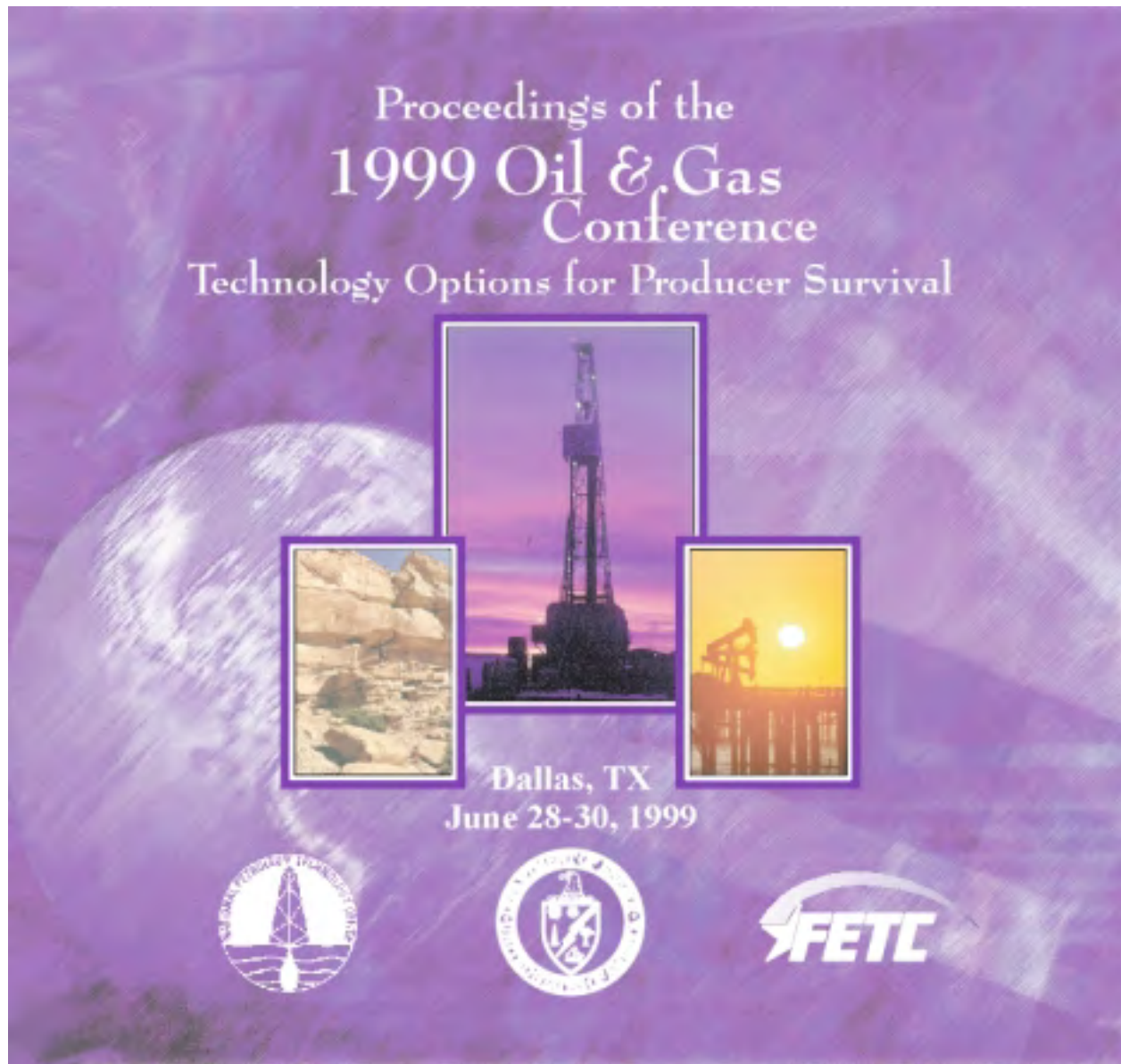


DOE/FETC-99/1103



Cosponsored by the U.S. Department of Energy's
Federal Energy Technology Center
and
National Petroleum Technology Office

Contents

This primary contents page has been set up with each section (or session) title linked to the corresponding section/session. To use this feature, move your cursor to the section/session you wish to view. (Your cursor will change to a pointing finger.) Click your left mouse button to jump to the beginning of that session.

[Disclaimer](#)

[Foreword](#)

[Pre-Conference Workshops](#)

[Conference Participants](#)

[Papers and Presentations](#)

[Opening Session](#)

[Session 1 — Converting Your Resources Into Reserves](#)

[Session 2A — Converting Your Resources Into Reserves](#)

[Session 2B — Clarifying Your Subsurface Vision](#)

[Poster Presentations](#)

[Session 3A — Converting Your Resources Into Reserves](#)

[Session 3B — High Performance, Cost Effective Drilling, Completion,
Stimulation Technologies](#)

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference therein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed therein do not necessarily state or reflect those of the United States Government or any agency thereof.

Available to DOE and DOE contractors from the Office of Scientific and Technical Information, P.O. Box 62, 175 Oak Ridge Turnpike, Oak Ridge, TN 37831; prices are available by phone: (423)576-8401; fax: (423)576-5725; or e-mail: reports@adonis.osti.gov.

Available to the public from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Road, Springfield, VA 22161; phone orders accepted at (703) 487-4650; or e-mail: info@ntis.fedworld.gov.

Foreword

The 1999 Oil & Gas Conference was cosponsored by the U.S. Department of Energy (DOE), Office of Fossil Energy, Federal Energy Technology Center (FETC) and National Petroleum Technology Office (NPTO) on June 28 to 30 in Dallas, Texas.

DOE sponsors technology research and development for the oil and natural gas industries. Periodically, DOE presents the results of this research in a conference format to provide technology transfer to interested parties and to keep the public informed. The Oil & Gas Conference theme, *Technology Options for Producer Survival*, reflects the need for development and implementation of new technologies to ensure an affordable, reliable energy future.

The conference was attended by nearly 250 representatives from industry, academia, national laboratories, DOE, and other Government agencies. Three preconference workshops (*Downhole Separation Technologies: Is it Applicable for Your Operations*, *Exploring and developing Naturally Fractured Low-Permeability Gas Reservoirs from the Rocky Mountains to the Austin Chalk*, and *Software Program Applications*) were held. The conference agenda included an opening plenary session, three platform sessions (Sessions 2 and 3 were split into 2 concurrent topics), and a poster presentation reception. The platform session topics were *Converting Your Resources Into Reserves* (Sessions 1 and 2A), *Clarifying Your Subsurface Vision* (Session 2B), and *High Performance, Cost Effective Drilling, Completion, Stimulation Technologies* (Session 3B). In total, there were 5 opening speakers, 30 presenters, and 16 poster presentations.

The papers and presentations in this document were produced primarily from electronic files provided by the authors. They have been neither refereed nor extensively edited. The conference Proceedings was provided to participants on a CD-ROM. The papers and presentations are also available on the FETC home page at <http://www.fetc.doe.gov> (see Publications).

We acknowledge the Session Chairs for their help in making this conference a success: Opening Session — Philip D. Vasquez; Session 1 — Dan Ferguson and Thomas H. Mroz; Session 2A — Patrick Lowry, Dan Ferguson, and Thomas H. Mroz; Session 2B — Robert Lemmon and William J. Gwilliam; Session 3A — Rhonda P. Lindsey and Charles A. Komar; and Session 3B — Cindy A. Reece, Jim Barnes, and Roy Long.

We thank the following NPTO and FETC employees for their help in preparation for the conference and production of this proceedings: Mike Antkowsky, Brian Albin, Helen Bresson, Joe Clevenger, Marty Dombrowski, Sarah Forbes, Mike Gray, Bill Kawecki, Kate Lessing, Carolyn Moore, Betty Robey, Chris Roe, Carla Santee, Pam Stanley, Terry Summers, Chuck White, and N. Marlene Williams.

Conference Coordinator

Kimberly Yavorsky

Conference Technical Contacts

William J. Gwilliam, FETC

Betty Felber, NPTO

Pre-Conference Workshops

This primary contents page has been set up with each session title linked to the corresponding session. To use this feature, move your cursor to the session you wish to view. (Your cursor will change to a pointing finger.) Click your left mouse button to jump to the beginning of that session.

Downhole Separation Technologies: Is It Applicable For Your Operations?
Feasibility Evaluation of Downhole Oil/Water Separator (DOWS) Technology;
John A. Veil, Bruce G. Langhus, and Stan Belieu

Exploring and Developing Naturally Fractured Low-Permeability Gas Reservoirs
from the Rocky Mountains to the Austin Chalk Workshop

Software Program Applications Workshop

Opening Session

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

Welcome; Robert W. Gee — Assistant Secretary, Fossil Energy U.S. Department of Energy

Techinomics; Edward J. Di Paolo — Senior Vice President, Global Business Development Halliburton Energy Services and Brown & Root Energy Services

Technology is Key to Establishing a Competitive Advantage; Leo A. Schrider — Senior Vice President, Belden & Blake Corporation; Board of Directors Chairman, Petroleum Technology Transfer Council

DOE Natural Gas Program; Rita A. Bajura — Director, Federal Energy Technology Center, U.S. Department of Energy

Successes and Challenges for the Oil Program; William F. Lawson — Director, National Petroleum Technology Office, U.S. Department of Energy

Session 1 — Converting Your Resources Into Reserves

This session contents page has been set up with each paper title linked to the corresponding paper. To use this feature, move your cursor to the paper you wish to view. (Your cursor will change to a pointing finger.) Click your left mouse button to jump to the beginning of that paper.

- (1.1) *A Resource Development Manual for Secondary Gas Recovery in Conventional-Permeability Sandstone Reservoirs*; Robert J. Finley — Bureau of Economic Geology, The University of Texas at Austin
- (1.2) *A Small Independent Producer's Design, Construction and Operation of a Flue Gas Injection Project East Edna Field, Okmulgee County, Oklahoma*; John Godwin — Driver Production, Inc.; and David Olsen — International Centre for Heavy Hydrocarbons
- (1.3) *Air Injection in a Gulf Coast Light Oil Field*; Ken Haley — BP-Amoco
- (1.4) *Overview of the CO₂ Pilot in the Spraberry Trend Area*; David S. Schechter — New Mexico Petroleum Recovery Research Center; and Todd M. Yocham — Pioneer Natural Resources USA, Inc.

Session 2A — Converting Your Resources Into Reserves

This session contents page has been set up with each paper title linked to the corresponding paper. To use this feature, move your cursor to the paper you wish to view. (Your cursor will change to a pointing finger.) Click your left mouse button to jump to the beginning of that paper.

- (2A.1)** *Sizing Gelant Treatments in Hydraulically Fractured Production Wells*; Randy Seright, Jenn-Tai Liang — New Mexico Petroleum Recovery Research Center; and Mailin Seldal — Saga Petroleum a.s.
- (2A.2)** *Increasing Production and Profitability by Use of a Computer Monitoring Program*; Jerry James and Gene Huck — James Engineering, Inc.
- (2A.3)** *Improved Oil Recovery in Fluvial Dominated Deltaic Reservoirs of Kansas — Near-Term*; Rodney R. Reynolds, Don W. Green, G. Paul Wilhite, Michael J. Michnick, and Dwayne McCune — Kansas Geological Survey, University of Kansas
- (2A.4)** *Increased Oil Production and Reserves Utilizing Secondary/Tertiary Recovery Techniques on Small Reservoirs in the Paradox Basin, Utah*; Thomas C. Chidsey, Jr. and Craig D. Morgan — Utah Geological Survey
- (2A.5)** *Cost-Effective Techniques for Improved Oil Recovery in Mississippian Carbonate Reservoirs of Kansas — Near Term — Class 2*; Timothy R. Carr, S. Bhattacharya, A. Byrnes, E. Franseen, P. Gerlach, W. Guy, and L. Watney — Kansas Geological Survey, University of Kansas
- (2A.6)** *MEOR — A Low Cost Solution for Enhanced Waterflood Performance*; James O. Stephens — Hughes Eastern Corporation; Lewis R. Brown and Alex A. Vadie — Mississippi State University

Session 2B — Clarifying Your Subsurface Vision

This session contents page has been set up with each paper title linked to the corresponding paper. To use this feature, move your cursor to the paper you wish to view. (Your cursor will change to a pointing finger.) Click your left mouse button to jump to the beginning of that paper.

- (2B.1)** *Studies of Natural Gas Resources in Deep Sedimentary Basins*; Thaddeus S. Dyman, James W. Schmoker, Vito F. Nuccio, Robert A. Crovelli, Timothy C. Hester, Ronald C. Johnson, Michael L. Lewan, Christopher J. Schenk, Kenneth Takahashi, Dennis B. Riggins, Troy A. Cook, and Allison A. Henry — U.S. Geological Survey
- (2B.2)** *Discrete Feature Network Methods for IOR in Heterogeneous Reservoirs*; William Dershowitz, T. Cladouhos, P. LaPointe, and E. Wadleigh — Golder Associates, Inc.
- (2B.3)** *Analysis of Rift Basins for Optimum Development: Mississippi Interior Salt Basin*; Ernest A. Mancini, William C. Parcell, and T. Markham Puckett — University of Alabama
- (2B.4)** *Basin-Scale Mapping and Visualization of Dolomite “Chimneys” in the Michigan Basin*; James R. Wood and William B. Harrison — Michigan Technological University
- (2B.5)** *New Techniques for Using Old Geophysical Logs in Reservoir Characterization: Examples from Bell Canyon Sandstones, Ford Geraldine and East Ford Units, Delaware Basin, Texas*; Shirley P. Dutton — Bureau of Economic Geology, The University of Texas at Austin; George B. Asquith — Department of Geosciences, Texas Tech University; William A. Flanders — Transpetco Engineering of the Southwest, Inc.; Jose I. Guzman and Helena H. Zirczy — Bureau of Economic Geology, The University of Texas at Austin
- (2B.6)** *Application of a New Exploration Strategy for Unconventional Basin Center Hydrocarbon Accumulations in the Riverton Dome Area*; Ronald C. Surdam, Z.S. Jiao, and N.G.K. Boyd — Institute for Energy Research, University of Wyoming

Poster Presentations

This session contents page has been set up with each poster title linked to the corresponding poster. To use this feature, move your cursor to the poster you wish to view. (Your cursor will change to a pointing finger.) Click your left mouse button to jump to the beginning of that poster.

- (P.1) *The Use of Advanced Acoustic Cavitation for Applications in the Oil and Natural Gas Industry*; Robert W. Peters, Michael L. Wilkey — Argonne National laboratory; and James C. Furness, Jr. — Furness-Newburge, Inc.
- (P.2) *Ruggedized Optical Fiber Sensors for Downhole Monitoring*; Russell G. May, Anbo Wang, Hai Xiao, and Jiangdong Deng — Bradley Department of Electrical and Computer Engineering, Virginia Polytechnic Institute
- (P.3) *Electrical Resistance Tomography Using Steel Cased Boreholes as Long Electrodes*; Robin L. Newmark, William D. Daily, and Abelardo L. Ramirez — Lawrence Livermore National Laboratory
- (P.4) *Microhole Drilling and Instrumentation*; James N. Albright and Donald S. Dressen — Los Alamos National Laboratory
- (P.5) *Advances in Crosswell Electromagnetics: Steel Cased Boreholes*; Barry A. Kirkendall and Phillip E. Harben — Lawrence Livermore National Laboratory
- (P.6) *Design and Development of Gas Liquid Cylindrical Cyclone Compact Separators for Three-Phase Flow*; Ram S. Mohan and Ovadia Shoham — University of Tulsa
- (P.7) *Performance Characteristics of an Extended Throat Flow Nozzle for the Measurement of High Void Fraction Multi-Phase Flows*; Richard Rice, J.R. Fincke, C.L. Jeffery — Idaho National Engineering and Environmental Laboratory; C.C. Ronnenkamp, D. Kruse, J. Krogue, and D. Householder — Perry Equipment Company
- (P.8) *Large Downhole Seismic Sensor Array*; J.R. Fincke, P.B. West, D.M. Weinberg — Idaho National Engineering and Environmental laboratory; and L.A. Walter — Geospace Instruments
- (P.9) *Biological Oxidation of Sulfides in Oilfield Brines*; Greg A. Bala — Idaho National Engineering and Environmental Laboratory; G.E. Jennema — Phillips Petroleum Company; and K.L. Sublette — Center for Environmental Research and Technology, University of Tulsa

Poster Presentations (Continued)

This session contents page has been set up with each poster title linked to the corresponding poster. To use this feature, move your cursor to the poster you wish to view. (Your cursor will change to a pointing finger.) Click your left mouse button to jump to the beginning of that poster.

- (P.10)** *Suction Pulse Drilling System*; Jack J. Kollé and Mark M. Marvin — Tempres Technologies, Inc.

- (P.11)** *Development of an Advanced Cuttings Transport Facility and Optimization of Wellbore Hydraulics at Elevated Temperatures and Pressures*; Ergun Kuru, Stefan Miska, Nicholas Takach, and Mark Pickell — University of Tulsa

- (P.12)** *Interpretation of Deep Complex Structure in a Limited-Quality 3-D Seismic Image*; Bob A. Hardage — Bureau of Economic Geology, The University of Texas at Austin

- (P.13)** *Seismic Data Acquisition Through Tubing*; Michael Buettner — Lawrence Livermore National Laboratory; and Michael Jervis — Tomoseis

- (P.14)** *Application of High Resolution Seismic Imaging Methods for Fracture Quantification*; Ernest L. Majer, T.M. Daley, L.R. Myer, K. Nihi, M. Feighner, J.E. Peterson, V. Korneev — Lawrence Berkeley National Laboratory; J. Queen, D. Cox — Conoco, Inc.; and T. Mroz — Federal Energy Technology Center

- (P.15)** *Bed-Isolation Treatments of a Mature Well in the Bluebell Field of the Uinta Basin, Utah, That Has Undergone Numerous High-Volume Shotgun Completions*; Craig D. Morgan — Utah Geological Survey; and Milind D. Deo — University of Utah

- (P.16)** *Greater Green River Basin Production Improvement Project, Rock Island 4-H, Table Rock Field, Frontier Formation*; Frank H. Lim — Union Pacific Resources

Session 3A — Converting Your Resources Into Reserves

This session contents page has been set up with each paper title linked to the corresponding paper. To use this feature, move your cursor to the paper you wish to view. (Your cursor will change to a pointing finger.) Click your left mouse button to jump to the beginning of that paper.

- (3A.1)** *Low Cost Methods for Finding Tight Gas, Gas Shales and Coalbed Methane*; Vello A. Kuuskraa and David J. Campagna — Advanced Resources International, Inc.
- (3A.2)** *Optimization of Infill Drilling in Naturally-Fractured Tight-Gas Reservoirs in the San Juan Basin*; Lawrence W. Teufel — New Mexico Institute of Mining and Technology
- (3A.3)** *Major Pennsylvanian Fluvial-Dominated Deltaic Reservoir Systems in Oklahoma*; Jock A. Campbell, Richard A. Andrews — Oklahoma Geological Survey; Robert A. Northcutt — Independent Geologist; Roy M. Knapp and Mary K. Banken — University of Oklahoma
- (3A.4)** *Incorporating Seismic Attribute Modeling into a Flow Model of the Grayburg Reservoir in the Foster-South Cowden Field*; Robert C. Trentham, Richard M. Weinbrandt, and William C. Robinson — Laguna Petroleum Corporation
- (3A.5)** *Multi-Disciplinary and High-Resolution Seismic Survey on Native American Lands in Osage County, Oklahoma*; T. K. Reeves, Bijon Sharma, Sanjay Banerjee, Genliang Guo, Len Volk, David Djikine, and Steve George — Formerly of TRW Petroleum Technologies
- (3A.6)** *Integrated Approach Towards the Application of Horizontal Wells to Improve Waterflooding Performance*; Mohan Kelkar — University of Tulsa
- (3A.7)** *Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs*; Bill Weiss — Strata Production Company

Session 3B — High Performance, Cost Effective Drilling, Completion, Stimulation Technologies

This session contents page has been set up with each paper title linked to the corresponding paper. To use this feature, move your cursor to the paper you wish to view. (Your cursor will change to a pointing finger.) Click your left mouse button to jump to the beginning of that paper.

- (3B.1)** *Advanced Fracturing Technologies for Marginal Oil and Gas Wells*; Scott R. Reeves — Advanced Resources International

- (3B.2)** *A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam*; Philip Scott Hara — Tidelands; Oil Production Company; Julius J. Mondragon III — University of Southern California; and David K. Davies — David K. Davies and Associates, Inc.

- (3B.3)** *Coiled-Tubing High-Pressure Jet Drilling System*; William C. Maurer, Curtis E. Leitko, and C. Mel Hightower — Maurer Engineering, Inc.

- (3B.4)** *High-Power Drilling Motor Field Tests*; John H. Cohen, Curtis E. Leitko, and William C. Maurer — Maurer Engineering, Inc.

- (3B.5)** *Advanced Mud Hammer Systems*; David S. Pixton and D. Hall — Novatek, Inc.

- (3B.6)** *New High Strength and Faster Drilling TSP Diamond Cutters*; Robert P. Radtke — Technology International, Inc.

- (3B.7)** *New Lightweight Fluid for Underbalanced Drilling*; William J. McDonald, John H. Cohen, and C. Mel Hightower — Maurer Engineering, Inc.

Feasibility Evaluation of Downhole Oil/Water Separator (DOWS) Technology

John A. Veil, Bruce G. Langhus, and Stan Belieu

Executive Summary

The largest volume waste stream associated with oil and gas production is produced water. Treatment and disposal of produced water represent significant costs for operators. A relatively new technology, downhole oil/water separators (DOWS), has been developed to reduce the cost of handling produced water. DOWS may also be referred to as DHOWS or as dual injection and lifting systems (DIALS). DOWS separate oil and gas from produced water at the bottom of the well and reinject some of the produced water into another formation or another horizon within the same formation, while the oil and gas are pumped to the surface. Since much of the produced water is not pumped to the surface, treated, and pumped from the surface back into a deep formation, the cost of handling produced water is greatly reduced. When DOWS are used, additional oil may be recovered as well. In cases where surface processing or disposal capacity is a limiting factor for further production within a field, the use of DOWS to dispose of some of the produced water can allow additional production in that field. Simultaneous injection using DOWS has the added benefit of minimizing the opportunity for contamination of underground sources of drinking water through leaks in tubing and casing during the injection process. Similar devices have been used to a much greater extent for downhole gas/water separation. However, this report is limited to discussion of oil-water separators.

Two basic types of DOWS have been developed - one type using hydrocyclones to separate oil and water and one relying on gravity separation. Hydrocyclone-type DOWS can handle larger flow volumes than gravity separator-type DOWS but are significantly more expensive. Several alternative designs of DOWS are available from different vendors. Hydrocyclones have been paired with electric submersible pumps, rod pumps, and progressing cavity pumps, while gravity separator-type DOWS have utilized only rod pumps. In order to fit into 5.5-inch or 7-inch casings, DOWS are designed as long, slender tools.

Most DOWS installations have been set up with the producing zone above the injection zone. DOWS can potentially be used for waterflooding. DOWS could also be used for reverse coning to reduce the degree of water influx into oil-producing zones.

Conversion of a well from a regular pump to a DOWS is a relatively expensive undertaking. Total costs include the DOWS tool itself and well workover expenses. Costs for the hydrocyclone-type DOWS are fairly high. For example, the cost of an electric submersible pump-based DOWS system is approximately double to triple the cost of replacing a conventional electrical submersible pump and is often in the range of \$90,000 - \$250,000, excluding the well workover costs, which can often exceed \$100,000. Costs are somewhat lower for the gravity separation-type DOWS, ranging from \$15,000 - \$25,000, and the cost of a complete gravity separator-type DOWS installation was \$140,000 Canadian (Reid 1998).

DOWS installations will not necessarily be cost-effective for all wells. Knowledge of the reservoir and historical production are important before selecting a DOWS installation. The characteristics of wells that are likely to work well with DOWS include, among others, a high water-to-oil ratio, the presence of a suitable injection zone that is isolated from the production zone, compatible water chemistry between the producing and injection zones, and a properly constructed well with good mechanical integrity. DOWS installations in wells that meet these requirements must still remain in good operating conditions for long enough that the accrued monthly savings can offset the initial purchase costs of the equipment. The track record of existing installations is mixed, with some DOWS remaining in service for more than two years but with others failing within a few days. This situation is understandable given that fewer than 40 DOWS have been installed in North America through mid-1998. The technology is new and is still being refined and improved with each successive installation.

This report includes information on 37 DOWS installations in North America. Key statistics from that set of data include:

- More than half of the installations to date have been hydrocyclone-type DOWS (21 compared with 16 gravity separator-type DOWS).
- Twenty-seven installations have been in Canada and ten installations have been in the United States.
- Of the 37 DOWS trials described in this report, 27 have been installed in four producing areas - southeast Saskatchewan, east-central Alberta, the central Alberta reef trends, and East Texas.
- Seventeen installations were in 5.5-inch casing, 14 were in 7-inch casing, 1 was in 8.625-inch casing, and 5 were unspecified.
- Twenty of the DOWS installations have been in wells located in carbonate formations and 16 in wells located in sandstone formations. One trial did not specify the lithology. DOWS appeared to work better in carbonate formations, showing an average increase in oil production of 47% (compared with an average of 17% for sandstone formations) and an average decrease in water brought to the surface of 88% (compared with 78% for sandstone formations)
- The volume of oil increased in 19 of the trials, decreased in 12 of the trials, stayed the same in 2 trials, and was unspecified in 4 trials. The top three performing hydrocyclone-type wells showed oil production increases ranging from 45% to 1,162%, while one well lost all oil production. The top three gravity separator-type wells showed oil production increases ranging from 106% to 233%, while one well lost all oil production.
- All 29 trials for which both pre-installation and post-installation water production data were provided showed a decrease in water brought to the surface. The decrease ranged from 14% to 97%, with 22 of 29 trials exceeding 75% reduction.

- The data on injectivity and the separation distance between producing and injection formations do not correlate well with the decrease in water volume brought to the surface.

Some of the installations experienced problems that impeded the ability of the DOWS to function properly. At least two installations suffered from low injectivity of the receiving zone; in both cases, incompatible fluids contacted sensitive reservoir sands, which plugged part of the permeability. Several installations noted problems of insufficient isolation between the producing and injection zones. If isolation is not sufficient, the injectate can migrate into the producing zone and then short-circuit into the producing perforations. The result will be recycling of the produced water, with oil production rates dropping to nearly zero. Other DOWS have been plugged by fines or sand. Several trials were canceled prematurely because of corrosion and scaling problems. Finally, some of the early installations suffered from poor design features.

Because the technology is still new, no regulatory requirements for DOWS exist in many jurisdictions. The U.S. Environmental Protection Agency (EPA) does not now have a formal position on how to regulate DOWS. Four states (Colorado, Oklahoma, Louisiana, and Texas) have developed either regulations or administrative guidelines for DOWS. Those states regulate DOWS with requirements comparable to or less stringent than those for regular Class 11 injection wells. There is some concern that EPA might decide that DOWS are not covered under the definition of a Class U well, thereby potentially leading to stricter requirements that could hinder future use of DOWS. It is important for EPA and state regulators to develop reasonable regulatory requirements for DOWS in order not to impede their use in the future.

Exploring and Developing Naturally Fractured Low-Permeability Gas Reservoirs from the Rocky Mountains to the Austin Chalk Workshop

This workshop contents page has been set up with each abstract title linked to the corresponding abstract. To use this feature, move your cursor to the abstract you wish to view. (Your cursor will change to a pointing finger.)

The U.S. Department of Energy's Program in Low-Permeability Naturally Fractured Gas Reservoirs; Bill Gwilliam — Federal Energy Technology Center

Piceance Basin/Rulison Field Case Study; Dave Campagna — Advanced Resources International

GGRB/Table Rock Field Case Study; Lee Krystinik — Union Pacific Resources and Dave Campagna — Advanced Resources International

Wind River Basin/Madden Field Case Study; Allen Middleman — Burlington Resources

Advanced Surface Seismic for Natural Fracture Detection; Richard Van Dok — Western Geophysical

Austin Chalk Deep Gas Play; Gerry Drake — Union Pacific Resources

Translating Western Basin Success to Other Low Permeability Gas Plays and Basins; Vello Kuuskraa — Advanced Resources International

The U.S. Department of Energy's Program in Low-Permeability Naturally Fractured Gas Reservoirs

W. J. Gwilliam
Senior Geologist/Project Manager
U.S. Department of Energy
Federal Energy Technology Center

Abstract

The original goal of the U.S. Department of Energy's research program in low-permeability gas reservoirs was to expand the level of industry development and production efficiency from these reservoirs in the U.S. From the beginning, natural fractures were felt to be the key to better production from these extensive reservoirs, which are concentrated heavily but not exclusively in the Rocky Mountain region. The need for a Federal role in gaining access to this resource has been apparent for some time. By the year 2015 DOE's Energy Information Agency (1998) expects a declining conventional national gas supply of approximately 20 TCF/Year and a steady 5 TCF/Year gas import volume. In order to meet demand at that time, low-permeability resources will be required to supply up to 10 TCF/Year. The first step in DOE's program at its inception in the early 1980's was to better characterize the geology of key Rocky Mountain Basins and refine the low-permeability resource and reserve numbers via our interagency agreement with the U.S. Geological Survey, the Scotia Group and others. While this effort still continues to this point in time, we initiated a companion effort to search for geophysical and other geoscience methodologies that could aid in high-grading the location of natural fracture sweet-spots in the early 1990's. The summaries and synthesis of six of these studies are compiled on the CD-ROM entitled "Detection and Analysis of Naturally Fractured Gas Reservoirs," and is available for free distribution to attendees of this workshop. The more recent emphasis of our program has shifted somewhat toward that of participating in cooperative field verification opportunities to test our findings with companies such as Barrett Resources in the Piceance Basin, Louisiana Land and Exploration in the Wind River Basin and Union Pacific Resources in the Greater Green River Basin. You will have an opportunity to hear about the results of these efforts during the workshop, as well as a discussion of the deep Austin Chalk formation, and its potential for future study as a low-permeability gas resource. We at DOE and the Federal Energy Technology Center want to express our appreciation to our co-hosts: Union Pacific Resources, Advanced Resources International, and Western Geophysical as well as Burlington Resources for assisting in the conduct of this workshop. We also invite your participation in round-table discussions at the conclusion of our structured presentations and hope that you will contribute your comments and thoughts to us at that time.

Piceance Basin/Rulison Field Case Study

David J. Campagna (dcampagna@adv-res.com; 703-528-8420)

Advanced Resources International
1110 N. Glebe Road, Suite 600
Arlington, Virginia 22201

Abstract

The presence of natural fractures is required for the economic development of low-permeability reservoirs. Technology for reliably locating natural fractures before drilling ranks as one of industry's top goals. This presentation discusses the geomechanical approach that allows for the prediction of natural fracture clusters that control reservoir permeability and describes a case study of the application at the Rulison field in the Piceance Basin, Colorado.

Fractured reservoirs often show characteristics indicating the presence of local natural fracture clusters which are a dense network of fractures that may differ in style and orientation from regional trends. Natural fracture clusters can be developed around local deformation events such as faulting or folding of the reservoir strata. Natural fracture clusters are generally responsible for zones of increased reservoir permeability beyond that caused by any uniformly distributed fracture system.

Geomechanical models provide the means to predict the occurrences and characteristics of natural fractures around faults and thus allow a semi-quantitative prediction of fracture-related reservoir "sweet spots." A geomechanical method can predict the location and orientations of fault-related natural fracture clusters. The approach approximates faults as surfaces of displacement discontinuity in an elastic material and employs a 3D numerical code to calculate regions of stress concentrations that cause the natural fracture clusters.

The case study is located in the Rulison field, Piceance basin, Colorado. There, production is from the tight-gas reservoir is the Cretaceous Williams Fork fluvial sands. The reservoir consists of massively stacked fluvial sandstones with an average 12% porosity and permeability in the microdarcy range. The EUR ranges from .5 to 4.0 Bcf and can quickly change from a good to a sub-economic area in less than a mile. Using the geomechanical approach to delineate the area's "sweet spots," the predicted areas in the Rulison area are shown to correlate with regions of high permeability and significant EUR.

Greater Green River Basin Production Improvement Project: Rock Island 4-H Well, Table Rock Field, Frontier Formation

Lee F. Krystinik (LeeKrystinik@upr.com; 817-321-6702)

Frank H. Lim (FrankLim@upr.com; 817-321-7889)

Union Pacific Resources Company

P.O. Box 7

Fort Worth, TX 76101

Abstract

The UPR Rock Island 4-H well, located on the north plunge of Table Rock Field in Sweetwater County, Southwest Wyoming (S4-T19N-R97W), is the culmination of 5 years of cooperative government and industry research in the DOE Greater Green River Basin Production Improvement Project, a research partnership between DOE-FETC, Union Pacific Resources and GRI. The primary goal of this project is to explore technologies which could make production of the very large tight gas resources in southwestern Wyoming technically and economically feasible. The Union Pacific Resources Rock Island 4-H well (UPR RI 4-H) appears to be a successful attainment of this goal in the area north of Table Rock Field.

Notable milestones achieved in the span of this project include:

- (1) The reduction of drilling time and expense for vertical wells deeper than 15,000' to less than half of the average time and cost encountered by industry during the last decade. This is critical to making deep, vertical or horizontal tight gas sandstone wells a viable option.
- (2) One of the deepest horizontal tight gas sandstone wells in the world (>14,950' TVD).
- (3) Greater than 95% recovery of three of the deepest horizontal cores in the world.
- (4) One of the highest unstimulated, sustained gas flow capacities (12-14 MMCFD) ever encountered in the tight-gas province of the Cretaceous Frontier Formation in Wyoming.
- (5) The initiation of ongoing plans for a horizontal drilling effort by industry to evaluate and exploit this previously unattainable resource.

The UPR RI 4-H offsets a vertical completion by 1.5 miles to the east-northeast (Government Union #4 well, S8-T19N-R97W). Core and log information and production test data from the Government Union #4 well (GU #4), combined with structural data derived from approximately 1000 square miles of 3-D seismic data were major factors in the site selection for the UPR RI 4-H horizontal well. The reservoir is highly fractured, massive to hummocky cross-stratified, very-fine

grained, nearshore marine (lower shoreface) sandstone, with 10-12% porosity and 25 microdarcies permeability.

Fractures in vertical core from GU #4 and the horizontal core from the UPR RI 4-H exhibit slickensides and bedding offset which document shear displacement with a dominant strike in the range of 80-110 degrees. The fractures are open to partially filled with quartz, calcite, kaolinite and bitumen. Fracture spacing is variable within the horizons penetrated and fracturing appears to be most intense near several small faults penetrated by the well. Work by John Lorenz with Sandia National Labs and David Campana with ARI documents that the open fractures which strike east-west, nearly perpendicular to the well bore, occur along the entire horizontal length of the UPR RI 4-H well, as observed in core and resistivity image log data.

We anticipate that the success of the UPR Rock Island 4-H Well will spark renewed drilling by industry in the Greater Green River Basin. Horizontal drilling is attractive because it allows large well spacings, making per well recoveries larger while greatly reducing the environmental impact of the drilling program. Union Pacific Resources and its partners are forming a Federal Unit to efficiently develop this play. Further testing of advanced drilling and stimulation techniques will occur as industry works to optimize technological and economic solutions. This project underscores the value of government and industry research partnerships aimed at solving problems which the private sector alone has been unable to solve within the present challenging economic environment of the energy industry.

Acknowledgment: This research was sponsored by the U.S. Department of Energy's Federal Energy Technology Center, under Contract DEAC21-95MC31063 with Union Pacific Resources Company, P.O. Box 7, Fort Worth, TX 76101; (817) 321-6000. UPR wishes to acknowledge positive, professional and highly efficient interaction with the personnel of the DOE-FETC during the course of this project, especially that of the FETC Contracting Officer's Representatives (COR), Karl-Heinz Frohne (April 1995 to September 1996) and Gary L. Covatch (October 1996 to Present).

Wind River Basin/Madden Field Case Study

Allen Middleman (amiddleman@br-ine.com; 915 688 9048)

Burlington Resources Oil and Gas Company

3300 N. "A" St., Bldg. 6

Midland, Texas 79705-5406

Blackhawk Geometrics, Inc.

301 B. Commercial Road

Golden, CO 80401

Abstract

Naturally occurring effective fractures strongly influence the flow rates of gas wells in the Madden field, Fremont and Natrona Counties, Wyoming. The objective of this project was to characterize the spatial distribution of natural fractures from which gas is produced in the Tertiary, Lower Fort Union (LFU) interval in Madden Field. A cost-effective means of predicting the presence of these fractures can help manage risk associated with field development. It was hoped that P wave seismic data could be used to diagnose the fracture density and orientation within the 37 square mile 3D area. The seismic processing was designed to reveal the azimuthal anisotropy in the seismic response of the target interval.

A Gas Prospectivity Map, which incorporates both geologic and geophysical attributes, was created from the available data. A positive correlation was found to exist between this map and LFU well reserve estimates. The seismic techniques used in this study provide a cost-effective tool to evaluate fracture intensity and direction in the LFU. The results of this study are taken into account, along with other subsurface and production data, in the ongoing Madden field LFU development program.

Advanced Surface Seismic for Natural Fracture Detection

Richard R. Van Dok (rich.van.dok@westgeo.com; 303-629-9250)

Western Geophysical Company
1625 Broadway, Suite 1300
Denver, CO 80202

Abstract

Determining the nature of low-permeability fractured gas reservoirs is critical to the successful development of any given reservoir model. Historically, this information has come from sparsely distributed well information and has required interpolation in order to create a complete reservoir picture. With recent advances in the application of surface seismic data we can now provide some meaningful information in the intra-well spaces. This presentation will provide an overview of some of the techniques currently being investigated for the detection of natural fractures using surface seismic techniques. Examples demonstrating each technique will also be presented.

The use of surface seismic data is not new to the exploration and exploitation of naturally fractured gas reservoirs. Many seismic surveys have been acquired, processed and interpreted in an effort to better understand the nature of these reservoirs. These efforts, however, have been primarily limited to indirect indicators requiring a good deal of interpretive input from the geologists, geophysicists and engineers in order to make some qualitative judgement about the fracture distribution within a field.

More direct methods of fracture detection, while not new in theory, are being utilized in greater numbers due in large part to advances in data acquisition and processing technologies along with a better interpretive understanding of the results. These methods can be divided into two basic categories depending on whether we are using compressional (P) or shear (S) waves. In both cases, however, our goal is to identify and quantify the azimuthal anisotropy inherent in the rock properties of a fractured reservoir. This anisotropy produces a differential response of the seismic wave depending on the direction the fractures are encountered. In order to properly sample this azimuthal difference several propagation ray paths must be analyzed. To accomplish this, seismic surveys must be designed so that they are not only properly sampled in time and space but also in azimuth and offset.

The first method involves the use of conventional P-waves and can often be accomplished with a small increase in data acquisition effort. This fact alone may be the reason several of our clients are pursuing this approach on new 3D surveys. Again, this method involves the acquisition of many propagation azimuths and the subsequent processing and interpretation of the different responses. The effects of natural fractures on P-waves are not, however, easily generalized. Our current tools are designed to measure differences in amplitudes (AVOAz) or travel-times (velocity) with seismic propagation azimuth. The technology will be illustrated on real 3-D

P-wave data shot over gas fields in central Wyoming. Frequency attenuation is another property some are investigating. Ultimately, with a better understanding of the physics, we may be able to come up with a single inversion procedure that accounts for all the effects we observe on the seismic data.

The use of shear waves for fracture detection is a relatively well understood science. It has been investigated for years, not only by those using surface seismic but also well log scientists who, long ago, realized that shear waves exhibit a very useful property called birefringence. What this means is that shear waves, which travel in orthogonally polarized pairs, tend to align themselves in the preferred stress directions and propagate at different velocities depending upon their orientation. These preferred directions often correspond to directions of fracturing and the difference in propagation velocity can be correlated to the magnitude or density of fracturing. By measuring the amplitude and travel-time differences of the various recorded shear waves we can then determine something about the nature of the fractured reservoir.

Over the years there have been several successful projects using shear waves for fracture detection. These surveys involve both the creation of shear waves and the subsequent recording of their reflected energy. Three-component (X, Y, Z) sources and detectors are required. Most of these surveys have been limited to small-scale university projects or internal research experiments at larger oil companies. This limitation is usually due to the significant increase in acquisition effort and cost related to these types of surveys. Also, it is often difficult to generate shear waves with enough energy to investigate many deeper targets.

The logistics of a shear wave source survey are often prohibitive and have led many to investigate the use of mode-converted seismic surveys. To accomplish this we use conventional P-wave sources (dynamite, vibrators or air guns) and record the shear wave energy created in the subsurface. This is a result of the mode conversion from P to S that takes place at any given seismic interface. The resulting upcoming shear wave can then be measured using many of the same tools used to analyze standard shear wave birefringence. This approach will be compared to the azimuthal P-wave-only technique discussed previously.

Also, due to the fact that shear-waves do not propagate in fluids, conventional shear wave acquisition has not been available offshore. New acquisition technologies like ocean bottom 4-C cable recording, along with advances in processing and interpretation tools have allowed us to now offer valuable shear wave information utilizing a cost-effective acquisition approach.

Advances in seismic acquisition, processing and interpretation technology now offer the explorationist information about their fractured reservoir in areas where no well control exists. All of the direct methods, whether they use P-waves or S-waves, may provide a more detailed picture of the fractured reservoir, resulting in a better reservoir model and improved production. While conventional P-wave seismic has been an extremely effective tool for finding and delineating fractured reservoirs, we now have other options that can provide additional information about the nature of the subsurface.

The difficulty comes, just as with other exploration tools, in balancing the value added from the increased information with the additional costs. Each geologic situation will have its own set of problems which must be considered when choosing any of these methods.

Austin Chalk Deep Gas Play

Gerry Drake (gerrydrake@upr.com; 817/321-6747)
Union Pacific Resources
Advanced Resources International, Inc.
777 Main Street
Fort Worth, TX 76102

Abstract

The Late Cretaceous Austin Chalk formation is present in the subsurface paralleling the U.S. Gulf Coast from Mexico to Florida and produces from numerous fields in Texas and Louisiana along a trend over 300 miles in length and over 40 miles in width. Conventional drilling with vertical wells was marginally successful in developing the fractured Austin Chalk reservoir. The development of horizontal techniques greatly enhanced the productivity of the wells by intersecting multiple fracture sets. Various methods of exploration have been used to explore for the sweet spots within the chalk with mixed results. No one method has worked in all areas and seldom in many of the sweet spots.

The Austin Chalk reservoir is described as tight, fossiliferous, fractured limestone interbedded with shales and marls. Although the matrix contributes to production, the high initial rates result from fracture permeability. The thickness of the Austin Chalk ranges from 50 to more than 600 feet with specific targets within this interval. The depth of the main productive chalk trend ranges from 5500' to 16000'.

The deep gas play of Giddings Field began in Washington County of central Texas and has expanded into Austin, Colorado, and Grimes counties of central Texas. The Austin Chalk lies at a depth of 12500' to 16500' with a total thickness from 295' to over 400'. The primary target, the "B" zone, is 23-50' thick and is characterized by less than 3% porosity and resistivity values greater than 40 Ohms. The wells are drilled with a single lateral, 5000' in length, or as opposing laterals, each 3000 to 4000 feet long and perpendicular to N65°E fracture strike. Production is generally dry gas with small amounts of water and completions are based on the quantity and quality of shows encountered while drilling.

Translating Western Basin Success to Other Low Permeability Gas Plays and Basins

Vello A. Kuuskraa (vkuuskraa@adv-res.com; (703) 528-8420)
Dr. David J. Campagna (dcampagna@adv-res.com; (703) 528-8420)
Advanced Resources International, Inc.
1110 North Glebe Road, Suite 600
Arlington, VA 22201

Abstract

The natural fracture detection R&D sponsored by DOE/FETC has been tested in several Rocky Mountain basins and gas plays, including:

- Mesaverde (Williams Fork) tight, lenticular sandstones at Rulison Field, Piceance Basin, Colorado
- Frontier tight sandstones, Table Rock Field, Greater Green River Basin, Wyoming
- Fort Union sandstones, Madden Field, Wind River Basin, Wyoming

Still, numerous other naturally fractured, low permeability natural gas formations and basins exist, particularly in the Mid-Continent and Texas:

- Anadarko/Arkoma
- East Texas/ North Louisiana
- Texas Gulf Coast/Austin Chalk
- Permian/Val Verde

Question: How might the natural fracture detection technology developed in the Rockies be adapted to these other basins?

The presentation reviews the published information on the structural setting, observed natural fracture characteristics, and resource potential in these low permeability natural gas basins and plays.

Particular emphasis will be given to obtaining workshop participation and comments on how the natural fracture detection technology developed for the Rockies' tight gas basins needs to be modified and tested to meet the geologic, structural and operating conditions of the Mid-Continent, Texas and Louisiana low permeability gas basins and plays.

Software Program Applications Workshop

June 28, 1999

Moderator: Sandra Mark, PTTC

Time	Topic	Presenter and Organization
1:00 p.m.	Welcome and Introduction	Betty Felber, NPTO
1:05 p.m.	Reservoir Characterization	Paul Knox, BEG
1:35 p.m.	DOE CD-ROM and Risk Analysis	
2:05 p.m.	Break	
2:20 p.m.	PfEFFER	John Doveton, KGS
3:35 p.m.	PTTC Sampler	Sandra Mark, PTTC
4:05 p.m.	Thanks and Evaluation Form	Betty Felber, NPTO
4:10 p.m.	Adjourn	Betty Felber, NPTO

Conference Participants

James N. Albright

Geoengineering Group, Los Alamos National Laboratory
Mail Stop D443, Los Alamos, NM 87544
Phone: 505-667-4318; Fax: 505-667-8487; E-mail: j_albright@lanl.gov

Tom J. Alexander

U.S. Department of Energy — NPOSR
100 Independence Ave SW, Mail Stop FE-47, Washington, DC 20585
Phone: 202-586-5561, Fax: 202-586-4446, E-mail: tom.alexander@hq.doe.gov

David Alleman

National Petroleum Technology Office
P.O. Box 3628, Tulsa, OK 74101-3628
Phone: 918-699-2057, Fax: 918-699-2005, E-mail: dalleman@npto.doe.gov

Edith C. Allison

U. S. Department of Energy
100 Independence Ave SW, Mail Stop FE-32, Washington, DC 20585
Phone: 202-586-1023, Fax: 202-586-6221, E-mail: edith.allison@hq.doe.gov

Gene L. Ames

Venus Exploration Inc.
1250 NE Loop 410, Suite 1000, San Antonio, TX 78209
Phone: 210-930-4900, Fax: 201-930-4901, E-mail: games3@venusexploration.com

Raymond P. Anderson

Idaho National Engineering & Environmental Laboratory
P.O. Box 1625, Mail Stop 2110, Idaho Falls, ID 83415-2110
Phone: 208-526-1623, Fax: 208-526-9822, E-mail: anderp@inel.gov

Sandy Andrew

Idaho National Engineering & Environmental Laboratory
907 N Poplar, Suite 150, Casper, WY 82601
Phone: 907-261-5161 ext. 5019, Fax: 307-261-5997, E-mail: sandy.andrew@rmotc.com

Paul L. Archer

Geopetro LLC
6463 Proprietors Road, Suite 03, Worthington, OH 43085
Phone: 614-885-9350, Fax: 614-885-1082, E-mail: geopetro@aol.com

Conference Participants

(continued)

Paul Babcock

Burlington Resources

5051 Westheimer, Suite 1400, Houston, TX 77056

Phone: 713-624-9367, Fax: 713-624-9680, E-mail: pbabcock@br-inc.com

Jeffrey R. Bailey

Exxon Production Research Co.

P.O. Box 2189, Mail Stop N-130, Houston, TX 77056

Phone: 713-431-4163, Fax 713-431-7265

Rita A. Bajura

Federal Energy Technology Center

3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507-0880

Phone: 304-285-4511, Fax: 304-285-4292, E-mail: rbajur@fetc.doe.gov

Greg A. Bala

Idaho National Engineering & Environmental Laboratory

P.O. Box 1625, Mail Stop 2203, Idaho Falls, ID 83415-2203

Phone: 208-526-8178, Fax: 208-526-0828, E-mail: gb3@inel.gov

James Barnes

National Petroleum Technology Office

P.O. Box 3628, Tulsa, OK 74101-3628

Phone: 918-699-2076, Fax: 918-699-2005, E-mail: jbarnes@npto.doe.gov

Robert J. Beams

Samson Oil Company

842 One Energy Square, Dallas, TX 75206-4016

Phone: 214-369-2207, Fax: 214-739-5027

Jamel Belhadi

ARCO

6400 Ohio Drive, Plano, TX 75024

Phone: 972-964-5625, Fax: 972-758-0001, E-mail: gueldamen@aol.com

Stan Bennett

Koch Industries

20 East Greenway Plaza, Sixth Floor, Houston, TX 77046

Phone: 713-544-4562, Fax: 713-544-6161, E-mail: bennetts@kochind.com

Conference Participants

(continued)

Rhys J. Best

Lone Star Technologies Inc.
P.O. Box 803546, Dallas, TX 75380-3546
Phone: 972-770-6406, Fax: 972-770-6411, E-mail: best@lonestartech.com

Dale S. Bilhartz

JRB Oil & Gas Co.
627 Mercury Avenue, Ducanville, TX 75137
Phone: 972-296-1793, Fax: 972-296-2364

Randal L. Billingsley

Advanced Resources International
4 Wild Turkey Lane, Littleton, CO 80127
Phone: 303-979-3559, E-mail: badger74@aol.com

David J. Borns

Natural Gas & Oil Technologies, Sandia National Laboratories
Mail Stop 0750, Albuquerque, NM 87185-0750
Phone: 505-844-7333, Fax: 505-844-7354, E-mail: djborns@sandia.gov

Bob Boyd

St. Paul Fire & Marine Ins. Co.
2545 NW 30, Oklahoma City, OK 73112
Phone: 405-858-7422, Fax: 405-858-7450, E-mail: bob.boyd@stpaul.com

Nicholas G. K. Boyd

Institute for Energy Research, University of Wyoming
P.O. Box 4068, Laramie, WY 82071-4068
Phone: 307-766-4211, Fax: 307-766-2737, E-mail: mzungu@uwyo.edu

Charles F. Brandenburg

Gas Research Institute
8600 West Bryn Mawr Avenue, Chicago IL 60631
Phone: 773-399-8324, Fax: 773-399-4609, E-mail: cbranden@gri.org

Kevin Brannon

Aurion Technologies LLC
3102 Maple Avenue, Suite 600, Dallas, TX 75201
Phone: 214-290-9000, Fax: 214-290-9200

Conference Participants

(continued)

Jerry Paul Brashear

The Brashear Group LLC
10121 Donegal Court, Potomac, MD 20854
Phone: 301-765-0157, Fax: 301-765-0527, E-mail: jpb@brashear-group.com

Helen Bresson

National Petroleum Technology Office
One West Third Street, Suite 1400, Tulsa, OK 74103
Phone: 918-699-2014, Fax: 918-699-2005, E-mail: hbresson@npto.doe.gov

Angela Brown

Aurion Technologies LLC
3102 Maple Avenue, Suite 600, Dallas, TX 75201
Phone: 214-290-9000, Fax: 214-290-9200, E-mail: angelab@aurora-gas.com

Lewis R. Brown

Mississippi State University
5 Hialeah Drive, Starkville, MS 39759-2745
Phone: 662-325-7593, Fax: 662-325-7939

David J. Campagna

Advanced Resources International
104 Wake Robin Road, Williamsburg, VA 23185-4442
Phone: 757-229-1661, Fax: 757-229-1661, E-mail: dcampagna@adv-res.com

Timothy R. Carr

Kansas Geological Survey
1930 Constant Avenue, Lawrence, KS 66047-3726
Phone: 785-864-3965, Fax: 785-864-5317, E-mail: tcarr@kgs.ukans.edu

Jerry F. Casteel

National Petroleum Technology Office
P.O. Box 3628, Tulsa OK, 74101-3628
Phone: 918-699-2042, Fax: 918-699-2005, E-mail: jcasteel@npto.doe.gov

Derald Chriss

Southern University
P.O. Box 10572, Baton Rouge, LA 70813-0572
Phone: 225-771-3990, Fax: 225-771-3992, E-mail: dchriss1@aol.com

Conference Participants

(continued)

John Cohen

Maurer Engineering Inc.
2916 West TC Jester, Houston, TX 77018-7098
Phone: 713-683-8227 ext. 215, Fax: 713-683-6418, E-mail: jhc@maureng.com

Lance Cole

Petroleum Tech Transfer Council
1101 16th Street NW, Suite 1-C, Washington, DC 20036
Phone: 202-785-2225, Fax: 202-785-2240, E-mail: lcole@pttc.org

Eddie Cousins

Conoco
600 N Dairy Ashford, Houston, TX 77252
Phone: 281-293-2296, Fax: 281-293-2158, E-mail: eddie.t.cousins@nsa.conoco.com

Peter Cover

U.S. Department of Energy
1000 Independence Avenue, Mail Stop FE-30, Washington, DC 20585
Phone: 202-586-7297, Fax: 202-586-6221, E-mail: peter.cover@hq.doe.gov

Alex Crawley

National Petroleum Technology Office
P.O. Box 3628, Tulsa OK 74101-3628
Phone: 918-699-2055, Fax: 918-699-2005, E-mail: acrawley@npto.doe.gov

Jerry R. Crocker

Rush-Andrus Engineering
P.O. Box 4088, Edmond, OK 73083
Phone: 405-359-0400, E-mail: raecrocker@juno.com

Bill Dershowitz

Golder Associates/FracMan
18300 Union Hill NE, Suite 200, Redmond, WA 98052
Phone: 425-885-7648 ext. 2141, Fax: 425-882-5498, E-mail: dersh@golder.com

Edward Jed Di Paolo

Halliburton Energy Services
5151 San Felipe Street, Houston, TX 77056
Phone: 713-624-7490, Fax: 713-840-2707, E-mail: jed.dipaolo@halliburton.com

Conference Participants

(continued)

John H. Doveton

Kansas Geological Survey
1930 Constant Avenue, Lawrence, KS 66047
Phone: 785-864-3965, Fax: 785-864-5317, E-mail: doveton@kgs.ukans.edu

Gerry Drake

Union Pacific Resources
777 Main Street, Mail Station 36-01, Fort Worth, TX 76102
Phone: 814-321-6747, Fax: 817-321-4960, E-mail: gerrydrake@upr.com

Douglas A. Draves

Consulting Geologist
2007 Encino Vista, San Antonio, TX 78259
Phone: 210-497-3350, E-mail: ageowiz@msn.com

Shari Dunn-Norman

University of Missouri at Rolla
119 McNutt Hall, Rolla, MO 65401
Phone: 573-341-4840, Fax: 573-341-6935, E-mail: caolila@umr.edu

Shirley P. Dutton

Bureau of Economic Geology, University of Texas at Austin
University Station, Box X, Austin, TX 78713
Phone: 512-471-0329, Fax: 512-471-0140, E-mail: duttons@begv.beg.utexas.edu

Thaddeus S. Dyman

U.S. Geological Survey
P.O. Box 25046, Mail Stop 939, Denver, CO 80225
Phone: 303-236-5730, Fax: 303-236-0459, E-mail: dyman@usgs.gov

Eric Ecklund

Alta Mesa Resources Inc.
6200 Highway 6 South, Suite 201, Houston, TX 77083
Phone: 281-530-0991, Fax: 281-530-5278, E-mail: mikeelis@altamesa.net

Jeffrey Eppink

Advanced Resources International
1110 North Glebe Road, Arlington, VA 22201
Phone: 703-528-8420, Fax: 703-528-0439, E-mail: jeppink@adv-res.com

Conference Participants

(continued)

Howard J. Erlichman

E4 Inc.

4711 Spicewood Springs Road, Suite 133, Austin, TX 78759

Phone: 703-528-8420, Fax: 703-528-0439, E-mail: he4@prodigy.com

Sam Farris

Interstate Oil and Gas Compact Commission

P.O. Box 53127, Oklahoma City, OK 73152-3127

Phone: 405-525-3556, Fax: 405-252-3592, E-mail: sam.farris@iogcc.state.ok.us

Betty Felber

National Petroleum Technology Office

P.O. Box 3628, Tulsa, OK 74101-3628

Phone: 918-699-2031, Fax: 918-699-2005, E-mail: bfelber@npto.doe.gov

Dan Ferguson

National Petroleum Technology Office

P.O. Box 3628, Tulsa, OK 74101-3628

Phone: 918-699-2047, Fax: 918-699-2048, E-mail: dferguso@npto.doe.gov

Robert J. Finley

Bureau of Economic Geology, University of Texas at Austin

University Station, Box X, Austin, TX 78713

Phone: 512-282-6409, Fax: 512-471-0140, E-mail: rfinley@texas.net

Diane M. Finstrom

Society of Independent Professional Earth Scientists

4925 Greenville Avenue, Suite 1106, Dallas, TX 75206

Phone: 214-363-1780, Fax: 214-363-8195, E-mail: sipes@sipes.org

John Robert Flournoy

Northern Michigan Oil & Gas

P.O. Box 1958, Fort Worth, TX 76101

Phone: 817-599-3065, Fax: 817-599-3221

Fred Followill

Lawrence Livermore National Laboratory

7000 East Avenue, Mail Stop L-644, Livermore, CA 94551-0808

Phone: 925-422-3920, Fax: 925-423-7914, E-mail: followill@llnl.gov

Conference Participants

(continued)

Larry R. Forney

Goldrus Producing Company

17314 State Highway 249, Suite 300, Houston, TX 77064-1140

Phone: 281-807-6114, Fax: 281-807-4477

Mike Fox

Centrilift

200 West Stuart Roosa Drive, Claremore, OK 74017

Phone: 981-342-8671, Fax: 981-342-8660, E-mail: mike.fox@centrilift.com

Rick Frederick

Gas Research Institute

3555 NW 58th Street, Suite 400, Oklahoma City, OK 73112

Phone: 405-942-2334 ext. 212, Fax: 405-942-4636, E-mail: rfrederick@oipa.com

Mark C. Freeman

Independent Geologist

6061 Village Bend Drive, Suite 1405, Dallas, TX 75206

Phone: 214-696-4415

Bob Gaskill

Arkansas Oil & Gas Commission

4977 Old Greenwood Road, Fort Smith, AR 72903

Phone: 501-646-6611

Robert Gee

U.S. Department of Energy

1000 Independence Avenue SW, Mail Stop FE 1, Washington, DC 20585

Phone: 202-586-6660, Fax: 202-586-7847, E-mail: robert.gee@hq.doe.gov

Zola George

Marathon Oil Company

909 ESE Loop 323, Tyler, TX 75713

Phone: 903-509-5550, Fax: 903-509-5588, E-mail: zlgeorge@marathonoil.com

Paul M. Gerlach

Kansas Geological Survey

1930 Constant Avenue, Lawrence, KS 66047-3726

Phone: 785-864-3965, Fax: 785-864-5317, E-mail: pgerlach@kgs.ukans.edu

Conference Participants

(continued)

Mark Germinario

Union Pacific Resources

777 Main Street, Mail Station 30-01, Fort Worth, TX 76102

Phone: 817-321-7351, Fax: 817-321-5724, E-mail: markgerminario@upr.com

Boyd Getz

J P Oil Company Inc.

1604 West Pinhook, MS 70508, Lafayette, LA 70508

Phone: 318-234-1170 ext. 217, Fax: 318-234-9891, E-mail: boyd@jpoil.com

John Godwin

Driver Production Inc.

P.O. Box 696, Okmulgee, OK 74447

Phone: 918-756-7498, Fax: 918-756-4178

Norman E. Goldstein

Lawrence Berkeley National Laboratory

One Cyclotron Road, Mail Stop 90-1126, Berkeley, CA 94720

Phone: 510-486-5961, Fax: 510-486-4686, negoldstein@lbl.gov

Paul Grabowski

U.S. Department of Energy

1000 Independence Avenue SW, Mail Stop EE-12, Washington, DC 20585

Phone: 202-586-0478, Fax: 202-586-8185, E-mail: paul.grabowski@hq.doe.gov

Leonard E. Graham

Federal Energy Technology Center

3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507-0880

Phone: 304-285-4714, Fax: 304-285-4292, E-mail: lgraha@fetc.doe.gov

Don W. Green

Tertiary Oil Recovery Project

4008 Learned Hall, Lawrence, KS 66044-7526

Phone: 785-864-2911, Fax: 785-864-4967, E-mail: dgreen@ukans.edu

Tim S. Green

Idaho National Engineering & Environmental Laboratory

P.O. Box 1625, Idaho Falls, ID 83415-2107

Phone: 208-526-9420, Fax: 208-526-9822, E-mail: tsgr@inel.gov

Conference Participants

(continued)

Ron Grubbs

Society of Independent Professional Earth Scientists
4925 Greenville Avenue, Suite 1106, Dallas, TX 75206
Phone: 214-363-1780, Fax: 214-363-8195, E-mail: sipes@sipes.org

Hugh D. Guthrie

Federal Energy Technology Center
3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507-0880
Phone: 304-285-4632, Fax: 304-285-4216, E-mail: hguthr@fetc.doe.gov

W. J. (Bill) Gwillaim

Federal Energy Technology Center
3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507-0880
Phone: 304-285-4401, Fax: 304-285-4403, E-mail: wgwill@fetc.doe.gov

Purna C. Halder

National Petroleum Technology Office
P.O. Box 3628, Tulsa, OK 74101-3628
Phone: 918-699-2084, Fax: 918-699-2005, E-mail: phalder@npto.doe.gov

Ken Haley

BP Amoco Exploration
501 Westlake Park, Houston, TX 77253
Phone: 281-366-7360, Fax: 281-366-4519, E-mail: haleyka@bp.com

Scott Hara

Tidelands Oil Production Co.
301 East Ocean Blvd, Suite 300, Long Beach, CA 90802
Phone: 562-495-9351, Fax: 562-495-1950, E-mail: tidelands@95net.com

Bob Hardage

Bureau of Economic Geology, University of Texas at Austin
10,100 Burnet Road, Austin, TX 78758-4497
Phone: 512-471-0300, Fax: 512-232-2388, E-mail: hardageb@begv.beg.utexas.edu

William B. Harrison

Western Michigan University, Department of Geosciences
Kalamazoo, MI 49008
Phone: 616-387-5488, Fax: 616-387-5513, E-mail: harrison@wmich.edu

Conference Participants

(continued)

Neil Haugland

Rocky Mountain Oilfield Testing
907 North Poplar, Suite 150, Casper, WY 82601
Phone: 307-261-5161 ext. 5017, Fax: 307-261-5997, E-mail: neil.haugland@rmotc.com

A. Hayatdavoudi

University of Southwestern Louisiana
3901 Crow Canyon Road, San Ramon, CA 94583
Phone: 925-735-7174, E-mail: lhayat@aol.com

David L. Henderson

Seely Oil Company
815 West 10th Street, Fort Worth, TX 76102
Phone: 817-332-1377, Fax: 817-332-1426

Thomas B. Henderson

Henderson Exploration
915 Furman Avenue, Corpus Christi, TX 78404-3225
Phone: 361-883-2834, Fax: 361-883-2874, E-mail: tbhl@flash.net

James Hicks

Energy Information Administration
1999 Bryan Street, Suite 1110, Dallas, TX 75201-6801
Phone: 214-720-6156, Fax: 214-720-6155, E-mail: jhicks@eia.doe.gov

Tom Highsmith

Hunt Oil Company
1445 Ross, Dallas, TX 75202
Phone: 214-978-8287, Fax: 214-978-8888, E-mail: tom@huntoilexpl.com

Danny Hill

Burlington Resources
3535 East 30th Street, Farmington, NM 87402
Phone: 505-326-9504, Fax: 505-326-9880, E-mail: dhill@br-inc.com

Hugh Horn

Independent Geologist-Geophysicist
P.O. Box 126, McComb, MS 39649
Phone: 601-684-2303, Fax: 601-684-2303

Conference Participants

(continued)

Gene Huck

James Engineering Inc.
231 Third Street, Marietta, OH 45750
Phone: 740-373-9521, Fax: 740-373-2750, E-mail: jeitsk@ee.net

Richard Hughes

University of Oklahoma
100 East Boyd, Room T319, Norman, OK 73019
Phone: 405-325-8141, Fax: 405-325-7477, E-mail: rghughes@ou.edu

Robert Hugman

EEA Inc.
1655 North Fort Myer Drive, Suite 600, Arlington, VA 22209
Phone: 703-528-1900, Fax: 703-528-5106, E-mail: bhugman@eea-inc.com

Joe Lovenitti

Weiss Associates
5801 Christie Avenue, Emeryville, CA 94608-1827
Phone: 510-450-6141, Fax: 510-547-5043, E-mail: jli@weiss.com

Lorri Jackson

Rocky Mountain Oilfield Testing
907 North Poplar, Suite 150, Casper, WY 82601
Phone: 307-261-5000 ext. 5011, Fax: 307-261-5997, E-mail: lorri.jackson@rmotc.com

Jerry James

James Engineering Inc.
231 Third Street, Marietta, OH 45750
Phone: 740-373-9521, Fax: 740-373-2750, E-mail: jeitsk@ee.net

Perry Jarrell

BP Amoco
501 Westlake Park Blvd, Houston, TX 77070
Phone: 281-366-7309, Fax: 281-366-4519, E-mail: jarrelpm@bp.com

Farzaneh Jebrail

Texas A&M University, Texas Engineering Extension Services
301 Tarrow, College Station, TX 77840
Phone: 409-862-8587, Fax: 409-845-3559, E-mail: ecjebrai@teexnet.tamu.edu

Conference Participants

(continued)

Michael Jervis

TomoSeis

1650 West Sam Houston Pkwy N, Houston, TX 77043

Phone: 713-461-4620, Fax: 713-461-7312, E-mail: michael.jervis@tomoseis.com

Zun Sheng Jiao

University of Wyoming, Institute for Energy Research

P.O. Box 4068, Laramie, WY 82071-4068

Phone: 307-766-2703, Fax: 307-766-2737, E-mail: jiao@uwyo.edu

Robert T. Jubin

Oak Ridge National Laboratory

One Bethel Valley, P.O. Box 2008, Oak Ridge, NT 37831-6223

Phone: 423-574-6874, Fax: 423-574-6870, E-mail: jubinrt@ornl.gov

Edward L. Kainer

Technical Toolboxes Inc.

3801 Kirby Drive, Suite 340, Houston, TX 77098

Phone: 713-630-0505, Fax: 713-630-0560, E-mail: info@ttoolboxes.com

Mohan Kelkar

University of Tulsa

600 South College Avenue, Tulsa, OK 74104

Phone: 918-631-3036, Fax: 918-631-2979

Ron Kelley

Duke Energy

P.O. Box 1642, Houston, TX 77251-1642

Phone: 713-627-5937, Fax: 713-989-1522, E-mail: rjkelley@duke-energy.com

Frank King

Francis W. King

P.O. Box 2587, Edmond, OK 73083-2587

Phone: 405-348-2562, Fax: 405-348-7027, E-mail: fwking@hotmail.com

Barry Kirkendall

Lawrence Livermore National Laboratory

P.O. Box 808, Mail Stop 206, Livermore, CA 94550

Phone: 925-423-1513, Fax: 925-422-3118, E-mail: kirkendall1@llnl.gov

Conference Participants

(continued)

Roy M. Knapp

University of Oklahoma
3910 Northridge Road, Norman OK 73072-3212
Phone: 405-325-6829, Fax: 405-325-7477, E-mail: knapp@ou.edu

Tim Knobloch

James Engineering
231 Third Street, Marietta, OH 45750
Phone: 740-373-9521, Fax: 304-428-8850

Paul R. Knox

Bureau of Economic Geology, University of Texas at Austin
University Station, Box X, Austin, TX 78713-8924
Phone: 512-471-7313, Fax: 512-471-0140, E-mail: knoxp@beg.utexas.edu

Jack J. Kollé

Tempress Technologies Inc.
19308 68th Avenue S, Kent, WA 98032-1192
Phone: 253-872-1980, Fax: 253-395-9276, E-mail: jkollé@tempresstech.com

Charles A. Komar

Federal Energy Technology Center
3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507-0880
Phone: 304-285-4107, Fax: 304-285-4403, E-mail: ckomar@fetc.doe.gov

Philip Kreick

Kestrel Resources
2626 Cole, Suite 501, Dallas, TX 75204
Phone: 214-871-0999, Fax: 214-871-5040

Darrell Kruse

Perry Equipment Corporation
Fort Wolters Industrial Park, Mineral Wells, TX 76068
Phone: 800-877-7326, Fax: 940-325-4624, E-mail: dkruse@pecousa.com

Lee F. Krystinik

Union Pacific Resources
P.O. Box 7, Mail Station 34-01, Fort Worth, TX 76102-0007
Phone: 817-321-6702, Fax: 817-820-7108, E-mail: leekrystinik@upr.com

Conference Participants

(continued)

Ergun Kuru

University of Tulsa
600 South College Avenue, Mail Stop NC 208D, Tulsa, OK 74104
Phone: 918-631-5174, Fax: 918-631-5009, E-mail: ergun-kuru@utulsa.edu

Vello A. Kuuskraa

Advanced Resources International
1110 North Glebe Road, Suite 600, Arlington, VA 22201
Phone: 703-528-8420, Fax: 703-528-0439, E-mail: vkuuskraa@adv-res.com

Bruce Langhus

CH2M HILL
502 South Main Street, Suite 400, Tulsa, OK 74103
Phone: 918-583-3057, Fax: 918-584-5826, E-mail: blanghus@ch2m.com

Lorie Langley

Oak Ridge National Laboratory
P.O. Box 2008, Mail Stop 6248, Oak Ridge, TN 37831-6248
Phone: 423-574-4185, Fax: 423-576-6118, E-mail: ll8@ornl.gov

William F. Lawson

National Petroleum Technology Office
P.O. Box 3628, Tulsa, OK 74101-3628
Phone: 918-699-2001, Fax: 918-699-2005, E-mail: blawson@npto.doe.gov

Jeff Lenard

Petroleum Technology Transfer Council
1101 16th Street NW, Suite 1-C, Washington, DC 20036
Phone: 202-785-2225, Fax: 202-785-2240, E-mail: jlenard@pttc.org

Frank H. Lim

Union Pacific Resources
777 Main Street, Mail Station 30-01, Fort Worth, TX 76102
Phone: 817-321-7889, Fax: 817-321-7974, E-mail: franklim@upr.com

Rhonda P. Lindsey

National Petroleum Technology Office
P.O. Box 3628, Tulsa, OK 74101-3628
Phone: 918-699-2037, Fax: 918-699-2005, E-mail: rlindsey@npto.doe.gov

Conference Participants

(continued)

Charles S. Logan

Florida Geological Survey
903 West Tennessee Street, Gunter Building, Suite 720, Tallahassee, FL 32304-7700
Phone: 850-487-2219, Fax: 850-488-8086, E-mail: charles.logan@dep.state.fl.us

Gary Long

Energy Information Administration
1999 Bryan Street, Suite 1110, Dallas, TX 75201-6801
Phone: 214-720-6182, Fax: 214-720-6155, E-mail: glong@eia.doe.gov

Roy Long

Federal Energy Technology Center
3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507-0880
Phone: 304-285-4236, Fax: 304-285-4403, E-mail: rlong@fetc.doe.gov

John C. Lorenz

Sandia National Laboratories
P.O. Box 5800, Mail Stop 0750, Albuquerque, NM 87185
Phone: 505-844-3695, Fax: 505-844-7354, E-mail: jcloren@sandia.gov

Patrick Lowry

The Scotia Group
4849 Greenville Avenue, Suite 1150, Dallas, TX 75206
Phone: 214-987-1042, Fax: 214-987-1047

David A. Luttner

Hunt Oil Company
1445 Ross Avenue, Dallas, TX 75202-2785
Phone: 214-978-8450, Fax: 214-978-8888, E-mail: david.luttner@huntoil.com

Heloise Lynn

Lynn Inc.
14732 F. Perthshire Road, Houston, TX 77079
Phone: 281-497-1238, Fax: 281-497-1249, E-mail: lynninc@compuserve.com

Mark Mahoney

Harbison-Fischer Manufacturing Co.
P.O. Box 2477, Fort Worth, TX 76113-2477
Phone: 817-297-2211, Fax: 817-297-4248

Conference Participants

(continued)

Ernest L. Majer

Lawrence Berkeley National Laboratory
One Cyclotron Road, Mail Stop 90-1116, Berkeley, CA 94720
Phone: 510-486-6709, Fax: 510-486-5686, E-mail: elmajer@lbl.gov

Ernest Mancini

University of Alabama, Department of Geology
P.O. Box 870338, Tuscaloosa, AL 35487
Phone: 205-348-4319, Fax: 205-348-0818, E-mail: emancini@wgs.geo.ua.edu

A. J. (Chip) Mansure

Sandia National Laboratories
P.O. Box 5800, Mail Stop 1033, Albuquerque, NM, 87185-1033
Phone: 505-844-9315, Fax: 505-844-3952, E-mail: ajmansu@sandia.gov

Sandra Mark

Petroleum Technology Transfer Council, Colorado School of Mines
Golden, CO 80401
Phone: 303-273-3107, Fax: 303-273-3859, E-mail: smark.95@alum.mines.edu

Bill Maurer

Maurer Engineering Inc.
2916 West TC Jester, Houston, TX 77018-7098
Phone: 713-683-8227 ext. 208, Fax: 713-683-6418, E-mail: maurer@maureng.com

Russell G. May

Virginia Tech, Bradley Department of Electrical Engineering
Blacksburg, VA 24061-0111
Phone: 540-231-1837, Fax: 540-231-2158, E-mail: may@vt.edu

Dwayne McCune

North Midcontinent — Petroleum Technology Transfer Council
1930 Constant Avenue, Lawrence, KS 66047
Phone: 785-864-7398, Fax: 785-864-7399, E-mail: dmccune@cpe.engr.ukans.edu

Bill McDonald

Maurer Engineering Inc.
2916 West TC Jester, Houston, TX 77018-7098
Phone: 713-683-8227 ext. 210, Fax: 713-683-6418, E-mail: mcdonald@maureng.com

Conference Participants

(continued)

Gil McGurl

Federal Energy Technology Center
626 Cochran Mill Road, P.O. Box 10940, Pittsburgh, PA 15236-0940
Phone: 412-386-4462, Fax: 412-386-6127, E-mail: mcgurl@fetc.doe.gov

Linda McKee

Quanterra Inc.
5514 Decker Drive, Baytown, TX 77520
Phone: 281-424-3008, Fax: 281-424-5161, E-mail: mckeel@quanterra.com

Mark L. McKoy

EG&G TSWV Inc.
3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507-0880
Phone: 304-285-4426, Fax: 304-285-4403, E-mail: mmckoy@fetc.doe.gov

Steve Melzer

Melzer Exploration Company
P.O. Box 2083, Midland, TX 79702
Phone: 915-682-7664, Fax: 915-682-9955, E-mail: melzerls@aol.com

Harry M. Meyer

Oak Ridge National Laboratory
P.O. Box 2009, Oak Ridge, TN 37831
Phone: 423-576-3866, Fax: 423-574-9407, E-mail: h65@ornl.gov

Moe Miceli

Collina Exploration
410 17th Street, Suite 1140, Denver, CO 80202
Phone: 303-629-1914, Fax: 303-629-1932, E-mail: moe_miceli@msn.com

Tom Michael

Vista Resources Inc.
61 McMurray Road, Suite 300, Pittsburgh, PA 15241
Phone: 412-833-8884, Fax: 412-833-4339, E-mail: www.vista@nb.net

Michael J. Michnick

University of Kansas
4008 Learned Hall, Lawrence, KS 66045-2936
Phone: 785-864-2913, Fax: 785-864-4967, E-mail: michnick@kuhub.cc.ukans.edu

Conference Participants

(continued)

Allen Middleman

Burlington Resources

3300 North A Street, Midland, TX 79705

Phone: 915-688-9048, Fax: 915-688-6072, E-mail: amiddleman@br-inc.com

Stefan Miska

University of Tulsa

600 South College Avenue, Mail Stop NC 208D, Tulsa, OK 74104

Phone: 918-631-5167, Fax: 918-631-5009, E-mail: stefan-miska@utulsa.edu

Gary Mitchell

Hunt Oil Company

1445 Ross Avenue, Dallas, TX 75202-2785

Phone: 214-978-8642, Fax: 214-978-8888, E-mail: gary@huntoilexpl.com

Ram S. Mohan

University of Tulsa

600 South College Avenue, Tulsa, OK 74104-3189

Phone: 918-631-2075, Fax: 918-631-2397, E-mail: ram-mohan@utulsa.edu

Craig Morgan

Utah Geological Survey

P.O. Box 146100, Salt Lake City, UT 84114-6100

Phone: 801-537-3370, Fax: 801-537-3400, E-mail: nrugs.cmorgan@state.ut.us

David G. Morse

Illinois State Geological Survey

615 East Peabody Drive, Champaign, IL 61820

Phone: 217-244-5527, Fax: 217-244-2785, E-mail: morse@geoserv.isgs.uiuc.edu

Thomas H. Mroz

Federal Energy Technology Center

3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507-0880

Phone: 304-285-4071, Fax: 304-285-4469, E-mail: tmroz@fetc.doe.gov

David M. Munson

David M. Munson Inc.

