance Analysis of Several Polyacrylamide Floods in North German Oil Fields," paper SPE 24118 presented at the 1992 SPE Symposium on Enhanced Oil Recovery, Tulsa, April 22-24.

6. Weiss, W.W.: "Performance Review of a Large-Scale Polymer Flood," paper SPE 24145 presented at the 1992 SPE Symposium on Enhanced Oil Recovery, Tulsa, April 22-24.

7. Putz, A.G. and Rivenq, R.C.: "Commercial Polymer Injection in the Courtenay Field," *J. Polym. Sci. & Eng.* (April 1992) **7**, Nos. 1,2, 15-23.

8. DuBois, B.M.: "North Stanley Polymer Demonstration Project, Third Annual and Final Report," Report BETC/RI-78/19, U.S. DOE, (Nov. 1978).

9. Hessert, J.E. and Fleming, P.D.: "Gelled Polymer Technology for Control of Water in Injection and Production Wells," presented at the Third Tertiary Oil Recovery Conference held in Wichita, KS, April 1979.

10. Woods, P. *et al.*: "In-Situ Polymerization Controls CO_2/Water Channeling at Lick Creek," paper SPE/DOE 14958 presented at the 1986 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 20-23.

11. Sydansk, R.D. and Moore, P.E.: "Gel Conformance Treatments Increase Oil Production in Wyoming," *Oil & Gas J.* (Jan. 20, 1992) 40-45.

12. *Near-Wellbore Technology*, Phillips brochure 1024-87LT (1987).

13. Seright, R.S.: "Placement of Gels to Modify Injection Profiles," paper SPE/DOE 17332 presented at the 1988 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 17-20.

14. Liang, J., Lee, R.L., and Seright, R.S.: "Gel Placement in Production Wells," *SPE Production & Facilities* (Nov. 1993) 276-284.

15. Seright, R.S.: "Effect of Rheology on Gel Placement," *SPE Reservoir Engineering* (May 1991) 212-218; *Trans.*, AIME, **291**.

16. Seright, R.S.: "Impact of Dispersion on Gel Placement for Profile Control," *SPE Reservoir Engineering* (Aug. 1991) 343-352.

17. Seright, R.S. and Martin, F.D.: "Fluid Diversion and Sweep Improvement with Chemical Gels in Oil Recovery Processes," second annual report, DOE/BC/14447-10, U.S. DOE (Nov. 1991) 45-110.

18. Sorbie, K.S. and Seright, R.S.: "Gel Placement in Heterogeneous Systems with Crossflow," paper SPE 24192 presented at the 1992 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 22-24.

19. Leonard, J.: "Increased Rate of EOR Brightens Outlook," *Oil & Gas J.* (April 14, 1986) 71-101.

20. Aalund, L.R.: "EOR Projects Decline, but CO_2 Pushes Up Production," *Oil & Gas J.* (April 18, 1988) 33-73.

21. Moritis, G.: "CO_2 and HC Injection Lead EOR Production Increase," *Oil & Gas J.* (April 23, 1990) 49-82.

22. Moritis, G.: "EOR Increases 24% Worldwide; Claims 10% of U.S. Production," *Oil & Gas J.* (April 20, 1992) 51-79.

23. Moritis, G.: "More Enhanced Oil Recovery Projects," *Oil & Gas J.* (June 29, 1992) 70-71.

24. Mack, J.C. and Warren, J.: "Performance and Operation of a Crosslinked Polymer Flood at Sage Spring Creek Unit A, Natrona County, Wyoming," *J. Petroleum Tech.* (July 1984) 1145-56.

25. Hochanadel, S.M., Lunceford, M.L., and Farmer, C.W.: "A Comparison of 31 Minnelusa Polymer Floods with 24 Minnelusa Waterfloods," paper SPE/DOE 20234 presented at the 1990 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 22-25.

26. Vela, S., Peaceman, D.W., and Sandvik, E.I.: "Evaluation of Polymer Flooding in a Layered Reservoir With Crossflow, Retention, and Degradation," *Soc. Pet. Eng. J.* (April 1976) 82-96.

27. Jennings, R.R., Rogers, J.H., and West, T.J.: "Factors Influencing Mobility Control By Polymer Solutions," *J. Petroleum Tech.* (March 1971) 391-401.

28. Zaitoun, A. and Kohler, N.: "The Role of Adsorption in Polymer Propagation Through Reservoir Rocks," paper SPE 16274 presented at the 1987 SPE International Symposium on Oilfield Chemistry, San Antonio, Oct. 4-6.

29. Fletcher, A.J.P. *et al.*: "Deep Diverting Gels for Very Cost-Effective Waterflood Control," *J. Polym. Sci. & Eng.* (April 1992) **7**, Nos. 1,2, 33-43.

30. Craig, F.F., Jr.: *The Reservoir Engineering Aspects of Waterflooding*, Society of Petroleum Engineers, Dallas (1971) 62-67.

31. 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-AIME Improved Oil Recovery Symposium, Tulsa, April 22-24.

32. Koch, R.R. and McLaughlin, H.C.: "Field Performance of New Technique for Control of Water Production or Injection in Oil Recovery," paper SPE 2847 presented at the 1970 SPE Practical Aspects of Improved Recovery Techniques Meeting, Fort Worth, March 8-10.

33. McLaughlin, H.C., Diller, J., and Ayres, H.: "Treatment of Injection and Producing Wells with Monomer Solution," paper SPE 5364 presented at the 1975 SPE Regional Meeting, Oklahoma City, March 24-25.

34. Avery, M.R., Burkholder, L.A., and Gruenenfelder, M.A.: "Use of Crosslinked Xanthan Gels in Actual Profile Modification Field Projects," paper SPE 14114 presented at the 1986 SPE International Meeting on Petroleum Engineering, Beijing, China, March 17-20.

35. Avery, M.R. and Wells, T.A.: "Field Evaluation of a New Gelant for Water Control in Production Wells," paper SPE 18201 presented at the 1988 SPE Annual Technical Conference and Exhibition, Houston, Oct. 2-5.

36. Sydansk, R.D.: "A Newly Developed Chromium (III) Gel Technology," *SPE Reservoir Engineering* (Aug. 1990) 346-352.

37. "Operators Seek Economical Production Fluid Performance," *Petroleum Engineer International* (Oct. 1992) 32-33.

38. Seright, R.S., Liang, J., and Sun, H.: "Gel Treatments in Production Wells with Water Coning Problems," *In Situ* (1993) **17**, No. 3, 243-272.

39. Root, P.J. and Skiba, F.F.: "Crossflow Effects During an Idealized Displacement Process in a Stratified Reservoir," *Soc. Pet. Eng. J.* (Sept. 1965) 229-237.

40. Scott, T. *et al.*: "In-Situ Gel Calculations in Complex Reservoir Systems Using a New Chemical Flood Simulator," *SPE Reservoir Engineering* (Nov. 1987) 634-646.

41. Gao, H.W. *et al.*: "Permeability Modification Simulator Studies of Polymer-Gel-Treatment Initiation Time and Crossflow Effects on Waterflood Oil Recovery," *SPE Reservoir Engineering* (Aug. 1993) 221-227.

42. Liang, J., Sun, H., and Seright, R.S.: "Reduction of Oil and Water Permeabilities Using Gels," paper SPE 24195 presented at the 1992 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 22-24.

43. Hall, H.N.: "How to Analyze Waterflood Injection Well Performance," *World Oil* (Oct. 1963) 128-130.

44. Earlougher, R.C., Jr.: *Advances in Well Test Analysis*, Monograph Series, SPE Dallas, (1977) **5**, 85-87.

45. Buell, R.S., Kazemi, H., and Poettmann, F.H.: "Analyzing Injectivity of Polymer Solutions with the Hall Plot," *SPE Reservoir Engineering* (Feb. 1990) 41-46.

46. Erbstoesser, S.R.: "Improved Ball Sealer Diversion," *J. Petroleum Tech.* (Nov. 1980) 1903-1910.

47. Gabriel, G.A. and Erbstoesser, S.R.: "The Design of Buoyant Ball Sealer Treatments," paper SPE 13085 presented at the 1984 SPE Annual Technical Conference and Exhibition, Houston, Sept. 16-19.

48. Hejri, S., Green, D.W., and Willhite, G.P.: "In-Situ Gelation of a Xanthan/Cr(III) Gel System in Porous Media," paper SPE 19634 presented at the 1989 SPE Annual Technical Conference and Exhibition, San Antonio, Oct. 8-11.

49. Seright, R.S. and Martin, F.D.: "Impact of Gelation pH, Rock Permeability, and Lithology on the Performance of a Monomer-Based Gel," *SPE Reservoir Engineering* (Feb. 1993) 43-50.

50. Seright, R.S. and Martin, F.D.: "Effect of Cr^{3+} on the Rheology of Xanthan Formulations in Porous Media: Before and After Gelation," *In Situ* (1992) **16**, No. 1, 1-16.

51. Seright, R.S.: "Impact of Permeability and Lithology on Gel Performance," paper SPE/DOE 24190 presented at the 1992 SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, April 21-24.

52. Moffitt, P.D.: "Long-Term Production Results of Polymer Treatments on Producing Wells in Western Kansas," *J. Petroleum Tech.* (April 1993) 356-362.

53. Muskat, M. and Wyckoff, R.D.: "An Approximate Theory of Water-Coning in Oil Production," *Trans.*, AIME (1935), **114**, 144-161.

54. Karp, J.C., Lowe, D.K., and Marusov, N.: "Horizontal Barriers for Controlling Water Coning," *J. Petroleum Tech.* (July 1962) 783-90.

55. Veatch, R.W., Jr., Moschovidis, Z.A., and Fast, C.R.: "An Overview of Hydraulic Fracturing," *Recent Advances in Hydraulic Fracturing*, Monograph Series, SPE, Richardson, TX (1989) **12**, 3-4.

56. Pfizer advertisement, *J. Petroleum Tech.* (Nov. 1991) 1305.

57. Muskat, M.: *Physical Principles of Oil Production*, McGraw-Hill Book Co., Inc., New York (1949) 226-40.

58. Schols, R.S.: "An Empirical Formula for The Critical Oil Production Rate," *Erdoel Erdgas, Z.* (1968) **88**, No. 1, 6-11.

59. Abass, H.H. and Bass, D.M.: "The Critical Production Rate in Water-Coning System," paper SPE 17311 presented at the 1988 SPE Permian Basin Oil and Gas Recovery Conference, Midland, TX, March 10-11.

60. Meyer, H.I. and Garder, A.O.: "Mechanics of Two Immiscible Fluids in Porous Media," *Journal of Applied Physics* (1954) **25**, No. 11, 1400-06.

61. Chappelear, J.E. and Hirasaki, G.J.: "A Model of Oil-Water Coning for Two-Dimensional, Areal Reservoir Simulation," *Soc. Pet. Eng. J.* (April 1976) 65-72.

62. Chaperon, I.: "Theoretical Study of Coning Toward Horizontal and Vertical Wells in Anisotropic Formations: Subcritical and Critical Rates," paper SPE 15377 presented at the 1986 SPE Annual Technical Conference and Exhibition, New Orleans, Oct. 5-8.

63. Wheatley, M.J.: "An Approximate Theory of Oil/Water Coning," paper SPE 14210 presented at the 1985 SPE Annual Technical Conference and Exhibition, Las Vegas, Sept. 22-25.

64. Chaney, P.E. *et al.*: "How to Perforate Your Well to Prevent Water and Gas Coning," *Oil & Gas J.* (May 7, 1956) 108-14.

65. Hoyland, L.A., Papatzacos, P., and Skjaeveland, S.M.: "Critical Rate for Water Coning: Correlation and Analytical Solution," paper SPE 15855 presented at the 1986 SPE European Petroleum Conference, London, Oct. 20-22.

66. Lee, S.H. and Tung, W.B.: "General Coning Correlations Based on Mechanistic Studies," paper SPE 20742 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 23-26.

67. Bournazel, C. and Jeanson, B.: "Fast Water-Coning Evaluation Method," paper SPE 3628 presented at 1971 SPE Annual Meeting, New Orleans, Oct. 3-6.

68. Kuo, M.C.T. and DesBrisay, C.L.: "A Simplified Method for Water Coning Predictions," paper SPE 12067 presented at the 1983 SPE Annual Technical Conference and Exhibition, San Francisco, Oct. 5-8.

69. Muskat, M.: *Flow of Homogeneous Fluids Through Porous Media*, McGraw-Hill Book Co., Inc., New York (1946) 377-399.

70. Seright, R.S. and Martin, F.D.: "Fluid Diversion and Sweep Improvement with Chemical Gels in Oil Recovery Processes," first annual report, DOE/BC/14447-8, U.S. DOE (June 1991) 34-55, 87-109.

71. Seright, R.S. and Martin, F.D.: "Fluid Diversion and Sweep Improvement with Chemical Gels in Oil Recovery Processes," final report, DOE/BC/14447-15, U.S. DOE (Sept. 1992) 28-58, 77-93.

72. Dake, L.P.: *Fundamentals of Reservoir Engineering*, Elsevier Scientific Publishing Co., New York (1982) 110, 375, 343-430

73. Howard, G.C. and Fast, C.R.: *Hydraulic Fracturing*, Monograph Series, SPE, Richardson, TX (1970) **2**, 32-90.

74. Anderson, R.W., Cooke, C.E., and Wendorff, C.L.: "Propping Agents and Fracture Conductivity," *Recent Advances in Hydraulic Fracturing*, Monograph Series, SPE, Richardson, TX (1989) **12**, 109-130.

75. Penny, G.S. and Conway, M.W.: "Fluid Leakoff," *Recent Advances in Hydraulic Fracturing*, Monograph Series, SPE, Richardson, TX (1989) **12**, 147-176.

76. Ben-Naceur, K.: "Modeling of Hydraulic Fractures," *Reservoir Stimulation*, 2nd ed., Prentice Hall, Englewood Cliffs, NJ (1989) **12**, 3.1-3.31.

77. Jousset, F. *et al.*: "Effect of High Shear Rate on In-Situ Gelation of a Xanthan/Cr(III) System," SPE/DOE paper 20213 presented at the 1990 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 22-25.

78. Todd, B.J., Green, D.W., and Willhite, G.P.: "A Mathematical Model of In-Situ Gelation of Polyacrylamide by a Redox Process," *SPE Reservoir Engineering* (Feb. 1993) 51-58.

79. Todd, B.J., Willhite, G.P., and Green, D.W.: "Radial Modeling of In-Situ Gelation in Porous Media," paper SPE 21650 presented at the 1991 Production Operations Symposium, Oklahoma City, April 7-9.

80. Hoefner, M.L. *et al.*: "Selective Penetration of Biopolymer Profile-Control Gels: Experimental and Model," *J. Pet. Sci. & Eng.* (1992) **7**, Nos. 1,2, 53-66.

81. Willhite, G.P.: *Waterflooding,* SPE, Richardson, TX (1986) **3**, 21-24.

82. Jones, S.C. and Roszelle, W.O.: "Graphical Techniques for Determining Relative Permeability From Displacement Experiments," *J. Petroleum Tech.* (May 1978) 807-817.

83. Sandiford, B.B. and Graham, G.A.: "Injection of Polymer Solutions in Producing Wells," AIChE Symposium Series, (1973) **69**, No. 127, 38.

84. Schneider, F.N. and Owens, W.W.: "Steady-State Measurements of Relative Permeability for Polymer/Oil Systems," *Soc. Pet. Eng. J.* (Feb. 1982) 79.

85. Sparlin, D.D.: "An Evaluation of Polyacrylamides for Reducing Water Production," *J. Petroleum Tech.* (Aug. 1976) 906-914.

86. White, J.L., Goddard, J.E., and Phillips, H.M.: "Use of Polymers To Control Water Production in Oil Wells," *J. Petroleum Tech.* (Feb. 1973) 143-150.

87. Zaitoun, A. and Kohler N.: "Two-Phase Flow Through Porous Media: Effect of an Adsorbed Polymer Layer," paper SPE 18085 presented at the 1988 SPE Annual Technical Conference and Exhibition, Houston, Oct. 2-5.

88. Zaitoun, A. and Kohler N.: "Thin Polyacrylamide Gels for Water Control in High-Permeability Production Wells" paper SPE 22785 presented at the 1991 SPE Annual Technical Conference and Exhibition, Dallas, Oct. 6-9.

89. Perkins, T.K. and Johnston, O.C.: "A Review of Diffusion and Dispersion in Porous Media," *Soc. Pet. Eng. J.* (March 1963) 70-84.

90. Odeh, A.S.: "Effect of Viscosity Ratio on Relative Permeability," *Petroleum Transactions, AIME* **216** (1959) 346-353.

91. Sparlin, D.D. and Hagen, R.W., Jr.: "Controlling Water in Producing Operation - Part 5," *World Oil* (June 1984) 137-142.

92. Nathan, C.C. and Perry, R.B.: "Treating Permeable Underground Formations," U.S. Patent No. 2,990,881 (1961).

93. Bond, D.C. and O'Brien, J.L.: "Selective Plugging Between Contiguous Strata," U.S. Patent No. 3,013,607 (1961).

94. Holm, L.W.: "Micellar Flooding Process for Heterogeneous Reservoirs," U.S. Patent No. 4,140,183 (1979).

95. Megyeri, M., Konez, G.T., Tiszai, G., and Paal, T.: "Process for Increasing the Yield of Oil Reservoirs," U.S. Patent No. 4,844,155 (1989).

96. Hower, W.F. and Ramos, J.: "Selective Plugging of Injection Wells by In-Situ Reactions," *J. Petroleum Tech.* (Jan. 1957) 17-20.

97. King, J.A. and Fallgatter, S.F.: "Method of Increasing Oil Recovery," U.S. Patent No. 2,747,670 (1956).

98. Bernard, G.G.: "Method for Water Flooding Heterogeneous Petroleum Reservoirs," U.S. Patent No. 3,530,937 (1970).

99. Sydansk, R.D.: "Process for Improving Conformance and Flow Profiles in a Subterranean Formation," U.S. Patent No. 4,304,301 (1981).

100. Sydansk, R.D.: "Process For Improving Conformance and Flow Profiles in a Subterranean Sandstone Formation," U.S. Patent No. 4,287,951 (1981).

101. Harwell, J.H. and Scamehorn, J.F.: "Method for Selectively Plugging the More Permeable Regions of an Underground Formation Having Non-uniform Permeability," U.S. Patent No. 4,745,976 (1988).

102. Chamberlain, L.C. and Robinson, H.A.: "Treatment of Earth Formation," U.S. Patent No. 2,238,930 (1941).

103. Routson, W.G.: "Method for Controlling Flow of Aqueous Fluids in Subterranean Formations," U.S. Patent No. 3,687,200 (1972).

104. Mohnot, S.M. and Chakrabarti, P.M.: "Alkaline Water Flooding with a Precipitation Inhibitor for Enhanced Oil Recovery," U.S. Patent No. 4,714,113 (1987).

105. Paul, J.M.: "Method for Selectively Plugging Deep Subterranean Formations with Polysulfides," U.S. Patent No. 4,773,480 (1988).

106. Llave, F.M., Burchfield, T.E., and Dobson, R.E., Sr.: "A Novel Method of Developing In-Depth Permeability Modification Using Surfactant-Alcohol Blends," *SPE Reservoir Engineering* (Aug. 1993) 228-232.

107. Phelps, C.H., Strom, E.T., and Hoefner, M.L.: "In-Situ Emulsion Polymerization of Ethylene Derivatives," U.S. Patent No. 5,048,607 (1991).

APPENDIX A

BIBLIOGRAPHY FOR CHAPTER 2:

A SURVEY OF FIELD ACTIVITY FOR GEL TREATMENTS IN INJECTION WELLS: 1980-1992

APPENDIX A

Bibliography for Chapter 2

Jones, M.A.: "Waterflood Mobility Control: A Case History," *JPT* (Sept. 1966) 1151-56.

Robertson, J.O., Jr. and Oefelein, F.H.: "Plugging Thief Zones in Water Injection Wells," *JPT* (Aug. 1967) 999-1004.

Ustick, R.E. and Hillhouse, J.D.: "Comparison of Polymer Flooding and Waterflooding at Huntington Beach, California," *JPT* (Sept. 1967) 1103-11.

Sloat, B. and Brown, M.: "How to Flood a Tight Sand with Wide Permeability Variations," paper SPE 2129 presented at the 1968 SPE Rocky Mountain Regional Meeting, Billings, MT, June 5-7.

Smith, L.R., Fast, C.R., and Wagner, O.R.: "Development and Field Testing of Large Volume Remedial Treatments for Gross Water Channeling," *JPT* (Aug. 1969) 1015-25.

Moore, J.K.: "Reservoir Barrier and Polymer Waterflood, Northeast Hallsville Crane Unit," *JPT* (Sept. 1969) 1130-36.

Hess, P.H., Clark, C.O., Haskin, C.A., and Hull, T.R.: "Chemical Method for Formation Plugging," *JPT* (May 1971) 559-64.

Harrison, N.W.: "Diverting Agents - Their History and Application," paper SPE 3653 presented at the 1971 SPE Illinois Basin Section Regional Meeting, Evansville, IN, Nov. 18-19.

