O300.8 D479 C. 1

DETERMINATION OF RESIDUAL OIL SATURATION

OKLAHOMA DEPARTMENT OF LIBRARIES
OKLA. PUBLICATIONS CLEARINGHOUSE
COPY 1

Interstate Oil Compact Commission

OKLAHOMA PUBLICATIONS CLEARINGHOUSE
OKLAHOMA DEPARTMENT OF LIBRARIES
200 N. E. 18th ST.
OKLAHOMA CITY, OK 73105

DETERMINATION OF RESIDUAL OIL SATURATION

INTERSTATE OIL COMPACT COMMISSION
OKLAHOMA CITY, OKLAHOMA

June, 1978
Copyright© by The Interstate Oil Compact Commission
Printed in the United States of America. All Rights Reserved.
Library of Congress Catalog Card Number: 77-78927

PREFACE

Four years ago, the Interstate Oil Compact Commission was privileged to publish "Secondary and Tertiary Oil Recovery Processes," the first of what is now planned to be a trilogy. That publication essayed to present the current state of the art for all known recovery processes. Its success is shown by the fact it shortly will go into its second printing.

Almost immediately after that publication, the same editors commenced putting together this work, "Determination of Residual Oil Saturation." Increased need for domestic petroleum and somewhat brighter economics have stimulated the evolution in this field of study along with other research efforts in the petroleum industry. The editors have bravely attempted to keep up with these developments. The Compact is particularly grateful to the principal editor, Dr. Donald C. Bond, as well as his associates in this project, Dr. Fred H. Poettmann and Dr. Claude R. Hocott. We are equally thankful for the major effort expended by the authors of each of the chapters herein. All have been dedicated and have served without financial remuneration.

These men are making a contribution towards what the Compact believes to be an attainable goal — the energy sufficiency of this nation.

W. Timothy Dowd
Executive Director

June, 1978

INTRODUCTION

The Executive Committee of the IOCC, at a meeting in Fort Worth, Texas, March 15, 1971 adopted this motion with respect to the activities of the Research Committee of the IOCC:

> The Research Committee is charged with the responsibility of reporting to the Commission on new theories and improvements in existing methods of the conservation of oil and gas. It should select projects that will keep the Commission and the Compact states advised of technological advances being studied and used in the development of energy sources consistent with good conservation practices. In this connection, the Research Committee is encouraged to be creative and imaginative in its approach to increasing the existing recovery of hydrocarbons.

In response to this directive, the Research Committee of the IOCC formed an Oil Recovery Subcommittee, whose purpose was to summarize technical information about processes for the secondary and tertiary recovery of oil. The Subcommittee prepared a book which was published by the IOCC in 1974 under the title, "Secondary and Tertiary Oil Recovery Processes."

In the preparation of that book the members of the Subcommittee, and of the Research Committee itself, became more and more aware of the importance of the determination of the amount of oil in a reservoir. They saw that accurate knowledge of the oil content of a reservoir was critical in the economic evaluation of any prospect for enhanced recovery after conventional recovery by primary and by injection of water or gas.

Therefore, in 1975 the Research Committee set up a Residual Oil Subcommittee to study this question: "How can we determine how much residual oil is in a reservoir, available for enhanced

recovery?"

The members of the Residual Oil Subcommittee are:

D. C. Bond, Chairman	L. F. Elkins
R. J. Blackwell	C. R. Hocott
F. W. Cole	E. H. Koepf
H. A. Deans	F. H. Poettmann
R. C. Earlougher, Jr.	R. E. Wyman

Their study has resulted in the present book: "Determination of Residual Oil Saturation."

Various members of the Subcommittee were responsible for writing the different chapters of the book:

R. J. Blackwell wrote Chapter I on "Residual Oil Saturation and Tertiary Oil Recovery" and Appendix A on "Tertiary Oil Recovery Processes";

E. H. Koepf, Chapters II and III on "Coring Methods" and "Core Handling — Core Analysis Methods";

F. W. Cole, Chapter IV on "Volumetric Methods and Production Data";

R. E. Wyman, Chapter V on "Logging Methods";

R. C. Earlougher, Jr., Chapter VI on "Well-Testing Methods";

H. A. Deans, Chapter VII on "Single-Well Tracer Methods";

and L. F. Elkins, Chapters VIII and IX on "Evaluation" and "Results — Recommendations."

Although the authors listed above are responsible for the content of their chapters, some of the chapters present a consensus of the Subcommittee. Chapters I, VIII, and IX, in particular, give the thinking of most of the Subcommittee. In places where significant difference of opinion exists, we have tried to present both viewpoints.

An editorial board consisting of D. C. Bond, C. R. Hocott and F. H. Poettmann reviewed and edited the various chapters and assembled them into the final book. Certain chapters were edited by Mary Ann Noonan and Ione Nielsen, of the editorial staff of the Illinois State Geological Survey; figures in some of the chapters were drafted by Marie Martin, of the staff of the

Survey. We are grateful for this help from the Survey. W. Timothy Dowd, Executive Director of the IOCC, and Margaret Ray, of the IOCC staff, were extremely helpful in editing and in coordinating the effort.

This book is designed to aid middle-management people (engineers, geologists, and others) who need to make decisions about the possibilities for enhanced recovery of oil from specific reservoirs. Although the book is not written primarily for researchers or specialists, they, too, may find much of it useful.

We need to say a word about the terms "enhanced recovery" and "tertiary recovery." In some circles "enhanced recovery" covers waterflooding as well as more exotic oil recovery processes. However, as used in this book, "enhanced recovery" means recovery that is enhanced with respect to that which is obtained by conventional water- and gas-injection methods. "Tertiary recovery" is loosely equivalent to "enhanced recovery," but the two terms are not necessarily equivalent; for example, polymer flooding, being non-conventional, could be classed as an enhanced-recovery method, although it might not be a tertiary method.

Ideally, when considering the prospects for enhanced recovery, we should know the amount of oil in the part of a reservoir that has been contacted by injected water and we should know how this oil is distributed within the reservoir. This information is needed if we are to make estimates of the amount of oil that is susceptible to being mobilized by an oil recovery agent. In reality, though, we can learn only the oil saturation at points near a well bore, or the average saturation over a considerable volume of the reservoir, depending upon the method used.

The methods that are described here do not necessarily measure exactly the same quantity. Each author describes the target for measurement by his method. The various techniques—and the quantities that are measured—are compared in Chapters I, VIII, and IX.

Differences in oil saturation exist from point to point in a water-flooded reservoir. These may be caused by saturation gradients that result from the water-flood process itself, particularly in an oil-wet reservoir. Or differences can be caused by

heterogeneities in the rock. Present technology permits the estimation of these differences imperfectly, at best. A future volume on heterogeneity and oil recovery is being prepared for the IOCC by a Subcommittee of the Research Committee headed by Charles J. Mankin.

D. C. Bond
Chairman
Residual Oil Subcommittee

CONTENTS

PREFACE v

INTRODUCTION vii

LIST OF FIGURES xvii

LIST OF TABLES xxii

Chapter I

RESIDUAL OIL SATURATION AND TERTIARY OIL RECOVERY 1
by R. J. Blackwell
Introduction 1
TOR Potential 2
Definition of Residual Oil Saturation 4
Estimation of Residual Oil Saturations 6
Sensitivity of TOR Process Economics to Residual Oil Saturation 9
Summary 11

Chapter II

CORING METHODS 13
by E. H. Koepf
Introduction 13
Effects of Formation Rock Properties 14
Selection of Drilling Mud Properties 14
Coring Methods 18
Conventional Diamond-Bit Coring 19
Rubber-Sleeve Coring 24
Pressure Core Barrel 28
Summary and Conclusions 32

Chapter III

CORING HANDLING—CORE ANALYSIS METHODS 36
by E. H. Koepf
Introduction 36
Sampling and Preservation of Core at Rig Site 39
Conventional Diamond Cores 39
Cores Cut With Pressure Core Barrel 40
Analytical Techniques 41
Permeability 41
Porosity 42
Fluid Saturations 45
Fluid Saturations from Core Samples Obtained by Pressure-Core Barrel 47
Waterflood Displacement Studies 48
Basic Waterflood Tests 49
Water-Oil Relative Permeability Data 49
Use of Native-State, Fresh, or Restored-State Cores 50
Use of Nonsteady-State or Steady-State Conditions 51
Supplemental Tests 54
Porosity Reduction with Overburden Pressure 54
Electrical Measurements 57
Cation Exchange Capacity 59
Wettability 61
Acoustic Velocity 63
Grain Density 66
Summary and Conclusions 66

Chapter IV

VOLUMETRIC METHODS AND PRODUCTION DATA 72
by Frank Cole
Introduction 72
Production History 72
Calculating Residual Oil Saturation 74
Production History Plots 77
Material Balance Equation 81
Models 84
Summary 86
Nomenclature 87

Chapter V

LOGGING METHODS 89
by Richard E. Wyman
Introduction 89
Resistivity Log 91
Resistivity Log-Inject-Log 93
Summary of Resistivity Log-Inject-Log Techniques 94
Pulsed Neutron Capture Log 95
Conventional PNC Log Techniques 96
Log-Inject-Log Waterflood Technique 96
Log-Inject-Log With Strip 98
Corrections Needed for PNC Tool Readings 100
Summary of PNC Log-Inject-Log Techniques 102
Nuclear Magnetism Log 104
Conventional NML Logging for Heavy Oil 105
Inject-Log Technique for Normal Crude Reservoirs 105
Summary of NML Inject-Log Technique 109
Carbon/Oxygen Log 109
Gamma Radiation Log 111
Dielectric Constant Logging 112
Conclusions 112
Nomenclature 114

Chapter VI

WELL-TESTING METHODS 117
by Robert C. Earlougher, Jr.
Introduction 117
Single-Well Transient Testing Methods 118
Drawdown Testing 118
Buildup Testing 126
Estimating Saturations 131
Multiple-Well Testing Methods 135
Interference Testing 135
Estimating Saturations 143
Computer Methods 144
Estimating Saturations from Production Rates 145
Summary 149
Nomenclature 150

Chapter VII

SINGLE-WELL TRACER METHODS 156
by H. A. Deans
Introduction 156
Theory of Tracer Movement 157
Possible Field Test Procedures 159
Two-Well Method 159
Single-Well Methods 160
Tracer Chemicals 162
Design and Implementation of a Typical Single-Well Test 163
Factors Influencing Feasibility and Sensitivity of Test 170
Test-Well Preparation 170
Planning Test-Fluid Volume 171
Test-Fluid Handling 171
Summary of Field Experiences 173
Conclusions 174
Nomenclature 175