1600 Pacific Avenue, Suite 3020, Dallas, TX 75201

Phone: 214-954-0260, Fax: 214-954-0867

Conference Participants

(continued)

Larry Myer

Lawrence Berkeley National Laboratory
One Cyclotron Road, Mail Stop 90-1116, Berkeley, CA 94720
Phone: 510-486-6456, Fax: 510-486-5686, E-mail: lrmyer@lbl.gov

Carl Wes Myers

Los Alamos National Laboratory
P.O. Box 1663, Mail Stop D-446, Los Alamos, NM 87545
Phone: 505-667-3644, Fax: 505-667-3494, E-mail: wmeyers@lanl.gov

Robin L. Newmark

Lawrence Livermore National Laboratory
7000 East Avenue, P.O. Box 808, L-208, Livermore, CA 94550
Phone: 925-423-3644, Fax: 925-422-3925, E-mail: newmark1@llnl.gov

Mark A. Nieberding

Gaffney, Cline & Associates
16775 Addison Road, Suite 400, Addison, TX 75001
Phone: 972-733-1183, Fax: 972-380-0180, E-mail: mnieberding@gaffney-cline.com

Ken Oglesby

Oak Resources Inc.
P.O. Box 9665, Tulsa, OK 74157-0665
Phone: 918-627-8012, Fax: 918-627-8013, E-mail: oakk@aol.com

Patrick Overman

PJ Overman Inc.
458 West Austin, Giddings, TX 78942
Phone: 409-542-2516, Fax: 409-542-2500

Butch Owen

Cudd Well Control
800 East Campbell Road, Suite 199, Richardson, TX 75081
Phone: 972-680-5110, Fax: 972-699-7893, E-mail: blowout@wtd.net

Susan Owen

CMS Energy
P.O. Box 4967, Houston, TX 77210-4967
Phone: 713-627-5939, Fax: 713-989-3096, E-mail: swowen@cmsenergy.com

Conference Participants

(continued)

David Palm

Palm Oil & Gas Company
P.O. Box 520965, Tulsa, OK 74114
Phone: 918-747-8640, Fax: 918-712-1770

Barry F. Petty

ARCO Permian
600 North Marienfeld, Midland, TX 79701-4373
Phone: 915-688-5822, Fax: 915-688-5271, E-mail: bpetty@is.arco.com

Barrett W. Pierce

Rio Petroleum Inc.
2805 West 15th Avenue, Amarillo, TX 79102-2244
Phone: 806-356-8033, Fax: 806-358-8231, E-mail: riobwp@arn.net

David Pixton

Novatek
2185 South Larsen Parkway, Provo, UT 84606
Phone: 801-374-2755, Fax: 508-256-8303, E-mail: dpixton@novatekonline.com

Mike Prairie

Sandia National Laboratories
P.O. Box 5800, Mail Stop 1033, Albuquerque, NM 87185-1033
Phone: 505-844-7823, Fax: 505-844-3952, E-mail: mrprair@sandia.gov

William Preeg

Schlumberger
8311 North FM 620, Austin, TX 78726
Phone: 512-331-3710, Fax: 512-331-3065, E-mail: preeg1@slb.com

Robert Radtke

Technology International Inc.
2103 River Falls Drive, Kingwood, TX 77339
Phone: 281-359-8520, Fax: 281-359-8527, E-mail: radtke@kingwoodcable.com

Hafeez Rahman

U.S. Department of Energy
1999 Bryan Street, Suite 1110, Dallas, TX 75201
Phone: 214-720-6162, E-mail: hafeez.rahman@eia.doe.gov

Conference Participants

(continued)

Doug Ratcliff

Bureau of Economic Geology, University of Texas at Austin
10,100 Burnet Road, Austin, TX 78758-4497
Phone: 512-471-5117, Fax: 512-471-0140, E-mail: doug.ratcliff@beg.utexas.edu

Cindy Reece

Exxon Upstream Development Co.
16945 Northchase Drive, Houston, TX 77060
Phone: 281-423-4510, Fax: 281-423-4646, E-mail: cindy.a.reece@exxon.com

Scott R. Reeves

Advanced Resources International
9801 Westheimer, Suite 805, Houston, TX 77042
Phone: 713-780-0815, Fax: 713-780-3819, E-mail: sreeves@adv-res.com

T. K. Reeves

P.O. Box 2008, Bartlesville, OK 24005-2008
Phone: 918-331-0012, E-mail: treeves@ionet.net

Rodney R. Reynolds

University of Kansas
4008 Learned Hall, Lawrence, KS 66045
Phone: 785-864-7398, Fax: 785-864-7399, E-mail: reynolds@cpe.engr.ukans.edu

Richard Rice

Idaho National Engineering & Environmental Laboratory
P.O. Box 1625, Idaho Falls, ID 83415-2110
Phone: 208-526-1992, Fax: 208-526-9822, E-mail: rrr@inel.gov

Richard Rinehart

Kestrel Resources
2626 Cole, Suite 501, Dallas, TX 75204
Phone: 214-871-0999, Fax: 214-871-5040, E-mail: rdrkestrel@aol.com

Deborah Rowell

Petroleum Technology Transfer Council
1101 16th Street NW, Washington, DC 20036
Phone: 202-785-2225, Fax: 202-785-2240, E-mail: drowell@pttc.org

Conference Participants

(continued)

Ralph Russell

Energy Information Administration
1999 Bryan Street, Suite 1110, Dallas, TX 75201-6801
Phone: 214-270-6196, Fax: 214-720-6155, E-mail: russell@eia.doe.gov

David S. Schechter

Petroleum Recovery Research Center, New Mexico Tech
801 Leroy Place, Socorro, NM 87801
Phone: 505-835-5572, Fax: 505-835-6031, E-mail: schech@baervan.nmt.edu

Dale Schlinsog

Koch Industries
20 East Greenway plaza, 6th Floor, Houston, TX 77046
Phone: 713-544-5214, Fax: 713-544-6161, E-mail: schlinsd@kochind.com

David K. Schmalzer

Argonne Fossil Energy
955 L'enfant Plaza North SW, Suite 600, Washington, DC 20024
Phone: 202-488-2415, Fax: 202-488-2413, E-mail: schmalzer@anl.gov

Leo A. Schrider

Belden & Blake Corporation
5200 Stoneham Road, North Canton, OH 44720
Phone: 330-499-1660, Fax: 330-497-5470

William Schuller

EG&G Technical Services of West Virginia Inc.
3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507-0880
Phone: 304-285-4019, Fax: 304-285-4403, E-mail: wschul@fetc.doe.gov

Valary L. Schulz

Consulting Geologist
3500 Oak Lawn, Suite 720, Dallas, TX 75219
Phone: 214-520-2929, Fax: 214-520-2930

C. W. Seely

Seely Oil Company
815 West 10th Street, Fort Worth, TX 76102
Phone: 817-332-1377, Fax: 817-332-1426

Conference Participants

(continued)

Randy Seright

Petroleum Recovery Research Center, New Mexico Tech
801 Leroy Place, Socorro, NM 87801
Phone: 505-835-5571, Fax: 505-835-6031, E-mail: randy@prrc.nmt.edu

Beverly Seyler

Illinois State Geological Survey
615 East Peabody Drive, Champaign, IL 61820
Phone: 217-244-2389, Fax: 217-333-2830, E-mail: seyler@isgs.uiuc.edu

Guy Shafer

Cudd Well Control
1675 Broadway, Suite 1800, Denver, CO 80202
Phone: 303-571-1734, Fax: 303-575-9358

John Sharry

Consulting Geologist
7525 Twin Oaks Court, Garland, TX 75044
Phone: 972-414-2643, E-mail: jsharry@ix.netcom.com

Rodney D. Shepherd

Hunt Oil Company
1445 Fountain Place, Dallas, TX 75202-2785
Phone: 214-978-8659, Fax: 214-978-8677, E-mail: rod@huntoilexpl.com

Thomas R. Sifferman

Texas Independent Producers and Royalty Owners/Gas Research Institute
4800 Research Forest Drive, The Woodlands, TX 77381-4142
Phone: 281-363-7993, Fax: 281-363-7990, E-mail: tom@tipro.org

Barbara Skelton

Interstate Oil and Gas Compact Commission
P.O. Box 53127, Oklahoma City, OK 73152-3127
Phone: 405-525-3556 ext. 107, Fax: 405-525-3592, E-mail: barbara.skelton@iogcc.state.ok.us

Robert Stayton

Gas Research Institute
4800 Research Forest Drive, The Woodlands, TX 77381-4142
Phone: 281-363-7991, Fax: 281-363-7990, E-mail: rstayton@gri.org

Conference Participants

(continued)

James O. Stephens

Hughes Eastern Corp.
403 Towne Center Blvd, Suite 103, Ridgeland, MS 39157
Phone: 601-898-0051 ext. 305, Fax: 601-898-0233

George Stosur

U.S. Department of Energy
1000 Independence Avenue, Washington, DC 20545
Phone: 202-586-8379, Fax: 202-586-6221, E-mail: george.stosur@hq.doe.gov

Joseph Summa

Technical Toolboxes Inc.
3801 Kirby Drive, Suite 340, Houston, TX 77098
Phone: 713-630-0505, Fax: 713-630-0560, E-mail: jsumma@ttoolboxes.com

Ronald C. Surdam

University of Wyoming, Institute for Energy Research
P.O. Box 4068, Laramie, WY 82071-4068
Phone: 307-766-4201, Fax: 307-766-4203, E-mail: rcsurdam@uwyo.edu

Dexter Sutterfield

National Petroleum Technology Office
P.O. Box 3628, Tulsa, OK 74101-3628
Phone: 918-699-2039, Fax: 918-699-2005, E-mail: dsutterf@npto.doe.gov

Lawrence W. Teufel

New Mexico Tech, Petroleum Engineering Department
Socorro, NM 87801
Phone: 505-835-5483, Fax: 505-835-5210, E-mail: lteufel@nmt.edu

Jimmy D. Thomas

Castaneda Consulting LLC
3705 Bluebonnet Circle, Weatherford, TX 76078
Phone: 817-596-8359, Fax: 817-596-8910, E-mail: jtexpl@fastlane.net

Herbert Tiedemann

National Petroleum Technology Office
One West Third, Suite 1400, Tulsa, OK 74103
Phone: 918-699-2017, Fax: 918-699-2005, E-mail: htiedema@npto.doe.gov

Conference Participants

(continued)

Thomas M. Torkos

Federal Energy Technology Center
626 Cochrans Mill Road, P.O. Box 10940, Pittsburgh, PA 15236
Phone: 412-892-6125, Fax: 412-892-6127, E-mail: torkos@fetec.doe.gov

Jose E. Torres

U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 1200, Dallas, TX 75202
Phone: 214-665-8092, Fax: 214-665-2191, E-mail: torres.jose@epamail.epa.gov

Robert C. Trentham

Laguna Petroleum Corporation
1003 North Big Spring Street, Midland, TX 79701
Phone: 915-686-9692, Fax: 915-686-9692, E-mail: muskoka@texasonline.net

Alex Vadie

Mississippi State University
P.O. Box 5423, Mississippi State, MS 39762
Phone: 601-325-7224, Fax: 601-325-0656, E-mail: vadie@ra.msstate.edu

Richard R. Van Dok

Western Geophysical Company
1625 Broadway, Suite 1300, Denver, CO 80202
Phone: 303-629-9250, Fax: 303-595-0667, E-mail: rich.van.dok@westgeo.com

Gregory A. Vance

Production Gathering Company
9319 LBJ Freeway, Suite 204, Dallas, TX 75243
Phone: 972-680-9737, Fax: 972-680-3688, E-mail: gvance@pgcgas.com

Philip D. Vasquez

U.S. Department of Energy
1000 Independence Avenue SW, Mail Stop FE 30, Washington, DC 20585
Phone: 202-586-1583, Fax: 202-586-6221, E-mail: philip.vasquez@hq.doe.gov

James Vass

U.S. Environmental Protection Agency
1445 Ross Avenue, Dallas, TX 75202-2733
Phone: 214-665-7335, Fax: 214-665-2191, E-mail: vass.jim@epa.gov

Conference Participants

(continued)

Michael Volk

University of Tulsa
600 South College Avenue, Tulsa, OK 74104-3189
Phone: 918-631-5127, Fax: 918-631-5112, E-mail: michael-volk@utulsa.edu

John W. Walker

Rio Petroleum Inc.
2805 West 15th Avenue, Amarillo, TX 79102-2244
Phone: 806-356-8033, Fax: 806-358-8231

Larry Walter

OYO Geospace Instruments
12750 South Kirkwood, Suite 200, Stafford, TX 77477
Phone: 281-494-8282 ext. 312, Fax: 281-494-8310, E-mail: lwalter@oyo.com

Shoubo Wang

University of Tulsa
600 South College Avenue, Tulsa, OK 74104-3189
Phone: 918-631-3257, Fax: 918-631-2059, E-mail: wangs@centum-utulsa-edu

Bernadette C. Ward

National Petroleum Technology Office
P.O. Box 3628, Tulsa, OK 74101-3628
Phone: 918-699-2033, Fax: 918-699-2048, E-mail: bward@npto.doe.gov

Dave Weinberg

Idaho National Engineering & Environmental Laboratory
P.O. Box 1625, Idaho Falls, ID 83415
Phone: 208-526-4274, Fax: 208-526-9822, E-mail: weinbe@inel.gov

Bill Weiss

Petroleum Recovery Research Center, New Mexico Tech Campus
Socorro, NM 87801
Phone: 505-835-5220, Fax: 505-835-6031, E-mail: weiss@baervan.nmt.edu

Robert V. Westermarck

Oil & Gas Consultants International, Inc.
4111 South Darlington, Suite 700, Tulsa, OK 74135-6377
Phone: 918-828-2543, Fax: 918-828-2582, E-mail: bwestermarck@ogci.com

Conference Participants

(continued)

Ginny Weyland

National Petroleum Technology Office
P.O. Box 3628, Tulsa, OK 74101-3628
Phone: 918-699-2041, Fax: 918-699-2005, E-mail: gweyland@npto.doe.gov

Troy White

Cudd Well Control
4544 Post Oak Place, Suite 280, Houston, TX 77027
Phone: 713-877-8961, Fax: 713-877-8961, E-mail: twhite@cudd.com

James Whiteley

Marconi Aerospace
6500 Tracor Lane, Austin, TX 78660
Phone: 512-929-2029, Fax: 512-929-2055, E-mail: jwhiteley@tracor.com

Earl Whitney

Los Alamos National Laboratory
P.O. Box 1663, Mail Stop D446, Los Alamos, NM 87545
Phone: 505-667-3595, Fax: 505-667-3494, E-mail: whitney@lanl.gov

Michael Wilkey

Argonne National Laboratory
9700 South Cass Avenue, Building 362, Argonne, IL 60439
Phone: 630-252-9240, Fax: 630-252-9281, E-mail: mwilkey@anl.gov

G. Paul Willhite

Tertiary Oil Recovery Project
4008 Learned Hall, Lawrence, KS 66044-7526
Phone: 785-864-2906, Fax: 785-864-4967, E-mail: willhite@cpe.engr.ukans.edu

Thomas E. Williams

Westport Technology Center
6700 Portwest Drive, Houston, TX 77024
Phone: 713-479-8400, Fax: 713-864-9357, E-mail: williams@neosoft.com

Ronald Wilson

LAHD Energy Inc.
307 West 7th Street, Suite 1717, Fort Worth, TX 76102
Phone: 817-332-8181, Fax: 817-332-8187, E-mail: lahd@aol.com

Conference Participants

(continued)

James R. Wood

Michigan Technological University
1400 Townsend Drive, Houghton, MI 49931
Phone: 906-487-2894, Fax: 906-487-2531, E-mail: jrw@mtu.edu

John H. Wood

Energy Information Administration
1999 Bryan Street, Suite 1110, Dallas, TX 75201-6801
Phone: 214-720-6160, Fax: 214-720-6155, E-mail: jwood@eia.doe.gov

Lesli Wood

Bureau of Economic Geology, University of Texas at Austin
10,100 Burnet Road, Austin, TX 78758-4497
Phone: 512-471-0328, Fax: 512-471-0140, E-mail: woodl@begv.beg.utexas.edu

Todd M. Yocham

Pioneer Natural Resources
303 West Wall Street, Suite 101, Midland, TX 79701
Phone: 915-571-1342, Fax: 915-571-5062, yochamt@pioneernc.com

Albert B. Yost II

Federal Energy Technology Center
3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507-0880
Phone: 304-285-4479, Fax: 304-285-4469, E-mail: ayost@fetc.doe.gov

Mir Yousufuddin

Energy Information Administration
1999 Bryan Street, Suite 1110, Dallas, TX 75201-6801
Phone: 214-720-6186, Fax: 214-720-6155, E-mail: ymir@eia.doe.gov

Welcome

Robert W. Gee
Assistant Secretary for Fossil Energy
U.S. Department of Energy

It is a pleasure to be here with you this morning. I appreciate the opportunity to open this conference.

As you know, the subtitle for this conference is “technology options for producers’ survival.” For better or worse, it is an appropriate title – particularly when we emphasize the last word, “survival.”

For the last several months, many of you – and many of your colleagues – have had to deal with that word, “survival.” You have ridden a roller coaster of prices – again, like you did in the mid-80s and again in the early 90s. This time, however, the declines were steeper and more severe than at any time in post-war memory. And the upturns have been gradual and filled with uncertainty.

I’m not going to dwell on the last 18 or 19 months. You have lived through it. You have survived. The purpose of this conference is to look into the future...to discuss ways to avoid – or at least smooth out – the roller coaster rides that will inevitably strike this industry again.

Last December, when the price plunge was approaching its most severe decline, Secretary Richardson appointed an Oil Emergency Task Force. I was asked to chair it. We had a very clear mandate from the Secretary – it was NOT to prop up the domestic industry....or to find ways to artificially push up prices. A lot of people were confused about that.

The mission of the Task Force was to find ways to preserve the domestic production capacity of our domestic oil and gas fields....to look across the industry – and across the government – for ways to prevent a further erosion of our nation’s domestic energy security. In other words, were there things we could do that would smooth out the roller coaster ride – not only today, but in the future?

That’s why – even with the recent upturn in prices – this Task Force still has work to do. That’s why – at the urging of Secretary Richardson – the White House created an Interagency Working Group on oil and gas matters. That working group continues to function today – working under the leadership of Gene Sperling, chairman of the National Economic Council, and his deputy Ron Minsk.

As many of you know, the DOE Task Force has already initiated some actions, several of which I will describe in a moment. I believe you are also going to see some additional actions come out of the White House Interagency Group. Several things have occurred in the last few weeks – even as the immediate crisis of low oil prices has abated somewhat.

For one thing, many people inside – and outside – the Administration are gaining a much better appreciation of the challenges you face. They are beginning to understand, for example, that oil reservoirs are not like an upside-down spigot. They are beginning to recognize that it isn't as simple as when prices go up, the spigot turns on and when prices go down, the spigot turns off. They are beginning to appreciate the fact that every time your industry goes through a roller coaster like the last one – or the one in the 80s – some part of our domestic resource is lost forever.

They are now beginning to understand that Infrastructure gets removed. Leases are lost. Fields are plugged and abandoned. And when this occurs, the resource in those fields – certainly a significant portion of it – is effectively and financially lost. It won't be produced under any reasonable price scenario – certainly not in the foreseeable future...perhaps never at all.

People both inside and outside the Administration are beginning to understand that what happens in the oil industry also affects natural gas. Twenty percent (20%) of the nation's natural gas production is linked directly to the production of crude oil. And a lot more of our domestic gas production is linked to investment decisions that are driven by crude oil prices.

So people are beginning to get a better appreciation for the fact that turbulence in the oil industry has some ominous impacts on whether this nation can meet some of its environmental goals – and do so affordably and reliably.

People are beginning to understand that, like any landowner, the Federal Government has a financial stake in the health of the domestic oil industry. Twenty-five percent (25%) of our domestic oil production and 37 percent of our domestic gas production comes from Federal lands. That translates into more than \$6 billion a year in royalties, bonuses, and rentals flowing into the U.S. Treasury. And, of course, States who share in those revenues, also have a financial stake in the ups-and-downs of the industry.

Finally, people are beginning to appreciate that the U.S. oil industry of 1999 is not the industry of 1979 or 1969...or perhaps even 1989. It is a changed industry – both in its core make-up, and by extension, in its vulnerability to sharp price swings.

Today's domestic industry is increasingly an industry of independents. Fifty percent (50%) of the crude oil and 60 percent of the natural gas produced in the lower 48 States is produced by independent companies, 90 percent of whom employ 20 workers or less. These companies – many of you in this audience – drill 85 percent of all new wells in the United States.

Fifteen or 20 years ago, an industry dominated by major, multinational companies had the resources to wait out the “bust” cycles. They could remain solvent while awaiting the next “boom.” But that is no longer the case in this industry. You know that better than any one. Many in your industry are walking a financial tightrope – and when prices plunge, so do they.

These are factors that exist in your industry that many people don't fully appreciate. Together, they add up to a direct impact on this Nation's long-term energy security....and that means an impact on this Nation's long-term economic security.

Many people appreciate the need to diversify world oil supplies. They recognize that with oil imports likely to grow to 65 percent of domestic consumption in the next 20 years – or perhaps even 70 percent or more if prices stay low – it is in our national interest to support efforts in the Caspian and in central Asia to bring in new supplies.

Throw into that equation the forecast that the Persian Gulf could regain control over half of the world's oil for export in 10 years, and the energy security argument is strengthened.

But few people fully appreciate that the crude oil produced in THIS country by small independent producers is about the same quantity as the oil we import from Saudi Arabia or Venezuela. If the flow of oil from those countries was threatened, a lot of people would sit up and take notice. What we are doing in the interagency process is trying to impress upon people that they should sit up and take notice when an equivalent flow of crude oil from KNOWN fields within our own borders is threatened. And I believe we are having some success.

Now, let me turn to some of the things we are doing – and specifically those things that relate directly to the theme of this conference “technology options for producers survival.”

When we put out our first description of oil initiatives being developed by the Emergency Oil Task Force back in February, we outlined four overarching strategies:

One, enhancing America's energy security, primarily by taking advantage of low oil prices to begin refilling the Nation's Strategic Petroleum Reserve; Two, preserving domestic oil and gas production capacity; Three, finding ways to lower the costs of production, and Four, improving government decisionmaking.

At the heart of two of those strategies – preserving production capacity and lowering costs of production – is technology. We are a big believer in technology – not just because it's what we do in the Office of Fossil Energy, but because of the results we have seen.

Who could have anticipated or even imagined in the 1970s and early 1980s the potential of new technology that now exists within the industry?

Daniel Yergin and Joseph Stanislaw, president and managing director, respectively, of Cambridge Energy Research Associates, wrote an article in the LA Times a little over a year ago in which they said that (quote) “Oil is a prime example of an industry transformed by the computer” (unquote).

They cited computer imaging and visualization technologies that Hollywood has used for films like “Jurassic Park” that are now being applied to oil exploration and production.

Without computer design, it would be too costly, they stated, to build the huge platforms necessary to drill in deep waters offshore.

I would add that without computer processing, it would also be far too difficult and unreliable to “see” beneath the salt structures in the Gulf where there appears to exist potentially huge new oil and gas resources.

Today, because of computer technology, we not only have affordable 3-D seismic but also 4-D seismic, which adds time to the equation. 4-D seismic is now a half-billion dollar industry in the Gulf. And I’m proud to say that it was a government-industry partnership that brought the technology out of the research stage and moved it across the commercial threshold.

These are remarkable achievements. But as important as they are to future exploration and production in our domestic lands and waters, they are by no means the full extent of what we should be focusing on.

We have to remember the changing make-up of the domestic industry. We have to recognize that technology improvements that once flowed from majors to independents doesn’t move as quickly or, in some cases, at all in today’s circumstances.

That’s why we are targeting a large part of our program to assist smaller, independent oil operators develop and gain confidence in new or improved technologies.

That’s why we continue to support the Petroleum Technology Transfer Council and the excellent work it is doing in conveying technology and other assistance to independents in its 10 regions.

Last week, we announced 7 new grants to independent oil producers – those with less than 50 employees – to encourage the use of technologies that can keep oil flowing from domestic fields. Technologies range from the use of water-jet technology for lateral drilling to the use of new types of tracers to the installation of remote solar-powered monitoring equipment to gather well data.

These awards were the first of a series of cost-sharing grants we intend to provide to small operators. In the next few weeks, a second round of awards will be announced. And for those who are interested in this program, you still have until August 31 and November 30 to submit your applications for future grants.

We have also reopened our Reservoir Class Field Program. This was an effort the Department began in 1992 to encourage domestic producers – both large and small – to adopt technologies that could prolong the economic life of some of our most endangered oil fields.

The first 3 rounds of this program have produced some excellent results. I mentioned 4-D seismic earlier, which is a product of this program. I was also particularly pleased to see that this month, Hart's Publications – one of the industry's leading publishers, as many of you know – recognized four of the Reservoir Class projects in its "Best of Class" awards. A fifth award came from our R&D program.

Now we beginning to evaluate a new group of proposals – 27 in all – and we expect to announce about \$18 million in Federal cost-sharing later this summer.

Technology is also at the heart of a new partnership we have created with the National Association of State Energy Officials. We are bringing together oil producers and electric power companies in a pilot program that offers utility financing for more energy efficient production equipment.

This is an effort that has paid dividends in terms of reduced costs in small field tests – in Kansas, for example. Now, we're expanding the effort with workshops in California, New Mexico, and Utah – and more to follow. An efficiency guide for producers is scheduled to be completed this summer.

Finally, we are initiating a pilot program here in Texas that will replace reams of paper forms with a cost-saving on-line digital processing system. If this approach is successful, oil and gas producers may soon be able to complete and submit electronic permit applications by Internet.

Over the course of this conference, you are going to hear more about these and other initiatives – all with a focus on technology not only for the short-term, but also for the longer-term.

Just as we have to be concerned with ways to ensure your survival today, we must also prepare for the era 20 or 25 years from now when we will need to rely increasingly on deeper, more complex reservoirs or perhaps formations – like gas hydrates – that are beyond the reach of today's technologies.

We are committed to these types of near- and long-term technology efforts. We believe the track record shows that these efforts produce results – meaningful results that directly benefit your industry and, in turn, benefit the energy and economic security of this country.

But as I said earlier, a large part of this is education – ensuring that people understand WHAT we are doing, WHY we are doing it, and WHAT BENEFIT we are trying to achieve.

That is why we are preparing to publish in the next few weeks a comprehensive description of our entire energy R&D portfolio – not only our efforts in oil and gas exploration and production, but also our efforts in alternative vehicles, in the development of more efficient gas turbines, in fuel cells and solar energy, in coal...and wind...and geothermal.

Until now, no such description existed. No one – in the Administration, on Capitol Hill, or in the industry – could pick up a single document and get a FULL picture of the spectrum of research

conducted by the Department.

Why is this important? Because we need to understand whether our portfolio is balanced, whether it meets our broader national policy goals, whether we have an adequate road map to achieve those goals, and whether our dollars are going into the right areas.

The Energy R&D Portfolio we will publish in the next few weeks has taken a year to produce. But if we are going to convince those in Congress – as well as those of you in industry – that government R&D partnerships pay off, we need to be able to describe those partnerships and show how they fit together. So, in many ways, this portfolio will be another education tool – both for us and for others.

Our goal is to maximize the full potential of America's energy strengths. And oil and gas are two of the resources that are vital to that strength.

But another of those strengths – in many ways, a strength unique to this country – is the partnerships we have in research and development between government, industry and academia.

These partnerships are the product of education also. You must know what we are doing. We must know what you need.

Our roles must be based on communication and interaction -- not only in the field but in workshops and conferences like this. That's why we have put this conference together. It will help us identify – as partners – where we should be going in the future....what are the right combination of policies and programs...where are the gaps and how best do we fill them.

In other words, what it will take in terms of technology for you to “survive in the 21st century.” I am extremely pleased that you have taken the time to join us here this week.

Thank you very much.



Techninomics

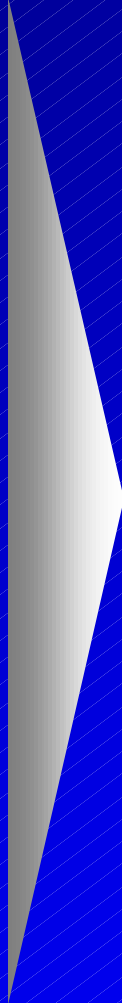
Jed DiPaolo
Senior Vice President
Halliburton Energy Services





Producer Challenges

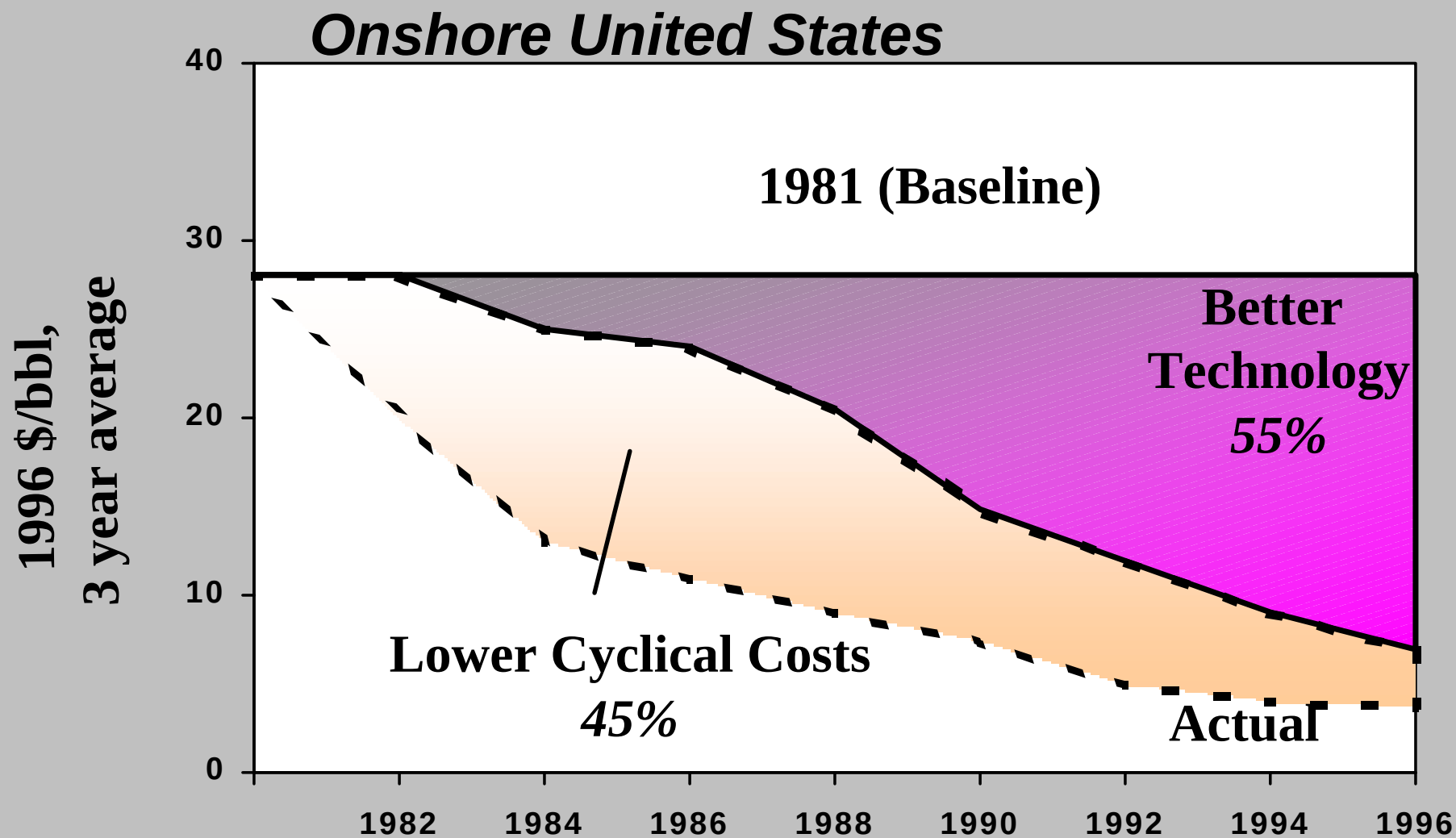
- Finding Cost
- Reduce Capital Expense
- Reduce Operating Expense
- Increase Reserves



**Exploit
Techninomics**



Crude Oil Finding and Development Costs



Source: CERA



Key Technology that will Drive Change

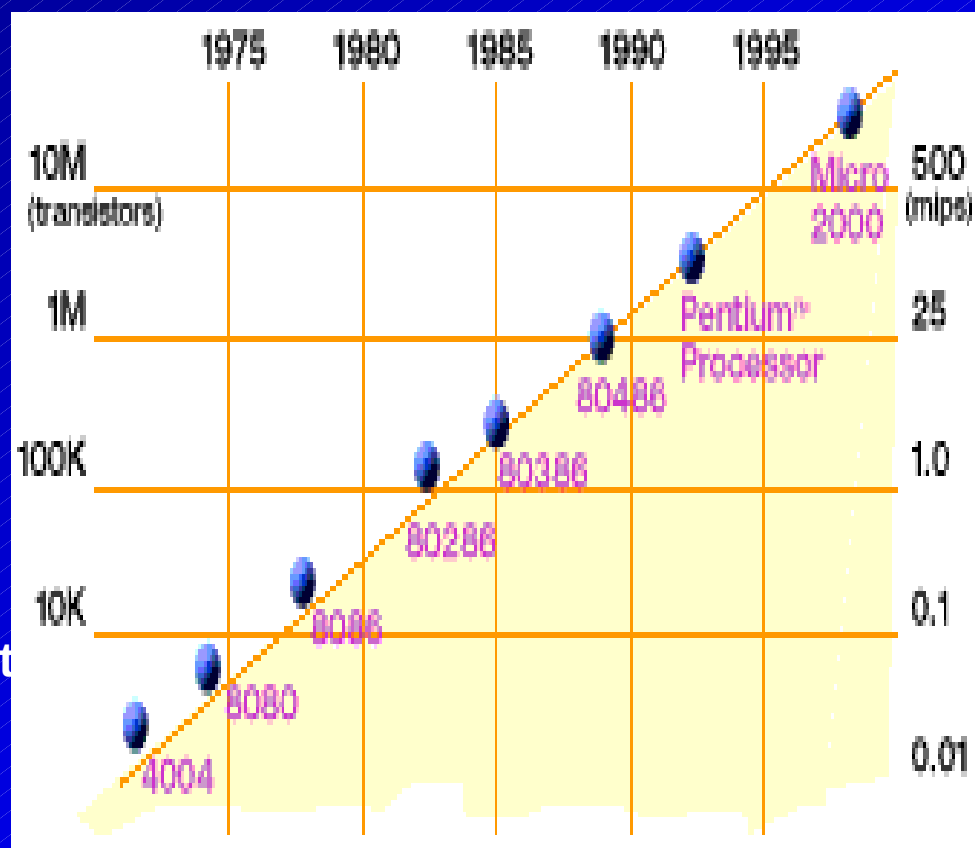
- **Computer Technology**
- **Telecommunication Technology**
- **Sensor Technology**



Advances in Computer Technology

...Quantum Changes in Computing Power

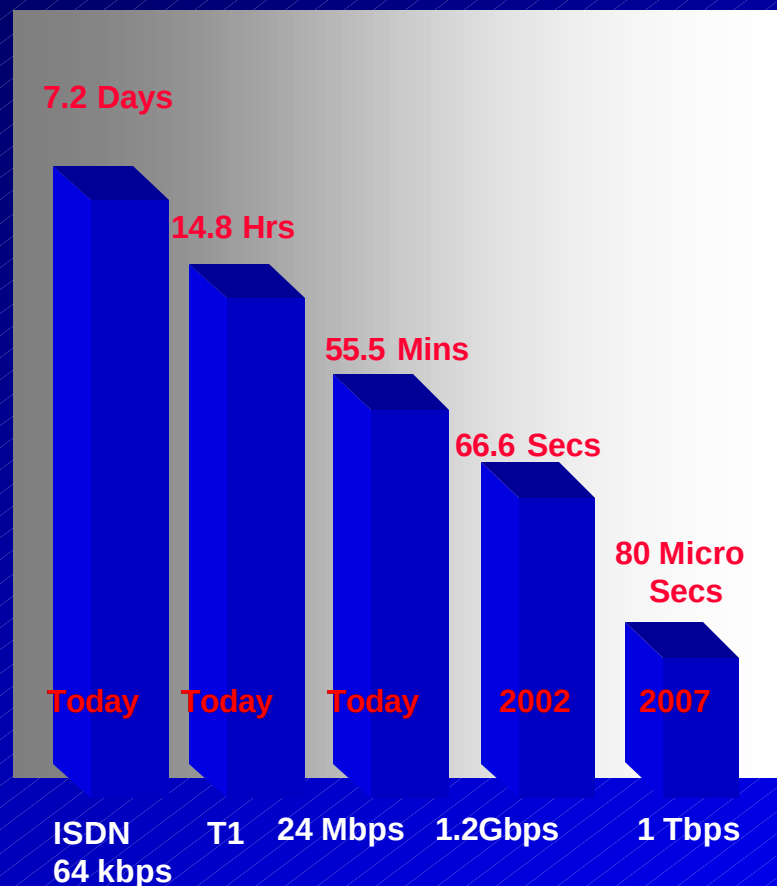
- **3D Seismic**
 - Marginal Field Development
 - Characterization of Complex Reservoirs
 - Development of Production Geophysics
- **4D Seismic**
 - Improved Recoverability
 - Improved Reservoir management
 - Real Time Solutions
- **3D Visualization**





Advances in Telecommunications

Time to transfer 10 gigabytes of data



- Rapid Transfer of New Technology
- Virtual Teams
- Expert Solution In Remote Locations
- Real Time Solutions
- Effective Reservoir Management



Sensor Technology



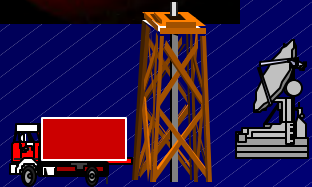
Sensors for Data

- Fluid Data
- Formation Data

Sensors for Controls

- Surface Equipment
- Downhole Equipment
- Remote Sensing

Real Time Reservoir Solution



Cementing

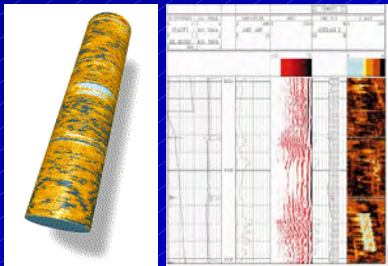


HES Office
RDCs



Customer
Office

Stimulation

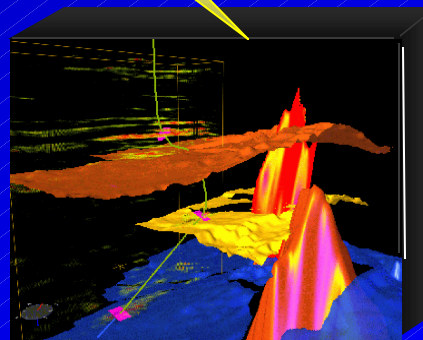


Logging

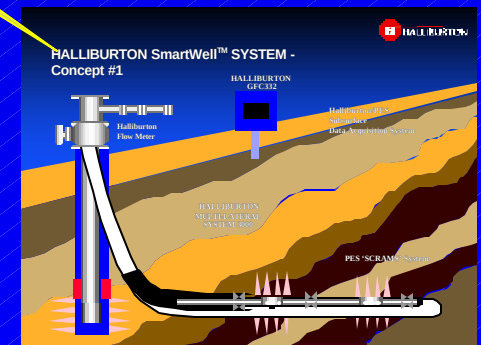


Customer

- DRILLING
- TOOLS /TESTING
- COMPLETIONS



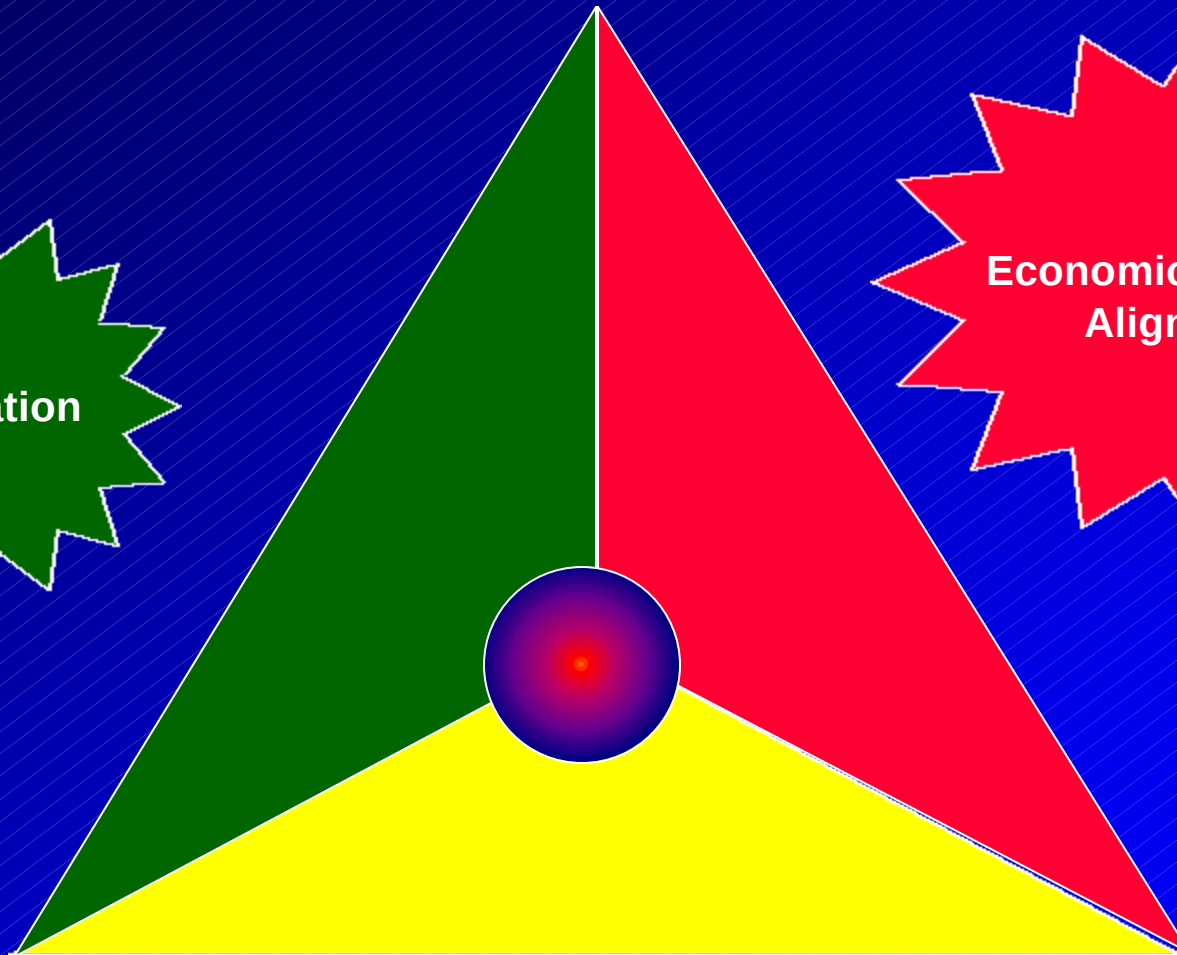
Reservoir



Smart Well



Techninomics...the value growth alliances





Summary: Technomics

Exploitation of Technology can reduce cost while improving production

Incremental Value can be realized from the Integrated Service Company who can provide reservoir optimization

Alignment of Producer/Service Company commercial terms to share in the created value.

Technology is Key to Establishing a Competitive Advantage

Leo Schrider
Chair, Petroleum Technology Transfer Council, and
Senior Vice President, Belden & Blake Corp.,
N. Canton, Ohio

Abstract

In the recent oil price crisis, independent oil and natural gas producers have struggled to keep their wells producing. Low crude oil prices forced many wells to be shut in or abandoned, unless ways were found to reduce costs and improve production efficiency. For many operators, technology can be applied to successfully achieve these desired results. In addition, technology can be key to obtaining critical exploration and development information — now even through the Internet or by using new software tools and computer-related information.

Today, it's essential for independents to gain — and maintain — a competitive advantage in the marketplace. There are two basic ways to establish a competitive advantage — do things better than others or do things differently.

At Belden & Blake, an independent based in the Northeast, technology is very important to the company's success. For example, in Michigan, the company recently was recognized by the Gas Research Institute (GRI) for its success in promoting market adoption of new natural gas technology. By applying advanced technologies and integrating research on improved reservoir characterization, Belden & Blake was able to remain active in its Antrim shale development — even without a tax credit that expired in 1992. The incremental revenue to the company from applying this new technology has been substantial.

Belden & Blake has successfully implemented many other new technologies, some which are directly related to the Department of Energy's research programs. In one instance, the company used carbon dioxide methods, which DOE helped develop, to restore a well's productivity from nearly zero to 500 thousand cubic feet of gas per day. It also has found success with other programs, such as those related to tight gas sands and coal bed methane. In fact, nearly 80 percent of Belden & Blake's drilling today would fall under the category of "unconventional" that was used back in the 1970s when these resources were first identified as having the potential for future drilling and replacement of produced resources.

Other sources of new technologies can be found through organizations such as the Petroleum Technology Transfer Council (PTTC). The non-profit national association acts as a "technology connection" in helping transfer technological information to U.S. independent producers. PTTC's low-cost technology programs can help producers reduce costs, improve operating efficiency, increase ultimate recovery, add new oil and gas reserves, and comply with environmental requirements.

Ultimately, informed decisions can be developed and implemented for most E&P programs.

Technology remains the key to determining the correct course of action, whether independents gain a competitive advantage by doing things better — or doing things differently. Resources like those offered by DOE, PTTC, GRI, and others can help independents identify the best technology options for their particular needs. By using new tools and technologies, independents can expand their knowledge base and gain a competitive advantage. Most importantly, they can weather the storm and survive the next downturn during times of low oil and natural gas prices.

Technology Is Key to Establishing Competitive Advantage

Leo A. Schrider

Senior Vice President, Belden & Blake Corp.

North Canton, Ohio

1999 DOE Oil & Gas Conference

June 29, 1999

Dallas, Texas

Establishing Competitive Advantage

There Are Only Two Basic Ways to Establish Competitive Advantage

- ◆ Do things better than others
- ◆ Do things differently

-- Karl Albrecht, futurist

Belden & Blake - From McKinley to Clinton

Late 1890s (McKinley is President)

- ◆ Belden Brick use coal to fire its kilns for manufacturing bricks

During 1930s (Roosevelt is President)

- ◆ Belden explores using natural gas in its kilns

Late 1940s (Truman is President)

- ◆ Belden uses hydraulic fracturing in Ohio gas/oil pools
- ◆ Clinton fields are opened - To date, over 20,000 wells have been drilled, accumulating over 100 million barrels of oil and 4 Tcf of gas

Belden & Blake - From McKinley to Clinton

Early 1970s (Nixon is President)

Project Independence announced and DOE formed

- ◆ Synfuels and Unconventional Gas Recovery programs begin
- ◆ Tax credit allowed to develop gas from unconventional sources

1980s (Reagan is President)

- ◆ Belden & Blake develops unconventional gas sources (tight sands, Devonian/Antrim Shale, and coalbed methane)

Belden & Blake - From McKinley to Clinton

Late 1990s (Clinton is President)

- ◆ B&B spends about \$100 million, drilling over 700 wells (1996-98)
- ◆ Adds 116 Bcf to proved developed reserve base
- ◆ About 75% of these newly discovered reserves (87 Bcf) would be classified as “unconventional” gas sources, as defined by DOE in 1970s

Belden & Blake - Doing Things Differently

The Role of Technology

- ◆ B&B uses current and emerging technologies, such as:
 - ◆ CO₂ to improve production (natural gas sand)
 - ◆ Production enhancements by deepening wellbore and replacing conventional lift methods (Antrim Shale)
 - ◆ Improved production methods (coalbed methane)

Belden & Blake - Doing Things Differently

Liquid CO₂ Remediation Example

Background/Problem:

- ◆ Wayne County (Ohio) well - Reached TD in Sept. 1995
- ◆ Jan. 1998 - Output plummets from 700 to 10 Mcfd in 30 days
- ◆ Suspected cause: Near-wellbore liquid blocking
- ◆ Cumulative prod. (through '98): 800 Mmcf/gas and 3,200 bbls/oil

Solution:

- ◆ Pumped 60 tons of liquid CO₂ to correct relative gas permeability
- ◆ Restored gas production rate to 500 Mcfd

Belden & Blake - Doing Things Differently

Norwood (Antrim) Example

- ◆ 32 wells deepened to expose the lower Norwood zone
- ◆ Total cost = \$1,065,000 (Avg. cost per well = \$33,000)
 - ◆ Avg. gas production increase per well = 107 Mcf/d
 - ◆ Avg. reserves added per well = 100 - 200 Mmcf

Results

- ◆ Added 5 Bcf to reserve base at a finding cost of \$0.20/Mcf
- ◆ In 1999, B&B received GRI's "Pacesetters Award"

Belden & Blake - Doing Things Differently

Coalbed Methane Technology

- ◆ Geological areas
 - ◆ Defining coal measures
 - ◆ Computerized mapping systems
- ◆ Completion areas
 - ◆ Cased hole fracturing
 - ◆ Service company “alliance”
 - ◆ Sand control

Belden & Blake - Doing Things Differently

Coalbed Methane Technology

- ◆ Production and operations areas
 - ◆ Requires preplanning with state agencies
 - ◆ Establishes coalbed methane reserves and production in Pennsylvania
 - ◆ Expands along geologic trend with 80,000 acres under lease
 - ◆ Creates drilling opportunities for next 5 to 10 years

Belden & Blake - Establishing a Competitive Advantage

- ◆ 100 years from Belden Brick to Belden & Blake Oil & Gas demonstrates importance of technology
- ◆ Hydraulic fracturing - Important technology step for initial growth
- ◆ Recent growth from properties classified as “unconventional sources”
- ◆ Most new technology from programs supported by DOE and GRI
- ◆ Consider using other organizations for access to technology solutions

Petroleum Technology Transfer Council

PTTC's Low-cost Technology Programs Help Independents:

- ◆ Reduce costs
- ◆ Improve operating efficiency
- ◆ Increase ultimate recovery
- ◆ Add new oil and gas reserves
- ◆ Comply with environmental rules

Serving Independents' Needs

PTTC - "Technology Connections"

- ◆ Estimated 7,000 - 8,000 independent producers in U.S.
- ◆ Independents drill 85% of domestic wells, produce 65% of U.S. natural gas, and 40% of oil
- ◆ Independents produce 60% of oil output in lower 48 states
- ◆ For 1st half 1999, PTTC sponsored/cosponsored 64 workshops, with nearly total 3,000 attendees
- ◆ More than 10,000 industry contacts in 1998

Regional and National Focus

PTTC's 10 Regions Offer:

- ◆ Technology workshops
- ◆ Regional Resource Centers
- ◆ Websites/Newsletters

National Program Offers:

- ◆ CD-ROM Software Sampler - Published November 1998
- ◆ E&P Case Study Digest - Available September 1999
- ◆ National quarterly newsletter/Award-winning website

A Resource for Independents





A Resource for Independents

Primarily funded by the U.S. Department of Energy,

Office of Fossil Energy (NPTO,FETC)

PTTC is:

The independent producer's "Bridge to Solutions"

1-888-THE-PTTC

www.pttc.org

DOE Natural Gas Program

Rita A. Bajura
Federal Energy Technology Center
U.S. Department of Energy

Good morning. Speaking for my organization, the Federal Energy Technology Center — FETC for short — I welcome you to the 1999 Oil and Gas Conference. The theme of this year's conference is "Technology Options for Producer Survival." During this conference, you will hear about the new and improved technologies that are evolving from DOE-sponsored R&D. We in DOE hope that you will find this information useful; we will consider this conference a success if your bottom line benefits because of the research that we are sponsoring.

In my paper, keeping with the theme of this conference, I'd like to share with you what we are doing to develop and transfer new technologies to domestic operators and the service industry — technologies that reduce the cost of finding and producing natural gas, technologies that ensure that the U.S. continues to have an affordable supply of clean-burning natural gas. I would also like to share with you DOE's vision of an integrated natural gas program, a program encompassing all aspects of natural gas: exploration and production, transport, storage, distribution, and use.

Let me start by describing my organization and how we contribute to natural gas technology development. FETC is a field office of the U.S. Department of Energy. We report to Bob Gee's Office, the Office of Fossil Energy. We conduct and manage R&D in cooperation with industry, academia, and our national labs. Most of our R&D supports the Office of Fossil Energy, although we do support other parts of the Department and other Federal agencies.

Among other things, FETC is responsible for implementing natural gas R&D programs for the Office of Fossil Energy. Our natural gas program has four major elements. In no particular order:

- The first element is a \$9-million-per-year natural gas processing program. The goal of this element is two-fold: (1) to develop low-cost ways to convert natural gas to premium liquid fuels — these are natural-gas-to-liquids technologies — and (2) to upgrade low-quality gas to pipeline specifications.
- The second element is \$1-million-per-year gas delivery and storage program. The goal is to enhance reliability of the natural gas infrastructure to ensure that it can meet the peak delivery requirements of market hubs, large central-station power plants, and distributed power plants.
- The third element is an \$85-million-per-year gas utilization program. The goal is to develop high-efficiency, clean, gas-fueled power systems. We are developing fuel cell systems for the dispersed power market, and large gas turbine combined-cycle systems for the utility sector.
- The last element, of greatest interest to this conference, is DOE's \$13-million-per-year gas

supply program. The goal is to reduce the cost of finding and producing natural gas.

In the technical sessions today and tomorrow, you will hear detailed presentations on the R&D activities underway in the gas supply program. Let me present the summary view of the major pieces of this program.

- We currently manage a dozen projects to assess our resources and reserves. These projects characterize geology, gas availability, trapping mechanisms, and specific reservoir geometry. Projects include developing gas atlases and databases, and conducting secondary gas recovery studies. Thus, we believe, these projects assist you in industry by providing you the information you need to better locate gas in new and existing fields.

A success story in this area is the USGS project in Wyoming. We funded the USGS to estimate the basin-centered gas potential in the Big Horn Basin. This kind of information is an essential first step to stimulate investment in this basin. USGS estimated the basin contains more than 300 Tcf of undeveloped gas.

- The second research area is drilling, completion, and stimulation research. We manage about 20 projects in this area. These projects are leading the way toward faster, deeper, cheaper, and cleaner drilling and completion systems for difficult geological settings — the kind of reservoirs encountered in gas production. New technologies are very important for the deep high-pressure and high-temperature reservoirs.

Maurer Engineering's drilling system is a success story that is still unfolding in this area. Maurer demonstrated a high-powered, slim-hole directional drilling system. The high-powered motors drilled through dolomitic formations at 48 ft/hr, compared with 23 ft/hr for conventional motors. These tests were conducted at the Catoosa test site near Tulsa.

- The third research area is low-permeability formations — the resource that will provide an increasing percentage of U.S. gas. We manage 10 projects that are characterizing the tight gas resources in the western United States, identifying ways to improve the success rate of finding gas, and developing cost-effective recovery options.

In a major success story, Advanced Resources International (ARI) developed an integrated approach to locate the highly productive areas in low-permeability formations — the areas with an abundance of natural fractures. ARI used remote sensing and high-resolution aeromagnetic surveys to map deep basement rock. API estimates that wells drilled in the high productivity trends will have ultimate recoveries eight to ten times higher than wells drilled outside. Union Pacific Resources drilled a 1,750 ft horizontal well using API's methodology and confirmed the success of this approach. The Union Pacific well is in the Table Rock Field in Wyoming. The well depth was 15,000 ft — one of the deepest horizontal wells ever drilled in tight sandstone in the world.

In the natural gas supply program, we are just starting projects in two areas. One area is gas stripper wells. A Request for Proposals is on the street for techniques to revitalize gas stripper wells — where it makes economic sense.

The other new area in the gas supply program is methane hydrates. Actually, hydrate research really isn't new; we are moving back into it after an absence of several years. Methane hydrates are, potentially, an enormous resource — roughly 300 million Tcf of gas. Even if we can produce only a small fraction of it, we would have a several-hundred-year supply of natural gas. Hydrates are also a concern in global climate change scenarios. Small changes in ocean temperature could release large quantities of natural gas — a potent greenhouse gas.

Last week, we issued a *National Methane Hydrate Multi-Year R&D Program Plan*. It includes four technology areas: characterizing the methane hydrates resource; determining ways to produce methane from hydrates in the ocean and in Arctic regions; determining hydrate's role in the global carbon cycle; and addressing the petroleum industry's concerns about safety and sea floor stability — these are concerns when methane hydrates are present, or when they form, during the exploration, production, and transportation of conventional hydrocarbons.

If you would like to know more about the hydrate research program, fact sheets are available at the FETC display booth, or you can ask any of the FETC people here to send you a copy, or you can check our website — electronic versions of the plan will also be available soon.

The FY 1999 budget for methane hydrates research is modest: \$500,000. To implement the methane hydrate plan, we will need a significant ramp up in funding. For FY 2000, the Administration requested \$2 million for hydrates research. Congress seems to be very interested in the program; several hydrates research bills are pending. We are optimistic that Congress will provide the \$2 million of funding, and they may increase it even further. The President's Council on Science & Technology recommended that a 10-year hydrate program be initiated with a total funding of \$150 to \$200 million.

Let me switch topics to an “integrated natural gas program.” When we look at the total gas program funded by the Office of Fossil Energy, we already have R&D programs in natural gas supply, processing, delivery and storage, and utilization. So what would be gained by integrating these individual programs in an integrated natural gas program? Three major drivers are causing us to rethink our natural gas programs:

- The first driver is demand growth. The electric market represents the largest growth area for gas; gas use for power generation is expected to triple over the next 20 years. Total demand is expected to increase by almost 50 percent by 2015, with a total gas demand of 30 Tcf. Both estimates are for a business-as-usual scenario — no changes in current environmental policy.
- The second driver is increased recognition of the environmental qualities of natural gas. Natural gas produces roughly one-half the CO₂ emissions of coal. Here in Texas, the state legislature has recognized the environmental qualities of gas. When the state's electricity deregulation bill

was signed into law two weeks ago, it labeled gas a “green” fuel, and required that, come January, half of all new generation capacity installed in Texas must be gas-fired. With this legislation, Texas may have set a precedent for the 16 other states that have green power initiatives. If the Kyoto Protocol is implemented, the environmental qualities of natural gas will really come into play. Gas consumption could increase to 35 Tcf per year — a 60 percent increase.

- The third driver causing us to rethink our natural gas program is convergence of the gas and electric industries. Evidence of convergence abounds:
 - Some majors used to burn off much of the gas found with oil deposits. Now they are converting themselves to be gas giants as well, and many of them are embracing power generation. They are even thinking about getting into retail markets for the distribution of gas and electricity.
 - More than three-quarters of all new electricity-generating capacity in the United States is using gas.
 - According to a recent article in *The Economist*, the energy firm of the future may be one “that reaches from the wellhead all the way to the final destination, the customer.”
 - And the company names on many of your business cards are different from a year ago as businesses merge and realign.

Recognizing these three drivers — sharply increased demand, environmental benefits, and convergence — the Office of Fossil Energy and FETC sponsored meetings in January and February of this year in Texas. The meeting examined the challenges facing the gas industry, and the implication of these challenges for DOE’s gas R&D programs. We invited senior executives in the gas industry to the first meeting, and R&D managers in the gas industry to the second. For these meeting, we broadly defined the gas industry as producers, pipeline companies, distributors, and users. Meeting participants identified five broad issues facing the gas industry as it moves into the new millennium:

- The integrity of the gas delivery and storage infrastructure — maintaining it, protecting it, and expanding it — will be critical in meeting demand growth.
- Gas and electric industries will continue to converge as markets restructure. The telecommunications industry could also be part of this restructured market.
- Distributed generation — fuel cells, micro turbines, reciprocating engines — will change the patterns of energy supply and demand. We will need new technology to ensure reliable, low-cost power systems and networks.
- Regulatory policy needs to be more predictable to stabilize business strategies and encourage

technology investment.

- Government funding of public-benefit R&D will become even more critical. In the very competitive energy markets, private firms lose incentives for long-term public-benefit R&D.

Many of these issues can only be addressed if DOE's R&D programs better respond to the needs of an industry that is undergoing unprecedented change. To do this, we are moving toward integrated planning of the gas R&D programs. We believe integrated planning, coordinated with industry, will better identify R&D gaps — enabling us to more rapidly develop the technologies needed to fill those gaps. To make this integrated gas program work, we need two things:

- We need to increase the size of the natural gas supply R&D program. It needs to be consistent with the role that natural gas will play in providing clean, affordable, and dependable energy for our nation.
- We need to create a new natural gas infrastructure program to address the aging, existing infrastructure; the construction of new infrastructure; and the protection of this infrastructure from deliberate and natural threats.

Let me make a few concluding remarks. Natural gas is the bridging fuel that will lead to a fully sustainable energy future. Whatever that energy future is, we do not have that technology yet. Meanwhile, we have to depend on natural gas. Under a business-as-usual scenario, gas use will increase significantly; under a Kyoto scenario, gas use will grow dramatically!

For you, the gas production community, our job in the Government is to give you technology options to ensure that we continue to have an affordable supply of clean-burning natural gas. Our hope is that these technology options will also help ensure your survival. If you are not around, the U.S. does not have a gas supply.

As we move through the next two days, I invite your thoughts and insight on DOE's program — on what we are doing, on where we should be going. So you know who "we" is, it is the people in DOE — the people at HQ, NPTO, and FETC — who plan and manage the program and who also arranged this conference. Could I ask them all to stand for a second?

My challenge to my people at FETC is for each of you to come back with one idea that will make the program better. For you in industry, your ideas are critical to designing a rational program — one that meets your need to survive as a producer, one that meets the national need of having a reliable, affordable supply of a clean-burning fuel. Have a good conference.

Thank you.

Successes and Challenges for the Oil Program

W.F. Lawson
Director, National Petroleum Technology Office
U.S. Department of Energy

Distinguished guests, ladies and gentlemen, good morning. It is a great pleasure to join with the Federal Energy Technology Center (FETC) and our Fossil Energy Headquarters in sponsoring the first DOE Joint Oil and Gas Conference. I am delighted to report over 230 people in attendance.

The National Petroleum Technology Office enjoys more and more benefits working with FETC than ever before. I would like to recognize Rita Bajura and her organization for their great support of our office. Thank you, Rita.

The technical presentations you will hear in the next few days were selected for the success and state of development of the projects they describe. Assistant Secretary Gee has already mentioned our pride about the 1999 Hart's Oil and Gas World awards. One of the presentations on the agenda is an awardee: The Best Advanced Recovery Project of the Gulf Coast by Hughes Eastern Corporation of Jackson, Mississippi, who used microflora in oil-bearing formations to selectively plug porous zones to increase oil recoveries in Alabama.

Three other DOE projects not represented on the agenda but 1999 Best of the Regions winners, also, are the Best Field Improvement Project of the Pacific by Tidelands Oil Company who, with the City of Long Beach, developed a lower-cost hydrogen sulfide caustic scrubber program in Southern California; the Best Advanced Recovery Project of the Pacific by the University of Utah who developed a technique which restored production to some properties in Kern County, California; and the Best New Technology of the Midcontinent by LeNorman Energy Corporation who, with TRW, designed and installed a very successful alkali-surfactant-polymer flood in the Sho-Vel-Tum Field in Oklahoma. I know representatives are here from some of these winners. How about a round of applause for these projects.

I want to leave you with three things today. First, I want to describe our office and the program in broad terms. Second, I'll briefly mention some successes and benefits. And then I'll address a few important challenges.

NPTO Programs

Let me tell you briefly about the National Petroleum Technology Office and what we do. The National Petroleum Technology Office is the implementing arm for oil research of the Office of Fossil Energy. We are 26 people responsible for initiating and managing about \$50 million dollars a year developing

new and improved oil technology and oilfield environmental technology – technology for use by the US petroleum industry to benefit American consumers.

The role of the private sector is to make money for stockholders. The role of the Federal government is doing that work which benefits the nation that the private sector can not, will not, or should not do; work that market forces alone will not accomplish. With low oil prices for more than a decade, corporate executives have cut R&D spending dramatically to preserve profits and remain competitive. The Office of Fossil Energy fulfills the role of Federal support for oil R&D with the Federal Energy Technology Center and the National Petroleum Technology Office as its implementation arms. Indeed, taken together, DOE's upstream oil and gas programs today make up about a quarter of the total domestic upstream R&D expenditures.

As you have already heard today, the US Government is the caretaker of the largest accumulation of oil and gas properties in the country—federal lands. Onshore and offshore leases and royalties generate billions of dollars a year for the treasury without counting corporate tax revenues. Spending a very small percentage in technology development to better exploit those resources responsibly is a good investment. And it's not just federal lands: Oil and gas resources are national assets deserving of good stewardship.

Our efforts are both short and long term. During the oil price crisis this past year we shifted some more effort to short term, bottom line projects like the Technology Development with Independents solicitation and the National Association of State Energy Officials' workshops to advise operators of methods to reduce electricity and other costs. We also supported the Petroleum Technology Transfer Council in sponsoring a variety of regional workshops with practical emergency information as well as technology assistance.

But, we maintain a long term R&D focus, too, because of its critical importance to domestic petroleum operations in the future – for our energy security. The impact of the technology developments of the last few decades on this industry is incredible. It has opened new resources and reduced finding and production costs. It is essential that we continue to maintain technology leadership for the domestic industry. Otherwise domestic oil will not be able to compete and our ability to produce a precious domestic resource will be significantly compromised.

The impact of technology in the oil and gas business over the next two decades will be even more incredible.

Successes

The oil and gas industry has had many successes. Many of the recent DOE oil and gas program successes you will hear about today and tomorrow.

But if I had to pick just one recent program success still unfolding, it would be the sub-salt imaging technology that was spurred by Los Alamos National Laboratory working with a consortium of companies using defense technology. In the Gulf of Mexico this technology has allowed exploration booking at least a billion barrels of new oil reserves already. And more discoveries are on the way. The increased resolution provided by the processing algorithm has revolutionized imaging of reservoirs hidden by salt structures.

The Class Reservoir program has generated important results applicable to many producers, reducing costs and increasing reserves. Some of them are being reported here. This program has been so successful we have just had another solicitation round called the Class Revisit which closed last month. Successful proposals should be selected in a couple of months.

Perhaps the biggest success of the technology advances in the industry is also the best kept secret. New finding technologies have reduced costs. New lifting technologies have reduced costs. New processing technologies have reduced costs. All have reduced environmental impacts significantly, too – by reducing footprints with lateral drilling and multiple wells off the same pad, by reducing dry holes, by employing environmentally friendly exploration tools, by increasing efficiency and reducing waste. New technologies such as downhole separators and coiled tubing reduce cost and environmental impact. And all these finding and producing technologies enable us to remove more oil from the same reservoirs – real resource conservation. Today's industry can brag about its environmental posture.

I invite you to check our homepage (www.npto.doe.gov) for more information about all of our project results, available software and other tools.

Challenges

We face a variety of challenges to maintain the health of the industry into the future. For all the dramatic technology advances realized, much more is demanded in the future.

Improved productivity and efficiency in the E&P sector is critical to meeting the challenges of an evolving and volatile marketplace. Assistant Secretary Gee has listed many of the elements of today's business environment. So, our base program is geared to providing new and improved technologies for finding and producing petroleum and for reducing costs. We share in the risk of trying new technologies in field demonstration programs. So there is an emphasis on continuous improvement. But we need dramatic decreases in costs of operations in order to keep the domestic industry competitive and to exploit difficult reservoir targets. New ideas and bold approaches are required.

The biggest challenge we may face is the rapidly changing structure of this business. Of particular interest is the increasing move of the majors overseas to concentrate on developing the giant and more virgin fields elsewhere around the globe. One possible endpoint is that in a very few years only the independents may be left to produce the mature lower 48 domestic resources. The big service

companies will likely follow the majors. So, it could be that we will depend entirely on the independent producers and smaller service companies to maintain the flow of oil and gas from our domestic resources, with the exception of Alaska and offshore. And those groups of smaller companies are changing as fast as the majors with mergers, acquisitions, and reactions to market fluctuations. The majors would focus on their primary business interests as would the big service companies. We could experience a growing technology gap that could keep our domestic resources from being cost competitive. How would the innovative technologies needed to produce our oil and gas be developed? How would advanced technologies be transferred to the domestic industry? Market forces may work for some of an imagined shortfall, especially for gas which is absolutely necessary to meet National goals, but what about oil? How much of this gap would the government be expected to fill? Who else might provide needed R&D and technology transfer? How would new technologies be deployed? What new business structures might be developed to meet the needs of the domestic industry?

Another challenge: Some of the best remaining domestic oil and gas prospects lie on Federal lands – including wildlife refuges, national parks and seashores, and the Outer Continental Shelf. These areas are held in trust for the American people for multiple uses, however, and access is limited unless and until exploration and production technologies can provide confidence that other uses can be accommodated along with oil and gas activities. This has been especially true in the Rocky Mountain and Alaskan areas as well as the offshore. While significant improvements in environmental impacts have been made during the last two decades in the upstream industry, we must strive to achieve even lower impacts and do so with significant cost reductions. Pristine and delicate environments may require extreme measures and novel thinking to harvest their oil and gas bounty while preserving other uses.

So, to gain access to Federal lands the technical challenges are to provide less intrusive and more effective finding technologies, minimal impact drilling and completion technologies, and transport capabilities consistent with other uses. Many of these resources are found in tight or otherwise complex reservoirs. And all must be accomplished cost competitively. This is a real research and development challenge, properly pursued in part by DOE and is in the best interests of industry, government, and the public. This is also an achievable goal if we can maintain the R&D momentum that has brought us the tremendous technology advances of the last few decades.

Lastly, new environmental restrictions will further challenge the domestic oil and gas industry in the future. Whether it be air emissions from natural gas fired compressor engines or automotive emissions; whether it be water quality related to injected fluids or surface waters; or some other environmental issue related to this industry, DOE will continue to bring sound science to the regulators' discussion table and pursue new technical developments to avoid unnecessary costs while achieving a common goal of a quality environment in which to live.

So, let me close by wishing you a good conference. I encourage you to participate fully in the technical sessions of interest to you. Visit the exhibits during the conference and the poster session tonight.

Please take advantage of this conference to provide feedback to the DOE representatives to enable us to make the program more responsive to your needs. Thank you for your kind attention.

A Resource Development Manual for Secondary Gas Recovery in Conventional-Permeability Sandstone Reservoirs

Robert J. Finley
Bureau of Economic Geology
The University of Texas at Austin

Abstract

The Secondary Gas Recovery (SGR) Project, funded by the U.S. Department of Energy and the Gas Research Institute, addressed the recovery of incremental, or secondary, natural gas from existing, conventional-permeability fields. This additional resource in heterogeneous, or compartmentalized, reservoirs is commonly known as the reserve growth resource. From 1988-93, the project focused on the Tertiary of the onshore Gulf Coast of Texas and from 1993-95 the focus was on Pennsylvanian reservoirs of the Ft. Worth basin, Texas. Out of the extensive documentation of those phases of the SGR project, a project manual was developed. This manual serves as a guidebook that defines steps a producer can take to evaluate candidate reservoirs and potentially add reserves in depositionally complex reservoirs. While structural complexity and pervasive low permeability are acknowledged as also leading to reserve growth potential, the SGR project was primarily focused on facies complexity inherited from the original depositional system.

The approach taken in developing the manual was generic. It should be applicable to assessing heterogeneous gas reservoirs in many basinal settings after taking into account facies differences, subsidence rates, source-material differences, and other factors that define sedimentary environments. The producer is assumed to have basic knowledge of the depositional systems and facies associations composing the target reservoirs and on the generalized rates of subsidence and creation of accommodation space that affect facies geometries in the target basin. Background references on these topics are included in the manual. A key starting point for the SGR approach to natural gas reserve growth is the national atlas series of major gas reservoirs supported by the Gas research Institute and the U.S. Department of Energy.

The key element of the manual is a large-format (11.5x39 in) flow chart for the reservoir evaluation and development process called the "secondary gas recovery road map". This chart outlines the entire process of evaluating a property, down to the reservoir level, for its natural gas reserve growth potential on the basis of reservoir heterogeneity. The process outlined within the chart comprises six major sections and serves as an outline and index for manual as a whole: characterizing reservoir heterogeneity, confirming the opportunity, analyzing depositional heterogeneity, defining the specific target, developing the

resource, and extending the opportunity. These six areas are then divided into 29 modules that comprise the 123-page manual. The manual focuses on integrated application of state-of-the-art geology, geophysics, reservoir engineering and well-log analysis needed to develop a reservoir for incremental natural gas resources.

The first step, characterizing reservoir heterogeneity, begins with accurate location and stratigraphic information to enter one of the gas atlases that cover major producing regions of the U.S. An applicable gas play is identified and using characteristics of that play, the producer makes an initial determination of styles of heterogeneity. Pervasive low-permeability, or heterogeneity that is largely structural, is presumed to be handled outside the SGR process. If the SGR approach is deemed applicable on a preliminary basis, then the next major step is to confirm the opportunity. This involves conducting a geologic and engineering screening to further confirm that the reservoir behaves heterogeneously. With this confirmation, the producer moves into a full analysis of depositional heterogeneity based on an initial flow unit concept of how the reservoir behaves. This is the critical step in the process since it is here that assessments are made to guide definition of specific resource targets. Included would be a geologic analysis, a pressure and production history analysis, a reservoir quality analysis, and a basic geophysical assessment, all depending on available data. The integration of these assessments leads to definition of the specific target and the strategy to test the prospect, i.e., a recompletion, new infill well, or horizontal lateral from an existing well. Developing the resource involves developing a data collection plan, recompleting or drilling the prospect, analyzing the data, and refining and further developing the concept of reserve growth applicable to this reservoir or play. With success, the producer will look to extend the opportunity, either within the initial play or elsewhere, and the process may begin again.

The manual is supported by six pages of references including many publications produced during the progress of the SGR project. Of particular note are a series of free technical summaries, short 9 to 15 page documents on engineering, geophysical and log-analysis topics applicable to natural gas reserve growth, that can be requested with purchase of the SGR manual. Also, 3-D seismic data sets for Stratton field (onshore South Texas) and Boonesville field (Ft. Worth basin, Texas) are available with supporting well logs, VSP, and other data at very modest cost. These data sets illustrate the applicability of 3-D seismic for detailed in-field reservoir development. The manual, seismic data, and other publications are available from the Bureau of Economic Geology, The University of Texas at Austin, (Publication Sales: 1-888-839-4365 toll free).

1.2 A Small Independent Producer's Design, Construction and Operation of a Flue Gas Injection Project, East Edna Field, Okmulgee County, Oklahoma

John Godwin (918-756-7498)

Driver Production, Inc.
P.O. Box 696
Okmulgee, OK 74447

Abstract

Driver Production was one of four companies awarded a grant from the U.S. Department of Energy as a result of a competitive procurement for small independent producers to demonstrate economic application of gas repressurization of oil reservoirs. Driver Production proposed a Flue Gas Injection (N_2 and CO_2) project in a five-spot pattern in the East Edna Field, Okmulgee County, Oklahoma, USA. The paper describes the design, construction, start-up, expansion and operation of a flue gas project that uses produced natural gas as the energy source for combustion and compression. Changing the engine to a larger unit to allow for higher gas injection capacity and for injection at higher pressure demonstrated the need for critical control of flue gas quality to minimize corrosion problems associated with CO_2 injection. The project has demonstrated that even small operators can successfully implement gas repressurization to increase oil production from a pressure-depleted reservoir. The project, initiated in 1996, continues to increase oil and natural gas production as long as flue gas is injected. The economics of the project and success to date have prompted the project operator and other operators who have visited and analyzed the project to consider application of flue gas in their small pressure depleted reservoirs.