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 Fall Meeting, San Antonio, Oct. 8-11.

McCartney, J.A. and Sloat, B.: "Polymers Reduce Risk in Waterflooding," *Pet. Eng.* (Dec. 1972) Betz reprint 101.

Sloat, B.: "Choosing the Right Floods for Polymer Treatment," reprint from *Pet. Eng.* (1972).

Sloat, B.: "How Six Polymer Floods are Faring," *Oil & Gas J.* (Dec. 11, 1972) Betz reprint 99.

Rowalt, R.J.: "A Case History of Polymer Waterflooding - Brelum Field Unit," paper SPE 4671 presented at the 1973 Fall Meeting of SPE of AIME, Las Vegas, NV, Sept. 30-Oct. 3.

Mazzocchi, E.F. and Carter, K.M.: "Pilot Application of a Blocking Agent—Weyburn Unit, Saskatchewan," *JPT* (Sept. 1974) 973-78.

Fitch, J.P. and Canfield, C.M.: "Field Performance Evaluation of Crosslinked Polymers to Increase Oil Recovery in the Wilmington Field, California," paper SPE 5366 presented at the 1975 SPE California Regional Meeting, Ventura, CA, April 2-4.

Farley, R.W., Ellebracht, J.F., and Friedman, R.H.: "Field Test of a Self-Conforming Oil Recovery Fluid," paper SPE 5553 presented at the 1975 SPE Fall Meeting, Dallas, Sept. 28-Oct. 1.

Ford, W.O., Jr. and Kelldorf, W.F.N.: "Field Results of Short Setting Time Polymer Placement Technique," paper SPE 5609 presented at the 1975 SPE Fall Meeting, Dallas, Sept.28-Oct. 1.

Sloat, B.: "Increasing Oil Recovery by Chemical Control of Producing Water-Oil Ratios," paper SPE 5341 presented at the 1975 SPE Rocky Mountain Regional Meeting, Denver, CO, April 7-9.

Baxter, D., Bowman, R.W., Tinker, G., and Bates, T.: "Biopolymer Pilot Facilities - Coalinga," paper SPE 6118 presented at the 1976 SPE Fall Technical Conference and Exhibition, New Orleans, Oct. 3-6.

Tholstrom, K.V.: "Performance History and Operating of Two Minnelusa Reservoirs - West Semlek Field, Crook County, Wyoming," paper SPE 6164 presented at the 1976 SPE Fall Technical Conference and Exhibition, New Orleans, Oct. 3-6.

Krebs, H.J.: "Wilmington Field, California, Polymer Flood—A Case History," *JPT* (Dec. 1976) 1473-80.

Sparlin, D.D.: "Polyacrylamides Can Restrict Water, Oil, and Gas Production - It's Your Choice," paper SPE 6473 presented at the 1977 SPE Oklahoma City Regional Meeting on Operating Practices in Drilling and Production, Oklahoma City, Feb. 21-22.

Townsend, W.R., Becker, S.A., and Smith, C.W.: "Polymer Use in Calcarenous Formations," paper SPE 6382 presented at the 1977 SPE Permain Basin Oil and Gas Recovery Conference and Exhibition, Midland, TX, March 10-11, 122-29.

Groeneveld, H., George, R.A., and Melrose, J.C.: "Permbina Field Polymer Pilot Flood," *JPT* (May 1977) 561-70.

Sloat, B.: "How to Get More for Your Chemical Dollar," *Pet. Eng.* (Nov. 1977) 20-23.

Mack, J.C.: "Improved Oil Recovery - Product to Process," paper SPE 7179 presented at the 1978 SPE Rocky Mountain Regional Meeting, Cody, Wyoming, May 17-19.

Grodde, K.-H. and Schaefer, W.: "Experience with the Application of Polymer to Improve Water Flood Efficiency in Dogger Reservoirs of the Gifhorn Trough, Germany," *Erdoel-Erdgas-Zeitschrift* (July 1978) **94**, 252-59.

Chang, H.L.: "Polymer Flooding Technology—Yesterday, Today, and Tomorrow," *JPT* (Aug. 1978) 1113-28.

Weiss, W.W. and Chain, J.: "Owasco Unit Polymer Flood," *Oil & Gas J.* (Aug. 7, 1978) 80-82.

Strickland, P.H., Wilson, J.T., and Warnock, W.E., Jr.: "The Feasibility of Converting an Existing Waterflood to a Polymer Flood: A Case History of West Yellow Creek," paper SPE 7462 presented at the 1978 SPE Fall Technical Conference and Exhibition, Houston, Oct. 1-3.

Weaver, J.D.: "A New Water-Oil Ratio Improvement Material," paper SPE 7574 presented at the 1978 SPE Annual Fall Technical Conference and Exhibition, Houston, Oct. 1-3.

DuBois, B.M.: "North Stanley Polymer Demonstration Project, Third Annual and Final Report," Report BETC/RI-78/19, U.S. DOE, Washington, D.C., November, 1978.

Sinclair, B.C. and Ott, W.K.: "Polymer Reduces Channeling, Ups Waterflood Oil Recovery," *World Oil* (Dec. 1978) 101-04.

"Update on Polymer Flood Project in Coalinga, Calif.," *Oil & Gas J.* (Jan. 29, 1979) 162, 167.

"DOE Reports on Polymer Flood Field Test," *Oil Regulation Report*, TX State House Reporter, Inc., Vol. 45, No. 234 (March 12, 1979) 1-2.

Hessert, J.E. and Fleming, P.D.: "Gelled Polymer Technology for Control of Water in Injection and Production Wells," presented at the Third Tertiary Oil Recovery Conference, Wichita, KS, April 1979, 58-70.

"Polymer Test Has Good Recovery, Slim Profit," *Oil & Gas J.* (April 2, 1979) 56.

Gill, D.: "CO_2 and Polymers May Recover Additional Oil," *Western Oil Reporter* (June 1979) 35.

Gill, D.: "Progress of Waterflood Projects in Region Listed," *Western Oil Reporter* (Sept. 1979) 1-3.

Gill, D.: "Polymer and Waterfloods Continue to Increase in Region," *Western Oil Reporter* (Sept. 1979) 4-5.

Gordon, S.P. and Owen, O.K.: "Surveillance and Performance of an Existing Polymer Flood: A Case History of West Yellow Creek," paper SPE 8202 presented at the 1979 SPE Fall Technical Conference and Exhibition, Las Vegas, NV, Sept. 23-26.

Mack, J.: "Process Technology Improves Oil Recovery," *Oil & Gas J.* (Oct. 1, 1979) 67-72.

Peddycoart, L.R.: "Water Control for ER Production Improvement," *Oil & Gas J.* (Feb. 4, 1980) 52-54.

Matheny, S.L., Jr.: "EOR Methods Help Ultimate Recovery," *Oil & Gas J.* (March 31, 1980) 79-124.

Peddycoart, L.R.: "Polymer A Practical Approach to Enhanced Oil Recovery," report to 1980 Annual Meeting of Kentucky Oil & Gas Assoc., June 11-13.

"Enhanced Oil Recovery Test Advances in Kansas," *Oil & Gas J.* (Aug. 20, 1979) 46-47.

Ruble, D.B.: "Case Study of a Multiple Sand Waterflood, Hewitt Unit, Oklahoma," paper SPE 9478 presented at the 1980 SPE Annual Fall Technical Conference and Exhibition, Dallas, Sept. 21-24.

"Miscible Polymer Flooding - Not for Every Reservoir," *Enhanced Recovery Week* (Sept. 15, 1980) 5.

Gill, D.: "Tiorco Concentrates on Sweep Improvements," *Western Oil Reporter* (Sept. 1980).

Gill, D.: "New Generation Techniques Beckon Operators," *Western Oil Reporter* (Sept. 1980).

"Tenneco Sets La. Field for Huge Polymer Project," *Enhanced Recovery Week* (Oct. 13, 1980) 1-2.

"Phillips-Hercules Venture to do 100 Polymer Jobs in 1981," *Enhanced Recovery Week* (Oct. 13, 1980) 5-6.

"Continuation of Fluid Injection Approved," *Oil Regulation Report*, TX State House Reporter, Inc. (Oct. 24, 1980) 15.

"Polymerflood Expansion Authorized," *Oil Regulation Report*, TX State House Reporter, Inc. (Nov. 3, 1980) 8.

"Tenneco Starts Polymer-Augmented Waterflood," *Oil & Gas J.* (Nov. 17, 1980) 177.

Smith, R.V. and Burtch, F.W.: "Study Shows N. Stanley Field Polymer Flood Economics," *Oil & Gas J.* (Nov. 24, 1980) 127-34.

"Surfactants, Polymers Meet the Rock," *Enhanced Recovery Week* (Dec. 1, 1980) 4.

"Sun Texas Buys 30 Million Pounds of Cyanamid Polymers," *Enhanced Recovery Week* (Dec. 8, 1980) 1-2.

"CO_2 Leads in Front-End Recoupment," *Enhanced Recovery Week* (Dec. 8, 1980) 3.

"DeG & MacN VP Pans CO_2, Chemical Recovery," *Enhanced Recovery Week* (Dec. 8, 1980) 5-6.

"Tertiary Recovery Certification Sought," *Oil Regulation Report*, TX State House Reporter, Inc., Vol. 48, No. 164 (Dec. 2, 1980) 1-2.

"Tertiary Certification, Entity for Density Treatment Sought," *Oil Regulation Report*, TX State House Reporter, Inc., Vol. 48, No. 164 (Dec 3, 1980) 2-3.

"Tertiary Recovery Certification," *Oil Regulation Report*, TX State House Reporter, Inc., Vol. 48, No. 181 (Dec. 30, 1980) 1-2.

"Tennessean an EOR Leader Among Independents," *Enhanced Recovery Week* (Jan. 19, 1981) 1-2.

"Anderson Seeks 310,000 bbls. with Polymer-Caustic," *Enhanced Recovery Week* (Jan. 19, 1981) 1.

"Texaco to Try Polymer Flood in Oklahoma," *Enhanced Recovery Week* (Feb. 2, 1981) 5.

"Gulf Tries In-Situ, Polymer, Caustic in W. Tex.," *Enhanced Recovery Week* (Feb. 9, 1981) 2.

"Terra Gets 1.4 Million bbls. with Polymers," *Enhanced Recovery Week* (Feb. 9, 1981) 6.

"Mitchell Injects Polymer/Caustic at Three Sites," *Enhanced Recovery Week* (Feb. 16, 1981) 7.

"Wyoming Field Gets Second Shot of Polymer," *Enhanced Recovery Week* (Feb. 23, 1981) 5.

"Kansas Independents get EOR Overview," *Enhanced Recovery Week* (March 16, 1981) 5.

"Hale Joins Exxon for Okla. Polymer Flood," *Enhanced Recovery Week* (March 30, 1981) 2.

"Marathon to Add Fireflood, Polymer Plant in Illinois," *Enhanced Recovery Week* (March 30, 1981) 2-3.

"Sho-Vel-Tum Polymers Have Mobil Clapping for More," *Enhanced Recovery Week* (March 30, 1981) 4.

Mickey, V.: "Incentives Spur Fina's Polymer-Augmented Waterflood," *Drill Bit* (April 1981) 71-76.

"Tex., Wyo., La. Fields Get Polymers from Sun," *Enhanced Recovery Week* (April 6, 1981) 5-6.

"Exxon's Yellow Creek Polymers Add $2-$4/bbl," *Enhanced Recovery Week* (April 13, 1981) 4.

"Exxon is Using Polymers in Heavy Oil," *Enhanced Recovery Week* (April 27, 1981) 6.

"Samedan Polymers Make it Two at Kuehne," *Enhanced Recovery Week* (May 4, 1981) 4-5.

Maitin, B.K. and Volz, H.: "Performance of Deutsche Texaco Ag's Oerrel and Hankensbuettel Polymer Floods," paper SPE/DOE 9794 presented at the 1981 Annual OTC, Houston, May 4-7.

"Marathon Delays Polymers at Lindsay Unit," *Enhanced Recovery Week* (May 18, 1981) 4.

"Record-Setting Polymer Flood Used in Historic Westbrook Unit," *Well Servicing* (May/June 1981) 22-24.

"Cyanamid Tops Own Record in Big Polymer Deal," *Enhanced Recovery Week* (June 8, 1981) 6.

"On-Site Polymerization Nears Commercial Usage," *Enhanced Recovery Week* (June 15, 1981) 1.

"Texaco is Mum on Polymer Deal," *Enhanced Recovery Week* (June 15, 1981) 1.

"Hunt, Placid Plan Side-by-Side Polymers at E. Texas," *Enhanced Recovery Week* (June 15, 1981) 4-5.

"Nalco's Polymer Process Sits on a Shelf," *Enhanced Recovery Week* (June 29, 1981) 4.

"Firms Plan East Texas Field Polymer Waterflood," *Oil & Gas J.* (June 29, 1981) 192.

"Gulf's Osage Polymers Trust New Economics," *Enhanced Recovery Week* (July 20, 1981) 2.

"Tesoro to Fight Clays with Polymers," *Enhanced Recovery Week* (July 20, 1981) 5-6.

"Goodyear Enters the Polymer Sales Market," *Enhanced Recovery Week* (Aug. 3, 1981) 1.

"Acid Said to Give Polymers More Punch," *Enhanced Recovery Week* (Aug. 3, 1981) 1-2.

"Jurisdictional Certification Sought," *Energy Regulation Report*, TX State House Reporter, Inc., Vol. 49, No. 90 (Aug. 11, 1981) 1-3.

"Texas Waterfloods, Injection Project Proposed," *Oil & Gas J.* (Aug. 24, 1981) 76.

Labastie, A. and Vio, L.: "The Chateaurenard (France) Polymer Flood Field Test," *Proc.*, 1981 European Symposium on Enhanced Oil Recovery, Bournemouth, 213-22.

"Synthetic Polymer Gets High Marks," *Enhanced Recovery Week* (Sept. 7, 1981) 1-2.

"Brent Favors Polymers and Hot Water Over Steam," *Enhanced Recovery Week* (Sept. 28, 1981) 1.

Posey, L.S.: "Enhanced Recovery Methods Make Gains," *The Digest* (Oct. 1981) 15.

"Long Beach Details High-Cost Flood," *Enhanced Recovery Week* (Nov. 2, 1981) 3.

"Mabee, Slaughter to Get Polymers from Texaco," *Enhanced Recovery Week* (Nov. 2, 1981) 4.

"Dow Boosts Polymer Capacity," *Enhanced Recovery Week* (Nov. 9, 1981) 1.

"Tests Show Clay Can Kill Polymer Floods," *Enhanced Recovery Week* (Nov. 16, 1981) 5-6.

"Quest Readies Large Polymer Pilot, *Enhanced Recovery Week* (Nov. 23, 1981) 3-4.

"Eldorado Readies Two Texas Polymer Floods," *Enhanced Recovery Week* (Dec. 7, 1981) 1.

"Gulf Aims Polymers at Dune's Dolomite," *Enhanced Recovery Week* (Dec. 7, 1981) 2.

"Polymers Wait, Fireflood Starts at Teapot Dome," *Enhanced Recovery Week* (Dec. 14, 1981) 1-2.

Rogers, D.L. and Carrizales, D.: "Application of Enhanced Recovery in the North Ward-Estes Field," Report for Gulf Oil Exploration & Production Co., Midland, TX (1982) 29-55.

"Polymer Prices to Increase," *Enhanced Recovery Week* (Jan. 11, 1982) 1-2.

"Texaco Readies Oklahoma Polymer Flood," *Enhanced Recovery Week* (Jan. 11, 1982) 4.

"Canada-Cities Eyes Polymers in Ontario," *Enhanced Recovery Week* (Jan. 11, 1982) 6.

"British Firm Tests Polymers in North Sea," *Enhanced Recovery Week* (Jan. 18, 1982) 5-6.

"Planet Sticks with Polymers in Wyoming," *Enhanced Recovery Week* (Feb. 1, 1982) 1.

"Old Lisbon Shows First Polymer Results," *Enhanced Recovery Week* (Feb. 8, 1982) 1.

"Warrior Resources Sells Polymer-Flood Interest," *Enhanced Recovery Week* (Feb. 8, 1982) 5-6.

"Canadian Firm Tests Steamflood Gel," *Enhanced Recovery Week* (March 8, 1982) 3.

"Oman Readies Polymer and Hot-Water Floods," *Enhanced Recovery Week* (March 8, 1982) 4.

"Shell to Start Micellar Test in Brunei," *Enhanced Recovery Week* (March 8, 1982) 8.

"RPM to Try Alkaline, Polymer Flood on Cache's Clays," *Enhanced Recovery Week* (March 15, 1982) 2-3.

"Mitchell Plans Polymers for Jacksboro Field," *Enhanced Recovery Week* (March 15, 1982) 3.

"Petrofina Schedules Polymers for Garza," *Enhanced Recovery Week* (March 22, 1982) 6.

Wash, R.: "Gulf Injects Polymer for Better Water Distribution in Yates Sand," *Drill Bit* (March 1982) 93-96.

"Chinese Polymer Gets Best of Two Worlds," *Enhanced Recovery Week* (March 29, 1982) 4.

Ruble, D.B.: "Case Study of a Multiple Sand Waterflood, Hewitt Unit, OK," *JPT* (March 1982) 621-27.

Bragg, J.R., Gale, W.W., McElhannon, W.A., Jr., Davenport, O.W., Petrichuk, M.D., and Ashcraft, T.L.: "Loudon Surfactant Flood Pilot Test," paper SPE/DOE 10862 presented at the 1982 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 4-7.

Bragg, J.R., Roesner, R.E., and Strassner, J.E.: "Measuring Well Injection Profiles of Polymer-Containing Fluids," paper SPE/DOE 10690 paper SPE/DOE 10862 presented at the 1982 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 4-7.

Sloat, B. and Zlomke, D.: "The Isenhour Unit—A Unique Polymer-Augmented Alkaline Flood," paper SPE/DOE 10719 presented at the 1982 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 4-7.

"Steam Dominates Enhanced Oil Recovery," *Oil & Gas J.* (April 5, 1982) 139-51.

"Halliburton Rethinks On-Site Polymerization," *Enhanced Recovery Week* (April 12, 1982) 3.

"Wyoming Flood Combines Caustic and Polymers," *Enhanced Recovery Week* (April 12, 1982) 5-6.

"Phillips Anticipates High Return on N. Burbank Polymers," *Enhanced Recovery Week* (April 19, 1982) 1-2.

"Hunt and Placid Cooperate on Polymer Flood," *Enhanced Recovery Week* (April 26, 1982) 3.

"Goodyear Introduces New Polymers," *Enhanced Recovery Week* (April 26, 1982) 5.

Wilson, L.: "Cyanamid Announces Sharp Increase in Polyacrylamide Capacity," *Cyanamid News & Information* (May 6, 1982).

"Cyanamid Boosts Polyacrylamide Capacity," *Enhanced Recovery Week* (May 10, 1982) 6.

Mack, J.C.: "Performance and Operation of Sage Spring Creek Unit 'A', Natrona County, Wyoming," paper SPE 10876 presented at the 1982 SPE Rocky Mountain Regional Meeting, Billings, MT, May 19-21.

"Petrofina Awaits Polymer Response at Westbrook," *Enhanced Recovery Week* (May 24, 1982) 5.

"Emulsions Put Polymer Expansion on Hold," *Enhanced Recovery Week* (May 31, 1982) 1.

"Plugging Can Be Curse or Blessing," *Enhanced Recovery Week* (May 31, 1982) 6.

"Illinois Polymer Flood Continues to Produce Oil at Higher Rate," Bartlesville Energy Technology Center *Research Brief* (June 1982).

"Borden Develops a Polymer for Steamflooding," *Enhanced Recovery Week* (June 14, 1982) 1.

"Saudis Begin Long-Term EOR Research," *Enhanced Recovery Week* (June 14, 1982) 5.

"Texaco to Try Polymers at Lone Grove," *Enhanced Recovery Week* (Aug. 2, 1982) 2.

"Masek Boosts Tyro Production with Polymers," *Enhanced Recovery Week* (Aug. 2, 1982) 5.

"Firm to Scour Rockies for EOR Sites," *Enhanced Recovery Week* (Aug. 9, 1982) 1.

"Nalco Sues Allied Colloids Over Polymer Patents," *Enhanced Recovery Week* (Aug. 9, 1982) 4.

"NCRA Wants Bigger Response from Waterloo Polymers," *Enhanced Recovery Week* (Aug. 9, 1982) 5-6.

"With Polymers on Track, Anderson Eyes Surfactants," *Enhanced Recovery Week* (Aug. 16, 1982) 1.

"Samedan Likes Polymers at Kuehne Ranch," *Enhanced Recovery Week* (Aug. 16, 1982) 4.

"DOE Outlines EOR Water Requirements," *Enhanced Recovery Week* (Aug. 23, 1982) 4.

"Demand for EOR Chemicals to Soar, Firm Says," *Enhanced Recovery Week* (Aug. 23, 1982) 4-5.

"Tenneco Tests Polymers in Utah's Upper Valley Field," *Enhanced Recovery Week* (Aug. 23, 1982) 5.