Chapter VIII

EVALUATION 177
by Lincoln F. Elkins
Introduction 177
Comparison of Residual Oil Saturation:
Material Balance vs Other Methods 178
Porosity Measurements: Consolidated Formations 180
Field Examples of Comparisons of Porosities 182
Effects of Compaction: Consolidated Formations 184
Porosity Measurements: Unconsolidated Formations 188
Initial Water Saturation 190
Interpretation of Resistivity Logs 190
Coring With Oil-Base Drilling Fluids 196
Restored-State Capillary Pressure Tests 197
Residual Oil Saturation: Watered-Out Areas 199
Vertical Variations in Oil Saturation 201
Areal Variations in Oil Saturation 206
Newer Log and Core Methods of Determining
Residual Oil Saturation 219
Pulsed Neutron Capture Logs 219
Pulsed Neutron Capture Logs: Log-Inject-Log 220
Induction Logs: Log-Inject-Log 224
Nuclear Magnetism Logs 225
Core Analysis 226

EVALUATION (Continued)

Determining Residual Oil Saturation by Reservoir Performance 230
Material Balance Estimates of Oil-in-Place 231
Determining Residual Oil Saturation from Well Tests 234
Determining S_{or} From Total Compressibility 235
Determining S_{or} From Effective Permeability 236
Determining S_{or} From Water-Oil Ratios 242
Single-Well Tracer 243
Background 243
Vertical Variations: Porosity, Permeability and Residual Oil Saturation 245
Alteration of Properties of Residual Oil by Injection of Brine 251
Determination of Residual Oil Saturations, Comparison of Results of All Methods 254

Chapter IX

RESULTS—RECOMMENDATIONS 262
by Lincoln F. Elkins
Introduction 262
Summary of Residual Oil Saturation Determinations—Sandstone Reservoirs 264
S_{or} From Formation Resistivity 264
S_{or} From Pulsed Neutron Capture Logs 266
S_{or} From Pressure Cores 267
S_{or} From Single-Well Tracer Tests 268
Relation of Residual Oil Saturation to Reservoir Properties — Sandstone Reservoirs 269
Comparison of Residual Oil Saturations, Subsurface Measurements Versus Other Studies — Sandstone Reservoirs 273
Summary of Residual Oil Saturation Determinations — Carbonate Reservoirs 277
Geographical and Geological Distribution of Residual Oil Saturation 284
Selection of Methods to Determine Residual Oil Saturation 284
Summary 289

Appendix A

TERTIARY OIL RECOVERY PROCESSES 291
by R. J. Blackwell
Description of TOR Processes 294

Appendix B

AUTHORS AND EDITORS 298

LIST OF FIGURES

Chapter I

Figure 1 — Comparison of waterflood behavior for mixed-wettability and water-wet cores. 5
Figure 2 — Sensitivity of TOR economics to residual oil saturation (hypothetical reservoir). 10

Chapter II

Figure 1 — Example of clean sandstone (upper) and vuggy, fractured limestone. 15
Figure 2 — Conventional diamond-bit coring tool. 19
Figure 3 — Recommended rotating speeds for diamond core bits. .. 23
Figure 4 — Rubber-sleeve core barrel showing three positions. 26
Figure 5 — Rubber-sleeve core. 28
Figure 6 — Pressure-retaining core barrel. 29
Figure 7 — System for displacing coring fluids from pressure core barrel. 31

Chapter III

Figure 1 — Typical fluid contents of a core sample, from reservoir to surface — virgin oil-productive formation. 37
Figure 2 — Typical fluid contents of a core sample, from reservoir to surface — waterflooded or pressure depleted oil reservoir. 38
Figure 3 — Typical water-oil relative permeability characteristics, fresh and restored-state samples. 52
Figure 4 — Typical water-oil relative permeability characteristics, fresh and restored-state samples. 52
Figure 5 — Typical water-oil relative permeability characteristics, steady-state and nonsteady-state displacements. 53
Figure 6 — Porosity reduction with overburden pressure. 56
Figure 7 — Typical water-oil relative permeability characteristics, water-wet and oil-wet samples. 64
Figure 8 — Typical water-oil relative permeability characteristics, water-wet and oil-wet samples. 64

Figure 9 — Effect of overburden on acoustic velocity and calculated porosity, Gulf Coast siliceous sandstone. 65
Figure 10 — Effect of overburden on acoustic velocity and calculated porosity, West Texas dolomite. 65

Chapter IV

Figure 1 — Typical waterflood decline curve, semi-log plot. 77
Figure 2 — Relationship between oil-producing rate and water-injection rate. 78
Figure 3 — Produced water/oil ratio vs. cumulative oil produced. .. 79
Figure 4 — Log-log decline curve. 80

Chapter V

Figure 1 — Diagrammatic summary of resistivity log-inject-log technique. 94
Figure 2 — Diagrammatic summary of PNC log-inject-log waterflood technique. 97
Figure 3 — Diagrammatic illustration of PNC log-inject-log strip technique. 99
Figure 4 — Correction to apparent neutron decay time. 101
Figure 5 — NML signals before and after deadening water. 104
Figure 6 — Diagrammatic illustration of NML inject-log technique. . 106
Figure 7 — Oscillograms of NML signals. 108
Figure 8 — Carbon/oxygen ratio in laboratory sand formation. 111

Chapter VI

Figure 1 — Idealized rate schedule and pressure response for a drawdown test. 119
Figure 2 — Log-log graph of pressure drawdown data. 120
Figure 3 — Semilog graph of pressure drawdown data. 120
Figure 4 — Influence region for a drawdown or buildup test. 125
Figure 5 — Idealized rate schedule and pressure response for a pressure buildup test. 126
Figure 6 — Log-log graph of pressure buildup data. 127
Figure 7 — Horner graph of pressure buildup data. 128
Figure 8 — Miller-Dyes-Hutchinson graph of pressure buildup data. 130
Figure 9 — Example of relative permeability curves. 132
Figure 10 — Schematic of active and observation wells in an interference or pulse test. 135
Figure 11 — Idealized rate schedule and pressure response for an interference test in which the rate is decreased. 136

Figure 12 — Approximate influence region in interference and pulse testing. 136
Figure 13 — Type curve for interference test analysis (exponential integral). 138
Figure 14 — Steps in type-curve matching for interference test analysis. 139
Figure 15 — Illustration of type-curve matching for interference test data analysis. 143
Figure 16 — Relative permeability ratio curve for relative permeability data of Figure 9. 146
Figure 17 — Log-log plot used to estimate fluid saturations from three-phase production data. 147

Chapter VII

Figure 1 — Movement of tracer chemical *i* with oil and water in a typical pore. 157
Figure 2 — The reversibility problem in a single-well test with two tracers. 161
Figure 3 — Avoiding the reversibility problem by producing the second tracer in situ. 162
Figure 4 — Equilibrium distribution coefficients for ethyl acetate in a hypothetical oil-brine system at reservoir temperature. 165
Figure 5 — Tracer concentration data for the production phase of a hypothetical single-well tracer test. 168
Figure 6 — Best-fit computer model simulation of the ethyl acetate and methanol data to obtain drift and dispersion. 169
Figure 7 — Computer model simulation of ethanol data using best-fit drift and dispersion parameters and various values of S_{or} 169

Chapter VIII

Figure 1 — Comparison of residual oil saturations determined by material balance and residual oil saturations determined by other methods. 179
Figure 2 — Simulation of effects of overburden pressure on porosity of a consolidated sandstone. 186
Figure 3 — Relations between formation resistivity factor and porosity for sandstone reservoirs. 192
Figure 4 — Relations between formation resistivity factor and porosity for carbonate reservoirs. 193

Figure 5 — Simulation of effects of overburden pressure on formation resistivity factor of a consolidated sandstone. 195
Figure 6 — Example of significant variation in residual oil saturation in vertical section: Results of log-inject-log study and core analyses, First Wall Creek Sand, Wyoming. 202
Figure 7 — Example of intermediate variation in residual oil saturation in vertical section: Results of resistivity log analysis and core analyses, Bartlesville Sand, Delaware District, Oklahoma. 203
Figure 8 — Example of minor variation in residual oil saturation in vertical section: Results of electrodrill core analysis, Bartlesville Sand, Tallala Field, Oklahoma. 204
Figure 9 — Example of bypassed oil in vertical section in a very permeable sandstone reservoir, Wesson Field, Arkansas. 205
Figure 10 — Theoretical distribution of residual oil saturation in octant of a 5-spot waterflood after 0.7 pore volume water injected: Computer model study of 119-R area, Robinson Field, Illinois. 207
Figure 11 — Saturation distribution between injectors and producers, 119-R area, Robinson Field, Illinois. 208
Figure 12 — Five-spot waterflood performance, 119-R area, Robinson Field, Illinois. 210
Figure 13 — Areal distribution of residual oil saturations determined from resistivity logs, Tract 97, North Burbank Field, Oklahoma. 212
Figure 14 — Areal distribution of oil saturations determined from conventional core analyses, micellar-polymer test area, El Dorado Field, Kansas. 214
Figure 15 — Comparison of log-derived residual oil saturation and core oil saturation, micellar-polymer test area, El Dorado Field, Kansas. 216
Figure 16 — Areal distribution of log-derived residual oil saturation, micellar-polymer test area, El Dorado Field, Kansas. ... 217
Figure 17 — Comparison of pressure coring and conventional coring results for a water-invaded midcontinent sand. 227
Figure 18 — Conceptual design of ERDA pressure core barrel to minimize flushing of core by mud filtrate. 229
Figure 19 — Results of interference test, micellar-polymer test area, El Dorado Field, Kansas. 237
Figure 20 — Relative permeability to water of Admire Sandstone, micellar-polymer test area, El Dorado Field, Kansas. ... 238
Figure 21 — Simulated single well tracer test, First Wall Creek Sand: Example of significant variation in residual oil saturation in vertical section. 247

Figure 22 — Simulated single well tracer test, Bartlesville Sand: Example of intermediate variation in residual oil saturation in vertical section. 249
Figure 23 — Comparison of residual oil saturations determined by pressure coring and residual oil saturations determined by other methods. 255
Figure 24 — Comparison of residual oil saturations determined by pulsed neutron capture logs and residual oil saturations determined by other methods. 256
Figure 25 — Comparison of residual oil saturations determined by resistivity logs and residual oil saturations determined by other methods. 256
Figure 26 — Comparison of residual oil saturations determined by single well tracer tests and residual oil saturations determined by other methods. 257

Chapter IX

Figure 1 — Residual oil saturations determined from resistivity logs (sandstone reservoirs). 265
Figure 2 — Residual oil saturations determined from PNC logs (sandstone reservoirs). 266
Figure 3 — Residual oil saturations determined from pressure cores (sandstone reservoirs). 268
Figure 4 — Residual oil saturations determined from single-well tracer tests (sandstone reservoirs). 269
Figure 5 — Residual oil saturations determined from resistivity logs, effect of permeability (sandstone reservoirs). 270
Figure 6 — Residual oil saturations determined from PNC logs, effect of permeability (sandstone reservoirs). 272