1999 OIL and GAS CONFERENCE
Technology Options for Producer Survival
JUNE 28-30, 1999
Dallas, Texas, USA
Sponsored by USDOE FETC and NPTO

John Godwin, Driver Production
PO Box 696 Okmulgee, Oklahoma, 74447

David Olsen, International Centre for Heavy Hydrocarbons
Tulsa, Oklahoma 74101

**A SMALL INDEPENDENT PRODUCER'S DESIGN, CONSTRUCTION AND
OPERATION OF A FLUE GAS INJECTION PROJECT,
EAST EDNA FIELD, OKMULGEE COUNTY OKLAHOMA, USA**

Based in part on SPE 39637
PRESENTED AT 1998 SPE / DOE
IMPROVED OIL RECOVERY CONFERENCE,
TULSA, OKLAHOMA
and

Summary of the above paper reprinted in
SPE Journal Petroleum Technology, January 1999, p46

**A SMALL INDEPENDENT PRODUCER'S DESIGN,
CONSTRUCTION AND OPERATION OF A FLUE GAS
INJECTION PROJECT, EAST EDNA FIELD,
OKMULGEE COUNTY OKLAHOMA, USA**

AUTHORS

JOHN GODWIN	DRIVER PRODUCTION INC.
TREVOR LYONS	LYONS & LYONS INC.
NANCY RICHARDSON	OKLAHOMA INDEPENDENT PETROLEUM ASSN.
DAVID OLSEN	INTERNATIONAL CENTRE FOR HEAVY HYDROCARBONS

OUTLINE OF PRESENTATION

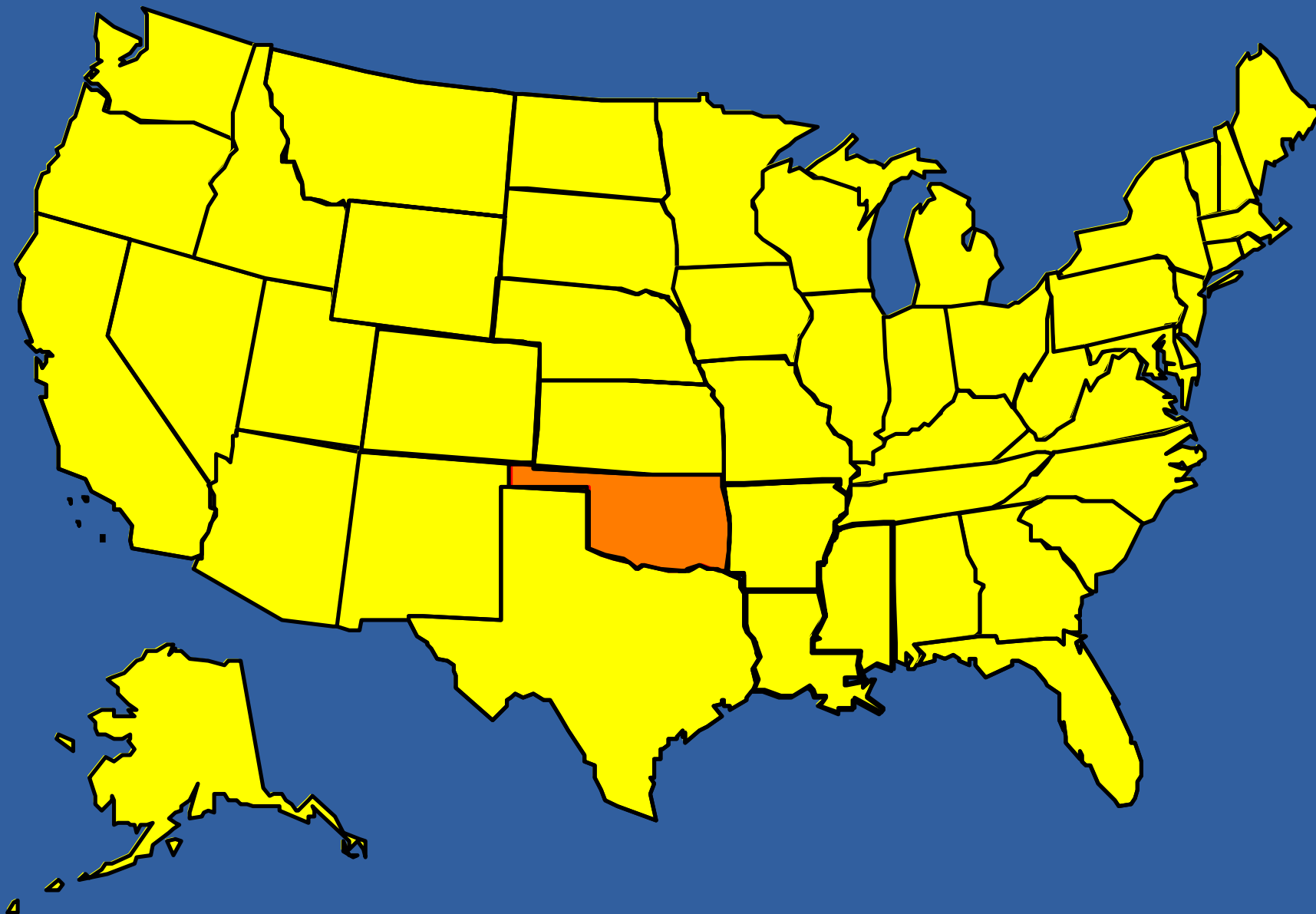
- ✿ COMPANY BACKGROUND AND PROJECT OBJECTIVE
- ✿ FIELD HISTORY
- ✿ CONDITIONS AT START OF PROJECT
- ✿ DESIGN, CONSTRUCTION AND STARTUP OF SYSTEM
- ✿ RESPONSE TO GAS INJECTION
- ✿ ECONOMICS OF PROJECT
- ✿ LESSONS LEARNED FROM PROJECT
- ✿ 20/20 HINDSIGHT and TWO YEARS OF LOW OIL PRICES 1997-1998
- ✿ FUTURE GAS REPRESSURIZATION BY DRIVER PRODUCTION

BACKGROUND AND OBJECTIVE OF PROJECT

DRIVER PRODUCTION COMPANY IS A SMALL FAMILY-OWNED, TWO PERSON COMPANY, 100% EQUITY IN ALL PROJECTS, NEVER HAS SOLD A PROPERTY

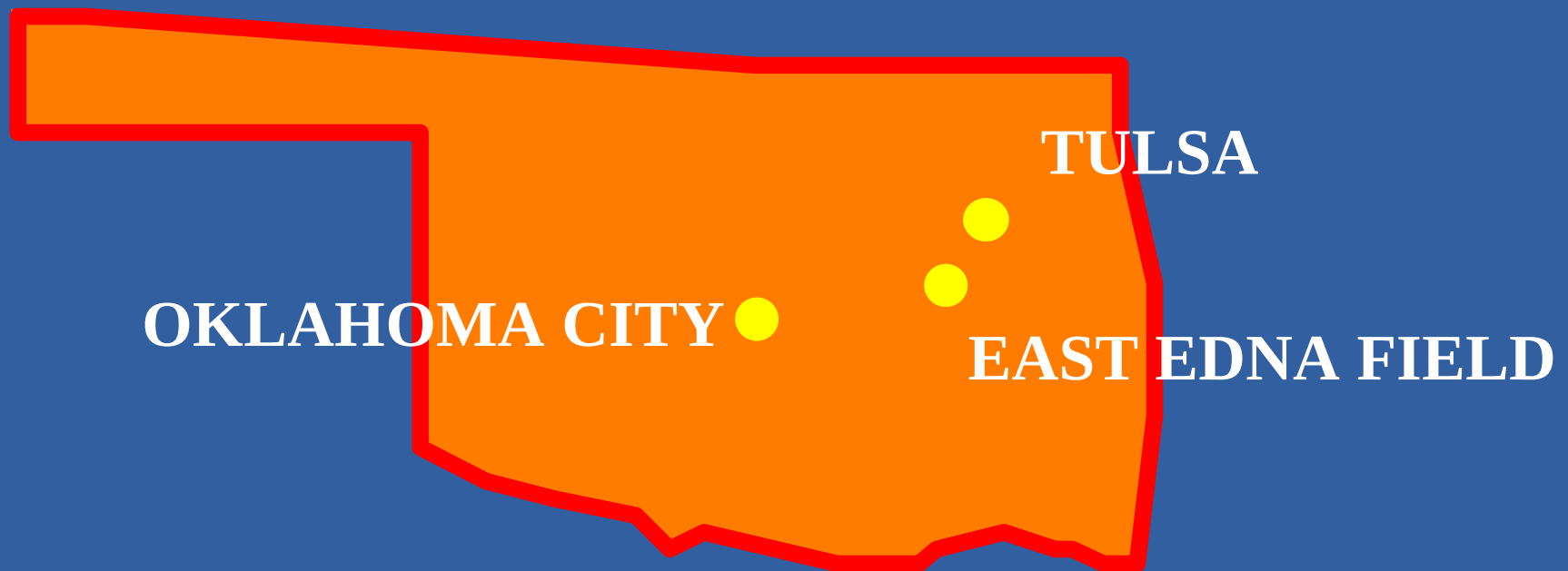
DRIVER RESPONDED TO A 1995 USDOE COMPETITIVE SOLICITATION FOR PROPOSALS FOR COST-SHARED FIELD PROJECT (one year time limit) FOR APPLICATION OF GAS REPRESSURIZATION BY SMALL INDEPENDENT OPERATORS

AWARDED Project - Spring 1996 for Flue Gas Repressurization Project for purpose of increasing oil production from marginal stripper well lease operated by small independent

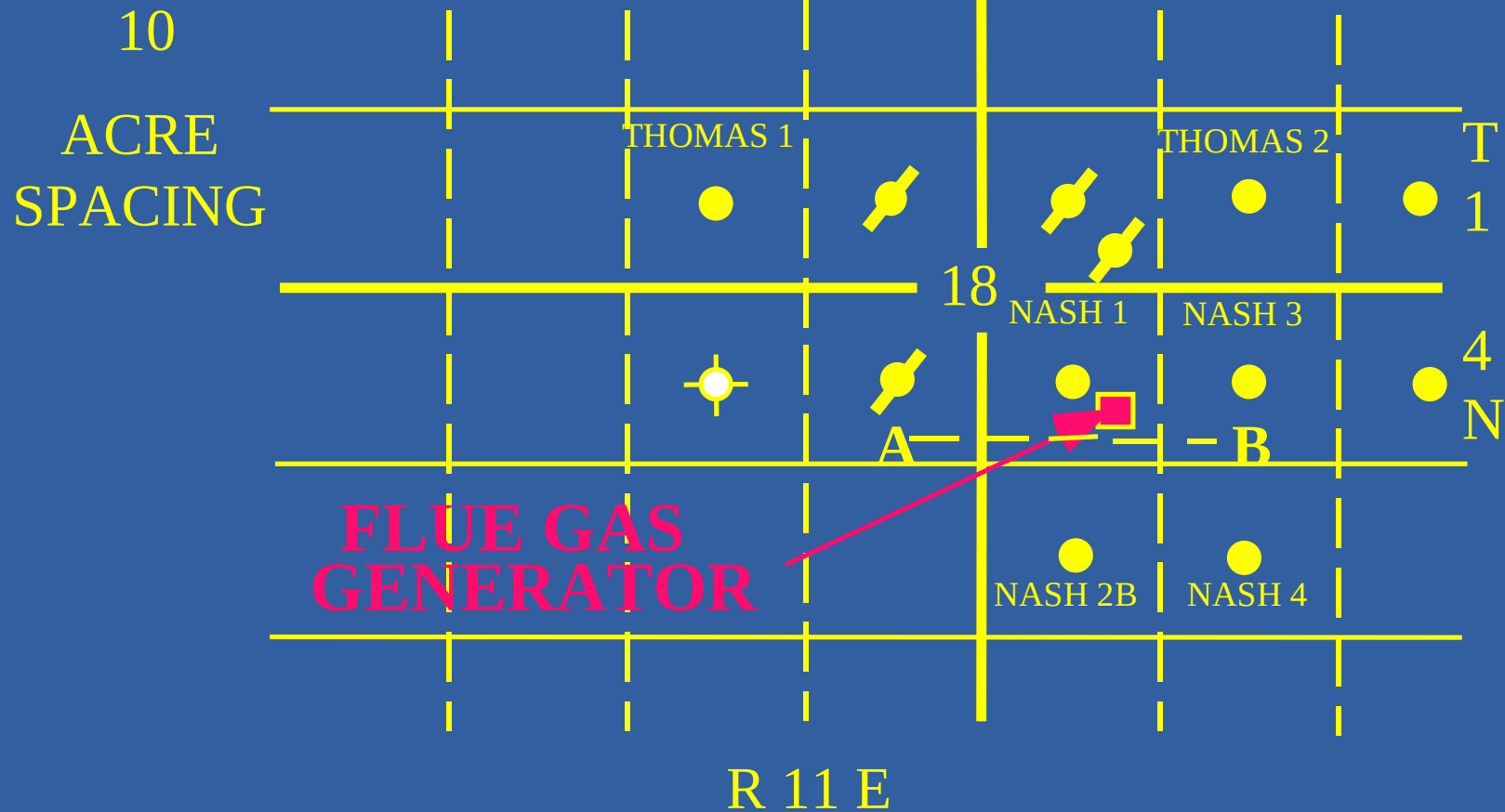


EAST EDNA FIELD, OKMULGEE OKLAHOMA

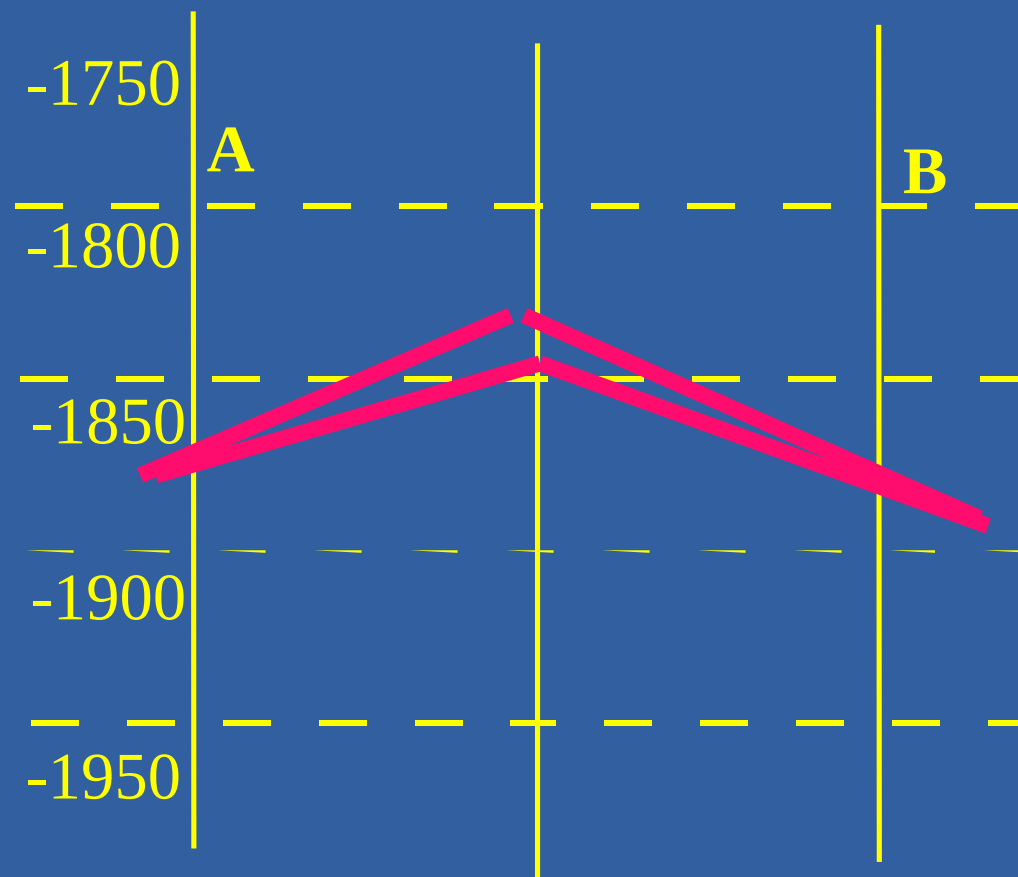
40 MILES SOUTHWEST OF TULSA



EAST EDNA FIELD LAYOUT



CROSS SECTION OF LINE A TO B IN DUTCHER SANDSTONE

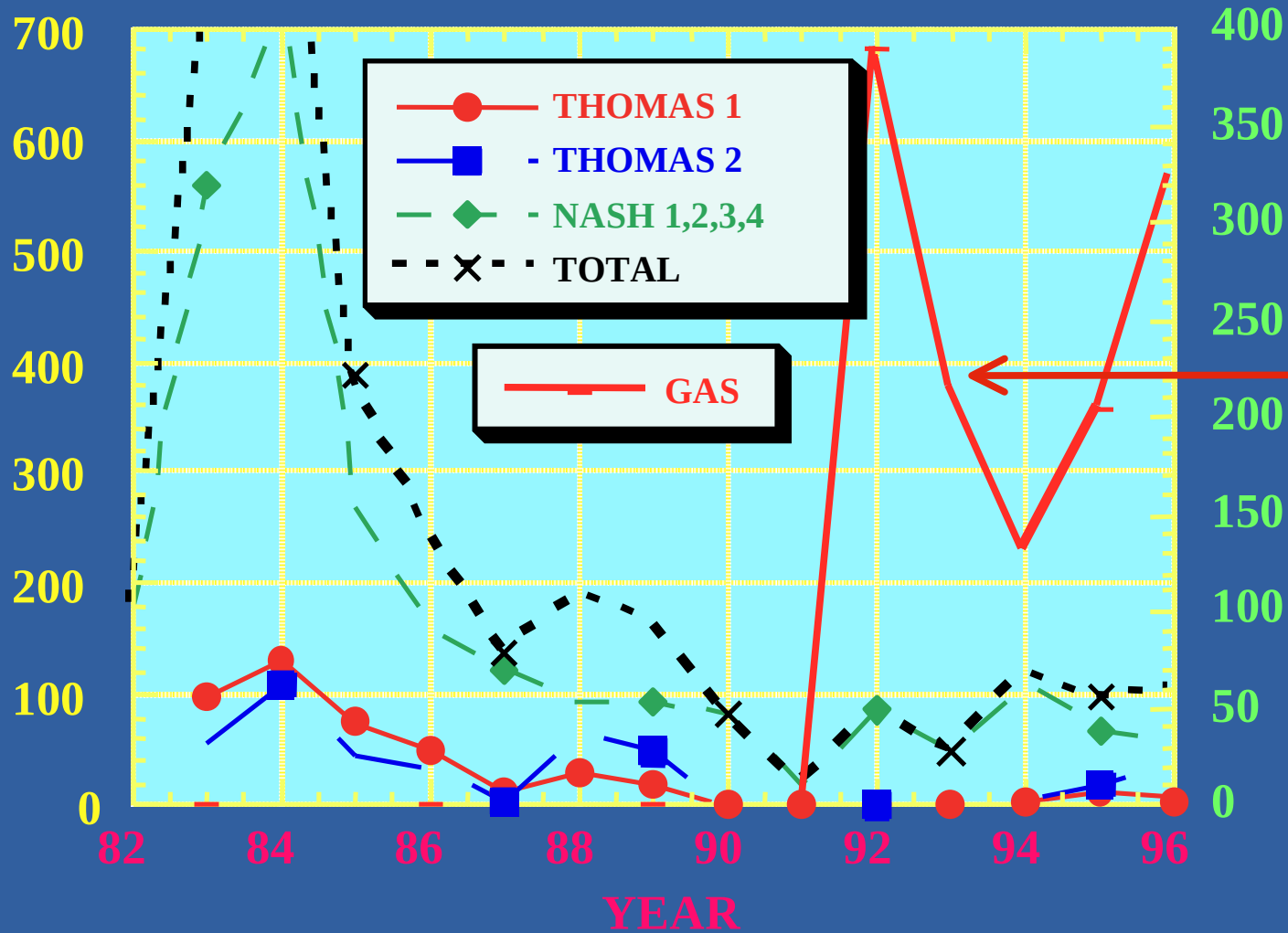


CONDITIONS AT START OF PROJECT

AVERAGE PRE-INJECTION DAILY PRODUCTION

Well	Oil B/D	Gas MCF/D	Water B/D
Thomas 1	0.5	—	Trace
Thomas 2	0.3	—	Trace
Nash 1,2,3,4	<u>1.75</u>	<u>11.6</u>	<u>Trace</u>
TOTAL 6 WELLS	2.55	11.6	Trace

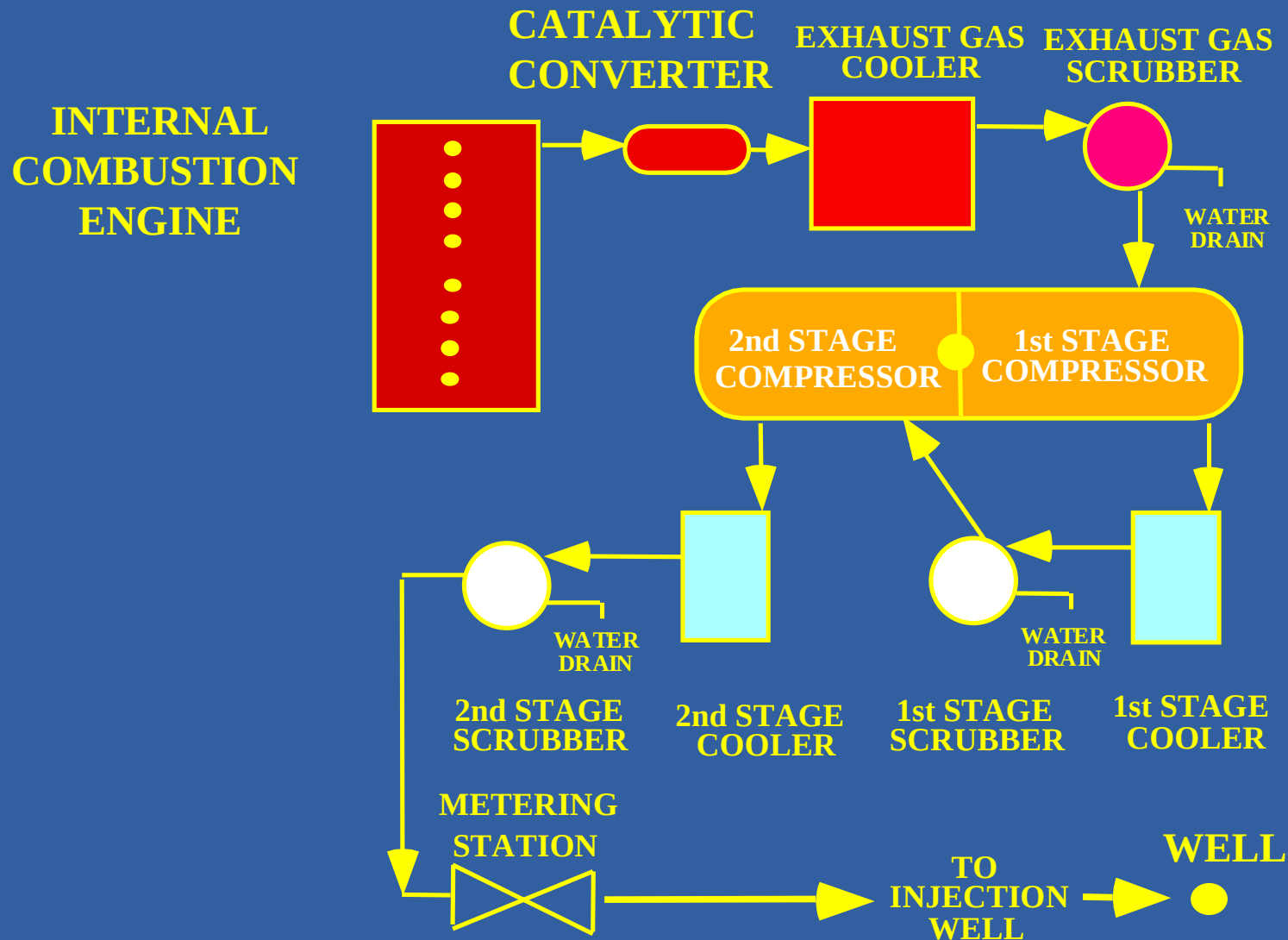
OIL, AVERAGE B / MONTH



GAS, AVERAGE MCF / MONTH

AVERAGE MONTHLY PRODUCTION

DESIGN AND CONSTRUCTION OF SYSTEM



STARTUP PROBLEMS

- ✿ **AQUIRING & DELIVERY OF EQUIPMENT**

- ✿ **ASSEMBLY OF ENTIRE SYSTEM**

- ✿ **WEATHER DELAYS**

OPERATION PROBLEMS

-  **CORROSION OF PIPING IN HIGH TURBULANCE AREAS**
-  **LABOR INTENSIVE, REQUIRES BEING AT PROJECT SITE 24 HRS/DAY (NON-AUTOMATED SYSTEM)**
-  **CHANNELING OF INJECTED GAS**

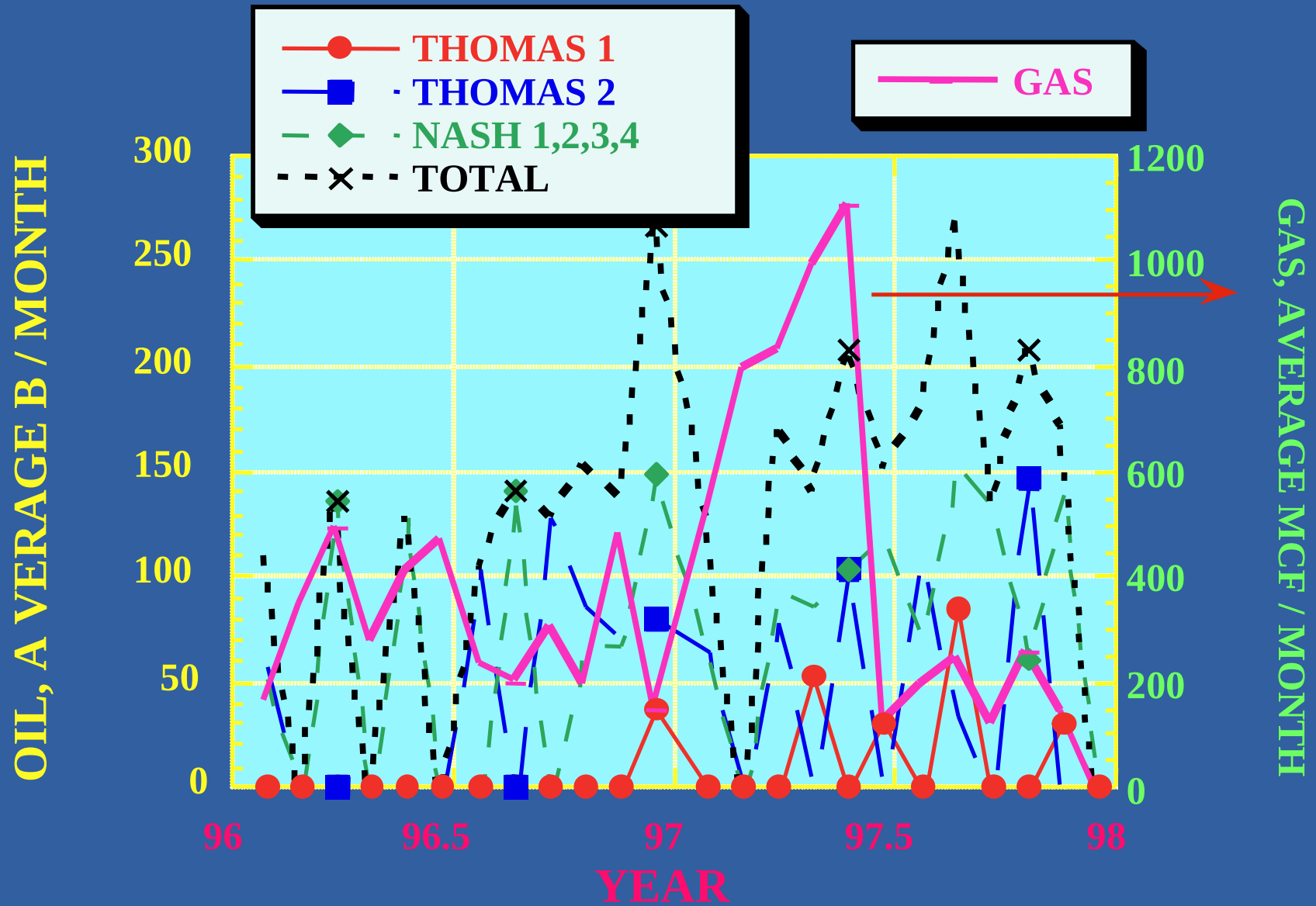
RESPONSE TO GAS INJECTION

- ✿ **TIME FRAME FROM START-UP TO POSITIVE RESULTS WILL NOT OCCUR OVERNIGHT**
- ✿ **ONCE POSITIVE RESULTS START, SLOW DOWN INJECTION VOLUME AND MONITOR INDIVIDUAL WELLS FOR DIRECTION OF GAS**
- ✿ **IN THIS PROJECT, GAS ARRIVED FIRST AT THE PRODUCER WELLBORE AND THEN THE OIL INCREASE ARRIVED**

GAS ANALYSIS BY % FROM NASH LEASE

Component	Pre-project	1/20/97	3/31/97	5/15/97
CO2	0.425	2.971	6.420	6.678
N2	4.531	56.182	72.751	66.090
O2	0.000	0.920	0.000	0.000
C1	62.300	20.987	9.096	13.563
C2	12.654	7.903	3.565	4.371
C3	10.296	6.255	4.638	5.015
IC4	1.241	0.740	0.559	0.659
NC4	3.173	1.881	1.417	1.679
IC5	0.786	0.446	0.335	0.368
NCF	0.929	0.538	0.388	0.377
C6	3.665	1.177	0.831	1.200
	100.000	100.000	100.000	100.000
Z Factor	0.993	0.9978	0.9986	0.9983
BTU - Wet	> 1,400	681.34	399.60	498.19

PRODUCTION BEFORE AND DURING PROJECT



ECONOMICS OF PROJECT

Production Expenses

	Jan-June Prior to Project Monthly	July 1996	July 1997	Oct 1997
Pumper	\$ 500	\$ 2,000	\$ 1,050	\$ 1,100
Electricity	85	130	230	230
Chemical	30	30	80	165
Miscellaneous	25	40	60	15
Ave. Pump Change	140	300	140	150
	<u>\$ 780</u>	<u>\$ 2,500</u>	<u>\$ 1,560</u>	<u>\$ 1,660</u>

Production Income

Oil Sales	\$ 1,000	\$ 1,000	\$ 1,820	\$ 2,080
Gas Sales	<u>350</u>	<u>350</u>	<u>1,100</u>	<u>1,320</u>
	<u>\$ 1,350</u>	<u>\$ 1,350</u>	<u>\$ 2,930</u>	<u>\$ 3,400</u>

LESSONS LEARNED FROM PROJECT

- ✱ ALLOCATION OF TIME
- ✱ ANTICIPATE PROBLEMS
- ✱ KNOWLEDGE AND USE OF EQUIPMENT
- ✱ CONTROL AND MEASUREMENT
- ✱ CORROSION CONTROL
- ✱ PATIENCE

PROJECTED ECONOMICS OF PROJECT

Assumed \$80,000 Investment
 \$17.25 / B oil \$1.40 / MCF gas
 Pay Out in 26 Months

YEAR	GROSS MB	GROSS MMCF	NET B	NET MCF	STATE REV	EXPENSE \$	TAX \$	COI \$	INVEST \$	NOI \$	DISC \$
1997	2	6	2022	4835	41647	19200	2915	19532	80000	-60468	-60468
1998	5	11	3890	9304	82109	38400	5748	37961	0	37961	37582
1999	5	11	3685	8814	81675	38400	5717	37558	0	37558	36814
2000	4	10	3481	8324	80993	38400	5670	36923	0	36923	35832
2001	4	10	3276	7835	80038	38400	5603	36036	0	36036	34623
2002	4	9	3071	7345	78786	38400	5515	34871	0	34871	33170
2003	4	8	2866	6855	77208	38400	5405	33403	0	33403	31459
2004	3	8	2662	6366	75275	38400	5269	31606	0	31606	29470
2005	3	7	2457	5876	72956	38400	5107	29449	0	29449	27186
2006	3	7	2252	5386	70217	38400	4915	26902	0	26902	24588
ST	37	87	29663	70940	740904	364800				244241	230242
RM	11	27	9057	21661	328657	224000				81651	72776
TL	48	114	38720	92601	1069561	588800				325892	303018

PROJECTED ECONOMICS OF PROJECT

Assumed \$80,000 Investment
\$17.25 / B oil \$1.40 / MCF gas
Pay Out in 26 Months

YEAR	EXPENSE	DISC
	\$	\$
1997	19200	-60468
1998	38400	37582
1999	38400	36814
2000	38400	35832
2001	38400	34623
2002	38400	33170
2003	38400	31459
2004	38400	29470
2005	38400	27186
2006	38400	24588
ST	364800	230242
RM	224000	72776
TL	588800	303018

CONCLUSIONS

- ✿ FIRST HAND KNOWLEDGE IN ALL ASPECTS OF THE PROJECT ARE NOT REQUIRED
- ✿ BASIC KNOWLEDGE OF OIL & GAS PRODUCTION EQUIPMENT AND USE OF EQUIPMENT IS REQUIRED
- ✿ RESOURCES ARE AVAILABLE TO GET HELP — SPEND TIME TO SEEK SOLUTIONS BEFORE INVESTING AND STARTING THE PROJECT —
- ✿ DO YOUR HOMEWORK

WHAT I WOULD DO DIFFERENT NEXT TIME

- 1. SMALLER VOLUME OF INJECTED GAS**
- 2. SEPARATE GAS SUPPLY FROM FUEL SUPPLY**
- 3. INSTITUTE CHEMICAL CORROSION PROGRAM AT START-UP, INSTEAD OF AFTER CORROSION PROBLEMS OCCUR**
- 4. SLOW DOWN INJECTION AND REASSESS AFTER POSITIVE RESULTS OCCUR**
- 5. DO NOT RUSH, IT TAKES TIME TO START REPRESSURIZATION OF FORMATION**
- 6. TEST EACH WELL WITH PORTABLE FLUE GAS GENERATOR BEFORE START-UP OF PERMANENT SYSTEM**

ACKNOWLEDGEMENT

THIS PROJECT WAS COST-SHARED BETWEEN DRIVER PRODUCTION AND U.S. DEPARTMENT OF ENERGY. AUTHORS THANK US DOE AND BDM-OKLAHOMA FOR THEIR ASSISTANCE.

1.3

Air Injection in a Gulf Coast Light Oil Field

Ken A. Haley (haleyka@bp.com; 281-366-7360)
Gulf Coast Business Unit

Abstract

Why inject air in an oil reservoir? In Southwest Louisiana, air injection is proving to be a low cost way of generating 280 BOPD of incremental oil production. While air injection is historically associated with heavy oil or low permeability light oil reservoirs, the West Hackberry Air Injection Project is proving that air can do more. In three high permeability light oil reservoirs, air injection is repressuring the reservoir, repositioning the oil rim, and improving recovery through the Double Displacement Process. The Double Displacement Process is the gas displacement of a water invaded oil column for the purpose of recovering oil through gravity drainage. In high permeability light oil reservoirs, gravity drainage can recover 80% to 90% of the oil in place versus waterdrive recoveries of 50% to 60% of the oil in place.

1.4 Overview of the CO₂ Pilot in the Spraberry Trend Area

David S. Schechter (schech@baervan.nmt.edu; 505-835-5142)
New Mexico Petroleum Recovery Research Center
801 Leroy Place
Socorro, NM 87801

Todd M. Yocham (yochamt@pioneer-nrc.com; 915-571-1342)
Pioneer Natural Resources USA, Inc.
303 W. Wall St., Suite 101
Midland, TX 79701

Abstract

The overall goal of this project is to assess the economic feasibility of CO₂ flooding the naturally fractured Spraberry Trend Area in West Texas. This objective is being accomplished by conducting research in four areas and implementation of a field demonstration pilot. Research areas are as follows: 1) extensive characterization of the reservoirs, 2) experimental studies of crude oil/brine/rock (COBR) interaction in the reservoirs, 3) analytical and numerical simulation of Spraberry reservoirs, and, 4) experimental investigations on CO₂ gravity drainage in Spraberry whole cores. This report provides initial results of the project for each of the four areas and outlines the field demonstration pilot progress.

In the first area, reservoir characterization has been established based on petrophysical and geological analysis combined with core-log integration. A shaly sand rock model for describing the Spraberry Trend Area Reservoir has been established, and as a result, a better log interpretation algorithm for identifying Spraberry pay zones has been developed.

In the second area, COBR interaction in the Spraberry matrix has been analyzed based on results of laboratory experiments. Initial water saturation and historical water saturation in the Spraberry sands has been determined to be between 0.20 and 0.40 depending on permeability of the sand. Macroscopic displacement efficiency during water imbibition has been estimated to be about 50%. Wettability of the Spraberry sands has been determined. The Amott wettability index to water was estimated to be about 0.55 indicating that the Spraberry sands are weakly water wet. Water-oil capillary pressure has been established. The experimental capillary pressure curve confirms the rock wettability determined based imbibition test. Interfacial tension (IFT) between Spraberry oil and brine has been measured to be 32 mN/m. Experimental results have been used in analytical and numerical reservoir simulations.

In the third area, performance of the Spraberry reservoirs has been explored based on reservoir characterization and laboratory investigations. Scaling of imbibition oil recovery results to reservoir geometry indicates that higher oil recovery should have been achieved during water flooding, although the Spraberry sands are weakly water wet.

Reasons for the poor performance of water flood were analyzed. Inflow performance of Spraberry Trend wells has been analyzed using a new mathematical model developed for wells intersecting long fractures. Computer simulation of a Spraberry waterflood pilot has been conducted using laboratory measured parameters to understand Spraberry waterflood performance.

In the fourth area, efficiency of CO₂ gravity drainage has been investigated based on laboratory experiments. Minimum Miscibility Pressure (MMP) was measured to be 1,550 psig. IFT of the CO₂/Spraberry oil under reservoir conditions was determined. The IFT at the MMP is about 1.5 mN/m. Investigation of vaporization of oil fractions into CO₂ was initiated. Preliminary results show insignificance of the mechanism. CO₂ gravity drainage experiments were carried out using Spraberry oil and whole cores. 51% of original oil in place was recovered from a 0.01 md Spraberry whole core within 200 days during CO₂ gravity drainage. Experimental data were matched by a mathematical model.

The field demonstration pilot is underway to test the results of the laboratory and modeling applications. This pilot consists of 6 WIW's, 3 producers, and 4 GIW's and the associated production/injection facilities. The GIW's will be drilled during the end of 1999 and the CO₂ injection is slated to begin during the 1st quarter of 2000. Extensive field testing is ongoing to further characterize the reservoir. These tests include pressure buildups and falloffs, step-rate injection tests, injection profile logs, and the interference test currently in progress.

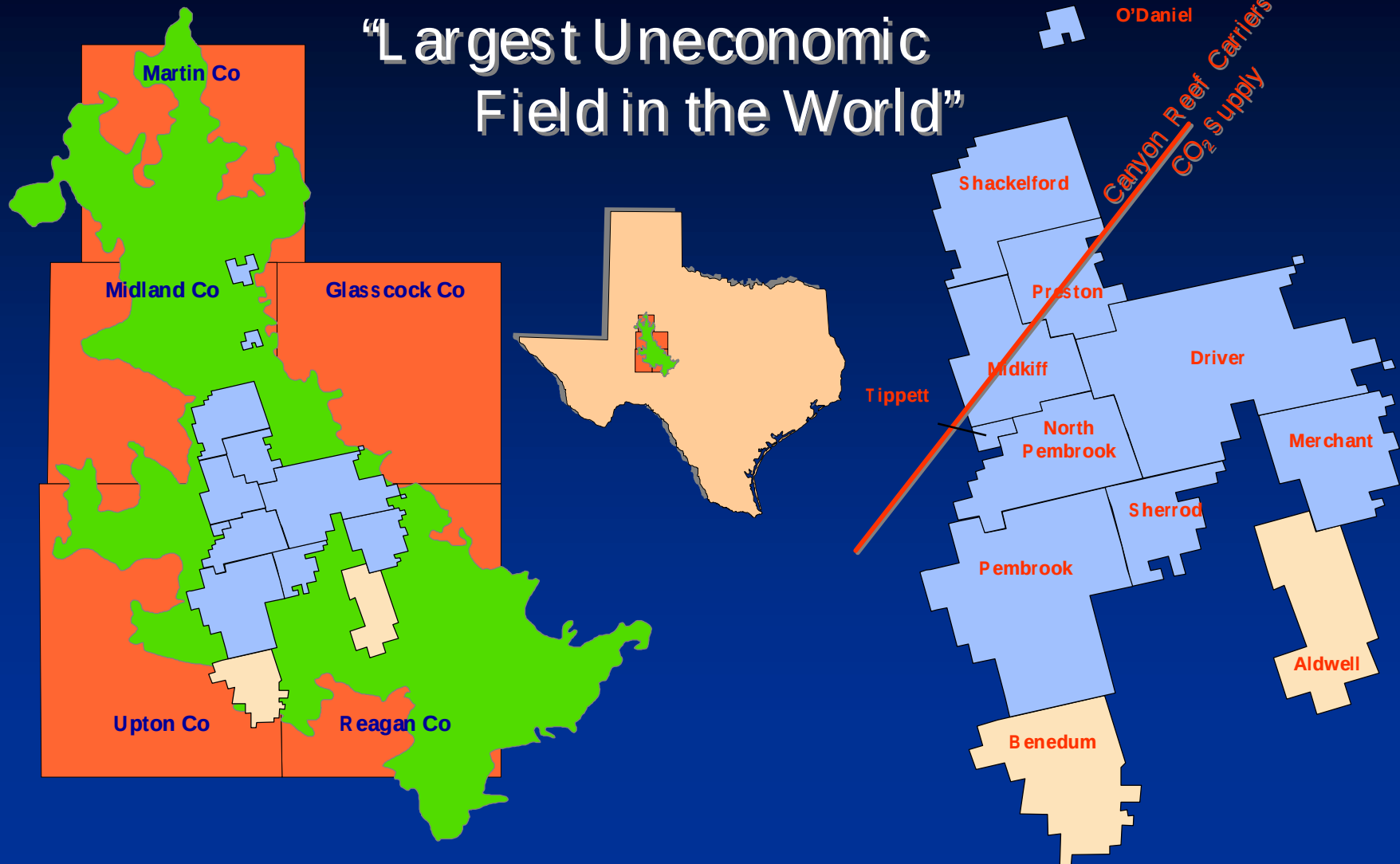
*“Overview of DOE /NPT O Class III
Field Demonstration: CO₂ Pilot in the
Naturally Fractured
Spraberry Trend Area”*

David S. Schechter

*Petroleum Recovery Research Center
New Mexico Institute of Mining and
Technology*

Spraberry Trend Area

“Largest Uneconomic Field in the World”



Key Elements in Designing Water and Gas Injection in Naturally Fractured Reservoirs

I. Extent and location of matrix porosity

II. Wettability of oil saturated matrix

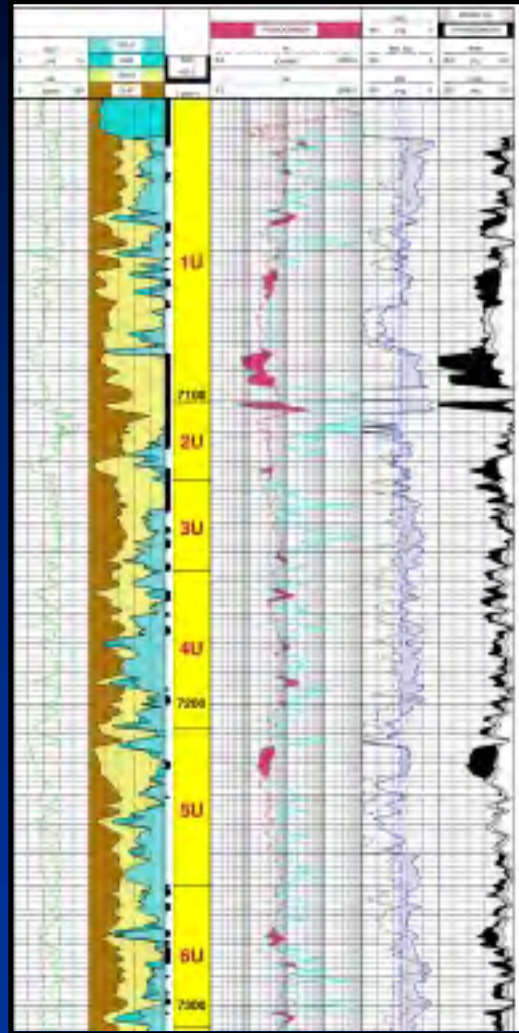
III. Connectivity of fracture system

- Vertical communication**
- Areal communication**

IV. Time scale for transfer mechanisms

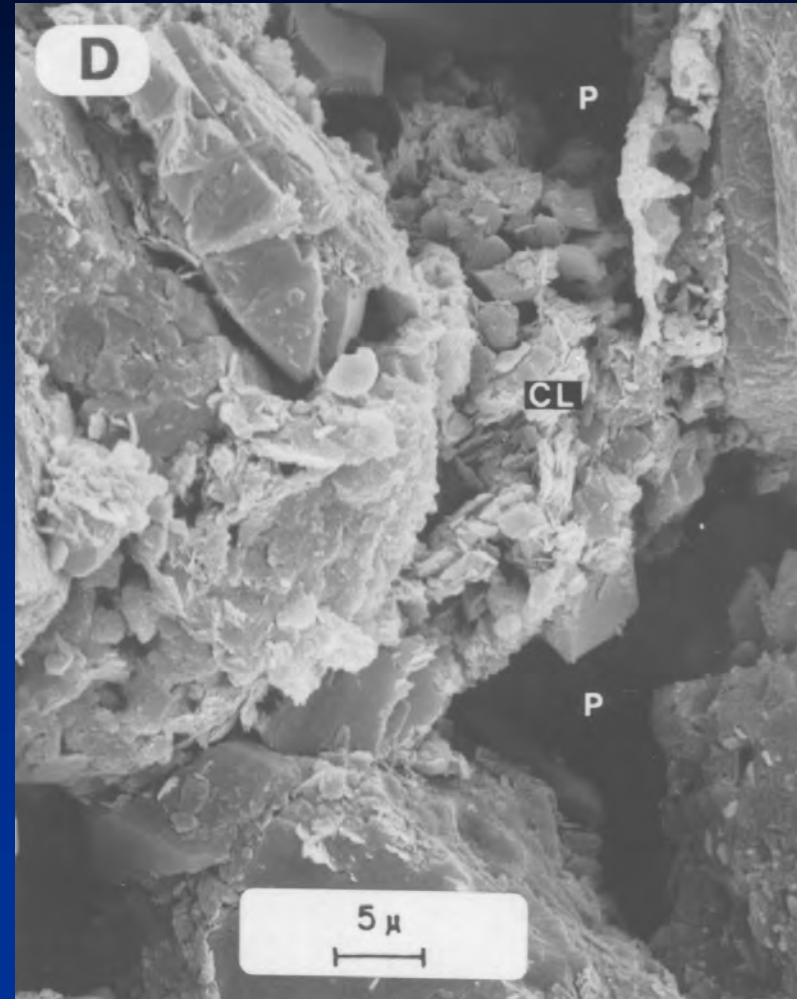
- Capillary imbibition**
- Diffusion**
- Gravity drainage**

Upper Spraberry Type Log



Rock Type A: Main Pay

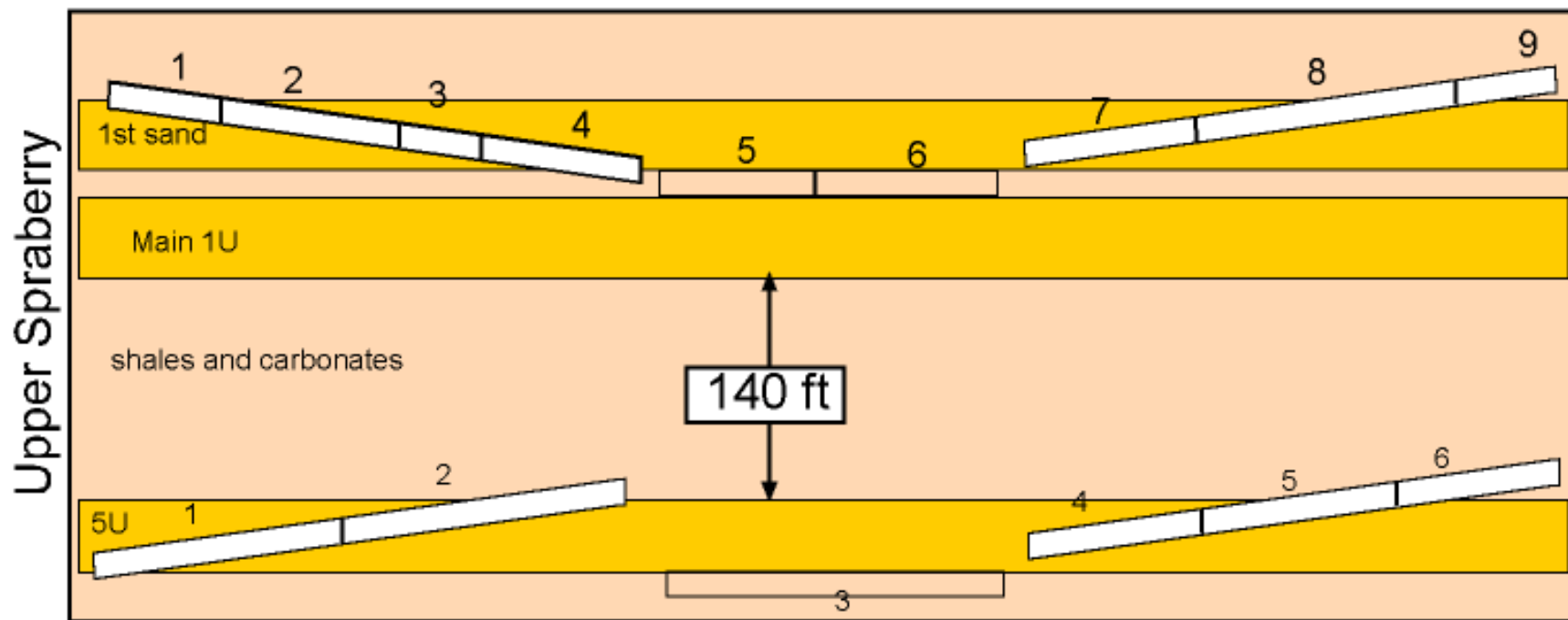
- $\phi > 7\%$
- $k > 0.1$ md
- Clay $< 7\%$
- Intergranular Pores
- Swi: 35 - 50 %



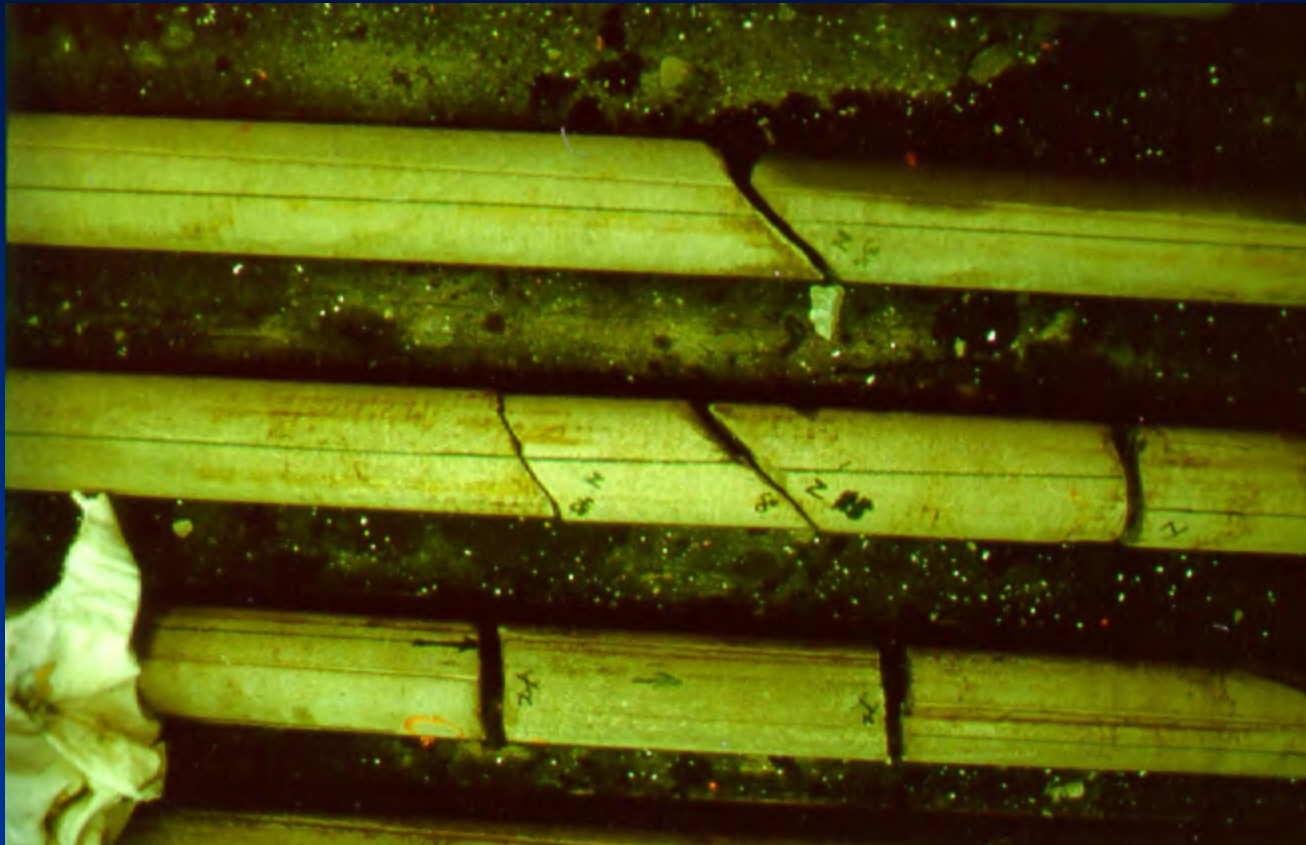
Vertical, Mineralized Fracture: 1U Payzone Shackelford 1-38A

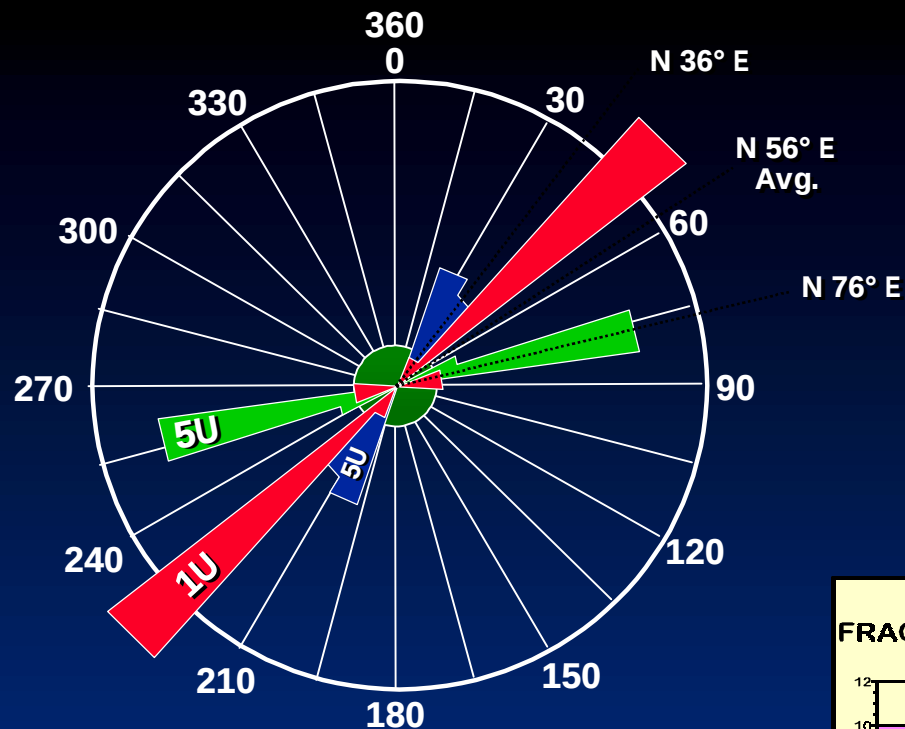


Horizontal Core Well - O'Daniel #28

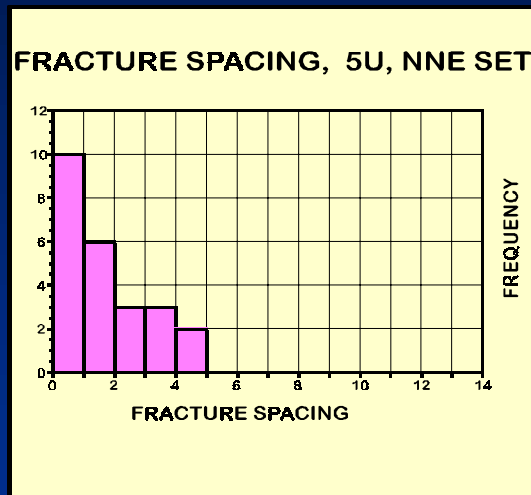
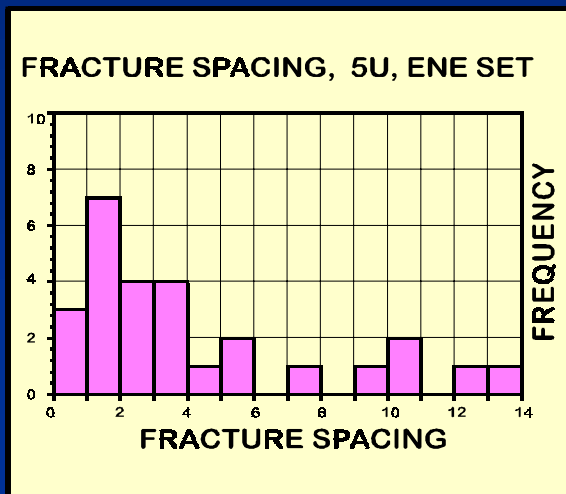


5U ENE & NNE Fractures

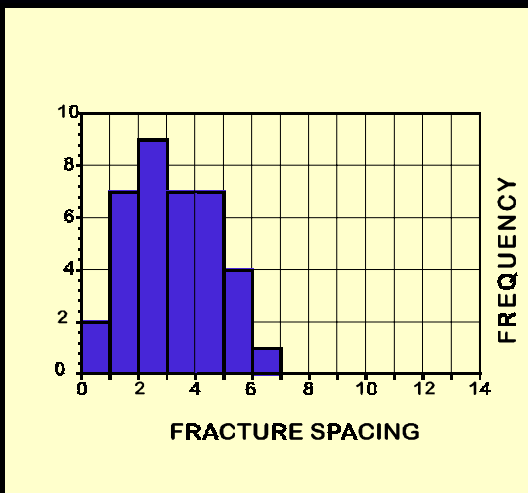




Overlay of 1U and 5U Fractures



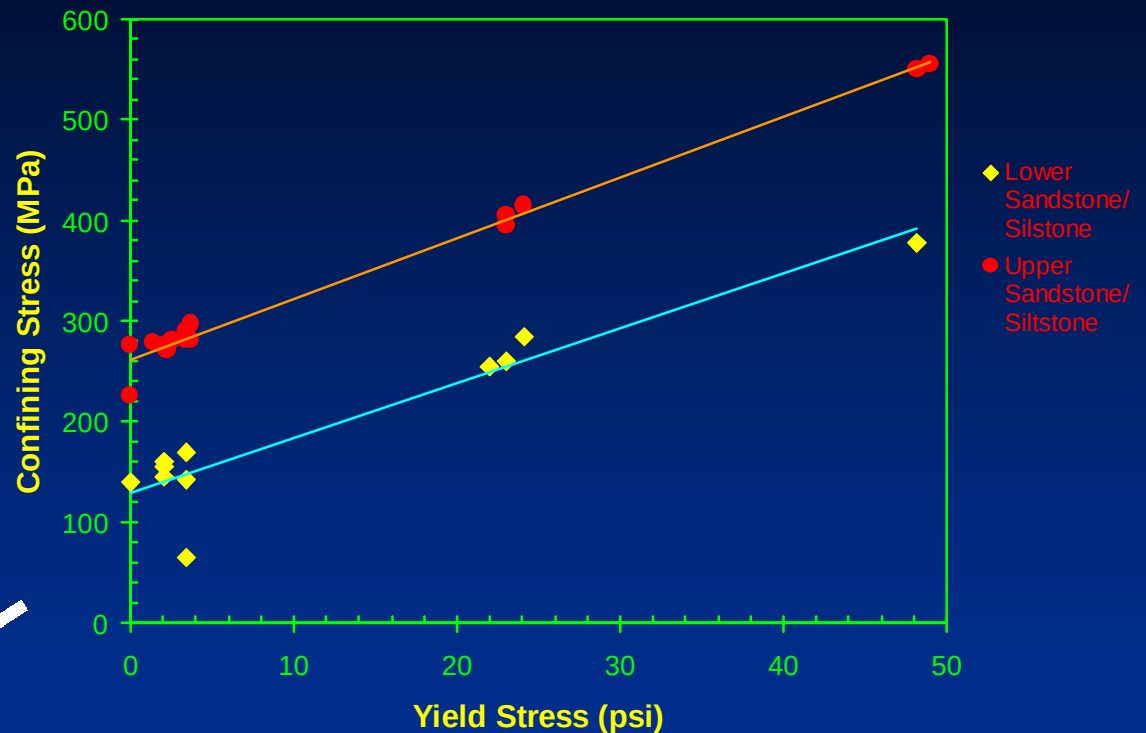
- N70E orientation.
- Spacing skewed normal distribution with an average of 3.79 ft.
- Fractures have smooth surfaces
- No obvious mineralization.



- N42E orientation.
- Average spacing of 3.2 ft
- Smooth mineralized surfaces.

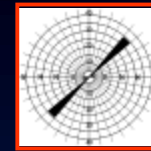
Geomechanical Properties of Upper (1U) and Lower (5U) Sand Intervals

- Low average Poisson's ratio (0.11)
- Elastic moduli of these units are nearly equal (about 2.4×10^4 MPa).
- Yield stress (mechanical yield strength) of the upper unit is nearly twice that of the lower unit.



Fracture variability between 1U and 5U due to differences in the clay and quartz content, 1U low clay, high cementation - stronger rock than 5U

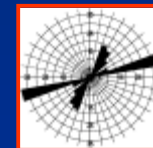
Average fracture spacing
3.17 ft (N42E)



Sand layer
1U (10 ft)

Shale layer
(140 ft)

Sand layer
5U (15 ft)



Pay zone, 1U
Siltstone,
 $V_{shl} < 15\%$,
 $\phi > 7\%$

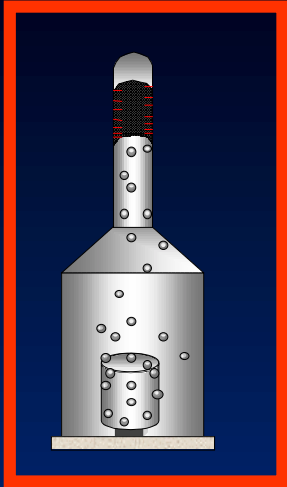
Non-pay zone,
2U, 3U, and 4U
Siltstone +
Dolomite,
 $V_{shl} < 15\%$,
 $\phi < 7\%$

Pay zone, 5U
Siltstone,
 $V_{shl} < 15\%$,
 $\phi > 7\%$

Average fracture spacing
1.62 and 3.8 ft (N32E and N80E)

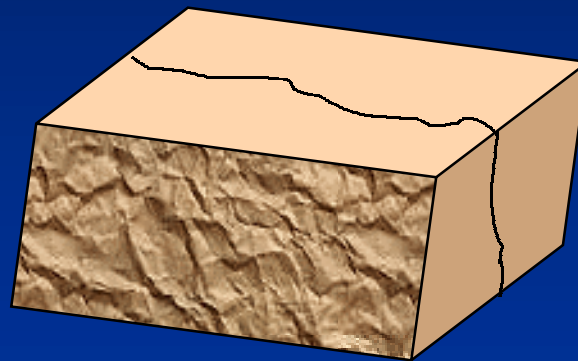
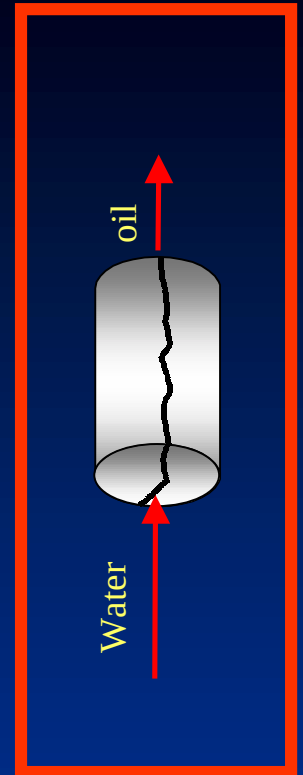
Spraberry Fracture
System Schematic

Overview of Imbibition Study



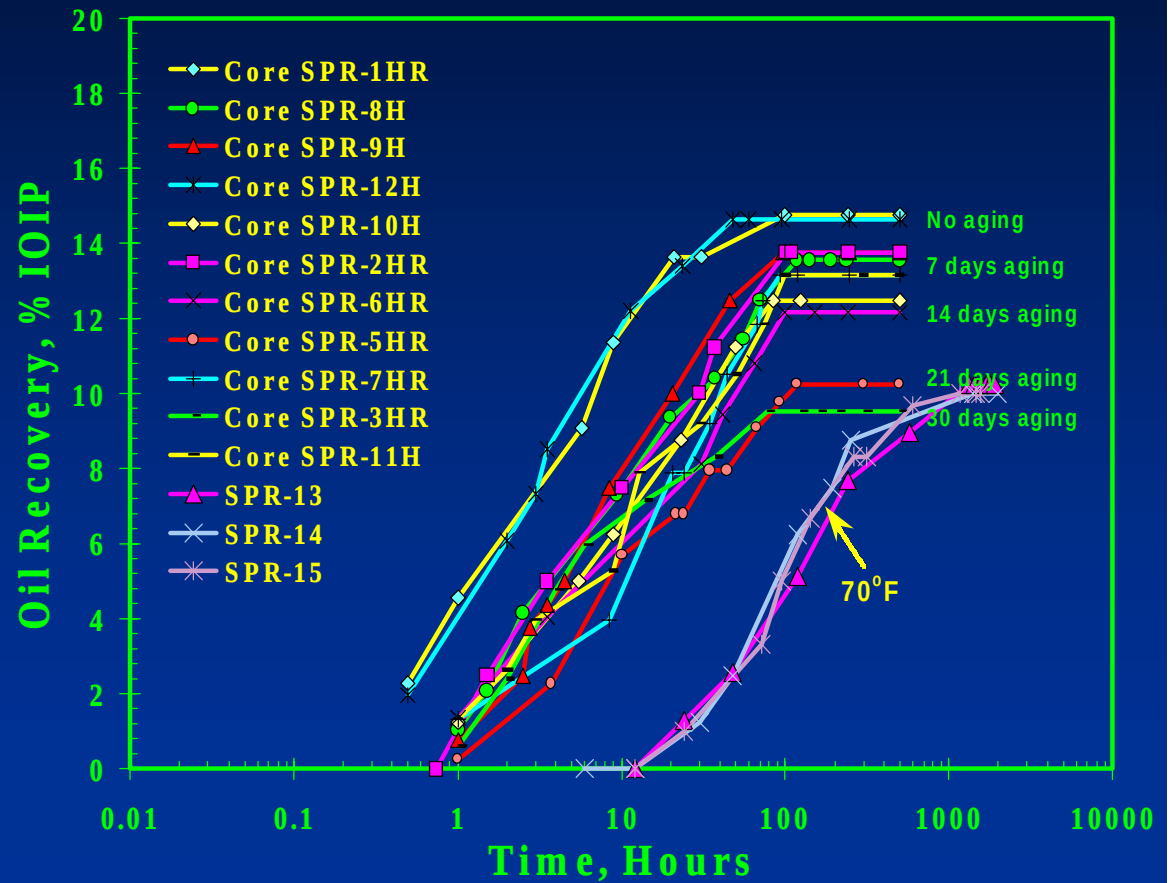
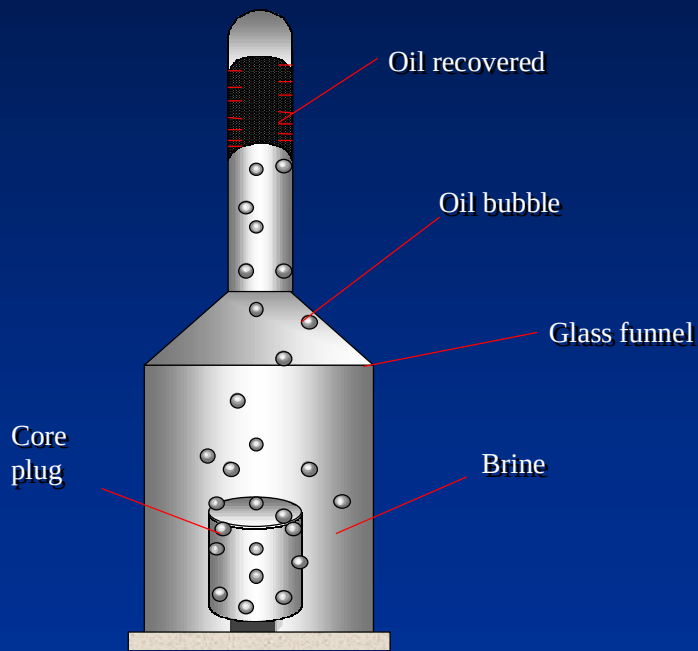
- Wettability Index
- Aging effect on oil recovery
- Effect of P and T on oil recovery
- Upscaling the data
- Capillary pressure curve

- Oil recovery profile
 - modeling the experiments
- Capillary pressure curve
- Key variables in dual porosity simulation
 - Determine critical injection rate

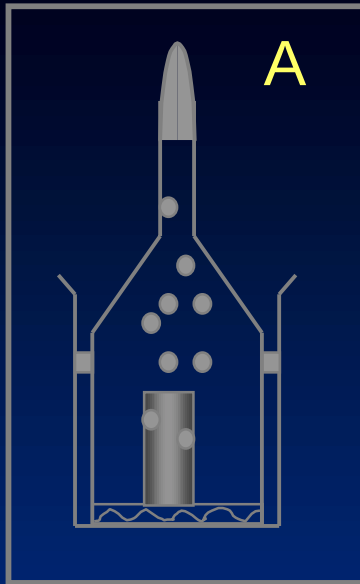


Field dimension

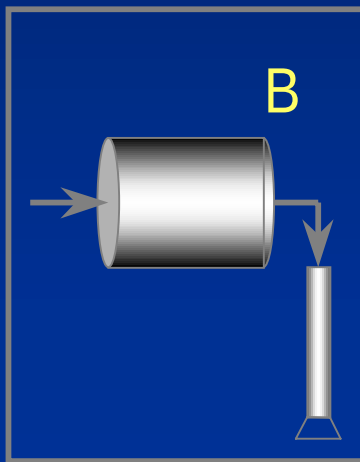
Experimental Set-up for Static Imbibition Tests at Ambient Conditions



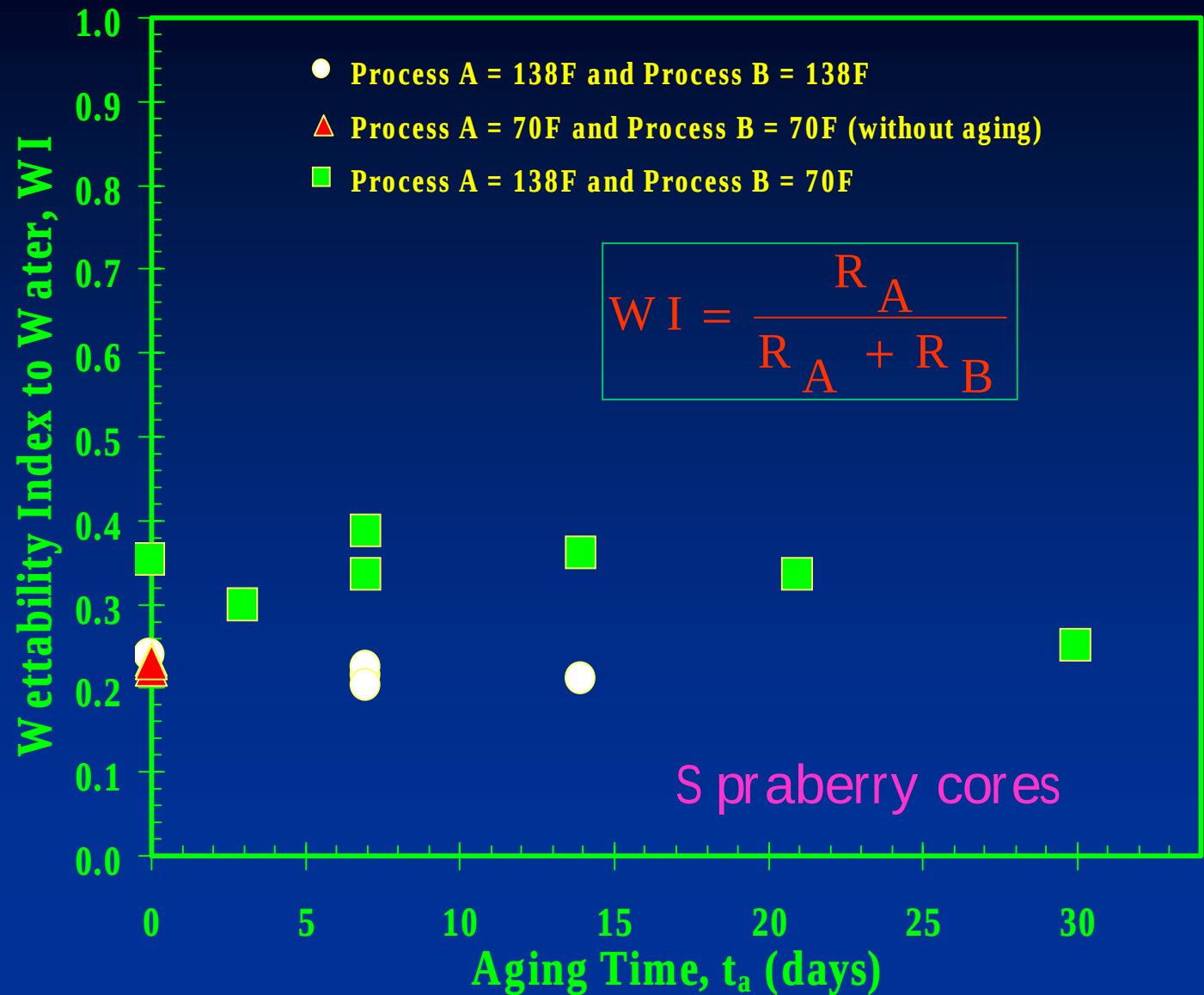
Static imbibition



Displacement



Wettability index vs aging time for different experimental temperatures



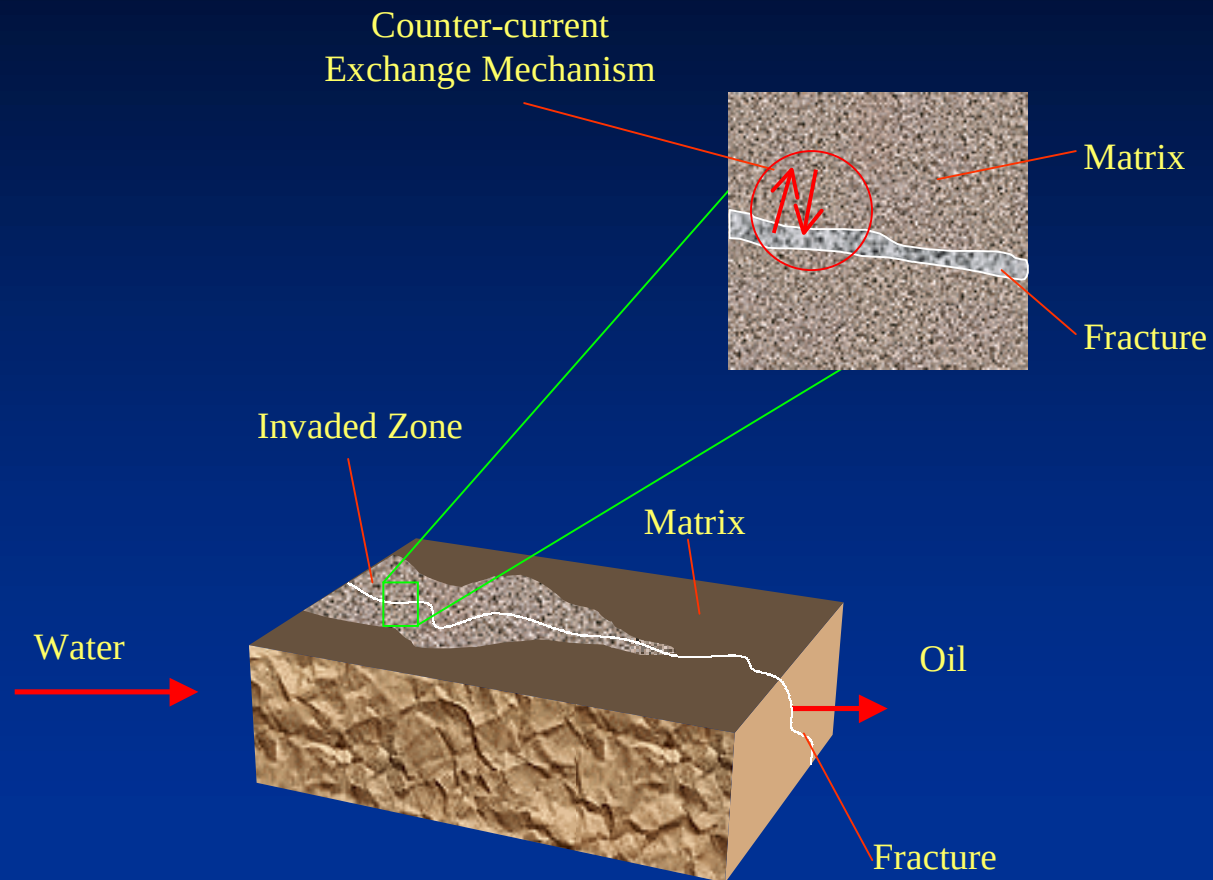
Evidence of Weakly Water-Wet Behavior in Spraberry

- Spontaneous imbibition of oil into water saturated Spraberry core
- Spontaneous imbibition of oil into water saturated core during static Eq. P_c meas.
- Low P_c during drainage and imbibition
- Low Amott wettability indices $I_w \sim 0.2 - 0.3$
- Scaled mercury contact angle of 50°
- Reservoir condition contact angle measurements of 50° (within 10°)

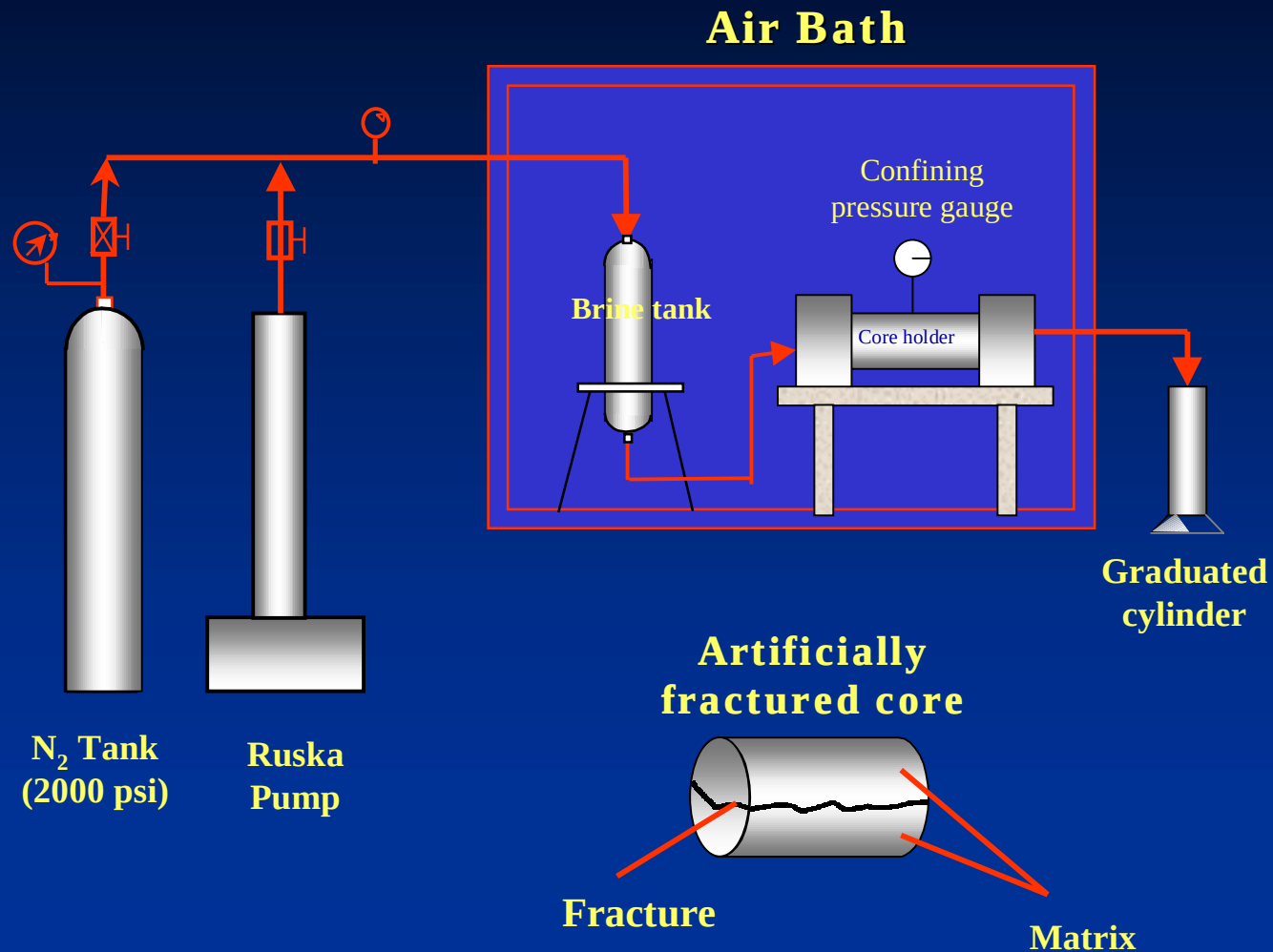
Slow Imbibition is the Rate-Limiting Step