"Burlington Likes Polymers' Tax Benefits," *Enhanced Recovery Week* (Aug. 30, 1982) 1-2.

McClaine, S.J.: "Polymers Can be Effective as Vertical Sweep Improvement Agents," *NE Oil Reporter* (Sept. 1982) 63-67.

"Tesoro Proceeds with Polymers at Elaine," *Enhanced Recovery Week* (Sept. 13, 1982) 3-4.

Teeuw, D., Rond, D., and Martin, J.H.: "Design of a Pilot Polymer Flood in the Marmul Field, Oman," paper SPE 11504 presented at the 1982 SPE Annual Fall Technical Conference and Exhibition, New Orleans, Sept. 26-29.

"New Polysaccharide Shows Promising Tests Results," *Enhanced Recovery Week* (Sept. 20, 1982) 1.

"Hale Credits Polymers with Halting Production Decline," *Enhanced Recovery Week* (Sept. 27, 1982) 2.

"Hercules Doubles Polyacrylamide Capacity," *Enhanced Recovery Week* (Oct. 11, 1982) 1.

"Petrofina Expands Westbrook Polymer Flood," *Enhanced Recovery Week* (Nov. 29, 1982) 1.

"Buckhorn Patches Sumatra with Polymers," *Enhanced Recovery Week* (Jan. 10, 1983) 2.

"Homes Likes Polymers in Wyoming's Minnelusa," *Enhanced Recovery Week* (Jan. 10, 1983) 2-3.

"Denver Independent Wants Polymers for Wyo.'s Muddy," *Enhanced Recovery Week* (Jan. 17, 1983) 2.

"Phillips Likes N. Burbank's Polymer Response," *Enhanced Recovery Week* (Jan. 31, 1983) 1.

"Storms Pool Effort is Over and Out," *Enhanced Recovery Week* (Feb. 14, 1983) 1.

"Sun Pleased with Eliasville Polymers," *Enhanced Recovery Week* (Feb. 14, 1983) 3.

"Production is Up at Samedan's Polymer Flood," *Enhanced Recovery Week* (Feb. 28, 1983) 1.

"Marathon to Try Polymers in N.W. Wyoming," *Enhanced Recovery Week* (Feb. 28, 1983) 3.

Moffitt, P.D. and Mitchell, J.F.: "North Burbank Unit Commercial Scale Polymerflood Project—Osage County, Oklahoma," paper SPE 11560 presented at the 1983 SPE Production Operation Symposium, Oklahoma City, Feb. 27-March 1.

Bruning, D.D., Hedges, J.H., and Zornes, D.R.: "Use of the Aluminum Citrate Process in the Commercial Scale North Burbank Unit Polymerflood," *Proc.*, Fifth Kans. Univ. Tertiary Oil Recovery Conf., Wichita, KS, (March 9-10, 1983) No. 7, 111-30.

"Caustic Polymer Project Aims for 1.6 Million bbl," *Oil & Gas J.* (March 21, 1983) 67.

"Tenneco Drops New Mexico Fireflood, Eyes Polymers," *Enhanced Recovery Week* (March 28, 1983) 1.

"Tenneco Unimpressed with Polymers at Panhandle," *Enhanced Recovery Week* (March 28, 1983) 4.

"Sho-Vel-Tum Gets Second Polymer Flood," *Enhanced Recovery Week* (April 4, 1983) 2.

"Mobil Completes Sho-Vel-Tum Polymer Injection," *Enhanced Recovery Week* (April 11, 1983) 4.

"Caustic/Polymer Reduces Injectivity at Alba," *Enhanced Recovery Week* (April 18, 1983) 3.

"Gulf Starts Offshore Polymer Injection," *Enhanced Recovery Week* (April 18, 1983) 4.

"Polymer Increases Recovery from Stewart Ranch," *Enhanced Recovery Week* (April 25, 1983) 4.

"Enhanced Oil Recovery Opportunities with Halliburton's Polyflood Service," *Pet. Eng. International* (May 1983) 99.

"Getty Nears End of Polymer Injection at Illinois Micellar," *Enhanced Recovery Week* (May 2, 1983) 1.

"Big Piney Polymer Flood Shows Moderate Response," *Enhanced Recovery Week* (May 16, 1983) 3.

"Hitts Lake Responds to Polymer in One Pattern," *Enhanced Recovery Week* (May 23, 1983) 2.

"Placid Schedules Second La. Polymer Flood," *Enhanced Recovery Week* (May 23, 1983) 3.

"Texaco, Union Plan Tertiary Recovery Projects," *Oil & Gas J.* (June 13,1983) 56.

"Polymers Give Slaughter a Boost in Production," *Enhanced Recovery Week* (June 20, 1983) 1.

"Phillips Hikes Output at Oklahoma EOR Projects," *Oil & Gas J.* (June 27, 1983) 36-37.

"Hunt Sees Response from East Texas Polymer Flood," *Enhanced Recovery Week* (June 27, 1983) 1-2.

"Quest Injects Polymer, Citrate at Wimberly," *Enhanced Recovery Week* (June 27, 1983) 3-4.

"Polymers Reduce Water Cut at McElroy Flood," *Enhanced Recovery Week* (July 11, 1983) 1-2.

"Gulf Scales Down Polymer Use at South Stanley," *Enhanced Recovery Week* (July 11, 1983) 2.

"Marathon Prepares Yates Field for Polymer Flood," *Enhanced Recovery Week* (July 25, 1983) 2.

"Poor Injectivity Halts Polymer at Ky. Micellar," *Enhanced Recovery Week* (July 25, 1983) 3.

Bilbrey, D.G. and Blackmar, G.E.: "Polymer Floods Begin in South Louisiana Waters," *Ocean Industry* (Aug. 1983) 69-74.

"Mitchell Plans EOR Project in Borden County," *Oil & Gas J.* (Aug. 1, 1983) 59.

"Crown Begins Polymer/Alkaline Test," *Enhanced Recovery Week* (Aug. 1, 1983) 1.

"Home Tries Polymer on Wyoming's Minnelusa," *Enhanced Recovery Week* (Aug. 1, 1983) 2.

"Halliburton's Synthetic Polymer Has Tough Time," *Enhanced Recovery Week* (Aug. 8, 1983) 2.

"Texaco Gambles on Polymers at Black Diamond...and at Levelland as Well," *Enhanced Recovery Week* (Aug. 8, 1983) 3.

"Survey of EOR Water Requirements," *Enhanced Recovery Week* (Aug. 15, 1983) 1-2.

"Boston Firm Promotes Modified Acrylamide," *Enhanced Recovery Week* (Aug. 22, 1983) 2-3.

"Texaco to Conclude Polymer Injection at Mabee," *Enhanced Recovery Week* (Aug. 22, 1983) 4.

"Marathon Expects 200 Million Barrels from Yates Polymer," *Enhanced Recovery Week* (Aug. 29, 1983) 3.

"Fiddler Creek Responds to Polymer Flood," *Enhanced Recovery Week* (Aug. 29, 1983) 3-4.

"Tenneco Chooses Polymer Over Gas at Yolumne," *Enhanced Recovery Week* (Aug. 29, 1983) 4.

"Union Adds Polymer to Howard-Glasscock," *Enhanced Recovery Week* (Aug. 29, 1983) 4.

"Keplinger Reviews Shell's Coalinga Polymer," *Enhanced Recovery Week* (Aug. 29, 1983) 4-5.

Manning, R.K. *et al.*: "A Technical Survey of Polymer Flooding Projects," DOE report DOE/BC/10327-19, U.S. DOE, Washington, D.C., September, 1983.

Gill, D.: "Rockies Flood Projects Add to Production," *Western Oil Reporter* (Sept. 1983) 30-37.

"Mobil Budgets $54 Million for Polymers at Postle," *Enhanced Recovery Week* (Oct. 3, 1983) 1.

"Texaco to Spend $18 Million on Polymer Flood," *Enhanced Recovery Week* (Oct. 17, 1983) 1.

"Getty Begins Microemulsion Pilot at Sho-Vel-Tum," *Enhanced Recovery Week* (Oct. 17, 1983) 3.

"American Cyanamid Acquires CORT," *Enhanced Recovery Week* (Oct. 24, 1983) 3.

"Marathon to Start Wyoming Polymer Flood," *Enhanced Recovery Week* (Oct. 31, 1983) 2-3.

"No Change in Sight for EOR Economics," *Enhanced Recovery Week* (Oct. 31, 1983) 5-6.

"Petro-Lewis Sees Response from Polymer," *Enhanced Recovery Week* (Nov. 7, 1983) 2.

"Chemical Flood Gains Credited to Government Help," *Enhanced Recovery Week* (Nov. 7, 1983) 4.

"Texaco Uses Polymer with Some Success at Balko," *Enhanced Recovery Week* (Dec. 5, 1983) 6.

"Petro-Lewis Sees Polymer Response at Winnett Junction," *Enhanced Recovery Week* (Dec. 12, 1983) 2.

"Gulf Awaits Production Response at Dune Polymer Project," *Enhanced Recovery Week* (Dec. 12, 1983) 4.

"West Texas Floods Start on Polymer, May Switch to CO_2," *Enhanced Recovery Week* (Dec. 19, 1983) 3-4.

"Phillips Gets Mixed Results with Polymer," *Enhanced Recovery Week* (Dec. 26, 1983) 4.

"Union Adds Polymer at Farnsworth Field in Texas," *Enhanced Recovery Week* (Jan. 9, 1984) 1.

"Tenneco Ready to Resume Upper Valley Polymer Flood," *Enhanced Recovery Week* (Jan. 9, 1984) 4.

"Texaco Plans Two Oklahoma Polymer Floods," *Enhanced Recovery Week* (Jan. 9, 1984) 6.

"Gary Energy Injecting Polymer at South Johnson," *Enhanced Recovery Week* (Jan. 16, 1984) 2.

"Texaco Schedules Robertson Polymer Flood," *Enhanced Recovery Week* (Jan. 23, 1984) 2-3.

"Nalco Markets Biocide for Polymer Floods," *Enhanced Recovery Week* (Jan. 23, 1984) 3.

"Terra to Use Polymer at Twin Peaks," *Enhanced Recovery Week* (Jan. 30, 1984) 1.

"Texaco Foresees Big Payoff from Harris Polymers," *Enhanced Recovery Week* (Feb. 6, 1984) 3-4.

"Texaco Lets Big Polymer Contract to Cyanamid," *Enhanced Recovery Week* (Feb. 13, 1984) 1-2.

"Production Up at Sun's Hitts Lake Polymer Flood," *Enhanced Recovery Week* (Feb. 13, 1984) 2.

"Polymer Improves Production at Naval Reserve Unit," *Enhanced Recovery Week* (Feb. 20, 1984) 4.

Petzet, G.A. and Williams, B.: "Enhanced Oil Recovery Projects Moving to Field at Slower Pace," *Oil & Gas J.* (Feb. 20, 1984) 19-22.

"Belco Finishing Polymer Injection," *Enhanced Recovery Week* (March 12, 1984) 2-3.

"Davis Plans Polymer Flood at Edsel Field," *Enhanced Recovery Week* (March 19, 1984) 4.

"Marathon Plans Polymer Flood at Garland Field," *Enhanced Recovery Week* (March 26, 1984) 4.

"Arco Begins Two Wyoming Polymer Projects," *Enhanced Recovery Week* (March 26, 1984) 4.

Leonard, J.: "EOR Set to Make Significant Contribution," *Oil & Gas J.* (April 2, 1984) 83-105.

"Nebo Hemphill Caustic/Polymer Flood Under Study," *Enhanced Recovery Week* (April 9, 1984) 4.

Abdo, M.K., Chung, H.S., and Phelps, C.H.: "Field Experience With Floodwater Diversion by Complexed Biopolymers," paper SPE/DOE 12642 presented at the 1984 SPE Symposium on Enhanced Oil Recovery, Tulsa, April 15-18.

Dovan, H.T. and Hutchins, R.D.: "Development of a New Aluminum-Polymer Gel System for Permeability Adjustment," paper SPE/DOE 12541 presented at the 1984 SPE Symposium on Enhanced Oil Recovery, Tulsa, April 15-18.

Weiss, W.W. and Baldwin, R.W.: "Planning and Implementing a Large-Scale Polymer Flood," paper SPE/DOE 12637 presented at the 1984 SPE Symposium on Enhanced Oil Recovery, Tulsa, April 15-18.

"Aluminate Said to Offer Crosslinking Advantages," *Enhanced Recovery Week* (April 23, 1984) 1.

"Samedan Will Continue Polymers at Least Another Year," *Enhanced Recovery Week* (April 23, 1984) 6.

"Mobil Likes Crosslinked Biopolymer After Field Trials," *Enhanced Recovery Week* (April 30, 1984) 3.

"Cities Expects Madison Response This Summer," *Enhanced Recovery Week* (April 30, 1984) 3-4.

"Sun Sees Production Boost at Eliasville," *Enhanced Recovery Week* (April 30, 1984) 6.

"Texaco Readies Slaughter Polymer Flood," *Enhanced Recovery Week* (May 7, 1984) 3.

"Petrofina Unsure of Polymer Response at Westbrook," *Enhanced Recovery Week* (May 7, 1984) 4.

"Anderson Resumes Polymer at Sharp Field," *Enhanced Recovery Week* (May 7, 1984) 4.

"Hunt Finishes Polymer Injection at East Texas," *Enhanced Recovery Week* (May 14, 1984) 3-4.

"Tesoro Producing Incremental Oil at Elaine," *Enhanced Recovery Week* (May 14, 1984) 6.

Mack, J.C. and Duvall, M.L.: "Performance and Economics of Minnelusa Polymer Floods," paper SPE 12929 presented at the 1984 SPE Rocky Mountain Regional Meeting, Casper, May 21-23.

Doll, T.E.: "Polymer Mini-Injectivity Test: Shannon Reservoir, Naval Petroleum Reserve No. 3, Natrona County, WY," paper SPE 12925 presented at the 1984 SPE Rocky Mountain Regional Meeting, Casper, May 21-23.

"Grace Suspends Polymer Injection at High Five," *Enhanced Recovery Week* (May 21, 1984) 2-3.

"Burbank Crosslinking Expected to Yield 8% More Oil," *Enhanced Recovery Week* (May 21, 1984) 7-8.

Bailey, R.E. and Curtis, L.B.: *National Petroleum Council* (June 1984) D-14-16.

Burkholder, L.A., Carruthers, M.S., and Rashan, J.M.: "Xanthan Gels for Injection Profile Control," paper presented at the Fifth Annual Advances in Petroleum Recovery & Upgrading Technology Conference, Calgary, June 14-15, 1984.

"Polymers Are Economic in Minnelusa Formation," *Enhanced Recovery Week* (June 25, 1984) 1-2.

Mack, J.C. and Warren, J.: "Performance and Operation of a Crosslinked Polymer Flood at Sage Spring Creek Unit A, Natrona County, Wyoming," *JPT* (July 1984) 1145-56.

"Bass Uses Chromate Crosslinker at Slaughter," *Enhanced Recovery Week* (July 2, 1984) 4-5.

"Exxon Aims Crosslinked Polymer at Webster Field," *Enhanced Recovery Week* (July 16, 1984) 3.

"Marathon Begins $50-Million Polymer Flood," *Enhanced Recovery Week* (July 16, 1984) 3-4.

"Samedan Plans to Resume Robertson Polymer," *Enhanced Recovery Week* (July 16, 1984) 5.

"NCRA Adding More Injectors at Stewart Ranch," *Enhanced Recovery Week* (July 16, 1984) 5-6.

"Texaco Sets EOR Project in Sho-Vel-Tum," *Oil & Gas J.* (July 23, 1984) 20.

"Clay Swelling Hurts Gulf's Offshore Chemical Floods," *Enhanced Recovery Week* (July 23, 1984) 1-2.

"Petrofina Plans Crosslinking for South Cowden," *Enhanced Recovery Week* (July 23, 1984) 5.

"Marathon Plans Wyoming Polymer Flood," *Enhanced Recovery Week* (July 30, 1984) 3.

"Production Goes Up at Mitchell's Jacksboro Polymer," *Enhanced Recovery Week* (July 30, 1984) 6.

"Union Injects Crosslinked Polymer at Orcutt Field," *Enhanced Recovery Week* (Aug. 13, 1984) 2.

"Inexco Expects 7.7% Incremental Recovery from Polymer," *Enhanced Recovery Week* (Aug. 27, 1984) 2.

"Conoco Plans Wyoming Polymer Flood," *Enhanced Recovery Week* (Aug. 27, 1984) 5.

"With No Polymer Response, Petrofina Considers CO_2 at Garza," *Enhanced Recovery Week* (Aug. 27, 1984) 6.

"Exxon Uses Crosslinked Polymer at Loudon Field," *Enhanced Recovery Week* (Sept. 3, 1984) 1.

"Marathon Official Discusses Polymer Flood Design," *Enhanced Recovery Week* (Sept. 3, 1984) 5.

"Chemical Companies Refine Polymer, Alkaline Techniques," *Enhanced Recovery Week* (Sept. 3, 1984) 5-6.

"Corsicana to Expand Polymer Flooding at Corsicana Shallow Field," *Enhanced Recovery Week* (Sept. 10, 1984) 3-4.

Greaves, B.L., Marshall, R.N., and Thompson, J.H.: "Hitts Lake Unit Polymer Project," paper SPE 13123 presented at the 1984 SPE Annual Technical Conference and Exhibition, Houston, Sept. 16-19.

"New Technology Would Boost Chemical EOR," *Enhanced Recovery Week* (Oct. 1, 1984) 1,4-5.

"Sun Gets Good Results with Polymer Through Careful Planning," *Enhanced Recovery Week* (Oct. 1, 1984) 5-6.

"Marathon Plans New Oregon Basin Polymer Flood," *Enhanced Recovery Week* (Oct. 8, 1984) 5-6.

"Conoco Decides Against Polymer Flood in Frannie Field," *Enhanced Recovery Week* (Oct. 22, 1984) 4-5.

"Arco Injects Polymer at Two Wyoming Fields," *Enhanced Recovery Week* (Oct. 22, 1984) 5-6.

"Texaco Extends Life of Cogdell Field with Polymers," *Enhanced Recovery Week* (Nov. 5, 1984) 1-2.

"Gary-Williams Injects Crosslinked Polymer at Bell Creek," *Enhanced Recovery Week* (Nov. 12, 1984) 5-6.

"Shell Improves Sholem Alechem Profile with Biopolymer," *Enhanced Recovery Week* (Dec. 10, 1984) 2-3.

"Polymer Flood at NPR-3 Draws to a Close," *Enhanced Recovery Week* (Dec. 24, 1984) 2-3.

Putz, A.: "Micellar and Polymer Pilot Floods in the Chateaurenard Field," (1984) 215-23.

"Dome to Convert Cessford Basil Colorado to Alkaline/Polymer," *Enhanced Recovery Week* (Jan. 7, 1985) 1-2.

"Texaco Completes Polymer Injection at Robertson," *Enhanced Recovery Week* (Feb. 4, 1985) 2-3.

"Monsanto Injects Polymer at Diamond M Field," *Enhanced Recovery Week* (Feb. 4, 1985) 3.

"Texaco Begins Injecting Polymer at Jordan Field," *Enhanced Recovery Week* (Feb. 4, 1985) 5.

"Monsanto Adds Diamond M Polymer Injectors," *Enhanced Recovery Week* (Feb. 18, 1985) 5.

"Coastal Gives Harris Wells Another Shot of Polymer," *Enhanced Recovery Week* (Feb. 18, 1985) 5-6.

"Bass Continues Polymer Flood, Considers Profile Modification," *Enhanced Recovery Week* (Feb. 25, 1985) 3-4.

"Ames to Expand Fiddler Creek Polymer Flood," *Enhanced Recovery Week* (March 4, 1985) 1.

"Texaco Slows Production Decline at Naval Reserve Unit," *Enhanced Recovery Week* (March 4, 1985) 2-3.

"Survey Shows Results, Potential of Polymers in Kansas," *Enhanced Recovery Week* (March 11, 1985) 3.

"Terra Begins Polymer Flood at Twin Peaks," *Enhanced Recovery Week* (March 11, 1985) 4.

"Davis Tries to Reduce Water/Oil Ratio with More Polymer," *Enhanced Recovery Week* (March 11, 1985) 4-5.

"Early Kansas Polymer Flood Indicates Potential," *Enhanced Recovery Week* (March 25, 1985) 4-5.

Shuler, P.J., Kuehne, D.L., Uhl, J.T., and Walkup, G.W., Jr.: "Improving Polymer Injectivity at West Coyote Field, California," paper SPE 13603 presented at the 1985 SPE California Regional Meeting, Bakersfield, March 27-29.

"Chemical Flooding Field Projects," U.S. DOE, Washington, D.C. (April 1985) 9-11, 27-30.

Weiss, W.W. and Baldwin, R.W.: "Planning and Implementing a Large-Scale Polymer Flood," *JPT* (April 1985) 720-730.

Dalrymple, D., Sutton, D., and Creel, P.: "Conformance Control in Oil Recovery," Halliburton Services report presented to Southwest Petroleum Short Course Texas Tech University, Lubbock, TX, April 1985.