LIST OF TABLES

Chapter I

Table 1 — Crude Oil Potential of TOR in the U. S. 2
Table 2 — Comparison of Residual Oil Saturation 7

Chapter III

Table 1 — Comparison of Results of Combination-Type Analysis and Conventional Summation of Fluids Analysis on Cores Containing Hydratable Clays 45
Table 2 — Effect of Overburden Pressure on Porosity — Cockfield "D" Sand 56
Table 3 — Effect of Confining Pressure on Porosity 57

Chapter V

Table 1 — Logging Tools and Techniques to Determine Residual Oil 91

Chapter VI

Table 1 — Dimensionless Pressure Function for Interference Testing — Infinite System (Exponential Integral) Solution 137
Table 2 — A Part of the Data Used to Construct Figure 17 148

Chapter VIII

Table 1 — Comparative Residual Oil Saturation Estimates Using Various Logging and Coring Devices 221
Table 2 — Comparison of $(\phi \cdot S_w)$ Values Calculated from the Modified PNC and the TDT-K 221
Table 3 — Comparative Residual Oil Saturation Estimates Using Various Logging and Coring Devices - San Andres Dolomite 222
Table 4 — Residual Oil Saturations Derived from Interference Test and Pressure Falloff Test El Dorado Micellar-Polymer Demonstration Project 240

Table 5 — Idealized First Wall Creek Test 246
Table 6 — Idealized Bartlesville Test 248
Table 7 — Comparison of 10-Layer Input Data and Single Layer Interpretation Simulated Single Well Tracer Tests 250

Chapter IX

Table 1 — Residual Oil Saturations — Carbonate Reservoirs 277
Table 2 — Residual Oil Saturations in Watered-Out Areas Sandstone and Carbonate Reservoirs Data From Literature and IOCC Survey 278
Table 3 — Basic Tools and Techniques to Determine Residual Oil Saturation 285
Table 4 — Suggested Procedures For Determining Residual Oil Saturation 286

Appendix A

Table 1 — Guidelines for Selection of TOR Candidates 292

Chapter I

RESIDUAL OIL SATURATION AND TERTIARY OIL RECOVERY

INTRODUCTION

The determination of the amount and distribution of oil remaining in a reservoir is essential for several reasons. Reservoir engineers have always required estimates of residual oil saturation (ROS) in order to estimate recoverable reserves by primary and secondary recovery methods. A more precise knowledge of the distribution of oil is a critical prerequisite in selection, design and evaluation of the economics of tertiary oil recovery (TOR) methods.

Although tertiary oil recovery methods have been under investigation for several decades, net oil production from their application is still small as compared to that from conventional primary and secondary techniques. This low level of application has been due in part to the need for further technological advances and in part to the much higher investments and operating costs associated with these more-complicated processes. In the light of increasing need for new petroleum reserves and of the changing economic environment, questions which naturally arise are: 1) To what extent can TOR methods add to U.S. oil reserves? and 2) At what cost?

Answers to both questions depend not only on the effectiveness of the various TOR processes but also very strongly on the amount of oil remaining after a waterflood in the portions of the

reservoir which will be contacted during a TOR flood. Although the various tertiary oil processes have been discussed extensively in the literature, a brief review of the basic characteristics and potential of TOR processes is included in Appendix A of this book. A review of TOR potential forecasts and the critical need for reliable estimates of the amounts of oil that can be contacted by TOR processes is presented in the following section.

TOR POTENTIAL

Several studies have been made of TOR potential in the U.S. Results from three of these studies are summarized in Table 1.

Table 1. Crude Oil Potential of TOR in the U.S.

	Potential Reserves (billions of barrels)
GURC[1] (1975)	
- from present methods	17.7 - 35.5
- with improved economics	33.6 - 40.7
- with improved methods and economics	50.3 - 61.0
FEA[2] (1976) (3 states)	
- average oil price $11.28/bbl	30.5
NPC[3] (1976)	
- oil price $15/bbl	(14 ?)
- oil price $25/bbl	(24 ?)

The GURC forecast of 17.7-61.0 billion barrels was based on a survey of scientists and companies with experience in TOR processes. Although the estimates "from present methods" were intended to reflect current TOR capabilities under favorable economic conditions, the economic conditions implicit in the estimates are not given, nor are the economic conditions corresponding to "improved economics" specified. Thus, even though this forecast appears to be somewhat more optimistic than those given by the other studies, a direct comparison with the other forecasts is not possible.

The FEA study used a data base of 245 reservoirs (175 fields) in California, Texas, and Louisiana; the reservoirs were screened

for the suitability of various processes. Reservoirs passing the screens were then subjected to an economic study based on simple process models and projections of the cost of injected materials, costs for drilling and completing new wells, workover costs, operating expenses, etc. The reserve estimate of 30.5 billion barrels was obtained for an "upper bound case" corresponding to an assumed average oil price of about $11.28 per barrel.

The NPC followed an approach similar to that used in the FEA study. However, for each of three dominant processes—miscible CO_2, surfactant flooding, and thermal—the TOR potential at roughly comparable oil prices was one-third to one-half that estimated in the FEA study. Since the detailed calculations made in the FEA study are not available, the difference in the two estimates cannot be accounted for with complete certainty.*

However, the difference in TOR potential appears to have arisen at least in part from the different methods used in the two studies to estimate the recoverable oil saturation in the reservoir volume swept by the injected fluids. The FEA study used the average residual oil saturation obtained from material-balance calculations. The recoverable oil saturation was estimated using the assumption that this average saturation was distributed uniformly throughout each reservoir. In the NPC study of surfactant flooding potential, lower residual oil saturations, corresponding to the waterflood residuals obtained in core analysis measurements, tracer studies, etc., were used. These lower values were assumed to approach the oil saturations remaining in the zones to be contacted during a surfactant flood.

Besides using a different method to estimate the residual oil saturation in the TOR target zone, the NPC study assumed that the average oil saturation remaining *after* a surfactant flood was 10 percent pore volume. This value was based on limited field test results and laboratory flood tests, run at rates of 1 ft/day or at a maximum pressure gradient of 2 psi/ft. In the earlier FEA study a value of 5 percent pore volume was assumed. This difference resulted in higher estimates of the recoverable oil saturation

*A comparison of the results obtained in the NPC study with those obtained in other studies is contained in Reference 3.

in the FEA study. In view of the uncertainties involved in estimating the recoverable oil saturation, the NPC report includes a sensitivity study in which the "base case" recoverable oil saturation was both increased and decreased by 5 percent pore volume. As discussed later in this chapter, the economics of surfactant flooding are extremely sensitive to this critical parameter. Since this parameter would be expected to vary with the surfactant system slug size, the extent to which a favorable mobility ratio can be achieved, and other factors, field tests will usually be required (at least until additional field experience with surfactant flooding has been obtained) to determine the optimum slug size for any given field application.

Despite these differences, the results presented in Table 1 show that with proper economic incentives, TOR processes could make a significant contribution to future U.S. oil production from known oil reservoirs. Futhermore, the results illustrate graphically the critical need for reliable measurements of the amounts of oil remaining in reservoirs that can be contacted and flushed by TOR processes.

DEFINITION OF RESIDUAL OIL SATURATION

The term "residual oil saturation" is used in many different contexts in the literature. These include:

(1) the irreducible oil saturation,
(2) an average (or material-balance) saturation, and
(3) the oil saturation remaining in the water-swept zones.

The irreducible oil saturation (IOS) is often used as a definition for ROS. The IOS is the oil saturation at which the remaining oil becomes immobile or completely trapped. Whereas an irreducible saturation can frequently be approached in a strongly water-wet rock (containing a low viscosity oil) by injecting approximately one pore volume of water, much larger volumes of water are required for mixed wettability systems. In some rocks a small but finite permeability to oil remains even after the rock has been flushed with many (several thousand) pore volumes of water. A comparison is presented in Figure 1 (from Salathiel[4]) for a water-wet core and for the same core

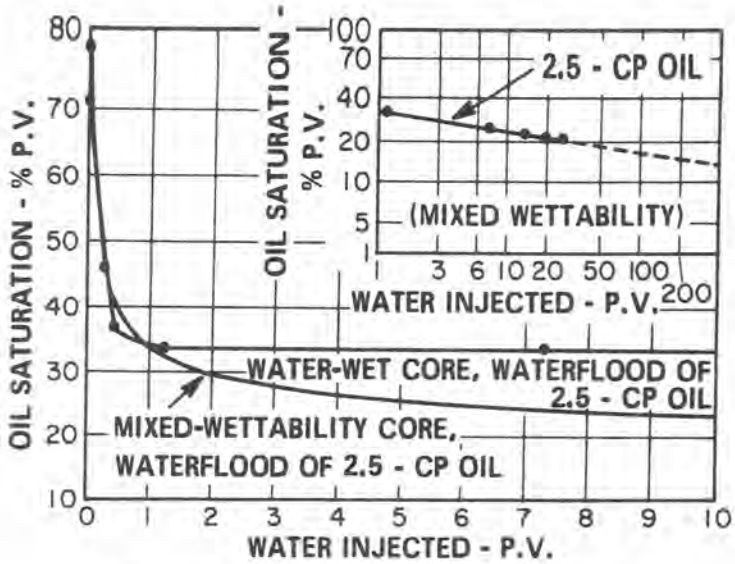

Figure 1 — Comparison of Waterflood Behavior for Mixed-wettability and Water-wet Cores (insert shows extension of mixed-wettability flooding data). *(Modified from Salathiel.[4])*

material after conversion to a mixed wettability system that strongly resembles East Texas field cores. In the mixed wettability system the producing water-oil ratio becomes very high (in excess of 100/1) long before the oil saturation approaches an "irreducible" value. In reservoirs such as the East Texas Field, oil saturation finally reached depends not only upon the total water throughput but also upon other factors such as gravity segregation of oil that occurs within stringers during the life of a flood. In such reservoirs it is possible that irreducible saturation will be reached near the injection wells, but the IOS must not be used as the measure of the oil saturation remaining in much of the reservoir.

Likewise, the average (or material-balance) oil saturation (AOS) remaining in a reservoir at the conclusion of a waterflood is frequently used for ROS. This estimate of residual oil (like IOS) can be misleading. Errors caused by the use of the average oil saturation arise because the remaining oil is not distributed uniformly. Variations in saturation are caused by numerous factors, including gravity segregation, permeability stratification,

areal heterogeneities, and differences in total water throughput in different parts of the field. Because of such factors, the average oil saturation (AOS) remaining in the reservoir can be only slightly larger than the saturation in the flushed zones or it may be significantly larger.