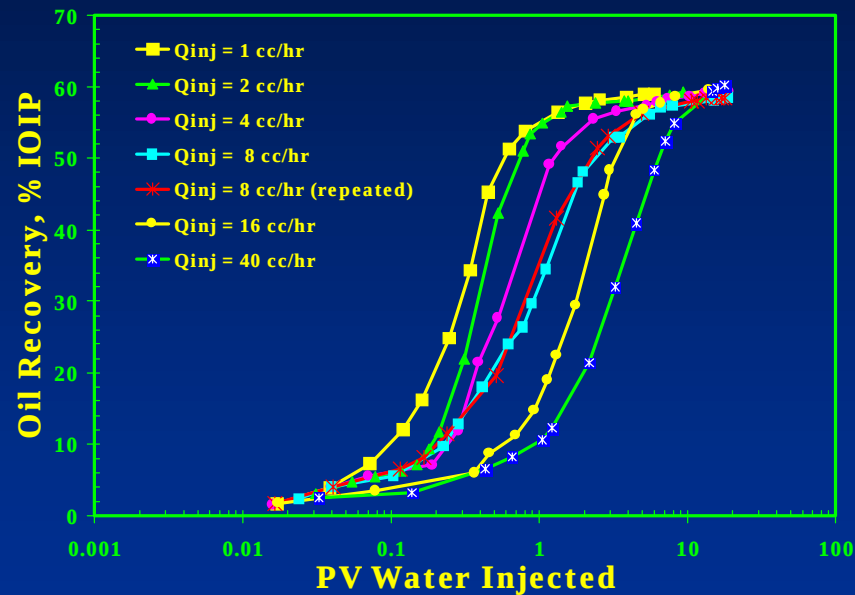
Concept of Dynamic Imbibition Process



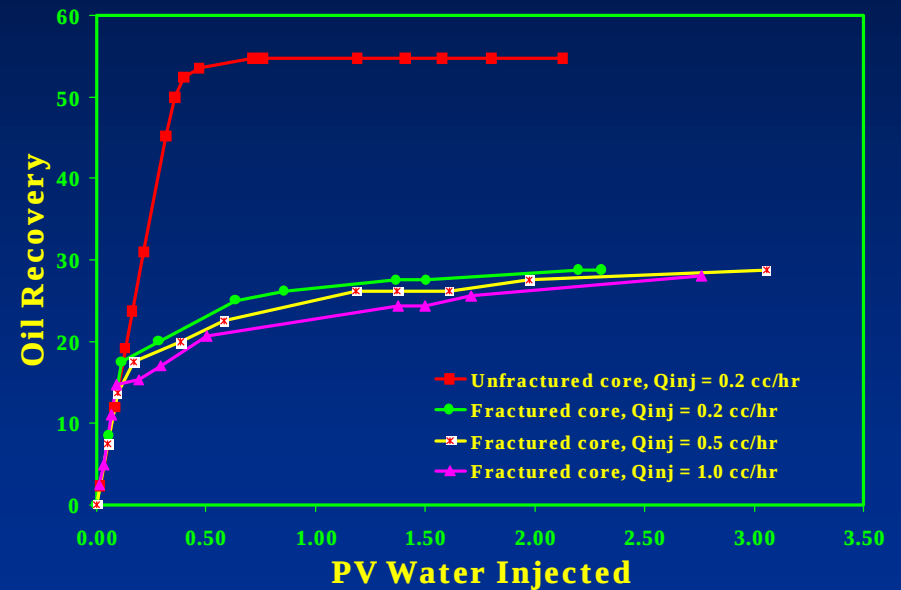
Experimental Set-up for Dynamic Imbibition Tests at Reservoir Temperature



Oil Recovery from Fractured Berea and Spraberry Cores using Different Injection Rates



Berea Cores



Spraberry Cores

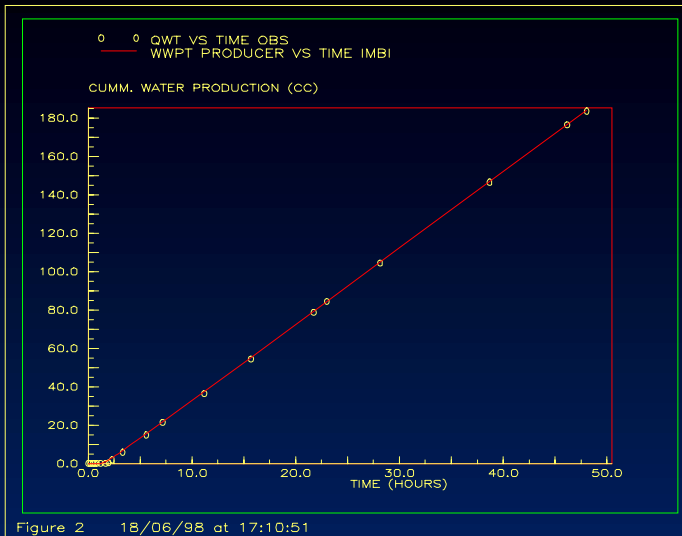
Dynamic Imbibition Modeling

- Single porosity, 2 phase and 3-D
- Rectangular grid block with grid size : 10 x 10 x 3 (Berea) ; z = 9 layers for Spraberry
- Fracture layer between the matrix layers
- Inject into the fracture layer
- Alter matrix capillary pressure only to match the experimental data
 - ☆ zero P_c for fracture
 - ☆ straight line for k_{rw} and k_{ro} fracture
 - ☆ use k_{rw} and k_{ro} matrix from the following equations (Berea core):

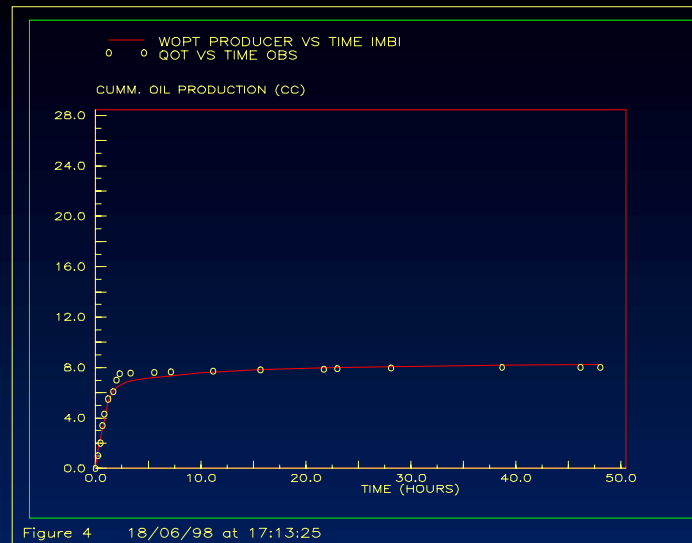
$$k_{rw} = S_w^3 \qquad k_{ro} = (S_o - S_{or})^3$$

Berea Core

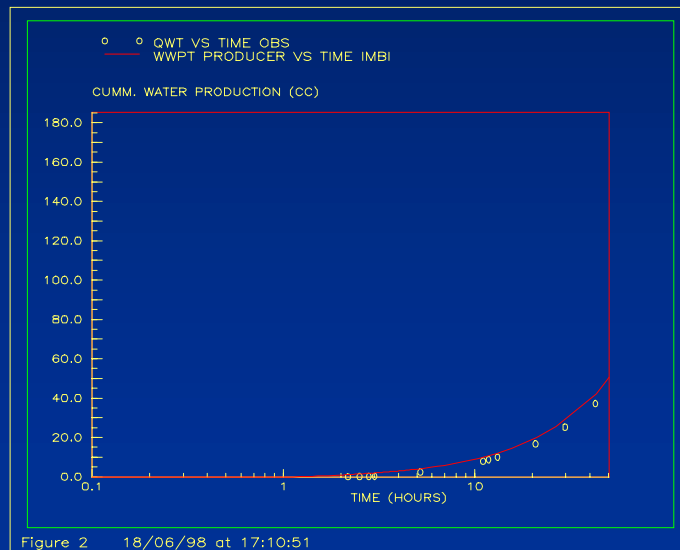
Match
Between
Experimental
Data and
Numerical
Solution



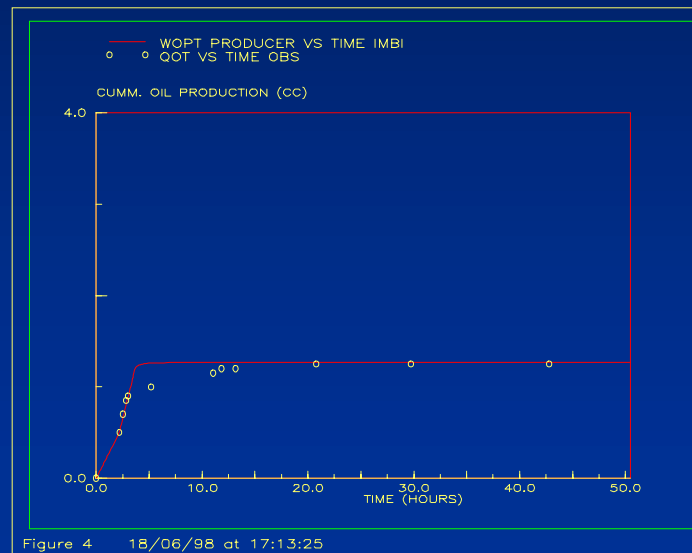
Cumulative water production vs. time



Cumulative oil production vs. time



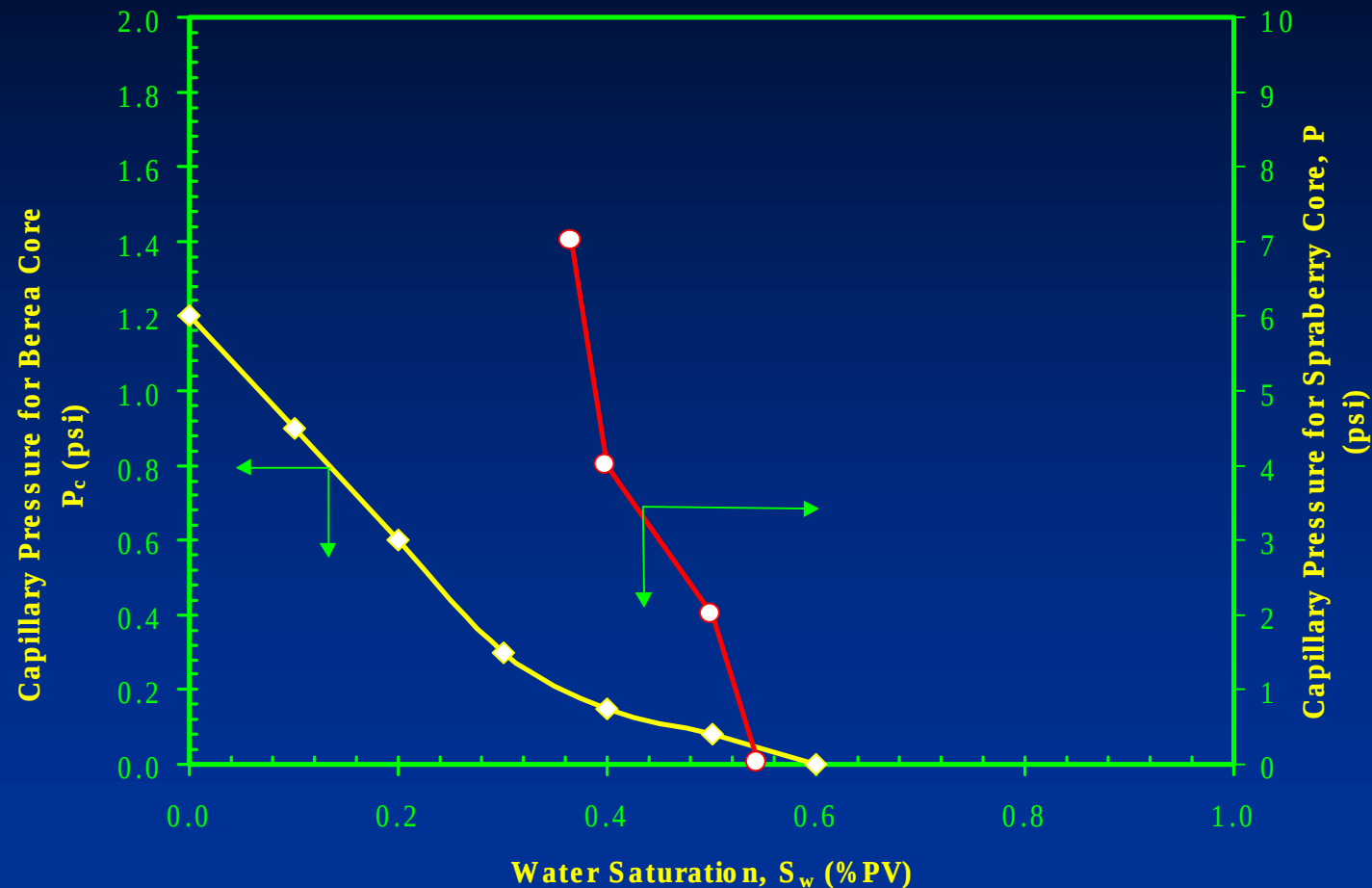
Cumulative water production vs. time

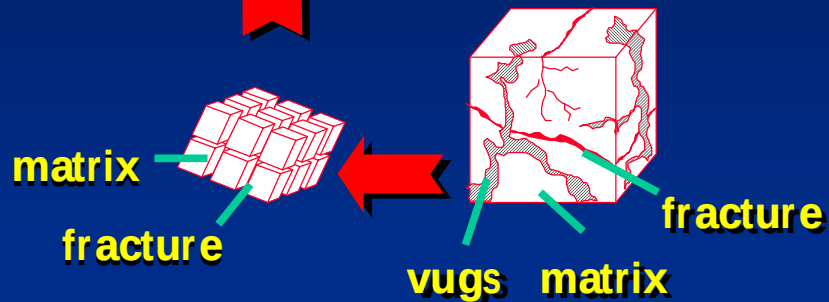


Cumulative oil production vs. time

Spraberry Core

Capillary Pressure Curves Obtained by Matching Experimental Data (Berea and Spraberry Cores)





NO COMMUNICATION BETWEEN LAYER

GRID DIMENSION IS 22X18X3

Reservoir Properties

Net pay zone thickness	20 ft.	log and core
Matrix permeability	0.03 md	well test
Matrix porosity	0.12	core
Gas saturation	0	assumed
Overall contact angle	50 degrees	measured
Effective fluid viscosity	0.9 cp	measured
Oil-water IFT	36 mN/m	measured
Oil FVF	1.35 rb/STB	known
Imbibition efficiency	13%	measured
Capillary pressure		history match
Fracture spacing	2.86 ft.	horizontal core
Initial water saturation S_{wi}	0.38	measured
Residual oil saturation	0.30	measured ?

History Matching

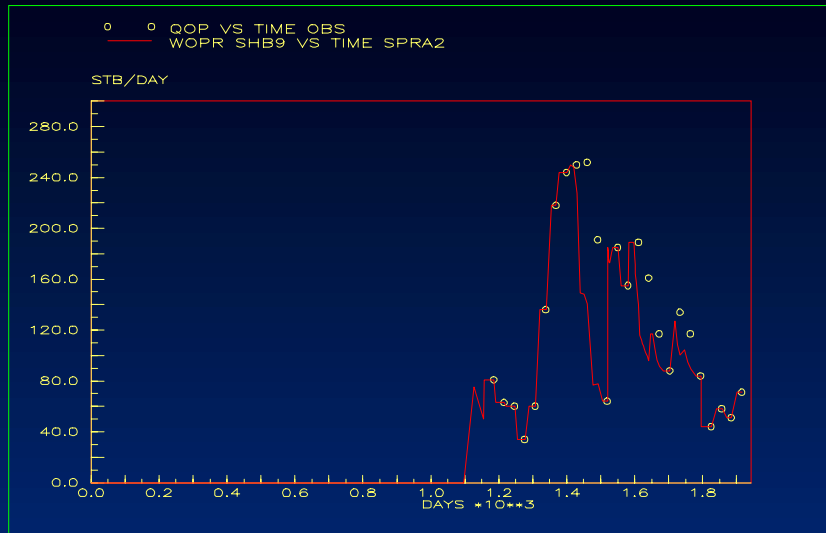


Figure 1 10/09/97 at 11:11:28

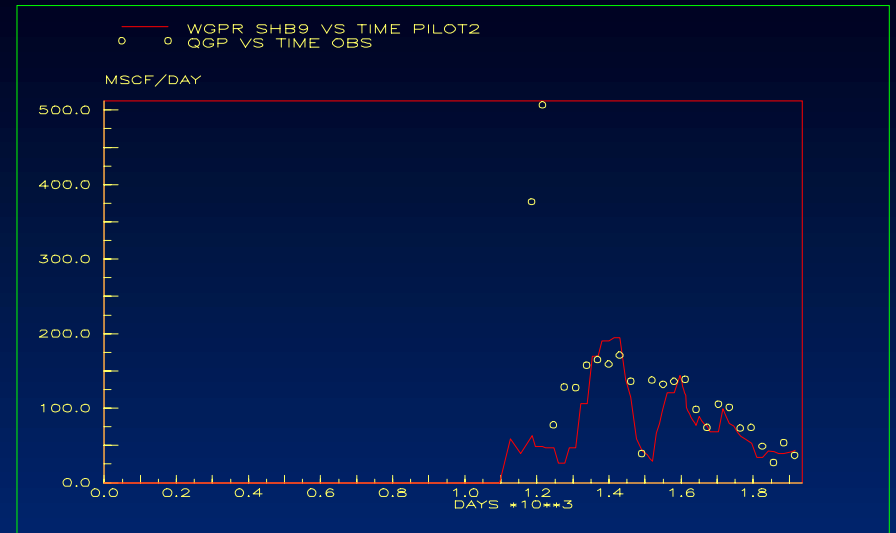


Figure 2 15/09/97 at 13:01:35

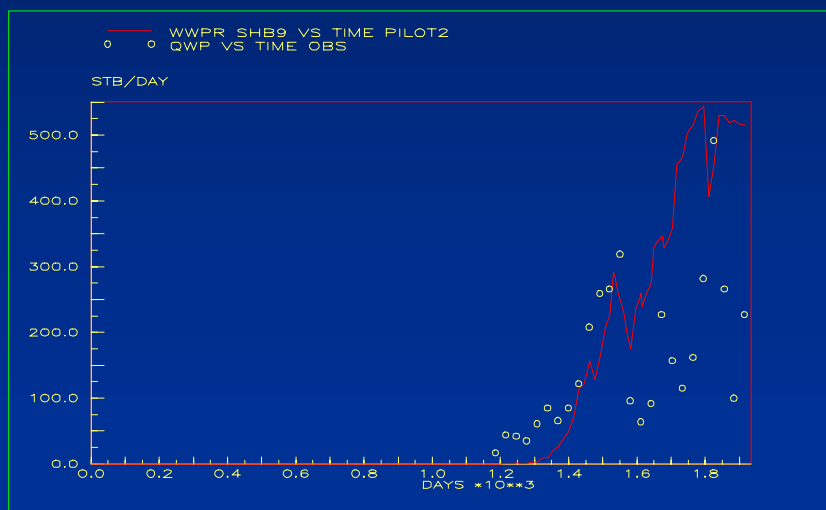


Figure 3 15/09/97 at 13:02:11

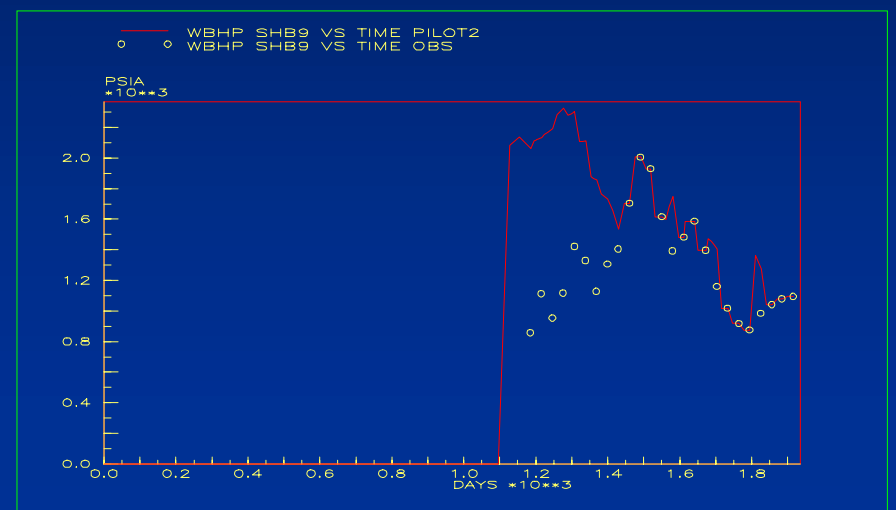
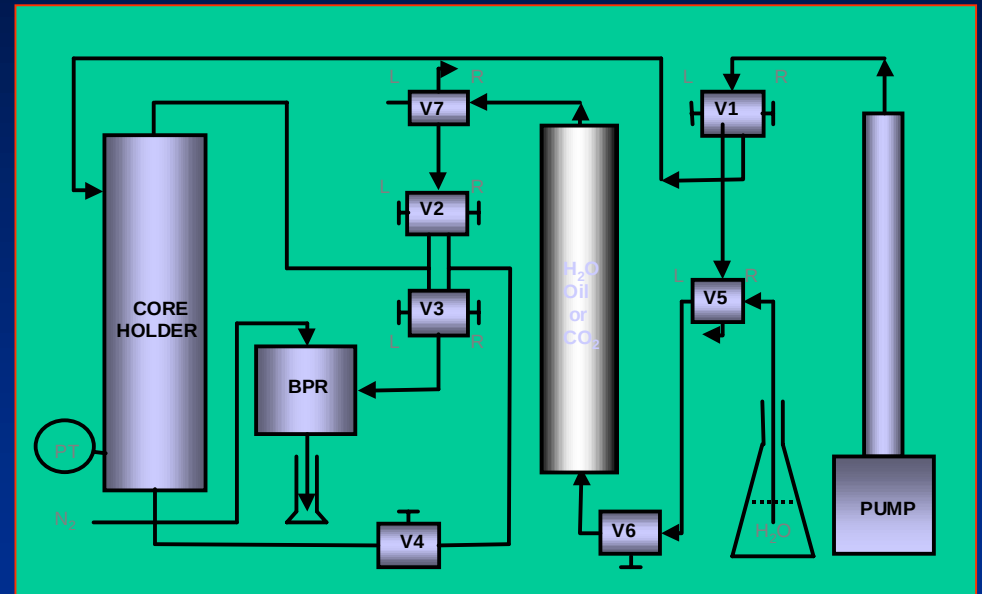


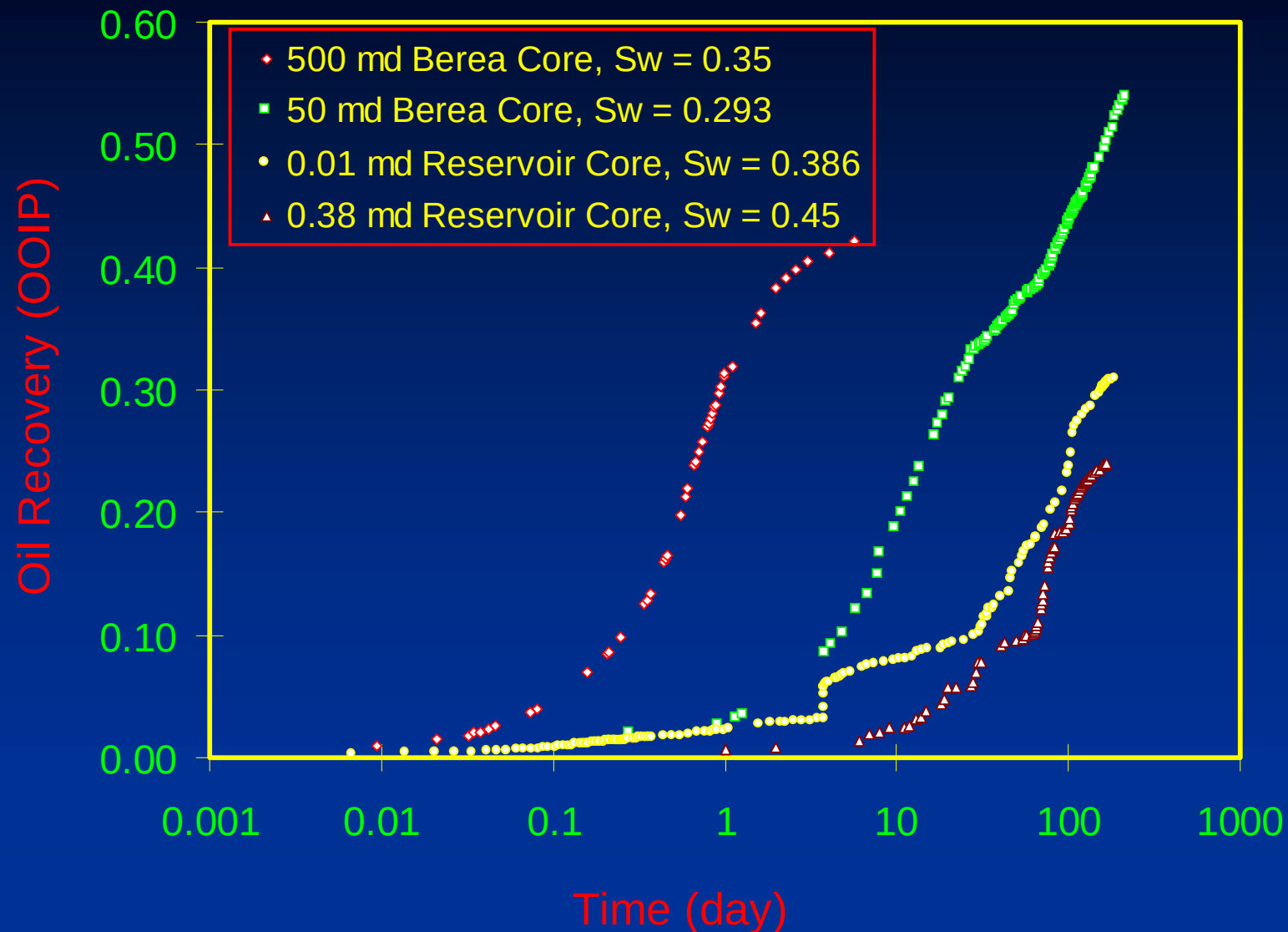
Figure 4 15/09/97 at 13:03:03

Gravity Drainage Experiment

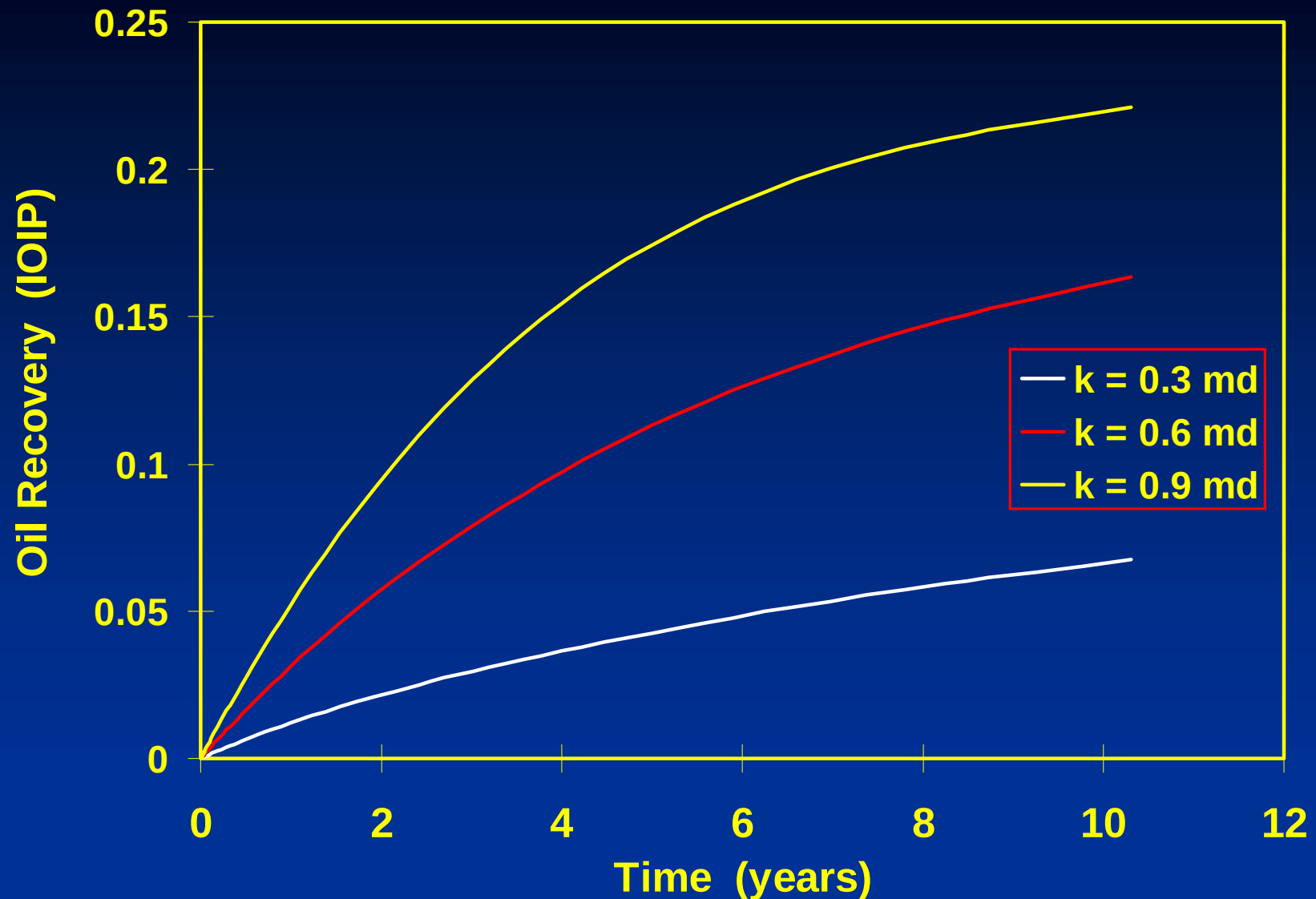


A Schematic Diagram of
Experimental Setup

Oil Recovery from CO₂ Gravity Drainage Experiments



Projection of Oil Recovery for the CO₂ Pilot, Fracture Spacing 3.2 ft, $S_w = 0.38$



Conclusions

- Volume of shale vs. effective porosity cross plots better describe the location of Spraberry pay zones.
- Horizontal cores demonstrate that even a flat lying structure like Spraberry is subject to complicated, multiple fracture sets.

Conclusions ... cont'd

- Wettability determined from capillary pressure, spontaneous oil/brine imbibition and contact angle experiments indicate Spraberry sands are weakly water-wet.
- Scaling imbibition results to the Humble waterflood pilot resulted in good history match.

Conclusions ... cont'd

- Experimental results of CO₂ gravity drainage in reservoir whole core at reservoir conditions indicate that CO₂ will recover additional oil in Spraberry reservoirs.
- CO₂ injection will commence in the next year to test the economic feasibility of CO₂ injection in the naturally fractured Spraberry Trend Area.

DOE Contract DE-FC22-95BC14292

Industrial Sponsors

- Arch Petroleum Co.
- Chevron
- Marathon
- Mobil
- Pioneer Nat. Res.
- Petroglyph Op. Co.

- Texaco

- The Wiser Oil Co.

- Union Pacific

Software Donations

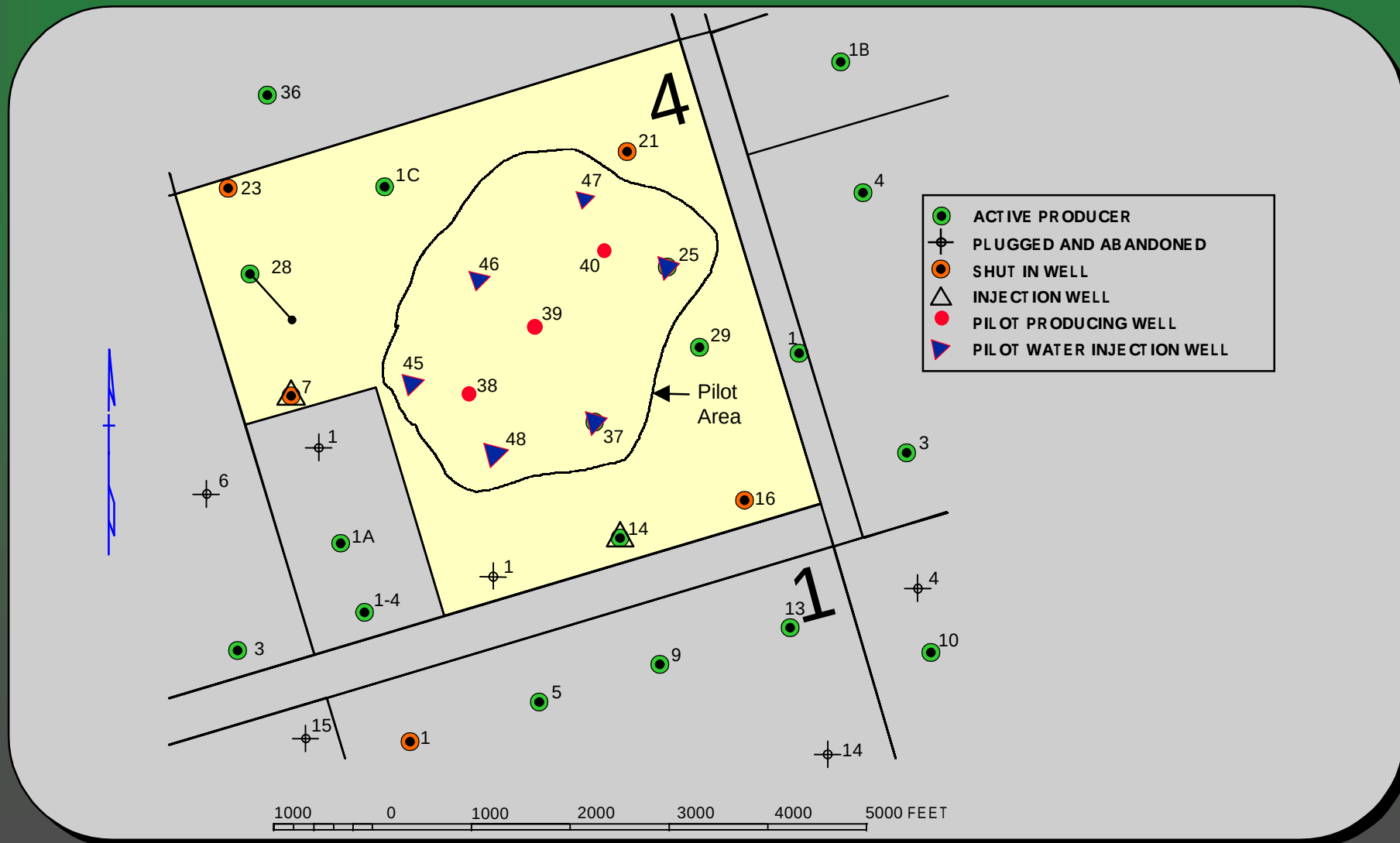
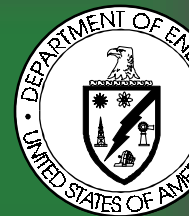
- Geoquest

- (ECLIPSE)

- Geografix (QLA2)

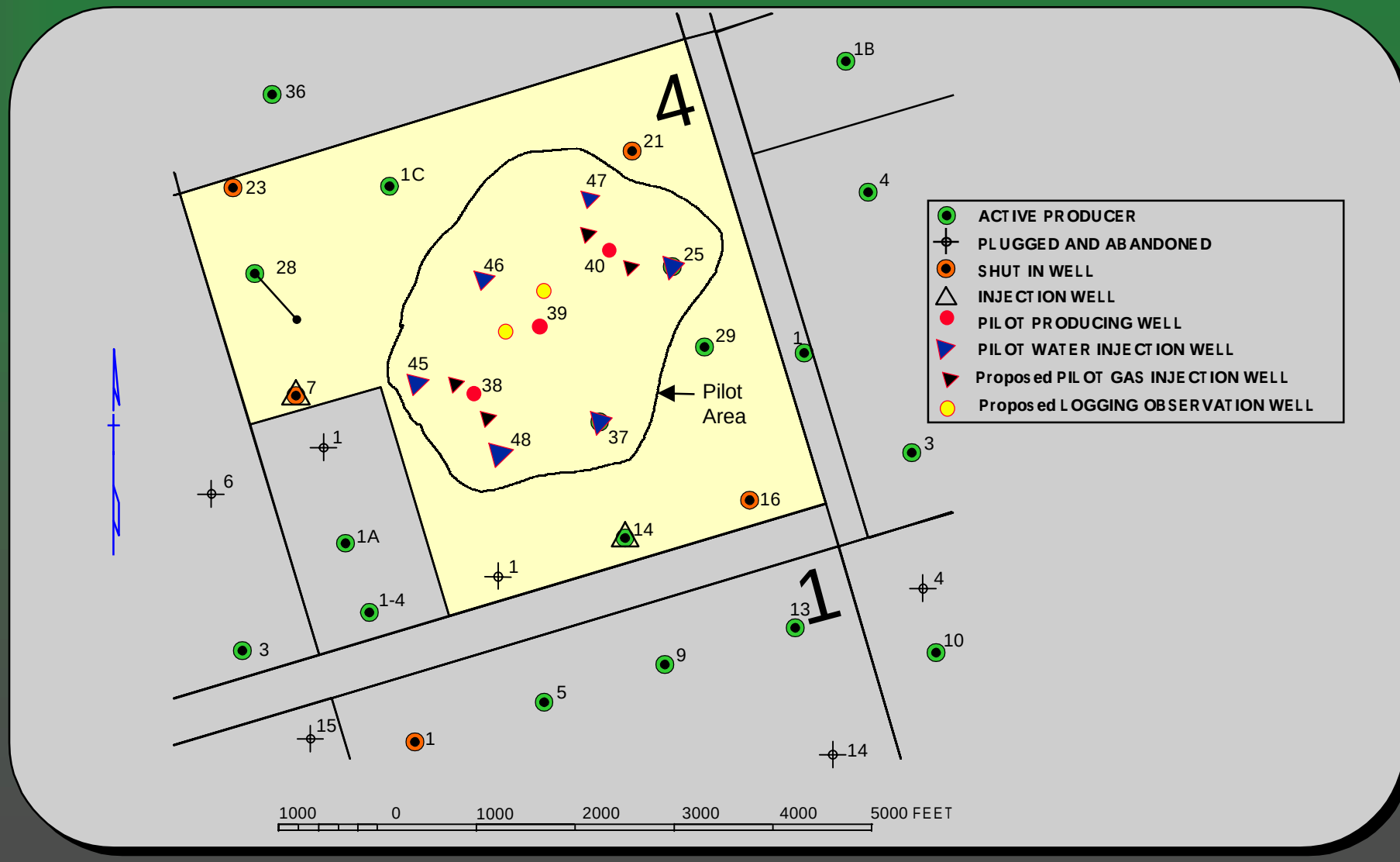
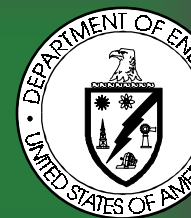


Pilot Design 1998 Drilling



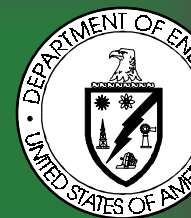


Pilot Design 2000 Drilling





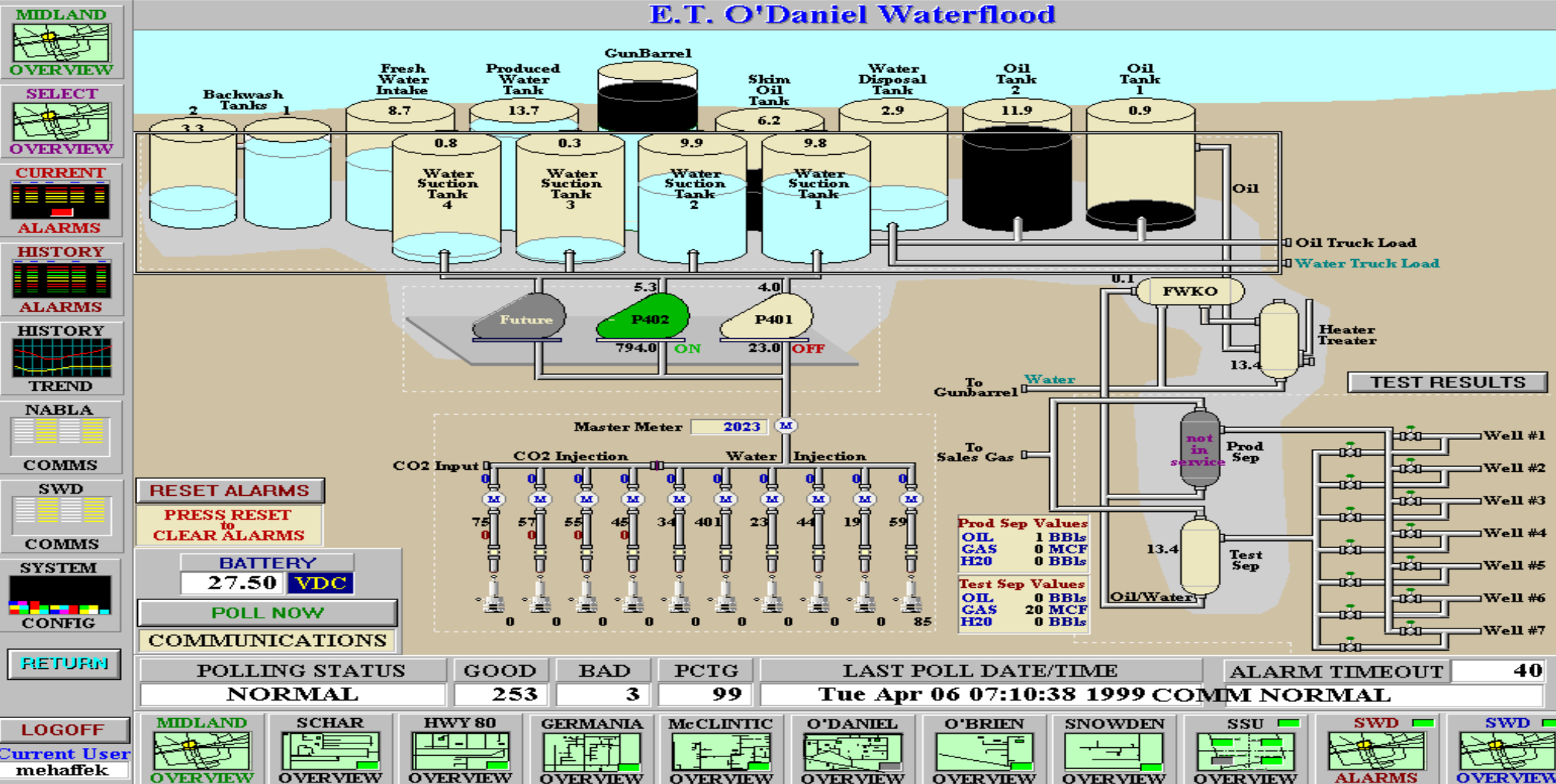
Facility Design



P PIONEER NATURAL RESOURCES USA, INC.

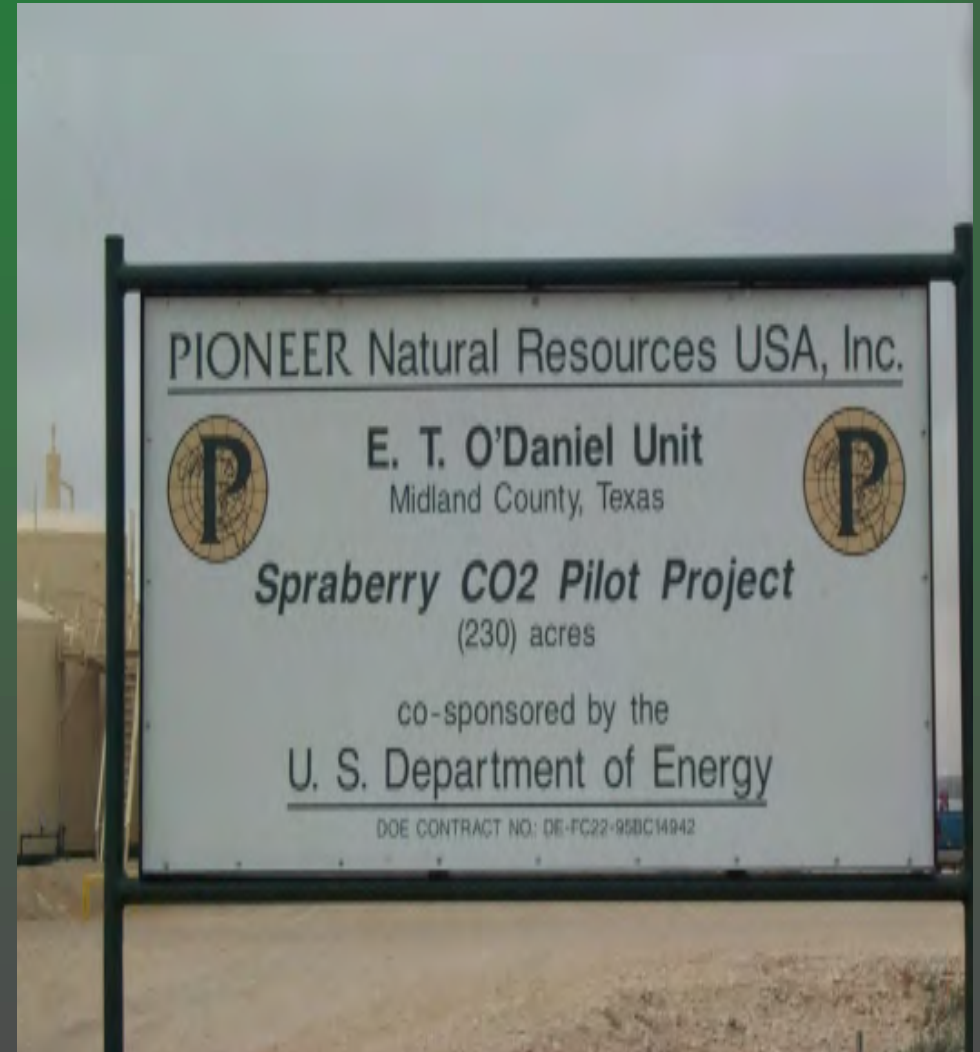
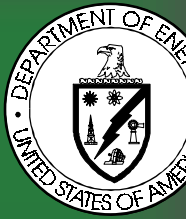
4/6/99
7:28:09

E.T. O'Daniel Waterflood



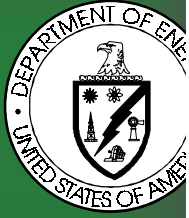


Facility Construction



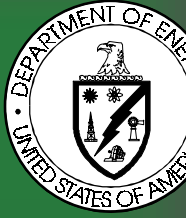


Facility Construction



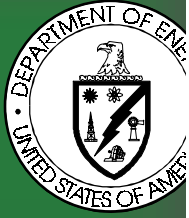


Facility Construction



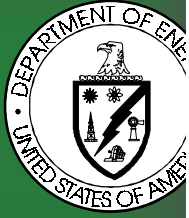


Facility Construction



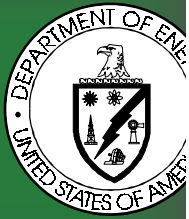


Facility Construction



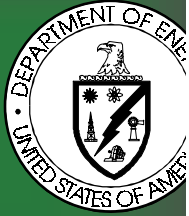


Facility Construction





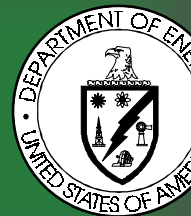
Current Field Testing



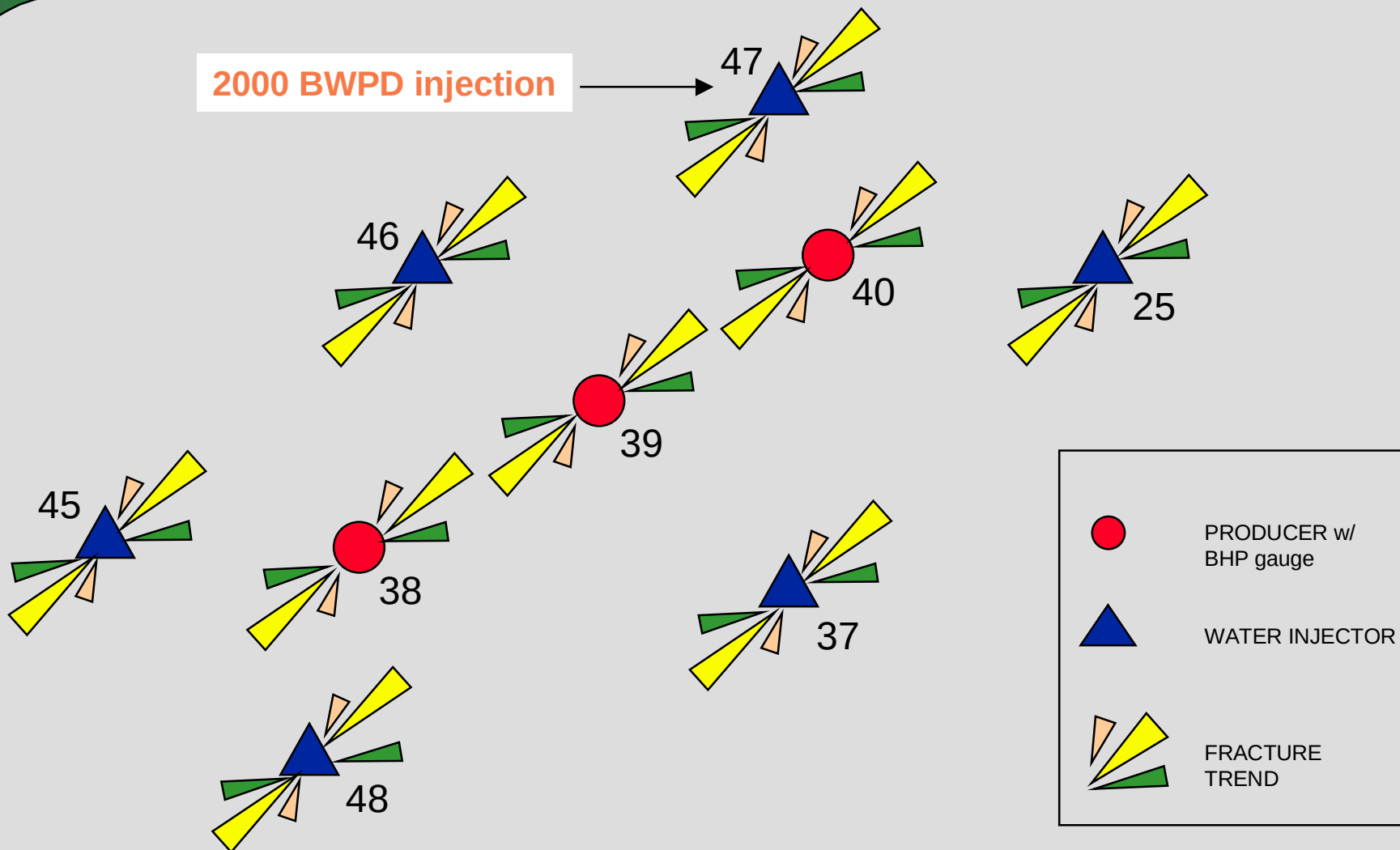
- **Pulse (Interference) Test**
 - provides information as to the fracture orientation, effective permeability and permeability anisotropy
 - in progress
- **Step Rate Injection Test**
 - determines the formation parting pressure
 - #47 WIW ~3200 psig bottom hole pressure
 - #46 WIW ~3050 psig bottom hole pressure
- **Injection Profile Log**
 - determines the injected fluid distribution
 - #47 WIW ~70% water into the 5U and 30% water into the 1U



Pulse Test



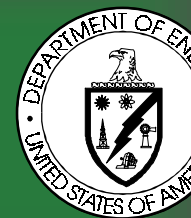
2000 BWPD injection



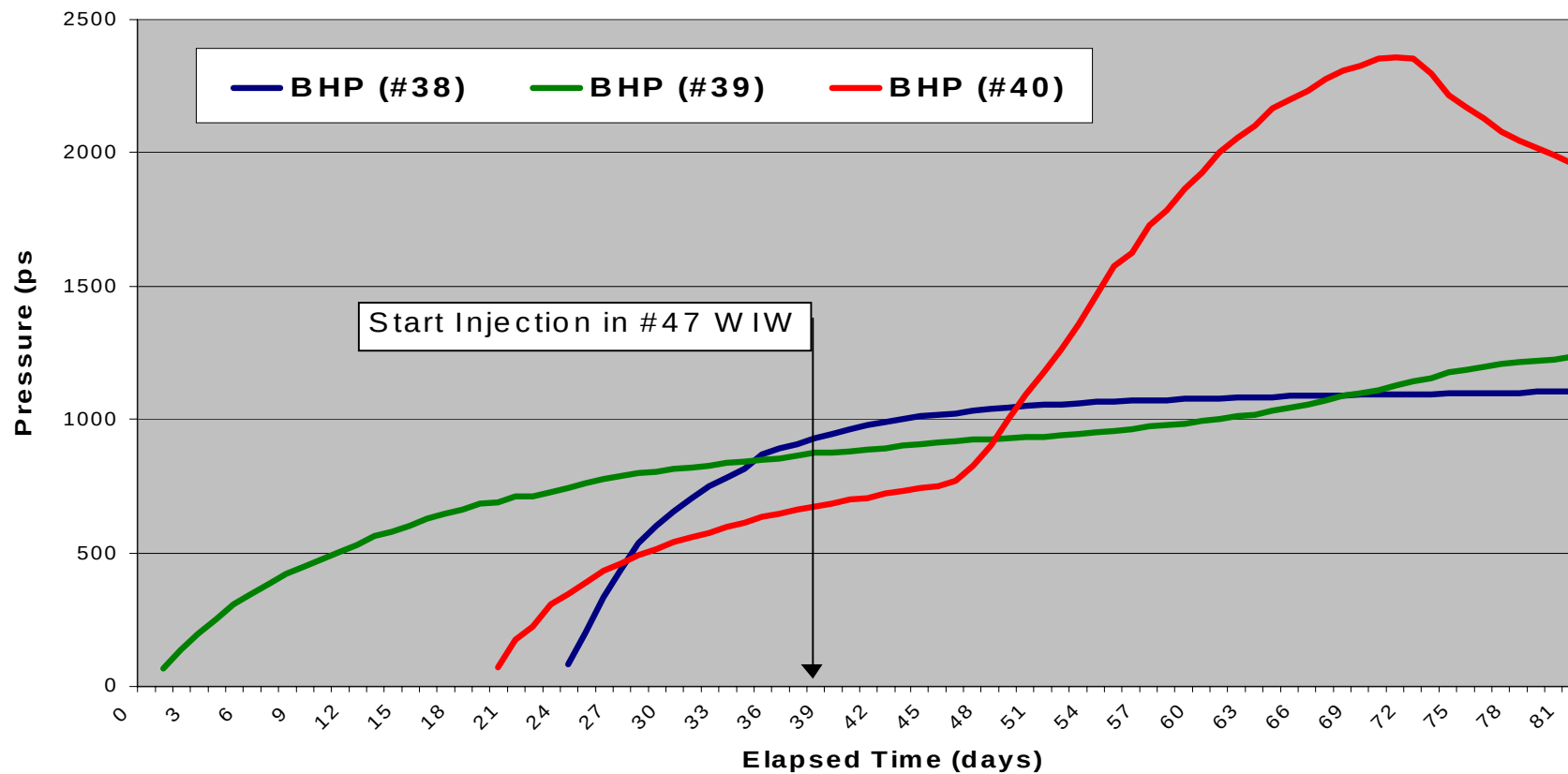


Pulse Test

Pressure Response in Producers



E.T. O'Daniel Pilot Producers BHPBU Overlay



2A.1

Sizing Gelant Treatments in Hydraulically Fractured Production Wells

Randy Seright (randy@prrc.nmt.edu; 505-835-5571)
Jenn-Tai Liang (liang@prrc.nmt.edu; 505-835-5574)

New Mexico Petroleum Recovery Research Center
New Mexico Tech
Socorro, NM 87801

Mailin Seldal (Mailin.Seldal@saga.com; 47-6712-6948)

Saga Petroleum a.s.
Kjorbovn. 16
P.O. Box 490
1300 Sandvika
Norway

Abstract

Often, when production wells are stimulated by hydraulic fracturing, the fracture unintentionally breaks into water zones, causing substantially increased water production. To correct this problem, we developed an engineering basis for designing and sizing gelant treatments in hydraulically fractured production wells. In these treatments, gelant penetrates a short distance from the fracture face into the porous rock associated with both water and hydrocarbon zones. Success for a given treatment requires that the gel reduce permeability to water much more than that to hydrocarbon. We present a simple 11-step procedure for sizing these gelant treatments. This procedure was incorporated in user-friendly graphical-user-interface software that can be downloaded from our web site at <http://baervan/ResSweepEffic/reservoir.htm>.

Sizing Gelant Treatments in Hydraulically Fractured Production Wells

R.S. Seright, Mailin Seldal,* and J. Liang
New Mexico Petroleum Recovery Research Center

(*Mailin Seldal is currently with Saga Petroleum)

E-mail: randy@prrc.nmt.edu

**Financial support is gratefully
acknowledged from the**

**NATIONAL PETROLEUM TECHNOLOGY OFFICE
(U.S. DOE) and**

**ARCO, BP, Chevron, CPC, CNPC, Conoco,
Exxon, Halliburton, Marathon, Norsk Hydro,
Phillips, Saga, Schlumberger, Shell, Statoil, and
Texaco.**

- When production wells are stimulated by hydraulic fracturing, the fracture often extends into water.
- **Gelant treatments can reduce water production.**
- An engineering-based design method for gelant treatments can be found in **SPEPF (Nov. 1998) 223-229** and in free software (**Gel Design**) from **<http://baervan.nmt.edu>**

SIZING GELANT TREATMENTS IN HYDRAULICALLY FRACTURED PRODUCTION WELLS

Previous designs have been strictly empirical:

- **1/2 to 1 day's production volume.**
- **Certain volume per foot of pay.**
- **Volume to achieve a certain radius from the well.**

Need an engineering-based approach to sizing.

DESIGN PROCEDURES SHOULD VARY WITH THE TYPE OF PROBLEM BEING TREATED:

- Flow behind pipe.
- Unfractured wells where crossflow cannot occur.
- Unfractured wells where crossflow can occur.
 - Hydraulically fractured wells.
 - Wells in naturally fractured reservoirs.

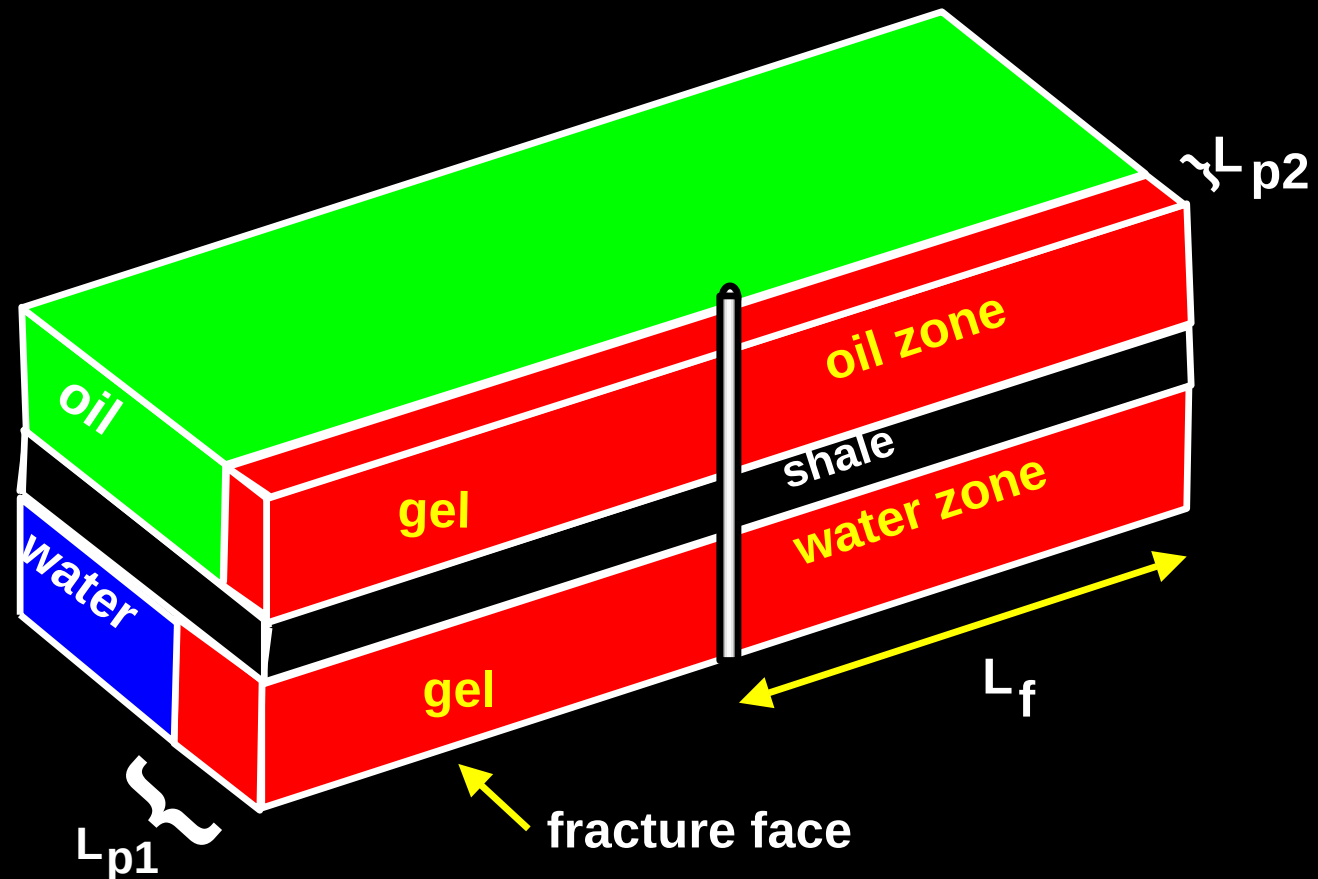
SIZING GELANT TREATMENTS IN HYDRAULICALLY FRACTURED PRODUCTION WELLS

Our design:

- **is based on sound engineering concepts.**
 - **involves a simple 11-step procedure.**
 - **software is available for easy application.**
- **is specific to hydraulically fractured production wells.**
 - **assumes that gelants are used.**
- **neglects the effects of gel in the fracture itself.**

Objective: Reduce water entry into the fracture without significantly reducing oil productivity.

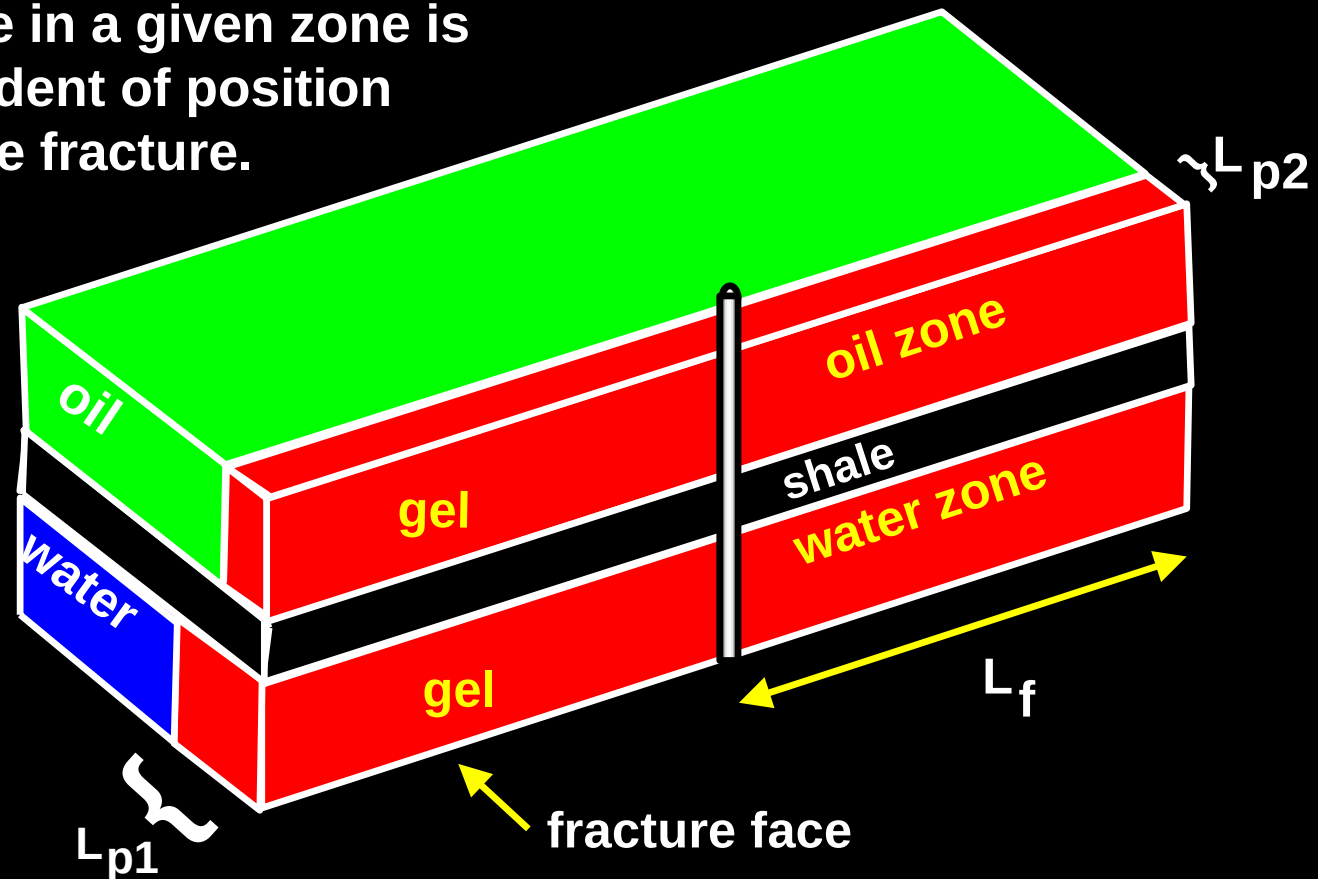
- Gelant flows rapidly along the fracture and leaks off a short distance into the porous rock in all fractured zones.
- Gel reduces permeability to water much more than that to oil.



Objective: Reduce water entry into the fracture without significantly reducing oil productivity.

METHOD ASSUMES:

- restriction to flow caused by gel in the porous rock is large compared to that caused by gel in the fracture.
- leakoff rate in a given zone is independent of position along the fracture.



SIZING GELANT TREATMENTS IN HYDRAULICALLY FRACTURED PRODUCTION WELLS

Documentation:

- ***SPE Production & Facilities, Nov. 1998, 223-229.***
- ***DOE Report DOE/PC/91008-4, 33-49 & 151-155.***

Software can be downloaded from:

- **www.baervan.nmt.edu/ResSweepEffic/reservoir.htm.**
- **Push the "Gel Design" hot key for the download.**
- **Only works for PC's (Windows 95, 98, NT).**

Program & Copyright Information



GelDesign Version 1.07

Copyright 1999

New Mexico Petroleum Recovery Research Center

Program Information

This program is for sizing treatments in
hydraulically fractured production wells.

Contact Information

Jenn-Tai Liang (505) 835-5574

Randy Seright (505) 835-5571

Continue

Exit

Candidate Selection Criteria For Hydraulically Fractured Production Wells

1. J/J_o is greater than 5.
where:
J is the actual well productivity.
J_o is the productivity of an unfractured and undamaged well.
2. High WOR.
3. Fracture cuts through distinct water and hydrocarbon zones.
4. Barriers to vertical flow exist except in the fracture.
5. A satisfactory mobile oil target exists.

Continue

Exit

Well and Reservoir Parameters



Please enter the following well parameters:

	<u>Default</u>	
Total Number of Layers:	(<u>2</u>)	Next
Well Spacing (acres):		
Wellbore Radius (ft):	(<u>40</u>)	
Oil Production Rate (BOPD):		Reset
Water Production Rate (BWPD):	(<u>0.5</u>)	
Downhole Pressure Drop (psi):		

10

1000

50

Exit

Fluid Properties



Please provide the following fluid properties:

Default

Reservoir Temperature:



Reservoir Brine Viscosity (cp):

(1 cp or calculated
w/Temp.)

Crude Oil Viscosity (cp):

Gelant Viscosity (cp):

(1 cp)

(20 cp)

Previous

Next

Reset

Cancel

Rock Properties



Enter Rock Properties for Layer 1:

	<u>Default</u>	
Absolute Permeability (md):	100	Please Check One Water Zone Oil Zone
Endpoint Brine Permeability (md):	10	
Porosity:	0.2	
Layer Thickness (ft):	0	
Residual Oil Saturation (Sor):	20	
	0.3	

Previous

Next Layer

Reset

Cancel

Rock Properties



Enter Rock Properties for Layer 2:

Default

Absolute Permeability

(md)

100

(equal to
absolute k)

Endpoint Oil

Permeability (md)

(0.2)

Porosity:

Layer Thickness (ft)

(0.3)

Residual Oil Saturation

(Sor)

20

Please Check One
Water Zone
Oil Zone

☐☒

Previous Layer

Finish

Reset

Cancel

Gelant Volume Calculation



Target Final Oil
Productivity Loss (%): Default
(10%)

Downhole Pressure Drop
After Treatment (psi): Same as Before
Treatment

Brine Residual Resistance
Factor (Frrw):

Oil Residual Resistance
Factor (Frro):

Calculate gelant
volume required?

Gel Design



Calculate Gelant Volume Required

Back Calculate Frrs from Field Data

Previous

Cancel

STOP



This is not a good candidate well ($J/J_o < 5$).

SUGGESTION: You might try a significantly lower downhole pressure drop (before the treatment).

OK

Treatment-Design Parameters

Target Oil Productivity Loss (%) 10
Brine Residual Resistance Factor (Fr_{rw}) 10100
Oil Residual Resistance Factor (Fr_{ro}) 14
J/Jo Before Treatment 9
Volume of Gelant Required (bbl) 4152

Treatment Results

	<u>Before Treatment</u>	<u>After Treatment</u>
Total Production Rate (bbl/D) =	<u>1010</u>	<u>45.5</u>
Producing Water Oil Ratio (WOR) =	<u>100</u>	<u>4.1</u>
Oil Production Rate (bbl/D) =	<u>10</u>	<u>9</u>
Water Production Rate (bbl/D) =	<u>1000</u>	<u>36.5</u>

Previous**Print****Next Case****Sensitivity Analysis****Restart****Exit**

Sensitivity Analysis

X

Effect of Amount of Gelant Injected

Effect of Frrw and Frro

Previous Page

Next Case

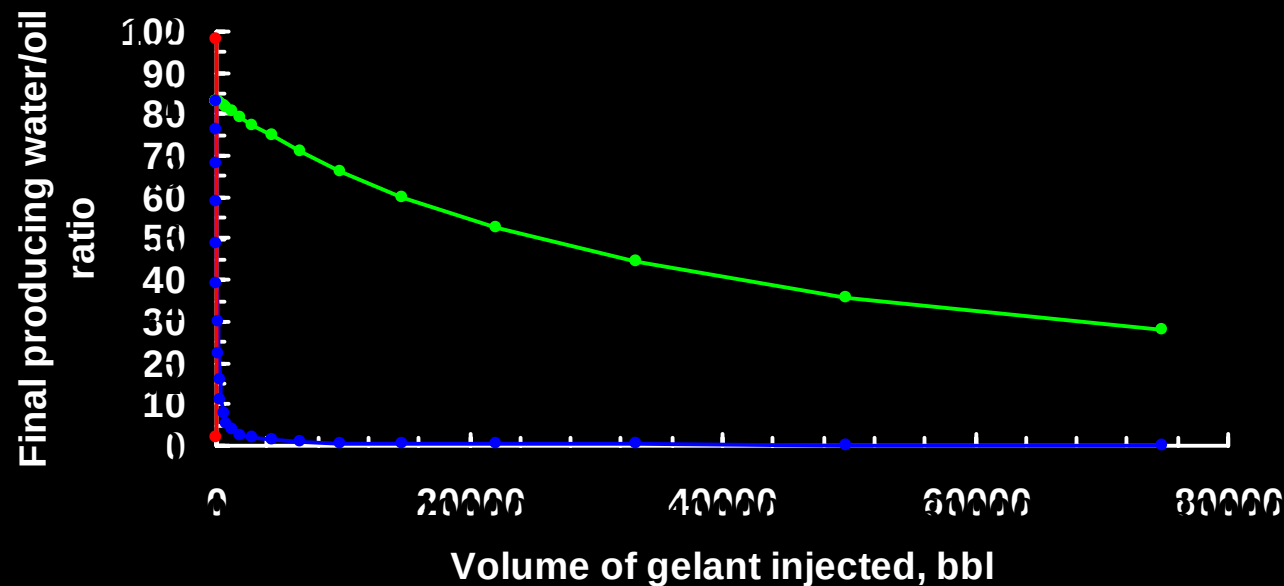
Restart

Exit Program

Effect of Gelant Volume on Treatment Results



Effect of Gelant Volume on WOR and Oil Productivity Loss



 Final WOR

 Oil productivity, final/initial

 Your design

$F_{rrw} = 10100$

$F_{rro} = 14$

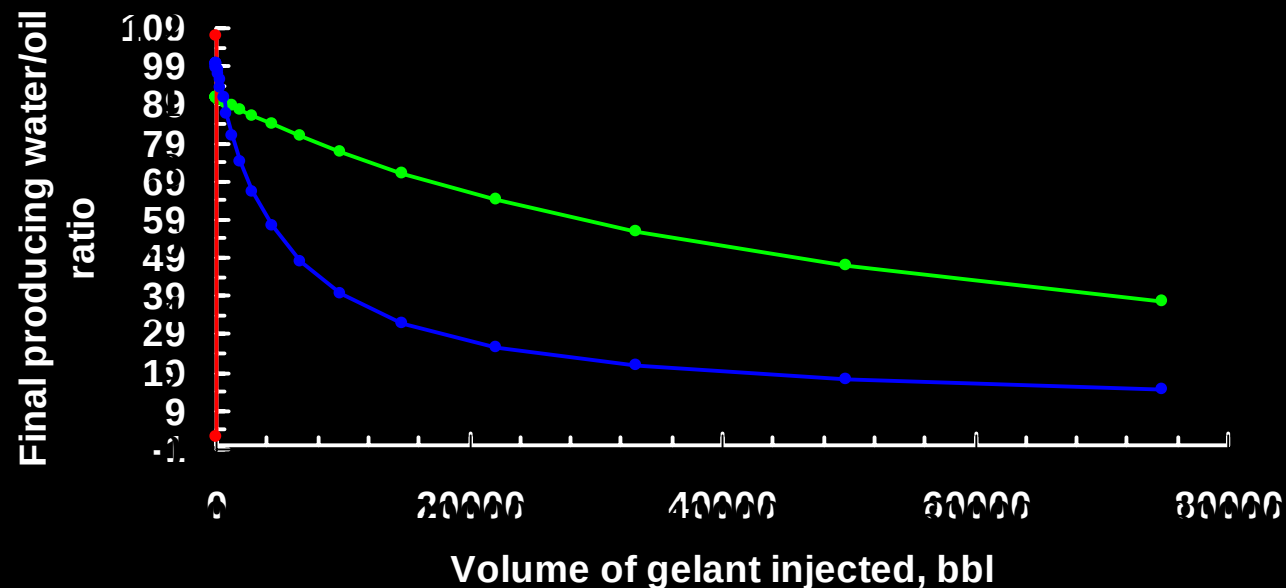
Your design (bbls of gelant) = 4152

[Previous](#)

[Print](#)

[Exit](#)

Effect of Frrw and Frro on WOR and Oil Productivity Loss



Final WOR

Oil productivity, final/initial

Your design

Frrw = 100

Frro = 10

Your design (bbls of gelant) = 5997

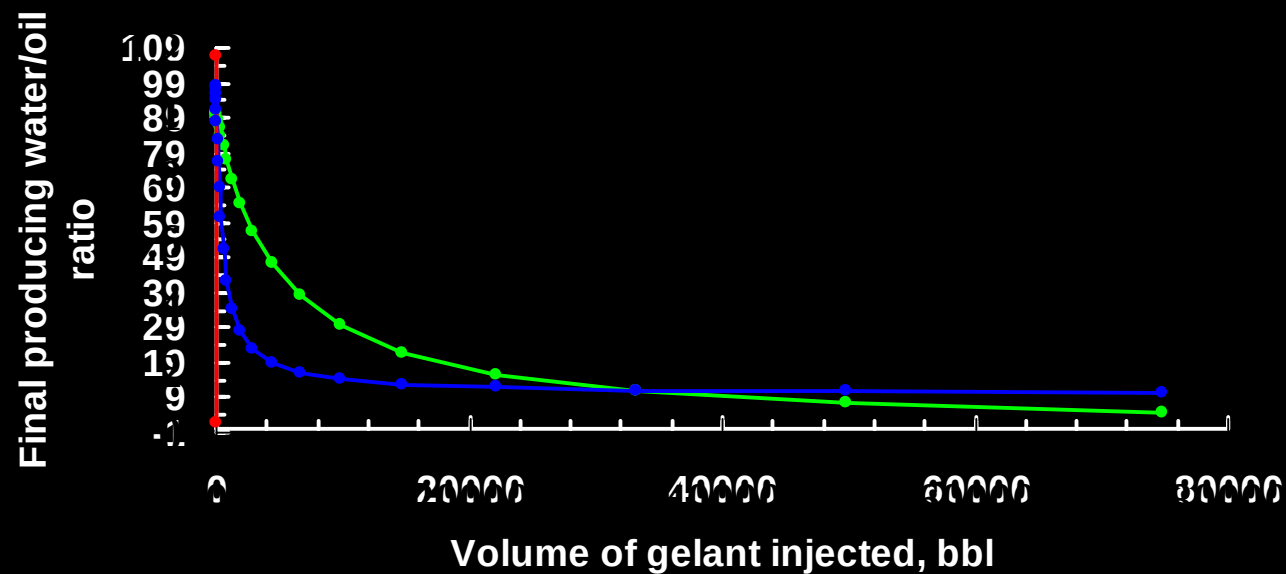
Previous

Print

Exit

Update Design

Effect of Fr_{rw} and Fr_{ro} on WOR and Oil Productivity Loss



■ Final WOR

■ Oil productivity, final/initial

■ Your design

Fr_{rw} = 1000

Fr_{ro} = 100

Your design (bbls of gelant) = 545

Previous

Print

Exit

Update Design

Gel Design



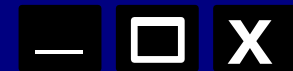
Calculate Gelant Volume Required

Back Calculate Frrs from Field Data

Previous

Cancel

Frrw & Frro Calculations From Field Data



Please provide the following data:

Volume of Gelant Injected (bbls)

Oil Production Rate After Treatment (BOPD):

Water Production Rate After Treatment (BWPD)

Downhole Pressure Drop After Treatment (psi):

Calculate Frrw and Frro?

Yes

Reset

Previous

Exit

Results from Frrw & Frro Calculations



The following Frrw and Frro values were calculated by the program based on the field data that you provided:

Frrw = 22256

Frro = 244

Next Case

Restart

Exit

CONCLUSIONS

- A procedure has been developed to size gelant treatments in hydraulically fractured production wells.
 - The procedure has been incorporated in user-friendly graphical-user-interface software.
- In the absence of water and oil residual resistance factors, the method can be used to calculate in-situ F_{rrw} and F_{rro} values.
- To properly use and test the procedure, F_{rrw} and F_{rro} values must be determined from laboratory corefloods or from in-situ values from a nearby field application.