Burkholder, L.: "Xanthan Gel System Effective for Profile Modification," *Oil & Gas J.* (April 25, 1985) 68-69.

"Texaco Gets High Recovery from Chemicals at Hankensbuettel," *Enhanced Recovery Week* (April 22, 1985) 1-2.

"Mobil Begins Polymer Flood in Salt Creek Field," *Enhanced Recovery Week* (April 22, 1985) 1.

"Shell Injects Crosslinked Polymer at Big Mineral Creek Field," *Enhanced Recovery Week* (May 6, 1985) 3.

"Harper Starts Polymer Pilot in Hot N.D. Reservoir," *Enhanced Recovery Week* (May 6, 1985) 3-4.

"Amoco Starts Large Polymer Flood in East Texas Field," *Enhanced Recovery Week* (May 13, 1985) 3.

"India Starts Polymer Pilot, Plans More," *Enhanced Recovery Week* (May 13, 1985) 5.

Dowell Schlumberger: "Channel Block Application, Phosphoria Unit, Big Horn Basin, Wyoming," *Proc.*, Enhanced Recovery Week's Chemical EOR: Searching for the Right Solution Seminar, Denver, (May 13-14, 1985).

Schurz, G.: "Present Status of Polymer Applications for EOR," *Proc.*, Enhanced Recovery Week's Chemical EOR: Searching for the Right Solution, Denver, (May 13-14, 1985).

Weiss, B.: "Eliasville, A Successful Large-Scale Polymer Flood," *Proc.*, Enhanced Recovery Week's Chemical EOR: Searching for the Right Solution, Denver, (May 13-14, 1985).

"Chemical EOR Methods Seen Converging," *Enhanced Recovery Week* (May 20, 1985) 1-2.

"Polymer Flooding Seen as Stronger than Projected," *Enhanced Recovery Week* (May 20, 1985) 2-3.

"Aberford Starts Rapdan Polymer Pilot," *Enhanced Recovery Week* (May 27, 1985) 5.

"Phillips Develops Polymer for Hot, Hard-Water Reservoirs," *Enhanced Recovery Week* (May 27, 1985) 5-6.

"Independents Told Polymer is Their Best Bet for EOR," *Enhanced Recovery Week* (June 3, 1985) 4-5.

"Enhanced-Oil-Recovery (EOR) Projects May Benefit from a New Biopolymer," *Chemical Engineering* (June 10, 1985) 10.

"Union Re-Certifies Howard-Glasscock Polymer Flood," *Enhanced Recovery Week* (June 10, 1985) 2.

"Goldking Chooses New Biopolymer for Hot, Salty Slocum Field," *Enhanced Recovery Week* (June 10, 1985) 2-3.

"Mitchell Plans Secondary Polymer Flood at Alba," *Enhanced Recovery Week* (June 10, 1985) 3.

"Sohio Injects Biopolymer at Northwest Ara Field," *Enhanced Recovery Week* (June 10, 1985) 5-6.

"Lario Changes from Cationic to Anionic Polymer at Lad Field," *Enhanced Recovery Week* (June 17, 1985) 3.

"Birdwell, Pleased with Polymer Flood, Plans More," *Enhanced Recovery Week* (June 17, 1985) 2.

"Polymer Flood Planned for Long Lake Field," *Enhanced Recovery Week* (June 17, 1985) 2-3.

"Cox & Cox to Complete Polymer Injection at Carthage," *Enhanced Recovery Week* (July 1, 1985) 5.

"Gulf Reverses McElroy Production Decline with Polymers," *Enhanced Recovery Week* (July 15, 1985) 3-4.

"Arco Plans Crosslinked Polymer for Hamilton Dome," *Enhanced Recovery Week* (July 15, 1985) 5-6.

"Exeter Starts Biopolymer Pilot at Dry Creek Field," *Enhanced Recovery Week* (Aug. 5, 1985) 3-4.

"Harper Starts Montana Polymer Flood at Kincheloe Sumatra," *Enhanced Recovery Week* (Aug. 12, 1985) 3.

"Chevron to Start Miscible Floods at Pembina, Bigoray," *Enhanced Recovery Week* (Aug. 19, 1985) 3-4.

"EOR Update - More Polymer is Better," *Enhanced Recovery Week* (Aug. 19, 1985) 4.

"Marathon Plans Polymer Flood at Grass Creek Field," *Enhanced Recovery Week* (Aug. 26, 1985) 1-2.

"Petroleum Inc. Prepares Minnelusa Polymer Flood at Kiehl Unit," *Enhanced Recovery Week* (Sept. 9, 1985) 2.

"Biopolymers' Slow Trek to the Oil Fields," *Chemical Week* (Sept. 11, 1985) 49-51.

"Union Injects Polymer at Smyer Field in West Texas," *Enhanced Recovery Week* (Sept. 16, 1985) 1-2.

Chang, P.W., Goldman, I.M., and Stingley, K.J.: "Laboratory Studies and Field Evaluation of a New Gelant for High-Temperature Profile Modification," paper SPE 15235 presented at the 1985 SPE Annual Technical Conference and Exhibition, Las Vegas, Sept. 22-25.

Grooms, G.E. and Schulte, R.K.: "Contributions of Observation Well Logging to the Evaluation of Polymer-Augmented Waterflood Pilots," paper SPE 14396 presented at the 1985 SPE Annual Technical Conference and Exhibition, Las Vegas, Sept. 22-25.

Basio, J., Lomer, J.R., and Putz, A.: "Injection of Chemicals for Enhanced Oil Recovery: A Technical and Economical Viewpoint Based on Practical Experience," *Proc.*, Indonesian Petroleum Association Fourteenth Annual Convention (Oct. 1985) 199-212.

Bleakley, W.B.: "Yates Field has Long History, Bright Future," *Pet. Eng. Intl.* (Oct. 1985) 21-24.

"Conoco Plugs Frannie Thief with Polymer," *Enhanced Recovery Week* (Oct. 7, 1985) 1-2.

"Inexco Suspends South Hearth Polymer Flood," *Enhanced Recovery Week* (Oct. 7, 1985) 2-3.

"Chevron Treats More Wonsits Wells with Polymer," *Enhanced Recovery Week* (Oct. 14, 1985) 2-3.

"K&R Begins Polymer Flood at Slaughter Field," *Enhanced Recovery Week* (Oct. 14, 1985) 3.

"EOR Projects Show Promise," *Pet. Eng. Intl.* (Nov. 1985) 21.

"Sun's Careful Planning Sparks High Recovery," *Pet. Eng. Intl.* (Nov. 1985) 24-28.

"EOR Update - Marathon Polymer Faces the Fracs," *Enhanced Recovery Week* (Nov. 4, 1985) 4.

"Anadarko to Start Injecting Polymer at Bracken Field," *Enhanced Recovery Week* (Nov. 11, 1985) 1-2.

"New Pfizer Gelant Works at Nelson Minnelusa," *Enhanced Recovery Week* (Nov. 11, 1985) 2.

"Texaco Suspends Jo-Mill Polymer Flood Plans," *Enhanced Recovery Week* (Nov. 11, 1985) 4-5.

"Texas Improves Profiles with Polymer at Sumatra Field," *Enhanced Recovery Week* (Nov. 18, 1985) 1.

"Polymer Flood Boosts Reagan Recovery at Sleepy Hollow," *Enhanced Recovery Week* (Nov. 18, 1985) 2.

"Thrash Starts Polymer, CO_2 Pilots in South Texas," *Enhanced Recovery Week* (Nov. 25, 1985) 1.

"Cities Tries Polymer on Hot, Salty Beverly Hills Field," *Enhanced Recovery Week* (Nov. 25, 1985) 2.

"W.E.M. Joint Ventures Starts Polymer Flood Right Away," *Enhanced Recovery Week* (Nov. 25, 1985) 3.

"Study Shows Gel Treatments Profitable Even at Low Oil Price," *Pfizer Oil Field Focus* (Dec. 1985) 1,4.

"High Temperature Gelants Reprints Available of Pfizer/ARCO SPE Paper," *Pfizer Oil Field Focus* (Dec. 1985) 2.

"Profile Modification Treatment Mobil Oil Corporation," *Pfizer Oil Field Focus* (Dec. 1985) 3.

"Townsend Calms Clays for Fiddler Creek Polymer Flood," *Enhanced Recovery Week* (Dec. 2, 1985) 3-4.

"State Denies Permit for Ohio's Second EOR Project," *Enhanced Recovery Week* (Dec. 9, 1985) 1, 4.

"Arco Gets Kick Out of East Texas with Biopolymer," *Enhanced Recovery Week* (Dec. 16, 1985) 3.

"Crosslinked Polymer Beats Micellar Economics at Bell Creek," *Enhanced Recovery Week* (Dec. 23, 1985) 3-4.

Dauben, D.L.: "Improved Waterflooding Techniques," 293-318.

"Toco Begins One-Well Polymer Pilot at Clareton Field," *Enhanced Recovery Week* (Jan. 6, 1986) 2.

"Tenneco Awaits Response from Elrick Polymer Treatments," *Enhanced Recovery Week* (Jan. 6, 1986) 3-4.

"New CO_2 and Polymer Projects Dot Texas in 1985," *Enhanced Recovery Week* (Jan. 6, 1986) 6-7.

"CO_2 Stalled in Rockies While Polymer Flooding Surged," *Enhanced Recovery Week* (Jan. 6, 1986) 7-8.

"Polymer Levels Production Decline at West Dollarhide," *Enhanced Recovery Week* (Jan. 13, 1986) 4.

"Arco Awaits Kick from Camrick Polymer," *Enhanced Recovery Week* (Jan. 20, 1986) 3.

"Union to Treat Tight, Heterogeneous Cut Bank with Polymer," *Enhanced Recovery Week* (Jan. 27, 1986) 3-4.

"Chevron to Treat More C-Bar Wells with Polymer," *Enhanced Recovery Week* (Jan. 27, 1986) 5.

"EOR for U.K. North Sea Subject to Two Studies," *Oil & Gas J.* (Jan. 27, 1986) 59.

"EOR Update - Polymer Doubles Electra Oil Rate," *Enhanced Recovery Week* (Feb. 3, 1986) 5.

"Aberford Begins Rapdan Polymer Flood This Month," *Enhanced Recovery Week* (Feb. 10, 1986) 2-3.

"Phillips Licks CO_2 Channeling with Polymer at Lick Creek," *Enhanced Recovery Week* (Feb. 17, 1986) 2-3.

"Texas Draws Plans for Three More EOR Projects," *Oil & Gas J.* (Feb. 24, 1986) 34-35.

"American Cyanamid Seeks Buyers for EOR Service Group," *Enhanced Recovery Week* (March 3, 1986) 1-2.

"Salt Creek: Polymer-Augmented Waterflood Expansion Permitted," *Energy Regulation Report*, TX State House Reporter, Inc. (March 4, 1986) 10-11.

"Mabee: Polymer Augmented Waterflood Approved," *Energy Regulation Reporter*, TX State House Reporter, Inc., Vol. 53, No. 225 (March 6, 1986) 2.

"Exxon Begins Polymer Project at Webster Field," *Enhanced Recovery Week* (March 10, 1986) 1-2.

"Oregon Basin Field Responds to Marathon Polymer Flood," *Enhanced Recovery Week* (March 17, 1986) 1.

"Powder River Plans Big Mac Polymer Flood," *Enhanced Recovery Week* (March 17, 1986) 2-3.

"EOR Update - Chevron Injects Polymer at Homer," *Enhanced Recovery Week* (March 17, 1986) 4.

Demin, W. and Jiali, T.: "Production Technology of Daqing Oil-Field During its High Water-Cut Stage," paper SPE 14847 presented at the 1986 SPE International Meeting on Petroleum Engineering, Beijing, China, March 17-20.

Surkalo, H., Pitts, M.J., Sloat, B., and Larsen, D.: "Polyacrylamide Vertical Conformance Process Improved Sweep Efficiency and Oil Recovery in the OK Field," paper SPE 14115 presented at the 1986 SPE International Meeting on Petroleum Engineering, Beijing, China, March 17-20.

Zengxiong, T., Heng, L., and Chengzao, J.: "Technical Measures for Improving Oilfield Development by Waterflooding in a Large Multi-Layered Heterogeneous Sandstone Reservoir," paper SPE 14860 presented at the 1986 SPE International Meeting on Petroleum Engineering, Beijing, China, March 17-20.

Zornes, D.R., Cornelius, A.J., and Long, H.Q.: "An Overview and Evaluation of the North Burbank Unit Block a Polymer Flood Project, Osage County, Oklahoma," paper SPE 14113 presented at the 1986 SPE International Meeting on Petroleum Engineering, Beijing, China, March 17-20.

"China Treats Renqiu Producing Wells with Polymer," *Enhanced Recovery Week* (March 31, 1986) 2-3.

"Brehm to Start North Deaver Polymer Flood," *Enhanced Recovery Week* (March 31, 1986) 3.

"Floperm 325 High Temperature Gelant System Now Commercially Available," *Pfizer Oil Field Focus* (Spring 1986) 1-2.

"Profile Modification Treatments Still Affordable," *Pfizer Oil Field Focus* (Spring 1986) 4.

Dailey, J.J. and Kochelek, J.T.: "Advanced EOR Technologies Raise Profit Potential," *Pet. Eng. Intl.* (April 1986) 29-39.

"Wimberly (Gunsight Unit): Polymer-Augmented Waterflood Expansion Permitted," *Energy Regulation Report,* TX State House Reporter Inc., Vol. 54, No. 3 (April 3, 1986) 1.

"Randado: Polymer-Augmented Waterflood Project Approved," *Energy Regulation Report,* TX State House Reporter Inc., Vol. 54, No. 3 (April 3, 1986) 2.

"China Begins Testing Giant Daqing's EOR Potential," *Enhanced Recovery Week* (April 7, 1986) 1-2.

"More Enhanced Oil Recovery Work Set or Under Way in Texas," *Oil & Gas J.* (April 14, 1986) 52-54.

"Phillips Finds Burbank Polymer Flood Successful But Slow," *Enhanced Recovery Week* (April 14, 1986) 2-3.

Leonard, J.: "Increased Rate of EOR Brightens Outlook," *Oil & Gas J.* (April 14, 1986) 71-101.

"Steam, Polymer Trials Begin at China's Shengli Field," *Enhanced Recovery Week* (April 21, 1986) 3.

"Polymer Kicks Byron Production Despite Cycling," *Enhanced Recovery Week* (April 21, 1986) 3-4.

"EOR Update - Phillips Eyes Polymer for CO_2 Flood," *Enhanced Recovery Week* (April 21, 1986) 6.

DeHekker, T.G., Bowzer, J.L., Coleman, R.V., and Bartos, W.B.: "A Progress Report on Polymer-Augmented Waterflooding in Wyoming's North Oregon Basin and Byron Fields," paper SPE/DOE 14953 presented at the 1986 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 20-23.

Hoelscher, L.E., Tan, H.C., and Fullbright, B.M.: "Field-Scale Polymer Flooding at Remote Site Presents Special Challenges," paper SPE/DOE 14952 presented at the 1986 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 20-23.

Woods, P., Schramko, K., Turner, D., Dalrymple, D., and Vinson, E.: "In-Situ Polymerization Controls CO_2/Water Channeling at Lick Creek," paper SPE/DOE 15948 presented at the 1986 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 20-23.

"Dow Gets on Site Polymer Rights in N. America," *Oil & Gas J.* (April 21, 1986) 24.

"Terra Polymer Flood Succeeds at Remote Twin Peaks Field," *Enhanced Recovery Week* (April 28, 1986) 3.

"You are New EOR Target....," *Enhanced Recovery Week* (April 28, 1986) 1-4.

"EOR Update - Dow to Market Marathon Polymer Process," *Enhanced Recovery Week* (April 28, 1986) 5-6.

Bleakley, W.B.: "How Chemicals Improve Ultimate Recovery," *Pet. Eng. Intl.* (May 1986) 53-58.

"Chinook's Rozet Polymer Flood Nearly Triples Production," *Enhanced Recovery Week* (May 12, 1986) 1-2.

"EOR Update - New Polymer Service Offers Quick Fix," *Enhanced Recovery Week* (May 12, 1986) 5.

"EOR Update - Teapot Dome Operator Gets Contract," *Enhanced Recovery Week* (May 19, 1986) 4.

Doll, T.E. and Hanson, M.T.: "Performance and Operation of the Hamm Minnelusa Sand Unit, Campbell County, Wyoming," paper SPE 15162 presented at the 1986 SPE Rocky Mountain Regional Meeting, Billings, MT, May 19-21.

"Home Hikes Hamm Minnelusa Production with Polymer," *Enhanced Recovery Week* (May 26, 1986) 1-2.

"Producing-Well Polymer Shuts Off Wagonhound Water," *Enhanced Recovery Week* (June 2, 1986) 2.

"McElroy Polymer Project Falls Below Texaco's Expectations," *Enhanced Recovery Week* (June 2, 1986) 3-4.

"Teapot Dome Pilots Underscore Need for Geologic Study," *Enhanced Recovery Week* (June 2, 1986) 4-5.

"EOR Update - Blue Buttes Polymer Must Wait," *Enhanced Recovery Week* (June 9, 1986) 5.

"Gulf Coast Field Shows Response to Polymer Program," *Oil & Gas J.* (June 9, 1986) 22.

"Amoco Levels East Texas Decline with Polymer," *Enhanced Recovery Week* (June 23, 1986) 2-3.

"Keplinger Finds Why Polymer Didn't Aid Storms Pool," *Enhanced Recovery Week* (June 30, 1986) 2-3.

"Petromac Trims Operating Costs at Slocum, Rankin," *Enhanced Recovery Week* (June 30, 1986) 3.

"EOR Update - Exxon Shelves I.A.B. Polymer Plans," *Enhanced Recovery Week* (June 30, 1986) 5.

"Staub Stops One Polymer Flood, Keeping Another Alive," *Enhanced Recovery Week* (July 14, 1986) 3-4.

"OK Polymer Treatments Beat Universal's Projections," *Enhanced Recovery Week* (July 14, 1986) 4-5.

"Cox Stops Carthage 1 Production Decline with Polymer," *Enhanced Recovery Week* (July 21, 1986) 3.

"Birdwell Tries Three Biopolymers at Archer Ranch," *Enhanced Recovery Week* (July 28, 1986) 3.

"Quintana Needs $10/bbl Oil for Victor Polymer Flood," *Enhanced Recovery Week* (July 28, 1986) 3-4.

"Biopolymer Fails to Boost Oil Rate at Northwest Ara," *Enhanced Recovery Week* (Aug. 4, 1986) 3.

"EOR Update - Sohio Puts Polymer Floods on Hold," *Enhanced Recovery Week* (Aug. 4, 1986) 6.

"Midcon Shuts Down Awry Polymer Flood at Rocky Ridge," *Enhanced Recovery Week* (Aug. 11, 1986) 3-4.

"Anadarko Begins Delayed Polymer Flood at Bracken," *Enhanced Recovery Week* (Aug. 18, 1986) 2-3.

"Enron Begins Alkaline-Polymer Pilot at Big Piney," *Enhanced Recovery Week* (Aug. 18, 1986) 4-5.

"EOR Update - Light-Oil EOR Projects Advance," *Enhanced Recovery Week* (Aug. 18, 1986) 5.

"CNG Evaluates Tricky SW Davis Polymer Flood," *Enhanced Recovery Week* (Aug. 25, 1986) 2-3.

"EOR Update - Mobil Texas Update," *Enhanced Recovery Week* (Sept. 1, 1986) 6.

Hawk, W.A. and Cooke, R.W.: "A Review of the Currently Available Technologies in the Area of Oilfield Crosslinked Polymer Applications: Case Histories," *Proc.,* ACS Meeting, Anaheim, CA (Sept. 1986) 763-69.

Cooke, R.W. and Hawk, W.A.: "Crosslinking of Polymers in Oilfield Conformance Control Applications: Advantages and Disadvantages of Natural vs. Synthetic Polymers," *Proc.*, ACS Meeting, Anaheim, CA (Sept. 1986) 778-83.

"Sun Gives Green Light to Stephens County Polymer Flood," *Enhanced Recovery Week* (Sept. 8, 1986) 1-2.

"Mitchell Plans Polymer Flood for Boonsville South Field," *Enhanced Recovery Week* (Sept. 8, 1986) 2-3.

"Chevron Canada Plans Polymer Flood for Taber Field," *Enhanced Recovery Week* (Sept. 15, 1986) 1-2.

"Kiehl Waterflood Surprises Petroleum Inc., Polymer Delayed," *Enhanced Recovery Week* (Sept. 15, 1986) 3.

"Polymer Flood Calms Clays at Triangle U," *Enhanced Recovery Week* (Sept. 15, 1986) 3-4.

"EOR Update - Thrash Starts Polymer, Holds CO_2," *Enhanced Recovery Week* (Sept. 22, 1986) 5.

"Remington Revives New Albany with Polymer Plugs," *Enhanced Recovery Week* (Sept. 29, 1986) 2-3.

"Graham Awaits $17/bbl Oil to Continue Hamilton Dome Polymer," *Enhanced Recovery Week* (Sept. 29, 1986) 4-5.