From a practical viewpoint the residual oil saturation (ROS) of particular interest is that which is left behind in the more permeable water-swept zones when the producing water-oil ratio reaches its economic limit. This definition is frequently used in the evaluation and design of many TOR processes.

Since this portion of the reservoir is the part that is most likely to be contacted during a TOR flood, it would be desirable to have a complete description of the oil saturations remaining in various parts of a reservoir. Unfortunately, no single method exists for obtaining this distribution although information obtained from two or more methods can sometimes be used to improve our knowledge of the total volume and location of "residual" oil. The objective of this book is to present an overview of the capabilities and limitations of the various methods that are commonly used for estimating ROS.

ESTIMATION OF RESIDUAL OIL SATURATIONS

Methods for measuring residual oil saturations to be discussed in this book are:

- core analysis
- specialized coring
- reservoir engineering studies
- logging
- pressure transient measurements (combined with core analysis data), and
- chemical tracer studies.

Each method has its advantages and limitations. Normally, data from several methods will be used in making estimates of the amount and distribution of residual oil remaining after a waterflood. Some methods (e.g., material-balance calculations obtained from studies of reservoir performance) yield an overall average residual for the reservoir. Others (e.g., specialized coring

and logging methods) provide data for the vertical distribution of residual oil in the immediate vicinity of the well bore. Still others (e.g., tracer studies) can sample a larger fraction of the reservoir—but provide an average residual saturation that is weighted in favor of the saturations remaining in more-permeable zones in the reservoir.

Which method or combination of methods is most useful in TOR evaluations depends on specific reservoir geology, individual reservoir production history, etc. In practice, because of the criticality of such information in evaluating the economic feasibility of TOR processes, information from all the above methods would be used if it were available.

The following somewhat simplified example illustrates benefits that can be obtained by combining the results of two methods: material-balance calculations and data from tracer tests. Data obtained for five reservoirs, using these methods, are presented in Table 2.

Table 2. Comparison of Residual Oil Saturation

	Residual Oil Saturation		
Field	Material Balance (MB) % Pore Volume	Tracer Test % Pore Volume	Ratio MB/Tracer
A	16	12	1.3
B	25	12	2.1
C	32	20	1.6
D	40	29*	1.4
E	44	12	3.7

*Measured in cores obtained using a pressure retaining core barrel.

As indicated earlier, material-balance calculations provide the average oil saturation remaining in a reservoir after a waterflood, but provide no information about the oil's distribution. On the other hand, tracer tests tend to measure the amount of oil remaining in the more permeable stringers most easily contacted during the subsequent application of a TOR process. Furthermore, as pointed out in Chapter IV and other chapters, the

residual oil value that is calculated by material balance is subject to considerable uncertainty; the value is sometimes unrealistically high. In making comparisons such as those outlined here, we should take into consideration the uncertainty in the material balance value. However, for purposes of comparison we assume here that the estimates in Table 2 are reliable.

Table 2 presents sets of residual oil values obtained from material balance and from tracer tests, as well as the ratios of the material-balance values to those obtained in tracer tests. A ratio of 1.0 can be interpreted as indicating a uniform distribution of residual oil; a high ratio indicates that much oil was left in areas not contacted by the tracer tests. Presumably, that oil is inaccessible to injected fluids during a TOR flood. In the case of Field A, we note a material-balance value of 16 percent and a tracer value of 12 percent. Both values of ROS are far too low for the practical application of existing tertiary recovery technology; it is unlikely that any appreciable reserves would be discovered by drilling extra wells between existing producers (the ratio of 1.3 indicates fairly even distribution of oil). Fields B and E are interesting from an infill drilling viewpoint, because the material-balance residuals are about 2.0 and 3.7 times, respectively, the 12 percent values remaining in the flushed zones (as indicated by tracer tests). These ratios suggest that considerable oil remains in isolated pockets in these fields. Hence, there is an opportunity for additional near-term oil production by infill drilling between existing wells if, and only if, it can be established that the incremental volume of crude is sufficient to economically justify the additional wells. Since the remaining oil saturation is only 12 percent, there is little potential for a tertiary recovery process by itself. Nevertheless, a combined infill drilling and tertiary recovery program could possibly recover reasonable volumes of oil that would otherwise be left in the ground. Field D with its 29 percent residual in the flushed zone and an overall material-balance residual of 40 percent would appear from these comparisons to have the best potential for a tertiary oil recovery process. It would be necessary to make economic calculations to determine whether it is or is not a good TOR candidate.

It is not necessary to make detailed economic calculations,

however, to arrive at a number of general observations. For example, the amounts of surfactant and polymer required for surfactant flooding depend primarily on total pore volume of the portions of the reservoir processed by the surfactant slug; the amounts are much less dependent on the amount of residual oil present in that region. Thus, a surfactant process in Field D has the potential of recovering almost 2.5 times the volume of oil per pound of chemical injected than it would from Field A. In Field D, for each barrel of oil produced, approximately 10 to 15 pounds of surfactants and other necessary chemicals might be required, so a TOR process may or may not be economically attractive. However, in Fields A, B, or E, we would anticipate recovering less than 40 percent as much oil for the same amount of chemical, so it is very unlikely that any enhanced recovery process could be economically attractive in these fields.

Additional benefits can be obtained by adding information obtained from other methods such as logging measurements or specialized coring procedures. The following section considers the impact that errors in estimating the residual oil saturation can have on the profitability of a TOR process.

SENSITIVITY OF TOR PROCESS ECONOMICS TO RESIDUAL OIL SATURATION

The volume of oil that can be recovered by any TOR process will obviously affect the profitability of its application in any reservoir. However, the relationship between economic viability and residual or recoverable oil is particularly important for expensive, front-end-loaded processes such as surfactant flooding.

Typically, a surfactant flood involves a rather large initial expense. It will usually require reworking old wells, drilling some new wells, and installing or remodelling oil production facilities—but the most significant cost is that of the surfactant system slug. These initial expenses are essentially independent of oil saturation. However, the saturation in the portion of the reservoir flushed by the surfactant slug affects not only the total amount of oil that can ultimately be recovered during a TOR flood but also the flood's response time, that is, the time required for the

banked-up oil ahead of the slug to reach a producing well. In general, the response time increases when the initial oil saturation decreases. The increase in response time can significantly decrease the profitability of a TOR project.

Sensitivity of TOR economics to residual oil saturation is illustrated in Figure 2 for a hypothetical reservoir. The rate of return of a surfactant flood is shown for residual oil saturations*

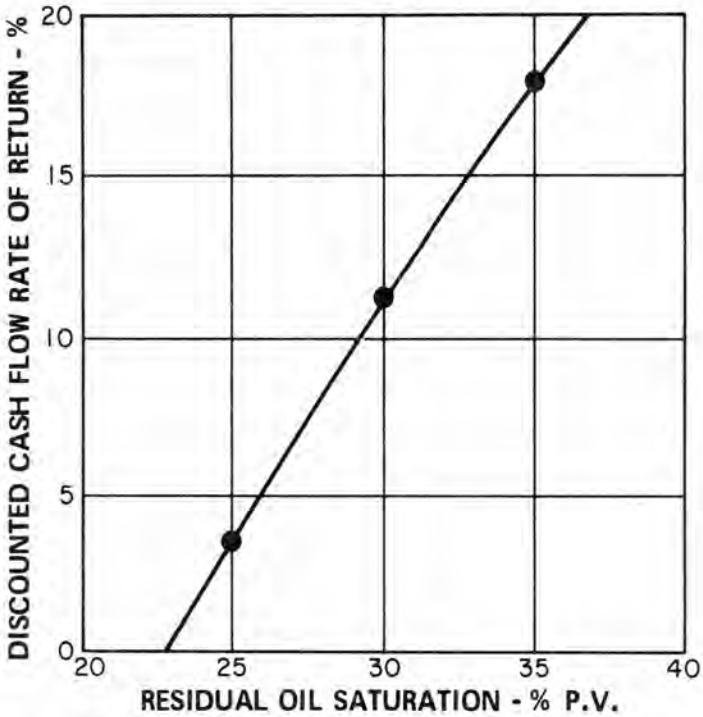

Figure 2 — Sensitivity of TOR Economics to Residual Oil Saturation (hypothetical reservoir).

* Because of process inefficiencies, unswept low-permeability regions, etc., the recoverable or target oil saturation will normally be somewhat less than the residual oil saturation. For this example, the recoverable oil saturation was assumed to be 10 percent PV smaller than the residual saturation, for all three saturations.

of 25, 30 and 35 percent pore volume. For a residual oil saturation of 30 percent pore volume, the rate of return is 11 percent. However, the rate of return drops to 3.4 percent for an ROS equal to 25 percent and increases to 17.8 percent for an ROS equal to 35 percent. For this hypothetical reservoir, the rate of return increases or decreases about 1.5 percent for each 1 percent pore volume change in the residual oil saturation; a small error in the residual oil estimate could change the predicted profitability of a project from a level that would encourage its implementation to a level that might (incorrectly) discourage any further consideration. In other reservoirs, the oil saturation critical to a surfactant process may be higher or lower than indicated by the example. However, even though this critical saturation will be different in a different reservoir and for different TOR processes, the basic concept applies to all TOR processes. Furthermore, even though an error of 10 percent pore volume in the oil saturation can normally be tolerated when primary or secondary recovery decisions are made, an error as small as 5 percent pore volume can lead to economic disaster in a TOR project.

SUMMARY

There is a need for methods of determining accurately the total amount and the distribution of oil remaining in a reservoir at the beginning of a TOR project. The need for these measurements will undoubtedly encourage continued research to improve them. Similarly, there will be increasing emphasis on the use of geologic studies,* (particularly with regard to the potential impact of rock heterogeneities and zone continuity) in conjunction with a suite of residual oil measurements, for evaluating and planning potential TOR applications.

This book is intended to present the state of the art of residual oil saturation measurements. Improvements in this type of measurement are likely. It is not intended to be a "do-it-yourself"

---

* Rock heterogeneity, stringerization, etc. can adversely affect the use of TOR processes. An I.O.C.C. book on the use of geologic studies in TOR applications has been proposed.

cookbook. It is intended to convey a clear picture of how such measurements are made, their accuracy and reliability. Finally, it presents an overall review of the advantages and disadvantages of the various methods.

REFERENCES

1. Anonymous: Preliminary Field Test Recommendations and Prospective Crude Oil Fields or Reservoirs for High Priority Field Testing, Gulf Universities Research Consortium Report No. 148, February 1976, Fig. 1, p. 6.
2. Anonymous: The Potential and Economics of Enhanced Oil Recovery, Lewin and Associates, Inc., Final Report, for FEA, April 1976, p. 13.
3. Anonymous: Enhanced Oil Recovery - An Analysis of the Potential for Enhanced Oil Recovery from Known Fields - 1976 to 2000, National Petroleum Council, December 1976.
4. Salathiel, R.A.: Oil Recovery by Surface Film Drainage in Mixed-Wettability Rocks, Trans. AIME, **255**, 1973, p. 1216-1224.