SPE 39416

Increasing Production and Profitability by use of a Computer Monitoring Program

Jerry James, SPE, and Gene Huck, SPE, James Engineering, Inc.

Copyright 1997, Society of Petroleum Engineers, Inc.

This paper was prepared for presentation at the 1997 SPE Eastern Regional Meeting held in Lexington, KY, 22-24 October 1997.

This paper was selected for presentation by an SPE Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Papers presented at SPE meetings are subject to publication review by Editorial Committees of the Society of Petroleum Engineers. Electronic reproduction, distribution, or storage of any part of this paper for commercial purposes without the written consent of the Society of Petroleum Engineers is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of where and by whom the paper was presented. Write Librarian, SPE, P.O. Box 833836, Richardson, TX 75083-3836, U.S.A., fax 01-972-952-9435.

Abstract

Profitability is normally maximized from oil and gas properties when maximum production rates are consistently obtained. The computer program discussed in this paper has been developed to help small operators realize that goal with a minimal time investment.

Introduction

This paper describes a software application that enables users to increase field profitability by analyzing monthly oil and gas production rates. Profitability is almost always increased from oil and gas properties when maximum production is obtained from every well. However, many managers charged with maximizing well performance do not have time to properly monitor each well to ensure production is maximized at all times. This project addresses this problem with the development of a user-friendly computer program that compares actual production volumes to forecasted production rates and alerts the user to wells that fall short of forecasted rates. The case study is comprised of 250 wells located in the State of Ohio. This group contains examples of wells that have under-produced at various times because of failure to detect and respond to decreases in production.

This program, called *Priority*, helps users quickly identify opportunities to maximize field profitability. By comparing actual oil and gas production volumes to forecasted producing rates for a specific production period, the program generates a discrepancy report which can rank the wells in order of the greatest production deficiency to identify wells that require attention. The program utilizes production forecast information imported from commercially available reserve/

evaluation software, but can also be utilized by companies that have access to spreadsheet software only.

This project was specifically developed for small operators in a cost sharing venture between James Engineering, Inc. and BDM-Oklahoma under the requirement entitled, "Research and Development by Small, Independent Petroleum Operators to Provide solutions towards Production Problems." BDM-Oklahoma is the management and operating contractor for DOE's National Oil and Related Programs under prime contract DE-AC22-94PC91008. The program will be available on the National Petroleum Technology Office (NPTO) Website (www.npto.doc.gov); the DOE program is under the supervision of Dr. Betty Felber.

Historical Monitoring Methods

After years of performing reserve evaluations on thousands of wells for numerous operators, experience indicates that operators often struggle to maintain maximum well production rates. Many operators monitor well performance but fail to achieve maximum production rates consistently. Current monitoring methods and their deficiencies are reviewed below.

The simplest method relies on the pumper to report decreases in production. This method often fails because pumpers are burdened with day-to-day activities and have insufficient information to develop a long-term production perspective. Therefore, many times gradual declines in production are not observed.

A second method consists of a tabular comparison of current monthly production to the previous month's production. This type of monitoring employs too short a time period and does not establish a production goal. Gradual declines in production can again be easily missed.

Another method employs a percentage rule. To identify problem wells, the monitoring system compares current production to the previous month's production but does not take action unless the downward variance exceeds, for instance, 10%. This type of monitoring again employs too short a time period and also does not establish a production goal. The 10% example above would allow a well to decline 5% each month over a period of time and have a significant production loss without tripping the percentage limit.

The most refined method is a sophisticated computerized

system used by some large independents and majors. This system utilizes production goals to compare with current producing rates. These systems collect and report vast quantities of information requiring so much time that the program is not always executed effectively. If the report is too burdensome, the goal becomes completing the report rather than identifying and acting upon the decreases in production. The monitoring program can work to identify a problem, but often lacks the follow-through in the implementation stage. This method may be impractical for the small, independent producer.

The first three methods identify large decreases in production, but often miss smaller decreases which can lead to significant losses in revenue. The last method, while in theory is workable, can be too burdensome for independents with small staffs to implement.

An Easier To Use Monitoring Method

Priority is a simplified software application that addresses the shortfall of the historical monitoring methods by comparing actual production volumes to production goals. The software uses actual measured production volumes as soon as they are available, to identify wells that fall short of these goals. This allows the user to prioritize the production deficits and provides the needed information to the field.

In this study, production histories were reviewed and analyzed to establish a reasonable forecast for each well. Production goals were set using Aries® software. This step made production input and forecasting relatively easy. *Priority* can utilize forecast information from forecasting programs or forecasts taken from simple hand plots of tabular information. In either case, a graphical presentation of the production history is recommended for forecasting purposes.

Prorated sales volumes have historically been plotted and were initially utilized for production comparisons. Integration volumes were eventually utilized to shorten the time between when a decrease in production is detected and the problem is addressed.

The program using the Aries® reverse-evaluation software follows path A in the Flowchart. Spreadsheet programs follow path B in the Flowchart.

Using a spreadsheet program, the wells with established production should have forecasted rates adjusted quarterly, newer wells should be adjusted monthly.

After the production data is imported, *Priority* permits the data to be sorted by negative variance and then printed out by area or pumper. An example of the printout is shown in Table 1.

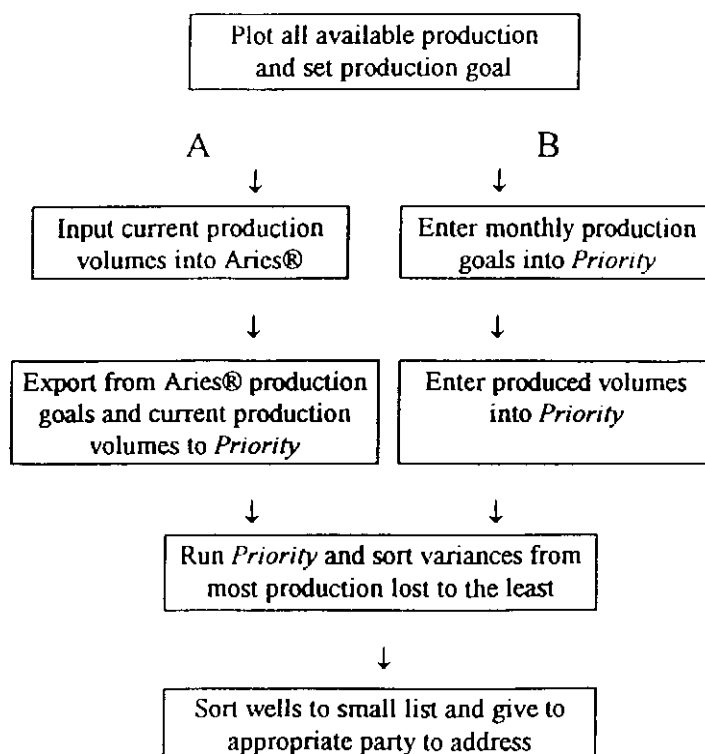
A number of the wells in the study group experienced abnormal production declines detected by the program. These wells appear to have been reasonably well produced by different operators over the years, but decreases in production were still undetected. Review of the 250 well study group indicates the vast majority of the wells have experienced some

underproduction for at least a period of one year during their lives.

The production histories have been included for three wells and are presented in figures 1, 2 and 3. In all three examples, the stabilized production declines were interrupted by decreases in production which went undetected or uncorrected for several years. Using *Priority*, the decreases were detected and corrective measures were implemented, which allowed the wells to be returned to expected production rates. The shaded portion below the projected performance line for each well represents the amount of underproduction. The H. Anderson No. 1 underproduced 11,658 mcf from 1989 to 1997. This represents revenue of \$29,145 (at \$2.50 per mcf). The A. Carter No. 1 underproduced 28,785 mcf from 1983 to 1997 representing revenue of \$71,963. The E. Wilson No. 1 underproduced 9421 mcf from 1994 to 1997, representing revenue of \$23,553.

The program was implemented in the middle of 1996. During a five month production period at the end of 1996 and the beginning of 1997, a total production for the 250 wells increased by approximately 5 ½ % over the same period in 1995 and 1996. It should be noted that the nominal decline for these wells is approximately 6 % per year. Small operators with similar opportunities can realize substantial economic benefit by simply investing a few hours each month to run the *Priority* Program.

Flowchart



Conclusions

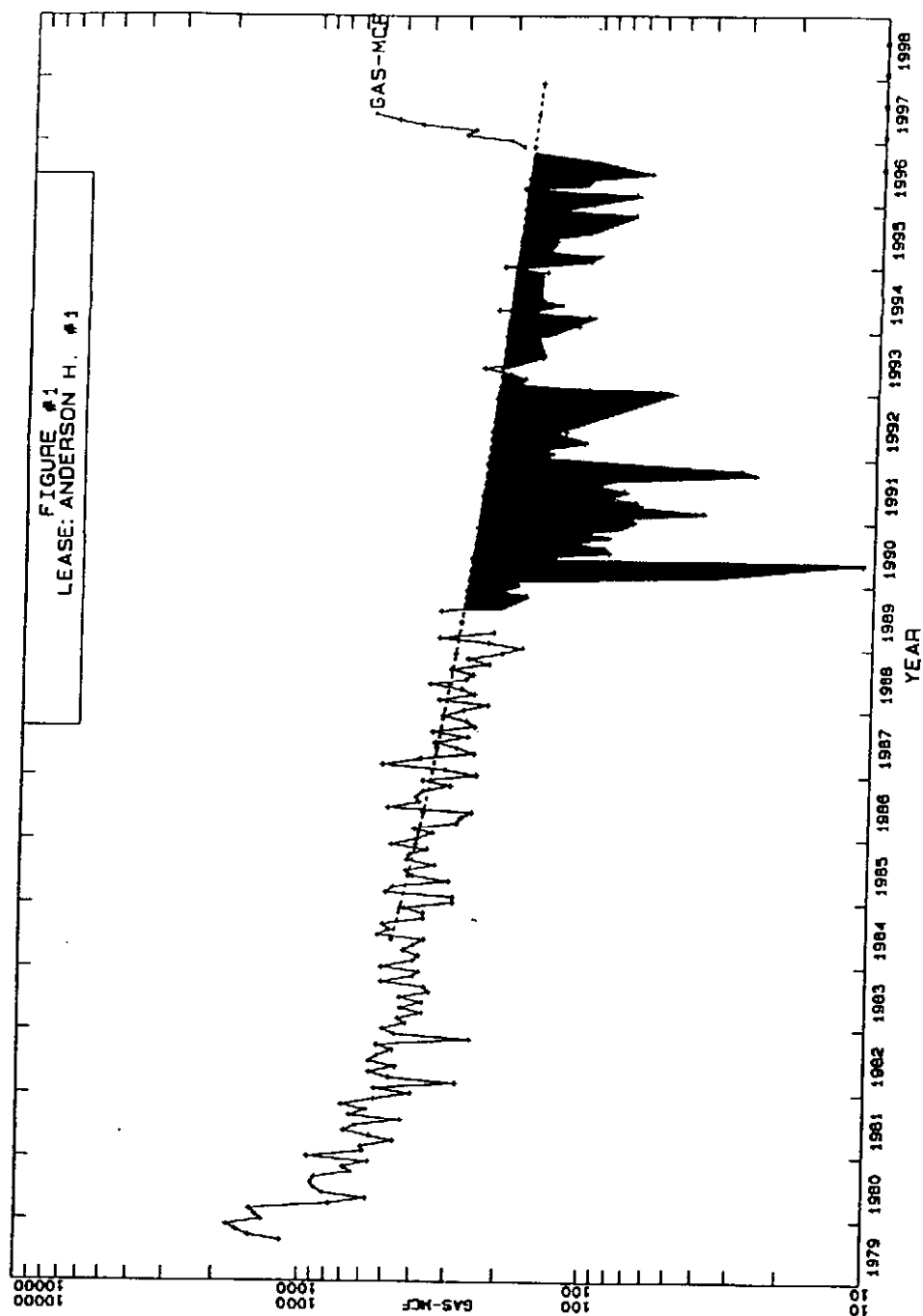
The *Priority* program is a simplistic management tool that enables users to identify problems and maximize production with a minimal time investment. *Priority* effectively identifies wells with production rates that vary from forecasted production goals. The program continues to remind the user of wells being underproduced until the problem is corrected or the production goal is changed. The examples provided demonstrate that users can gain significant economic benefit from this program with a small investment of their time.

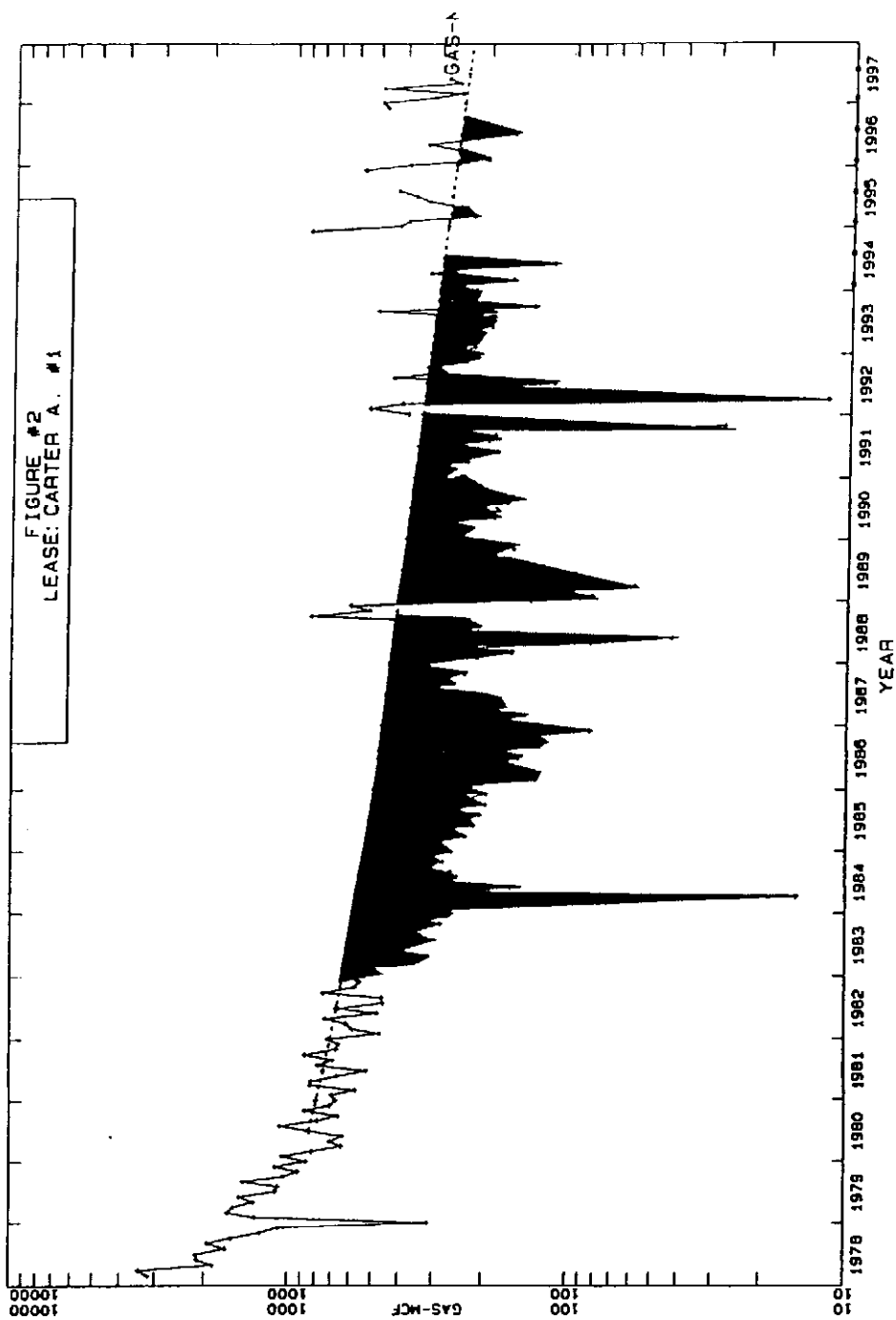
PRODUCTION MONITORING SYSTEM

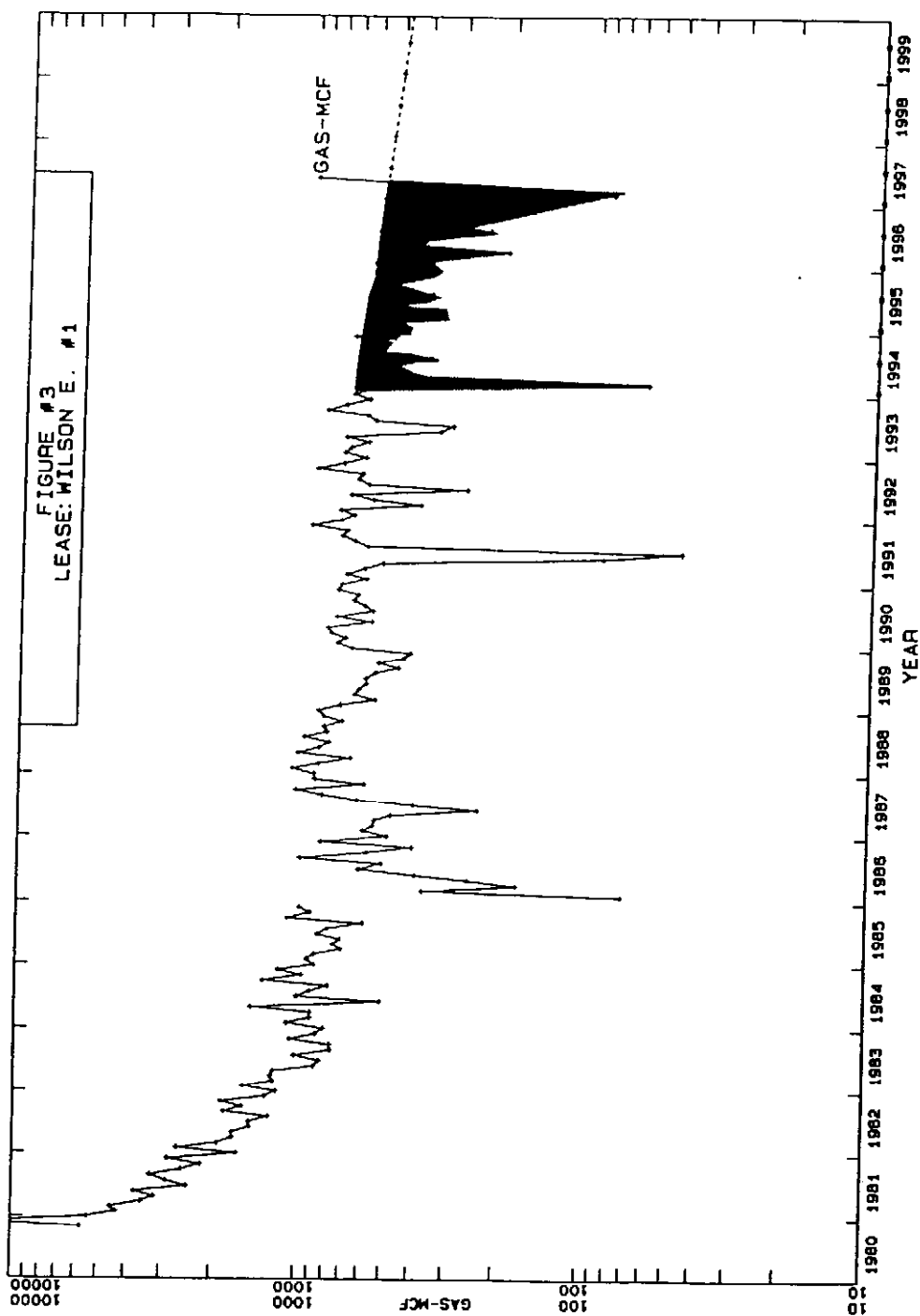
Evaluation for Production Month of: May 1997 INTEGRATED

WELL ID	WELL NAME	PUMPER	PIPELINE	PRODUCING METHOD	ACTUAL PROD.		FORECASTED PROD.		PROD. VARIANCE	
					(MCFM)	(BOPM)	(MCFM)	(BOPM)	(MCFM)	(BOPM)
2316355	GLASS #2	GG	A303	R	779		1041	1	-262	-1
2572961	KERR P. #1	GG	6033	R	15		262	0	-247	0
2572852	RIDENOUR G. #1	GG	A303	R	43		262	0	-219	0
2572683	LORENTZ #1	GG	A303	R	49		188	0	-139	0
2572613	GASSER #1	GG	A303		169		306	4	-137	-4
2573150	ANDERSON - MIZER #1	GG	A303	R	0	0	123	0	-123	0
2572936	SULZENER UNIT #1	GG	A303	R	12		124	0	-112	0
2572614	BUEHLER #1	GG	A291	S	91		179	0	-88	0
2573002	HANNI M. #1	GG	6033	R	62		118	0	-56	0
2573060	GANT UNIT #1	GG	A303	R	117		157	1	-40	-1
2572620	JOHN #1	GG	A303	R	137		161	0	-24	0
2573056	WAYNE FARMS #1	GG	A303	R	56		80	0	-24	0
2572950	BROWN G. #1	GG	A302	R	88		101	0	-13	0
2572646	EMIG #1	GG	5344	R	206		218	1	-12	-1

Table 1







Increasing Production and Profitability by Use of a Computer Monitoring Program

SPE 39416

Jerry James (jameseng@ee.net; 740-373-9521)
Gene Huck (740-373-9521)
James Engineering, Inc.
231 Third Street
Marietta, OH 45750

Abstract

Profitability is normally maximized from oil and gas properties when maximum production rates are consistently obtained. The computer program discussed in this paper has been developed to help small operators realize that goal with a minimal time investment.

Introduction

This paper describes a software application that enables users to increase field profitability by analyzing monthly oil and gas production rates. Profitability is almost always increased from oil and gas properties when maximum production is obtained from every well. However, many managers charged with maximizing well performance do not have time to properly monitor each well to ensure production is maximized at all times. This project addresses this problem with the development of a user-friendly computer program that compares actual production volumes to forecasted production rates and alerts the user to wells that fall short of forecasted rates. The case study is comprised of 250 wells located in the State of Ohio. This group contains examples of wells that have under-produced at various times because of failure to detect and respond to decreases in production.

This program, called *Priority*, helps users quickly identify opportunities to maximize field profitability. By comparing actual oil and gas production volumes to forecasted producing rates for a specific production period, the program generates a discrepancy report which can rank the wells in order of the greatest production deficiency to identify wells that require attention. The program utilizes production forecast information imported from commercially available reserve/evaluation software, but can also be utilized by companies that have access to spreadsheet software only.

This project was specifically developed for small operators in a cost sharing venture between James Engineering, Inc. and BDM-Oklahoma under the requirement entitled, "Research and Development by Small, Independent Petroleum Operators to Provide solutions towards Production Problems." BDM-Oklahoma is the management and operating contractor for DOE's National Oil and Related Programs under prime contract DE-AC22-94PC91008. The program

will be available on the National Petroleum Technology Office (NPTO) Website (www.npto.doe.gov); the DOE program is under the supervision of Dr. Betty Felber.

Historical Monitoring Methods

After years of performing reserve evaluations on thousands of wells for numerous operators, experience indicates that operators often struggle to maintain maximum well production rates. Many operators monitor well performance but fail to achieve maximum production rates consistently. Current monitoring methods and their deficiencies are reviewed below.

The simplest method relies on the pumper to report decreases in production. This method often fails because bumpers are burdened with day-to-day activities and have insufficient information to develop a long-term production perspective. Therefore, many times gradual declines in production are not observed.

A second method consists of a tabular comparison of current monthly production to the previous month's production. This type of monitoring employs too short a time period and does not establish a production goal. Gradual declines in production can again be easily missed.

Another method employs a percentage rule. To identify problem wells, the monitoring system compares current production to the previous month's production but does not take action unless the downward variance exceeds, for instance, 10 %. This type of monitoring again employs too short a time period and also does not establish a production goal. The 10 % example above would allow a well to decline 5 % each month over a period of time and have a significant production loss without tripping the percentage limit.

The most refined method is a sophisticated computerized system used by some large independents and majors. This system utilizes production goals to compare with current producing rates. These systems collect and report vast quantities of information requiring so much time that the program is not always executed effectively. If the report is too burdensome, the goal becomes completing the report rather than identifying and acting upon the decreases in production. The monitoring program can work to identify a problem, but often lacks the follow-through in the implementation stage. This method may be impractical for the small, independent producer.

The first three methods identify large decreases in production, but often miss smaller decreases which can lead to significant losses in revenue. The last method, while in theory is workable, can be too burdensome for independents with small staffs to implement.

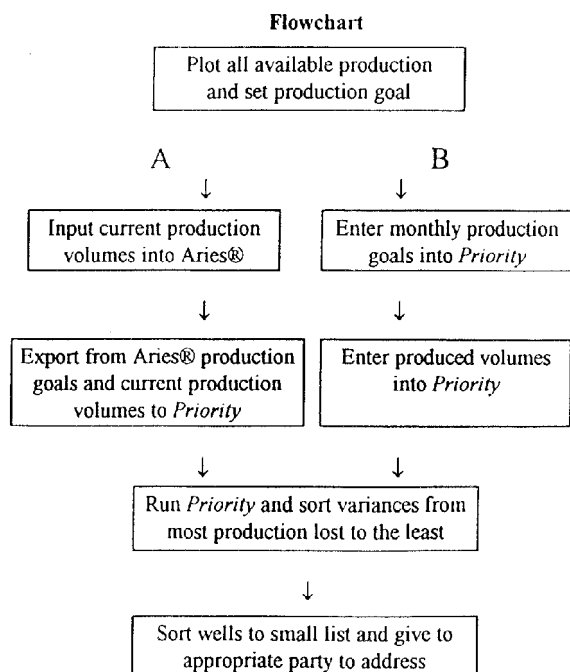
An Easier To Use Monitoring Method

Priority is a simplified software application that addresses the shortfall of the historical monitoring methods by comparing actual production volumes to production goals. The software uses actual measured production volumes as soon as they are available, to identify wells that fall short of these goals. This allows the user to prioritize the production deficits and provides the needed information to the field.

In this study, production histories were reviewed and analyzed to establish a reasonable forecast for each well. Production goals were set using Aries® software. This step made production input and forecasting relatively easy. *Priority* can utilize forecast information from forecasting programs or forecasts taken from simple hand plots of tabular information. In either case, a graphical presentation of the production history is recommended for forecasting purposes.

Prorated sales volumes have historically been plotted and were initially utilized for production comparisons. Integration volumes were eventually utilized to shorten the time between when a decrease in production is detected and the problem is addressed.

The program using the Aries® reverse-evaluation software follows path A in the Flowchart. Spreadsheet programs follow path B in the Flowchart.



Using a spreadsheet program, the wells with established production should have forecasted rates adjusted quarterly, newer wells should be adjusted monthly.

After the production data is imported, *Priority* permits the data to be sorted by negative variance and then printed out by area or pumper. An example of the printout is shown in Table 1.

A number of the wells in the study group experienced abnormal production declines detected by the program. These wells appear to have been reasonably well produced by different operators over the years, but decreases in production were still undetected. Review of the 250 well study group indicates the vast majority of the wells have experienced some underproduction for at least a period of one year during their lives.

The production histories have been included for three wells and are presented in figures 1, 2 and 3. In all three examples, the stabilized production declines were interrupted by decreases in production which went undetected or uncorrected for several years. Using *Priority*, the decreases were detected and corrective measures were implemented, which allowed the wells to be returned to expected production rates. The shaded portion below the projected performance time for each well represents the amount of underproduction. The H. Anderson No. 1 underproduced 11,658 mcf from 1989 to 1997. This represents revenue of \$29,145 (at \$2.50 per mcf). The A. Carter No. 1 underproduced 28,785 mcf from 1983 to 1997 representing revenue of \$71,963.

The E. Wilson No. 1 underproduced 9421 mcf from 1994 to 1997 representing revenue of \$23,553.

The program was implemented in the middle of 1996. During a five month production period at the end of 1996 and the beginning of 1997, a total production for the 250 wells increased by approximately 5 ½ % over the same period in 1995 and 1996. It should be noted that the nominal decline for these wells is approximately 6 % per year. Small operators with similar opportunities can realize substantial economic benefit by simply investing a few hours each month to run the *Priority Program*.

Conclusions

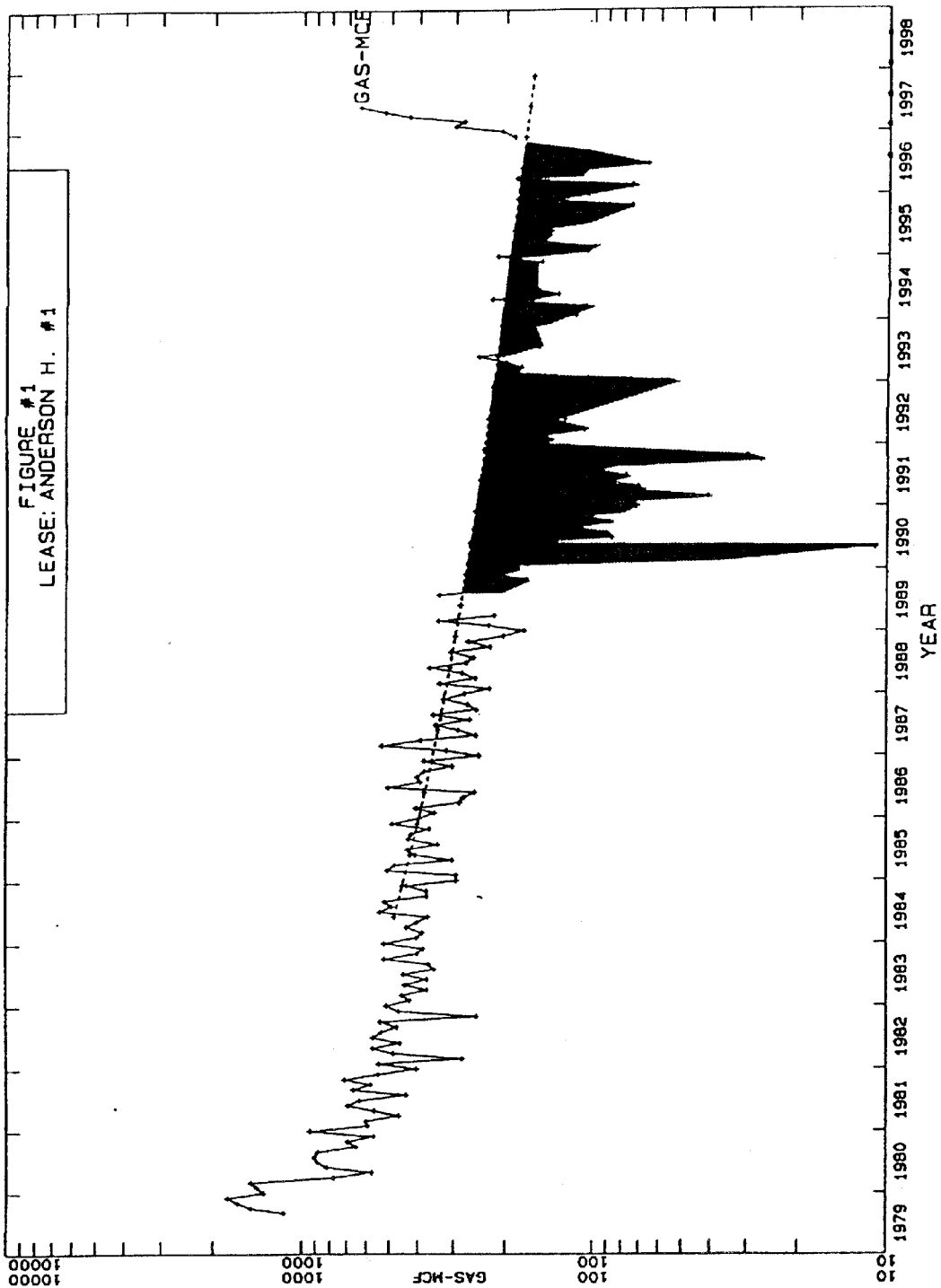
The *Priority* program is a simplistic management tool that enables users to identify problems and maximize production with a minimal time investment. *Priority* effectively identifies wells with production rates that vary from forecasted production goals. The program continues to remind the user of wells being underproduced until the problem is corrected or the production goal is changed. The examples provided demonstrate that users can gain significant economic benefit from this program with a small investment of their time.

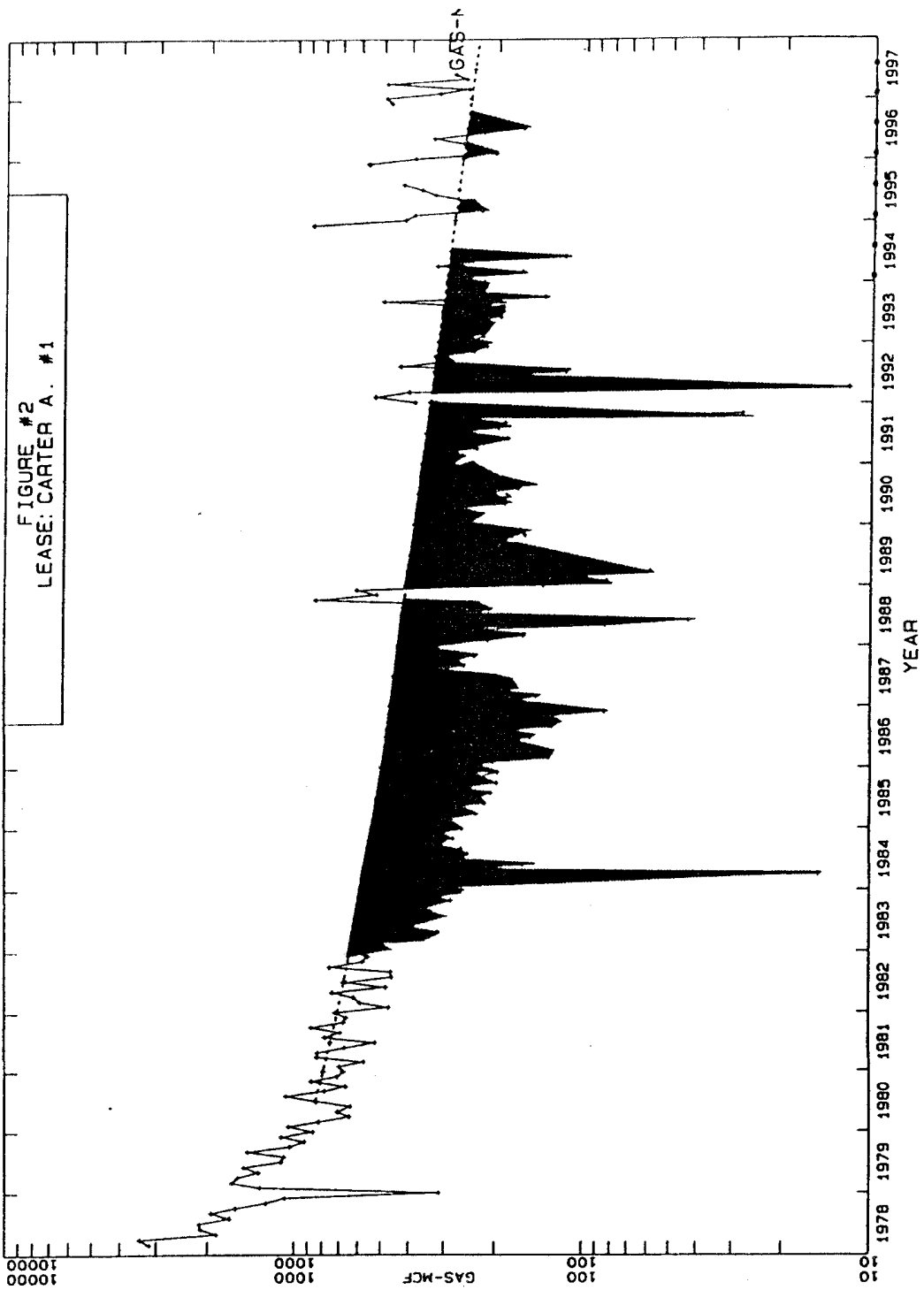
PRODUCTION MONITORING SYSTEM

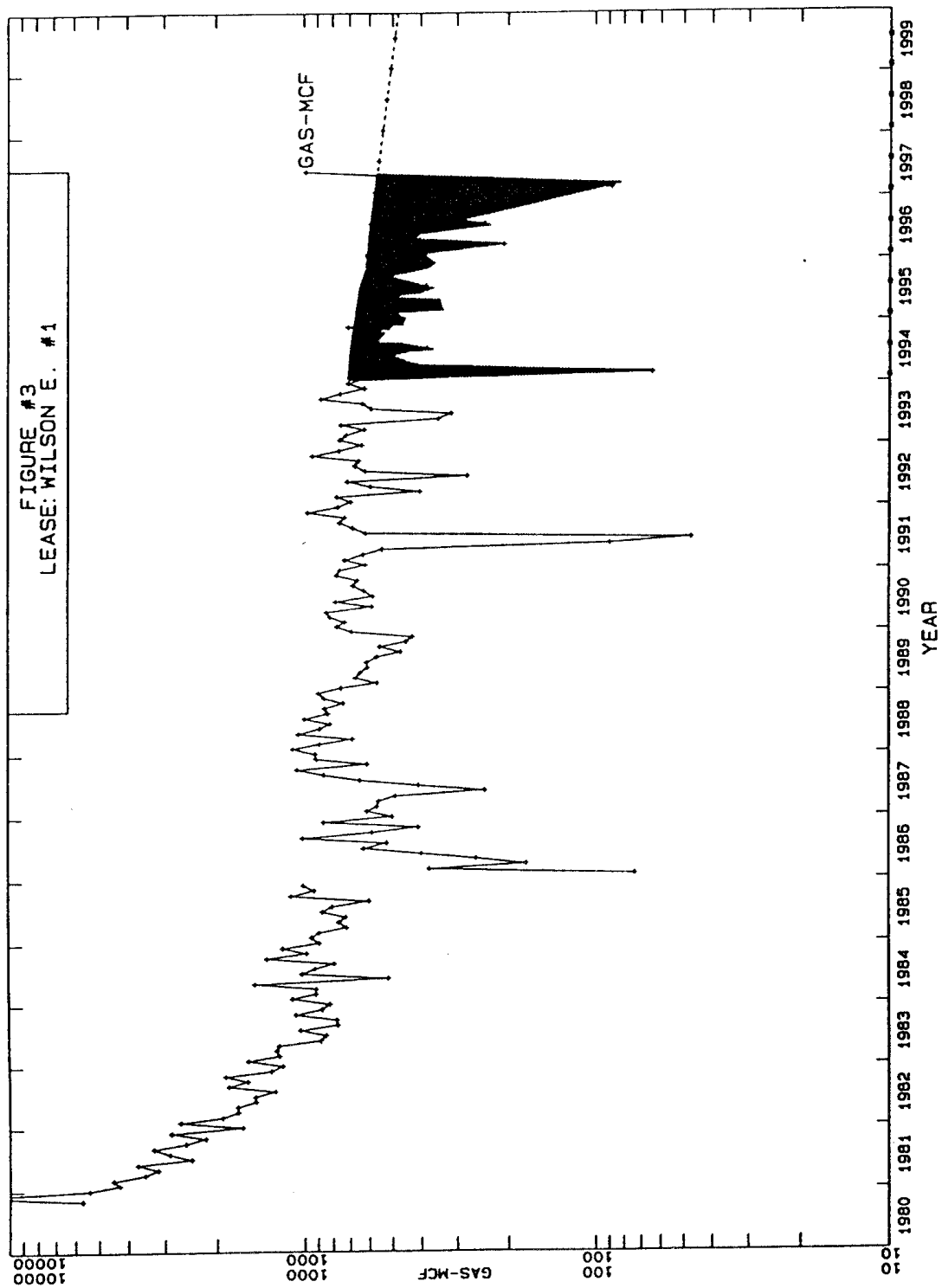
Evaluation for Production Month of: May 1997 INTEGRATED

WELL ID	WELL NAME	PUMPER	PIPELINE	PRODUCING METHOD	ACTUAL PROD.		FORECASTED PROD.		PROD. VARIANCE	
					(MCFM)	(BOPM)	(MCFM)	(BOPM)	(MCFM)	(BOPM)
2316355	GLASS #2	GG	A303	R	779		1041	1	-262	-1
2572961	KERR P. #1	GG	6033	R	15		262	0	-247	0
2572852	RIDENOUR G. #1	GG	A303	R	43		262	0	-219	0
2572683	LORENTZ #1	GG	A303	R	49		188	0	-139	0
2572613	GASSER #1	GG	A303		169		306	4	-137	-4
2573150	ANDERSON-MIZER #1	GG	A303	R	0	0	123	0	-123	0
2572936	SULZENER UNIT #1	GG	A303	R	12		124	0	-112	0
2572614	BUEHLER #1	GG	A291	S	91		179	0	-88	0
2573002	HANNI M., #1	GG	6033	R	62		118	0	-56	0
2573060	GANT UNIT #1	GG	A303	R	117		157	1	-40	-1
2572620	JOHN #1	GG	A303	R	137		161	0	-24	0
2573056	WAYNE FARMS #1	GG	A303	R	56		80	0	-24	0
2572950	BROWN G. #1	GG	A302	R	88		101	0	-13	0
2572646	EMIG #1	GG	5344	R	206		218	1	-12	-1

Table 1







Improved Oil Recovery In Fluvial Dominated Deltaic Reservoirs of Kansas

**By Rodney R. Reynolds, Don W. Green, G. Paul Willhite, Michael J. Michnick and Dwayne McCune
Tertiary Oil Recovery Project (TORP), University of Kansas**

Introduction

Common oil field problems exist in fluvial dominated deltaic reservoirs in Kansas. The problems are poor waterflood sweep efficiency and lack of reservoir management. The poor waterflood sweep efficiency is due to 1) reservoir heterogeneity, 2) channeling of injected water through high permeability zones or fractures, and 3) clogging of injection wells due to solids in the injection water. In many instances the lack of reservoir management results from 1) poor data collection and organization, 2) little or no integrated analysis of existing data by geological and engineering personnel, 3) the presence of multiple operators within the field, and 4) not identifying optimum recovery techniques.

This project involves two demonstration projects, one in a Morrow reservoir located in the southwestern part of the state and the second in the Cherokee Group in eastern Kansas. Morrow reservoirs of western Kansas are still actively being explored and constitute an important resource in Kansas. Cumulative oil production from the Morrow in Kansas is over 200,000,000 bbls. Much of the production from the Morrow is still in the primary stage and has not reached the mature declining stage of that in the Cherokee. The Cherokee Group has produced about 1 billion bbls of oil since the first commercial production began over a century ago. Many of the reservoirs are operated close to the economic limit, although the small units and low production per well are offset by low costs associated with the shallow nature of the reservoirs (less than 1000 ft. deep).

The project is being conducted in a cooperative manner involving University of Kansas scientists, engineers, and geologists and independent oil operators. Different independent oil operators operate the two demonstration sites. The Stewart Morrow Field is located in Finney County, Kansas and is operated by PetroSantander, Inc. This field was in the latter stage of primary production at the beginning of this project and is currently being waterflooded as a result of this project. The Nelson Lease (an existing waterflood) is located in Allen County, Kansas, in the N.E. Savonburg Field and is operated by James E. Russell Petroleum, Inc. The objective is to increase recovery efficiency and economics in these types of reservoirs. The technologies being applied to increase waterflood sweep efficiency are 1) in situ permeability modification treatments, 2) infill drilling, 3) pattern changes, and 4) air flotation to improve water quality. The technologies being applied to improve reservoir management are 1) database development, 2) reservoir simulation, 3) transient testing, 4) database management, and 5) integrated geological and engineering analysis.

Stewart Field Background

The Stewart Field ranges from 0.25 to 0.5 miles wide, is 4.5 miles long and covers approximately 2400 acres. The field was discovered in 1967 with the well being completed in a basal Pennsylvanian Morrow sand from 4755-4767 for 99 BOPD. Only four additional wells were drilled until 1985. Active development of the field took place from 1985 to 1994. Wells produced with minor stimulation until in 1990 and 1991 a field-wide hydraulic fracture program was conducted.

The Stewart Field contains 28°API oil with a small amount of solution gas (37 SCF/bbl). The initial reservoir pressure was estimated to be 1102 psig with a bubble point of approximately 180 psi. The reservoir oil was highly undersaturated and the expected primary production behavior was a rapid decline of reservoir pressure as the reservoir energy in the form of fluid and rock expansion was depleted.

Two field-wide shut-in tests were conducted in 1989 and 1991 to determine reservoir pressure distribution. Pressure tests indicated continuity of the reservoir over the 4.5 mile length of the field. Material balance calculations were performed from the initial reservoir pressure to the average reservoir pressures observed in the 1989 and 1991 field wide tests. Assuming no water influx, the fluid produced should be due to fluid and rock expansion over the given pressure drop. These calculations gave an estimate in excess of 100 million barrels of oil in place. Volumetric mapping of the net sand indicated only 22 million barrels in place.

It was determined that uncertainties in fluid and rock properties would not resolve the difference in determining the original oil in place between volumetric mapping of the net sand and material balance calculations. Either a large volume of the reservoir was yet to be defined or a limited water influx (pressure support) existed within the field. This uncertainty provided motivation for the extensive database development and reservoir study associated with this project.

Stewart Field Results

The Stewart Field project results include design, initiation and operation of a waterflood utilizing improved reservoir management techniques resulting in an increase in oil production rate from 270 to over 3150 BPD.

North American Resources Company (NARCO) was the operator that implemented the waterflood. The waterflood design was based on a reservoir simulation study conducted as part of this project. The original waterflood pattern was a modified six-line drive, resulting from six producing wells being converted to injection. Water injection began on October 9, 1995. In March 1996 oil production in the field began to respond to the water injection. Oil production increased to 1700 BOPD by October 1997 and NARCO sold the Stewart Field waterflood to PetroSantander, Inc., who subsequently converted six additional producing wells to injection. Oil production has continued to increase and as of December 31, 1998 total incremental waterflood response is over 2900 BOPD. Oil production over the life of the field is shown in **Figure 1**. The increase in production rates during the period from 1985-1989 was due to rapid development of the field. Peak primary production rates were observed following the hydraulic fracturing program carried out in 1990 and 1991, followed by a rapid decline in production. Current total field production is over 3150 BOPD. Total incremental waterflood production through December 1998 is 1,634,782 BO.

Savonburg Field Background

This project is comprised of three 160-acre leases totaling 480 acres in Sections 21, 28, and 29, Township 26 South, Range 21 East. The first well drilled in the location of this project was in 1962. Fifty-nine production wells and forty-nine injection wells have been drilled and completed since 1970. A pilot waterflood was initiated in March 1981 and expanded in 1983. Full development occurred in 1985.

In 1986, eleven gel polymer treatments were implemented successfully on the Nelson Lease. Overall incremental oil recovery was 3.5 barrels per pound of polymer placed which totaled 12,500 barrels. The production increase was not sustained due to wellbore plugging as a result of poor water quality.

Savonburg Field Results

This project started in June 1993. Although uncontacted regions of the reservoir were identified, the response to changes in water injection patterns stabilized the decline as shown in **Figure 2**. The principal results from this project is the improvement in the quality of the injection water and corresponding reduction in treating and wellbore cleanup costs.

The injection water at the Savonburg project is a mixture of supply water containing 40 mg/L sulfate and 50 mg/L sulfide and produced water containing 140 mg/L barium and 12 mg/L iron. Barium sulfate and black iron sulfide formed when the two waters were mixed. Before the project started, less than 1000 BPD of water could be processed through the water plant through 75-micron filter bags. Frequent well workovers were required to clean injection wells in order to restore injectivity.

An air flotation unit was developed to remove oil and suspended solids from the injection water. The AFU consists of a 4-foot diameter by 4-foot tall tank. Two venturi tubes are mounted two feet below the surface of the water at a 45° angle to the center of the tank. Clean water from the bottom of the AFU is pumped through the venturi tubes to produce a stream of small air bubbles, which rise, to the water surface, sweeping solids and oil from the water. A high molecular weight cationic polymer flocculation agent is used to enhance the separation. Now 1000 BPD of clean water is routinely processed by a pair of 1-micron filters that last as long as four days before replacement.

The goal for water quality at the Nelson Lease was less than 10 mg/L of suspended solids in the water sent to the field. **Figure 3** illustrates the turbidity measurements made by field personnel for 1998 by date. Note that the goal of less than 10 mg/L was achieved in early May when the 1 SCFM air per 10 gpm feed water was achieved and the waste weir was relocated to the center of the tank.

From July 2 through November 15, the solids in the feed water ranged from 47 to 370 mg/L with an average of 80 mg/L by turbidity (18 mg/L by weight). The solids in the clean water exiting the water plant ranged from 1 to 25 mg/L with an average of 7 mg/L (1.6 mg/L by weight). This corresponds to a decrease in solid content of 90%, which is equivalent to a decrease from 2300 to 200 pounds solids per year sent to the field.

Preliminary cost estimates are \$1.25, \$2.40, \$4.35, and \$9.40 per day for cationic polymer, hypochlorite, scale inhibitor, and filters, respectively for 1000 BPD of clean water, or \$0.02 per barrel of water. The clean water allowed the replacement of the 75-micron with 5 or 2-micron cartridge filters at each injection well. Cleaner water and better filtration at each injection well reduced the frequency of well cleaning by 50 to 75 percent for additional savings in the waterflood operation at the Nelson Lease.

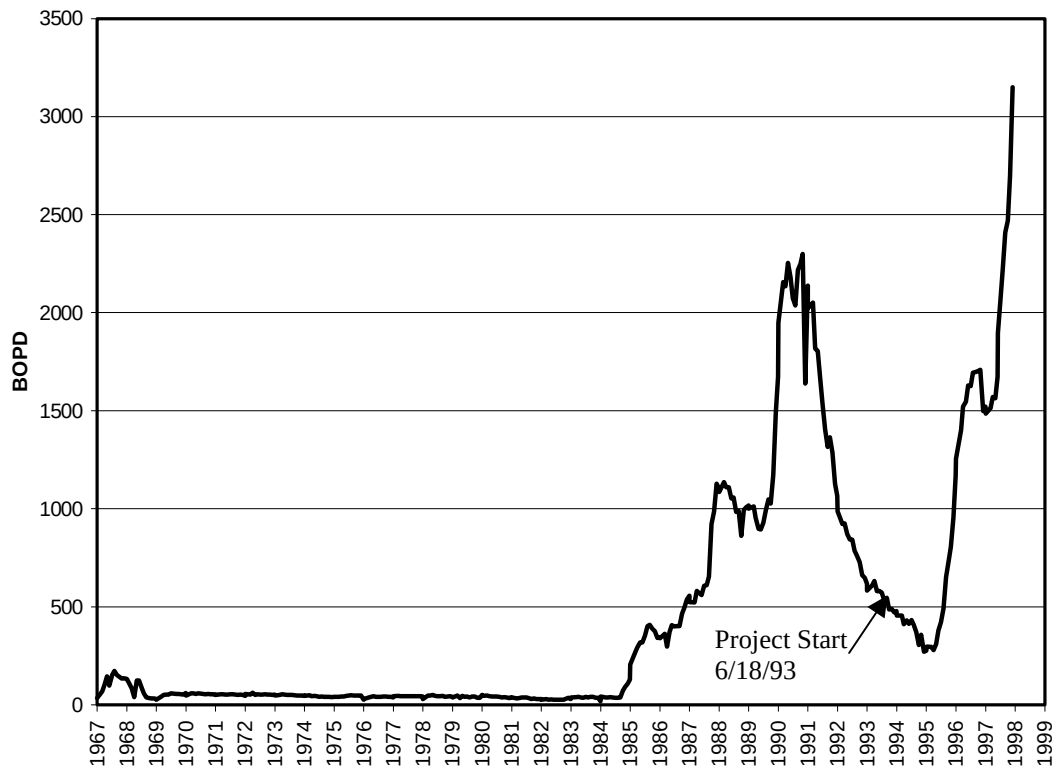


Figure 1. Stewart Field Oil Production

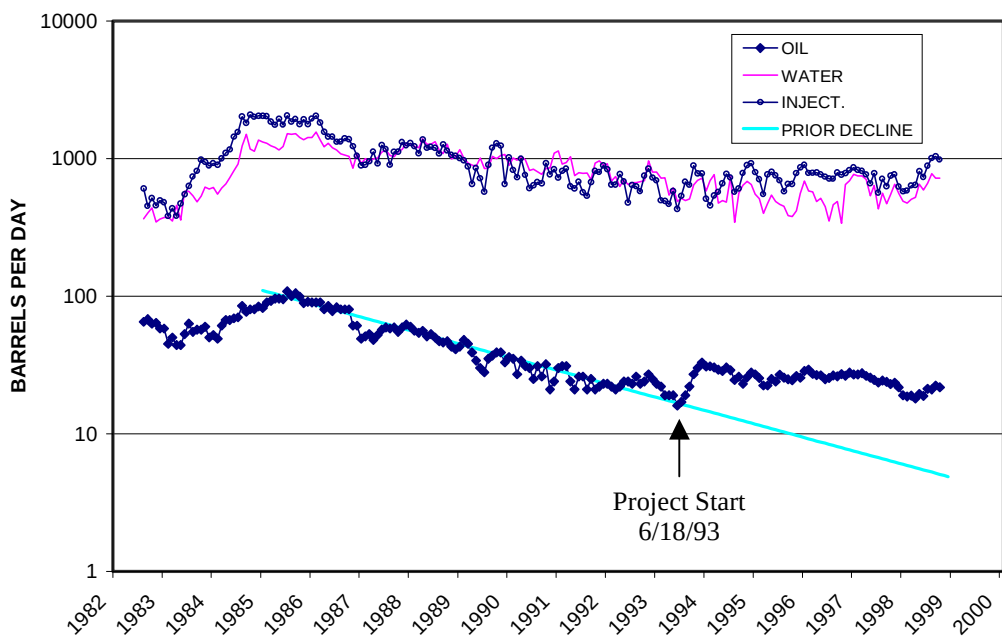


Figure 2. Savonburg Field Waterflood Production and Injection.

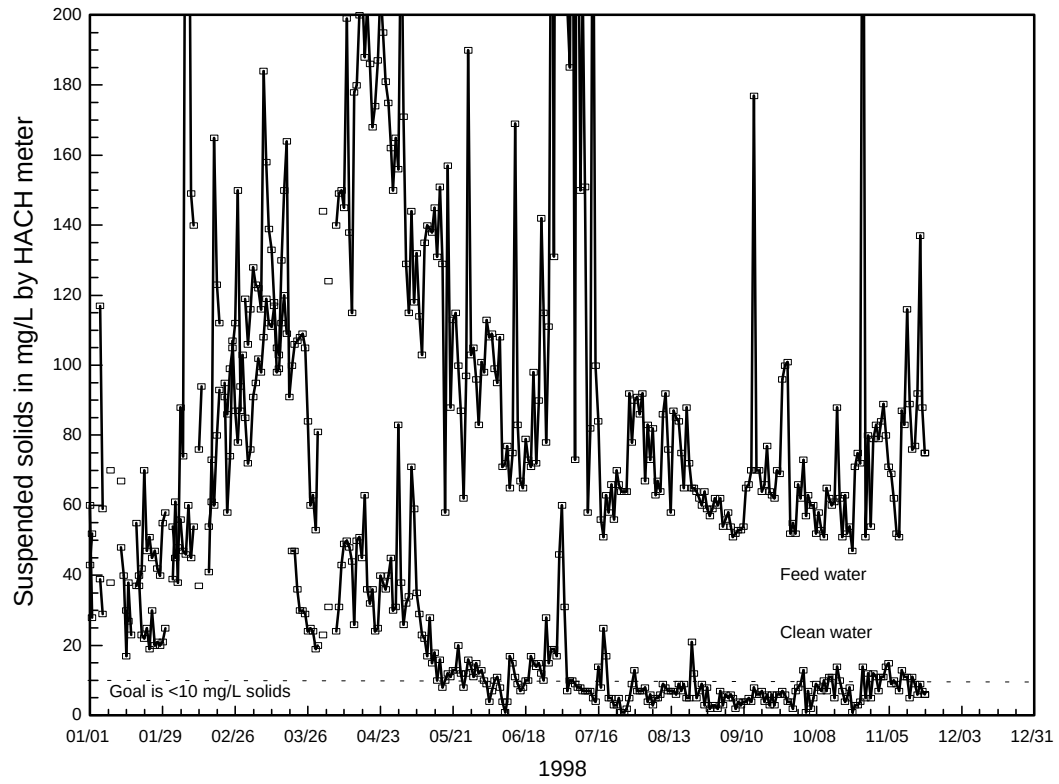


Figure 3. Savonburg Field Comparison of Suspended Solids Content for Water Entering and Exiting the Air Flotation Unit.

INCREASED OIL PRODUCTION AND RESERVES UTILIZING SECONDARY/TERTIARY RECOVERY TECHNIQUES ON SMALL RESERVOIRS IN THE PARADOX BASIN, UTAH

Thomas C. Chidsey, Jr. (nrugs.tchidsey@state.ut.us; 801-537-3364)
Utah Geological Survey
P.O. Box 146100
Salt Lake City, Utah 84114-6100

U.S. Department of Energy
National Petroleum Technology Office, Tulsa, Oklahoma
Class II Oil Program, Contract Number DE-FC22-95BC14988

INTRODUCTION

Over 400 million barrels of oil have been produced from shallow-shelf carbonate reservoirs in the Pennsylvanian (Desmoinesian) Paradox Formation in the Paradox basin of Utah, Colorado, and Arizona. With the exception of the giant Greater Aneth field, 100 plus oil fields in the basin typically contain 2 to 10 million barrels of original-oil-in-place per field. To date, none of these small fields have been the site of secondary/tertiary recovery (carbon dioxide- [CO₂-] miscible flood) techniques used in large carbonate reservoirs. Most of these fields are characterized by extremely high initial production rates followed by a very short production life (primary) and hence early abandonment. At least 200 million barrels of oil are at risk of being left behind in these small fields because of inefficient recovery practices and undrained heterogeneous reservoirs.

The Utah Geological Survey (UGS), the prime contractor, led a multidisciplinary team consisting of the UGS, Harken Southwest Corporation (Harken), and several subcontractors. This research was performed under the Class II Oil Program of the U.S. Department of Energy, National Petroleum Technology Office in Tulsa, Oklahoma.

During Budget Period I, we described the geological and reservoir characteristics of five small algal mound fields in the Paradox basin of southeastern Utah (figure 1), and conducted reservoir modeling and simulation on two of the project fields. The activities for Budget Period II, the field demonstration, will be: (1) implement a pilot CO₂ flood on a selected field, (2) monitor testing and production, (3) evaluate demonstration techniques and economic feasibility, (4) determine which project techniques are suitable for use in similar fields in the Paradox basin and throughout the U.S., and (5) technology transfer.

OBJECTIVE

The primary objective of this multi-year project is to enhance domestic oil production and increase reserves through detailed reservoir characterization and simulation. This objective will be accomplished via case studies of small fields in the Paradox basin of southeastern Utah, conducting a field demonstration

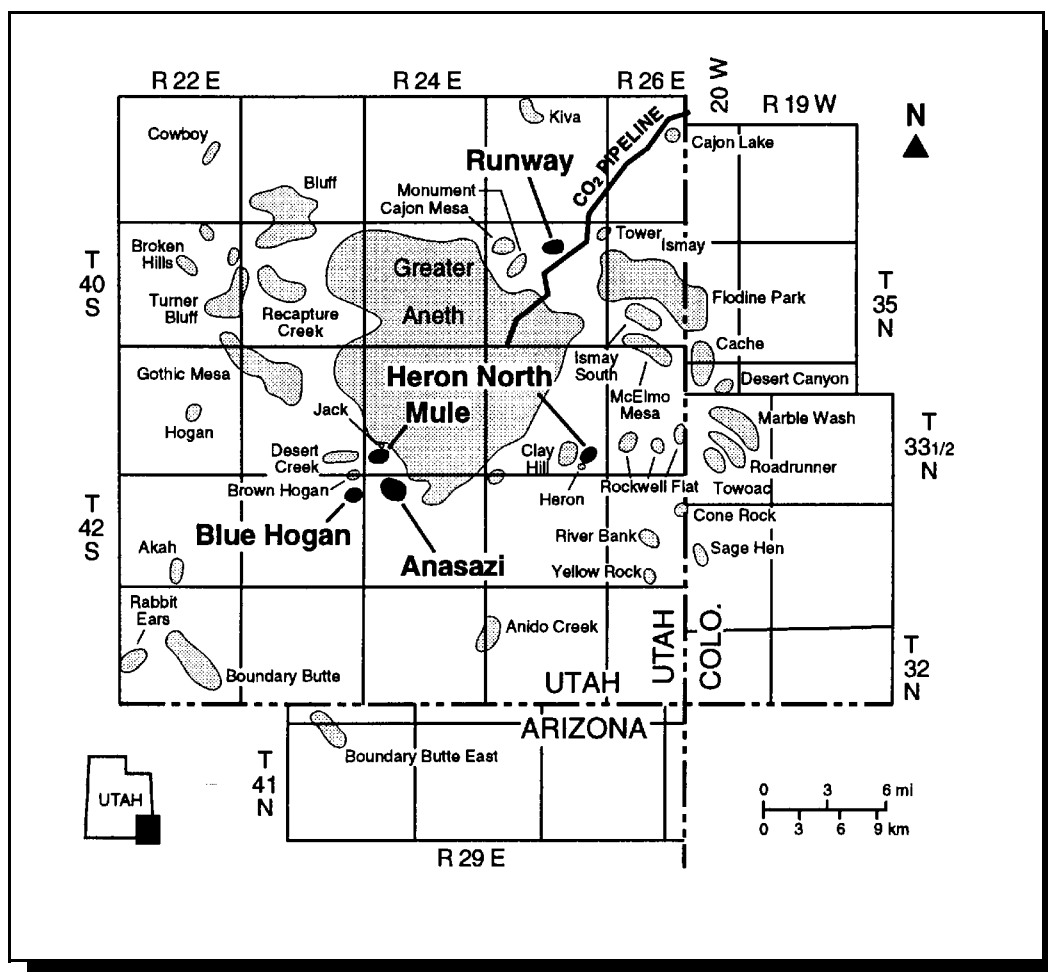


Fig. 1. Location of project fields (dark-shaded areas with names in bold type) in southwestern Paradox basin on the Navajo Nation, San Juan County, Utah.

of secondary/tertiary recovery techniques, and transferring results of developed technologies to industry. If this project demonstrates a technique with economic feasibility, the technique can be applied to about 100 additional small fields in the Paradox basin alone, and result in increased recovery of 150 to 200 million bbl of oil.

The objectives of Phase I were to characterize five, shallow-shelf carbonate reservoirs in the Paradox Formation and choose the best candidate for a pilot demonstration project for either a waterflood or CO₂-flood project. The objectives of Phase II, the field demonstration, are to test the conclusions of Phase I with a pilot CO₂ flood and monitor field performance. These activities will take place within the Navajo Nation.

The final objectives of this project will be to transfer the results and recommendations developed to the petroleum industry and other researchers through a petroleum extension service, creation and distribution of digital databases, technical workshops and seminars, field trips, technical presentations at national and regional professional meetings, and publications in newsletters and various technical or trade journals.

APPROACH AND PROJECT DESCRIPTION

Introduction

The geological and reservoir characteristics of five fields (Anasazi, Blue Hogan, Heron North, Mule, and Runway) within the Navajo Nation, San Juan County, Utah, were quantitatively determined to rank each field's suitability for enhanced recovery projects. These fields represent typical, small, shallow-shelf carbonate reservoirs producing oil and gas from the Desert Creek zone of the Paradox Formation. Our study included: (1) analyzing regional facies and outcrop analogs, (2) drilling development wells (one horizontal), (3) determining reservoir heterogeneity, quality, and lateral continuity or compartmentalization, (4) determining diagenetic fabrics and history, (5) extensive mapping of reservoirs, (6) determining field reserves, (7) laboratory testing and analogies to large-scale waterflood/CO₂ flood, and (8) reservoir modeling and simulation on two of the project fields.

Geological and Reservoir Characterization

Reservoir data, cores and cuttings, geophysical logs, various reservoir maps, and other information from the project fields and regional exploratory wells were collected. Well locations, production reports, completion tests, core analysis, formation tops, and other data were compiled and entered in a database developed by the UGS.

Three generalized facies belts were mapped in the Desert Creek zone of the Paradox Formation utilizing representative core and modern geophysical logs: (1) open-marine, (2) shallow-shelf and shelf-margin, and (3) intra-shelf, salinity-restricted facies (figure 2). Outcrops of the Paradox Formation Ismay zone along the San Juan River of southeastern Utah, provided small-scale analogues of the reservoir heterogeneity, flow barriers and baffles, and lithofacies geometry observed in the fields. These analogues include a phylloid-algal mound, (2) a "reef wall," and (3) a carbonate detrital wedge and fan. These outcrop characteristics were incorporated in the reservoir simulation models.

Geological characterization on a local scale focused on reservoir heterogeneity, quality, and lateral continuity, as well as possible compartmentalization within each of the five project fields. Structure contour maps on the top of the Desert Creek zone of the Paradox Formation and gross Desert Creek interval isopach maps were constructed for the project fields. These maps were combined to show carbonate buildup trends, define limits of field potential, and indicate possible combination structural and stratigraphic traps. Basic reservoir parameters and production histories for each field were also compiled and summarized. The typical vertical sequence, or cycle, of lithofacies from each field, as determined from conventional core, was tied to its corresponding log response. Diagenetic histories of the various Desert Creek reservoirs were determined from petrographic examination of thin sections from representative samples of conventional cores from each field. The petrographic descriptions were used to rank each field's suitability for enhanced recovery projects.

A team of geologists, reservoir engineers, and geophysicists from Harken evaluated potential development locations (for both vertical and horizontal wells) for the project fields. Project development

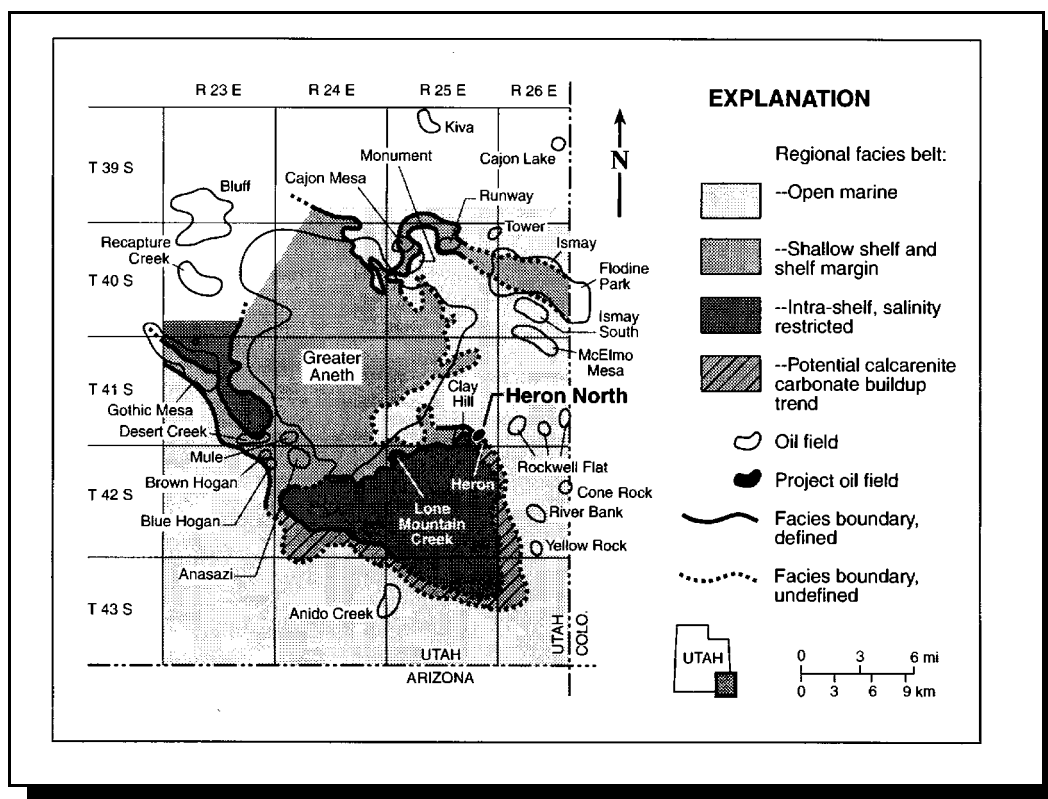


Figure 2. Generalized regional facies belts for the Desert Creek zone, Pennsylvanian Paradox Formation, southeastern San Juan County, Utah.

wells were designed to increase the well density from one well per 80 acres to one well per 30 to 40 acres. Additional seismic data were used to determine the extent of the algal mound in Mule field, and the orientations and lengths of horizontal development drilling. The data obtained from these new wells enabled the project team to assess: (1) the frequency of reservoir compartment changes (reservoir heterogeneity) in a given area, (2) the amount of communication between compartments, (3) how a waterflood or CO₂ flood will flow from one compartment to another, and (4) the areal extent of an average compartment.

Reservoir Modeling and Simulation

Two fields, Anasazi and Runway (figure 1), were selected for detailed geostatistical modeling and reservoir simulation in order to determine which field was the best candidate for a pilot waterflood or CO₂-flood demonstration project. Detailed quantitative reservoir descriptions, coupled with geostatistical modeling and composition simulations, were used to predict field performances under CO₂ flooding and waterflooding recovery processes. The internal architecture of the reservoir between the wells was modeled using a marked-point (Boolean) process for emplacement of constituent lithotypes (figure 3). Emplacement sequences were established and the relative lithotype proportions varied stochastically. The pair-wise, block-exchange process for simulating Desert Creek reservoir porosity between the field wells was carried out using the well-known stochastic relaxation technique known as simulated annealing.

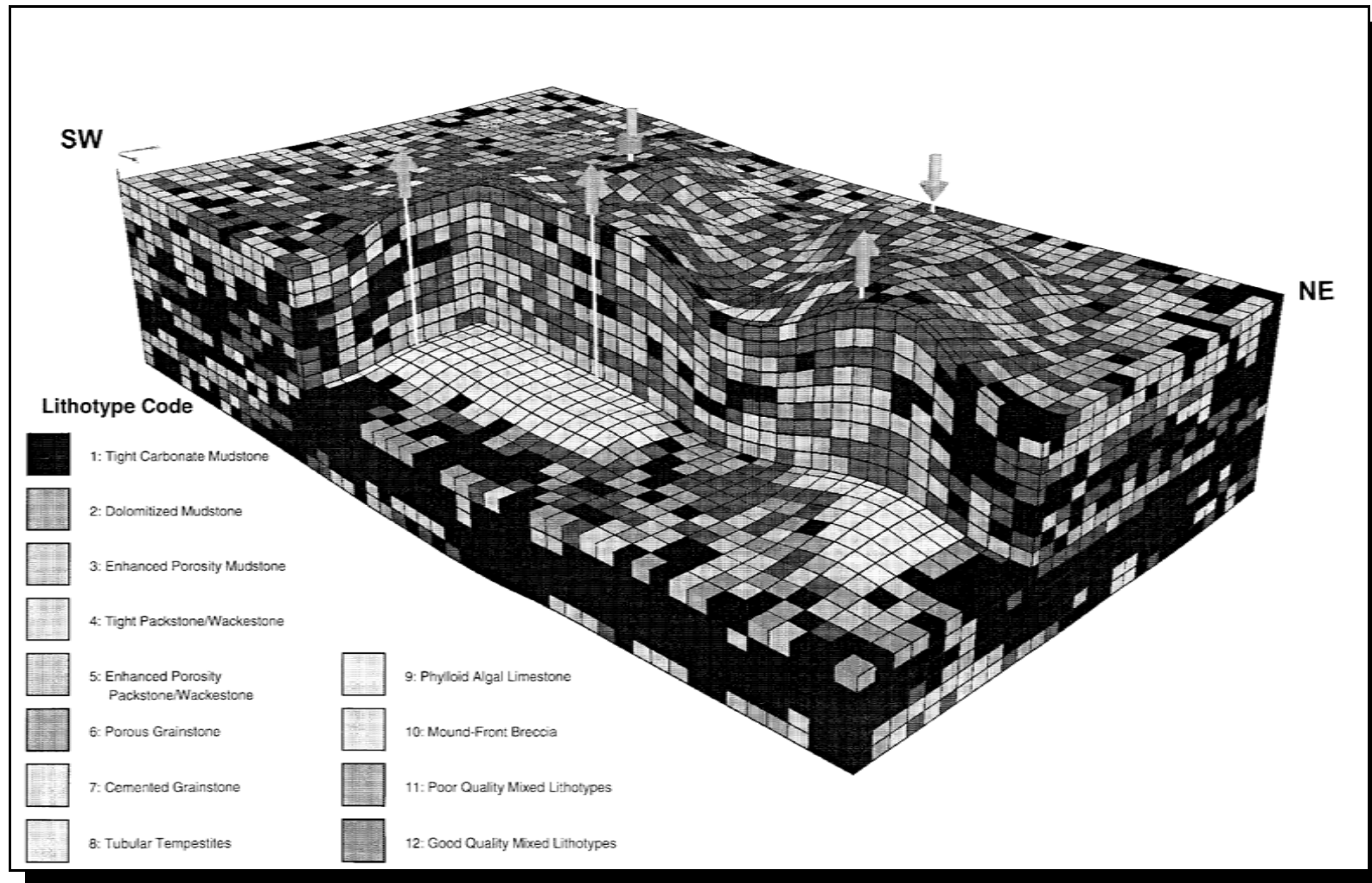


Figure 3. Block diagram displaying distribution of lithotypes in the reservoir simulation model, Anasazi field. Arrows directed up are producing oil wells, arrows directed down are CO₂ injectors. The layers consist of a 30 by 50 block grid (1,500 blocks per layer or a total of 22,500 blocks). The layer at the bottom of the “cut away” is the boundary between mound-core and supra-mound intervals.

Sensitivity studies were conducted which indicated that most of the variation in effective reservoir properties could be retained with careful scaling of porosity and permeability. Lithotypes were assigned to gridblocks in 15 layers. Porosity was volume-averaged for the 15-layer model, and effective permeability was computed by solution of the pressure equation using the field-scale reservoir simulator.

Compositional simulation was used to history match (model) predicted production to actual past production performance of the fields, as well as to predict the performance of continued primary depletion and various CO₂ floods (figure 4). The simulation study employed the stochastically generated reservoir description. The reservoir fluid was characterized via an equation-of-state calibrated using CO₂-swelling tests conducted on crude oil from Anasazi field and the original, black oil, pressure-volume-temperature data for both fields. Gas-oil and water-oil relative permeability, capillary pressure, and rockpore volume compressibility data were generated for the principal productive facies.

PROJECT RESULTS

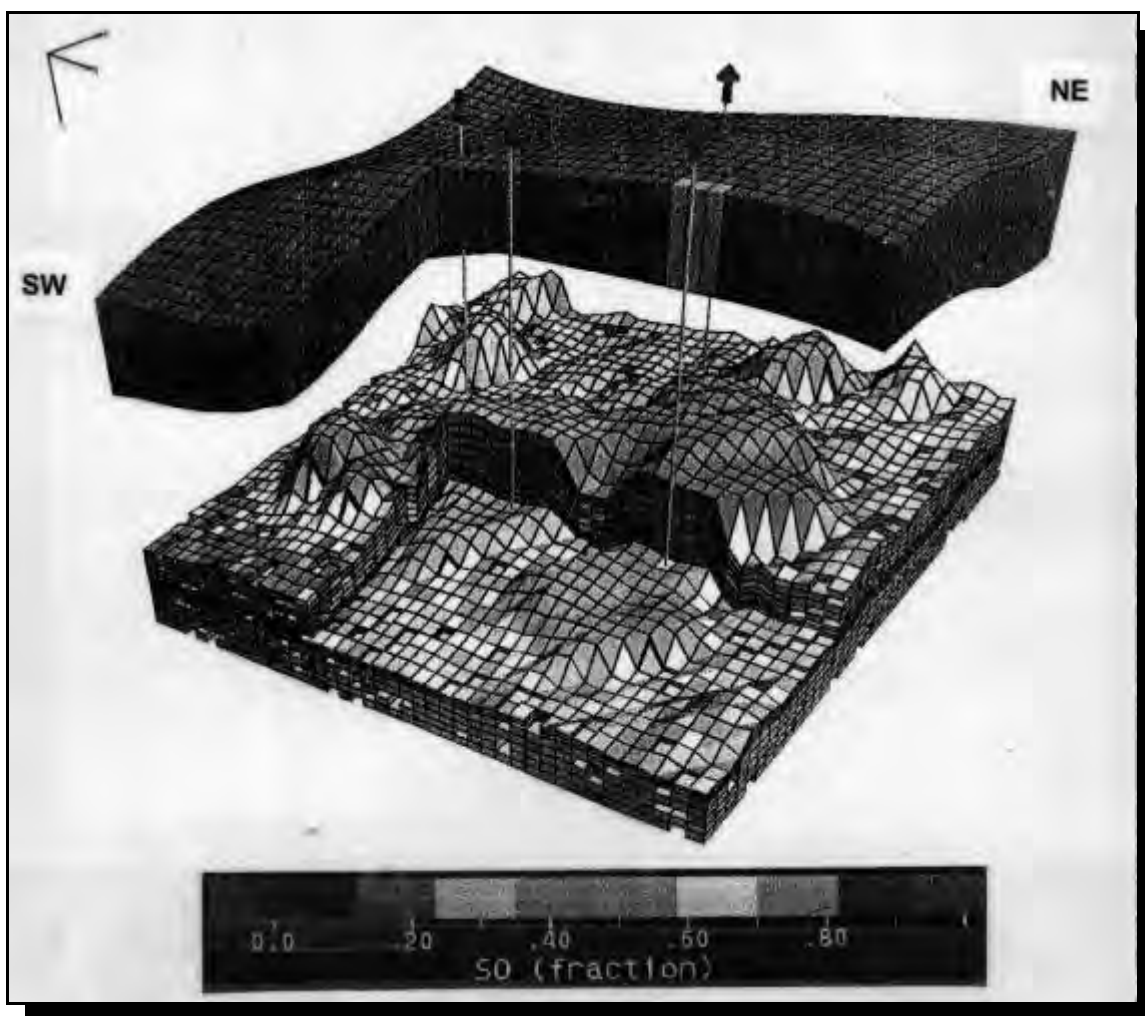


Fig. 4. Block diagram displaying reservoir oil saturation distribution after 4 years of CO₂ injection. Shown is a "cut away" through one of the proposed horizontal injector wells and the Runway Nos. 10G-1 and 10E-2 production well locations. SO (fraction) is the oil saturation.