Wagner, O.R., Weisrock, W.P., and Patel, C.: "Field Application of Lignosulfonate Gels to Reduce Channeling, South Swan Hills Miscible Unit, Alberta, Canada," paper SPE 15547 presented at the 1986 SPE Annual Technical Conference and Exhibition, New Orleans, Oct. 5-8.

"India to Launch Cambay Basin EOR with Polymer Flood," *Enhanced Recovery Week* (Oct. 6, 1986) 1-2.

"Texaco Polymer Flood Raises Franklin Oil Rate," *Enhanced Recovery Week* (Oct. 6, 1986) 1.

"Unocal Shuts Down Polymer Flood in Michigan," *Enhanced Recovery Week* (Oct. 6, 1986) 3.

"Quentin Little Withholds Polymer, Continues N_2 at Sho-Vel-Tum," *Enhanced Recovery Week* (Oct. 6, 1986) 5.

"EOR Update - Conoco Considers San Miguelito Polymer," *Enhanced Recovery Week* (Oct. 6, 1986) 5.

"Mobil Increases Salt Creek Polymer Injection Rate," *Enhanced Recovery Week* (Oct. 13, 1986) 1-2.

"EOR Service/Supply Companies Hold Breath, Turn Blue," *Enhanced Recovery Week* (Oct. 13, 1986) 1,6.

Matthews, B.A. and Butner, L.O.: "Kansas Polymer Floods Show Potential," *Halliburton Services,* Duncan, OK (Oct. 1986).

"Obscure Gel Plugs Thief Zone in Judy Creek's Hot Brine," *Enhanced Recovery Week* (Oct. 20, 1986) 2-3.

"Corco Closes Shop, Hands Keys to Employees," *Enhanced Recovery Week* (Oct. 27, 1986) 2-3.

"Amoco Taking Second Look at Lignosulfonate Polymer," *Enhanced Recovery Week* (Nov. 10, 1986) 4.

"Apache Considers Modification of Dry Creek Polymer Pilot," *Enhanced Recovery Week* (Nov. 17, 1986) 2-3.

"EOR Update - Polymer Boosts Homer Production," *Enhanced Recovery Week* (Nov. 17, 1986) 5.

"Occidental Tests Polymer at Rodney Field in Ontario," *Enhanced Recovery Week* (Nov. 24, 1986) 1-2.

"Chain Injects Second Polymer Slug at Warner Ranch," *Enhanced Recovery Week* (Nov. 24, 1986) 3.

"Chevron Goes From Polymer to CO_2 Test at North Ward Estes," *Enhanced Recovery Week* (Dec. 8, 1986) 1.

"Unocal Shuts Down Polymer-Plugged Coalinga Nose Pilot," *Enhanced Recovery Week* (Dec. 8, 1986) 3-4.

Johnson, H.R., Biglarbigi, K., Schmidt, L., Ray, R.M., and Kyser, S.C.: "Profile of a Giant: Rising Again," *Oil & Gas J.* (Dec. 15, 1986) 43-47.

"Apache to Start Polymer Flood at Lone Cedar Field," *Enhanced Recovery Week* (Jan. 5, 1987) 1,6.

"Operators Keep Faith in Rocky Mountain Polymer Floods," *Enhanced Recovery Week* (Jan. 5, 1987) 4-5.

"Conoco's Frannie Field Polymer Flood Survives," *Enhanced Recovery Week* (Jan. 12, 1987) 2-3.

Johnson, H.R., Biglarbigi, K., Schmidt, L., Ray, R.M., and Kyser, S.C.: "Reservoir/Fluid Characteristics Favor Enormous Long-Term Recovery Potential," *Oil & Gas J.* (Jan. 19, 1987) 38-43.

"Aberford Levels Production Decline with Polymer at Rapdan," *Enhanced Recovery Week* (Jan. 19, 1987) 2-3.

"EOR Update - Petroleum Inc. Plans Flood in Advance," *Enhanced Recovery Week* (Jan. 26, 1987) 4.

"EOR Update - Exxon Holds Webster Drilling," *Enhanced Recovery Week* (Jan. 26, 1987) 4.

"Santa Fe Plans Polymer Flood at Candy Draw," *Enhanced Recovery Week* (Feb. 16, 1987) 1-2.

"EOR Update - Brehm Gets N. Deaver Polymer Going," *Enhanced Recovery Week* (Feb. 16, 1987) 3.

"EOR Update - Union Pushes Cut Bank Polymer to '88," *Enhanced Recovery Week* (Feb. 16, 1987) 4.

"EOR Update - TOCO Unsure of Polymer at Mush Creek," *Enhanced Recovery Week* (Feb. 23, 1987) 4.

"Russell Plugs Savonburg Fractures with Polymer," *Enhanced Recovery Week* (March 9, 1987) 4.

"Dowell Develops Non-Polymer Gel System to Plug Thief Zones," *Enhanced Recovery Week* (March 16, 1987) 2.

"Polymer Helps El Dorado Recover Oil from Mississippian Formation," *Enhanced Recovery Week* (March 30, 1987) 2-3.

"Russell Petroleum Plans Two Polymer Floods at Colony North," *Enhanced Recovery Week* (April 13, 1987) 1-2.

Hanlon, D.J., Fulton, S., and Beny, M.: "New Chemical and Mechanical Technology for Injection Profile Control," *Proc.,* 34th Annu. Southwestern Petrol. Short Course Ass. *Et Al.* Mtg., Lubbock, TX (April 22-23, 1987) 163-68.

"Dome Plans Chemical Flood Instead of CO_2 at Grand Forks," *Enhanced Recovery Week* (May 4, 1987) 1-2.

"Mitchell Adds Well to Successful Jacksboro South Polymer Flood," *Enhanced Recovery Week* (May 4, 1987) 2-3.

Collier, T.S.: "Injection Monitoring and Control Dollarhide Clearfork AB Unit," *Proc.,* U.S. Environ. Protect. Agency *et al.* Subsurface Injection of Oilfield Brines Int. Symp., New Orleans (May 4-6, 1987) 63-78.

"Beren Finds Polymer for Gra-Rooks Field," *Enhanced Recovery Week* (June 8, 1987) 1-2.

"EOR Update - Pfizer Unveils New Polymer Line," *Enhanced Recovery Week* (June 8, 1987) 4.

"Dome Switches to Polymer at David Lloyd," *Enhanced Recovery Week* (June 15, 1987) 1,3.

"Remington to Use DOE Funds at New Albany Flood," *Enhanced Recovery Week* (June 22, 1987) 1,3.

"Unocal Injecting Polymer Offshore at Dos Cuadras," *Enhanced Recovery Week* (June 29, 1987) 1.

"EOR Update - Tiorco to Market Services in Egypt," *Enhanced Recovery Week* (June 29, 1987) 4.

"Apache Starts Two-Zone Chemical Flood in Wyoming," *Enhanced Recovery Week* (July 27, 1987) 1,3.

Campbell, T.A. and Bachman, R.C.: "Polymer-Augmented Waterflood in the Rapdan Upper Shaunavon Unit," *J. Cdn. Pet. Tech.* (July-Aug. 1987) 67-73.

"Phillips Keeping Burbank Polymer on Hold," *Enhanced Recovery Week* (Aug. 3, 1987) 2.

"Sun Gets Response to Stephens County Polymer," *Enhanced Recovery Week* (Aug. 17, 1987) 1-2.

Schoeling, L. and Green, D.W.: "Polymers Find Use in Central Kansas," *American Oil & Gas Reporter* (Aug. 1987) 53-55.

"BP Canada Planning Polymer Flood at Chauvin South," *Enhanced Recovery Week* (Sept. 7, 1987) 1-2.

"Polymer-Producing Microbes Tested in Alberta," *Enhanced Recovery Week* (Sept. 7, 1987) 2-3.

Clifford, P.J. and Duthie, A.: "Analysis of a Polymer Well Treatment in the Beatrice Field," paper SPE 16500 presented at the Offshore Europe '87, Abardeen, Sept. 8-77.

"EOR Update - Mitchell Evaluates Boonsville Polymer," *Enhanced Recovery Week* (Sept. 14, 1987) 3-4.

"Phillips' Vacuum Polymer Flood Matches Simulation," *Enhanced Recovery Week* (Sept. 28, 1987) 2-3.

Hovendick, M.D.: "Development and Results of the Hale-Mable Leases' Co-Operative Polymer EOR Injection Project, Vacuum (Grayburg-San Andres) Field, Lea County, New Mexico," paper SPE 16722 presented at the 1987 SPE Annual Technical Conference and Exhibition, Dallas, Sept. 27-30.

Singh, P.K., Agarwal, R.G., and Krase, L.D.: "Systematic Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure," paper SPE 16798 presented at the 1987 SPE Annual Technical Conference and Exhibition, Dallas, Sept. 27-30.

Campbell, T.A. and McKechnie, R.B.: "Progress Report on the Rapdan Polymer Flood," *Proc.*, Technical Meeting of South Saskatchewan Section, Petroleum Society of CIM, Regina (Oct. 6-8, 1987).

"Slawson Plans Polymer Flood for Lily Minnelusa," *Enhanced Recovery Week* (Oct. 19, 1987) 1,3.

"Germans Get Response from Biopolymer Pilot," *Enhanced Recovery Week* (Nov. 2, 1987) 3.

"Polymer Nears Expectations at Salty German Fields," *Enhanced Recovery Week* (Dec. 7, 1987) 2.

"EOR Update - Victor Unit Responds Quickly to Polymer," *Enhanced Recovery Week* (Dec. 7, 1987) 4.

Needham, R.B. and Doe, P.H.: "Polymer Flooding Review," *JPT* (Dec. 1987) 1503-07.

"Two More Operators Using Alkaline to Calm Clays in Wyo.," *Enhanced Recovery Week* (Dec. 14, 1987) 1,3.

"Elf's Polymer Flood Passes Peak at Chateaurenard," *Enhanced Recovery Week* (Dec. 21, 1987) 2.

"New Projects Dot U.S. and Canada in 1987," *Enhanced Recovery Week* (Jan. 4, 1988) 1,3-4.

"Many Delayed Projects Given Go Ahead Last Year," *Enhanced Recovery Week* (Jan. 4, 1988) 2-3.

"Chevron Plans $75 Million CO_2 Flood at North Ward Estes," *Enhanced Recovery Week* (Jan. 25, 1988) 1-2.

Russell, J.E.: "Polymer Flood Provides Economic EOR Result," *American Oil & Gas Reporter* (March 1988) 12-16.

"EOR Update - Texaco Adds Polymer Injectors at Harris Field," *Enhanced Recovery Week* (March 7, 1988) 4.

"Enron Expands Chemical Injection in Two Wyoming Fields," *Enhanced Recovery Week* (March 21, 1988) 1-2.

"Statoil Considering Polymer, Surfactant for North Sea," *Enhanced Recovery Week* (April 4, 1988) 1,3-4.

Aalund, L.R.: "EOR Projects Decline, but CO_2 Pushes Up Production," *Oil & Gas J.* (April 18, 1988) 33-73.

Christopher, C.A., Clark, T.J., and Gibson, D.H.: "Performance and Operation of a Successful Polymer Flood in the Sleepy Hollow Reagan Unit," paper SPE/DOE 17395 presented at the 1988 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 17-20.

Sydansk, R.D. and Smith, T.B.: "Field Testing of a New Conformance-Improvement-Treatment Chromium (III) Gel Technology," paper SPE/DOE 17383 presented at the 1988 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 17-20.

"Polymer Triples Production at Indiana Oil Field," *Enhanced Recovery Week* (May 9, 1988) 1,3.

King, W.A.: "Practical Application of a Reservoir Model to EOR: Lone Cedar Minnelusa Unit, Campbell County,Wyoming," paper SPE 17539 presented at the 1988 SPE Rocky Mountain Regional Meeting, Casper, WY, May 11-13.

"Amoco's Sleepy Hollow Polymer Successful Despite 1986," *Enhanced Recovery Week* (May 23, 1988) 1,4.

"Marathon Polymer Process Recovers Oil for Less Than $1/bbl," *Enhanced Recovery Week* (June 6, 1988) 2.

"Polymer Flood Gives North Glo Output Big Boost," *Enhanced Recovery Week* (June 13, 1988) 1-2.

"Wyoming EOR Development Still in Slowdown," *Enhanced Recovery Week* (July 4, 1988) 1,4.

"BP Using Biopolymer for Mobility Control at Chauvin," *Enhanced Recovery Week* (Aug. 29, 1988) 2-3.

"Terra Reconsidering T.A. Buttes Polymer Flood," *Enhanced Recovery Week* (Sept. 12, 1988) 2.

"Westburne Begins Polymer Flood at Long Tree," *Enhanced Recovery Week* (Sept. 19, 1988) 1-2.

Koning, E.J.L., Mentzer, E., and Heemskerk, J.: "Evaluation of a Pilot Polymer Flood in the Marmul Field, Oman," paper SPE 18092 presented at the 1988 SPE Annual Technical Conference and Exhibition, Houston, Oct. 2-5.

Putz, A.G., Lecourtier, J.M., and Bruckert, L.: "Interpretation of High Recovery Obtained in a New Polymer Flood in the Chateaurenard Field," paper SPE 18093 presented at the 1988 SPE Annual Technical Conference and Exhibition, Houston, Oct. 2-5.

"Petroleum Inc. Planning Two Polymer Floods in Wyoming," *Enhanced Recovery Week* (Oct. 3, 1988) 1-2.

"Oman Completes Marmul Polymer Pilot, Plans Second," *Enhanced Recovery Week* (Oct. 10, 1988) 1,3-4.

Lyle, D.: "EOR Boosts Rockies Output," *Western Oil World* (Oct. 1988) 9-14.

Lyle, D.: "DSGA Polymer Rejuvenates Wells," *Western Oil World* (Oct. 1988) 28-30.

"Terra Injects Water, Plans Polymer for Ammo," *Enhanced Recovery Week* (Oct. 24, 1988) 1-2.

Littman, W. and Westerkamp, A.: "Xanthan-Biopolymer Flooding in a North-German Oilfield," *Proc.,* 4th European EOR Conf. (Nov. 1988) 67-78.

Karau, D., Martischius, F.D., Sewe, K.U., and Weinreich, H.J.: "Polymer Project Bockstedt: New Technical Equipment for Dissolving and Shearing Polymers for EOR," *Proc.,* 4th European EOR Conf. (Nov. 1988) 195-205.

Smith, R.V.: "Enhanced Oil Recovery Update: Part 1—Improvement of Sweep Efficiency," *Pet. Eng. Intl.* (Nov. 1988) 29-40.

"Drilling and Exploration - IOR Conference Stresses Cost Effectiveness," *Pet. Eng. Intl.* (Nov. 1988) 60.

Chang, P.W., Burkholder, L.A., Phillips, J.C., Ghaemmaghami, M., Myer, M.A., and Babcock, R.E.: "Selective Emplacement of Xanthan/Cr(III) Gels in Porous Media," paper SPE 17589 presented at the 1988 SPE International Meeting on Petroleum Engineering, Tianjin, China, Nov. 1-4.

Chauveteau, G., Combe, J., and Dong, H.: "Preparation of Two Polymer Pilot Tests in Daqing Oil Field," paper SPE 17632 presented at the 1988 SPE International Meeting on Petroleum Engineering, Tianjin, China, Nov. 1-4.

Maitin, B., Daboul, B., and Sohn, W.O.: "Numerical Simulation for Planning and Evaluation of Polymer Flood Process: A Field Performance Analysis," paper SPE 17631 presented at the 1988 SPE International Meeting on Petroleum Engineering, Tianjin, China, Nov. 1-4.

Wang, Z., Zhang, J., and Jiang, Y.: "Evaluation of Polymer Flooding in Daqing Oil Field and Analysis of Its Favorable Conditions," paper SPE 17848 presented at the 1988 SPE International Meeting on Petroleum Engineering, Tianjin, China, Nov. 1-4.

Green, D. and Schoeling, L.: "Implementation of Gelled Polymer Technology, An Example of a Joint Industry-University Project," *Interstate Oil & Gas Compact & Committee Bulletin* (Dec. 1988) Vol. II, No. 2, 32-42.

"Researchers Promoting Crosslinked Polymer Use in Kansas," *Enhanced Recovery Week* (Dec. 12, 1988) 1-2.

"Polymer Cures Water Woes at Gillespie, Riffe Fields," *Enhanced Recovery Week* (Dec. 19, 1988) 3.

"U.S. Operators Bet on Long-Term Payoffs with New Projects," *Enhanced Recovery Week* (Jan. 9, 1989) 1,4.

"New Canadian Projects Dwindled as '88 Progressed," *Enhanced Recovery Week* (Jan. 9, 1989) 1-2.

"Polymer Producing Well Treatments Continue to Produce Incremental Oil in the Riffe Field," *TORP*, Vol. 5, No. 1 (Feb. 1989) 3.

Jurinak, J.J., Summers, L.E., and Bennett, K.E.: "Oilfield Application of Colloidal Silica Gel," paper SPE 18505 presented at the 1989 SPE International Symposium on Oilfield Chemistry, Houston, Feb. 8-10.

"France Develops Profile Treatment Without Crosslinker," *Enhanced Recovery Week* (Feb. 20, 1989) 1,3.

"Tyler Polymer Flooding Advice Offered," *Enhanced Recovery Week* (March 13, 1989) 1-2.

"Warner Ranch More Retentive Than Expected," *Enhanced Recovery Week* (March 13, 1989) 2-3.

Vangilder, J.B.: "Vollmer Unit Demonstrates Practical Polymer Flood," *American Oil & Gas Reporter* (March 1989) 22-27.

Weiss, W.W. and Chain, J.M.: "J-Sand Polymer Flood Performance Review," paper SPE 18974 presented at the 1989 SPE Low Permeability Reservoirs Symposium/Rocky Mountain Regional Meeting, Denver, March 6-8.

"KSL Enterprises Plans Chemical Flood at Moorcroft West," *Enhanced Recovery Week* (April 17, 1989) 1,3.

Børeng, T.L., Bjørnestad, E.Ø., and Foss, P.: "Development and Testing of Xanthan Products for EOR-Applications in the North Sea," presented at the 1989 European Symposium on Improved Oil Recovery, Budapest, April 25-27.

Chierici, G.L.: "ARM (Advanced Reservoir Management) vs. EOR," presented at the 1989 European Symposium on Improved Oil Recovery, Budapest, April 25-27.

Combe, J., Corlay, P., Valentin, E., Champlon, D., Bosio, J., De Haan, H.J., Hawaes, R.I., Pusch, G., Sclocchi, G., and Stockenhuber, F.: "EOR in Western Europe: Status and Outlook," presented at the 1989 European Symposium on Improved Oil Recovery, Budapest, April 25-27.

Simandoux, P., Champlon, D., and Valentin, E.: "Managing the Cost of Enhanced Oil Recovery," presented at the 1989 European Symposium on Improved Oil Recovery, Budapest, April 25-27.

"Wide Variety of Chemicals Available for Enhanced Recovery," *Pet. Eng. Intl.* (May 1989) 42-48.

"Reservoir Management - Polymer-Augmented Waterflooding," *Pet. Eng. Intl.* (May 1989) 51.

Basko, D.B.: "Current Status of Wyoming Tertiary Recovery Projects," Wyoming Oil & Gas Conservation Commission (May 1989).

"Six Years After Polymer, Texas Limestone Still Pumping," *Enhanced Recovery Week* (May 22, 1989) 2.

"AOSTRA, Pfizer Team Up for Polymer Pilot Program," *Enhanced Recovery Week* (May 15, 1989) 1.

"Ampol Getting Set for Polymer Flood at Little Missouri," *Enhanced Recovery Week* (May 15, 1989) 1-2.

"Turkey Compares Polymer and Silica Gels in Three Fields," *Enhanced Recovery Week* (May 15, 1989) 2-3.

"Polymer Keeping Water in Check at North Semlek," *Enhanced Recovery Week* (May 29, 1989) 1,3.

"Polymer Boosts Big Mac Production in Wyoming," *Enhanced Recovery Week* (July 10, 1989) 1,3.

"Polymers Boost Tyler Flood," *Western Oil World* (July 1989) 22-23.

"Maxus Prepares Alpha for Polymer Flood," *Enhanced Recovery Week* (Aug. 7, 1989) 1,3.

Johnson, S.: "Powder Responds Well to Treatment," *Western Oil World* (Aug. 1989) 18-22.

Svetgoff, J.A.: "Demulsification Key to Production Efficiency," *Pet. Eng. Intl.* (Aug. 1989) 28-29.

"Mobil Completes Polymer, Plans CO_2 at Salt Creek," *Enhanced Recovery Week* (Sept. 4, 1989) 1.

"General Atlantic Plans Quick Winter Draw Polymer Flood," *Enhanced Recovery Week* (Sept. 25, 1989) 1-2.

"North Finn to Inhibit Carson's Clays from Swelling," *Enhanced Recovery Week* (Sept. 25, 1989) 3-4.

Lyle, D.: "EOR Boosts Rockies Output," *Western Oil World* (Oct. 1989) 9-14.