Chapter II

CORING METHODS

INTRODUCTION

Values for residual oil saturation in reservoirs may be derived from a number of indirect types of measurement, but studies of cores provide the only direct measurement of the rock properties and the flow characteristics of the reservoirs. The use of core analysis data alone will usually provide an accurate evaluation, but the combined use of core analysis data and data from the other types of evaluation measurements will lend confidence to the evaluation.

The principal role of tertiary processes is to recover oil that is left in a waterflooded or partially depleted reservoir. An even greater degree of confidence in the estimates of oil in place is required when considering tertiary recovery projects than is required when evaluating the exploitation of newly discovered reserves, because of the higher cost per barrel of the oil recovered in a tertiary process. Rathmell *et al*[1] point out that uncertainties in waterflood sweep efficiency make estimates of residual oil saturation by material balance questionable; thus, an in situ evaluation is very desirable.

No one has yet developed a tool that will permit recovery of a core sample at the surface without altering some of the in situ properties and the fluid content. Two major problems are encountered.

The first results from filtrate invasion as the coring fluid flushes the formation ahead of the coring bit. Jenks *et al*[2] and other investigators have shown that the entire cross section of small cores, measuring up to 3½ inches in diameter, is usually flushed; thus, a near residual saturation of the mobile, displaced phase results.

Exceptions may occur in laminar sections; the impermeable layers in these sections prevent flushing ahead of the bit. Also, where the reservoir oil viscosity is high, flushing may be somewhat less than where the oil viscosity is low. Choice of the proper drilling fluid will usually permit determination of either residual oil saturation or residual water saturation, but not both with the same fluid. A careful choice of drilling fluid components and the control of drilling fluid properties and the rig operating variables can be used to minimize the flushing action and to permit evaluation of a residual saturation value.

The second major problem is caused by the expansion of gas and the expulsion of liquid as the core is brought to the surface and the pressure declines. This problem can be overcome by the use of a pressure-retaining core barrel.

EFFECTS OF FORMATION ROCK PROPERTIES

Formation rock properties are important in evaluating the reliability of estimates of residual oil saturation that are based upon core properties and core analysis. Clean, or nonshaly, permeable sandstones are usually flushed essentially to residual oil during coring; evolution and expansion of gas during transport to the surface further reduce the oil content. Tight, dirty sandstones and laminar, bedded zones are flushed to varying degrees. Vuggy, fractured cores usually show a highly flushed condition. Figure 1 exemplifies samples of nonshaly, permeable sandstone and vuggy, fractured limestone cores. The electrical and wettability properties of the reservoir rock may be affected appreciably by the composition and the properties of the drilling fluid.

SELECTION OF DRILLING MUD PROPERTIES

The drilling mud that is used in coring must be compatible with formation fluids and with the objectives of the coring project. The coring fluid must: 1) control wellbore pressure, 2) suspend weighting material and lift cuttings, 3) control loss of fluids to penetrated formations, and 4) cool and lubricate the bit. Drilling mud filtrate displaces some portion of the in-place mobile fluids from the core when any currently available coring tools are used.

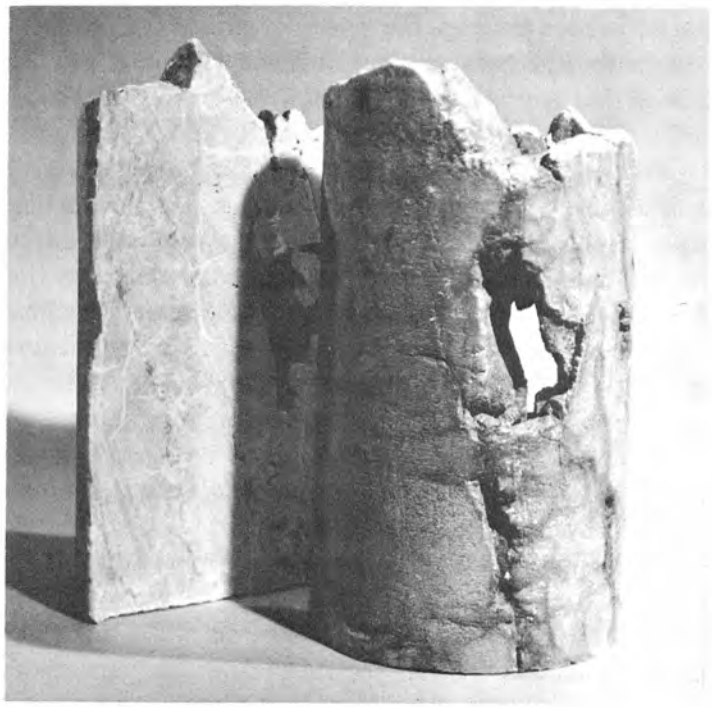

Figure 1 —Example of clean sandstone (upper) and vuggy, fractured limestone.
(Courtesy of Core Laboratories, Inc.)

Thus, a low filtrate loss and a filtrate that has minimum effect upon the saturation of the fluid being evaluated are desirable. Determination of residual oil saturation requires that no oil be introduced from the mud filtrate. Conversely, the determination of interstitial water requires that oil, rather than water, constitute the filtrate. The use of caustic or surfactants should be avoided or minimized, and minimally treated water-base muds should be used where unaltered wettability is an objective of the coring.[3-4-5]

According to Murphy and Owens,[6] the principal factors that influence the degree of invasion of drilling fluid filtrate include: 1) formation vertical permeability, 2) overbalance of pressure between the mud column and the formation, 3) spurt loss value for the mud (rapid fluid loss to the porous media, the loss occurring before and during the formation of a filter cake), which is controlled by the particle-size distribution in the mud, 4) rate of bit penetration, 5) interfacial tension between the reservoir oil and the filtrate, and 6) core diameter. In laboratory studies made with microbits, Jenks *et al*[2] showed that overbalance of pressure exerts more influence under normal coring conditions than do other factors.

Drilling mud systems that are used in coring to evaluate residual oil saturation vary widely. Normally, a bland mud system that has a low spurt loss[2] and a standard filtrate loss of less than 10 cc is desirable. Checks of filtrate loss should be made under dynamic conditions at regular intervals[7] in an effort to maintain a low value of approximately 1.5 cc/hr/sq in., measured at a given shear rate. In low-pressure, shallower formations a simple fresh-water or salt-water mud may be used. Some operators report[8] the use of plant injection water, similar in composition to the formation water, or the use of formation water[9] as the coring fluid. The use of formation water is ideal because the clay minerals and other solid surfaces within the formation are already in equilibrium with it. In order to permit identification of movable oil zones by means of electrical logs, it is desirable to match the resistivities of the filtrate and the formation water as closely as possible; this procedure enhances the accuracy of conventional log analysis.[7] If the composition of the formation water is not known, a simple 90% NaCl-10% $CaCl_2$ synthetic brine will probably provide a sufficiently close match to the ratio of monovalent cations to bivalent cations in the formation

water to avoid shocking the formation clays.

In some instances, salt/gel or pregelatinized starch muds have been used [5-7] as the coring fluid when coring to evaluate residual oil saturation. Bentonite, carboxymethyl cellulose, bactericides, and certain surface-active materials are usually required with these muds; the filtrate will cause changes in the wettability of the rock.

Mud filtrate may have a marked effect upon the wettability characteristics of the rock. If subsequent checks for wettability are to be made on the core samples, the coring fluid should contain no surface-active agents and a minimum of any treating agents. Deaerated brine or formation water containing an oxygen scavenger may be used[5] to minimize effects of the filtrate.

Because all cores are invaded to some extent by mud filtrate, it is frequently desirable to use a tracer in the mud fluid; the tracer will permit determination of the amount of filtrate in the sample. Tritium is an excellent tracer and is frequently used.[7-10-11-12] Tritiated hydrocarbons can be added to oil-emulsion or oil-base muds as an effective tracer.

Mud weight is an important factor in designing the mud system. Jenks *et al*[2] have shown that pressure overbalance is probably the most important factor in limiting the stripping of oil from the core by mud filtrate. An overbalance of 200 to 300 psi has been suggested[2-6-12] as desirable, but other constraints frequently make it necessary to core with an overpressure of 1,000 to 2,000 psi. In the coring of a loosely consolidated formation, the use of nitrogen[6] to lighten the mud column and to reduce pressure overbalance resulted in apparent disintegration and loss of the core. However, during the coring of a carbonate formation containing both intergranular and vuggy porosities, nitrogen was used[12] to lighten the mud column and no unfavorable effects were noted. All precautions should be taken to maintain the lowest practical mud weight during coring.

The pH of the mud system should be maintained at a relatively low level of 7.5 to 8.5. Mud filtrates with a high pH tend to alter the wettability characteristics of the cores and to reduce the residual oil saturation to levels appreciably below those in the reservoir. Therefore, in coring to evaluate residual oil saturations in reservoirs, the use of caustic and other surface-active agents should be avoided or minimized.

CORING METHODS

Coring service companies offer wireline coring systems, conventional core barrels, and specialty coring facilities of several varieties. Much of the coring uses diamond bits, but milled-tooth core bits also can be used quite effectively with the different types of core barrels. Cable tool coring occasionally is employed in shallow operations, but its use is quite limited because the core segments are thin in the vertical dimension and the core is essentially flushed. Wireline coring was rather widely used in the 1930s and 1940s. Its use declined as the need for large core samples to provide data for reservoir engineering evaluation became more important. The so-called, conventional rotary double-tube barrel, which normally uses a diamond coring bit, is reported[13] to be the most commonly used system today. However, the use of this system for core recovery from semiconsolidated, friable formations and from highly fractured zones is sometimes unsatisfactory. The rubber-sleeve core barrel is a specialty coring tool which was developed to provide better core recovery from unconsolidated, broken, or poorly cemented conglomerate formations. In this operation, as the core is cut, the rubber sleeve is pulled over the core progressively to encase the core in the rubber sleeve. In both the conventional and the rubber-sleeve coring systems, the core undergoes pressure reduction as it is brought to the surface. Therefore, liquid (oil and/or water) saturations measured on the recovered core may be considerably less than saturations in the reservoir; this is, in part, due to shrinkage resulting from liberation of dissolved gas and, in part, is due to the flushing action of the gas as pressure declines.