Geological and Reservoir Characterization

Regional Geological Setting

Facies belts and patterns are critical to the understanding of the heterogeneity and reservoir capacity of each of the five project fields evaluated for the demonstration project. In addition, the analysis of the vertical facies sequence in each field area was important in order to infer lateral relationships and overall depositional geometries of the reservoir facies, and the intervals that would tend to compartmentalize production. All five project fields, as well as the other Desert Creek fields in the region, are located within the shallow-shelf and shelf-margin facies belt (figure 2). This facies belt includes shallow-shelf carbonate buildups, platform-margin calcarenites, and platform-interior carbonate muds and sands. The regional lithofacies map indicated a relatively untested belt of shallow-shelf, calcarenite carbonate deposits (figure 2). This narrow, but long, belt of calcarenite lithofacies is between open marine lithofacies and the margins of intra-shelf, salinity-restricted lithofacies. Heron North field (figures 1 and 2), one of five project fields, is an excellent example of the type of field which potentially lies within this 20-mi-long lithofacies belt. Carbonate buildups located within the open-marine and intra-shelf, salinity-restricted facies belts typically have poor reservoir quality.

Field correlations of wells within the Desert Creek interval were critical to predicting reservoir development and continuity. In addition, sequence stratigraphic analysis of the excellent outcrops along the San Juan River just west of the study area helped to determine the factors which control facies and reservoir development. Outcrop study showed that morphologically, the buildups consist of large, northwest-trending algal banks separated by interbank troughs or channels. Smaller, secondary algal mounds and intermounds define the upper surfaces of the algal banks. By analogy, the presence of certain facies in a well core might serve as a proximity indicator for a more prospective drilling target. Reservoir-quality porosity may develop in troughs, detrital wedges, and fans identified from core and facies mapping. If these deposits are in communication with mound-reservoir facies in the subsurface, they could serve as conduits facilitating the sweep efficiency of secondary/tertiary recovery projects. However, the relatively small sizes and the abundance of intermound troughs over short distances, as observed along the river, suggests caution should be used when correlating these facies between development wells. Facies that appear correlative and connected from one well to another may actually be separated by low-permeability facies which inhibit flow and decrease production potential.

The results of these field investigations were incorporated into the geological constraints on facies distributions in the geostatistical models. Reservoir models for possible water and CO₂ floods of small Paradox basin fields were developed to determine the most effective secondary/tertiary recovery method. The models included lithologic fabrics, flooding surfaces, and inter-mound troughs, based on the mound complex exposed in the San Juan River Canyon.

Field-Scale Geologic Analysis

Field-scale geologic analysis was used to identify reservoir and non-reservoir rock, determine potential units suitable for water- and/or CO₂-flood projects, and compare field to non-field areas. The typical vertical sequence, or cycle, of lithofacies from each field, as determined from conventional core, was graphically tied to its corresponding log response. Structure contour maps on the top of the Desert Creek zone of the Paradox Formation and isopach maps of the gross Desert Creek interval were constructed for

the project fields. These maps were combined to show carbonate buildup trends, define limits of field potential, and indicate possible combination structural and stratigraphic traps.

From these analyses, productive carbonate buildups were divided into three types: (1) phylloid algal, (2) coralline algal, and (3) bryozoan. Hydrocarbons are stratigraphically trapped in porous and permeable lithotypes within the mound-core and supra-mound intervals of Desert Creek carbonate buildups. Primary oil recovery is about 40 percent in mound-core intervals but 15 percent or less in the supra-mound intervals. In these traps, determining the nature, location, and extent of reservoir heterogeneity was the key to increasing oil recovery.

Three factors create reservoir heterogeneity within productive mound-core and supra-mound intervals: (1) variations in lithotypes, (2) mound relief and flooding surfaces, and (3) diagenesis. The extent of these factors, and how they are combined, affect the degree to which they create barriers to fluid flow. The mound-core intervals, the most homogenous part of these buildups, are dominated by bafflestones. The overlying supra-mound intervals exhibit the greatest heterogeneity with multiple combinations of lithotypes and various lithofacies thicknesses.

Most shallow-shelf/shelf margin carbonate buildups in the study area had topographic relief which was subaerially exposed when sea level dropped. This produced four major diagenetic environments: (1) a fresh water (meteoric) vadose zone (above the water table, generally at or near sea level), (2) a meteoric phreatic zone (below the water table), (3) a marine phreatic zone, and (4) a mixing zone. Neomorphism, leaching/dissolution, and fresh water cementation took place within the vadose and meteoric phreatic zones. Both the meteoric phreatic zone and marine phreatic zone were dynamic, changing with sea level fluctuations. These phreatic zones were separated by a mixing zone (fresh and sea water) which also changed with sea level fluctuation. Early dolomitization took place in the mixing zone. That portion of the carbonate buildup facing the open-marine environment was generally a steep-wall complex where early-marine cements were deposited from invading sea water pumping through the system. The other side of the mound typically bordered a hypersaline lagoon. The dense brine from the lagoon seeped into the phreatic zone, a process termed seepage reflux, forming both early replacement dolomite and dolomite cement.

Core data, log data, pressure data, production data, PVT data, and oil-water relative permeability data were collected or determined to characterize the reservoirs in three dimensions. Permeability, porosity, heterogeneities, fractures, boundaries, layers, ineffective pay, and reservoir fluid and flow characteristics were cataloged and correlated from well to well across each field. Production histories were also plotted for each field. Primary recovery and original oil in place were determined from volumetric reserve calculations, material balance calculations, and decline curve extrapolations. The information and plots compiled were merged with geological characterization data and incorporated into reservoir statistical models and simulations.

Drilling of Development Wells

Seismic interpretation and mapping indicated that the mound buildup at Anasazi field (figure 1) extended to the west of the previously developed areas. A new well at a more westerly location could also serve as an Anasazi water/CO₂ injection well in the future. A new seismic program was also permitted and conducted in the Mule field (figure 1). The additional seismic data were used to determine the extent of the algal-mound buildup in the field and the orientations and lengths of any horizontal development drilling.

These seismic data were interpreted and incorporated into the overall interpretation of the southwest Aneth region.

During the first project year, one development well was drilled in the Anasazi field, the Anasazi No. 6H-1 well. Evaluation of the core suggests the well missed the main buildup or mound-core interval (algal-bafflestone reservoir) and penetrated poorer quality mound-flank deposits (mixed carbonate fabrics that are brecciated, slumped, and chaotic) instead. However, the dolomites in the upper part of the buildup or supra-mound may be connected to the upper Anasazi reservoirs in the rest of the field. Selected plugs from the reservoir were used to determine oil/water and gas/oil relative permeability measurements; the results were incorporated into the Anasazi reservoir flow simulation model. The Anasazi No. 6H-1 well was completed at a daily rate of 31.3 barrels of oil, 25 thousand cubic feet of gas, and 7.5 barrels of water per day in the Desert Creek and Ismay zones.

The Mule No. 31 K-1 sidetrack, with a horizontal displacement of 939 feet in a northwest direction, was the first horizontal test of a small algal buildup in the Paradox basin. Drill cuttings and the mud log (no geophysical logs were run) indicated the well intersected possible intercrystalline porosity zones in the supra-mound interval of the buildup facies, lagoonal overwash deposits (?), and mound-front facies. The well was completed at a rate of 149 barrels of oil and 223 barrels of water per day, respectively.

Reservoir Modeling and Simulation

The key to increasing ultimate recovery from the Anasazi and Runway fields (and similar fields in the basin), is to design either waterflood or CO₂-miscible flood projects capable of forcing oil from high-storage-capacity but low-recovery supra-mound units into the high-recovery mound-core units. The results of statistical models were used in reservoir simulations to test and design those types of projects. The secondary/tertiary recovery techniques simulated (with appropriate variations) were waterflooding and CO₂-miscible flooding, as well as a combination of the two (water alternating gas [WAG]).

Geostatistical Models

The geometry, lithology, internal architecture and reservoir properties of the Anasazi and Runway mound complexes were developed from a variety of data sources. Data sources included seismic, well logs, core, outcrop data, and well test results. This data and its interpretation were used to construct geostatistically based architectural representations of a number of different reservoir models, or realizations, and the associated properties of the facies contained in the architectural elements (figure 3).

The reservoir production history, and the various stages of depletion, were defined using production data, mechanistic, and full field simulation studies. Fluid property data were used to calibrate equation of states, which were subsequently used to conduct CO₂ process mechanistic studies and compositional simulation studies to define CO₂ miscibility conditions.

A complete review of existing well test data, and new interpretations of this data, were completed. Interpretations provided new insight into fluid flow among the principal rock types, and quantitative data to support reservoir characterization. Utilizing new reservoir property data, the calibrated equation of states and number of different geostatistically based reservoir models, a compositional simulator was used to history match past reservoir production performances. The reservoir properties that required modification to obtain history matches were reviewed, and the final predicted performances compared with historical data.

Using the history-matched simulator, continued primary production depletion was predicted. The simulator was used to predict performances of both CO₂ floods (figure 4) and waterfloods. The influence of the number of injectors, injector location, injector-well configuration (vertical versus horizontal), and production well operating conditions were assessed for both CO₂ floods and water flooding. In addition, the operating pressure required to maintain CO₂-crude oil miscibility and the impact of re-injecting unprocessed (CO₂ and hydrocarbons not separated) produced gas on CO₂ flood performance were assessed. Simulation results indicate that CO₂ flooding is superior to water flooding in terms of total oil recovery. Simulation results provided data to determine the CO₂ gas volume required and overall project injection requirements. Also, the field performance was simulated to compare the scenarios of continued CO₂ injection versus CO₂ injection followed by reservoir blowdown.

Reservoir Mechanistic Studies

Based on the calibrated equation of states, multiple contact phase behavior calculations, and one-dimensional compositional studies, it was concluded that:

1. The Anasazi and Runway crudes can be miscibility displaced by CO₂.
2. The CO₂ - crude mass transfer process can be characterized as a vaporizing gas drive process where the injected CO₂, via a multiple contact process, is enriched in intermediate components vaporized or extracted from the in-place oil.
3. Using oil compositions representative of the original oil and depleted oil in Anasazi, miscible displacement occurs over the pressure range of 2,400 to 3,100 pounds-per-square-inch absolute (psia). A pressure of 3,100 psia was used as a guideline for full field simulation studies assessing CO₂ injection. Using oil compositions representative of the original oil, miscible displacement will require a pressure in excess of 3,000 psia for Runway.

Two-dimensional, mechanistic, reservoir performance studies modeling the primary depletion stages of the Anasazi reservoir provided the following insights into basic reservoir prediction mechanisms for both reservoirs:

1. The initial Anasazi reservoir production behavior can be characterized as liquid expansion processes followed by a solution gas drive. The solution gas drive is accompanied by free-gas segregation into the supra-mound interval and the development of a secondary gas cap. The latter stage of production is characterized by secondary gas cap expansion and gravity drainage of oil from the supra-mound interval into the underlying core-mound interval (the dolomite/limestone unit).
2. The limestone unit (core-mound interval) contributes the major portion of production (>99 percent), but is continually recharged from the overlying supra-mound interval.

3. Vertical permeability is a key parameter that controls reservoir processes. The extent and nature of the supra-mound/core-mound (dolomite/limestone) communication plays a controlling role in reservoir performance.

Anasazi Reservoir Performance Predictions

The history-matched simulator was used to predict the production performance of the Anasazi reservoir under continued primary depletion, assess the potential of CO₂ flooding, and identify operating conditions needed to maximize CO₂ enhanced recovery (figure 5). In addition, the potential of water flooding was assessed. Major results of the predicted reservoir performances are presented below

1. The projected primary production through January 1, 2012 is 2.55 million stock tank barrels (STB). This represents 54 percent of the original oil in place (OOIP) in the mound complex proper and 22.3 percent of the OOIP in the total system.

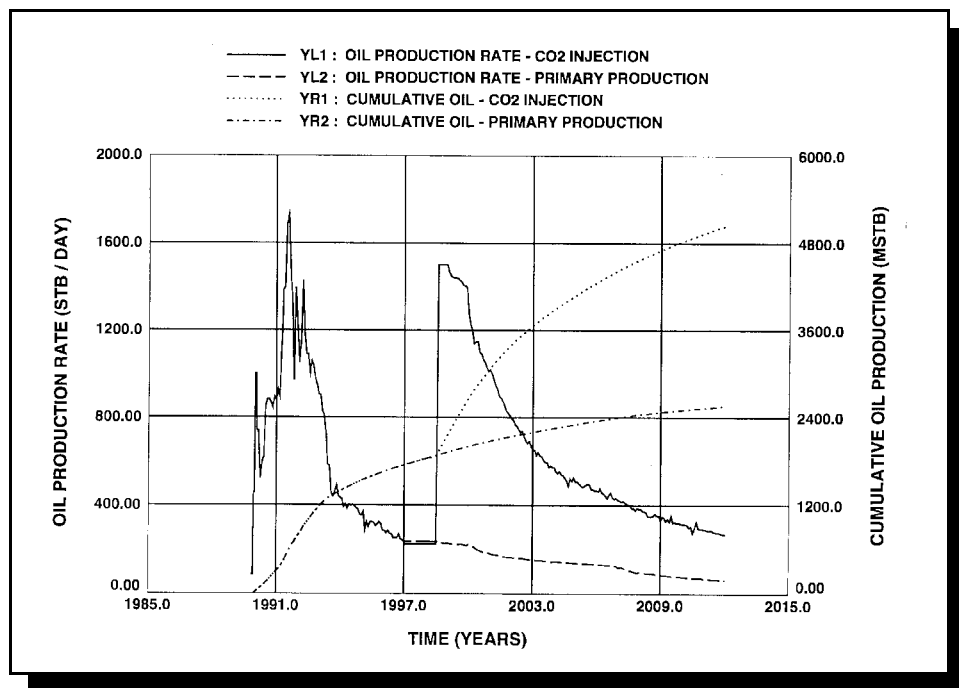


Figure 5. Oil recovery - primary depletion versus continuous CO₂-flood injection/flood recovery, Anasazi field.

2. An optimized CO₂ flood is predicted to recover a total 4.21 million STB. This represents an increase of 1.65 million STB over predicted primary depletion recovery as of January 1, 2012. The projected 4.21 million STB of oil production represents in excess of 89 percent of the OOIP in the mound complex and 36.8 percent of the OOIP of the total system modeled. The incremental recovery of 1.65 million STB requires the injection of the 35.0 billion standard cubic feet (BSCF) of gas and the purchase of 11.5 BSCF of CO₂.

3. Projected maximum CO₂ enhanced oil recovery will require pressurization of the reservoir to over 2,700 psia (core-mound core pressure in excess of 2,500 psia). This is the projected average operating pressure needed to provide miscibility, given past production and compositional changes.
4. Optimum recovery from CO₂ flooding will require one injector for each mound.
5. Vertical injection wells with injection restricted to the supra-mound interval provide the best recovery. Horizontal CO₂ injection wells have poorer recovery associated with early CO₂ break through.
6. Conditioning of produced gas to remove hydrocarbons prior to re-injection is not required to maintain miscible conditions in the reservoir and obtain high oil recovery.
7. The subject reservoir can maintain current production levels during reservoir fill-up without adversely impacting the CO₂ enhanced recovery process.
8. Comparison of continuous CO₂ injection versus CO₂ injection followed by blowdown favors continuous injection, since it is projected to recover 800,000 STB more oil than the case using blowdown.
9. Predicted waterflooding recovery was substantially below the projected CO₂-flood performance. The best waterflooding exhibited an incremental increase in oil recovery over primary production of 618,000 STB of oil versus the 1.65 million STB of additional recovery for the best CO₂ flood.
10. The low mobility of water (relative CO₂) and the corresponding poor injectivity of water injectors would require producers to operate at low bottom hole pressure to enhance water influx and improve water flood response time. Low reservoir pressure would result in three phase flow contributing to lower oil production rates and recovery.
11. Carbon dioxide flooding is favored over water flooding because:
 - a. higher oil recovery is possible,
 - b. substantially higher oil mobility which improves oil flow (CO₂) exhibited a maximum constrained rate of 1,500 STB/day versus a maximum waterflood rate of less than 400 STB/day,
 - c. project life is shorter, and
 - d. the possibility of return to primary depletion is possible after injecting CO₂; this is unlikely after injection of water.

Two additional simulation prediction cases (A and B) were run to assess the sensitivity CO₂ performance at Anasazi field to reductions in the CO₂ injection rate and to serve as the basis for the final economic assessment of CO₂ flooding. The principal operating parameters and simulation-related data used for these simulation cases were:

- C CO₂ injection starts on January 1, 2000.
- C Simulation case A uses an injection rate of 2.0 million standard cubic feet of gas per day (MMSCFGPD)/well and case B uses an injection rate of 4.0 MMSCFGPD/well. Injection was simulated through one well in each of the two mound lobes.
- C Production wells Anasazi No. 1, Anasazi No. 5L-3, and Sahgzie No. 1 were allowed to produce at the rate in effect on January 1, 2000 during reservoir fill-up.
- C Produced gas was recycled to reduce CO₂ make-up gas purchases. Thus, no conditioning was employed.
- C CO₂ injection was continuous from the start of injection until January 1, 2012.

The data show that for case A, the incremental oil recovery above primary was 951,000 STB as of January 1, 2012. This required injection of 17.5 BSCF of CO₂ and produced gas and purchase of 10.1 BSCF of CO₂. Simulation prediction results indicate that a CO₂ injection rate of 2.0 million SCFGPD/well would not be sufficient to meet ongoing production needs of the operator and generate acceptable economic returns. It would however, increase recovery by close to 1.0 million STB of oil over predicted primary recovery as of January 1, 2012.

The data show that for case B, the incremental oil recovery above primary was 1,654,000 STB as of January 1, 2012. This required injection of 35.0 BSCF of CO₂ and produced gas, and purchase of 11.5 BSCF of CO₂. Specifically, using a 4.0 million SCFGPD/day/well injection rate from two injectors, the CO₂ flood will recover 4.21 million STB. This represents an increase of 1.65 million STB over predicted primary recovery as of January 1, 2012. The projected 4.21 million STB represents more than 89 percent of the OOIP in the mound complex and 36.8 percent of the OOIP in the total system modeled.

Runway Reservoir Performance Predictions

The history-matched simulator was used to predict the performance of the Runway reservoir under continued primary depletion, and assess the potential of CO₂ flooding (figure 6). Major results of the predicted reservoir performances are presented below.

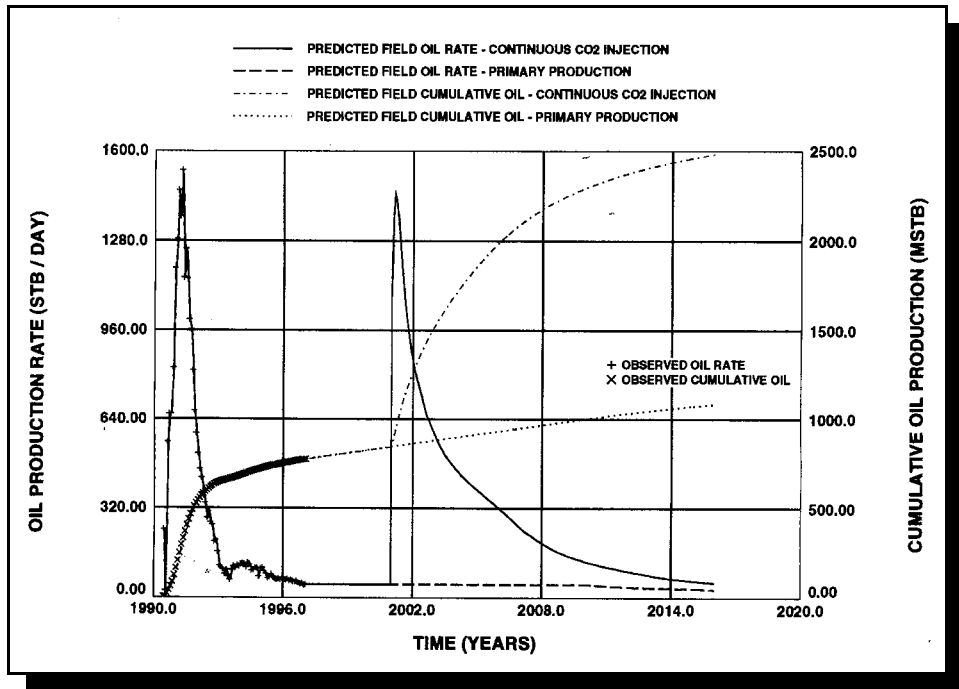


Fig. 6. Oil recovery - primary depletion versus continuous CO₂-flood injection/flood recovery, Runway field.

1. The projected primary production through January 1, 2012 is 1.032 million STB. This represents 31 percent of the OOIP in the mound complex proper and 21 percent of the OOIP in the mound and off-mound areas and the platform interval.
2. Of the limited number of prediction cases completed, the best CO₂ flood is predicted to recover a total 2.4 million STB. This represents an increase of 1.58 million STB over predicted primary depletion recovery as of January 1, 2012. The projected 2.4 million STB of oil production represents 71 percent of the OOIP in the mound complex and 48 percent of the oil in place of the total system modeled, excluding the Ismay. The incremental recovery of 1.58 million STB requires the injection of 51.0 BSCF of gas and the purchase of 8.7 BSCF of CO₂.
3. Projected maximum CO₂ enhanced oil recovery will require pressurization of the reservoir to over 3,000 psia. This is the projected average operating pressure needed to provide miscibility, given past production and compositional changes.
4. Optimum recovery from CO₂ flooding may only require one horizontal injector.
5. The reservoir can maintain current production levels during reservoir fill-up without adversely impacting the CO₂ enhanced recovery process.

6. Additional prediction cases are needed to assess the impact of operating the CO₂ flood at various injection rates. The 8.0 MMSCFPD case resulted in marginal economics despite reasonable overall oil recovery.

Economic Assessments of CO₂ Floods

Anasazi Field: Using reservoir simulation-based performance predictions and current CO₂ flood implementation costs, detailed economic assessments were conducted for a number of different CO₂ flood options. These studies indicated that:

1. A CO₂ flood of the Anasazi reservoir has robust economics. With U.S. Department of Energy (DOE) participation the project would have a rate-of-return (ROR) of 62 percent, a payout of 35 months, a profitability index (PI) of 15 to 1, and a discounted (10 percent) net-present-value (NPV) in excess of \$12,500,000. Harken's capital outlay would be \$1,728,000. Even without DOE participation the economics remain robust with a ROR of 48 percent, a payout of 39 months, a PI of 8 to 1, and a discounted NPV of over \$11,000,000. The capital requirements would be \$3,146,000.
2. Leasing the compressor on a five year contract basis is better economically than purchasing the compressor. Leasing improves the ROR by approximately \$1.0 million.
3. The benefit from processing produced gas to separate CO₂ from the hydrocarbons and using the hydrocarbons for fuel and sales are offset by the large capital investment required for a membrane separation facility. Thus, re-injection of all produced gas without conditioning is economically more attractive than implementing a CO₂ flood with gas processing.
4. The difference between a minimum and maximum cost option for installation of flow/injection lines and the CO₂ supply is approximately \$1,000,000. However, the economics are still robust. With DOE cost sharing, the ROR is 56 percent with a PI of 11.5 to 1.
5. Comparison of the economics of a process using blowdown after six years of CO₂ injection versus the continuous CO₂ injection case indicates that the ROR and the PI are not significantly different, but the NPV is substantially decreased (approximately \$1.4 million). The lower NPV is a result of lower oil recovery for the blowdown case (800,000 STB less than the continuous injection case).

Production data and injection gas requirements, including CO₂ make-up purchases, from case B information were used to assess, from an economic standpoint, the financial merits of CO₂ flood with a 8.0 MMSCFPD total injection rate commencing January 1, 2000. The economic assessment was conducted assuming the following conditions: (1) leased compressor (option 1 - \$19,500/option 2 - \$23,500 [same compressor with a different engine]), (2) CO₂ supply line construction using the minimum costs option (\$825,000), (3) no gas processing, and (4) cost sharing by the DOE. This assessment concludes that CO₂ flooding provides both an adequate flood response and an acceptable economic ROR of 32 percent and

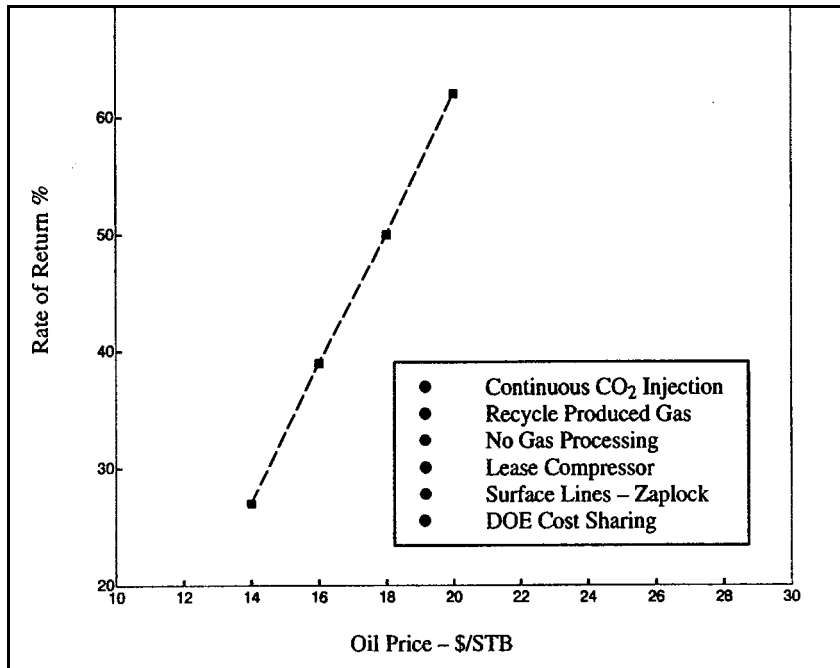


Figure 7. Rate of return versus price of oil, Anasazi field CO₂ flood at high rate.

a payout of 36 months. A discounted (10 percent) NPV of \$5.9 million could be realized by implementing a CO₂ flood under the proposed conditions. Harken's capital outlay with DOE participation would be \$1,493,000.

In summary, if the CO₂ flood performs as predicted, it is a financially robust process for increasing the reserves of the Anasazi reservoir. However, the ROR and NPV are very sensitive to oil prices (figures 7 and 8). Therefore economics should be rerun before installation of injection facilities.

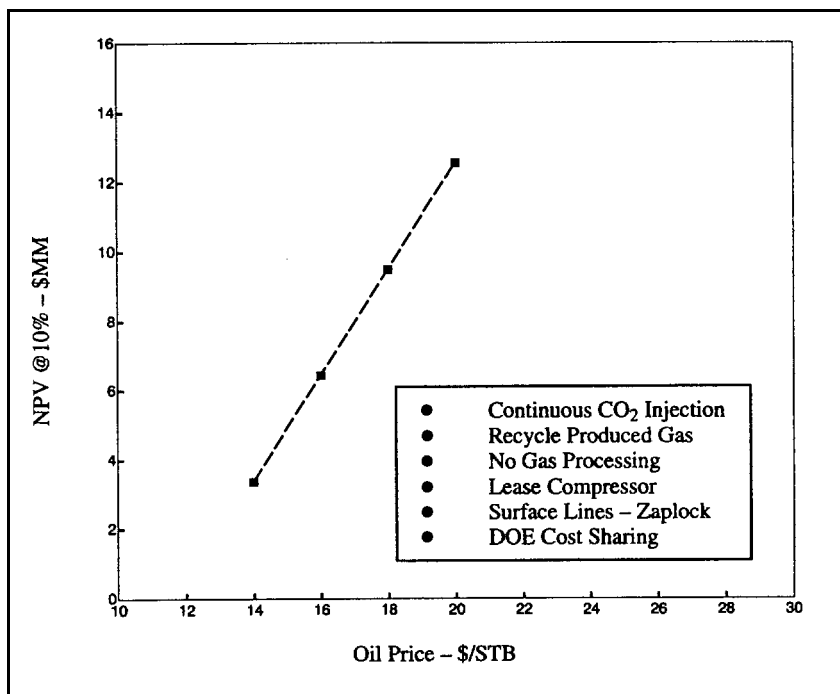


Figure 8. Net present value versus price of oil, Anasazi field CO₂ flood at high rate.

Runway Field: Using reservoir simulation-based performance predictions and current CO₂ flood implementation costs, detailed economic assessments were conducted for five different CO₂ flood options. This set of studies indicated that:

1. A CO₂ flood of the Runway reservoir has acceptable economics. With DOE participation the project would have a ROR of 30 percent, a payout of 32 months, a PI of 5 to 1, and a discounted (10 percent) NPV in excess of \$3,100,000. Harken's capital outlay would be \$1,532,000. Even without DOE participation the economics remain acceptable with a ROR of 21 percent, a payout of 39 months, a PI of 2.8 to 1, and a discounted NPV of almost \$2,000,000. The capital requirements would be \$2,789,000.
2. Based on the Anasazi study, leasing a compressor rather than purchase was adopted for the Runway evaluation.
3. The difference between a minimum and maximum cost option for installation of flow/injection lines and the CO₂ supply is approximately \$233,000. However, the economics are still acceptable. With DOE cost sharing, the ROR is 29 percent with a PI of 4.8 to 1, and a discounted NPV of \$2,900,000.
4. Most economic evaluations exhibited negative cash flows in the year 2008, when operating costs exceed revenues. At this point the projects were terminated. However, the reservoir process should have been changed from continuous CO₂ injection to blowdown and the economics re-run. The additional recovery from blowdown, without the operating costs associated with CO₂ injection, would improve economic returns. Thus, additional prediction runs should be completed to assess the conversion to blowdown on economics.

In summary, if the CO₂ flood performs as predicted, it is a financially acceptable process for increasing the reserves of the Runway reservoir. However, the ROR and NPV are very sensitive to oil prices (figures 9 and 10). Therefore economics should be rerun before installation of injection facilities.

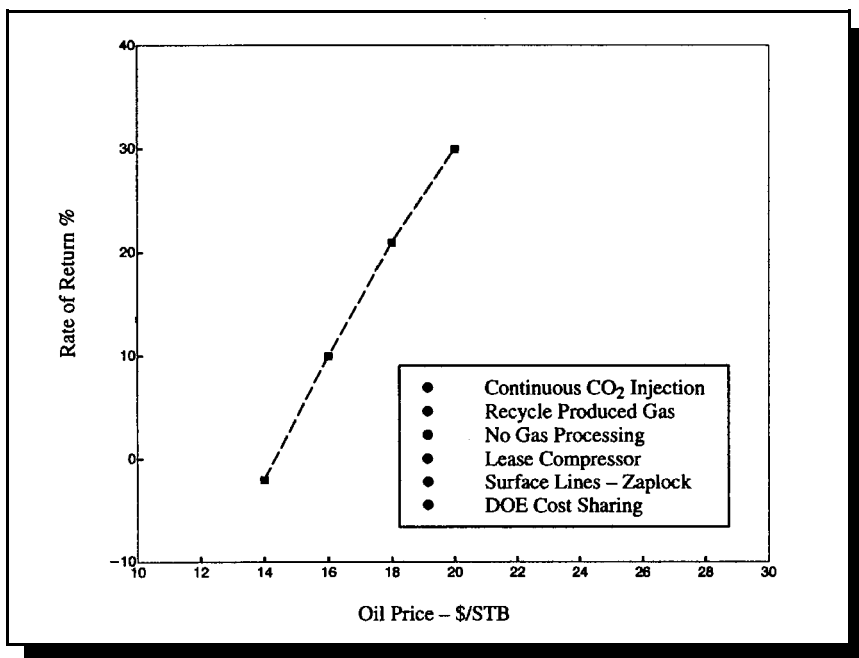


Figure 9. Rate of return versus price of oil, Runway field CO₂ flood at high rate.

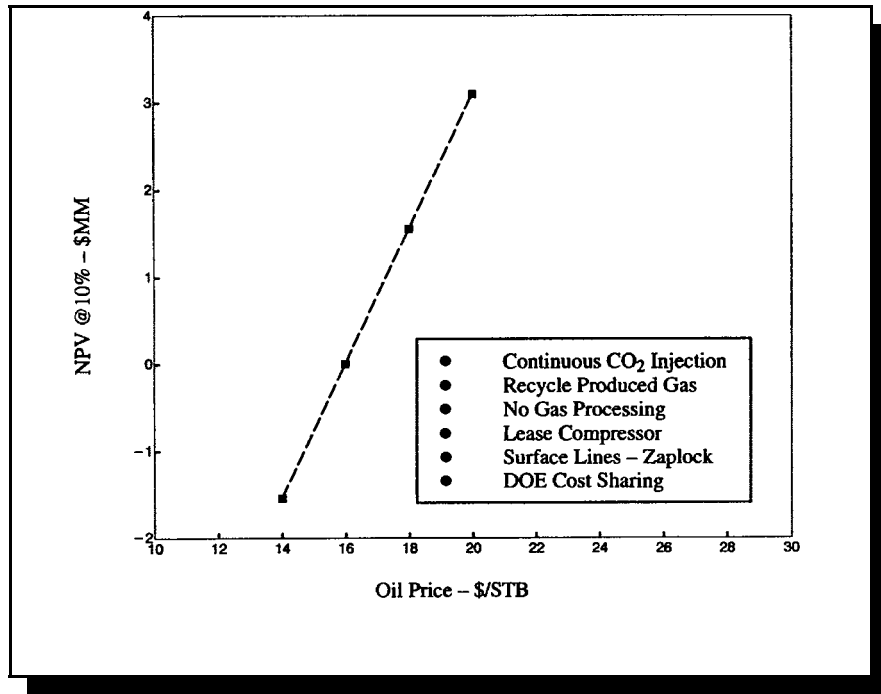


Figure 10. Net present value versus price of oil, Runway field CO₂ flood at high rate.

Conclusions, and Reserve and Recovery Determinations for Project Fields

The results of the Anasazi and Runway studies can be used to qualitatively assess the CO₂ recovery potential of other Paradox basin small, algal-mound reservoirs containing fluids with similar properties. However, the experience gained in history matching and predicting the performance of the Anasazi and Runway reservoirs indicates that the overall mound geometry and internal facies architecture is critical to matching and predicting performance.

The cumulative production for the five project fields as of January 1, 1999, is summarized on table 1. Heron North field is currently shut-in. Primary recovery and OOIP (table 2) were determined from volumetric reserve calculations, material balance calculations, and decline curve extrapolations, as well as refined geologic characterization. These volumetric calculations were made by evaluating well logs and reservoir aerial extent (as defined by seismic data), coupled with reservoir geometry. Material balance and decline curve calculations utilized the production and pressure history. Knowing the OOIP and the primary recovery, the amount of oil left behind was calculated. Lastly, utilizing the results from the simulation studies of Anasazi and Runway fields, sweep efficiencies for CO₂ flooding and the ultimate enhanced recovery were estimated for all project fields (table 2). Using the average predicted oil recovery rate of 71.8 percent (percent recovery of remaining oil in place after primary recovery) for the Runway and Anasazi reservoirs, the projected additions to reserves if CO₂ is also applied to all the project fields is over 8.2 million STB of oil.

Table 1. Cumulative production from project fields.

Project Field	Cumulative Production*		
	Oil (bbl)	Gas (MCF)	Water (bbl)
Anasazi	1,883,393	1,625,892	29,942
Blue Hogan	311,842	303,938	1,903
Heron North	206,446	328,713	34,820
Mule	410,792	273,247	31,710
Runway	801,889	2,675,307	5,987

* As of January 1, 1999; source - Utah Division of Oil, Gas and Mining.

Table 2. Reserve and recovery determinations.

Project Field	OOIP* (MSTB)	Primary Recovery		ROIP** (MSTB)	CO ₂ Flood Projected Recovery (MSTB)	CO ₂ Flood Recovery % ROIP
		Oil (MSTB)	Gas (MCF)			
Anasazi†	4,706	2,000	1,890,000	2,706	2,208	81.6
Blue Hogan	2,530‡	321	968,000	2,209	1,586	71.8
Heron North	2,640‡	216	2,650,000	2,424	1,740	71.8
Mule	2,000‡	454	288,000	1,546	1,110	71.8
Runway	3,372	825	2,830,000	2,547	1,577	61.9

* Original oil in place (thousand stock tank barrels [MSTB]), mound-core and supra-mound intervals (includes platform interval in Runway)

** Remaining oil in place

† High rate case starting CO₂ flood January 1, 2000

‡ Estimate based on approximate volumetric data

TECHNOLOGY TRANSFER

Project materials, results, and objectives were displayed at 13 professional society meetings and conventions. The UGS sponsored two workshops displaying core and results of the reservoir modeling. The UGS also conducted a field trip to the outcrops which served as reservoir analogs, and to field facilities. Thirteen technical papers with project results were presented at various professional society conventions and 25 papers were published in professional journals, guidebooks, and periodicals.

The UGS established a web site on the Internet with a Paradox basin project home page (<http://utstdpwww.state.ut.us/~ugs/paradox.htm>). The UGS also maintains a database which includes those companies or individuals (over 300) specifically interested in the Paradox basin project and who receive the UGS *Survey Notes* and *Petroleum News* periodicals.

BENEFITS

The benefits expected from the project are: (1) increased recoverable reserves by identifying untapped compartments created by reservoir heterogeneity, (2) increased deliverability through a CO₂-miscible flood in other small fields in the Paradox basin, (3) stimulation of exploration for field extensions and new fields along identified reservoir trends and Paradox basin fairways, (4) use of project technology in other basins with similar types of reservoirs, (5) prevention of premature abandonment of numerous small fields, (6) reduction of development costs by more closely delineating minimum field size and other parameters necessary to a successful flood, (7) more productive use of limited energy investment dollars, and (8) increased royalty income to the Navajo Nation; Federal, state, and local governments; and fee owners. Project benefits could apply to other areas in the Rocky Mountain region, the Michigan and Illinois basins, and the Midcontinent region.

Budget Period I of the project showed that a CO₂ flood, not a waterflood, would be best technically, as well as economically feasible. For Anasazi field, an optimized CO₂ flood is predicted to recover a total 4.21 million STB of oil. This represents an increase of 1.65 million STB of oil over predicted primary depletion recovery as of January 1, 2012. The projected 4.21 million STB of oil production represents in excess of 89 percent of the OOIP in the mound complex and 36.8 percent of the OOIP of the total system modeled. For Runway field, the best CO₂ flood is predicted to recover a total 2.4 million STB. This represents an increase of 1.58 million STB of oil over predicted primary depletion recovery as of January 1, 2012. The projected 2.4 million STB of oil production represents 71 percent of the OOIP in the mound complex and 48 percent of the OOIP of the total system modeled, excluding the Ismay reservoir.

FUTURE ACTIVITIES

Phase II will be a CO₂-miscible flood demonstration project on Anasazi field, as determined from the characterization study. This technique was identified as having the greatest potential for increased well productivity and ultimate recovery. The demonstration project will include:

- (a) conducting a CO₂ injection test(s),
- (b) acquiring a CO₂ source for the flood project,
- (c) acquiring a fuel gas source for the compressor,
- (d) rerunning project economics,

- (e) drilling a development well(s), vertically or horizontally, to facilitate sweep during the pilot flood,
- (f) purchasing and installing injection facilities,
- (g) flood management, monitoring field performance, and evaluation of results, and
- (h) determining the feasibility of transferring the project technologies to similar fields in the Paradox basin and throughout the U.S.

The results of this project will continue to be transferred to industry and other researchers through a petroleum extension service, creation of digital databases for distribution, technical workshops and seminars, field trips, technical presentations at national and regional professional meetings, maintaining a project home page on the Internet, and publication in newsletters and various technical or trade journals.

ACKNOWLEDGMENTS

This research is performed under the Class II Oil Program of the U.S. Department of Energy, National Petroleum Technology Office, Tulsa, Oklahoma, contract number DE-FC22-95BC14988. The Contracting Officer's Representative is Gary D. Walker, NPTO, Tulsa, OK. Budget Period I, the Geological and Reservoir Characterization was February 9, 1995 - August 31, 1998. Budget Period II, the Field Demonstration is September 1, 1998 - August 31, 2002.

Additional funding is being provided by the industry partner and subcontractor Harken Southwest Corporation, Houston, Texas, David Gibbs, Vice President, Engineering and Development, and Richard O. Cottle, Vice President, Engineering; and the Utah Office of Energy and Resource Planning, Jeff Burks, Director.

COST-EFFECTIVE TECHNIQUES FOR IMPROVED OIL RECOVERY IN MISSISSIPPIAN CARBONATE RESERVOIRS OF KANSAS -- NEAR TERM -- CLASS 2

DOE CONTRACT NUMBER: DE-FC22-93BC14987

DOE PROJECT MANAGER: Daniel J. Ferguson (dferguso@npto.doe.gov; 918.699.2047)

CONTRACT PERFORMANCE PERIOD: 9/16/1994 to 1/31/2000

T. CARR (tcarr@kgs.ukans.edu); S. BHATTACHARYA, (saibal@kgs.ukans.edu)
A. BYRNES, (abyrnes@kgs.ukans.edu); E. FRANSEEN, (evanf@kgs.ukans.edu; 785-864-3965)
P. GERLACH (pgerlach@kgs.ukans.edu); W. GUY, (bguy@kgs.ukans.edu)
L. WATNEY, (lwatney@kgs.ukans.edu)
Phone 785-864-3965

University of Kansas Energy Research Center
Kansas Geological Survey
University of Kansas
Lawrence, KS 6607-3726

The majority of Kansas production is operated by the small independent oil and gas producer (90% of the 3,000 Kansas producers have less than 20 employees). The independent producer does not have the extensive resources and the ready access to a research lab to develop and test advanced technologies. For the Kansas oil and gas industry, access to new technology remains a critical component to sustained production and increased economic viability. A major emphasis of the Kansas Class 2 project was collaboration of University of Kansas scientists and engineers with Kansas independent producers and service companies. The goal was to develop and modify cost-effective new technologies and to accelerate adaptation and evaluation of these technologies.

The project introduced a number of potentially useful technologies, and demonstrated these technologies in actual oil field operations. Advanced technology was tailored specifically to the scale appropriate to the operations of Kansas producers. An extensive technology transfer effort is ongoing. Traditional technology transfer methods (e.g., publications and workshops) were supplemented with a public domain relational database and online package of project results is available through the Internet. The goal is to provide the independent complete access to project data and technology on the desktop.

Project Background

The demonstration project was conducted in cooperation with Ritchie Exploration, Inc. of Wichita, which operates leases that were the focus of the demonstration. However, a number of major operators in the Schaben Field contributed data to the project, and tested and adopted project results. Schaben Field (1963 discovery) is located in Ness County on the western flank of the Central Kansas uplift, and is typical of Mississippian production in Kansas. Prior to project initiation, cumulative field production was 9.1 million barrels of oil, and daily production was 326 BOPD from 51 wells prior. In Kansas, the majority of Mississippian production occurs at or near the top just below a regional unconformity. Production from Mississippian reservoirs accounts for approximately 43% of total annual production, and cumulative production exceeds 1 billion barrels. Today, independent producers, operating many of these reservoirs and production units, deal with high water cuts and low recovery factors that place continued operations at or near economic limits.

Cost Effective Technology for Independent Producers

Common problems in Kansas reservoirs that affect producibility include; old and missing data, inadequate reservoir characterization, drilling and completion design problems, and non-optimal primary

recovery. The value of cost-effective techniques for reservoir characterization and simulation at Schaben Field were demonstrated to independent operators. All major operators at Schaben have used results of the reservoir management strategy to locate and drill additional infill locations. At the Schaben Demonstration Site, the additional locations resulted in incremental production increases of 200 BOPD from a smaller number of wells.

Integrated geologic reservoir characterization provided the basis for development of a quantitative reservoir model. Descriptive reservoir characterization entailed integration and creative application of existing vintage data, drilling and coring three new wells. Core analysis (including NMR), petrophysical analysis, calibration of logs and core data were integrated with existing well data into a computerized 3D visualization. Procedures and computer code were developed to modify, load and display well logs using seismic workstations for improved 3D visualization using available wireline log data. Geologic, engineering and production data were brought into a common set of relational databases. Much of the data from Schaben Field is available on-line at reservoir, lease and well levels.

Log and core analyses, and petrographic descriptions were completed to better understand the pore geometry of the carbonate reservoir. All of the complexities existing in an evaluation of an extremely heterogeneous reservoir are present in the producing reservoir at Schaben Field. Determination of pore size, throat size, irreducible water saturation, permeability, effective porosity, and movable oil was possible using cost-effective techniques on existing data. As an example, NMR and capillary pressure data on 18 core plugs were used to determine fluid filled porosity, free fluid porosity, bound water porosity, pore size, grain size, and irreducible water saturation. One aspect of the project involved development of a low-cost PC-based petrophysical analysis package (PfeFFER). The program, available to oil operators works as part of a spreadsheet, and is a practical tool for the real-time, interactive log analysis. Spreadsheet database and graphic features allow both rapid interaction and comparative evaluation of multiple interpretations or best case/worst case extremes. A project file manages multiple wells and zones, and can be generated that assembles reservoir parameter, grids them, and displays them as 2-D maps or 3-D surfaces. After completion of the reservoir characterization, the US DOE Boast 3 Reservoir Simulation Package was adapted for use at the full-field scale. The Boast Freeware was modified to work with commonly available, spreadsheet programs as pre- and post-processors. The result was a full field reservoir simulation model and management tool that the independent producer can run on a desktop PC using freeware and a spreadsheet.

Project design, methodologies, data, and results are disseminated to independent operators through focused technology transfer activities. These activities include development of cost-effective technologies (e.g. PfeFFER, "Pseudoseismic"), traditional publication; workshops and seminars; and public access through the Internet. In addition to traditional workshops, electronic courses covering important technologies are available on the North Mid-continent PTTC Internet Site. The target audience includes other operators in the demonstration area, operators of numerous other Mississippian sub-unconformity dolomite reservoirs in Kansas, operators of analogous shallow shelf carbonate reservoirs in the Mid-continent and technical personnel with reservoir development and management.

Summary

All technologies used have been adapted to be cost-effective for independent operators of mature fields. Technologies include petrophysical analysis (PfeFFER), visualization (Pseudoseismic), core analysis using NMR, numerical simulation on a PC, and Internet technology transfer. The value of these technologies for independent operators has been demonstrated. All major operators at Schaben have adopted the results of the reservoir management strategy developed as part of the study, and have located and drilled approximately 20 infill locations. Overall results of the incremental wells are very favorable. The procedures continued to be transferred to other independent operators through publication, presentations, hands-on computer workshops and Internet access.



Improved Oil Recovery in Mississippian Carbonate Reservoirs of Kansas

Appropriate Advanced Technology
for the
Independent Producer



Participants

Ritchie Exploration Inc., Wichita Kansas



Project Philosophy

- Appropriate Cost-Effective Technology
 - Application to Kansas Fields
 - Develop and Modify
 - Transfer
- Impact a Broad Base of Kansas Production
 - 3,000 Operating Companies
 - Mississippian
 - Cumulative 1 Billion Barrels
 - Producing Oil Wells 17,542

Project Accomplishments

■ Cost Effective Technology

Visualization

Petrophysical Analysis

Core Analysis

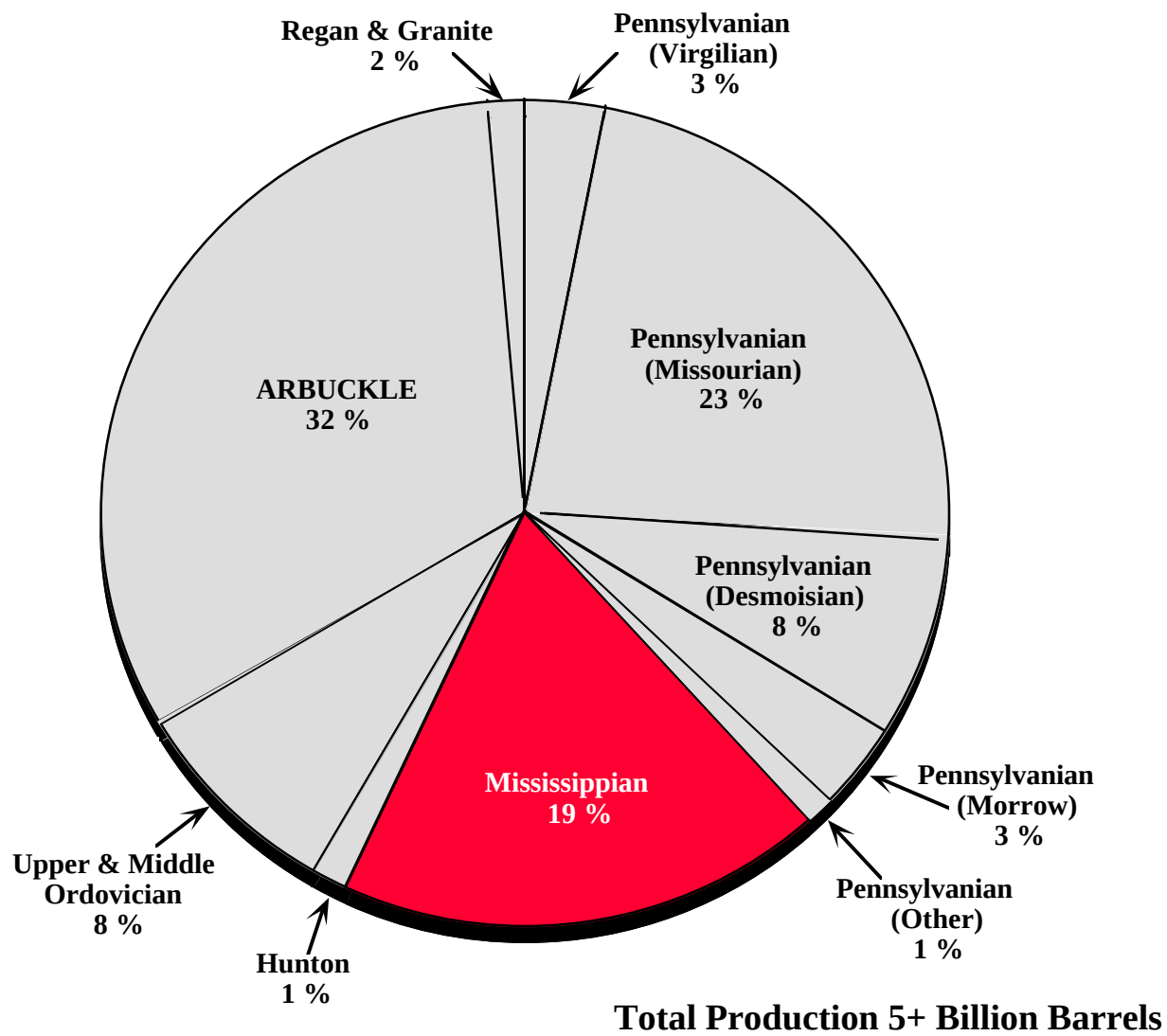
PC based Reservoir Simulation

Internet Technology Transfer

■ Incremental Oil

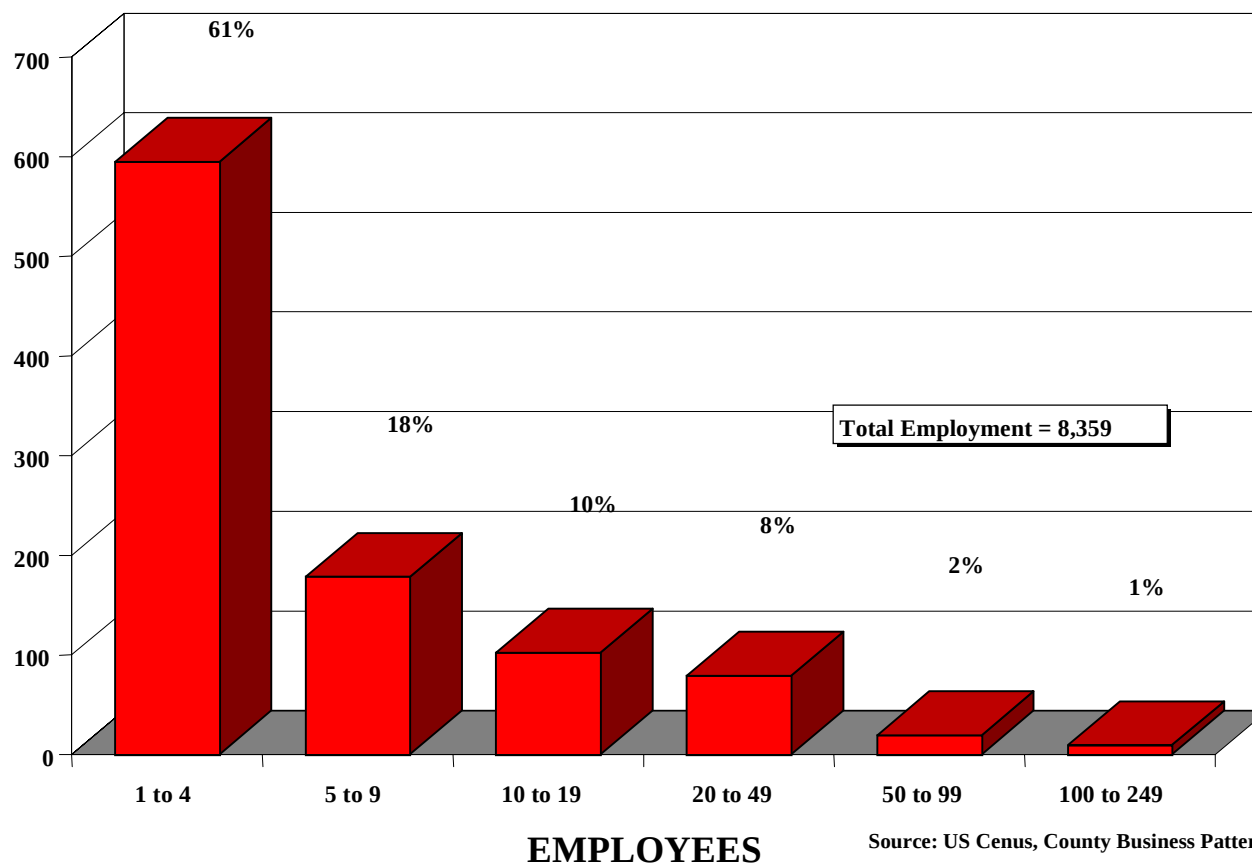
Additional 200 BOPD

Kansas Oil and Gas Industry



Kansas Oil and Gas Industry

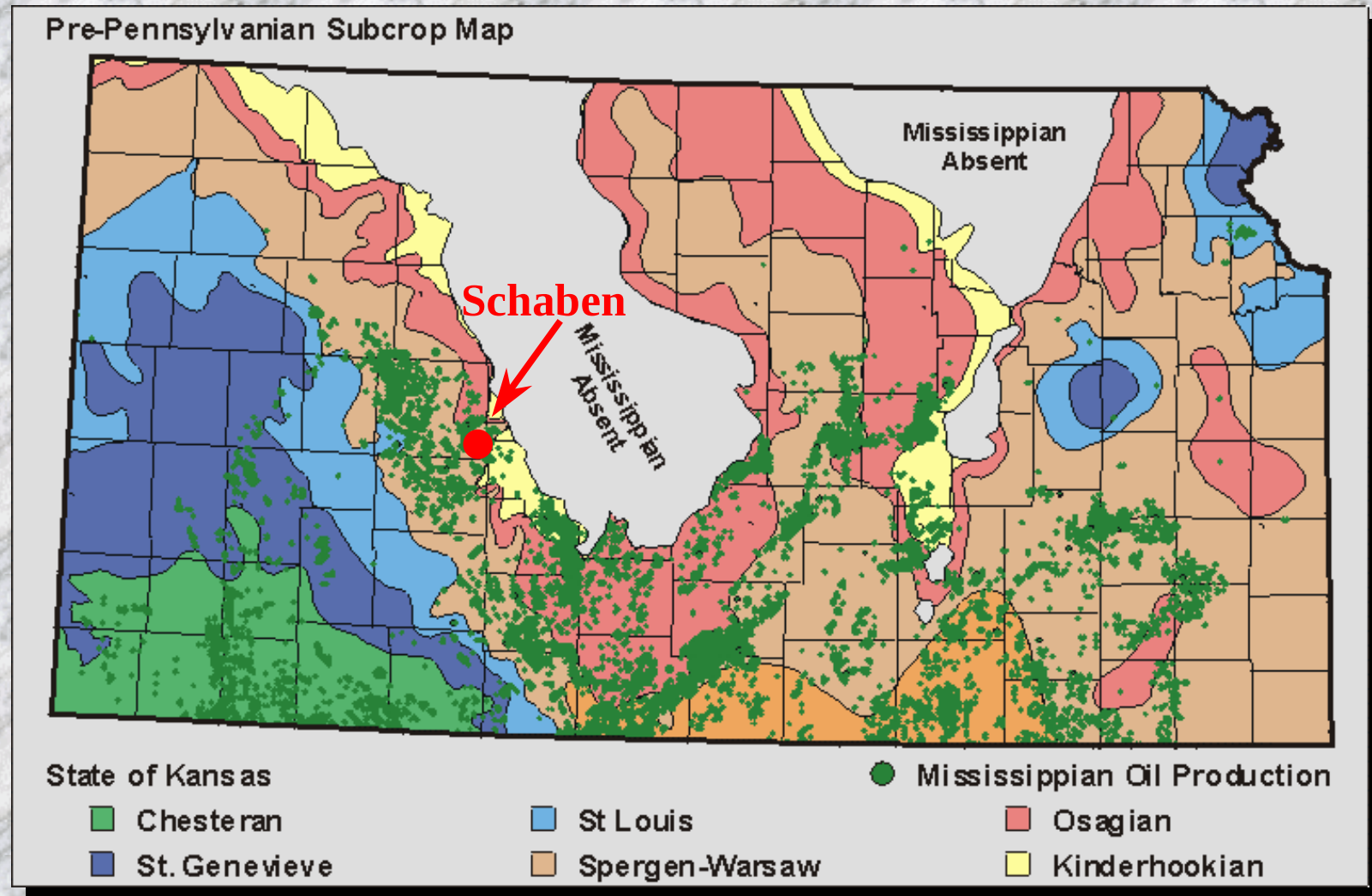
KANSAS OIL & GAS PRODUCERS



Schaben Field

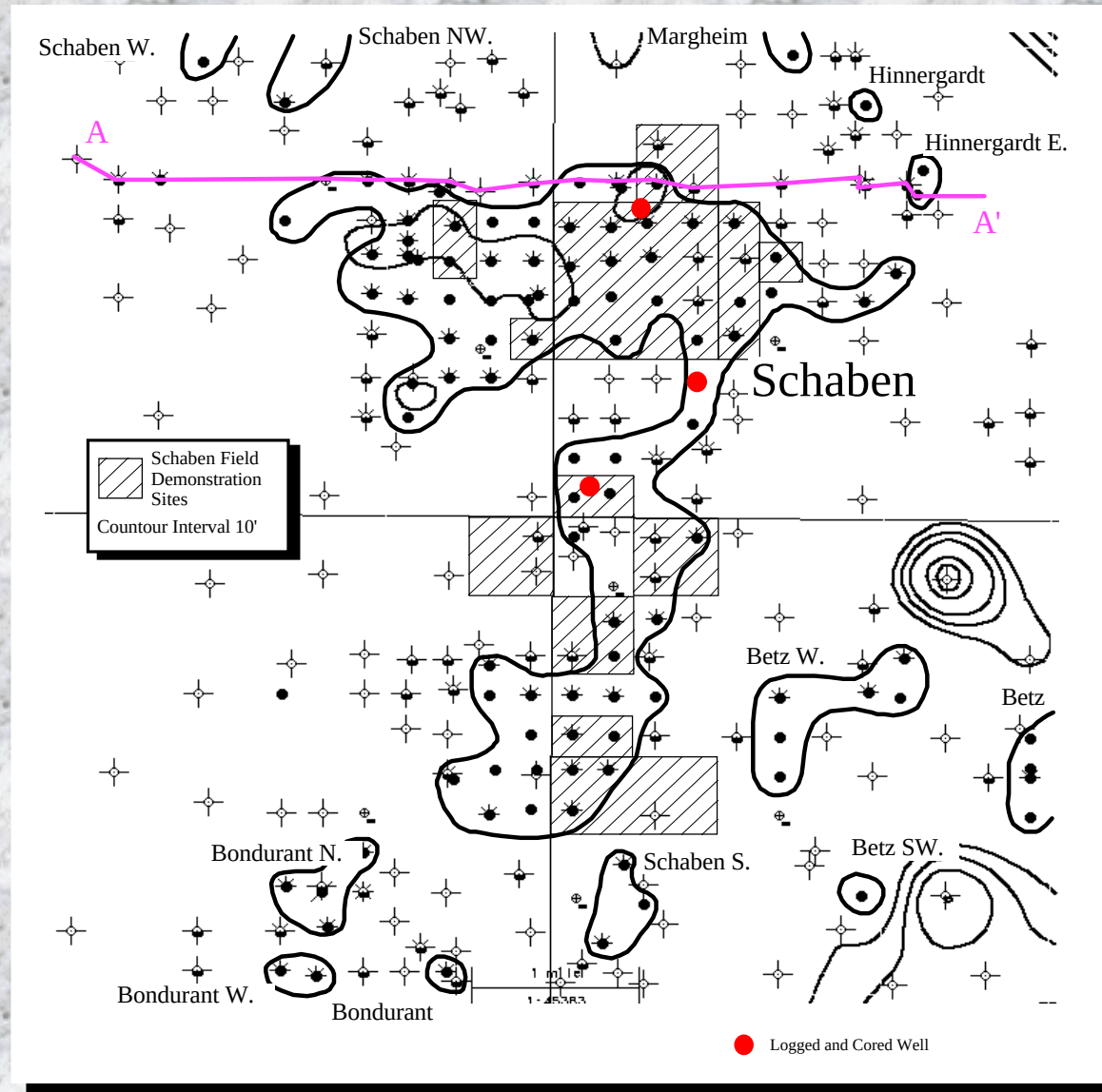
- Discovery Date: October, 1963
- Producing Horizon: Mississippian (Osagian)
- Active Water Drive
- Producing Depth: 4400'
- Cumulative Production: 9.3 MMBO
- Producing Wells: 47 (Oct-98)
- Estimated Field OOIP: 40-50 MMBO
- Average Field Rec. Eff. = 17%

Subcrop Map of Mississippian Rocks of Kansas



http://www.kgs.ukans.edu/DPA/Plays/ProdMaps/miss_sub_oil.html

Schaben Field Demonstration Area

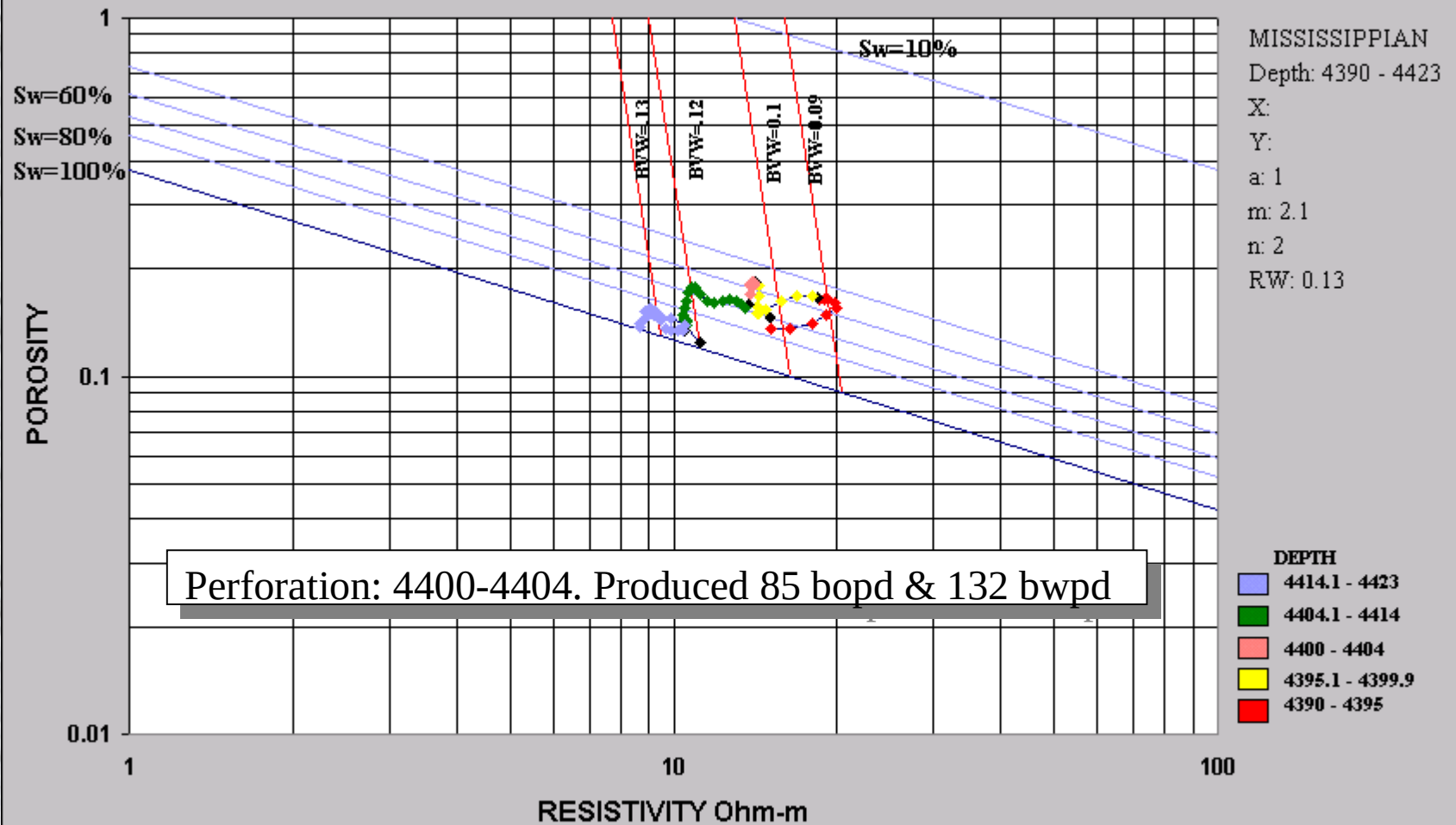




VERSION
PfEFFER 2.0/PRO
REAL-TIME INTERACTIVE LOG ANALYSIS.

- Petrofacies Evaluation of Formations For Engineering Reservoirs
- PfEFFER Ver. 2.0 -- February 1998
- Spreadsheet Based
- Digital Logs or Manual Entry
- Interactive
- Modules (8,000 lines of Visual Basic)

LYLE SCHABEN "2P"







PfEFFER VERSION **2.0/PRO**
REAL-TIME INTERACTIVE LOG ANALYSIS.

New Features

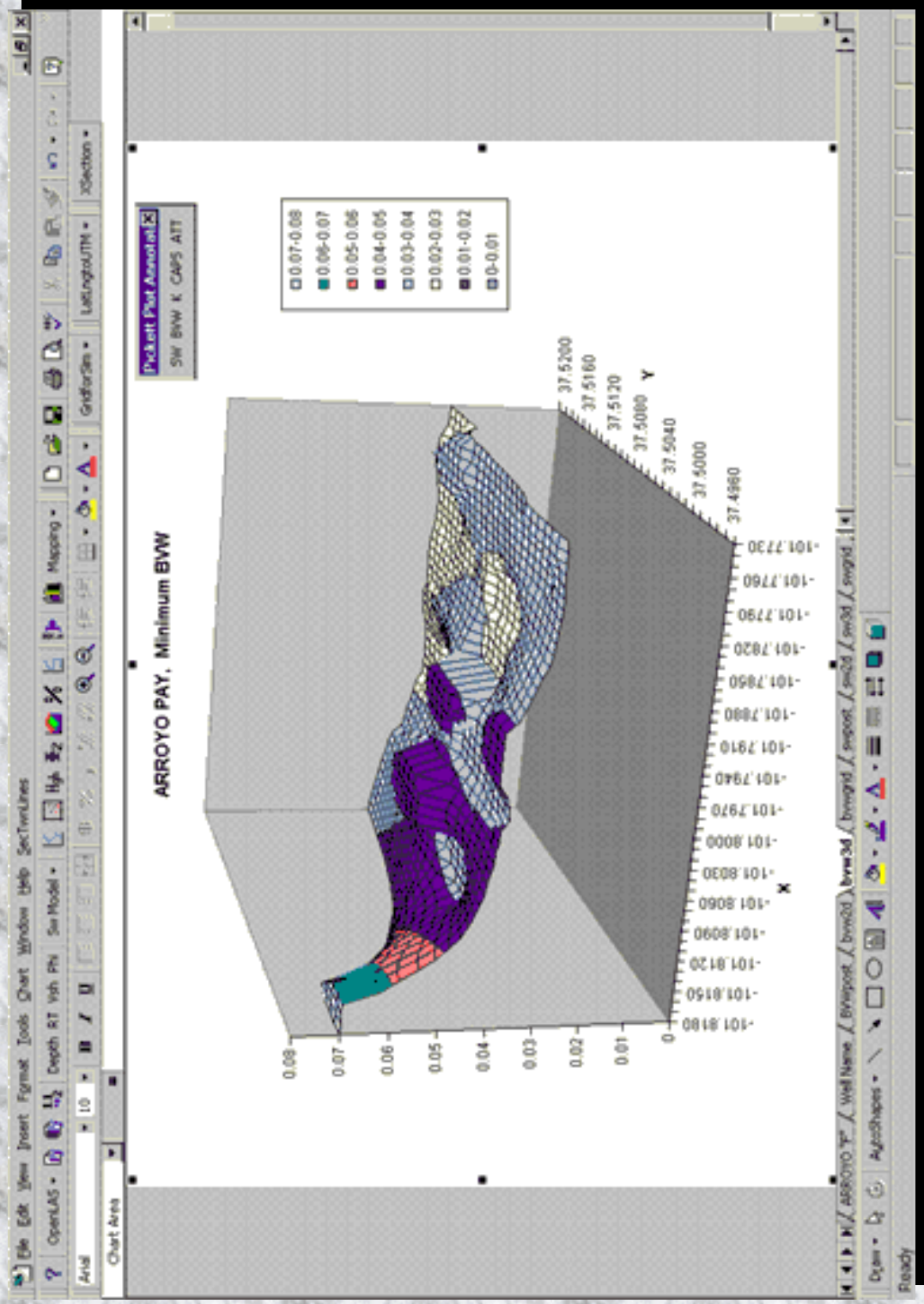
- Vshale
- Improved Porosity Calculations
- Shaly Sand Models
- Hough Transforms
- Moveable Hydrocarbons
- Lithological Analysis
- Improved 2D and 3D Mapping
- Generate Input Tables for Reservoir Simulation





VERSION PFEIFFER 2.0/PRO

REAL-TIME INTERACTIVE LOG ANALYSIS.