Schurz, G.F., Martin, F.D., Seright, R., and Weiss, W.W.: "Polymer-Augmented Waterflooding and Control of Reservoir Heterogeneity," *Proc.,* Centennial Symposium Petroleum Technology into the Second Century, Socorro, NM, Oct. 16-19.

"Polymer Flood Begins in Wolf Draw Field," *Enhanced Recovery Week* (Nov. 6, 1989) 2-3.

"Beard Rides Into Sleepy Hollow," *Western Oil World* (Nov. 1989) 18.

"Home Prepared to Flood Falcon Ridge," *Enhanced Recovery Week* (Nov. 13, 1989) 1-2.

"Kansas Operator Pleased with Wyoming Polymer Flood," *Enhanced Recovery Week* (Nov. 20, 1989) 1.

"Presidio Prepares to Flood Glo Field," *Enhanced Recovery Week* (Nov. 20, 1989) 3.

"EOR Update - On the Road with the Minnelusa," *Enhanced Recovery Week* (Dec. 18, 1989) 4.

Bruckert, L.: "Horizontal Well Improves Oil Recovery from Polymer Flood," *Oil & Gas J.* (Dec. 18, 1989) 35-39.

"Woods Prepared to Flood Summerfield Minnulusa," *Advanced Recovery Week* (Feb. 26, 1990) 2.

Hochanadel, S.M., Lunceford, M.L., and Farmer, C.W.: "A Comparison of 31 Minnelusa Polymer Floods with 24 Minnelusa Waterfloods," paper SPE/DOE 20234 presented at the 1990 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, April 22-25.

Moritis, G.: "CO_2 and HC Injection Lead EOR Production Increase," *Oil & Gas J.* (April 23, 1990) 49-82.

"Mitchell Energy Revives Polymer Flood Plan at Alba," *Advanced Recovery Week* (April 23, 1990) 1,3.

Sydansk, R.D. and Moore, P.E.: "Production Responses in Wyoming's Big Horn Basin Resulting from Application of Acrylamide-Polymer/Cr^{III}-Carboxylate Gels," *Proc.* Sixth University of Wyoming Enhanced Oil Recovery Symposium (1990) Casper, May 3-4.

"Polymer Floods Make a Difference in the Minnulusa," *Advanced Recovery Week* (May 7, 1990) 2-3.

"West Texas Operator Has Polymer Flood Under Way," *Advanced Recovery Week* (May 21, 1990) 1.

"Jade Resources Injecting Polymer Into Ottie Draw Field," *Advanced Recovery Week* (May 28, 1990) 2.

"Prenalta Obtains Tertiary Certification to Beat Deadline," *Advanced Recovery Week* (June 4, 1990) 3.

Hochanadol, S.M. and Townsend, C.L.: "Improving Oil Recovery in the Naturally Fractured, Tight, Dirty Sandstone of the Townsend Newcastle Sand Unit - Weston County, Wyoming," paper CIM/SPE 90-82 presented at the 1990 International Technical Meeting of CIM and SPE, Calgary, June 10-13.

"KOH, Polymers Give New Life to Depleted Wyoming Field," *Advanced Recovery Week* (June 25, 1990) 2.

"Operator Begins Polymer Flood at House Creek Field," *Advanced Recovery Week* (July 23, 1990) 2.

"Mobil Sets Stage for West Texas Miscible CO_2 Flood," *Advanced Recovery Week* (Aug. 6, 1990) 2.

Huh, C., Landis, L.H., Maer, Jr., N.K., McKinney, P.H., and Dougherty, N.A.: "Simulation to Support Interpretation of the Loudon Surfactant Pilot Tests," paper SPE 20465 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 23-26.

Moffitt, P.D., Zornes, D.R., Moradi-Araghi, A., and McGovern, J.M.: "Application of Freshwater and Brine Polymerflooding in the North Burbank Unit (NBU), Osage County, Oklahoma," paper SPE 20466 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 23-26.

Putz, A. and Lecourtier, J.: "Monitoring Polymer Properties in Production Wells of Chateaurenard Oilfield," presented at the 1990 IEA/EOR Symposium, Rueil Malmaison, Oct. 8-10.

"Unocal to Augment Waterflood at Wyoming Am-Kirk Unit," *Advanced Recovery Week* (Nov. 5, 1990) 1,4.

Al-Adawy, M.S. and Nandyal, M.: "Status and Scope for EOR Development in Oman," paper SPE 21407 presented at the 1991 SPE Middle East Oil Show, Bahrain, March 2-5.

Jack, L.M., Green, D.W., and Schoeling, L.: "Polymer Floods Show Varying Results," *American Oil & Gas Reporter* (May 1991) 93-100.

Jacquart, P.: "Improved Oil Recovery in the Global Energy Perspective," presented at the 1991 European Symposium on Improved Oil Recovery, Stavanger, Norway, May 21-23.

Putz, A. and Rivenq, R.: "Commercial Polymer Injection in the Courtenay Field," presented at the 1991 European Symposium on Improved Oil Recovery, Stavanger, Norway, May 21-23.

Schuhbauer, W., Maitin, B., and Volz, H.: "Application of a Synthetic Copolymer Under Harsh Environmental Conditions in the Ploen-OST Field," presented at the 1991 European Symposium on Improved Oil Recovery, Stavanger, Norway, May 21-23.

Littmann, W., Kleinitz, W., Kleppe, G., and Lund, T.: "A Commercial-Scale Xanthan Polymer Flood Project in a High-Salinity, Low-Viscosity Oil Reservoir," presented at the 1991 European Symposium on Improved Oil Recovery, Stavanger, Norway, May 21-23.

Weiss, W.W.: "A Review of Recent, Successful Polymerfloods," PRRC Report No. 91-32, New Mexico Tech, Socorro, NM (June 14, 1991).

Bokserman, A.A., Mamedov, Y.G., and Antonlady, D.G.: "Diverse Methods Spread Thermal EOR in U.S.S.R.," *Oil & Gas J.* (Oct. 7, 1991) 82-84.

"Phillips Mulls Switch to Brine Fluid in Okla. Polymer Field," *Advanced Recovery Week* (Oct. 14, 1991) 3.

"Texaco Develops Gel Treatment for Formation Brines," *Advanced Recovery Week* (Dec. 9, 1991) 2.

"LL&E Initiates Polymer-Aided Waterflood in Wyoming," *Advanced Recovery Week* (Jan. 6, 1992) 2.

Sydansk, R.D. and Moore, P.E.: "Gel Conformance Treatments Increase Oil Production in Wyoming," *Oil & Gas J.* (Jan. 20, 1992) 40-45.

"Pembina Sweep Efficiency Tests Under Way," *Improved Recovery Week* (March 2, 1992) 2-3.

"Kerr-McGee Starts Wyo. Flood," *Improved Recovery Week* (March 9, 1992) 1.

"Recovery Data Bank - Chemical, Microbial Studies Released," *Improved Recovery Week* (March 30, 1992) 5.

Hunter, B.L., Buell, R.S., and Abate, T.A.: "Application of a Polymer Gel System to Control Steam Breakthrough and Channeling," paper SPE 24031 presented at the 1992 Western Regional Meeting, Bakersfield, CA, March 30-April 1; *Proc.*, Eighth Symposium on Enhanced Oil Recovery, Tulsa, OK (1992) Vol. 1, 41-52.

Maitin, B.K.: "Performance Analysis of Several Polyacrylamide Floods in North German Oil Fields," paper SPE 24118 presented at the 1992 SPE Symposium on Enhanced Oil Recovery, Tulsa, April 22-24.

Littman, W., Kleinitz, W., Christensen, B.E., Torger, B., and Haugvallstad, T.: "Late Results of a Polymer Pilot Test: Performance, Simulation Adsorption, and Xanthan Stability in the Reservoir," paper SPE 24120 presented at the 1992 SPE Symposium on Enhanced Oil Recovery, Tulsa, April 22-24.

Zettlitzer, M. and Volz, H.: "Comparison of Polyacrylamide Retention in Field Application and Laboratory Testing," paper SPE 24121 presented at the 1992 SPE Symposium on Enhanced Oil Recovery, Tulsa, April 22-24.

Weiss, W.W.: "Performance Review of a Large-Scale Polymer Flood," paper SPE 24145 presented at the 1992 SPE Symposium on Enhanced Oil Recovery, Tulsa, April 22-24.

Putz, A.G. and Rivenq, R.C.: "Commercial Polymer Injection in the Courtenay Field," *J. Polym. Sci. & Eng.* (April 1992) **7**, Nos. 1,2, 15-23.

Zaitoun, A., Kohler, N., Maitin, B.K., and Zettlitzer, M.: "Preparation of a Water Control Polymer Treatment at Conditions of High Temperature and Salinity," *J. Polym. Sci. & Eng.* (April 1992) **7**, Nos. 1,2, 67-76.

Moritis, G.: "EOR Increases 24% Worldwide; Claims 10% of U.S. Production," *Oil & Gas J.* (April 20, 1992) 51-79.

Moritis, G.: "More Enhanced Oil Recovery Projects," *Oil & Gas J.* (June 29, 1992) 70-71.

APPENDIX B

BIBLIOGRAPHY FOR CHAPTER 3:

A SURVEY OF FIELD ACTIVITY FOR POLYMER AND GEL TREATMENTS IN PRODUCTION WELLS: 1970-1991

APPENDIX B

Bibliography for Chapter 3

Koch, R.R. and McLaughlin, H.C.: "Field Performance of New Technique for Control of Water Production or Injection in Oil Recovery," paper SPE 2847 presented at the 1970 Practical Aspects of Improved Recovery Techniques of SPE of AIME, Forth Worth, TX, March 8-10.

White, J.L., Goddard, J.E., and Phillips, H.M.: "Use of Polymers to Control Water Production in Oil Wells," *JPT* (Feb. 1973) 143-150.

Sandiford, B.B. and Graham, G.A.: "Injection of Polymer Solutions in Producing Wells," AIChE Symposium Series (1973) **69**, No. 127, 38.

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-AIME Improved Oil Recovery Symposium, Tulsa, April 22-24.

McLaughlin, H.C., Diller, J., and Ayers, H.J.: "Treatment of Injection and Producing Wells with Monomer Solution," paper SPE 5394 presented at the 1975 Oklahoma City SPE Regional Meeting, Oklahoma City, OK, March 24-25.

Sloat, B.: "Increasing Oil Recovery by Chemical Control of Producing Water-Oil Ratios," paper SPE 5341 presented at the 1975 Rocky Mountain Regional Meeting of SPE of AIME, Denver, CO, April 7-9.

Sparlin, D.D.: "An Evaluation of Polyacrylamides for Reducing Water Production," *JPT* (Aug. 1976) 906-914.

Hessert, J.E. and Fleming, III, P.D.: "Gelled Polymer Technology for Control of Water in Injection and Production Wells," *Proc.,* Third Tertiary Oil Recovery Conference, Wichita (1979) 58-70.

Peddycoart, L.R.: "Water Control for ER Production Improvement," reprint from *Oil & Gas J.* (Feb. 3, 1980).

Cole, R.C., Mody, B., and Pace, J.: "Water Control for Enhanced Oil Recovery," paper SPE 10396 presented at the 1981 SPE/AIME Offshore Europe 81 Conference, Aberdeen Petroleum Section, Aberdeen, Scotland, Sept. 15-18.

Sparlin, D.D. and Hagen, Jr., R.W.: "Part 5—Using Polyacrylamide Polymers, Controlling Water in Producing Operations," *World Oil* (July 1984) 137-142.

Olsen, E.H.: "Case History: Water Shutoff Treatment in the Phosphoria Formation, Hot Springs County, Wyoming," paper SPE 15163 presented at the 1986 SPE Rocky Mountain Regional Meeting, Billings, MT, May 19-21, 291-297.

Mabry, R.: "Water Treatment Technique Works," *The Oil Rag* (March 1, 1988) 1,5.

Mody, B.G., McKitrick, R.S., and Shahsavari, D.: "Proper Application of Crosslinked Polymer Decreases Operating Costs," paper SPE 17288 presented at the 1988 SPE Permian Basin Oil and Gas Recovery Conference, Midland, TX, March 10-11, 205-211.

"Water Shut-Off Treatment Results," Profile Control Services, Inc. (April 14, 1988).

Sydansk, R.D. and Smith, T.D.: "Field Testing of a New Conformance-Improvement-Treatment Chromium (III) Gel Technology," paper SPE/DOE 17383 presented at the 1988 SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, OK, April 17-20, 699-707.

Mody, B.G., McKitrick, R.S., and Lambillotte, J.D.: "Precision Casing Leak Squeeze Using Crosslinked Polyacrylamide," presented at the Southwest Petroleum Short Course, Department of Petroleum Engineering, Texas Tech University, Lubbock, TX, April 20-21, 1988.

Avery, M.R., Wells, T.A., Chang, P.W., and Millican, J.D.: "Field Evaluation of a New Gelant for Water Control in Production Wells," paper SPE 18201 presented at the 1988 SPE Annual Technical Conference and Exhibition, Houston, Oct. 2-5.

Jurinak, J.J., Summers, L.E., and Bennett, K.E.: "Oilfield Application of Colloidal Silica Gel," paper SPE 18505 presented at the 1989 SPE International Symposium on Oilfield Chemistry, Houston, Feb. 8-10, 425-454.

"Producing Well Treatments," Profile Control Services, Inc., Odessa, TX (March 31, 1990).

Wood, F., Dalrymple, D., McKown, K., and Matthews, B.: "Two-Stage Treatment Reduces Water/Oil Ratio," *Oil & Gas J.* (Sept. 10, 1990) 73-76.

Goltz, K.E. and Dabbous, M.K.: "Continuous Monitoring and Analysis Increases the Success of Reservoir Profile Control with Cross-Linked Polymer Systems," presented at the Tenth Petroleum Exploration and Production Conference, Cairo, Egypt, Nov. 17-20, 1990.

Jack, L.M., Green, D.W., and Schoeling, L.: "Polymer Floods Show Varying Results," *American Oil & Gas Reporter* (May 1991) 93-100.

Moffitt, P.D.: "Long-Term Production Results of Polymer Treatments on Producing Wells in Western Kansas," paper SPE 22649 presented at the 1991 SPE Annual Technical Conference and Exhibition, Dallas, Oct. 6-9.

Zaitoun, A. and Kohler N.: "Thin Polyacrylamide Gels for Water Control in High-Permeability Production Wells" paper SPE 22785 presented at the 1991 SPE Annual Technical Conference and Exhibition, Dallas, Oct. 6-9.

"Advanced, Oil-Permeable Gel Treatment Immobilizes Water, Boosts Oil Production Dramatically," Pfizer Oil Field Products Division (1991).

Sydansk, R.D. and Moore, P.E.: "Gel Conformance Treatments Increase Oil Production in Wyoming," *Oil & Gas J.* (Jan. 20, 1992) 40-45.

Malachosky, E. and Herd, M.: "Polymers Reduce Water Production," *Enhancement Services, Inc.*

APPENDIX C

OIL AND WATER COREFLOOD DATA

(SUPPLEMENT TO CHAPTER 10)

APPENDIX C

Table C-1a — Core SSH-36
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 3% resorcinol + 3% formaldehyde + 0.5% KCl + 0.42% $NaHCO_3$ (pH=6.5)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st WFAG-R (13)	0.023	666		614	
	0.047	534		506	
F_{rrw}=170	0.023	562		548	
(at u=0.389 ft/d, long segment)	0.093	517		344	
	0.047	358		303	
	0.023	360		309	
	0.187	312		218	
	0.023	299		239	
	0.389	236		170	
	0.023	247		201	
After 1st OFAG-R (15a)	6.223		111		22
	3.112		131		22
F_{rro}=23	1.556		169		22
(at u=6.223 ft/d, long segment)	0.778		237		22
	0.389		358		23
	0.187		573		22
	0.093		952		22
	0.047		680		23
	6.223		112		23

WFAG-R — Waterflood after gel treatment in the reversed direction.
OFAG-R — Oilflood after gel treatment in the reversed direction.

Table C-1a (continued) — Core SSH-36
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 3% resorcinol + 3% formaldehyde + 0.5% KCl + 0.42% $NaHCO_3$ (pH=6.5)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 2nd WFAG-R (15c)	0.389	372		104	
	0.187	386		115	
F_{rrw}=123	0.093	404		134	
(at u=0.389 ft/d, long segment)	0.047	405		158	
	0.023	398		161	
	0.389	382		123	
After 2nd OFAG-R (16a)	10.113		71		14
	6.223		76		14
F_{rro}=14	3.112		92		14
(at u=6.223 ft/d, long segment)	1.556		94		14
	0.778		83		14
	0.389		78		15
	0.187		73		15
	0.093		78		16
	6.223		63		14

Table C-1a (continued) — Core SSH-36
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 3% resorcinol + 3% formaldehyde + 0.5% KCl + 0.42% $NaHCO_3$ (pH=6.5)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 3rd WFAG-R (16c)	0.778	205		54	
	0.389	216		56	
F_{rrw}=62 (at u=0.0.778 ft/d, long segment)	0.187	239		61	
	0.093	259		67	
	0.047	269		76	
	0.023	271		85	
	0.778	209		63	
	0.389	222		62	
	0.187	239		70	
	0.093	250		76	
	0.047	252		79	
	0.023	247		80	
	0.778	210		62	

Table C-1b — Core SSH-38
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st WFAG-R (13)	not performed				
During 1st OFAG-R (15a)	0.023		16,550		2,293
(See next table for more readings at the stage.)	0.047		9,029		1,661
	0.023		13,460		686
	0.093		3,970		1,241
	0.047		2,575		1,278
	0.023		2,392		1,105
	0.187		1,551		1,085
	0.093		1,471		1,029
	0.047		4,608		752
	0.023		7,923		421
	0.389		2,055		815
	0.187		1,586		766
	0.093		1,522		758
	0.047		1,783		794
	0.023		2,204		785
	0.778		1,407		608
	0.389		1,367		621
	0.187		1,336		666
	0.093		1,369		766
	0.047		1,506		606
	0.023		2,116		664

Table C-1b (continued) — Core SSH-38
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st OFAG-R (15a) (See next table for more readings at the stage.)	1.167		1,322		496
	0.778		1,397		511
	0.389		2,025		551
	0.187		1,920		596
	0.093		2,341		604
	0.047		2,502		584
	0.023		2,557		610
	1.167		1,044		367
	1.945		637		302
	6.223		149		99
	3.112		198		132
	1.556		341		185
	0.778		473		238
	0.389		677		293
	0.187		805		357
	0.093		1,263		335
	0.047		2,225		296
	0.023		3,642		269

Table C-1b (continued) — Core SSH-38
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st OFAG-R (15a)	6.223		120		86
	3.112		141		114
$F_{rro}=133u^{-0.35}$ (For the last 9 readings for the long segment, r=0.990.)	1.556		174		155
	0.778		302		200
	0.389		510		246
	0.187		933		277
	0.093		1,010		318
	0.047		600		350
	0.023		1,576		272
	6.223		111		78
	11.668		69		55
	6.223		81		69
	3.112		106		93
	1.556		139		130
	0.778		191		163
	0.389		293		198
	0.187		446		223
	0.093		667		277
	11.668		57		49

Table C-1b (continued) — Core SSH-38
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 2nd WFAG-R (15c)	0.187	1,007		2,120	
	0.093	1,439		2,729	
$F_{rrw}=1,287u^{-0.33}$ (For all the readings for the long segment, r=0.991.)	0.047	2,250		3,604	
	0.023	3,295		4,323	
	0.187	1,084		2,329	
	0.093	1,473		2,798	
After 2nd OFAG-R (16a)	31.116		19		22
	23.337		20		24
$F_{rro}=63u^{-0.28}$ (For all the readings for the long segment, r=0.950.)	12.446		23		30
	6.223		28		40
	3.112		34		53
	1.556		50		68
	0.778		74		80
	0.389		120		93
	0.187		217		100
	0.093		385		107
	0.047		699		121
	0.023		1,184		107
	23.337		20		23

Table C-1b (continued) — Core SSH-38
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 3rd WFAG-R (16c)	1.011	146		462	
	0.933	148		463	
$F_{rrw}=476u^{-0.57}$ (For all the readings for the long segment, r=0.995.)	0.778	152		486	
	0.389	237		811	
	0.187	356		1,288	
	0.093	520		1,894	
	0.047	760		2,760	
	0.023	1,217		4,175	
	0.545	250		734	
	0.389	306		883	
	0.187	447		1,352	
	0.093	660		1,989	
	0.047	825		2,410	
	0.023	1,340		3,650	
	0.545	273		675	
	0.389	310		781	

Table C-1b (continued) — Core SSH-38
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 3rd WFAG-R (16c)	6.535	47		65	
	3.112	54		73	
$F_{rrw}=166u^{-0.51}$ (For all the readings for the long segment, r=0.994.)	1.556	67		109	
	0.778	90		188	
[Note: This set of readings was obtained after the core was exposed to a high pressure surge (about 1,000 psi)]	0.389	112		273	
	0.187	150		419	
	0.093	194		611	
	0.047	300		848	
	0.023	382		1,140	
	5.056	76		82	
	4.667	78		88	
	3.112	81		97	
	1.556	91		122	
	0.778	108		172	
	0.389	128		250	
	0.187	162		383	
	0.093	239		594	
	0.047	330		773	
	0.023	416		1,082	
	3.112	109		106	
	1.556	121		128	
	0.778	146		168	
	3.112	107		106	