Several types of pressure core barrels have been designed to minimize or to eliminate decompression of the core after cutting. The Carter Oil Company reported the development of one of the first of these units in 1939.[14] Numerous improvements in design now permit use of the pressure core barrel; it has a recovery efficiency of more than 80 percent, can recover cores in 10-foot lengths, and can work to pressures in excess of 4,000 psi. The pressure core barrel does not eliminate flushing by the filtrate during coring, but all fluids that are in the core when cutting is completed are still in the core when it is recovered at the surface. The pressure core barrel is

now being used widely in special field studies to evaluate in-place residual oil saturations after waterflood. A review of the development of the tool and a summary of its uses in evaluating residual oil saturations has been presented by Hagedorn and Blackwell.[12]

Conventional Diamond-Bit Coring

General features of a conventional double-tube, swivel-type rotary diamond coring tool are shown in Figure 2. In this core

Figure 2 —Conventional diamond-bit coring tool.
(Courtesy of Christensen, Inc.)

barrel, the outer tube is connected to the drill-collar string directly above it and to a core bit below. A steel inner tube with a core-catching device is suspended on bearings inside the barrel, and the nonrotating inner barrel is pushed down over the core as it is cut. A collet-type of core catcher slides over the core. When the barrel is picked up, the inner-tube shoe closes the collet on the core, which breaks off when tension is applied. A split inner-tube core barrel may be used for coring structurally complex formations, if use of the rubber-sleeve core barrel is not justified. The split tube eliminates the need to hammer or to pump on the core to get it out of the inner tube.

The principal problems of conventional coring are core jamming and incomplete recovery.[13] Fractured core is sometimes lost when coming out of the hole. Incomplete recovery frequently results when bridging occurs in the barrel, and new core is pulverized by the bridging that prevents its entering the barrel.

Conventional diamond core barrels normally consist of two sections of 25 feet or 30 feet each, but three or more sections can be used where conditions are suitable. Core sizes can be selected from a range of 1⅞ inches to 5¼ inches in diameter. While core is being cut, a ball-type valve is used to divert the mud flow from the inner barrel to the annulus between the inner and outer tubes; the valve can either be run in place with the barrel or it can be dropped from the surface. If extensive circulation is required while going into the hole, or if lost-circulation material is being used, the ball is left out until the bit is properly on bottom and is then dropped into place. Sand content of the drilling mud should be low to minimize the wear on barrel parts, but muds with 70 to 80 percent of lost-circulation material can be handled satisfactorily if the material is well dispersed.

Stepwise, detailed instructions for assembling and maintaining core barrels are contained in the manufacturer's literature and are presented in *Drilling Manual,* International Association of Drilling Contractors.[15] The instructions point out the importance of maintaining a clean borehole throughout the coring operation. Hazards to core bits include junk metal in the hole, pyrites, fractured formations, and conglomerates with one hard component. Suggested practices to insure a clean hole for coring

include: 1) Fish out all cones or bearings, if indicated; 2) Keep tong dies securely keyed in place; 3) Keep a wiper on the pipe when going into or out of a hole; and 4) Use a junk basket or a similar tool with the last few roller bits before coring.

Sufficient drill collars should be used to insure that the drill string is in tension at all times. When going to the bottom with a diamond core bit, stop at least two feet off the bottom and regulate the pump strokes to deliver the proper fluid capacity for the diamond bit that is being used. Then lower the bit to the bottom without rotating (if possible), in order to pump any metal pieces or hard formation fragments off the bottom. Then raise the bit to two or three feet off the bottom and rotate slowly (40 to 50 r.p.m.) while lowering it back to the bottom. Gradually increase the drilling weight and the r.p.m. until the maximum penetration rate is obtained.

As the bit becomes firmly embedded and develops its cutting pattern, the pump pressure, with fixed pump stroke rate, increases. The increase in pressure is due to the pressure drop across the face of the bit. The pump stroke rate may require some adjustment to maintain the desired volume. The pressure that is established after the bit begins drilling is very important and must be watched constantly during the coring operation. Any appreciable increase or decrease of this pressure is a definite indication of abnormal operation. The cause should be determined and corrected immediately to prevent damage to the bit and to insure recovery of the core.

Following are some of the problems that may influence pump pressure, along with recommended procedures for dealing with these problems:

1. If any change in pump pressure occurs, check pump strokes for volume output.
2. Bit failure allows the formation to wear into the bit matrix, restricting fluid passages and increasing pump pressure. Raising the bit off the bottom will reduce the pressure; setting it back on the bottom will cause the pressure to increase to the value noted before raising. If the symptoms are definite, pull the bit.

3. A plugged circulatory system will cause increased pressure. The pressure will remain unchanged when the bit is raised off the bottom. Coring may be continued, but it is a blind and hazardous operation; best practice is to come out of the hole and correct the problem.
4. Spotty, unbalanced mud condition may cause increased or decreased pressure. Correct the mud condition as rapidly as possible.
5. Wedged core holding the bit off the bottom causes decreased pressure, accompanied by loss of torque and slow drilling time. This occurs when coring harder formations; usually, the bit cannot be forced to cut. Come out of the hole.
6. A washout in the drill string will result in a significant pressure loss. Torque and penetration rate will help define the cause. Continue coring, or come out of the hole; the decision depends upon the degree of pressure loss and other conditions.
7. Fluctuating pump pressures frequently occur when coring softer, fractured formations. Fractures cause the core to wedge; the bit quickly cuts itself free and transfers the weight to the core. The rate of penetration slows appreciably until the weight crushes the soft core in the bit area. As the crushed core washes out through the small waterways, the pressure will increase 50 psi or more. As soon as the crushed core is removed, the pressure will return to normal and the penetration rate will increase. If the pump pressure fluctuates and drilling time is erratic when coring a formation known to be relatively soft and fractured, the core barrel should be pulled frequently to avoid loss of core.

It is not possible to predetermine the most effective combination of weight and rotary speed to use in different formations. The action of a diamond bit is similar to that of a "drag" bit. The weight causes the diamonds to penetrate, and the rotation moves the diamonds that remove the formation. The fluid velocity across the bit face must be sufficient to remove all cuttings and to keep the bit clean and cool so that new formation will be cut with each turn of the bit. Thus, the

rate of penetration is directly related to the mechanical factors of weight and rotary speed, and is related to the hydraulic factors as they affect the efficiency with which the weight and rotary speed are applied. The volume of fluid to be circulated is affected by the well condition, size and design of the bit, type of fluid, depth of hole, drill pipe and core barrel, and pump capacity. The most efficient conditions can be determined after the coring is underway and the core is entering the barrel. Weight and pump pressure should be set within optimum ranges for the well conditions, and the rotary speed should be varied until the best penetration rate is attained. After the desired drilling rate has been established, every effort should be made to keep the weight constant. The use of an automatic driller is recommended, but do not, under any circumstances, use a procedure of increasing the weight and allowing the bit to "drill off." The recommended rotating speeds for diamond core bits when coring different types of formations are shown in Figure 3. Pump pressure, torque, and penetration rate must be watched continuously for indications of malfunction.

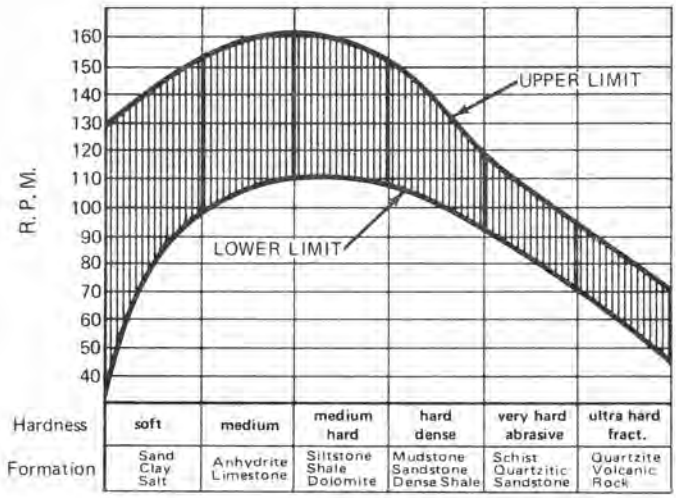

Figure 3 —Recommended rotating speeds for diamond core bits.
(Courtesy of Christensen, Inc.)

Unfortunately, the process of coring and bringing the core to the surface changes the fluid saturations in the core. During the cutting of the core, it is exposed to the circulating fluid, and the circulating fluid filtrate displaces certain of the fluids originally present in the reservoir. Several studies[2-6] have shown that factors such as spurt loss, the overbalance of pressure between the mud column and the formation, and the diameter of the core influence the degree of invasion. The spurt loss and the overbalance of pressure should be maintained at the lowest values that are practical under the existing well conditions, in order to minimize the filtrate invasion. Then, as the core is brought to the surface and the pressure is reduced, dissolved gases are released from solution and cause a portion of the contained fluids to be expelled from the core. Concurrently, the oil content of the core undergoes shrinkage as its dissolved gas is released. Thus, the saturations noted in core samples that are recovered at the surface are usually considerably less than the saturations that exist in the reservoir. Murphy and Owens[6] point out that in cases where the cored interval has been waterflooded and the residual oil contains little or no gas in solution, the in situ reservoir oil saturations will be essentially preserved in the cores as recovered at the surface. Also, Rathmell *et al*[1] have concluded that routine core-analysis oil saturations, adjusted for bleeding and oil shrinkage, can give reliable values for residual oil saturations after waterflooding in many sandstone reservoirs, particularly those where the oil viscosity is low.

Rubber-Sleeve Coring

The Christensen rubber-sleeve core barrel is widely used to improve core recovery in soft, friable formations, conglomerates, and badly fractured hard formations. General features of the operating characteristics of the tool are illustrated in the three photographs of Figure 4. The barrel operates at the end of a conventional drill string, and is rotated by the rotary table. The source of weight for cutting the core is provided by the circulating fluid, which exerts pressure on a nozzle plate. The weight is controlled by the drilling-fluid flow rate and by the number and sizes of the nozzles that are open in the nozzle plate.

The drilling fluids are conducted between the intermediate and

outer tubes of the tool and then out through the face discharge ports of the bit. Thus, the core is exposed to the moving drilling-fluid stream for only the short interval while being cut and while progressing into the rubber sleeve. Specially designed rubber-sleeve core bits minimize the distance between the bit face and the point at which the core enters the rubber sleeve.

The rubber-sleeve core barrel is designed to provide a core three inches in diameter and up to 20 feet in length. The core is encased as it enters the inner barrel. The diameter of the rubber sleeve is slightly smaller than the diameter of the core. As a result, the encased core is continuously and firmly supported and maintained in the same configuration in which it entered the sleeve. Because the rubber sleeve is open at the ends, the core is subjected to pressure and temperature reduction as it is brought to the surface. Thus, the gases released from solution with pressure decline cause shrinkage of the oil volume, and as the gases expand and escape from the core, they expel some of the core fluids. The encased cores are recovered at the surface, are cut into convenient lengths, and the ends of the sections are taped or capped; the cores are then sent to the laboratory for study and/or storage. The fully encased and capped sections do not require freezing or canning before being stored. Sections of an encased core are exemplified in Figure 5.