RITCHIE Exp. - "2 LYLE SCHWEN 'P'"
Sec. 31 T. 19 S. R. 21 W
NESS CO., KANSAS

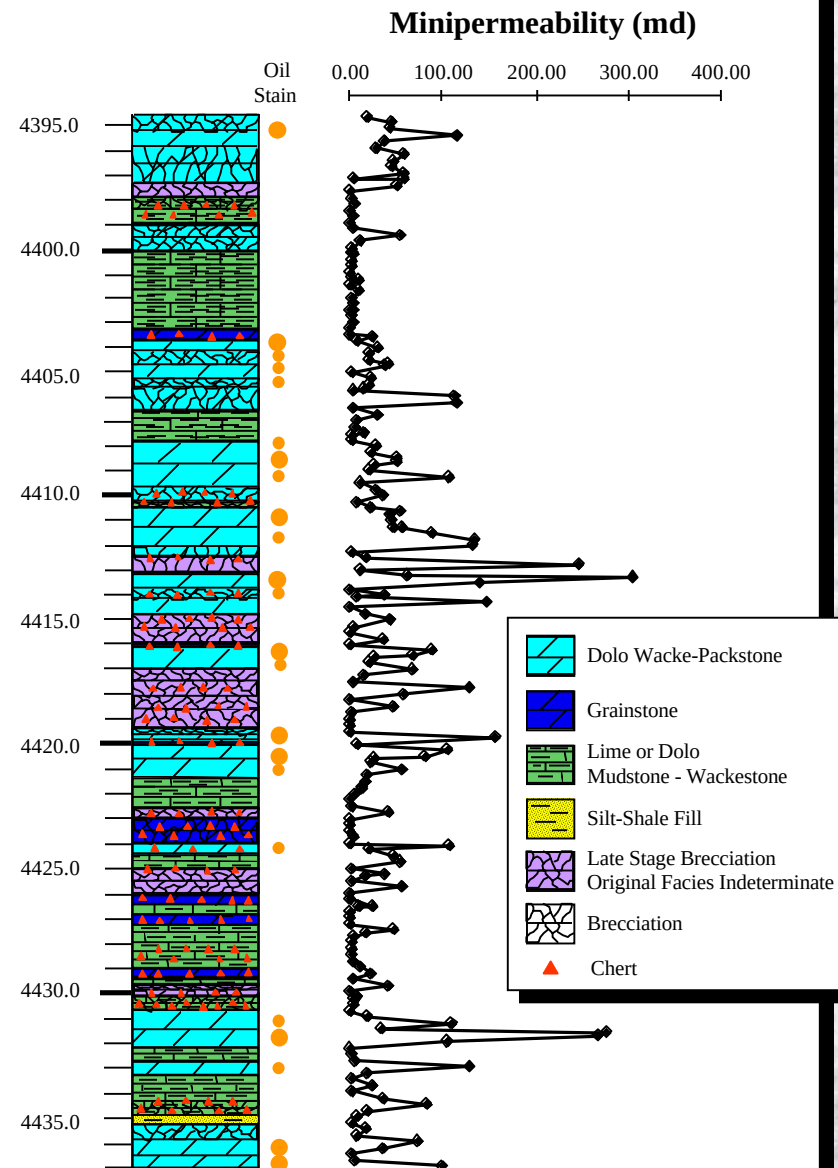


4418 TO 4425
Box 6 of 12

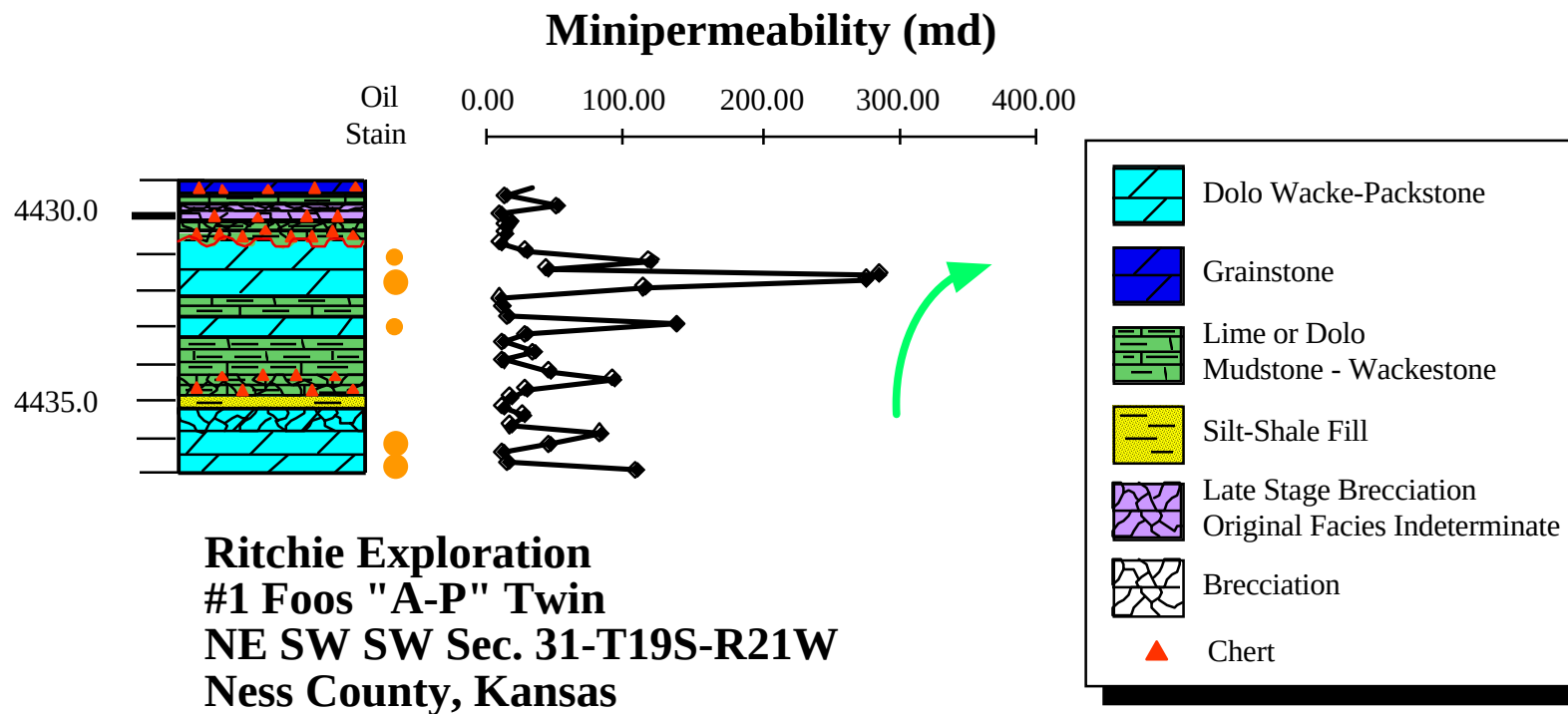


Geologic Reservoir Description

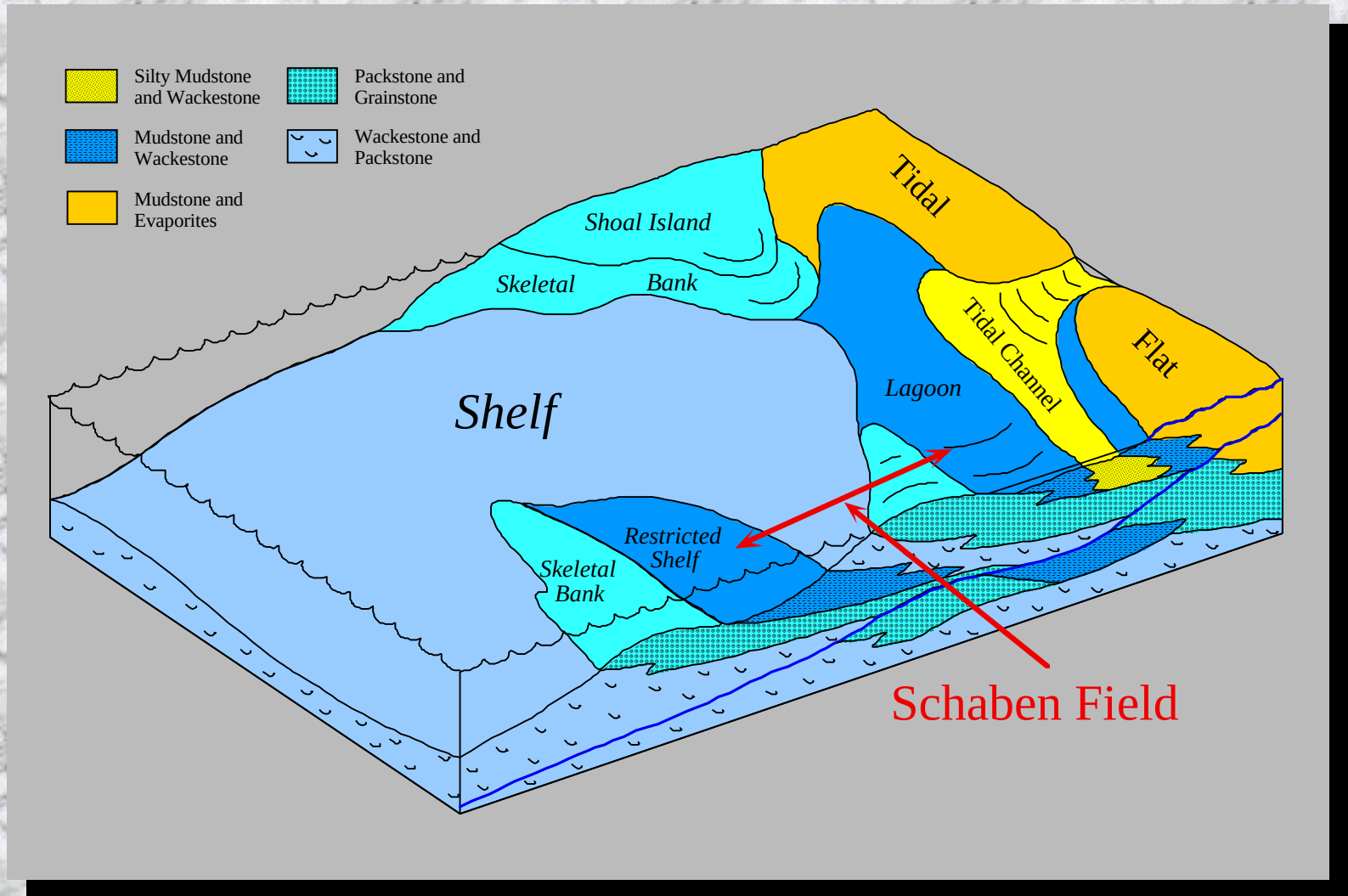
Ritchie Exploration1 Foos "A-P" Twin
NE SW SW Sec. 31-T19S-R21W
Ness County, Kansas



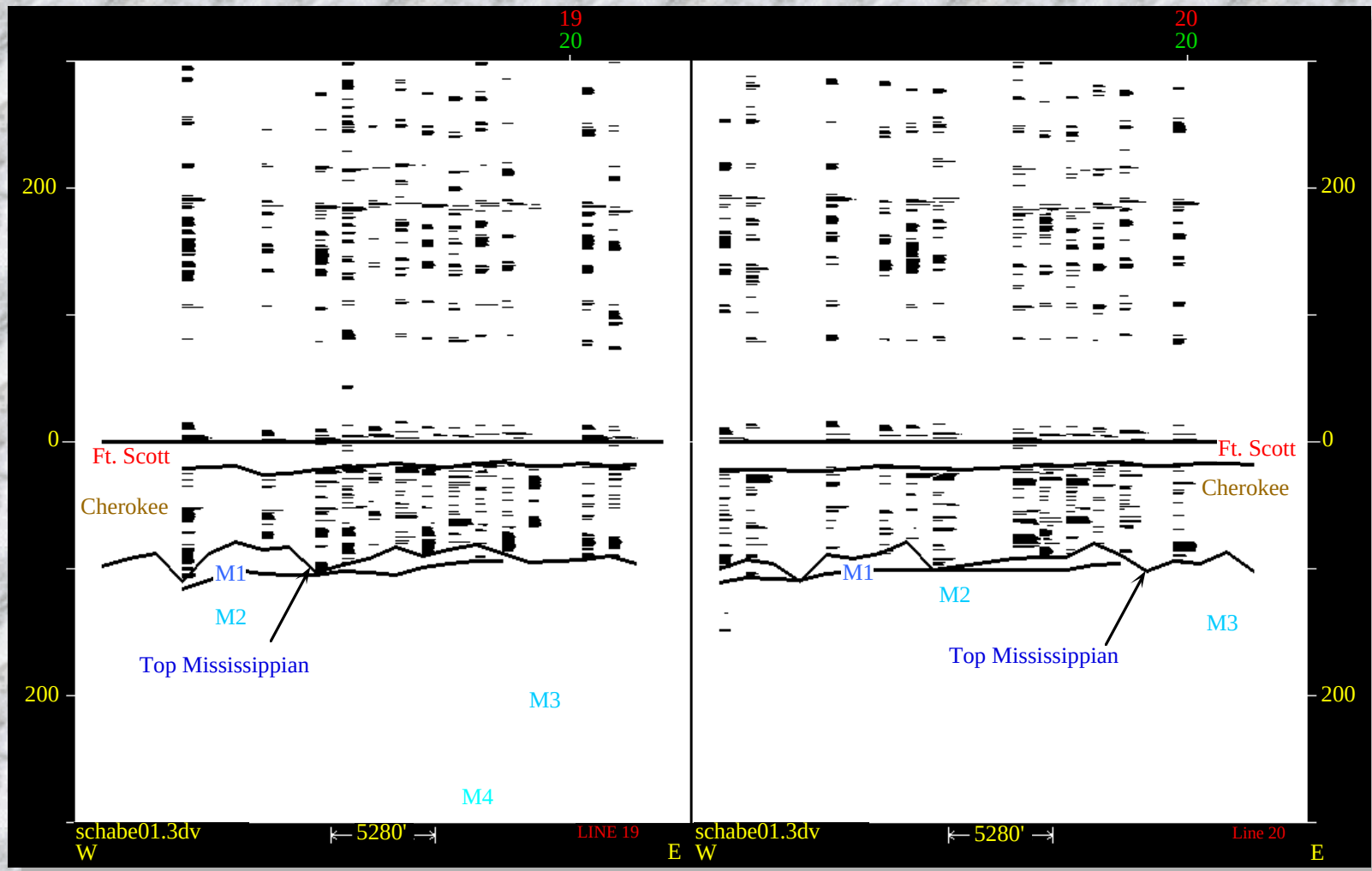
Geologic Reservoir Description



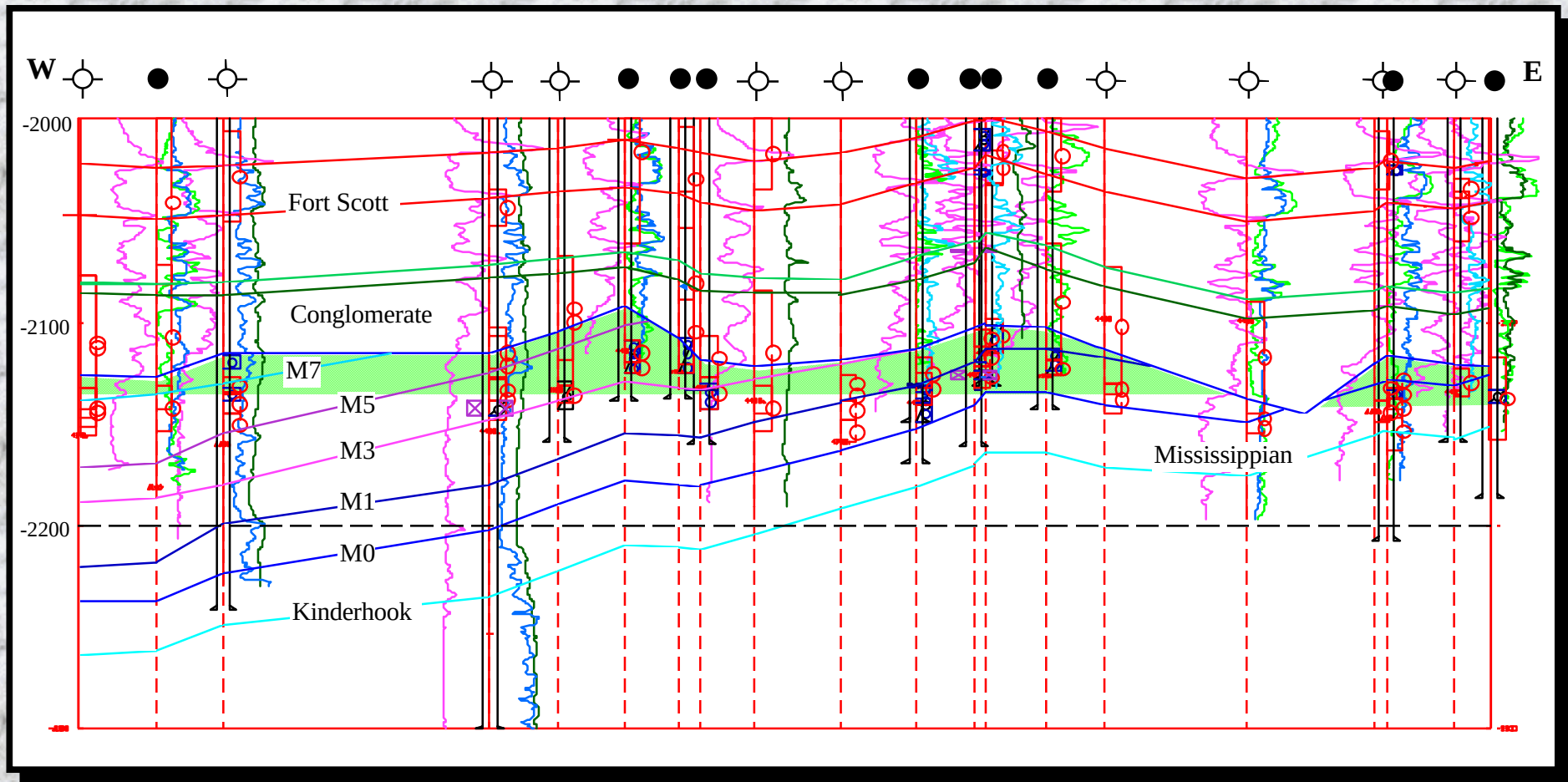
Depositional Model



Schaben Field: Visualization Pseudoseismic

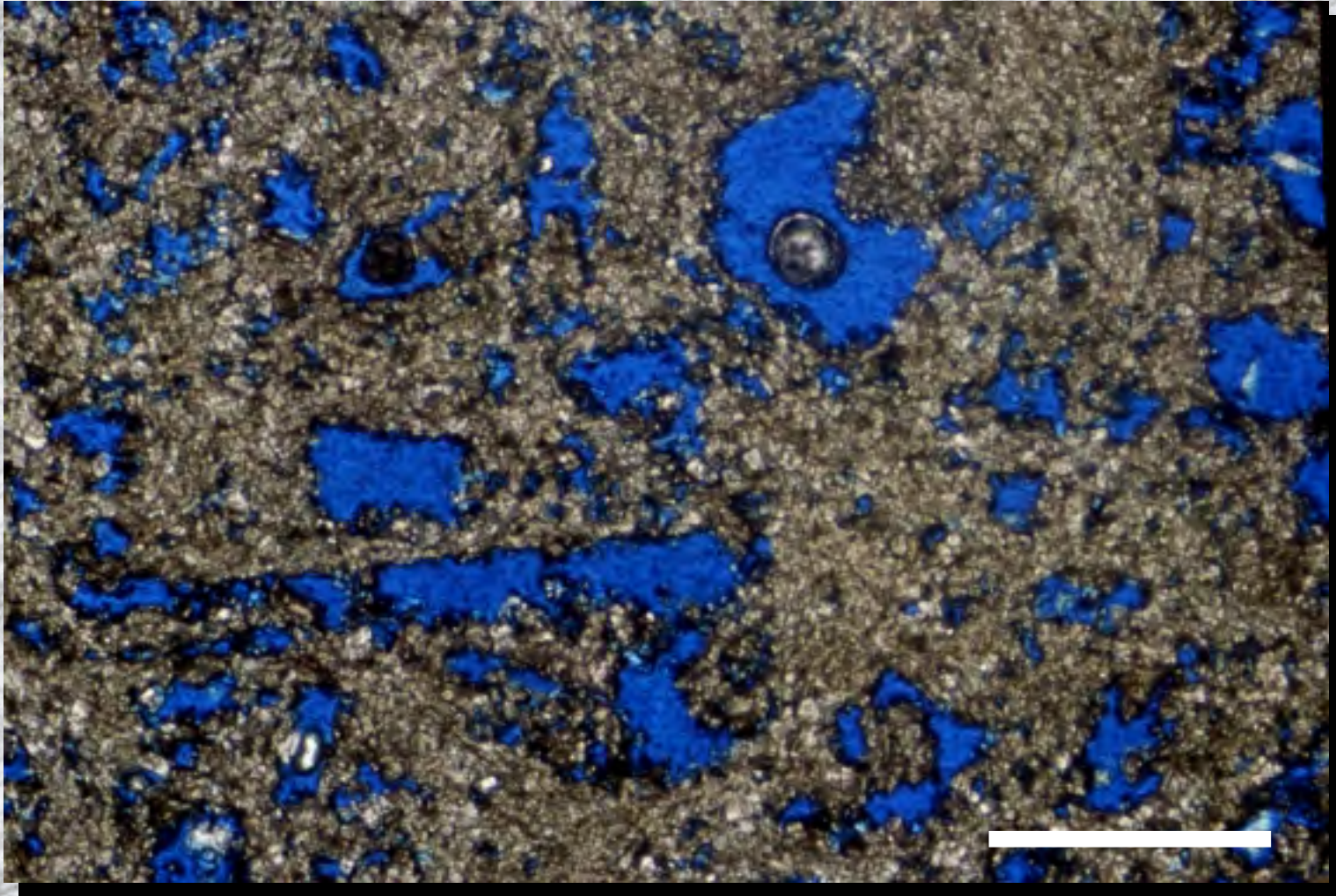


Schaben Field Structure Cross-Section



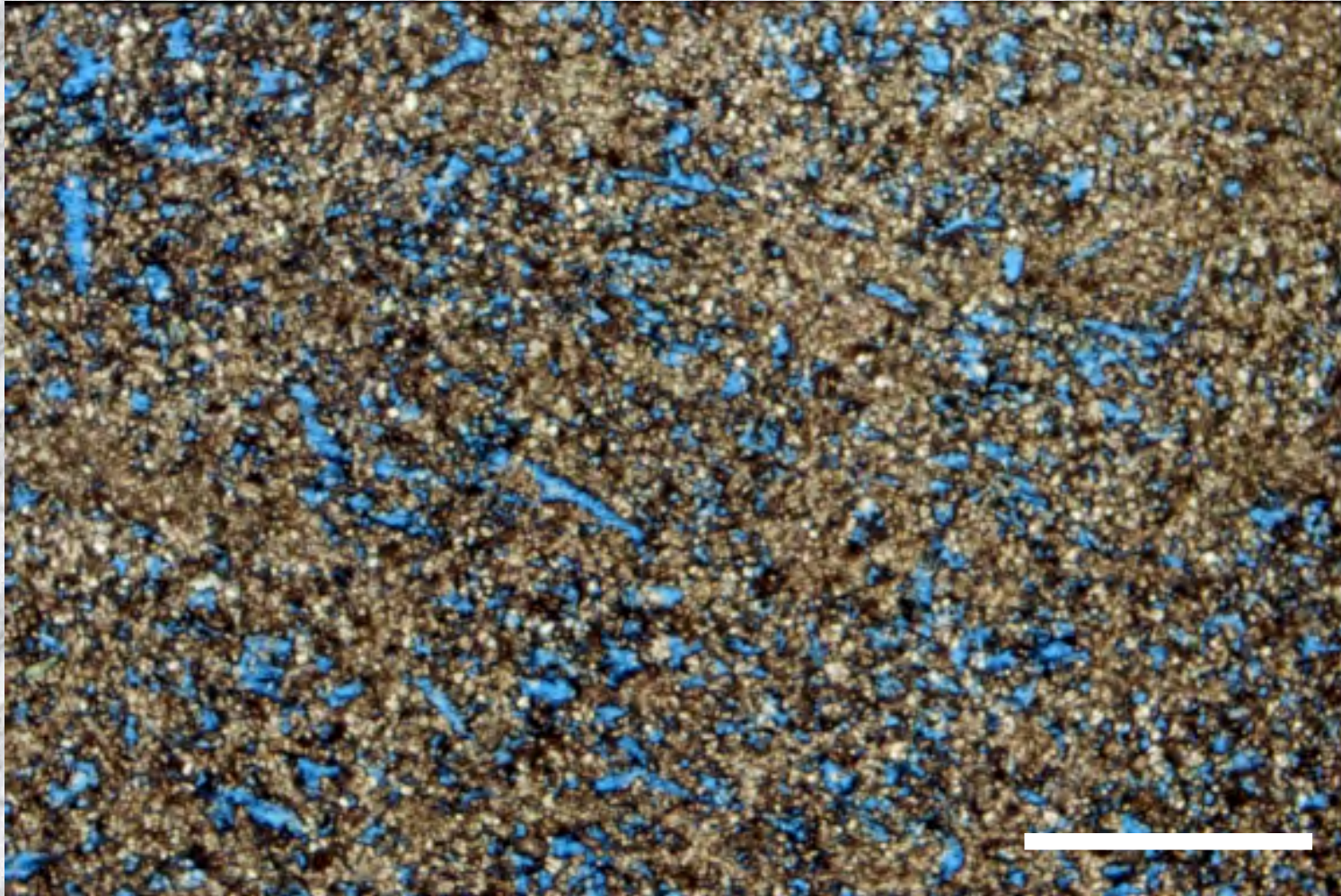
Reservoir Facies

Skeletal Wackestone - Packstone



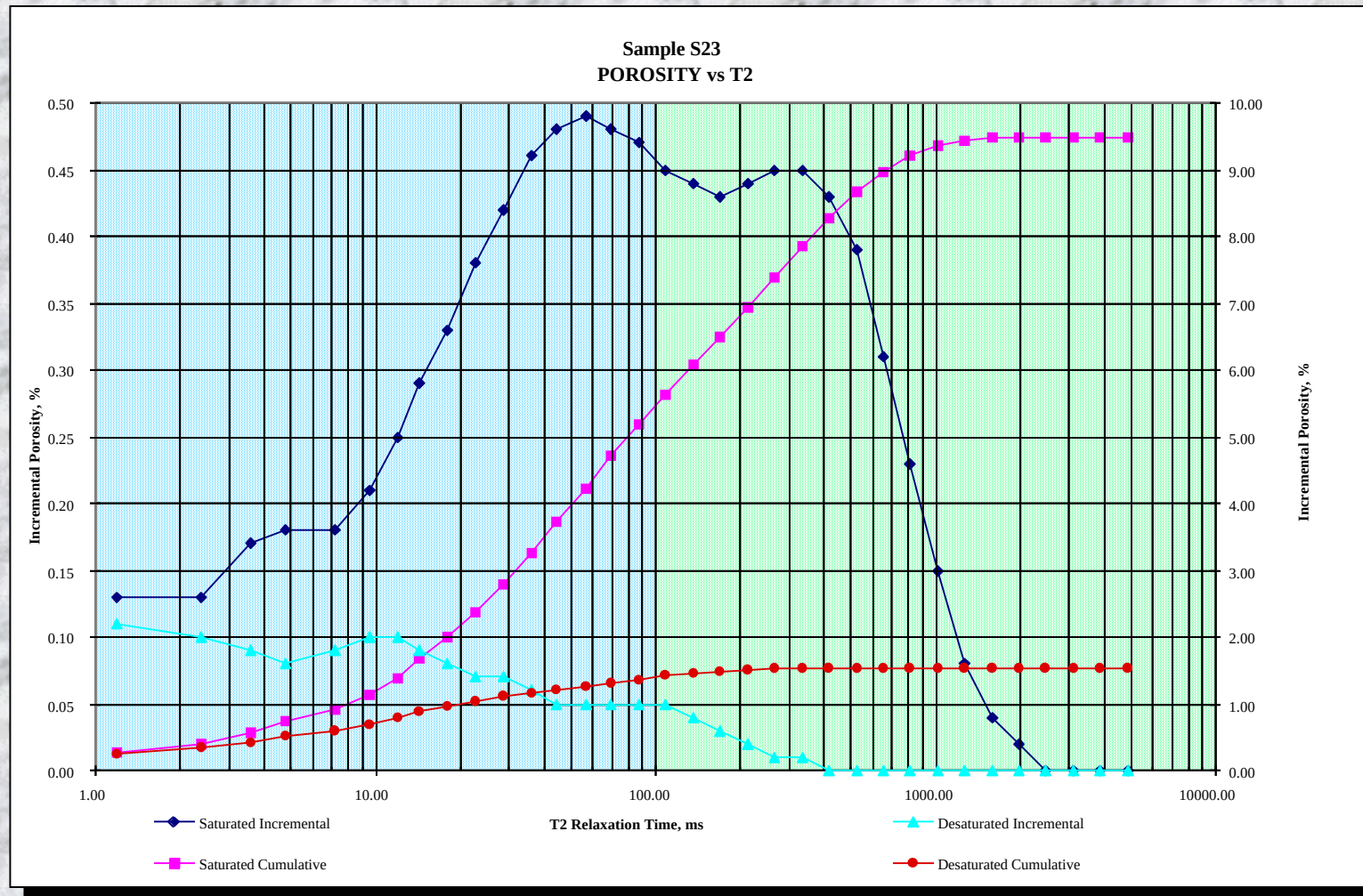
Ritchie 2 Schaben P

Spicule-Rich Mudstone -Wackestone Facies

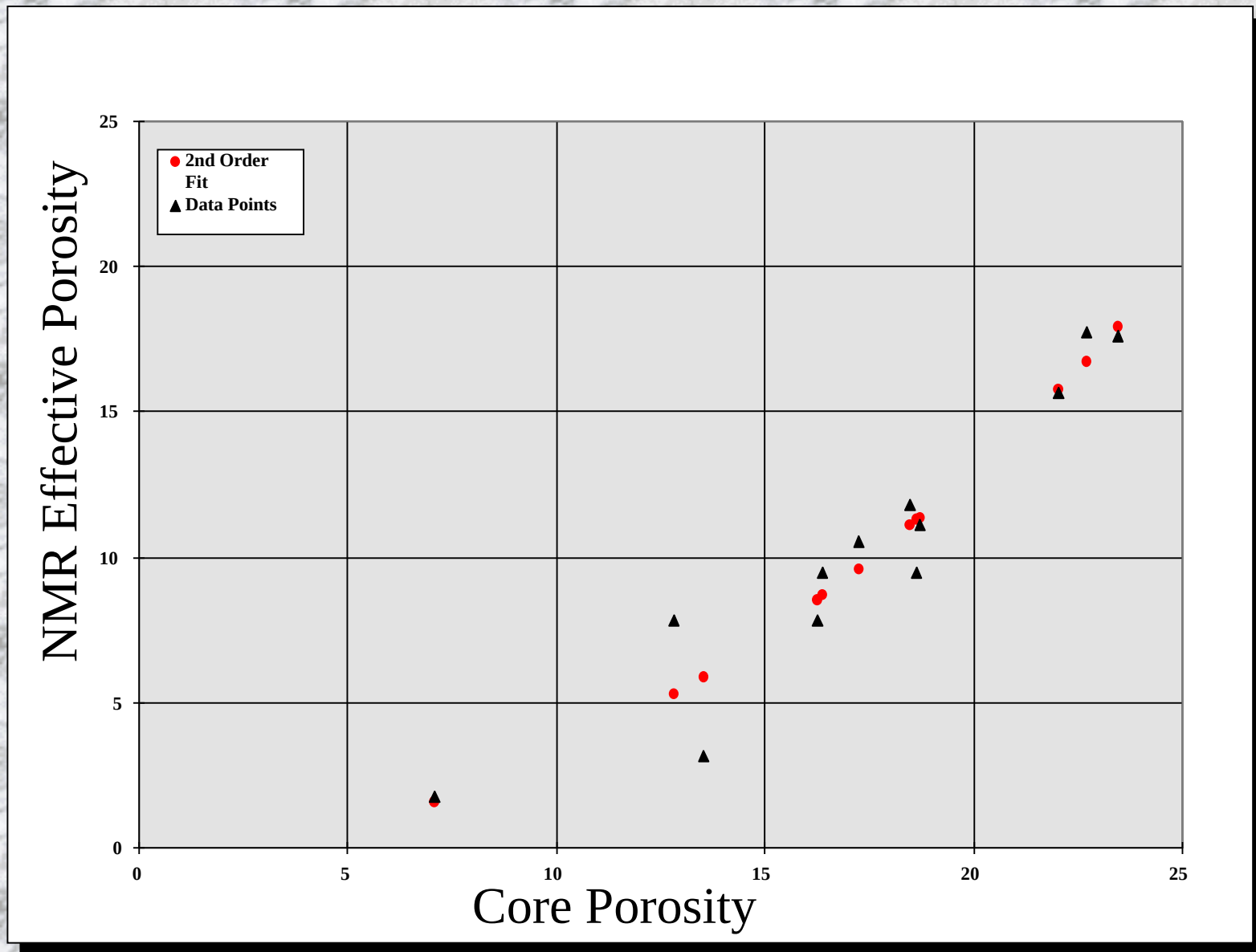


Ritchie 1 Moore B

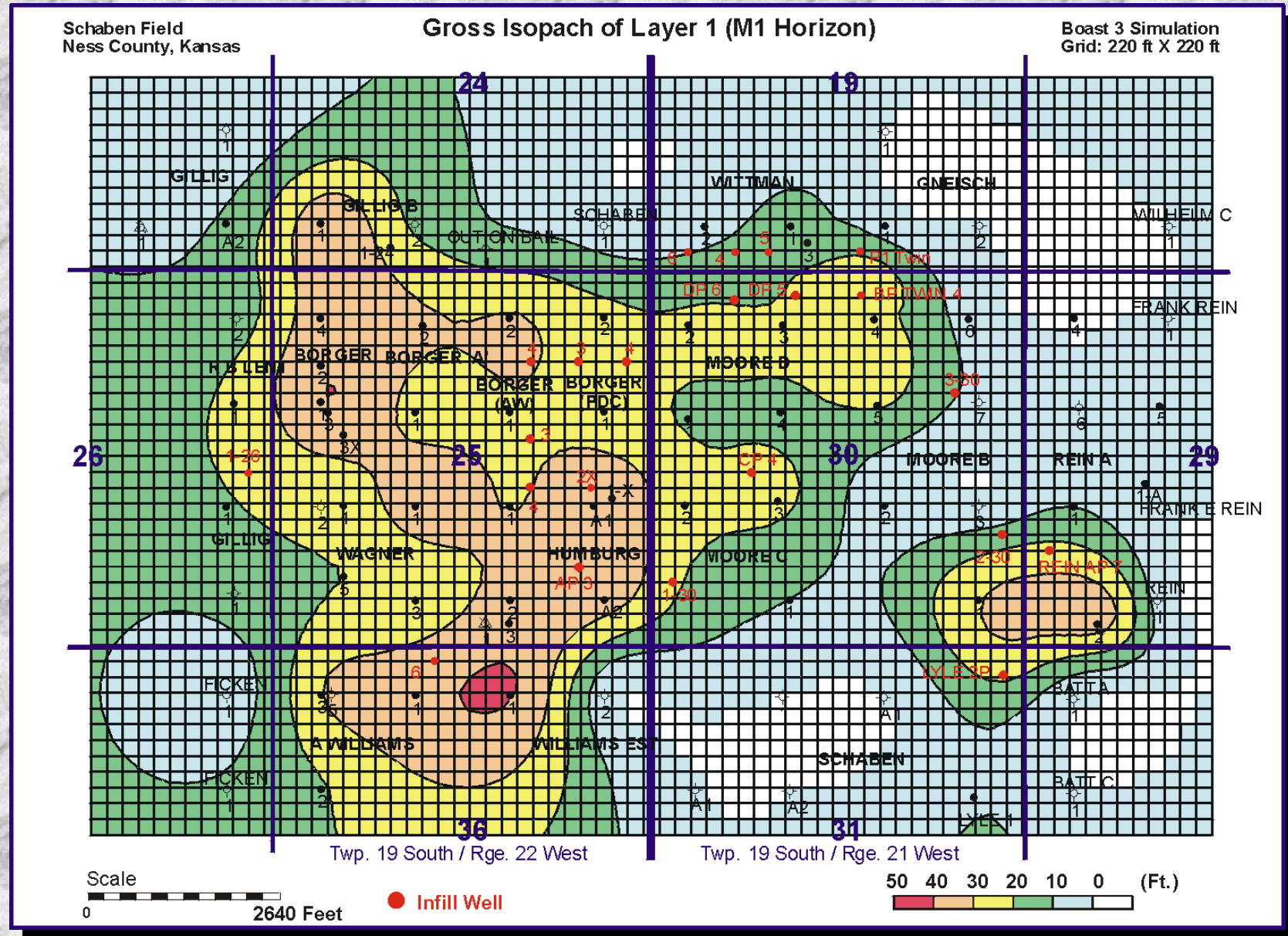
NMR Analysis of Core Plugs



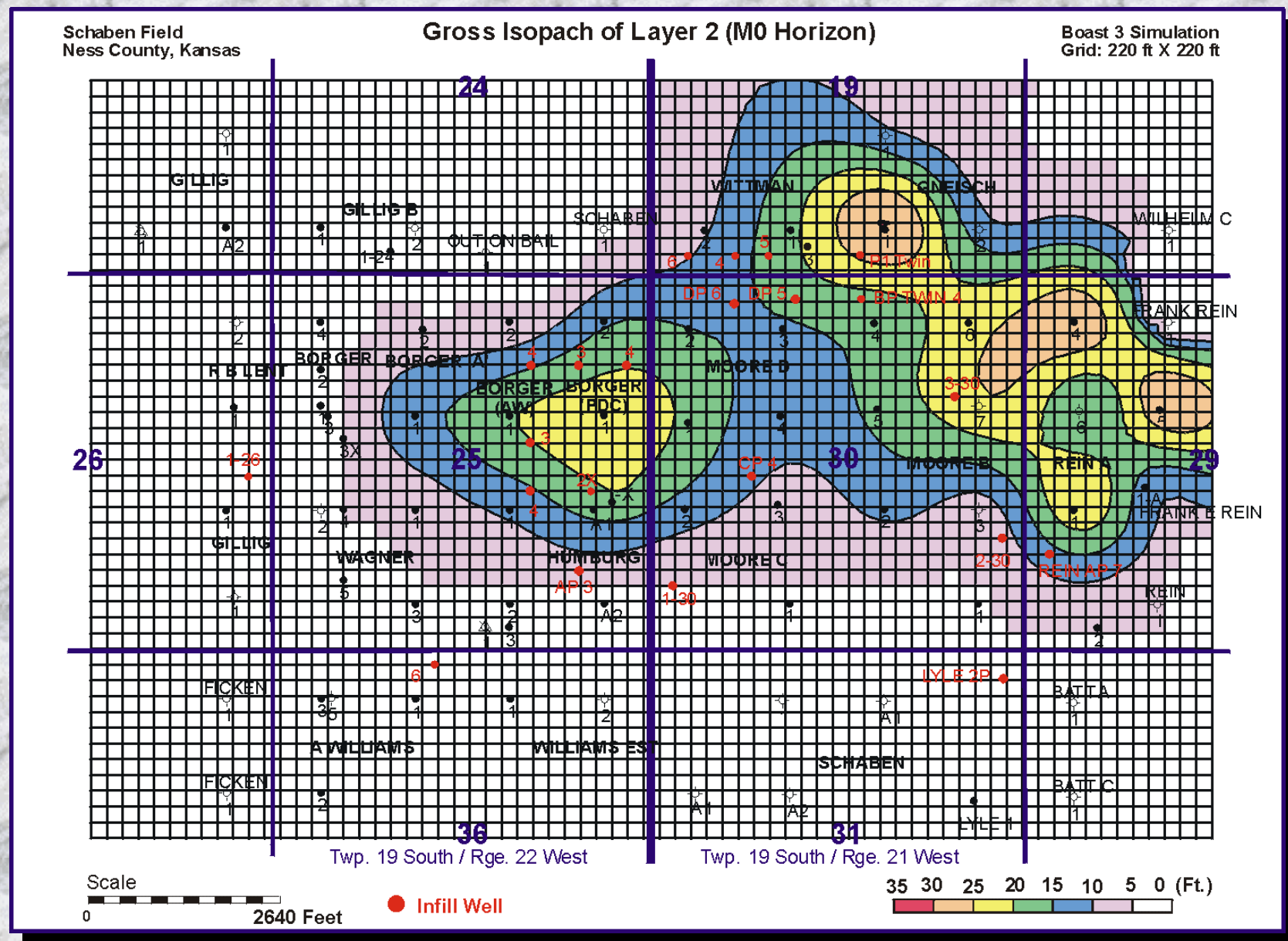
Schaben Field -- Effective Porosity



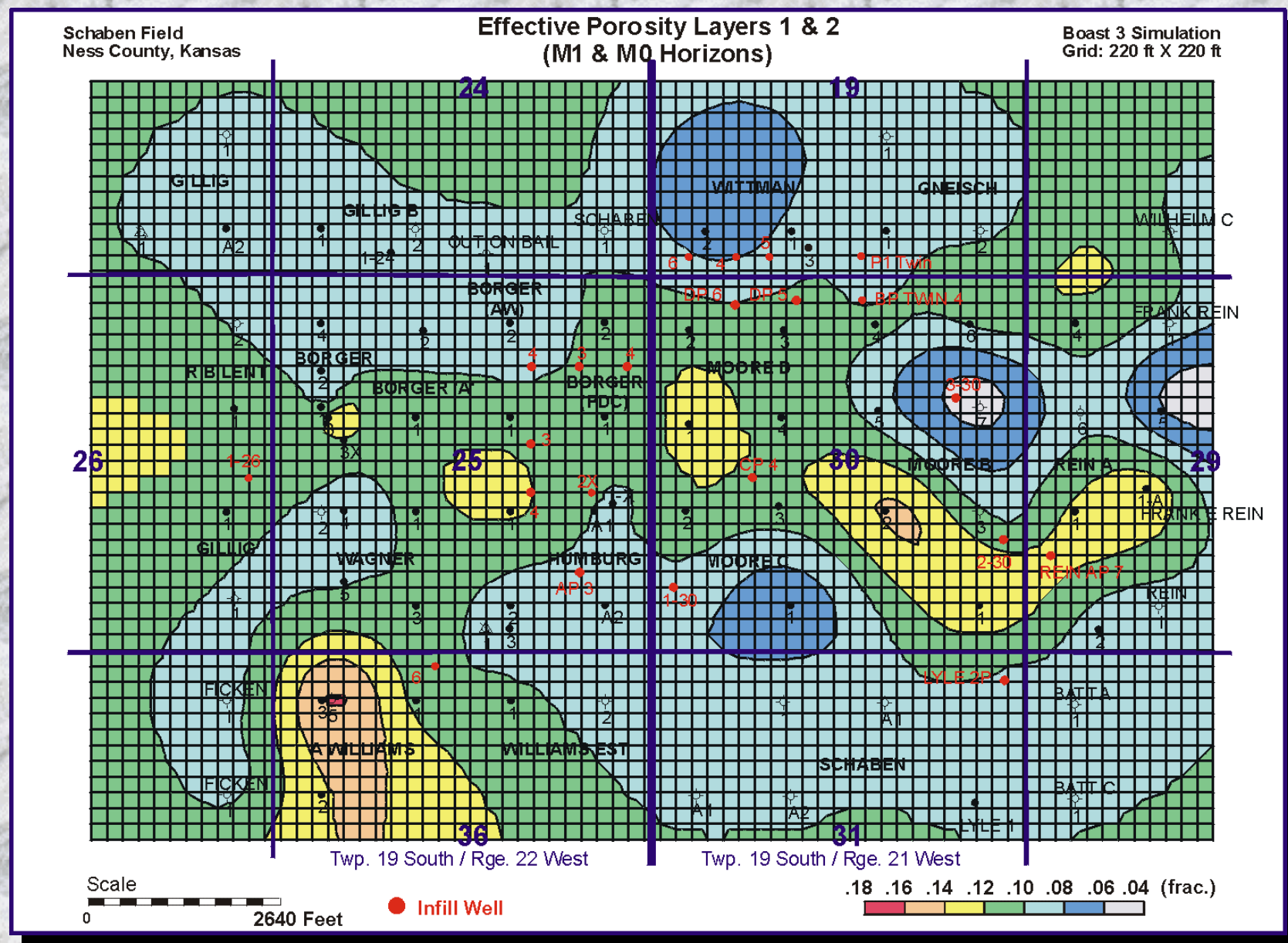
Schaben Field -- Reservoir Characterization



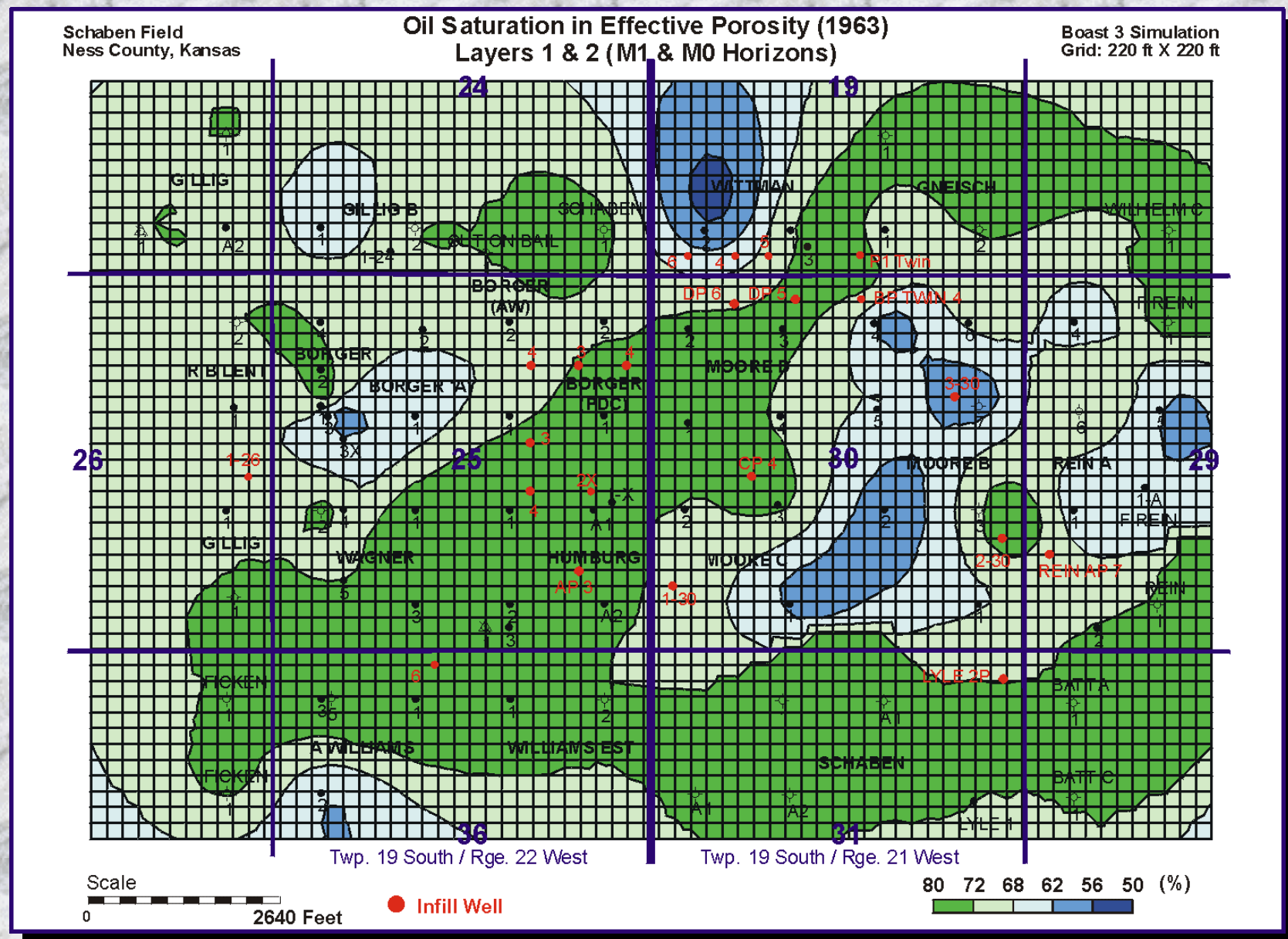
Schaben Field -- Reservoir Characterization



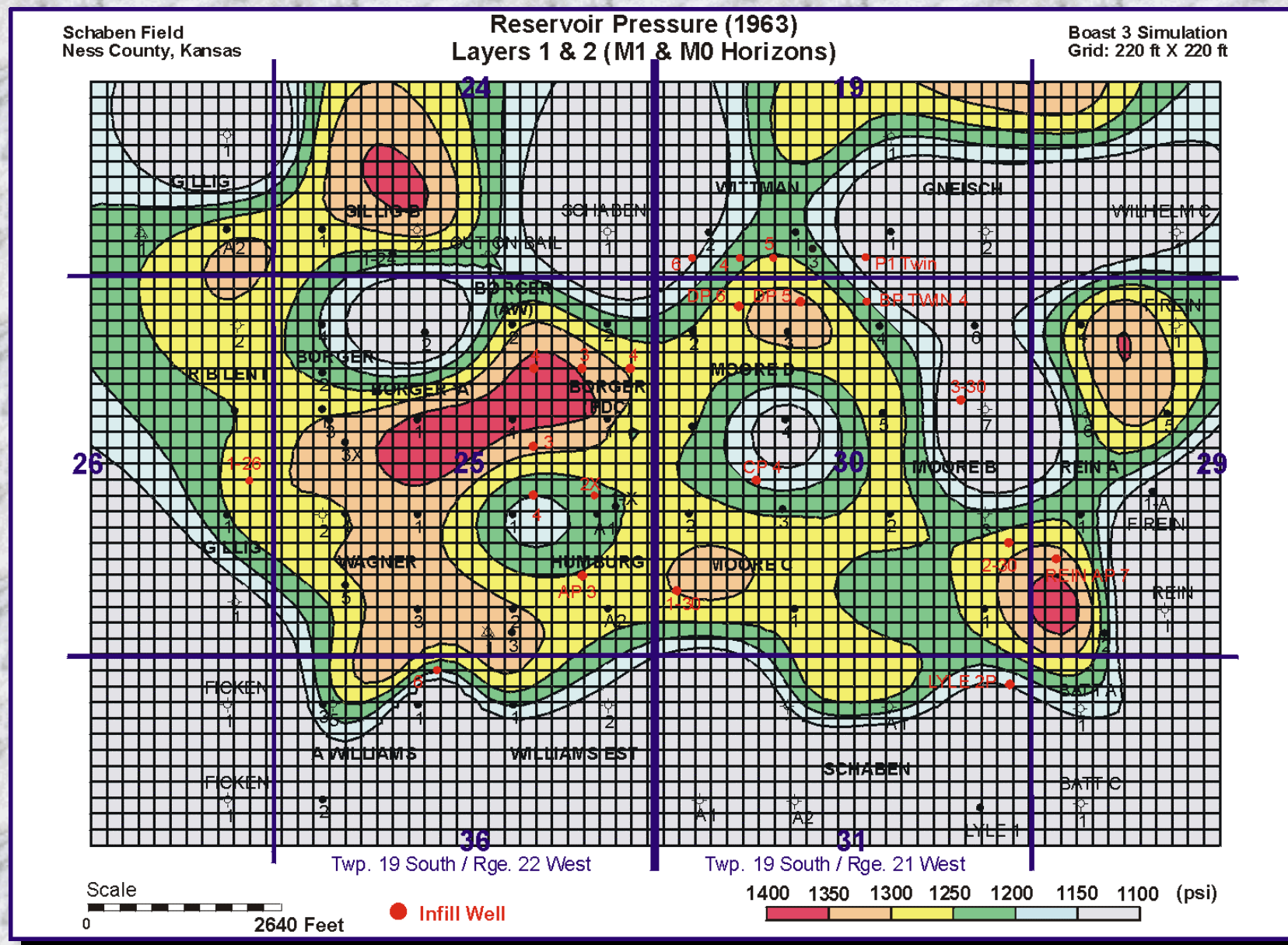
Schaben Field -- Reservoir Characterization



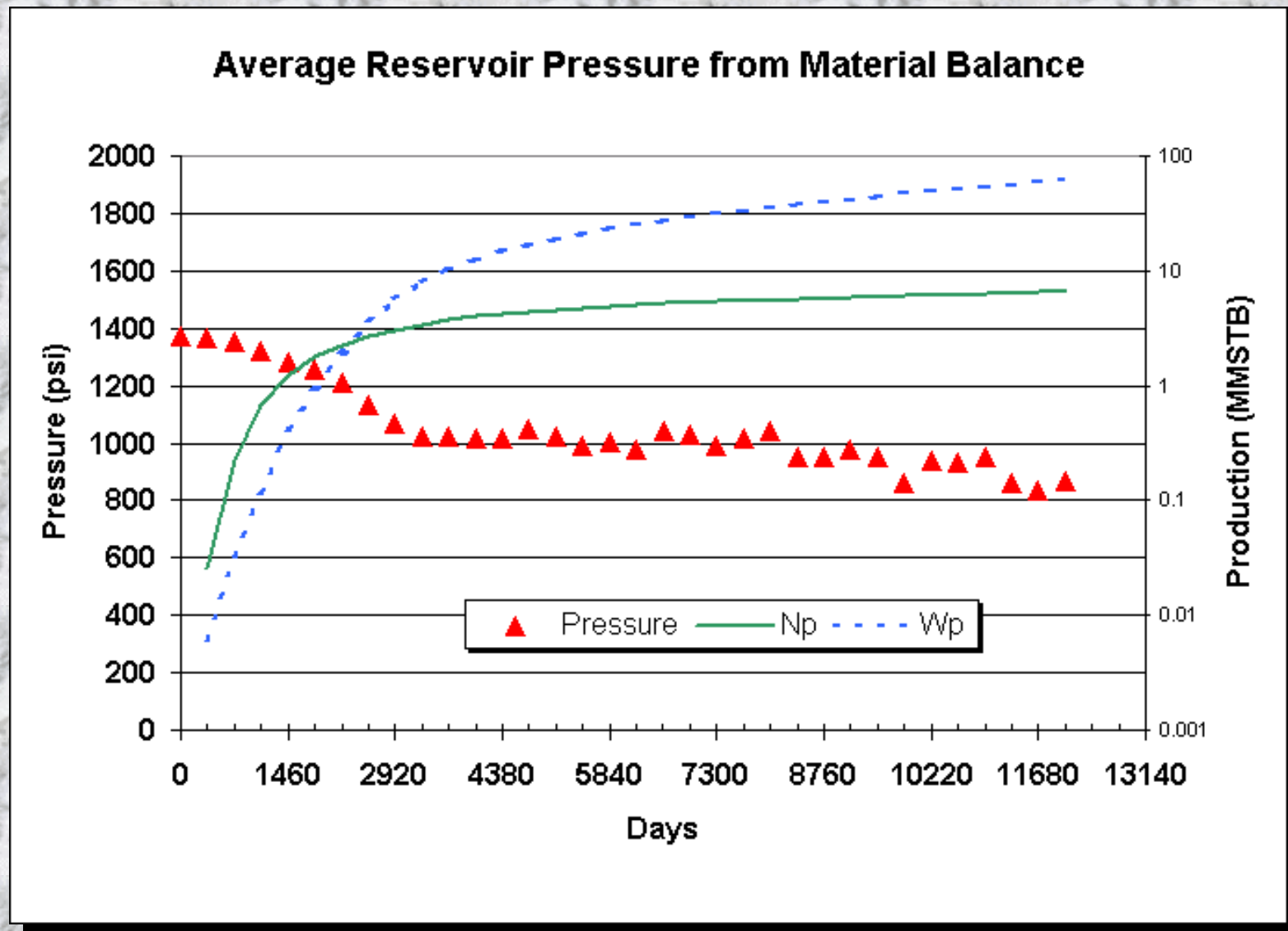
chaben Field -- Reservoir Characterization



Schaben Field -- Reservoir Characterization



Average Reservoir Pressure



Schaben Field -- Reservoir Simulation

- PC-Based
- Freeware BOAST 3
 - Full Field Simulation
 - Revised to Two Layer Reservoir
- PfEFFER
 - Pre-Processor
 - Post-Processor
- Good Match
 - Oil and Water Rates
 - 34 years of history
- Results
 - Located 22 Infill Wells to Decrease Spacing
 - Good Match to Performance Prediction

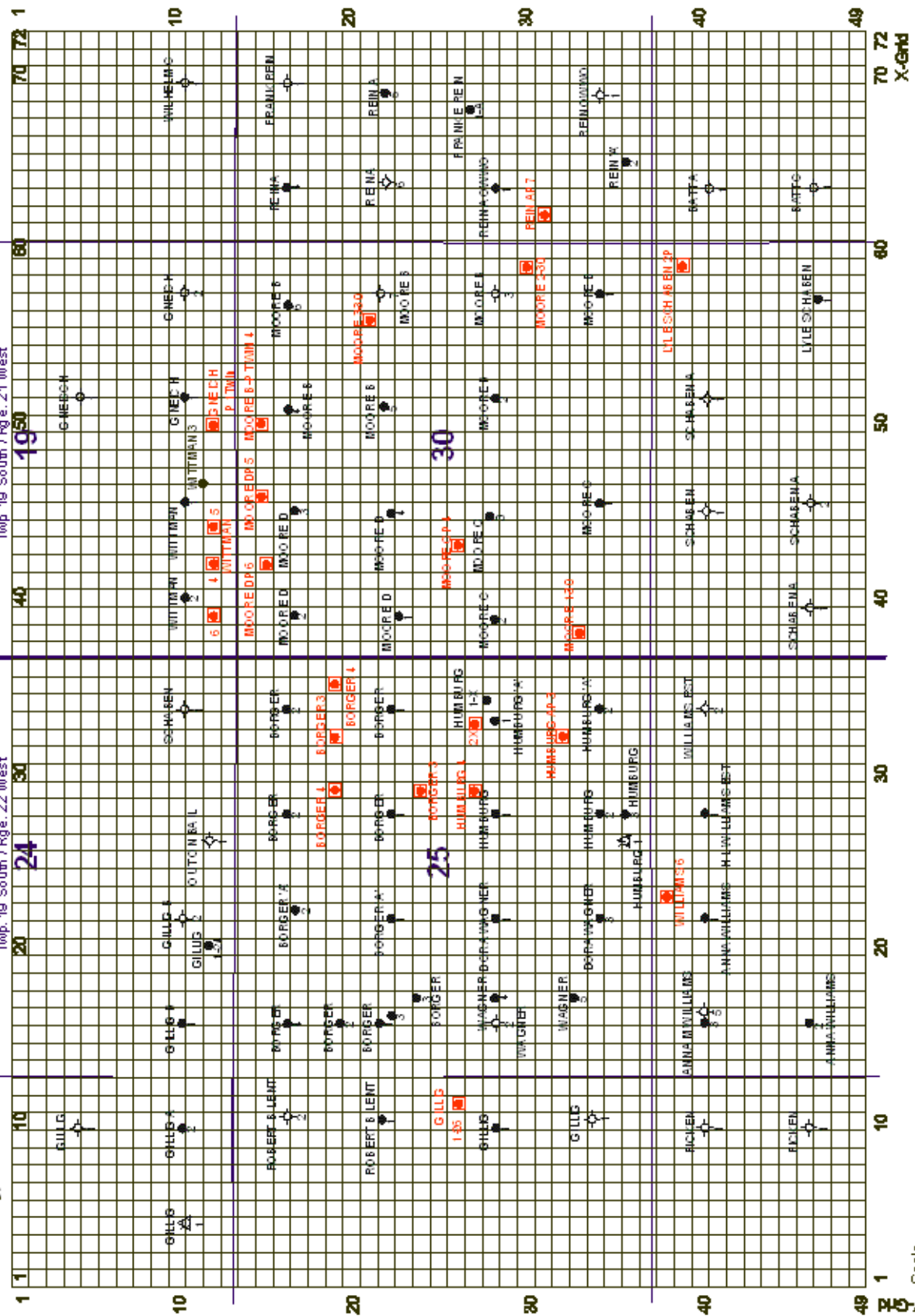
Well Locations and Grid Cells

Schaben Field
Iles County, Kansas

Boast 3 Simulation
Grid: 220 ft X 220 ft

Twp. 19 South / Rge. 22 West

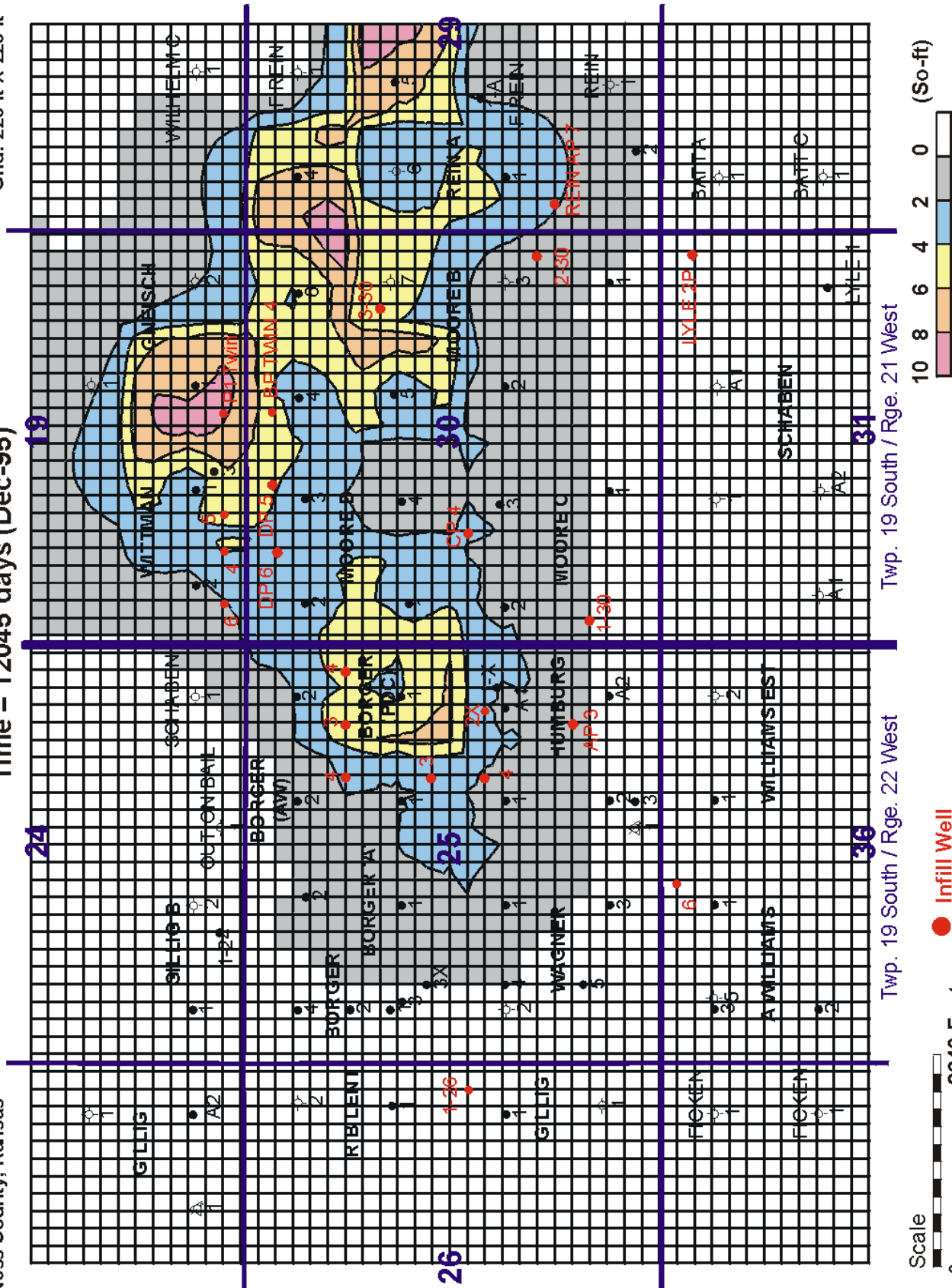
Twp. 19 South / Rge. 21 West



Schaben Field
Ness County, Kansas

Oil Saturation-Feet of Layer 2 (M0 Horizon) Time = 12045 days (Dec-95)

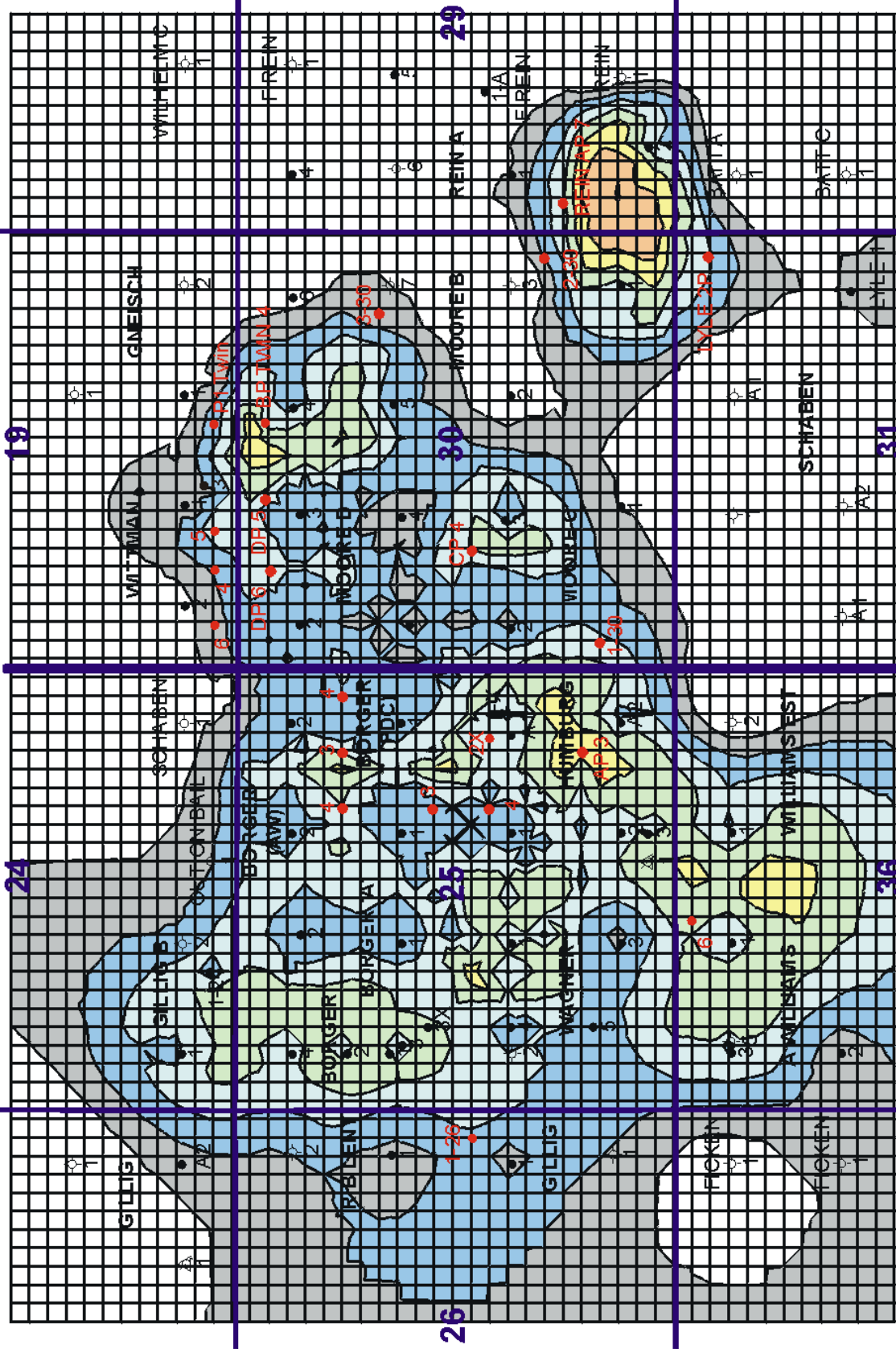
Boast 3 Simulation
Grid: 220 ft X 220 ft



Schaben Field
Ness County, Kansas

Oil Saturation-Feet of Layer 1 (M1 Horizon) Time = 12045 days (Dec-95)

Boast 3 Simulation
Grid: 220 ft X 220 ft



Scale



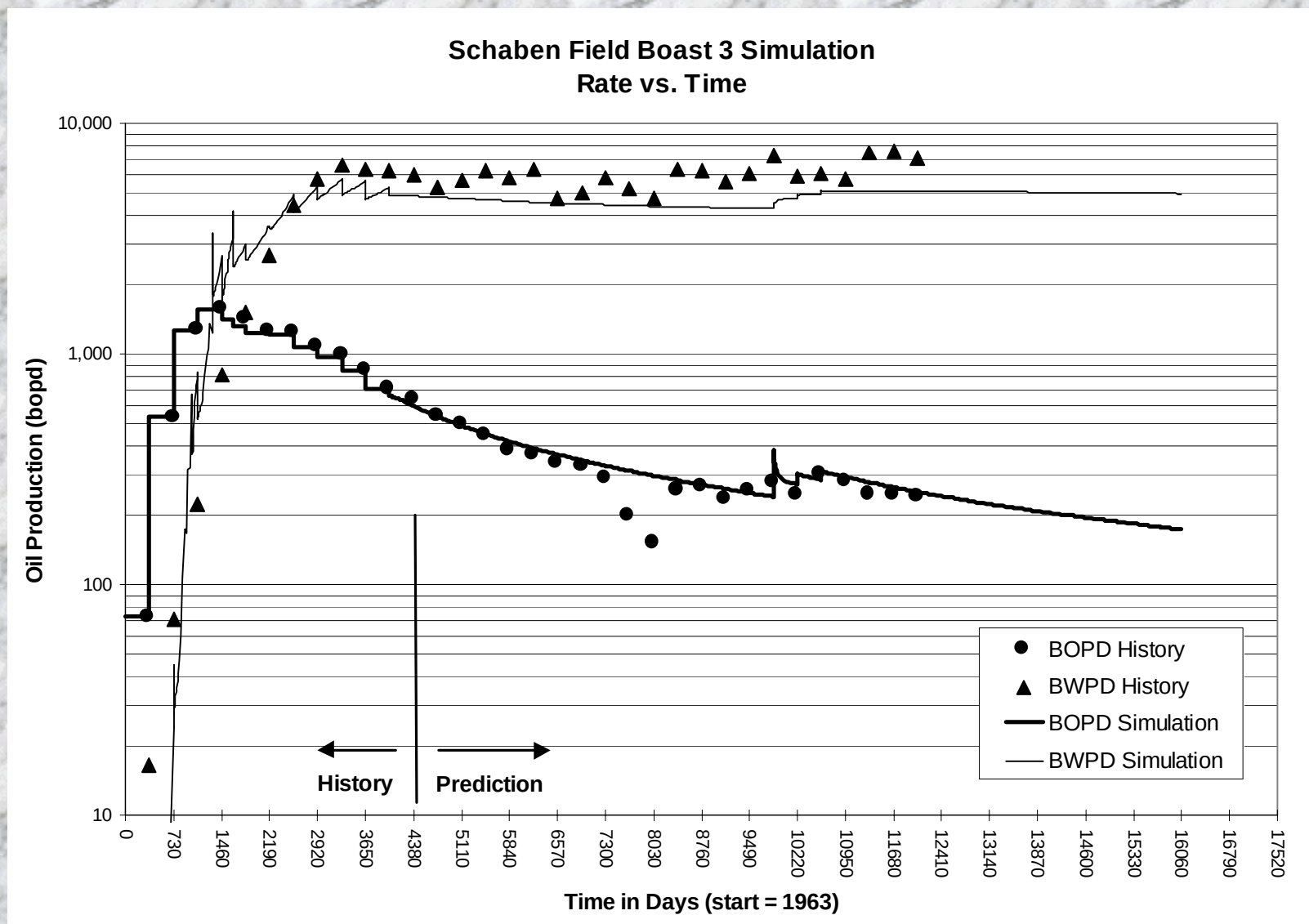
● Infill Well

Twp. 19 South / Rge. 22 West

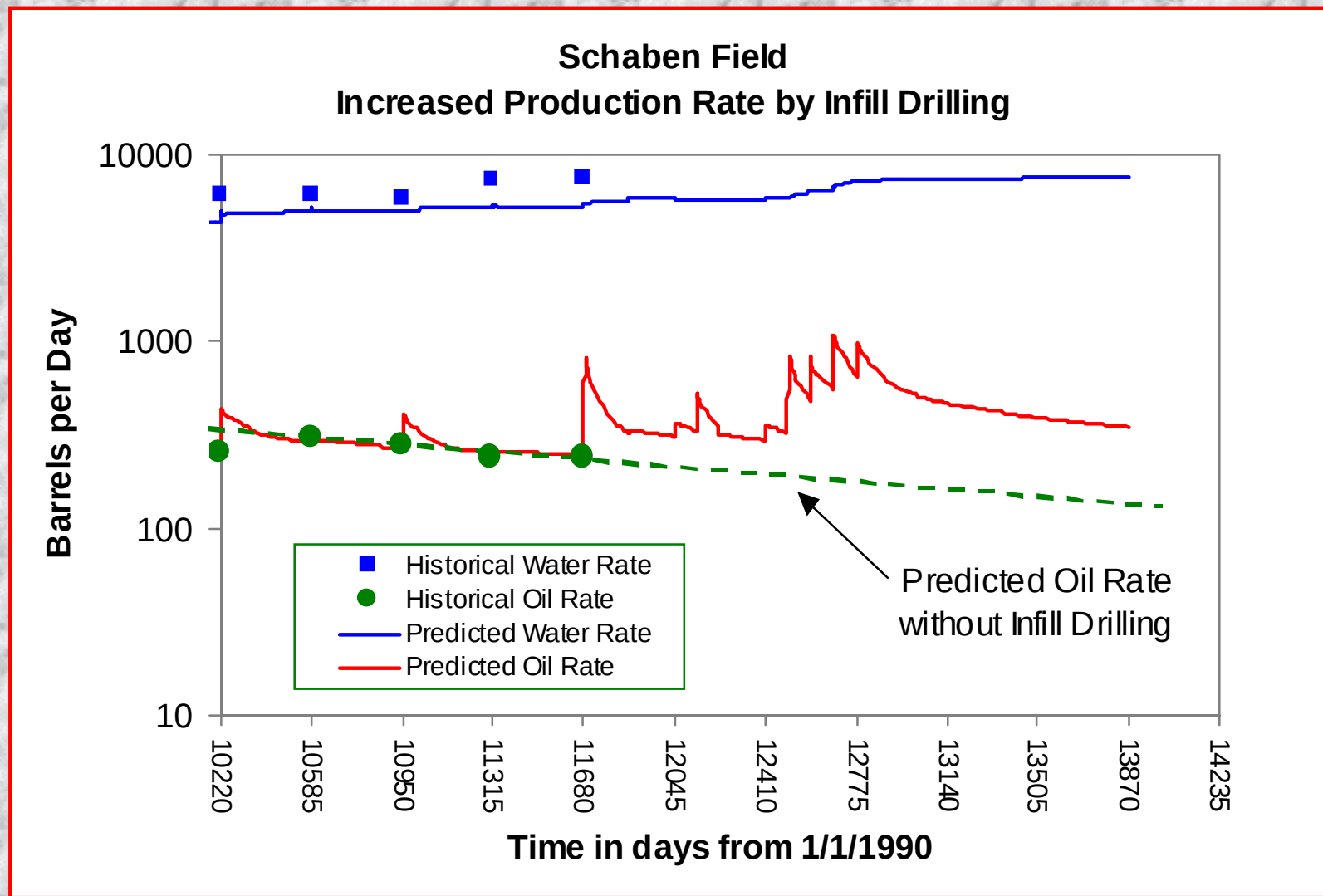
Twp. 19 South / Rge. 21 West

24 21 18 15 12 9 6 3 0 (So-Ft)

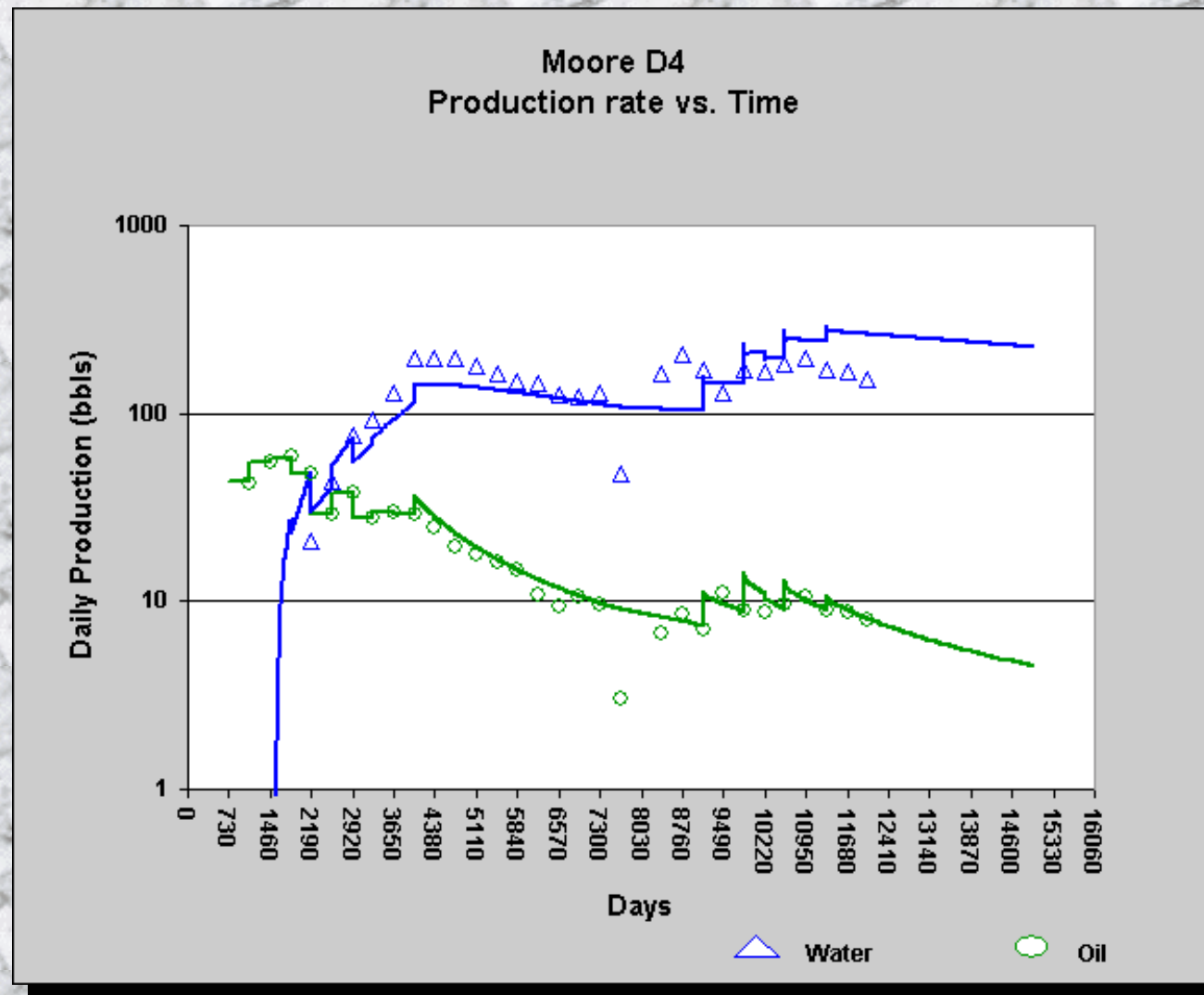
Schaben Field: History Match



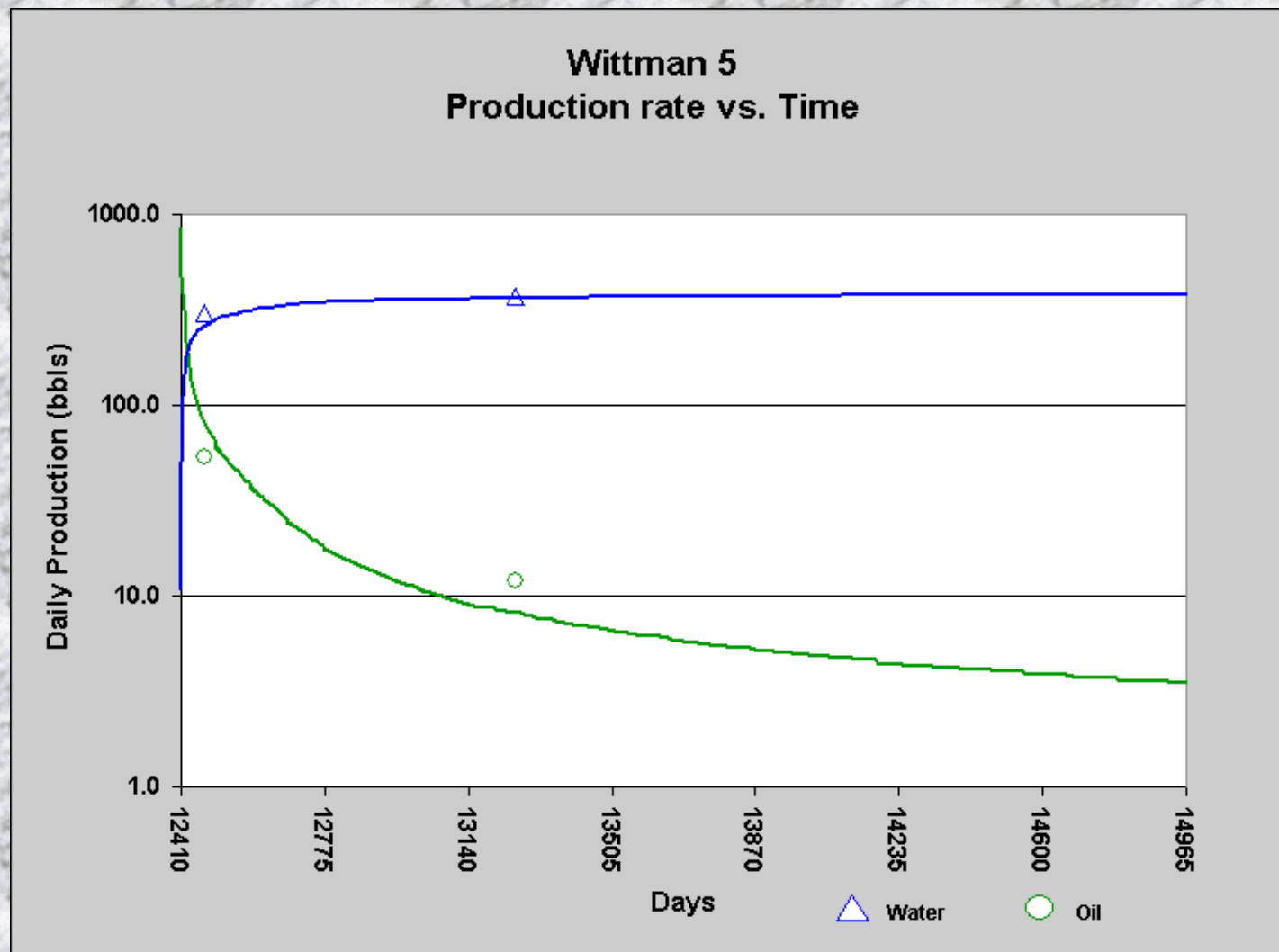
Schaben Field: Predicted Rates



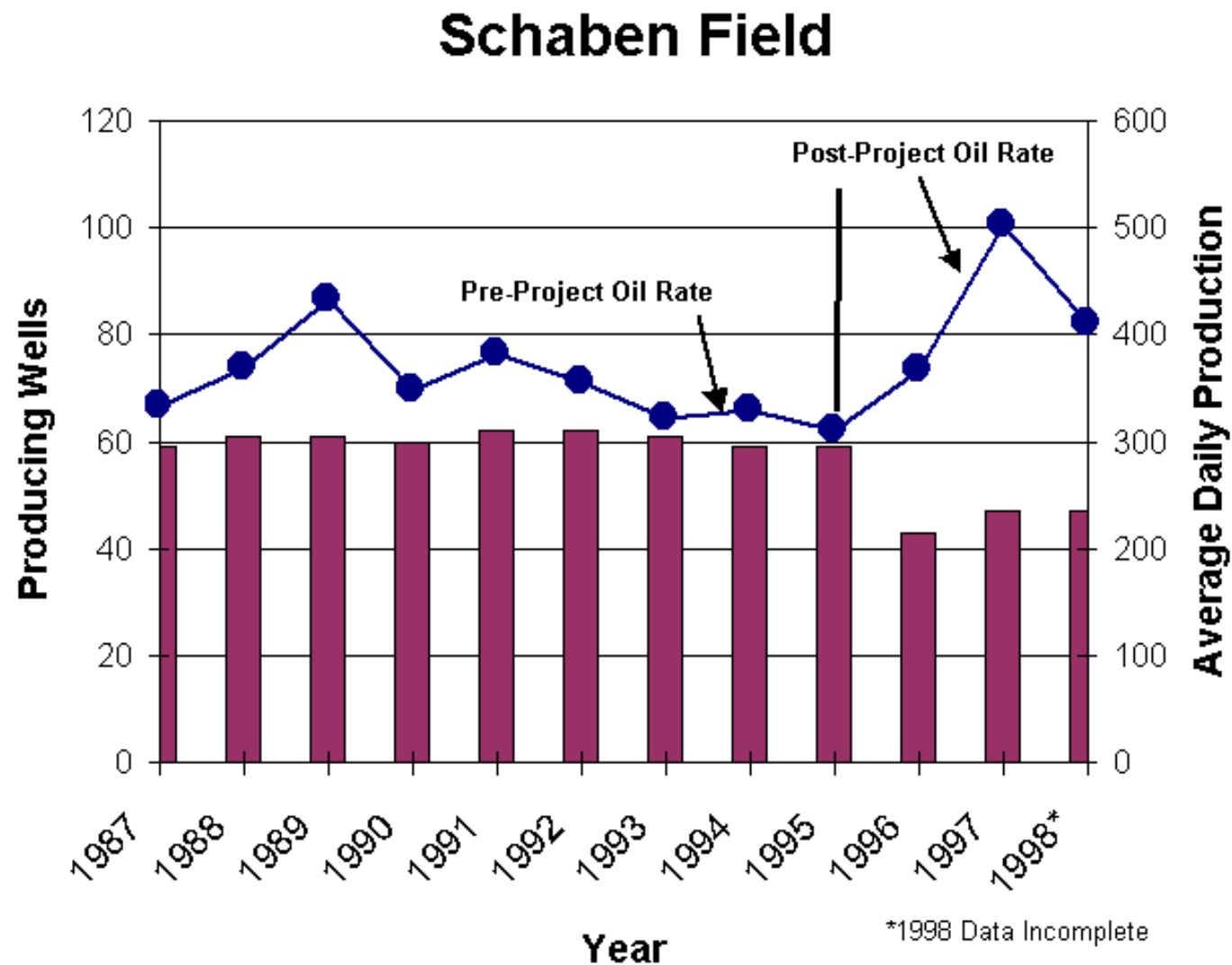
History Match: Existing Well



History Match: New Well



Schaben Demonstration Site: Production



Mississippian of Kansas Horizontal Well Technology

- Reservoir Characterization

 - Mississippian of southeast Saskatchewan

- Cost-Effective Screening Tools

 - “Quick-Look” Volumetric” Calculations

 - OOIP

 - ROIP and low recovery efficiency

 - Field --> Lease Level

- Reservoir Simulation

 - PfEFFER

 - Pre-Processor

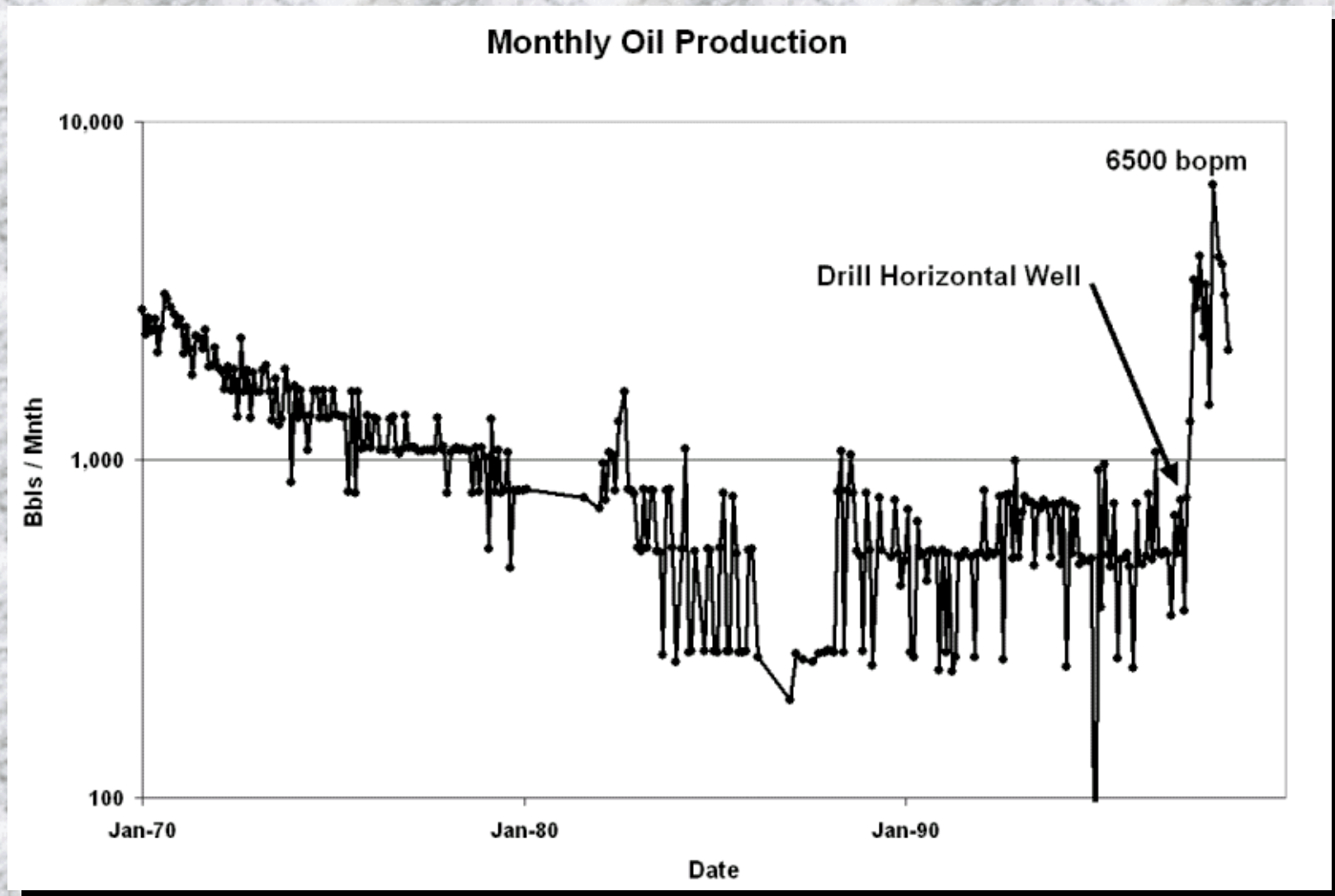
 - Post-Processor

 - BOAST VHS

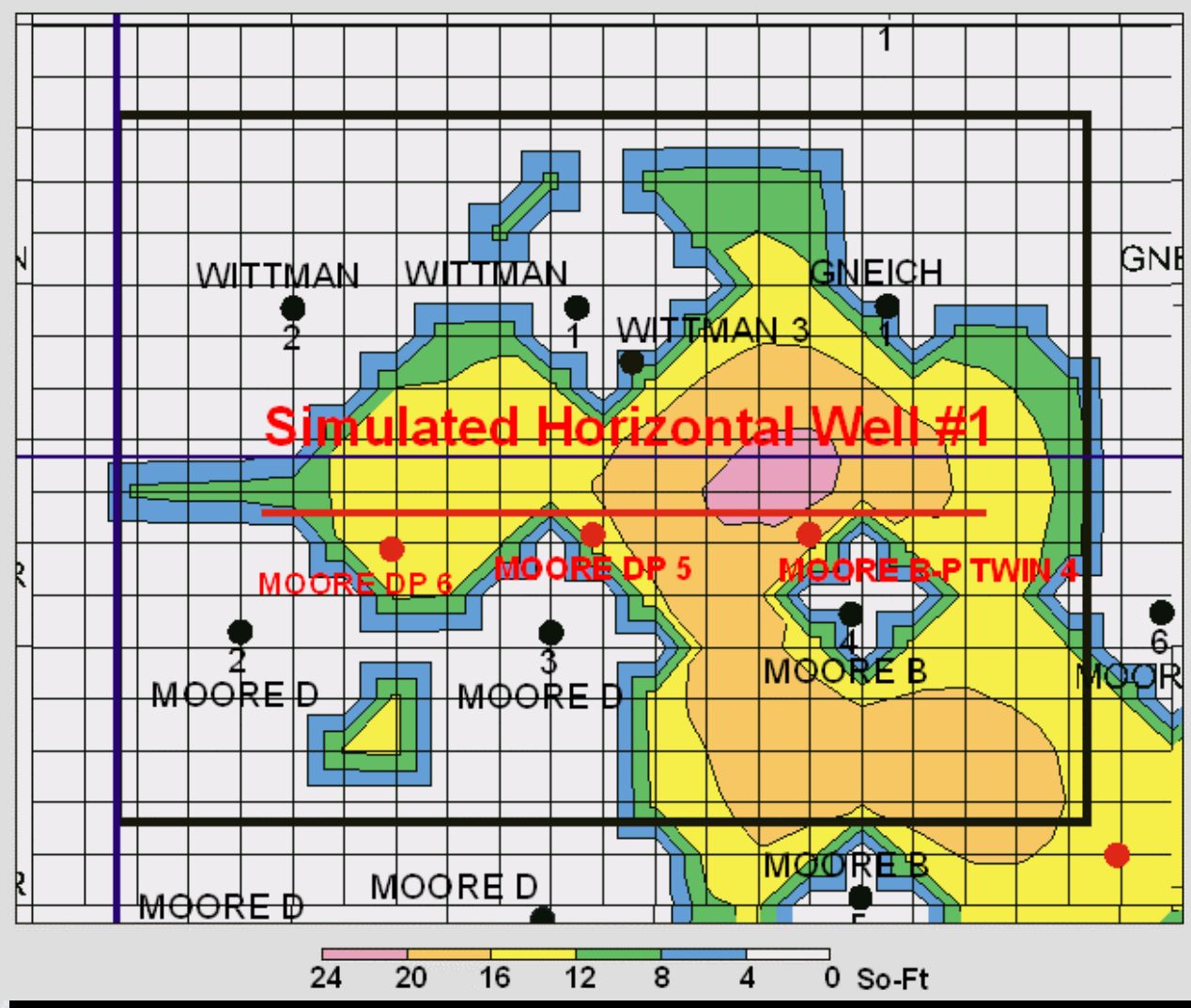
 - Field --> Lease --> Grid Cell Level

- Mixed Results

Wieland West Field, Hodgeman County Kansas.