Table C-1b (continued) — Core SSH-38
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 3rd OFAG-R (17a)	46.673		13		13
	23.337		14		15
$F_{rro}=27u^{-0.13}$ (For all the readings for the long segment, r=0.871.)	12.446		15		19
	6.223		15		23
	3.112		20		28
	1.556		37		29
	0.778		60		32
	0.389		107		33
	0.187		206		32
	0.093		370		34
	0.047		598		30
	0.023		1,236		42
	46.673		16		13
	1.556		43		26
After 4th WFAG-R (17c)	12.446	40		26	
(See next table for more readings obtained at this stage.)	6.223	44		30	
	3.112	58		39	
	1.556	84		56	
	0.778	123		94	
	0.389	173		151	
	0.187	238		249	
	0.093	322		336	
	0.047	399		467	
	0.023	523		637	

Table C-1b (continued) — Core SSH-38
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 4th WFAG-R (17c)	12.446	46		30	
	6.223	56		35	
$F_{rrw}=87u^{-0.52}$ (For all the readings for the long segment—including the readings in the previous table, r=0.991.)	3.112	70		45	
	1.556	87		57	
	0.778	124		89	
	0.389	161		137	
	0.187	206		197	
	12.446	45		29	
After 4th OFAG-R (18a)	46.673		13		9
	23.337		13		10
$F_{rro}=12$ (The average of all the readings for the long segment.)	12.446		14		12
	6.223		16		13
	3.112		24		14
	1.556		36		13
	0.778		62		13
	0.389		111		14
	0.187		197		13
	0.093		272		13
	0.047		398		15
	23.337		14		9

Table C-1c — Core SSH-43
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 0.4% CPAM + 1,520 ppm glyoxal + 2% KCl (pH=7.3)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st WFAG-R (13)	0.023	19,310		6,634	
	0.047	16,220		5,047	
$F_{rrw}=2{,}088u^{-0.32}$ (For all the readings for the long segment, r=0.804.)	0.023	18,140		6,027	
	0.093	11,880		3,776	
	0.047	13,980		4,655	
	0.023	16,690		5,821	
	0.078	13,610		4,374	
	0.047	15,350		5,148	
	0.023	17,680		6,335	
	0.070	14,970		4,912	
	0.047	16,790		5,685	
	0.023	19,130		6,843	
	0.070	15,760		5,159	
	0.047	17,340		5,908	
	0.023	20,930		7,456	
	0.062	16,430		5,577	
	0.047	18,140		6,399	
	0.023	20,990		7,823	
	0.047	17,760		6,399	
	0.023	20,610		7,974	
	0.047	17,420		6,386	

Table C-1c (continued) — Core SSH-43
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 0.4% CPAM + 1,520 ppm glyoxal + 2% KCl (pH=7.3)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 1st OFAG-R (15a) F_{rro}=23 (The average of all the readings for the long segment.)	46.673		22		9
	23.337		27		10
	12.446		33		11
	6.223		40		11
	3.112		49		12
	1.556		58		12
	0.778		75		12
	0.389		110		14
	0.187		176		14
	0.093		297		15
	0.047		529		15
	0.023		954		13
	46.673		20		9
After 2nd WFAG-R (15c)	31.115	24		14	
	23.337	23		13	
	12.446	25		14	
	6.223	28		16	
	3.112	34		18	
	1.556	246		88	
	0.778	380		145	
	0.389	380		164	
	0.187	709		324	
	0.093	937		426	
	0.047	1,276		584	
	0.023	1,629		739	

Table C-1c (continued) — Core SSH-43
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 0.4% CPAM + 1,520 ppm glyoxal + 2% KCl (pH=7.3)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 2nd WFAG-R (15c) $F_{rrw}=84u^{-0.59}$ (For all the readings for the long segment in this and the previous boxes, r=0.973.)	17.114	36		21	
	12.446	37		21	
	6.223	41		23	
	3.112	55		31	
	1.556	75		38	
	0.778	223		88	
	0.389	439		179	
	0.187	606		262	
	0.093	829		362	
	0.047	1,111		486	
	0.023	1,419		603	
	15.558	41		24	
	17.114	42		23	
	12.446	40		22	
	6.223	43		24	
After 2nd WFAG-R (15c) [Note: The readings in this box and the next box were obtained after the core was exposed to a pressure surge of about 700 psi.]	37.339	19		11	
	23.337	19		11	
	12.446	20		11	
	6.223	23		13	
	3.112	30		15	
	1.556	38		18	

Table C-1c (continued) — Core SSH-43
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 0.4% CPAM + 1,520 ppm glyoxal + 2% KCl (pH=7.3)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 2nd WFAG-R (15c)	0.778	52		24	
	0.389	86		39	
$F_{rrw}=30u^{-0.37}$	0.187	120		52	
(For all the readings in this box and the previous box for the long segment, r=0.967.)	0.093	195		82	
	0.047	268		113	
	0.023	362		154	
	23.337	25		13	
After 2nd OFAG-R (16a)	46.673		4		2
	23.337		5		2
$F_{rro}=2$	12.446		5		2
(The average of all the readings in this box and next two boxes for the long segment.)	6.223		5		2
	3.112		6		2
[Note: The readings were obtained when oil flowed in the core horizontally.]	1.556		6		2
	46.673		5		2
After 2nd OFAG-R (16a)	46.673		5		2
[Note: The readings in this box were obtained when oil flowed vertically upward in the core.]	23.337		5		2
	6.223		6		2
	1.556		9		2
After 2nd OFAG-R (16a)	46.673		5		2
[Note: The readings in this box were obtained when oil flowed vertically downward in the core.]	23.337		5		2
	6.223		6		2
	3.112		8		2

Table C-1c (continued) — Core SSH-43
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 0.4% CPAM + 1,520 ppm glyoxal + 2% KCl (pH=7.3)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 3rd WFAG-R (16c) F_{rro}=8 (The average of all the readings in this box and the next two boxes for the long segment.) [Note: The readings in this box were obtained when water flowed in the core horizontally.]	46.673	12		7	
	23.337	12		7	
	12.446	13		7	
	6.223	13		7	
	3.112	14		8	
	1.556	15		8	
	46.673	14		7	
After 3rd WFAG-R (16c) [Note: The readings in this box were obtained when water flowed vertically upward in the core.]	46.673	13		8	
	12.446	14		9	
	1.556	15		8	
After 3rd WFAG-R (16c) [Note: The readings in this box were obtained when water flowed vertically downward in the core.]	46.673	13		8	
	12.446	14		9	
	1.556	14		8	
After 3rd OFAG-R (17a) F_{rro}=2 (The average of all the readings for the long segment.)	46.673		3		2
	23.337		3		2
	12.446		3		2

Table C-1d — Core SSH-44
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 0.3% CPAM + 1,140 ppm glyoxal + 2% KCl (pH=7.3)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st WFAG-R (13)	0.023	8,920		2,681	
	0.047	6,688		1,977	
$F_{rrw}=849u^{-0.35}$ (For all the readings for the long segment in this and the next two boxes, r=0.945.)	0.023	9,642		2,892	
	0.093	5,866		1,750	
	0.047	7,964		2,669	
[Note: The readings in this box were obtained when water flowed in the core horizontally.]	0.023	9,547		3,533	
	0.187	5,141		1,532	
	0.093	6,417		1,972	
	0.047	7,984		2,714	
	0.023	10,580		3,432	
	0.187	5,093		1,528	
During 1st WFAG-R (13) [Note: The readings in this box were obtained when water flowed in the core vertically upward.]	0.047	8,062		2,674	
	0.187	4,870		1,521	
During 1st WFAG-R (13) [Note: The readings in this box were obtained when water flowed in the core vertically downward.]	0.047	8,097		2,557	
	0.187	4,998		1,529	

Table C-1d (continued) — Core SSH-44
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 0.3% CPAM + 1,140 ppm glyoxal + 2% KCl (pH=7.3)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 1st OFAG-R (15a)	46.673		14		6
	23.337		15		6
F_{rro}=7 (The average of all the readings for the long segment in this and the following two boxes.)	12.446		17		7
	6.223		20		7
	3.112		24		8
[Note: The readings in this box were obtained when oil flowed in the core horizontally.]	1.556		31		8
	0.778		75		12
	46.673		15		6
After 1st OFAG-R (15a)	46.673		15		6
[Note: The readings in this box were obtained when oil flowed in the core vertically upward.]	12.446		18		7
	1.556		35		7
After 1st OFAG-R (15a)	46.673		16		6
[Note: The readings in this box were obtained when oil flowed in the core vertically downward.]	12.446		19		7
	1.556		35		7

Table C-1d (continued) — Core SSH-44
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 0.3% CPAM + 1,140 ppm glyoxal + 2% KCl (pH=7.3)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 2nd WFAG-R (15c)	23.337	29		14	
	12.446	28		13	
$F_{rrw}=38u^{-0.42}$ (For all the readings for the long segment, r=0.958.)	6.223	31		15	
	3.112	40		19	
	1.556	58		27	
	0.778	73		34	
	0.389	94		44	
	0.187	133		59	
	0.093	301		145	
	0.047	422		198	
	20.225	34		15	
After 2nd OFAG-R (16a)	46.673		7		3
	23.337		7		4
$F_{rro}=4$ (The average of all the readings for the long segment.)	12.446		7		4
	6.223		7		4
	3.112		8		4
	46.673		7		3

Table C-1d (continued) — Core SSH-44
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 0.3% CPAM + 1,140 ppm glyoxal + 2% KCl (pH=7.3)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 3rd WFAG-R (16c)	45.895	15		7	
	23.337	14		7	
F_{rrw}=9 (The average of all the readings in this box.)	12.446	15		7	
	6.223	16		8	
	3.112	19		9	
	1.556	22		10	
	0.778	27		12	
	0.389	34		15	
	38.894	17		8	
After 3rd OFAG-R (17a)	46.673		5		2
	23.337		5		2
F_{rro}=3 (The average of all the readings for the long segment.)	12.446		6		2
	6.223		6		3
	3.112		6		2
	46.673		5		2
After 4th WFAG-R (17c)	46.673	13		7	
	23.337	12		6	
F_{rrw}=7 (The average of all the readings for the long segment.)	12.446	13		7	
	6.223	15		7	
	3.112	17		7	
	1.556	19		8	
	0.778	22		8	
	46.673	14		7	

Table C-1e — Core SSH-51
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st WFAG-R (13)	0.008	>53,687		>35,285	
After 1st OFAG-R (15aa) F_{rro}=49 (The average of all the readings for the long segment, Soltrol was injected, $S_{gel}+S_{wr}$=0.5.)	20.225		60		34
	12.446		73		36
	6.223		102		40
	3.112		140		44
	1.556		189		51
	0.778		259		53
	0.386		348		82
	0.187		72		66
	20.225		52		34
After 1st OFAG-R(15ab) F_{rro}=19 (The average of all the readings for the long segment, paraffin injected and more water produced, $S_{gel}+S_{wr}$=0.46.)	0.778		25		19
	0.389		32		19
	0.187		39		19
	0.093		46		19
	0.047		60		19
	0.023		83		20

Table C-1e (continued) — Core SSH-51
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 1st OFAG-R (15ac) $F_{rro}=19$ (The average of all the readings for long segment, Soltrol injected, no more water produced, $S_{gel}+S_{wr}=0.46$.)	0.778		78		19
	0.389		115		19
	0.187		189		20
	0093		187		20
	23.337		28		18
	12.446		33		18
	6.223		39		18
	3.112		49		19
	1.556		61		19
	0.778		84		19
	0.389		157		18
After 1st OFAG-R (15ac) $F_{rro}=13$ (The average of all the readings for the long segment, Soltrol injected. The readings were obtained after the core was exposed to a pressure surge. No more water produced, $S_{gel}+S_{wr}=0.46$.)	0.187		429		12
	23.337		29		13
	12.446		34		13
	6.223		42		14
	3.112		54		14
	1.556		74		13
	0.778		101		14
	0.389		128		14
	0.187		236		13

Table C-1e (continued) — Core SSH-51
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 1st OFAG-R (15ad) F_{rro}=11 (The average of all the readings for the long segment, paraffin oil injected, more water produced, $S_{gel}+S_{wr}$=0.43.)	1.556		22		9
	0.778		24		11
	0.389		31		11
	0.187		40		12
	0.093		46		12
	0.047		58		12
	0.023		83		12
	1.556		16		10
	0.778		19		10
After 1st OFAG-R (15ae) F_{rro}=10 (The average of all the readings for the long segment, Soltrol injected, a small amount of water produced, $S_{gel}+S_{wr}$=0.43.)	46.673		18		9
	23.337		20		10
	12.446		24		10
	6.223		30		10
	3.112		37		10
	1.556		47		10
	0.778		71		11
	0.389		100		10
	0.187		170		10
	23.337		22		10

Table C-1e (continued) — Core SSH-51
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 2nd WFAG-R (15ca)	0.078	4,352		4,262	
$F_{rrw}=1{,}429u^{-0.44}$	0.047	5,542		5,318	
(For all the readings for the long segment, r=0.998, S_{or}=0.44.)	0.023	7,946		7,426	
	0.078	4,257		4,395	
	0.047	5,385		5,416	
	0.023	7,602		7,437	
	0.078	4,259		4,432	
After 2nd WFAG-R (15cb)	0.078	4,171		4,430	
[A solution containing 1% NaCl, 212-ppm Cr^{3+} was injected. F_{rrw} decreased during continuous	0.078	reached pressure constraint (100 psi)			
injection with 0.047 ft/d, oil	0.047	5,667		5,900	
produced, S_{or}=0.43.]	0.047	5,408		3,418	
After 2nd WFAG-R (15cc)	0.047	6,432		3,565	
$F_{rrw}=2{,}125u^{-0.17}$	0.023	8,200		4,071	
(For all the readings for the long segment, r=0.984. The readings	0.078	5,066		3,289	
were obtained during the injection of	0.047	6,260		3,693	
1% NaCl after shutting-in core for 2 days.)	0.023	8,147		4,198	
	0.078	4,980		3,384	

Table C-1e (continued) — Core SSH-51
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 2nd OFAG-R (16aa) F_{rro}=28 (The average of all the readings for the longer segment, Soltrol injected, $S_{gel}+S_{wr}$=0.48.)	23.337		35		24
	12.446		47		27
	6.223		57		28
	3.112		76		30
	1.556		116		32
	0.778		145		31
	0.389		188		31
	23.337		4		23
After 2nd OFAG-R (16ab) F_{rro}=11 (The average of all the readings for the long segment. After paraffin was injected, more water was produced and $S_{gel}+S_{wr}$=0.41.)	1.556		12		11
	0.778		13		11
	0.389		15		11
	0.187		19		11
	0.093		24		11
	0.047		32		9
	0.023		53		10
	1.556		13		10

Table C-1e (continued) — Core SSH-51
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 2nd OFAG-R (16ac) F_{rro}=9 (The average of all the readings for the long segment. When Soltrol was injected, a small amount of water was produced and $S_{gel}+S_{wr}$=0.41.)	1.556		35		9
	46.673		15		8
	23.337		25		9
	12.446		27		9
	6.233		31		9
	3.112		38		9
	1.556		47		9
	0.778		64		9
	0.389		97		8
	23.337		22		10
After 3rd WFAG-R (16ca) $F_{rrw}=884u^{-0.40}$ (For all of the readings for the long segment, r=0.992. 1% NaCl was injected.)	0.187	496		1,661	
	0.093	594		2,053	
	0.047	734		2,661	
	0.023	1,088		4,394	
	0.187	707		1,815	
	0.093	891		2,254	
	0.047	1,149		3,029	
	0.023	1,439		3,950	
	0.187	744		1,882	

Table C-1e (continued) — Core SSH-51
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 1.39% HPAM + 212-ppm Cr^{3+} (acetate) + 1% NaCl (pH=6.0)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 3rd WFAG-R (16ca)	0.187	reached pressure constraint (100 psi)			
$F_{rrw}=1{,}132u^{-0.36}$ (For all the readings for the long segment, r=1.000. The readings were obtained after shutting-in core for 2 days. 1% NaCl was injected.)	0.156	1,063		2,230	
	0.124	1,160		2,384	
	0.093	1,288		2,636	
	0.047	1,638		3,404	
	0.023	2,070		4,387	
	0.156	1,149		2,200	
After 3rd WFAG-R (16ca)	0.156	1,292		2,199	
$F_{rrw}=1{,}101u^{-0.36}$ (For all the readings for the long segment, r=0.999. The readings were obtained after shutting-in core for 1 days. 1% NaCl was injected.)	0.093	1,544		2,577	
	0.047	1,994		3,316	
	0.023	2,605		4,387	
	0.156	1,277		2,184	
	0.124	1,349		2,317	
After 3rd WFAG-R (16cb) (The readings were obtained while injecting the solution containing 212-ppm Cr^{3+}, 1% NaCl.)	0.124	1,426		2,458	
	0.124	reached pressure constraint (100 psi)			
After 3rd WFAG-R (16cc)	0.124	reached pressure constraint (100 psi)			
$F_{rrw}=1{,}501u^{-0.33}$ (For all the readings for the long segment, r=1.000. The readings were obtained after shutting-in core for 2 days. 1% NaCl was injected.)	0.093	2,339		3,329	
	0.047	3,028		4,159	
	0.023	4,096		5,328	
	0.093	2,343		3,336	

Table C-1f – Core SSH-60
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulaiton: 1.39 % HPAM + 212-ppm Cr^{3+}(acetate) + 1 % NaCl (pH=6.0)]

Stage (Step)	Back pressure, psi	Flux, ft/d	1st segment (short)		2nd segment (long)	
			F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st OFAG-R F_{rro} = 33 (The average of the last four readings for the long segment, 2.27 ml of water produced during the process.)	0	0.394		52		46
		0.787		16		40
		0.787		77		45
		0.394		44		54
		0.197		28		49
		1.575		40		51
		3.150		35		54
		0.197		20		48
		6.300		21		42
		0.394		30		32
		0.787		26		34
		1.575		21		33
		6.300		21		31
Oil-tracer study (no water produced.)	0					
During 1st OFAG-R F_{rro} = 20 (The average of all the readings for the long segment, no water produced during the process.)	500	6.300		15		22
		3.150		15		22
		1.575		14		17
		0.787		23		14
		1.575		9		21
		0.394		13		25
		0.787		12		22

Table C-1f – Core SSH-60 (continued)
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulaiton: 1.39 % HPAM + 212-ppm Cr^{3+}(acetate) + 1 % NaCl (pH=6.0)]

Stage (Step)	Back pressure, psi	Flux, ft/d	1st segment (short)		2nd segment (long)	
			F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st OFAG-R F_{rro} = 18 (The average of all the readings for the long segment, no water produced during the process.)	1,000	0.394		10		18
		0.787		8		18
		1.575		9		17
		3.150		9		18
		6.300		9		18
During 1st OFAG-R F_{rro} = 17 (The average of the last five readings for the long segment, 0.35 ml of water produced during the process.)	1,500	0.394		38		39
		0.787		25		36
		1.575		21		34
		3.150		10		19
		6.300		9		18
		1.575		10		17
		0.787		11		16
		0.394		10		16
Oil-tracer study (0.15 ml of water produced)	1,500					
During 1st OFAG-R F_{rro} = 11 (The average of all the readings for the long segment, no water produced during the process.)	1,500	0.394		11		10
		0.787		11		12
		1.575		9		11
		3.150		7		11
		6.300		8		11

Table C-1f – Core SSH-60 (continued)
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulaiton: 1.39 % HPAM + 212-ppm Cr^{3+}(acetate) + 1 % NaCl (pH=6.0)]

Stage (Step)	Back pressure, psi	Flux, ft/d	1st segment (short)		2nd segment (long)	
			F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st OFAG-R F_{rro} = 11 (The average of all the readings for the long segment, no water produced during the process.)	1,000	0.394		11		11
		0.787		9		11
		1.575		9		11
		3.150		8		12
		6.300		7		11
During 1st OFAG-R F_{rro} = 9 (The average of all the readings for the long segment, no water produced during the process.)	500	0.394		4		9
		0.787		3		10
		1.575		6		9
		3.150		6		9
		6.300		6		9
During 1st OFAG-R F_{rro} = 9 (The average of all the readings for the long segment, no water produced during the process.)	0	0.394		10		8
		0.787		6		8
		1.575		6		9
		3.150		6		9
		6.300		5		9
Oil-tracer study (0.16 ml of water produced)	0					

Table C-1f – Core SSH-60 (continued)
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulaiton: 1.39 % HPAM + 212-ppm Cr^{3+}(acetate) + 1 % NaCl (pH=6.0)]