Drilling-fluid properties and the fluid circulation rate must be closely controlled. The mud-fluid stream provides the weight-on-bit for coring, in addition to its normal functions of removing cuttings and of cooling the bit. Changes in torque must be followed closely for an indication of malfunction. The mechanism of the tool must be reset after each two-foot interval is cored. Because of the high degree of complexity involved in operating this core barrel, a certified technical advisor should assist in the acquainting of field personnel with its operation.

Fluid saturation values determined on rubber-sleeve core do not represent in-place reservoir values. Flushing by the drilling fluid filtrate is essentially the same as in conventional coring. However, the shrinkage and expulsion effects, described above, are less than those encountered in conventional diamond coring. The actual reservoir oil saturation will always be somewhat more than is indicated by the recovered core.

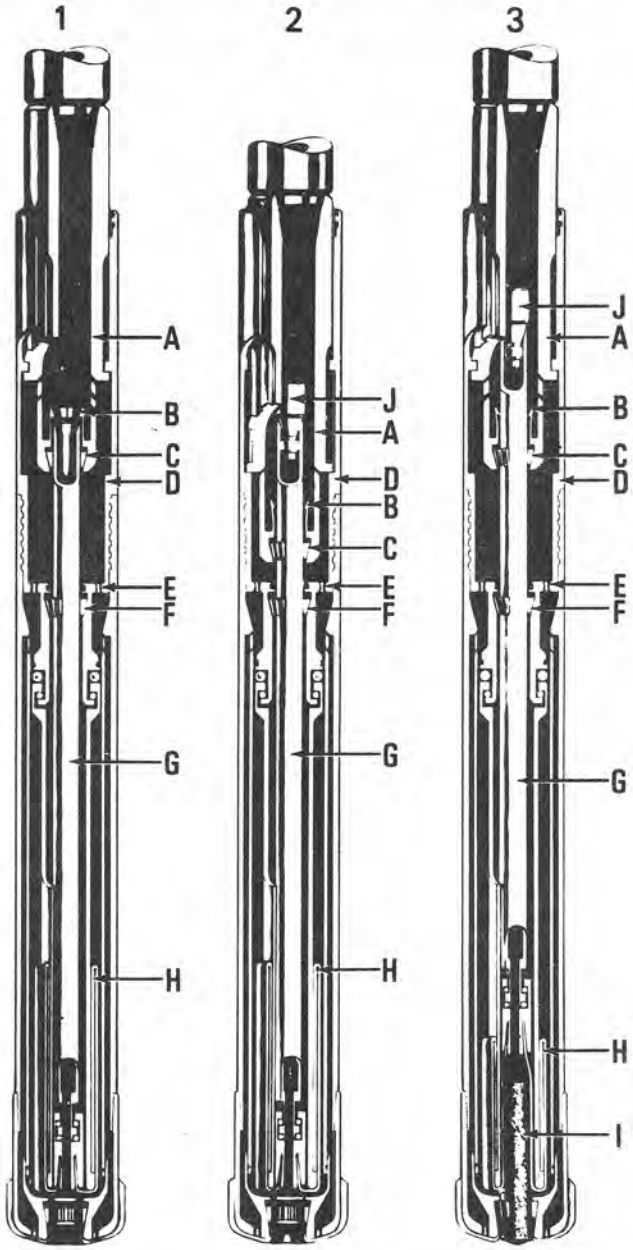

Figure 4 —Rubber-sleeve core barrel showing three positions.
(Courtesy of Christensen, Inc.)

Figure 4

OPERATION: The rubber sleeve core barrel operates at the end of a conventional drill string and is rotated by the rotary table. The source of weight for cutting the core is provided by the circulating fluid which exerts pressure on the nozzle hole-E. Weight is controlled by the flow rate and the number and size of nozzles open in the nozzle plate.

1. Barrel is advanced to bottom and fluid circulated to condition mud. Expansion joint (A) is held in an extended position by the stripper tube latch (B). This latch also restricts the stripper tube (G) from any upward movement. The stripper tube is prevented from moving down through the barrel by the lower stripper tube ratchet spring (F). This spring works on the same principle as does a core spring. Any downward movement of the tube causes the constriction of the spring.

2. The stripper tube release plug (J) has been dropped through the drill string to its seat in the top of the stripper tube (G). The barrel has been set on bottom and the expansion joint (A) collapsed until it shoulders on the top sub (D) a distance of two feet. As coring commences, the upper stripper tube ratchet spring (C) holds the tube and prevents its downward movement. As the lower barrel advances into the formation, it releases the tension of the lower ratchet spring (F) and carries it down the stripper tube.

3. Two feet of core has been cut and the expansion joint (A) is again extended. Notice that rubber sleeve (H) and the core (I) being held by the stripper tube (G) has entered the core barrel. The expansion joint may now again be collapsed, the lower stripper ratchet spring (F) will again prevent downward movement of the tube while the upper ratchet spring (C) is carried down with the expansion joint.

Figure 5 —Rubber-sleeve core.
(Courtesy of Christensen, Inc.)

Pressure Core Barrel

Efforts to develop a pressure-retaining core barrel have been underway for many years. The first design and application of such a core barrel was reported in 1939 by Sewell[14] of the Carter Oil Company; in 1949 Mullane[16] presented extensive data obtained from cores recovered in the Carter pressure core barrel. More recent studies reported by Murphy and Owens,[6] by Hagedorn and Blackwell,[12] and by Thomas and Ausburn[7] indicate that the system has been developed to a state of acceptable reliability. Hagedorn and Blackwell report that about 60 percent recovery was achieved in approximately 2,000 feet of formation cored in 43 projects from 1960 to 1971. They report also that the success ratio since 1966 increased to about 80 percent. However, Thomas and Ausburn report that there was a mechanical failure rate of about 50 percent for their operation. Use of the pressure core barrel is increasing, and it is generally agreed that cores obtained in this manner provide the best opportunity to determine in-place fluid saturations of reservoirs from core samples.

From a mechanical viewpoint, coring with the pressure-retaining core barrel differs from conventional coring only in that the core barrel is closed and sealed after the core is cut and prior to starting out of the hole. However, the design of the pressure core barrel, the associated operating procedures, and the techniques for handling and analyzing the cores are significantly different. At the current state of the art, application of the pressure core barrel should be done in close cooperation with the service company

providing the tool (Loomis International, Inc., P.O. Box 6408, Pasadena, TX 77506). A recent field application (not yet reported) demonstrated a success ratio above 90 percent, but this success was attained through very detailed planning, the checking of equipment and procedures by personnel of the oil company and the service company, and the provision of extensive facilities in the field for assembling and handling the core barrel.

General features of the pressure core barrel are shown in Figure 6. The maximum O.D. of the tool is six inches (at the ball valve housing). The overall length is about 19 feet, including the special

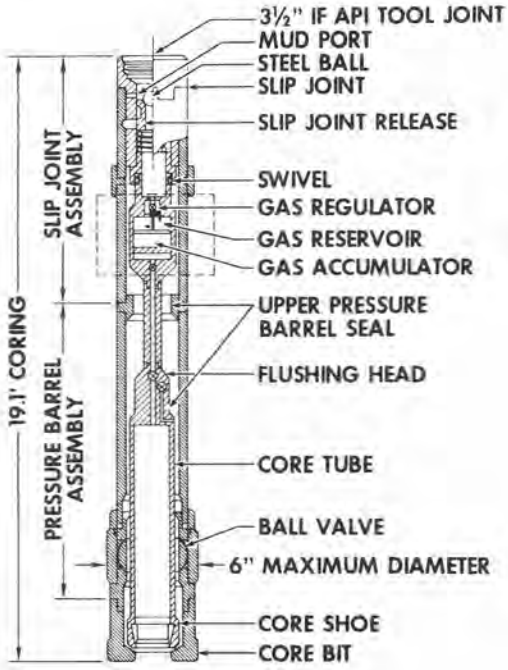

Figure 6 —Pressure-retaining core barrel.
(Courtesy of Loomis International, Inc.; developed and patented by Esso Production Research)

bit. The tool is capable of cutting and recovering 10 feet of 2⅝-inch diameter core and has a maximum working pressure of 4,000 psi. After the core is cut, the barrel is sealed by raising the barrel at least

two feet off the bottom and pumping a 1¼-inch diameter steel ball down the drill pipe to seat in the upper section. Pressure buildup in excess of 200 psi above the ball trips a slip-joint release mechanism. This action frees the outer barrel, and allows it to move down 19 inches relative to the inner barrel. This movement closes both the upper pressure seal and the ball valve, thus trapping the core at reservoir pressure. This downward movement of the outer barrel also uncovers mud ports in the top of the core barrel, permitting mud circulation that, in turn, allows the string to drain as the core barrel is being retrieved.

The tool contains a gas reservoir with a free piston, which acts as a cushion or a pneumatic spring to compensate for volume changes. These volume changes are due to thermal shrinkage of the barrel contents and to barrel expansion that occurs when the external pressure is reduced in coming to the surface.*

Much effort should be expended to minimize filtrate invasion and flushing of the core. Pressure overbalance should be maintained as low as possible, perhaps through the use of aerated mud fluid. The circulation rate should be as low as practical. Optimum bit weight and r.p.m. are varied as required to attain maximum penetration rate and minimize the time the core is exposed to the drilling fluid filtrate. Pump pressure, torque, and penetration rate should be monitored carefully to detect indications of malfunctions or failure of the core to properly enter the barrel.

Core handling procedures for pressure cores are more complicated than those for conventional cores; furthermore, the procedures differ in the coring of a predominantly oil-bearing zone or a water-invaded, gas-bearing zone. Figure 7 presents a schematic of the apparatus that is used when recovering a core from an oil zone. The coring fluid is displaced from the annular space between the inner and outer barrels with a gelled kerosene. The kerosene provides good displacement efficiency and will not solidify at dry ice temperatures. The coring fluid is displaced under a pressure at, or

---

*Christensen, Inc. is currently experimenting with a pressure-coring system similar to the Exxon (formerly Carter) system. It is possible that Christensen will offer an improved coring service, based on the results of their current testing.

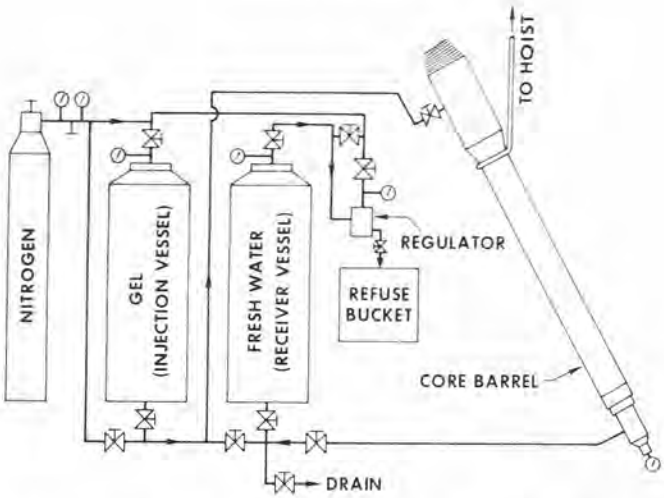

Figure 7 —System for displacing coring fluids from pressure core barrel.
(Courtesy of Loomis International, Inc.; developed and patented by Esso Production Research)

slightly above, the pressure in the core barrel. A mechanical pump with surge chamber arrangement and other minor modifications can be used in place of the nitrogen cylinder as a pressure source.

After the coring fluid has been displaced, with the internal pressure still at the preset value, the core barrel is packed in dry ice for three to four hours to freeze and thus to immobilize the liquids in the core. The barrel is then depressurized and the inner core tube with the frozen core is removed, is cut into shorter sections, and is packed in dry ice for transfer to the laboratory.

Procedures may be altered to meet specific field requirements or equipment limitations; alternate methods of transporting the pressure cores have been used successfully.[12] Techniques for handling pressure cores from water-invaded gas zones are more complex. Detailed procedures for recovering and handling the core should be developed for each specific project before the coring is initiated.

The pressure core barrel prevents loss of fluids by gas expansion; however, it does not prevent flushing by drilling-fluid filtrate. All fluids contained in the core as it enters the core barrel are

retained in-place as the core is brought to the surface, and they can be measured quantitatively. The amount of original in-place fluid displaced by drilling-fluid filtrate and by flushing may be 80 to 90 percent, but the percentage does vary with the existing conditions. The percentage must be estimated with consideration for other factors such as pressure overbalance, drilling fluid properties, drilling rate and time of exposure to drilling fluid, rock characteristics, and vertical permeability, or the presence of laminations in the formation.

SUMMARY AND CONCLUSIONS

1. When coring to evaluate residual oil saturation, the drilling and coring procedures and the drilling fluid system should be carefully chosen on the basis of all available knowledge of the reservoir rock properties, the reservoir pressure, and the probable state of saturation. This is necessary to minimize the effects of filtrate invasion during coring and to minimize the fluid expulsion that is caused by pressure decline as the core is brought to the surface.
2. A water-base drilling fluid should be used. No type of oil should be added to the drilling fluid if cores are to be taken to evaluate in situ residual oil saturation.
3. Current technology does not provide a means of taking a core from a subsurface reservoir without some flushing of the reservoir fluid content by the drilling fluid or the drilling fluid filtrate.* However, the degree of flushing can be reduced by proper planning and by the control of operating variables:
   a. Low mud weight - minimize pressure overbalance and restrict it to less than 200 psi, if possible; consider the use of aerated mud to reduce overbalance.

---

* A coring feasibility study, contracted by ERDA and awaiting publication, describes a possible method of recovering an unflushed core under reservoir pressure. The proposed method would utilize a replaceable pilot bit; the core barrel would be filled with a gelled material which could be extruded through the pilot bit as the core entered the barrel.[17]

b. A bland mud system; pH 7.5 to 8.5 - avoid use of caustic or surfactants, if unaltered wettability is an objective. This also reduces stripping of residual oil by the mud filtrate. Deaerated brine or formation water containing an oxygen scavenger can be used to minimize the effects of the filtrate on wettability.

c. Low spurt loss - maintain as low as possible, by the use of 200-mesh limestone and/or pulverized gilsonite to increase solids content and to provide a wide range of particle size.[2]

d. Low dynamic filtrate loss - a value of 1.5 cc/hr/sq in., or less, measured at a shear rate of 450 per second has been found to be satisfactory for a salt-gel/starch-mud system.[7]

e. Standard filtrate loss - maintain at less than 10 cc.

f. Low mud circulation rate - as low as practical (less than 200 gpm, if possible) to minimize (1) erosion in the restrictions within the core barrel, and (2) pressure gradients through the throat of the bit and around the bit.

g. High penetration rate - maintain a maximum consistent with good coring practice. Rates of 8 to 15 min/ft in hard formations and 2 to 8 min/ft in soft formations appear reasonable when using the pressure core barrel.[12] A high rate reduces the time of exposure of the core to drilling-mud filtrate.

4. A tracer, such as tritium, in water-base muds permits determination of the amount of drilling-fluid filtrate in the recovered core and thus allows evaluation of the degree of flushing.

5. The use of cable tool coring is essentially limited to shallow, low-pressure reservoirs in areas where most of the drilling is done with cable tool rigs. Major disadvantages are small core segments and complete flushing.

6. Conventional rotary coring, using the double-tube barrel and either a diamond bit or a milled-tooth bit is the most widely

used coring technique.

7. Rubber-sleeve coring offers advantages in retaining and recovering cores taken from soft, friable formations, conglomerates, and badly fractured, hard formations.

8. The pressure-retaining core barrel is the only device currently available that provides for sealing the core and its fluid contents as recovered in the reservoir and provides for retaining these contents undisturbed for laboratory measurement.

9. Recovery efficiency with the pressure core barrel is less than with conventional diamond coring or rubber-sleeve coring, but the advantages of retaining the fluids in the core and the success ratio attained with present equipment and techniques justify the use of the pressure core barrel in many cases where evaluation of residual oil saturation is of great importance.

10. Cores representative of formation rock can be recovered effectively with any one of several coring devices. These cores can be used for laboratory testing to evaluate in-place residual oil saturation and to obtain data for use in combination with other types of evaluation techniques to lend confidence to the overall evaluation.

REFERENCES

1. Rathmell, J.J., Braun, P.H. and Perkins, T.K.: "Reservoir Waterflood Residual Oil Saturation from Laboratory Tests," *Transactions*, AIME, 1973, **255**, 175-185.
2. Jenks, L.H., Huppler, J.D., Morrow, N.R. and Salathiel, R.A.: "Fluid Flow Within a Porous Medium Near a Diamond Core Bit," *Journal of Canadian Petroleum Technology* (October-December 1968), **7**, 172-180.
3. Raimondi, Pietro, Gallagher, B.J., Bennett, G.S., Erlich, R. and Messmar, J.H.: "Alkaline Waterflooding: Design and Implementation of a Field Pilot," SPE Paper 5831 presented at SPE Symposium on Improved Oil Recovery, April 16-19, 1972, Tulsa, OK.
4. Morgan, J.T. and Gordon, D.T.: "Influence of Pore Geometry on Water-Oil Relative Permeability," *Journal of Petroleum Technology*, October 1970, 1199-1208.
5. Pusch, W.H.: "Core Analysis Study for the Eldorado Micellar-Polymer Project," SPE Paper 5806 presented at SPE Symposium on Improved Oil Recovery, March 22-24, 1976, Tulsa, OK.
6. Murphy, R.P. and Owens, W.W.: "The Use of Special Coring and Logging Procedures for Defining Reservoir Residual Oil Saturations," *Transactions*, AIME, 1973, **255**, 841-850.
7. Thomas, E.C. and Ausburn, B.E.: "The Determination of Swept Zone Residual Oil Saturation in a Slightly Consolidated Reservoir in the Gulf Coast," SPE Paper 5803 presented at SPE Symposium on Improved Oil Recovery, March 22-24, 1976, Tulsa, OK.
8. Holm, L.W.: "Oil Saturation Measurements in the Bartlesville Sand After Waterflooding and After Propane Flooding," *Journal of Petroleum Technology*, December 1972, 1411-1416.
9. Cordiner, F.S., Gordon, D.T. and Jargon, J.R.: "Determination of Residual Oil Saturation After Waterflooding," SPE Paper 3791 presented at SPE Symposium on Improved Oil Recovery, April 16-19, 1972, Tulsa, OK.
10. Lovelace, K.B. and Armstrong, F.E.: "A Study of Core Invasion by Water-Base Mud Filtrate Using Tracer Techniques," *API Drilling and Production Practices*, 1961.
11. French, M.S., Keys, G.W., Stegemeier, G.L., Ueber, R.C., Abrams, A. and Hill, H.J.: "Field Test of an Aqueous Surfactant System for Oil Recovery, Benton Field, Illinois," *Transactions*, AIME, 1973, **255**, 195-204.
12. Hagedorn, A.R. and Blackwell, R.J.: "Summary of Experience with Pressure Coring," SPE Paper 3962 presented at 47th Annual Fall Meeting of SPE-AIME, October 8-11, 1972, San Antonio, TX.
13. Rowley, D.C.: private communication, Christensen, Inc., Diamond Technology Center, Salt Lake City, UT 84119.
14. Sewell, Ben W.: "The Carter Pressure Core Barrel," *API Drilling and Production Practices*, 1939.
15. *Drilling Manual*, Sections A5 and A6, International Association of Drilling Contractors, 7400 Harwin Street, #305, Houston, TX 77036.
16. Mullane, J.J.: "Pressure Core Barrel," *API Drilling and Production Practices*, 1941.
17. Ward, C.E. and Sinclair, A.R., "A Study to Determine the Feasibility of Obtaining True Samples of Oil and Gas Reservoirs," unpublished report prepared by Maurer Engineering, Inc. for ERDA, 1977.

Chapter III

CORE HANDLING—CORE ANALYSIS METHODS

INTRODUCTION

The discussions of coring (Chapter II) point out that the process of coring alters the fluid saturations of the intervals being cored. Figures 1 and 2 illustrate the changes in the fluid content of a core sample as the sample is cut and brought to the surface.

Figure 1 represents the changes in fluid contents of a core sample taken from a virgin reservoir that contains only oil and water. The figure illustrates two extreme conditions: 1) severe flushing by filtrate, and 2) no flushing. The filtrate flushes out the oil to some degree; the maximum flushing results in irreducible oil saturation. An exception may occur when oil or oil-base mud is used to core a zone that contains only oil and immobile connate water. As the core is brought to the surface, the pressure decreases; dissolved gas comes out of solution and expands, expelling both oil and water; evolution of gas causes shrinkage of the oil. Also, the decrease in the temperature, as the core is brought to the surface, causes minor additional shrinkage of the oil. Therefore, the fluid saturations as determined on conventionally recovered cores are not representative of formation saturations.

Figure 2 is a general representation of saturations encountered, and their alterations, in the coring of waterflooded or pressure depleted oil reservoirs. Although the values that are presented are idealized and will vary with properties of both the formation and its fluid contents, the values are representative of the type and