Stage (Step)	Back pressure, psi	Flux, ft/d	1st segment (short)		2nd segment (long)	
			F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
Water-tracer study (no oil produced)	0					
During 1st WFAG-R $F_{rrw} = 18\ u^{-0.18}$ (For all the readings for the long segment, r=0.938, no oil produced during the process.)	0	0.197	15		23	
		1.575	10		19	
		3.150	7		15	
		6.300	5		12	
During 1st WFAG-R $F_{rrw} = 16\ u^{-0.26}$ (For all the readings for the long segment, r=0.999, no oil produced during the process.)	500	0.394	5		20	
		0.787	5		18	
		1.575	4		15	
		3.150	4		12	
		6.300	3		10	
During 1st WFAG-R $F_{rrw} = 18\ u^{-0.31}$ (For all the readings for the long segment, r=0.999, no oil produced during the process.)	1,000	0.394	10		23	
		0.787	8		20	
		1.575	6		16	
		3.150	5		13	
		6.300	3		10	

Table C-1f – Core SSH-60 (continued)
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulaiton: 1.39 % HPAM + 212-ppm Cr^{3+}(acetate) + 1 % NaCl (pH=6.0)]

Stage (Step)	Back pressure, psi	Flux, ft/d	1st segment (short)		2nd segment (long)	
			F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st WFAG-R $F_{rrw} = 15\ u^{-0.24}$ (For all the readings for the long segment, r=0.999, no oil produced during the process.)	1,500	0.394	10		19	
		0.787	8		16	
		1.575	6		14	
		3.150	5		12	
		6.300	4		10	
Water-tracer study (no oil produced)	1,500					
During 1st WFAG-R $F_{rrw} = 9\ u^{-0.27}$ (For all the readings for the long segment, r=0.994, no oil produced during the process.)	1,500	0.394			11	
		0.787	7		10	
		1.575	6		8	
		3.150	5		7	
		6.300	4		5	
During 1st WFAG-R $F_{rrw} = 10\ u^{-0.31}$ (For all the readings for the long segment, r=0.934, no oil produced during the process.)	1,000	0.394	10		13	
		0.787	7		13	
		1.575	6		8	
		3.150	5		6	
		6.300	5		6	

Table C-1f – Core SSH-60 (continued)
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulaiton: 1.39 % HPAM + 212-ppm Cr^{3+}(acetate) + 1 % NaCl (pH=6.0)]

Stage (Step)	Back pressure, psi	Flux, ft/d	1st segment (short)		2nd segment (long)	
			F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st WFAG-R $F_{rrw} = 12\ u^{-0.29}$ (For all the readings for the long segment, r=0.979, no oil produced during the process.)	500	0.394	9		15	
		0.787	7		14	
		1.575	6		11	
		3.150	6		9	
		6.300	5		7	
During 1st WFAG-R $F_{rrw} = 13\ u^{-0.28}$ (For all the readings for the long segment, r=0.986, 0.3 ml of oil produced during the process.)	0	0.394	9		16	
		0.787	7		15	
		1.575	6		12	
		3.150	6		10	
		6.300	5		8	

Table C-1g — Core SSHM1
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 0.3% PAM-AMPS + 100-ppm Cr^{3+}(acetate)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
During 1st WFAG-R (13)	0.023	176		924	
	0.187	77		477	
	0.389	83		328	
F_{rrw}=44 (at u=0.778 ft/d, long segment)	0.187	108		467	
	0.389	101		330	
	0.778	62		177	
	0.187	74		286	
	0.389	88		228	
	0.778	70		135	
	0.187	66		202	
	0.778	water tracer study (38 pore volumes injected)			
	0.778	24		44	
After 1st OFAG-R (15a)	15.56		14		4
F_{rro}=4	7.779		13		4
(The average of all the readings for the long segment.)	3.389		15		4

Table C-1g (continued) — Core SSHM1
Residual Resistance Factors for Brine (F_{rrw}) and for Soltrol-130 (F_{rro})
[Gel formulation: 0.3% PAM-AMPS + 100-ppm Cr^{3+}(acetate)]

Stage (Step)	Flux, ft/d	1st segment (short)		2nd segment (long)	
		F_{rrw}	F_{rro}	F_{rrw}	F_{rro}
After 2nd WFAG-R (15c)	6.223	6		7	
	3.112	7		7	
	1.556	7		7	
$F_{rrw}=7$ (The average of all the readings for the long segment.)	12.446	5		6	
	1.556	5		7	
After 2nd OFAG-R (16a)	15.56		9		2
$F_{rro}=2$ (The average of all the readings for the long segment.)	7.78		11		2
	3.389		14		2
After 3rd WFAG-R (16c)	1.556	4		4	
	3.112	3		4	
$F_{rrw}=4$ (The average of all the readings for the long segement.)	6.223	3		4	
	3.112	3		4	
	12.446	3		4	
	1.556	3		4	

Table C-2a. Pore Volume Determination from Water-Tracer Studies
Core SSH-36 (Oil Phase: Soltrol-130, Gelant: 3% resorcinol, 3% formaldehyde)

Water-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{or}	S_{gel}
1st waterflood before gel (Step 7)	0.65	0.35	0.34	
1st waterflood after gel (Step 14)	0.53	0.47	0.34	0.13
2nd waterflood after gel (Step 15d)	0.24	0.76	0.49	0.27
3rd waterflood after gel (Step 16)	0.33	0.67	0.49	0.18

Table C-2b. Pore Volume Determination from Oil-Tracer Studies
Core SSH-36 (Oil Phase: Soltrol-130, Gelant: 3% resorcinol, 3% formaldehyde)

Oil-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{wr}	$S_{o(trap)}$
1st oilflood before gel (Step 5)	0.75	0.25	0.27	
1st oilflood after gel (Step 15b)	0.60	0.40	0.36*	0.04
2nd oilflood after gel (Step 16)	0.68	0.32	0.30*	0.02

* $S_{wr}+S_{gel}$

Table C-2c. Pore Volume Determination from Water-Tracer Studies
Core SSH-38 (Oil Phase: Soltrol-130, Gelant: 1.39% HPAM, 212-ppm Cr^{3+})

Water-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{or}	S_{gel}
1st waterflood before gel (Step 7)	0.70	0.30	0.30	
1st waterflood after gel (Step 14)			0.31	
2nd waterflood after gel (Step 15d)			0.28	
3rd waterflood after gel (Step 16)			0.27	
4th waterflood after gel (Step 17)	0.14	0.86	0.29	0.57

Table C-2d. Pore Volume Determination from Oil-Tracer Studies
Core SSH-38 (Oil Phase: Soltrol-130, Gelant: 1.39% HPAM, 212-ppm Cr^{3+})

Oil-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{wr}	$S_{o(trap)}$
1st oilflood before gel (Step 5)	0.75	0.25	0.29	
2nd oilflood before gel (Step 8)	0.75	0.25	0.26	
1st oilflood after gel (Step 15b)	0.10	0.90	0.60*	0.30
2nd oilflood after gel (Step 16)	0.11	0.89	0.62*	0.27
3rd oilflood after gel (Step 17)	0.16	0.84	0.58*	0.26
4th oilflood after gel (Step 18)	0.18	0.82	0.56*	0.26

* $S_{wr}+S_{gel}$

Table C-2e. Pore Volume Determination from Water-Tracer Studies
Core SSH-43 (Oil Phase: Soltrol-130, Gelant: 0.4% CPAM, 1,520-ppm glyoxal)

Water-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{or}	S_{gel}
1st waterflood before gel (Step 7)	0.70	0.30	0.28	
1st waterflood after gel (Step 14)			0.28	
2nd waterflood after gel (Step 15d)	0.43	0.57	0.31	0.26
3rd waterflood after gel (Step 16)	0.58	0.42	0.40	0.02

Table C-2f. Pore Volume Determination from Oil-Tracer Studies
Core SSH-43 (Oil Phase: Soltrol-130, Gelant: 0.4% CPAM, 1,520-ppm glyoxal)

Oil-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{wr}	$S_{o(trap)}$
1st oilflood before gel (Step 5)	0.74	0.26	0.27	
1st oilflood after gel (Step 15b)	0.43	0.57	0.44*	0.13
2nd oilflood after gel (Step 16)	0.64	0.36	0.33*	0.03
3rd oilflood after gel (Step 17)	0.67	0.33	0.22*	0.11

* $S_{wr}+S_{gel}$

Table C-2g. Pore Volume Determination from Water-Tracer Studies
Core SSH-44 (Oil Phase: Soltrol-130, Gelant: 0.3% CPAM, 1,140-ppm glyoxal)

Water-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{or}	S_{gel}
1st waterflood before gel (Step 7)	0.72	0.28	0.26	
1st waterflood after gel (Step 14)			0.26	
2nd waterflood after gel (Step 15d)	0.62	0.38	0.31	0.07
3rd waterflood after gel (Step 16)	0.68	0.32	0.38	0.00
4th waterflood after gel (Step 17)	0.70	0.30	0.41	0.00

Table C-2h. Pore Volume Determination from Oil-Tracer Studies
Core SSH-44 (Oil Phase: Soltrol-130, Gelant: 0.3% CPAM, 1,140-ppm glyoxal)

Oil-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{wr}	$S_{o(trap)}$
1st oilflood before gel (Step 5)	0.75	0.25	0.28	
1st oilflood after gel (Step 15b)	0.53	0.47	0.40*	0.07
2nd oilflood after gel (Step 16)	0.60	0.40	0.33*	0.07
3rd oilflood after gel (Step 17)	0.64	0.36	0.29*	0.07

Table C-2i. Pore Volume Determination from Water-Tracer Studies
Core SSH-51 (Oil Phase: Soltrol-130, Gelant: 1.39% HPAM, 212-ppm Cr^{3+})

Water-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{or}	S_{gel}
1st waterflood before gel (Step 7)	0.67	0.33	0.33	
2nd waterflood before gel (Step 8)	0.68	0.32	0.34	
3rd waterflood before gel (Step 9)	0.68	0.32	0.35	
4th waterflood before gel (Step 10)	0.69	0.31	0.36	
1st waterflood after gel (Step 14)			0.35	
2nd waterflood after gel (Step 15d)			0.44	

Table C-2j. Pore Volume Determination from Oil-Tracer Studies
Core SSH-51 (Oil Phase: Soltrol-130, Gelant: 1.39% HPAM, 212-ppm Cr^{3+})

Oil-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{wr}	$S_{o(trap)}$
1st oilflood before gel (Step 5)	0.78	0.22	0.26	
2nd oilflood before gel (Step 8)	0.81	0.19	0.22	
3rd oilflood before gel (Step 9)	0.77	0.23	0.22	
4th oilflood before gel (Step 10)	0.76	0.24	0.23	
1st oilflood after gel (Step 15b)	0.11	0.89	0.50*	0.49
After 1st Soltrol/paraffin cycle	0.22	0.78	0.46*	0.32
After 2nd Soltrol/paraffin cycle	0.29	0.71	0.43*	0.28

* $S_{wr}+S_{gel}$

Table C-2k. Pore Volume Determination from Water-Tracer Studies
Core SSH-60 (Oil Phase: Soltrol-130, Gelant: 1.39% HPAM, 212-ppm Cr^{3+})

Water-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{or}	S_{gel}
1st waterflood before gel (0 psi)	0.67	0.33	0.31	
1st waterflood before gel (1500 psi)	0.69	0.31	0.31	
1st waterflood after gel (0 psi)	0.16	0.84	0.24	0.6
1st waterflood after gel (1500 psi)	0.20	0.80	0.24	0.56

Table C-2l. Pore Volume Determination from Oil-Tracer Studies
Core SSH-60 (Oil Phase: Soltrol-130, Gelant: 1.39% HPAM, 212-ppm Cr^{3+})

Oil-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{wr}	$S_{o(trap)}$
1st oilflood before gel (0 psi)	0.74	0.26	0.24	
1st oilflood before gel (1500 psi)	0.75	0.25	0.24	
2nd oilflood before gel (0 psi)	0.75	0.25	0.24	
2nd oilflood before gel (1500 psi)	0.75	0.25	0.24	
1st oilflood after gel (0 psi)	0.12	0.88	0.60*	0.28
1st oilflood after gel (1500 psi)	0.15	0.85	0.59*	0.26
1st oilflood after gel(0 psi)	0.18	0.82	0.58*	0.24

* $S_{wr}+S_{gel}$

Table C-2m. Pore Volume Determination from Water-Tracer Studies
Core SSHM1 (Oil Phase: Soltrol-130, Gelant: 0.3% PAM-AMPS, 100-ppm Cr^{3+})

Water-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{or}	S_{gel}
1st waterflood before gel (Step 7)	0.65	0.35	0.35	
2ndt waterflood before gel (Step 8)	0.63	0.37	0.35	
3rd waterflood before gel (Step 9)	0.65	0.35	0.34	
4th waterflood before gel (Step 10)	0.65	0.37	0.33	
1st waterflood after gel (Step 14)	0.40	0.60	0.33	0.27
2nd waterflood after gel (Step 15d)	0.41	0.59	0.35	0.24
3rd waterflood after gel (Step 16)	0.41	0.59	0.37	0.22

Table C-2n. Pore Volume Determination from Oil-Tracer Studies
Core SSHM1 (Oil Phase: Soltrol-130, Gelant: 0.3% PAM-AMPS, 100-ppm Cr^{3+})

Oil-tracer study	V_p/V_{po}	$1-V_p/V_{po}$	S_{wr}	$S_{o(trap)}$
1st oilflood before gel (Step 5)	0.74	0.26	0.30	
2nd oilflood before gel (Step 8)	0.78	0.22	0.30	
3rd oilflood before gel (Step 9)	0.74	0.26	0.31	
4th oilflood before gel (Step 10)	0.74	0.26	0.32	
1st oilflood after gel (Step 15b)	0.50	0.50	0.52*	0.00
2nd oilflood after gel (Step 16)	0.50	0.50	0.46*	0.04

* $S_{wr}+S_{gel}$

Table C-3a Relative Dispersivities from Water-Tracer Studies,
(Core ID: SSH-36, Berea sandstone; Oil phase: Soltrol; Gelant: Resorcinol-formaldehyde)

Water-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st waterflood before gel treatment (Step 7)	16	39
After 1st waterflood after gel treatment (Step 14)	59	60
After 2nd waterflood after gel treatment (Step 15d)	142	81
After 3rd waterflood after gel treatment (Step 16d)	84	54

Table C-3b Relative Dispersivities from Oil-Tracer Studies,
(Core ID: SSH-36, Berea sandstone; Oil phase: Soltrol; Gelant: Resorcinol-formaldehyde)

Oil-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st oilflood before gel treatment (Step 5)	2	2
After 1st oilflood after gel treatment (Step 15b)	5	4
After 2nd oilflood after gel treatment (Step 16b)	4	3

Table C-3c Relative Dispersivities from Water-Tracer Studies,
[Core ID: SSH-38, Berea sandstone; Oil phase: Soltrol; Gelant: 1.39% HPAM, 212-ppm Cr^{3+}(acetate)]

Water-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st waterflood before gel treatment (Step 7)	21	47
After 4th waterflood after gel treatment (Step 17d)	168	85

Table C-3d Relative Dispersivities from Oil-Tracer Studies,
[Core ID: SSH-38, Berea sandstone; Oil phase: Soltrol; Gelant: 1.39% HPAM, 212-ppm Cr^{3+}(acetate)]

Oil-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st oilflood before gel treatment (Step 5)	2	1
After 2nd oilflood before gel treatment (Step 8)	2	1
After 1st oilflood after gel treatment (Step 15b)	123	112
After 2nd oilflood after gel treatment (Step 16b)	57	59
After 3rd oilflood after gel treatment (Step 17b)	43	33
After 4th oilflood after gel treatment (Step 18b)	24	25

Table C-3e Relative Dispersivities from Water-Tracer Studies,
(Core ID: SSH-43, Berea sandstone; Oil phase: Soltrol; Gelant: 0.4% CPAM, 1,520-ppm glyoxal)

Water-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st waterflood before gel treatment (Step 7)	15	32
After 2nd waterflood after gel treatment (Step 15da)	99	77
After 2nd waterflood after gel treatment (Step 15db)	98	55
After 3rd waterflood after gel treatment (Step 16d)	43	43

Table C-3f Relative Dispersivities from Oil-Tracer Studies,
(Core ID: SSH-43, Berea sandstone; Oil phase: Soltrol; Gelant: 0.4% CPAM, 1,520-ppm glyoxal)

Oil-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st oilflood before gel treatment (Step 5)	1	1
After 1st oilflood after gel treatment (Step 15b)	12	8
After 2nd oilflood after gel treatment (Step 16b)	3	2
After 3rd oilflood after gel treatment (Step 17b)	2	2

Table C-3g Relative Dispersivities from Water-Tracer Studies,
(Core ID: SSH-44, Berea sandstone; Oil phase: Soltrol; Gelant: 0.3% CPAM, 1,140-ppm glyoxal)

Water-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st waterflood before gel treatment (Step 7)	6	8
After 2nd waterflood after gel treatment (Step 15d)	100	90
After 3rd waterflood after gel treatment (Step 16d)	65	65
After 4th waterflood after gel treatment (Step 17d)	62	55

Table C-3h Relative Dispersivities from Oil-Tracer Studies,
(Core ID: SSH-44, Berea sandstone; Oil phase: Soltrol; Gelant: 0.3% CPAM, 1,140-ppm glyoxal)

Oil-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st oilflood before gel treatment (Step 5)	2	2
After 1st oilflood after gel treatment (Step 15b)	11	11
After 2nd oilflood after gel treatment (Step 16b)	6	6
After 3rd oilflood after gel treatment (Step 17b)	5	5

Table C-3i Relative Dispersivities from Water-Tracer Studies,
[Core ID: SSH-51, Berea sandstone; Oil phase: Soltrol; Gelant: 1.39% HPAM, 212-ppm Cr^{3+}(acetate)]

Water-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st waterflood before gel treatment (Step 7)	4	4
After 2nd waterflood before gel treatment (Step 8)	3	3
After 3rd waterflood before gel treatment (Step 9)	3	3
After 4th waterflood before gel treatment (Step 10)	3	3

Table C-3j Relative Dispersivities from Oil-Tracer Studies,
[Core ID: SSH-51, Berea sandstone; Oil phase: Soltrol; Gelant: 1.39% HPAM, 212-ppm Cr^{3+}(acetate)]

Oil-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st oilflood before gel treatment (Step 5a)	1	1
After 1st oilflood before gel treatment (Step 5c)	1	1
After 2nd oilflood before gel treatment (Step 8)	1	1
After 3rd oilflood before gel treatment (Step 9)	1	1
After 4th oilflood before gel treatment (Step 10)	1	1
After 1st oilflood after gel treatment (Step 15ba)	87	67
After 1st oilflood after gel treatment (Step 15bc)	27	18
After 1st oilflood after gel treatment (Step 15bc)	13	10
After 2nd oilflood after gel treatment (Step 16ba)	54	46
After 2nd oilflood after gel treatment (Step 16bc)	21	14

Table C-3k Relative Dispersivities from Water-Tracer Studies,
[Core SSH-60, Berea sandstone; Oil phase: Soltrol; Gelant: 1.39% HPAM, 212-ppm Cr^{3+}(acetate)]

Water-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st waterflood before gel treatment (0 psi)	36	44
After 1st waterflood before gel treatment (1500 psi)	28	34
After 1st waterflood after gel treatment (0 psi)	59	36
After 1st waterflood after gel treatment (1500 psi)	34	19

Table C-31 Relative Dispersivities from Oil-Tracer Studies,
[Core SSH-60, Berea sandstone; Oil phase: Soltrol; Gelant: 1.39% HPAM, 212-ppm Cr^{3+}(acetate)]

Water-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st oilflood before gel treatment (0 psi)	1	1
After 1st oilflood before gel treatment (1500 psi)	1	1
After 2nd oilflood before gel treatment (0 psi)	1	1
After 2nd oilflood before gel treatment (1500 psi)	1	1
After 1st oilflood after gel treatment (0 psi)	15	13
After 1st oilflood after gel treatment (1500 psi)	14	8
After 1st oilflood after gel treatment (0 psi)	11	9

Table C-3m Relative Dispersivities from Water-Tracer Studies,
[Core ID: SSHM1, Berea sandstone; Oil phase: Soltrol;
Gelant: 0.3% PAM-AMPS, 100-ppm Cr^{3+}(acetate)]

Water-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st waterflood before gel treatment (Step 7)	62	68
After 2nd waterflood before gel treatment (Step 8)	58	68
After 3rd waterflood before gel treatment (Step 9)	44	71
After 4th waterflood before gel treatment (Step 10)	30	59
After 1st waterflood after gel treatment (Step 14)		299
After 2nd waterflood after gel treatment (Step 15d)	104	93
After 3rd waterflood after gel treatment (Step 16d)	97	72

Table C-3n Relative Dispersivities from Oil-Tracer Studies,
[Core ID: SSHM1, Berea sandstone; Oil phase: Soltrol;
Gelant: 0.3% PAM-AMPS, 100-ppm Cr^{3+}(acetate)]

Oil-tracer study	α/α_0(10/90)	α/α_0(20/50)
After 1st oilflood before gel treatment (Step 5)	1	1
After 2nd oilflood before gel treatment (Step 8)	1	1
After 3rd oilflood before gel treatment (Step 9)	2	1
After 4th oilflood before gel treatment (Step 10)	2	1
After 1st oilflood after gel treatment (Step 15b)	16	8
After 2nd oilflood after gel treatment (Step 16b)	5	4