Schaben Field: Horizontal Well Simulation



Technology Transfer: Traditional

- Short Courses (PTTC)

 - PfEFFER, BOAST 3, Internet, Petrophysics

- Publications

 - 30 Publications & Numerous Presentations

- Data

 - Production, Well Data & Logs

 - Automatic Updating Using Relational Databases

- Products

 - Maps, X-Sections, Core Descriptions, etc.

- Technology Transfer

- <http://www.kgs.ukans.edu/Class2/index.html>

Technology Transfer

Data & Products

[DPA Home Page](#) [Kansas DPA Home](#) [Site Map](#) [Help](#)

[General](#)
[Geology](#)
[Geophysics](#)
[Reservoir](#)
[Wells](#)

Play: [Lower Mississippian](#)
Basin: [Anadarko](#)
County: [Ness County](#)

Schaben Field

You can explore the Schaben Field by clicking on the blue topic buttons to the left.
Use the Schaben Site Map to learn what resources are available for the Schaben Field.

[Field Site Map](#)

Field Boundary

Ness County, Kansas

Twp 19-20 S / Rge 21-22 W

Discovery Well
Cities Service Oil Company, #1 Moore 'B'
SE SE 30-T19S-R21W
09/04/63, Mississippian Oil, 4494' RTD

American Warrior, #1 Wittman, 'OWWO'
Champlin Petroleum, #1 Wittman
SE SW, 19-T19S-R21W
06/20/91, Marmaton & Cherokee, 4407' RTD

Field Size: 8,880 acres
Total Wells: 90
Productive Wells: 65
Abandoned Wells: 25

Cumulative Oil: 10,416,796 bbls as of 7/1/96
Cumulative Gas: 112,395 mcf as of 7/1/96

[Annual Field Production Data](#)

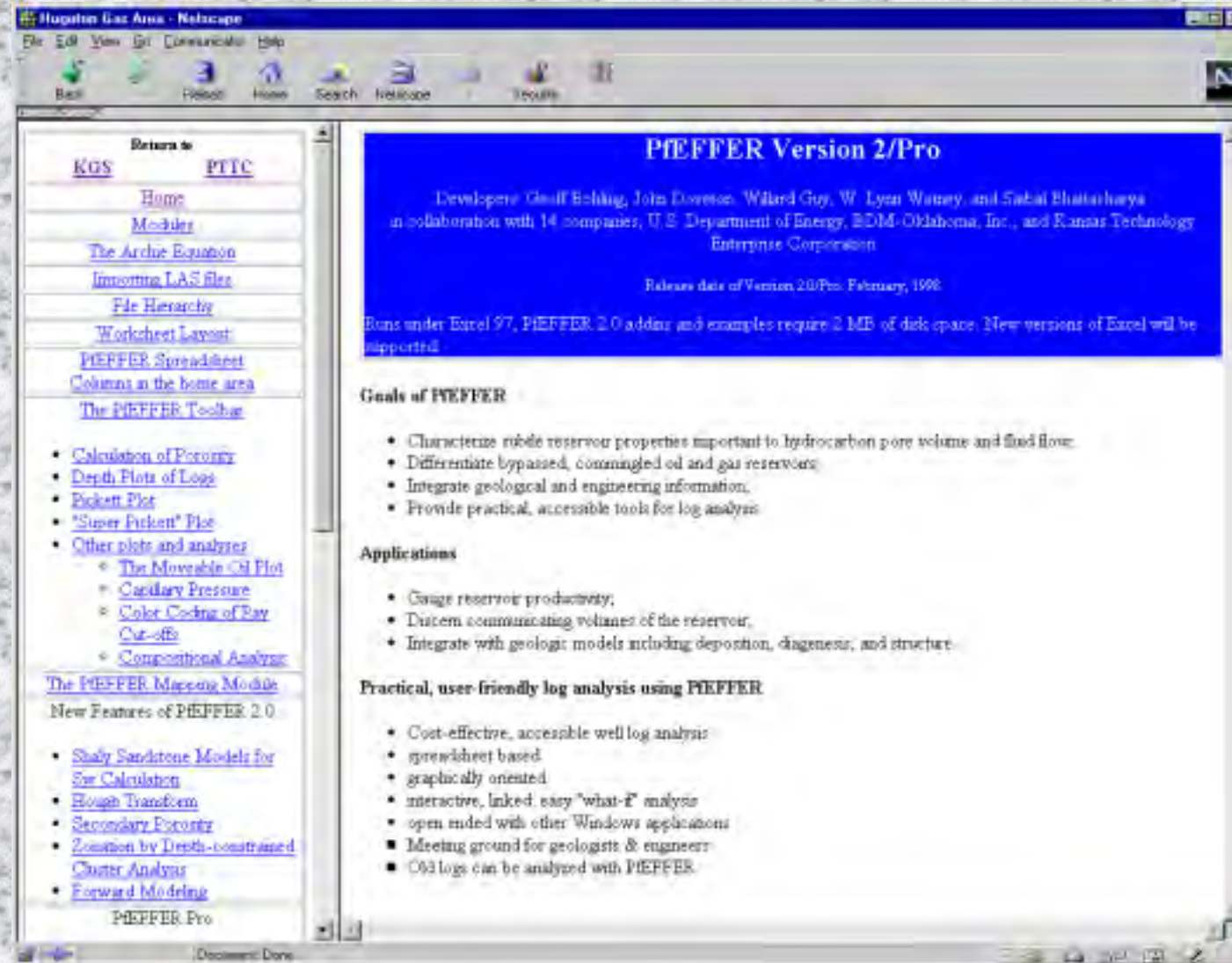
[Class 2 Project Page](#) also has info on the Schaben field.

[Kansas Geological Survey](#), Digital Petroleum Atlas
Send comments and/or suggestions to webadmin@kgs.ukans.edu
Updated Oct. 27, 1997
URL = <http://crude2.kgs.ukans.edu/DPA/Schaben/schabenMain.html>

<http://www.kgs.ukans.edu/DPA/Schaben/schabenMain.html>

Technology Transfer

Online Courses



<http://www.kgs.ukans.edu/General/Tutorial/pfeffer/>

Future Products

- Improved Online Courses
 - Distance Learning
 - PTTC
 - University of Kansas Continuing Education
- Complete Revised Reservoir Simulation
- Develop Online Petrophysical Atlas
- Complete Manuscripts and Final Report

Conclusions

- Need for Cost-Effective Advanced Technologies Focused on the Small Independent
PC Based
Commonly Available Programs
- Need for Online Technology Transfer
Data and Results
Technology
Distance Learning
- Large Mature Resource + Low Recovery Factors +
Appropriate Technology = **LARGE BENEFIT**

MEOR - A Low Cost Solution for Enhanced Waterflood Performance

James O. Stephens (jostephens@sprynet.com; 601-898-0051)
Hughes Eastern Corporation
403 Towne Center Blvd., Ste 103
Ridgeland, MS 39157

Dr. Lewis R. Brown (lrbsr@ra.msstate.edu; 601-325-7593)
Mississippi State University
Post Office Drawer GY
Mississippi State, MS 39762

Dr. Alex A. Vadie (vadie@ra.msstate.edu; 601-325-7224)
Mississippi State University
Post Office Box 5423
Mississippi State, MS 39762

DOE Contract No.: DE-FC22-94BC14962 (1/1/94 - 6/30/99)
FETC Contracting Officer's Representative: Martin J. Byrnes (412-892-4486)

Introduction

Poor waterflood sweep efficiency due to varying permeability within an oil reservoir is a common problem. The high permeability areas of the reservoir tend to be quickly flushed with water while low permeability areas are bypassed. Many billions of barrels of known domestic oil reserves remain unrecovered due to poor waterflood efficiency. Hughes Eastern Corporation and Mississippi State University, through a DOE sponsored Class 1 Oil Project, have successfully demonstrated that waterflood recovery can be enhanced by proper stimulation of indigenous microorganisms within a reservoir.

Project Objective

The objective of this project is to demonstrate that waterflood sweep efficiency can be improved by restricting high permeability zones through growth of indigenous bacteria so that water is diverted to low permeability zones which have been inefficiently waterflooded. The successful development and nationwide application of the microbial enhanced oil recovery (MEOR) technology could result in recovery of billions of barrels of bypassed oil which are now either unrecoverable or only recoverable at much higher cost.

Field Description

The field chosen for demonstration of the technology is the North Blowhorn Creek Oil Unit which is located in Lamar County, Alabama, about 75 miles west of Birmingham in the Black Warrior Basin producing region. The oil reservoir is the Carter sandstone of Mississippian age. The reservoir depth is about 2300' and the temperature is 90° F. The relatively clean but well compacted sand has an average porosity of 12%, an initial water saturation of 21% and a permeability varying from about one millidarcy to several hundred millidarcies. Initially a saturated oil reservoir with a primary gas cap, the reservoir held about 16 MMBO in place. The trapping mechanism is stratigraphic. Primary recovery was by depletion drive with no natural water influx. After discovery in 1979, the reservoir was developed on 80 acre spacing. Due to rapid depletion and a recognized need for secondary recovery, the field was unitized in 1983 and infill drilled on 40 acre spacing. Water injection began in late 1983. The reservoir responded very favorably to the waterflood, reached peak production of 85,000 BOPM in 1985 and then began declining in 1986. The current production rate is 8100 BOPM, 1200 MCFM and 90,000 BWPM. The waterflood injection rate is 104,000 BWPM. There are currently 23 active producing wells and 18 active injectors. The reservoir cumulative production through March 1999 was 5.82 MMBO, 3.2 BCF and 14.7 MMBW. The cumulative injected water was 22.3 MM bbls. Figure 1 is a net pay isopach showing the field geometry, the well locations and injection patterns.

MEOR Project Description

The microbial enhanced oil recovery project is organized in three phases. Phase I is the planning and analysis phase which lasted nine months and has been completed. Phase II is the field implementation phase which began in the fourth quarter of 1994 and has been completed. Phase III is the technology transfer phase which began in July 1998 and is now being concluded.

Phase I consisted of drilling and completing two new wells to obtain fresh cores and production data, special handling and analysis of the cores, a tracer study to determine fluid travel times and the collection of baseline data. The NBCU 34-6 No.3 was drilled in March 1994 and encountered 20 feet of net Carter oil sand. The well was completed and placed on rod pump at an initial rate of 25 BOPD and 1 BWPD. Current production is about 85 BOPD and 22 BWPD. The NBCU 34-3 No.2 was drilled in April 1994 and penetrated 21 feet of net pay sand. The core recovered from this well appeared to be unswept by the waterflood and contained a high saturation of bypassed oil. The well was completed, placed on rod pump and initially tested 43 BOPD and 43 BWPD. Recent production is about 5 BOPD and 180 BWPD.

One-foot sections were obtained as the core was removed from the core barrel. The sections were quickly transferred to special containers for transportation and storage in an oxygen-free environment. Core plugs were cut in a nitrogen environment and mounted in a special holder for core flooding tests to determine microbial nutrients to be used in the field. Other pieces of core were crushed into a fine powder to be used in determination of the microbial population. The laboratory testing was done to confirm four things: 1) that indigenous microbes were indeed present in the reservoir rock; 2) that the microbes could be stimulated to grow using the proper inorganic nutrients; 3) that flow through the cores could be restricted as a result of the microbial growth; and 4) a nutrient injection protocol could be developed for scale-up to field applications.

A radioactive tracer survey was performed in the first test pattern prior to start of nutrient injection. A tritiated water tracer (2 Ci) was injected into the 2-14 No.1 injection well to determine the fluid travel times to the producers in the pattern and thus give some indication of the minimum time required for detection of microbial activity. The tracer was injected on 4/27/94 and first detected in the 2-13 No.1 on 10/12/94. The tracer peaked in this well in January 1995. Tracer was detected in the 11-3 No. 1 in October 1995. Therefore, the minimum time required for flood water to travel to the highest rate offset producer is about six months. The time required for microbial growth to occur and result in increased production could easily be two or three times the fluid migration time.

Baseline data acquisition began during Phase I and continued during Phase II. Data was collected on four test patterns and four control patterns (shown as TP #1-4 and CP #1-4 on Figure 1). Fluid production and injection rates were stored in a data base and plotted frequently to scan for changes. In addition, water samples were analyzed for mineral and microbial content on a monthly basis. Oil samples were analyzed by gas chromatograph to look for shifts in hydrocarbon composition which may indicate microbial degradation of heavier hydrocarbons or that previously unswept oil was being recovered. Oil viscosity and gravity data were also collected on each producing well in the test and control patterns.

Phase II was the field implementation part of the MEOR project. Based upon the successful results of the laboratory waterflooding tests, a nutrient injection schedule was established for each of the four test pattern injectors. A three-day-a-week repeating schedule was established which consisted of injection of potassium nitrate every Monday and monosodium phosphate on Wednesdays and Fridays. In test patterns 2 and 4, molasses was substituted instead of monosodium phosphate on Wednesdays to test the effect of injecting an organic nutrient. Molasses were later added to test patterns 1 and 3.

Four nutrient injection skids were constructed as shown in Figure 2. The pump skids had to have the capability of mixing 50-300 lbs. of dry chemical with 200 - 300 gals/day of water and pumping the resulting solution at a constant rate over a 24-hour period at 1300 psi discharge pressure. The skids had to be simple, easily maintained and of rugged construction for operation by field personnel. The mixing hopper is an improvised design which takes advantage of the available 1200 psi waterflood water to jet mix the dry chemicals. The holding tank is a 300 gallon polypropylene tank of the type often used for oilfield chemicals. An electric mixer allows for stirring to insure that all the chemical goes into solution. The pumps selected were Cat Model 231 triplexes which are belt driven by DC motors with rheostat controls.

Nutrient injection was begun into the 2-14 No.1 well on 11/21/94. The waterflood injection rate was approximately 475 BWPD. Construction of the remaining three skids and initiation of injection into the other test patterns was delayed in order to allow time for mechanical evaluation of the equipment as well as time to detect any near-wellbore injectivity problems. No problems were encountered, so the remaining pump skids were completed in January 1995. Nutrient injection into 11-5 No.1 was begun on 1/16/95 and into 2-6 No.1 and 34-9 No.2 on 2/27/95. No significant injectivity or mechanical problems developed.

Three additional wells were drilled and completed in the Fall of 1996. The main purpose of the three wells was to obtain core data which would confirm whether or not nutrients were being widely dispersed into the reservoir and the effects of the nutrients on microbial growth. The first of the three wells was NBCU 2-5 No. 2 which was drilled near the boundary between Test Pattern 4 and Control Pattern 1 (Figure1). The well encountered 24 ft. of net Carter pay sand. The core analysis indicates that, as a general rule, the lower permeability rock retains a higher oil saturation while the high permeability rock is better swept resulting in lower oil saturation. Visual observation of the core indicated much remaining oil in the low permeability rock. The well was cased, perforated, fracture stimulated and placed on production.

The second of the Phase II wells to be drilled was the NBCU 2-13 No. 2 which was drilled northwest of Test Pattern 1. The well found 21 ft. of net Carter pay sand. The core analysis indicated much higher permeability in the upper ten feet of the sand than in the lower portion and, as in the previous well, the higher permeability rock generally has lower oil saturation than the lower permeability rock which is harder to sweep by waterflood. The well was cased, perforated and placed on production without fracture stimulation.

The third well drilled was the NBCU 2-11 No.3 which was drilled within Test Pattern 4 and within 500 ft. of the 2-6 No. 1 nutrient injector. The well encountered 36 ft. of Carter pay sand which was twice the anticipated thickness. A 32 ft. core was recovered which revealed significant remaining oil saturation, along with some portions which had obviously been swept by the waterflood. It was anticipated that the water swept sections would provide the best opportunity to observe microbial growth as a result of nutrient injection into the nearby 2-6 No. 1 well. The well was cased, perforated, fracture stimulated and placed on production.

The chemical and microbiological analyses of the cores from the three new wells was begun immediately by Mississippi State University. Ten sections of core from each well were stored anaerobically while six sections were stored under aerobic conditions. Initially five sections of core from each well were examined for the presence of nitrate ions and phosphate ions. Nitrate ions were present in four of the five sections from well 2-5 No. 2, three of the five sections from well 2-13 No. 2 and all five sections from well 2-11 No. 3. Phosphate ions were present in three of the sections from well 2-5 No.2, none of the sections from 2-13 No. 2 and one of the sections from well 2-11 No. 3.

Electron microscopic examinations of the four core sections from well 2-5 No. 2 revealed many microbial cells in three of the sections. Shown in Figure 3 are some of the representative SEM photographs. The large numbers of bacteria are obvious. The large numbers are in sharp contrast to the number seen in cores from the NBCU 34-3 No. 2 drilled at the beginning of the project.

Results

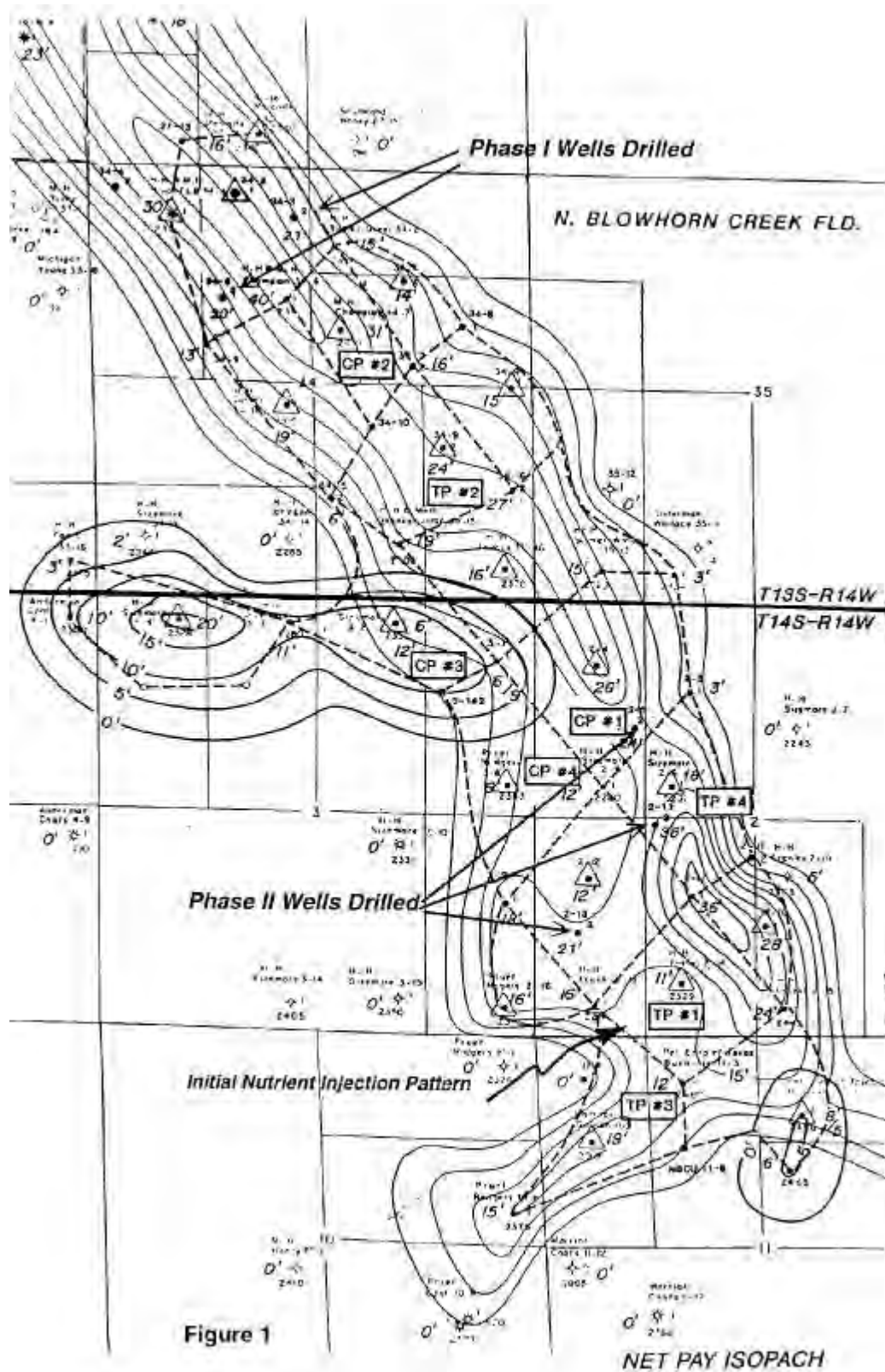
As of April 1997, eight out of fifteen test pattern wells had positive responses to the nutrient injection. Because of this success, the project was expanded to include six more nutrient injectors with hopes of further improving the MEOR response. By July 1998, after forty-two months of nutrient injection into four wells and only twelve months of nutrient injection into six wells, the performance had improved in twelve out of nineteen wells, or sixty-three percent. The performance of selected wells is seen in Figures 4 through 9.

By the end of 1998, incremental production due to the new wells drilled and the MEOR response was 161 MBO. Of this incremental, 92 MBO was due to new drilling and 69 MBO was due to MEOR (see Figure 10). The production decline rate had been reduced from 18.9%/yr prior to the project to between 7 and 12%/yr. Thus the remaining incremental reserves are between 434 MBO and 863 MBO based upon an abandonment rate of 1500 BOPM. The field life has been extended by a minimum of 53 months.

Economics and Benefits

Economics of the MEOR process were calculated by excluding all costs associated with the additional well drilling and costs of laboratory testing and documentation for DOE. The total cost of nutrients, engineering, field labor and injection skid LOE was \$658,000. The ultimate MEOR incremental reserves were estimated to be 499 MBO. Thus the incremental cost per barrel was \$1.32. The incremental cost of MEOR production recovered through the end of 1998 was \$9.54/bbl, thus the reserves recovered to date have already paid the cost of nutrient injection.

The MEOR technology employed in this project has proven successful and should have broad applicability across the nation. The process should work in any waterflood field having permeability variations. The technology should not be limited to sandstones, but should work in carbonates as well. The U. S. DOE has estimated the proven residual oil resource in the U. S. to be about 350 billion barrels. It is estimated that 50% of current domestic production comes from waterflooded fields and that somewhere between 50 and 75% of all fields have been or will be waterflooded. If MEOR can result in recovery of just 10% of the residual oil in waterflooded fields, the potential is about 20 billion barrels. If the additional recovery is 15% of residual oil, the potential is about 30 billion barrels, or roughly equal to the DOE's estimate of remaining economically recoverable domestic reserves.



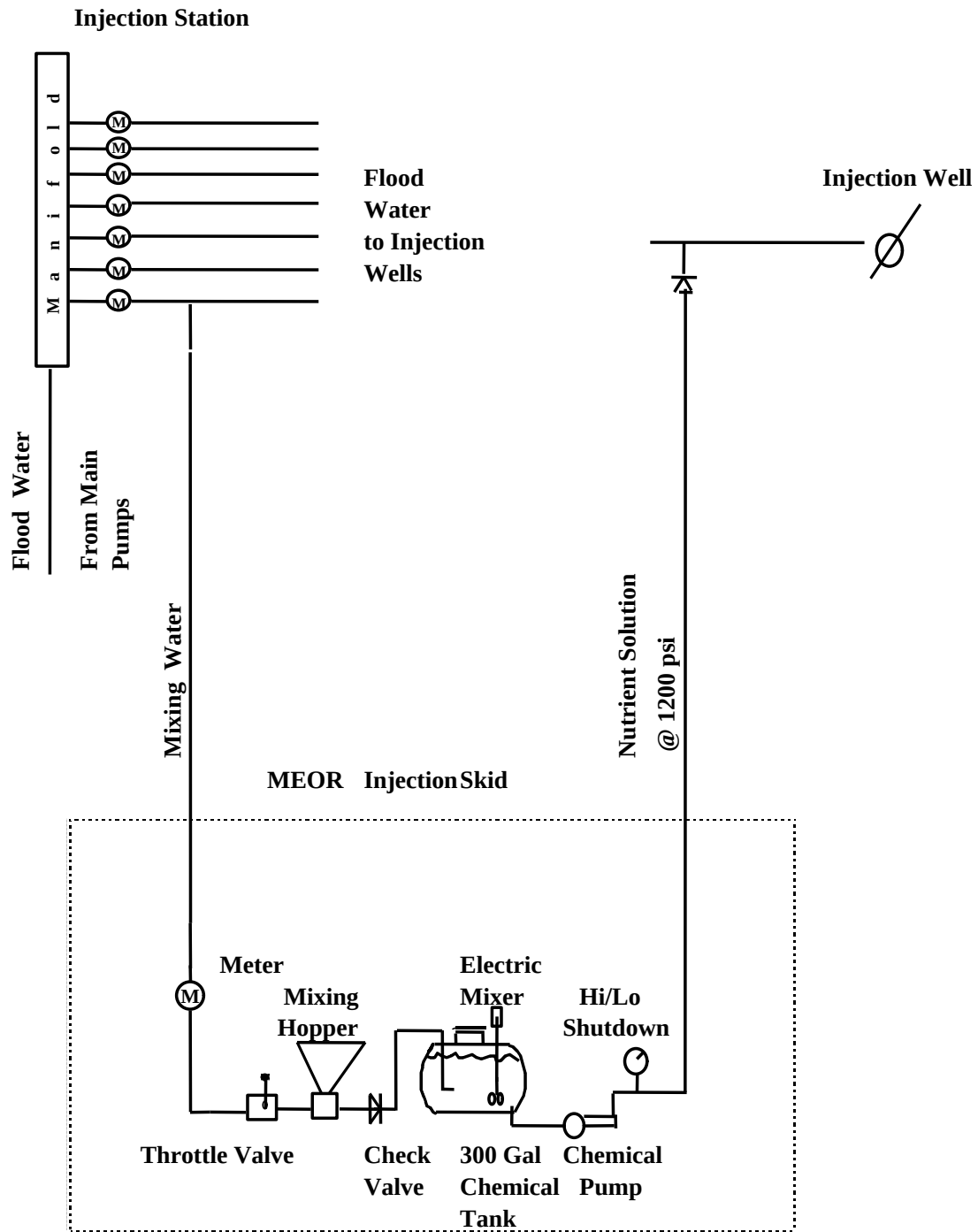
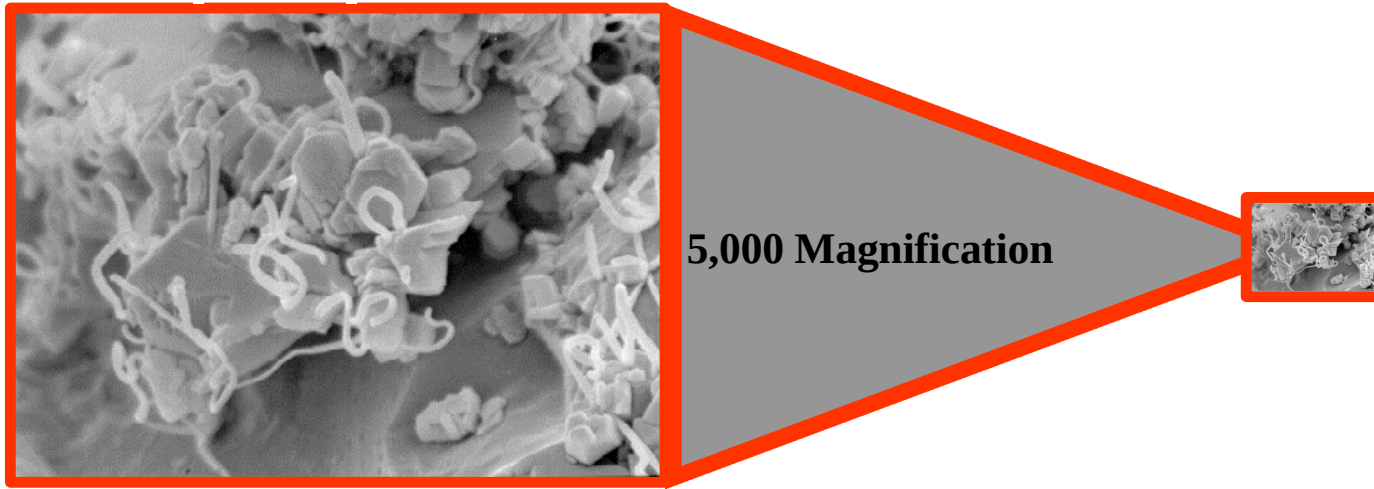


Figure 2: Flow Diagram for North Blowhorn Creek Unit MEOR Injection System

5 μm



2 μm

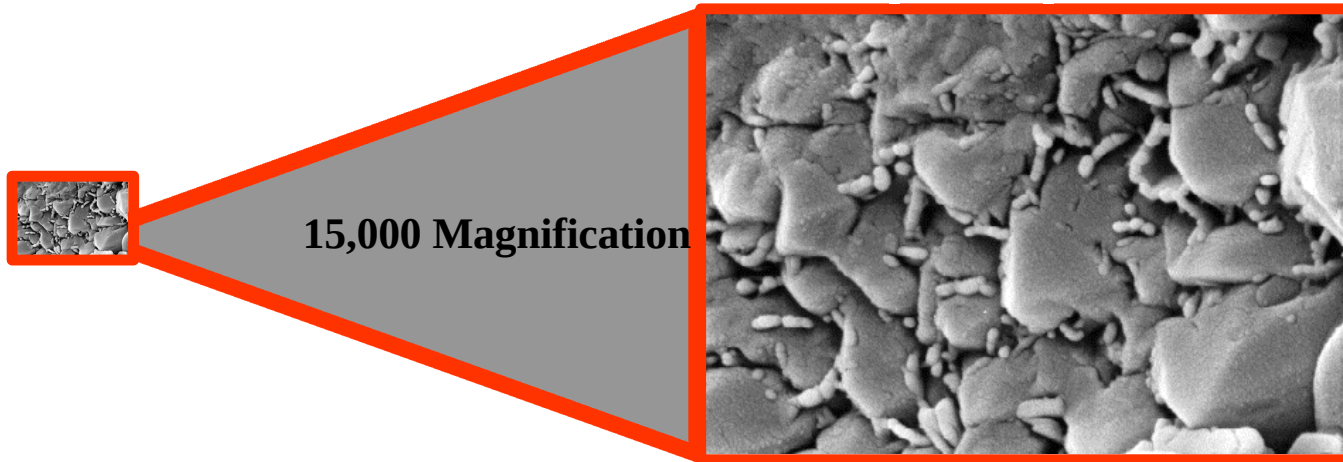


Figure 3. Photographs of microorganisms in cores from two newly drilled wells as seen using the electron microscope.

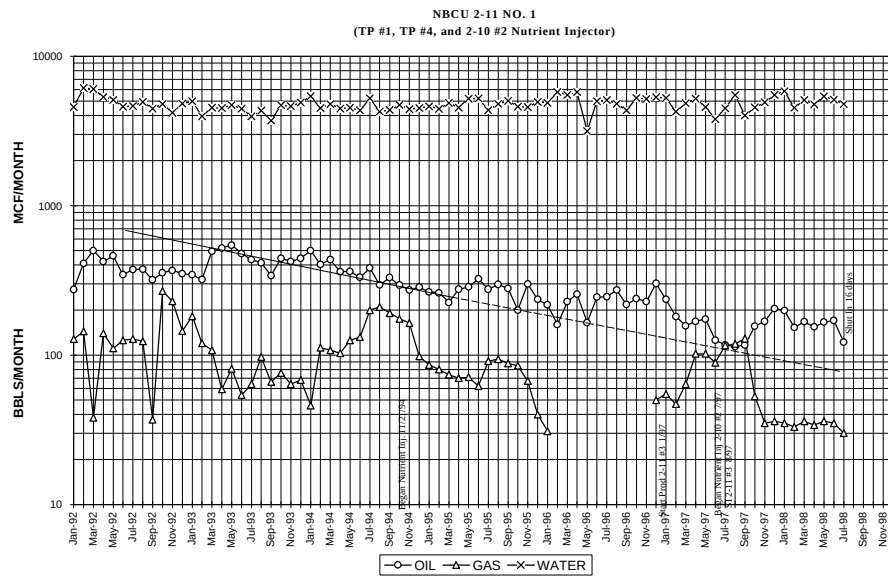


Figure 4: A production response began in this well about 5 months after starting nutrient injection in offset injector.

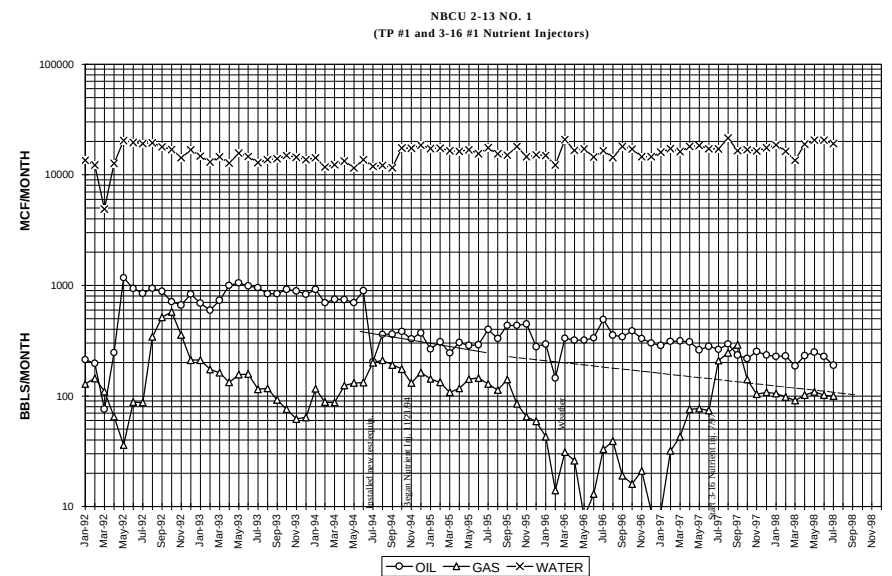


Figure 5: A significant production increase occurred about 7 months after starting nutrient injection in offset injector.

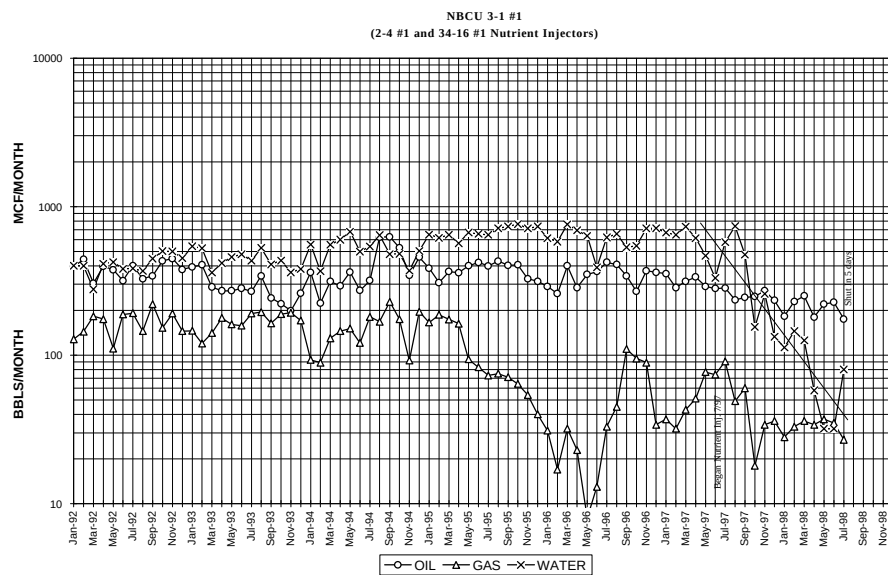


Figure 6: Note sharp decline in water production after 3 months of nutrient injection.

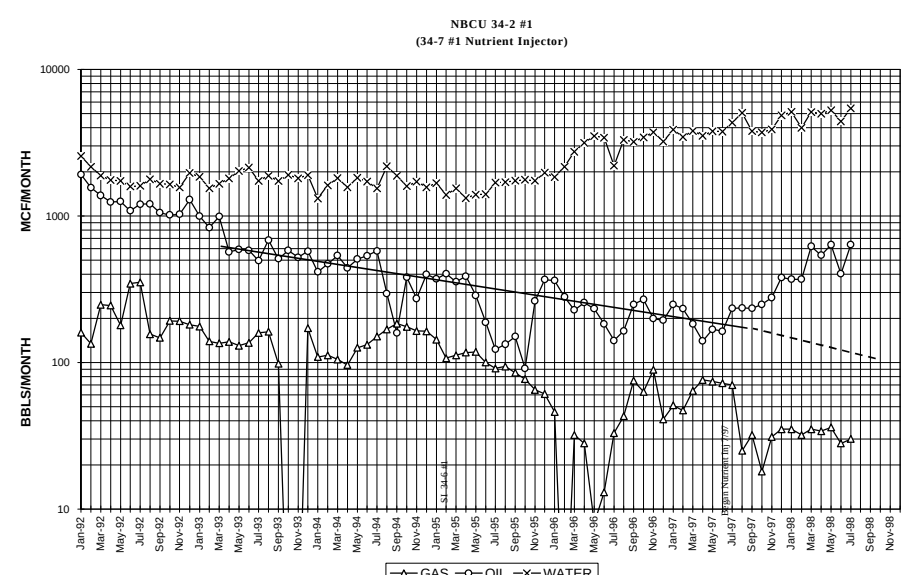


Figure 7: Production increased dramatically within 4 months of starting nutrient injection in offset injector.

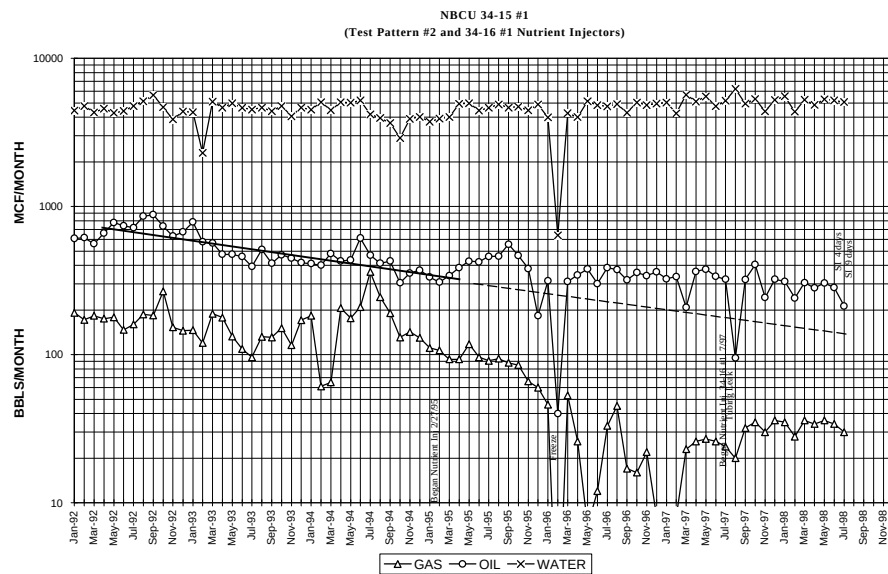


Figure 8: Note sustained change in decline slope as a result of MEOR response.

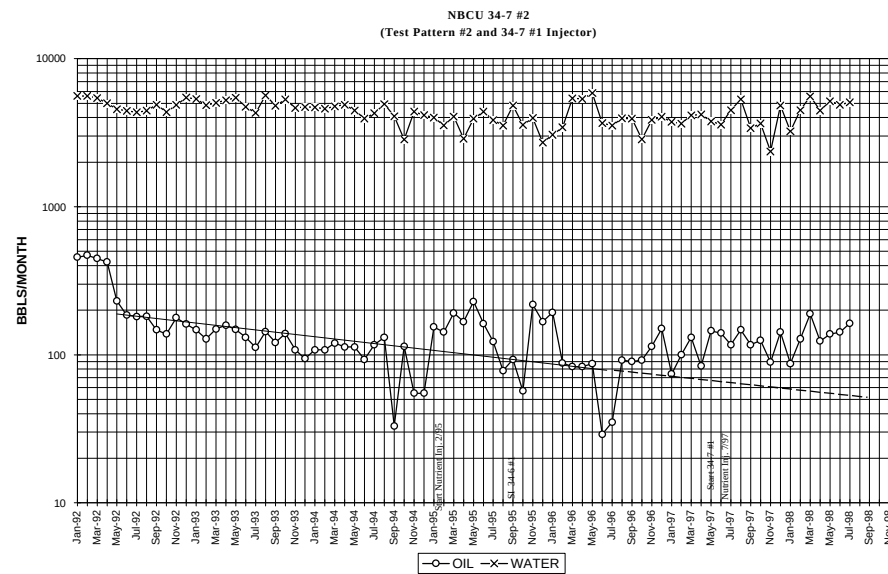


Figure 9: Two production responses are seen here, one after nutrient injection began in 1995 and another when Second offset nutrient injector began in 1997.

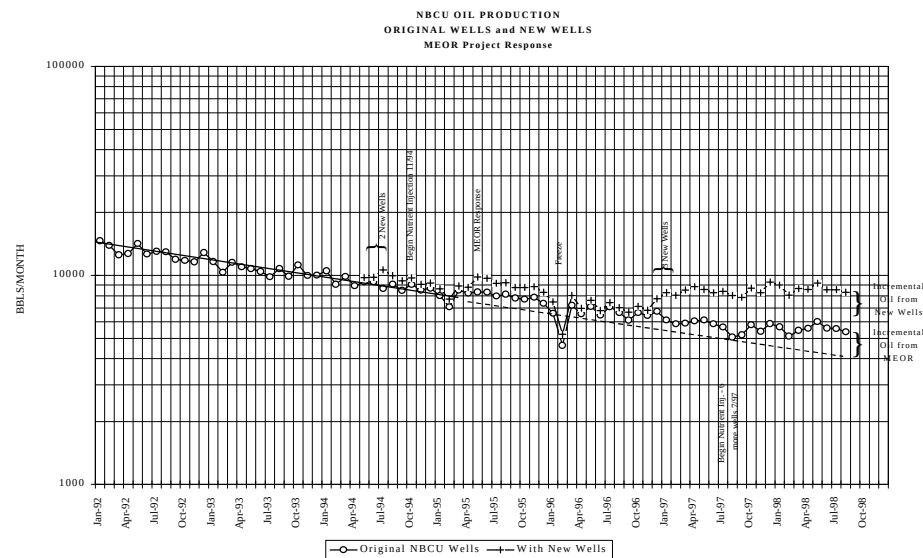


Figure 10: Field wide response to MEOR compared to baseline projection.

Studies of Natural Gas Resources in Deep Sedimentary Basins

Thaddeus S. Dyman (dyman@usgs.gov; 303-236-5730)
James W. Schmoker (schmoker@usgs.gov; 303-236-5794)
Vito F. Nuccio (vnuccio@usgs.gov; 303-236-1654)
Robert A. Crovelli (crovelli@usgs.gov; 303-235-5770)
Timothy C. Hester (hester@usgs.gov; 303-236-5792)
Ronald C. Johnson (rcjohnson@usgs.gov; 303-236-5546)
Michael L. Lewan (mlewan@usgs.gov; 303-236-9391)
Christopher J. Schenk (schenk@usgs.gov; 303-236-5796)
Kenneth I. Takahashi (kt@usgs.gov; 303-236-5722)
Dennis B. Riggin (driggin@usgs.gov; 303-236-5722)
Troy A. Cook (tcook@usgs.gov; 303-236-6594)
Allison A. Henry (c/o mlewan@usgs.gov; 303-236-9391)

U.S. Geological Survey Central Energy Team
P.O. Box 25046 MS 939
Denver, CO 80225

Contract DE-AT26-98FT40032
Task Order No. 009

Department of Energy Program Officer: William J. Gwilliam
Project Performance Period: April 7, 1998-May 1, 1999

INTRODUCTION

For strategic, economic, and environmental reasons, many U.S. drilling frontiers deserve further review. One such frontier is natural gas in deep sedimentary basins. Deep natural gas resources are distributed throughout many basins with widely different geological environments (Figure 1). According to the Potential Gas Committee (1999), the U.S. contains a total potential resource of 1,037 trillion cubic feet (Tcf) of natural gas resources including the growth of reserves in known fields and undiscovered resources. In 1995, the USGS estimated 1,074 Tcf of technically recoverable gas resources in the U.S. including gas as proved reserves, reserve growth in gas fields, undiscovered conventional and continuous gas, and gas in small fields (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995). Dyman and others (1996) identified about 113 Tcf of deep gas (gas in undiscovered fields

below 15,000 feet) from 162 deep conventional (55 Tcf) and 11 deep continuous-type plays (58 Tcf) in the U.S. based on the results of the USGS 1995 National Assessment. A more precise understanding of U.S. resources of deep gas will provide valuable economic and strategic information for future planning. In addition, an understanding of the Worldwide distribution of deep gas will provide a strategic perspective from which to view U.S. resources.

The word "deep" is used in a relative sense here, and its meaning varies for different tasks in this project and for different basins or regions. For the purpose of this paper, the word deep is defined to include all resources residing below 15,000 feet (~4.5 km), but may also refer to processes occurring at great depths, relating to resources now residing in shallow basin margins. Deep is used to focus a series of tasks in this project because it is an important classification criterion for both industry and governmental planning organizations, and the term implies important economic considerations because deep drilling frontiers are very expensive, and new technology advancements may improve their economic success.

This project evolved as an outgrowth of work on two previous projects, one funded by the Gas Research Institute (GRI) (Dyman and others, 1997) and the other by the U.S. Department of Energy (DOE) (Rice and others, 1992) on the geologic controls of deep gas. During both projects, important new research directions were identified. Many of these directions are addressed in this project. A precise understanding of the geologic controls governing the origin and distribution of deep natural gas resources may have a significant impact on the future energy resources of this Nation and the World.

This project is a two-year project which began in April 1998 and is closely related to another DOE-sponsored project dealing with the distribution of "new" basin-centered gas accumulations in U.S. basins regardless of depth (DOE project no. DE-AT26-98FT0031

entitled “Basin-Centered Gas Systems of the U.S.”-- V.F. Nuccio project chief). Results described in this report represent activities of Phase 1 or the first year of the project. Results (1) describe and analyze the geologic factors that control the distribution of deep conventional and unconventional gas accumulations in sedimentary basins of the U.S., and (2) characterize the distribution of deep conventional gas Worldwide.

Petroleum Resource Assessments

The USGS periodically conducts geologically- and probabilistically-based resource assessments and has completed four assessments for the Nation and the World in the last 20 years. This experience in conducting petroleum resource assessments forms the basis of much of our work on deep natural gas resources.

This project describes the potential for deep basin-centered gas accumulations in sedimentary basins of the U.S. based on results of these petroleum assessments, data from the published literature, and computerized well and reservoir data files. The USGS is currently re-evaluating the resource potential of selected deep basins and plays in the U.S. due to changing geologic perceptions and new data since the completion of the USGS 1995 National Petroleum Assessment.

Newly defined basin-centered accumulations in basins of the U.S. may result in new plays based on an analysis of data available since the USGS 1995 National Assessment (U.S. Geological Survey National Oil and Gas Assessment Team, 1995). These basin-centered gas accumulations vary qualitatively from low to high risk and may/may not survive rigorous geologic scrutiny leading toward a full geologic assessment based on plays.

Continuous-Type Accumulations

Continuous-type accumulations are large single fields having spatial dimensions equal to or exceeding those of conventional plays. They cannot be represented in terms of discrete, countable units delineated by downdip hydrocarbon-water contacts (as are conventional fields). The definition of continuous accumulations is based on geology rather than on government regulations defining low permeability (tight) gas. Common geologic and production characteristics of continuous accumulations include their occurrence downdip from water-saturated rocks, lack of obvious trap or seal, relatively low matrix permeability, abnormal pressures, large in-place hydrocarbon volumes, and low recovery factors (Crovetli and Balay, 1995; Schmoker, 1996).

Continuous plays were treated as a separate category in the USGS 1995 National Petroleum Assessment and were assessed using a specialized methodology (Crovetli and Balay; Schmoker, 1996). These continuous plays are geologically diverse and fall into the following categories: coal-bed gas, biogenic gas, fractured shale gas, and basin-centered plays. Only continuous-type basin-centered gas plays comprise significant future undiscovered resources in deep sedimentary basins.

Assessment of continuous plays is based on the concept that an accumulation can be regarded as a collection of hydrocarbon-bearing cells. In the play, cells represent spatial subdivisions defined by the drainage area of wells. Cells may be productive, nonproductive, or untested. Geologic risk, expressed as play probability, is assigned to each play. The number of untested cells in a play, and the fraction of untested cells expected to become productive (success ratio) are estimated based on available production data, and a probability distribution is defined for EURs for those cells expected to become productive cells. The combination of play

probability, success ratio, number of untested cells, and EUR probability distribution yields potential undiscovered resources for each play. Refer to Schmoker (1996), Crovelli and Balay (19095), and Schmoker and others (1995) for a detailed discussion of continuous-type plays and their assessment.

In 1995 the USGS defined 100 continuous-type plays with oil and gas reservoirs in sandstones, shales, chalks, and coals for all depth intervals. Of the 100 identified plays assessed, 73 were gas plays. Estimates of technically-recoverable gas resources from continuous-type sandstones, shales, and chalks range from 219 Tcf (95th fractile) to 417 Tcf (5th fractile), with a mean estimate of 308 Tcf. Estimates of technically-recoverable gas resources from coals in the lower-48 States range from 43 Tcf to 58 Tcf, with a mean estimate of 50 Tcf (U.S. Geological Survey National Oil and Gas Assessment Team, 1995). However, continuous coalbed gas resources will not be discussed further in this report because they are not deep. Continuous-type plays either not assessed or not identified in many areas or regions of the U.S. such as in Alaska, the Wind River, Bighorn, and Hanna basins of the Rocky Mountain region, the Anadarko basin of Oklahoma, and the Fort Worth basin of central Texas. Table 1 summarizes potential new deep continuous-type gas accumulations in the U.S.

Four categories of continuous-type plays can be identified with respect to new data and perceptions since the USGS 1995 National Petroleum Assessment: (1) Continuous-type plays that were correctly identified as such, assessed in 1995, but need to be updated because of new data. These plays will not be addressed further in this report. (2) Continuous-type plays that may have been identified incorrectly as conventional plays and assessed as such in 1995. (3) Continuous-type plays that were identified as such in 1995 but not assessed because of a lack of data. (4) New continuous-type plays that were not even identified in 1995.

Continuous Accumulations and Reserve Growth

In the traditional terminology of petroleum resource assessment, undiscovered resources are those postulated to exist outside of known fields, whereas inferred reserves are those forecast to be added to known fields as they are further developed (i.e. reserve growth). However, in the case of continuous accumulations, the distinction between undiscovered resources and reserve growth can be blurred. For example, in the USGS 1995 National Assessment, the existence and location of many of the continuous accumulations considered were well known, implying that the assessment procedure was an exercise in estimating reserve growth. However, the existence and location of some continuous accumulations were not at all certain, but were postulated from geologic knowledge and theory, so that the assessment procedure in these cases was an exercise in estimating undiscovered resources. In the context of this paper, some of the potential continuous gas plays are not well understood, but others have been drilled extensively. The assessment of the former resource constitutes undiscovered resources, whereas the latter resource constitutes an exercise in the estimation of reserve growth.

PROJECT OBJECTIVE

The objective of this project is to employ current and new procedures in resource assessment, quantitative production analysis, wireline log interpretation, organic geochemistry, and basic framework geology including reservoir characterization to better understand the nature and distribution of deep natural gas resources. Emphasis is placed on obstacles to deep drilling and development of predictive models that can be used to better identify future exploration and production strategies for industry and to provide more precise resource assessments.

The project is subdivided into seven research tasks: (1) New Deep Unconventional Gas Accumulations, (2) Undiscovered Resources for Deep Gas Plays, (3) Petrophysical evaluation of Deep Reservoirs Using the “Gas Effect”, (4) Geochemical Analysis of Deep Source and Reservoir Rocks, (5) Play Definition and Uncertainty of Deep Reservoirs and Plays, (6) Deep Gas and the World Petroleum Assessment, and (7) Directions for Future Study. The first six tasks are geochemical, geological, and petrophysical studies for one or more basins, regions, reservoirs, or plays. The seventh task will integrate results from the earlier tasks to answer questions about future directions of study and frontier drilling prospects during Phase 2 of this project. This report summarizes the first phase of the project (April 1998-March 1999).

RESEARCH TASKS--APPROACH

Task 1: New Deep Unconventional Gas Accumulations

The USGS did not define or assess unconventional (continuous-type) deep gas plays in some basins in its 1995 National Petroleum Assessment because of (1) a lack of data or (2) varying interpretations at the time that dealt with the conventional versus continuous nature of plays. As a result, we are compiling an inventory of deep continuous-type (basin-centered) accumulations in basins of the U.S. during Phase 1 of this project. The inventory includes geologic and production information about each accumulation and the potential for future play definition and assessment. Accumulations are rated as high, medium, or low based on the following criteria: (1) the amount of data available for an area, and our level of confidence in the data, (2) the 30-year impact of the potential accumulation, (3) the magnitude or size of the potential resource, (4) the geologic risk (e.g., depth, remoteness), (5) national distribution, and (6) the relationship to the USGS 1995 oil and gas assessment (have our perceptions about an area changed since then?).

During Phase 2 of this project, the highest priority accumulations will be evaluated in detail using well data and production characteristics. This project also relies on results from DOE project DE-AT26-98FT40031 which characterizes basin-centered gas systems regardless of depth in the U.S.

Task 2: Undiscovered Resources for Deep Gas Plays

Resource estimates are expressed as probability distributions for plays and represent the overall uncertainty in the estimation process. The uncertainty in resource estimates results from the lack of geologic and production data for plays and provinces, the experience and opinions of province geologists, and factors associated with assessment methodology. During Phase 1 of this project, we are identifying the range of estimates as fractiles of probability distributions in undiscovered conventional resources in natural gas plays for several regions identified in the 1995 USGS National Petroleum Assessment.

During Phase 2, conventional gas plays will be compared to continuous gas plays, and a priority list will be presented for play-re-evaluation. A ranking of plays based on relative uncertainty will prove helpful for exploration and development planning and for petroleum assessment.

Task 3: Evaluation of Deep Reservoirs Using the “Gas Effect”

Problems exist in evaluating prospective low permeability gas wells, especially at great depths. Nuclear porosity tools are used to investigate the differences in porosity and permeability in shallow versus deep well bores. During Phase 1 of this project, predictive models are being developed to identify the best procedures for evaluating reservoir rocks at great depths (as compared to shallow depths).

The relation of neutron, density, and gamma-ray tool responses to the presence of clay and gas in a formation is expressed by plotting the difference between neutron and density porosity (N-D) against gamma-ray intensity (GRI). This method has been used in the past to distinguish gas-producing from water-producing intervals in very shaly formations where conventional log-analyses are ineffective. Effectiveness of the crossplot depends on the existence, close proximity, and identification of water-saturated zones with geologic and production characteristics similar to those of prospective gas-producing intervals.

During Phase 2 of the project, the model will be applied to deep Morrow reservoirs of the Anadarko basin and reservoirs of the deep Gulf Coast region to determine if new deep gas resources can be identified.

Task 4: Geochemical Analysis of Deep Source and Reservoir Rocks

For task 4, gas-oil ratios (GORs) are being analyzed using published hydrous pyrolysis data from deep source rocks for economic evaluation and resource assessment. GORs vary significantly based on source-rock composition, thermal history during hydrocarbon generation, and the overall geologic history of the basin. Predicting the GOR of a petroleum play is important in evaluating the economics for an exploration venture and the input data for petroleum resource assessment. GORs are presented from hydrous-pyrolysis experiments conducted on immature source rocks and analyzed for how they are affected by kerogen type and thermal maturity during oil generation. Emphasis is placed on the role of increasing depth.

Key questions to be answered include: Can models be developed that allow us to predict volumes of gas generated based on depth, thermal maturity and kerogen type? Can hydrous-pyrolysis experiments be used to estimate the amount of gas generated under different thermal and source rock conditions?

During Phase two of the project, the role of water in gas generation will be evaluated using laboratory results from hydrous pyrolysis experiments.

Task 5: Play Definition and Uncertainty of Deep Reservoirs and Plays

Continued exploration interest in deep gas plays has prompted a re-evaluation of USGS plays assessed in the 1995 National Petroleum assessment. During Phase 1 of the project, gas plays are being evaluated on the level of uncertainty of the probability distributions of their undiscovered resources. Gas plays are being evaluated on differences in depth, lithology, and other geologic and production factors (see also Task 2 discussion).

Work during Phase 2 of this project will include a re-evaluation of the geologic framework of reservoir rocks with emphasis on the reservoir changes that occur with increasing depth and a reclassification of deep gas plays based on geologic characteristics. Emphasis will be placed on re-evaluating Jurassic and Cretaceous clastic plays of the Louisiana-Mississippi Salt Basins Province including the Cotton Valley Group and Travis Peak Formation plays. In 1995, the USGS identified five Cotton Valley plays, but only one (the Cotton Valley Blanket Sandstones Play) was assessed as a continuous-type play. A re-assessment of other Cotton Valley plays as continuous could significantly change the gas resource base for the onshore Gulf Coast region.

Task 6: Deep Gas and World Petroleum Assessment

The USGS World Petroleum Assessment Project is currently assessing undiscovered oil and gas resources for the most important 100 petroleum provinces of the World (extrapolated out to 30 years into the future). During Phase 1 of this project, the USGS is developing a procedure and computer software to allocate resources by depth.

During Phase 2, newly-released World resource estimates resulting from the World Petroleum Assessment Project will be subdivided into depth slices. Resources by depth

interval will be compiled by petroleum region, province, and nation. The total resource estimates needed for depth-slice allocation will not be available until near the end of the second year of this project when they become publicly available.

Task 7: Directions for Future Study

During Phase 2 of this project, results from the first six tasks will be integrated in order to summarize directions for future study. Questions to be answered include: Where do new deep undiscovered gas resources reside in the U.S.? What regions of the U.S. deserve the most attention with respect to future deep drilling? What are the primary controls governing the generation and distribution of deep gas, and how can we use this information to improve exploration methods and natural gas assessments? What can we learn about deep gas accumulations Worldwide to improve deep gas recovery in the U.S. Data on deep gas from the other nations will provide the basis for this summary.

SUMMARY OF PROJECT RESULTS—PHASE 1

Task 1: New Deep Unconventional Gas Accumulations

A priority list of potential deep basin-centered gas accumulations was prepared from a geologic and production evaluation by USGS Survey staff starting from the results of the 1995 National Petroleum Assessment (Gautier and others, 1996). This effort also relied on results from DOE project DE-AT26-98FT40031 which characterizes basin-centered gas systems regardless of depth throughout the U.S. For that project, we identified thirty-three potential basin-centered gas accumulations throughout the U.S. They include the: Sacramento/San Joaquin basins; Raton basin; Rio Grande rift; Anadarko basin; onshore Gulf Coast basin, Jurassic-Cretaceous Travis Peak and Eagle Ford Formations and Cotton Valley Group; Columbia basin/West Flank of the Cascade Mountains; Michigan basin; Cook Inlet basin,

Alaska; Permian basin; Hanna basin; Paradox basin (Pennsylvanian shales); Western North Slope of Alaska, Central Alaska; Wasatch Plateau; Puget Sound basin; Modoc basin, Northern California; Santa Maria basin, Monterey Formation; Los Angeles basin; Salton trough; Great Basin, Tertiary basins; Snake River downwarp; Paradox basin, Precambrian Chuar Group; Denver basin; Park basins, Colorado; North end of San Rafael Swell, Utah, Cretaceous Dakota Formation; Central Montana, Sweetgrass arch; Midcontinent rift; Arkoma basin; onshore Gulf Coast basin, Austin Chalk; Appalachian basin, Clinton-Medina and older Formations; Eastern U.S. Triassic Rift basins; and the Black Warrior Basin.

We summarized the geologic setting and data favoring the existence of potential basin-centered gas accumulations with respect to the USGS 1995 Petroleum Assessment. For each potential accumulation, we established whether new gas resources could be assessed if more data became available.

Table 1 contains a list of deep basins/areas that were evaluated for the presence/absence of a deep basin-centered gas accumulation based on work from project DE-AT26-98FT40031. The deep basins identified in Table 1 were reviewed by the USGS and grouped into three categories (high, medium, and low potential) based on the following criteria: (1) the amount of available data and overall level of confidence in that accumulation, (2) the 30-year impact of the potential accumulation on the Nation's endowment (Can we expect gas resources within the next 30 years from this accumulation?), (3) the magnitude of the potential resource, (4) the geologic risk (extreme depth, infrastructure, remoteness etc.), (5) the National distribution of accumulations, and (6) the relationship to the USGS 1995 National Petroleum Assessment (Have our perceptions changed about an accumulation?).

Task 2: Undiscovered Resources for Deep Gas Plays

Uncertainty in petroleum resource estimates can be subdivided into five broad areas: (1) compiling geologic and production data at the province level; (2) identifying and describing petroleum plays; (3) risking hypothetical plays; (4) estimating the sizes, numbers, and types of undiscovered accumulations; and (5) aggregating petroleum estimates. An analysis of these five areas of uncertainty provides insight into how resource assessments are conducted and helps answer important questions including: Are the play estimates of some province geologists more uncertain than the estimates of others? Can we define quantitative measures that capture uncertainty? Can we rank plays in an assessment based on their relative uncertainty? Can we identify the relative degree of uncertainty in plays with specific geologic and production characteristics?

We introduce a dimensionless uncertainty coefficient (UC) to compare the relative uncertainty of undiscovered conventional gas resource volumes of plays. The uncertainty coefficient is defined as:

$$UC = (F5 - F95) / \text{MEAN}$$

where F5 and F95 are fractiles of a probability distribution representing the estimate of undiscovered non-associated gas for each gas-bearing play, and MEAN represents the mean value of that estimate (Dyman and Schmoker, 1996; Crovelli and Balay, 1996). F95 represents a 19 in 20 chance and F5 represents a 1 in 20 chance of the occurrence of at least the resource amount identified. Use of the uncertainty coefficient is based on the assumption that the fractile range of the undiscovered resource for each play probability distribution (F5-F95) incorporates all areas of uncertainty that may be introduced into the assessment process.

New and useful information from the USGS 1995 National Petroleum Assessment is revealed when data on uncertainty are analyzed. Figure 2 is a plot of UC versus mean volume of undiscovered non-associated gas for each of 236 conventional gas-bearing plays from the USGS 1995 National Petroleum Assessment. The upper right-hand portion of the plot is shaded to represent larger-sized relatively uncertain plays ($UC > 2.0$ and resource > 1 Tcf of gas). Larger plays tend to be more certain than smaller plays. Of the 10 largest plays with respect to undiscovered resource, five are from the northern Alaska province (plays 111, 109, 105, 102, and 106), four are from Gulf Coast provinces (plays 4709, 4723, 4903, and 4727), and one is from the Permian basin province (play 4401). These 10 plays have a combined resource of 77.5 Tcf of gas. Only one of the largest plays has a UC much higher than 2.0 (play 105; $UC = 2.32$).

The most uncertain plays tend to be small with respect to undiscovered gas resources. The 10 most uncertain plays have a total combined undiscovered conventional resource of only 2.8 Tcf of gas. These plays are primarily hypothetical (no proven production in the play), occur in 9 widely distributed provinces, contain primarily clastic reservoirs, and are structurally controlled. These uncertain plays, although small, need to be re-evaluated from a geologic and engineering perspective to more precisely estimate their future resource potential.

Task 3: Evaluation of Deep Reservoirs Using the “Gas Effect”

The “gas effect” is a geophysical-tool response to gas in a formation, and occurs whenever gas is present. On well logs, the gas effect is often manifested as a visual “crossover” of neutron- and density-porosity curves. As clay volume and associated bound water increase in a formation, neutron- and density-porosity curves separate until the

crossover no longer occurs, and the gas effect, although still present, is no longer detectable. An alternative, empirical approach uses a crossplot of neutron porosity minus density porosity versus gamma-ray intensity to detect and measure the gas effect regardless of clay content (Figure 3).

The magnitude of the gas effect is directly related to the bulk volume of gas present. Therefore, the gas effect can substitute for water-saturation determinations as a qualitative measure of gas concentration and an indicator of production potential. This system has an advantage over conventional log analysis in areas, such as the shallow Cretaceous of the northern Great Plains, where clay volume makes water-saturation determinations unreliable. (Phase 2 testing will include deep Morrow reservoirs of the Anadarko basin.)

The crossplot is used to separate the effects of gas and clay-bound water, and to isolate the gas effect for calibration. An overlay is used in combination with the crossplot to establish a baseline from which to measure and scale the gas effect into 12 indexed levels of magnitude. The index links the gas effect to actual gas production, and provides an estimate of production potential for a broad range of reservoir conditions.

Task 4: Geochemical Analysis of Deep Source and Reservoir Rocks

During hydrous pyrolysis experiments, oil-prone source rocks (e.g. Type-I, II, and IIS kerogen) generate gas-to-oil ratios (GORs) between 382 and 2,381 standard cubic feet/barrel (scf/bbl) (Henry and Lewan, in press).

Source rocks with Type-III kerogen generate higher GORs than source rocks with more oil prone kerogen during oil generation. However, the more oil prone kerogens can generate twice as much hydrocarbon gas per gram of organic carbon than more gas-prone Type-III kerogen. During oil generation, GORs determined in closed-system anhydrous pyrolysis increase with increasing temperature, and GORs determined by hydrous pyrolysis decrease with increasing

temperature. As a result, hydrous pyrolysis GORs indicate that petroleum accumulations with GORs between 1,500 and 3,000 scf/bbl can be generated during the early stages of oil generation. Conversely, anhydrous-pyrolysis GORs indicate that petroleum accumulations with GORs greater than 2,000 scf/bbl can only be formed near the end of oil generation.

Task 5: Deep Gas and World Petroleum Assessment

A probabilistic method for subdividing resource estimates by depth was developed (Croveti, 1999). The software program, called Deep Energy Estimated Percentages (DEEP), uses a median-based triangular probability distribution as a probability model for drilling depth to estimate the percentages of petroleum resources below various depths or depth cutoffs, and also, between depth cutoffs. The standard characterizing parameters for the triangular probability distribution include the minimum, maximum, and modal depth of each assessment unit. The method is incorporated into a spreadsheet software system (DEEP) that can be easily expanded to include any number of depth slices.

Future Activities

At the end of Phase 2 of this project, results from the first six tasks will be integrated in order to summarize directions for future study. Questions to be answered include: What can we learn about deep gas accumulations Worldwide to improve our capacity to recover deep gas in the U.S. Data on deep gas from the other countries will provide the basis for this summary. What regions of the U.S. deserve the most attention with respect to future deep drilling? Work will also include final prioritizing of the deep parts of as-yet-undefined basin-centered deep gas plays.

For Phase 2 of this project, the following activities will be undertaken:

1. High priority deep basin-centered gas accumulations will be evaluated in further detail in order to define plays for each of them (Task 1).
2. All gas plays in the U.S. (including unconventional plays) will be evaluated on the basis of uncertainty as determined by the range of fractiles in the probability distributions for undiscovered resources (Task 2).
3. Deep Morrow sandstone reservoirs will be analyzed for the Gas Effect and Gas Production Index using gamma ray, neutron, and density logs (Task 3).
4. Deep gas plays will be evaluated for (a) potential gas-oil ratios for resource assessment and (b) the role of water in the generation of deep gas (Task 4).
5. Selected Gulf Coast region deep gas plays will be re-evaluated for resource assessment purposes. Plays will be analyzed for their continuous-type accumulation characteristics (Task 5).
6. Assessment unit resource estimates for about 100 provinces Worldwide will be subdivided into depth increments as data become available from the U.S. Geological Survey World Energy Assessment Project.

ACKNOWLEDGMENTS

This report covers research sponsored in part by the U.S. Department of Energy's Federal Energy Technology Center (FETC), under contract DE-AT26-98FT40032 Task Order No. 009 with the U.S. Geological Survey. The FETC Program Officer is William J. Gwilliam and the Project Performance Period for Phase 1 of the project was April 7, 1998 to May 1, 1999. We wish to acknowledge the helpful reviews of Mahendra Verma, Mitchell Henry, and Katharine Varnes of the U.S. Geological Survey, Central Energy Team.

REFERENCES

- Crovelli, R.A., and Balay, R.H., 1995, Probabilistic methodology and computer programs for assessment of unconventional oil and gas resources, *in* Gautier, D.L., Dolton, G.L., Takahashi, K.I., and Varnes, K.L., eds., 1995 National Assessment of United States oil and gas resources—Results, methodology, and supporting data: U.S. Geological Survey Digital data Series DDS-30 [CD-ROM].
- Crovelli, R.A. and Balay, R.H., 1996, Probabilistic methodology for GRASS: Gas Resource Assessment Spreadsheet System: U.S. Geological Survey Open-File Report 96-296, 20 p.
- Crovelli, R.A., 1999, Probabilistic method for subdividing petroleum resources into depth slices: U.S. Geological Survey Open-File Report 99-343, 9 p.
- Dyman, T.S., Rice, D.D., and Westcott, P.A., eds., 1997, Geologic controls of deep natural gas in the United States: U.S. Geological Survey Bulletin 2146, 239 p.
- Dyman, T.S., Schmoker, J.W., and Quinn, J.C., 1996, Reservoir heterogeneity as measured by production characteristics of wells—preliminary observations: U.S. Geological Survey Open-File report 96-059, 11 p.
- Dyman, T.S., Schmoker, J.W., and Root, D.H., 1996, USGS assesses deep undiscovered gas resource: Oil and Gas Journal, April 20, 1998, p. 99-104.

- Gautier, D.L., Dolton, G.L., Takahashi, K.I., and Varnes, K.L., eds., 1996, 1995 National assessment of United States oil and gas resources--results, methodology, and supporting data: U.S. Geological Survey Digital Data Series 30, Release 2.
- Hester, T.C., 1999, Calibration of the "Gas Effect" using neutron, density, and gamma-ray-intensity wire-line logs: U.S. Geological Survey Open-File Report 99-128, 23 p.
- Lewan, M.D. and Henry, A.A., in press, Gas:oil ratios for source rocks containing Type-I, II, IIS, and III kerogens as determined by hydrous pyrolysis: U.S. Geological Survey Open-File report, 17 p.
- Potential Gas Committee, 1999, Potential supply of natural gas in the United States: Report to the Potential Gas Committee (December 31, 1998): Potential Gas Agency, 195 p.
- Rice, D.D., Schenk, C.J., Schmoker, J.W., Fox, J.E., Clayton, J.L., Dyman, T.S., Higley, D.K., Keighin, C.W., Law, B.E., and Pollastro, R.M., 1992, Potential for deep natural gas resources in eastern Gulf of Mexico, *in* Malone, R.D., Shoemaker, H.D., and Byrer, C.W., eds., Proceedings of the natural gas research and development contractors review meeting: U.S. Department of Energy, Morgantown Energy Technology Center Report 92/6125, p. 151-166.
- Schmoker, J.W., Crovelli, R.A., and Balay, R.H., 1995, Potential additions to technically recoverable resources for each continuous-type (unconventional) play of the U.S. Geological Survey 1995 National petroleum assessment of oil and gas resources--graphical and tabular presentations: U.S. Geological Survey Open-File Report 95-75E, 57 p.
- Schmoker, J.W., 1996, Method for assessing continuous-type (unconventional) hydrocarbon accumulations, *in* Gautier, D.L., Dolton, G.L., Takahashi, K.I., and Varnes, K.L., eds.,

1995 National assessment of United States oil and gas resources--results, methodology, and supporting data: U.S. Geological Survey Digital Data Series 30, Release 2.

U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995, 1995

National assessment of United States oil and gas resources: U.S. Geological Survey Circular 1118, 20 p.

FIGURE CAPTIONS

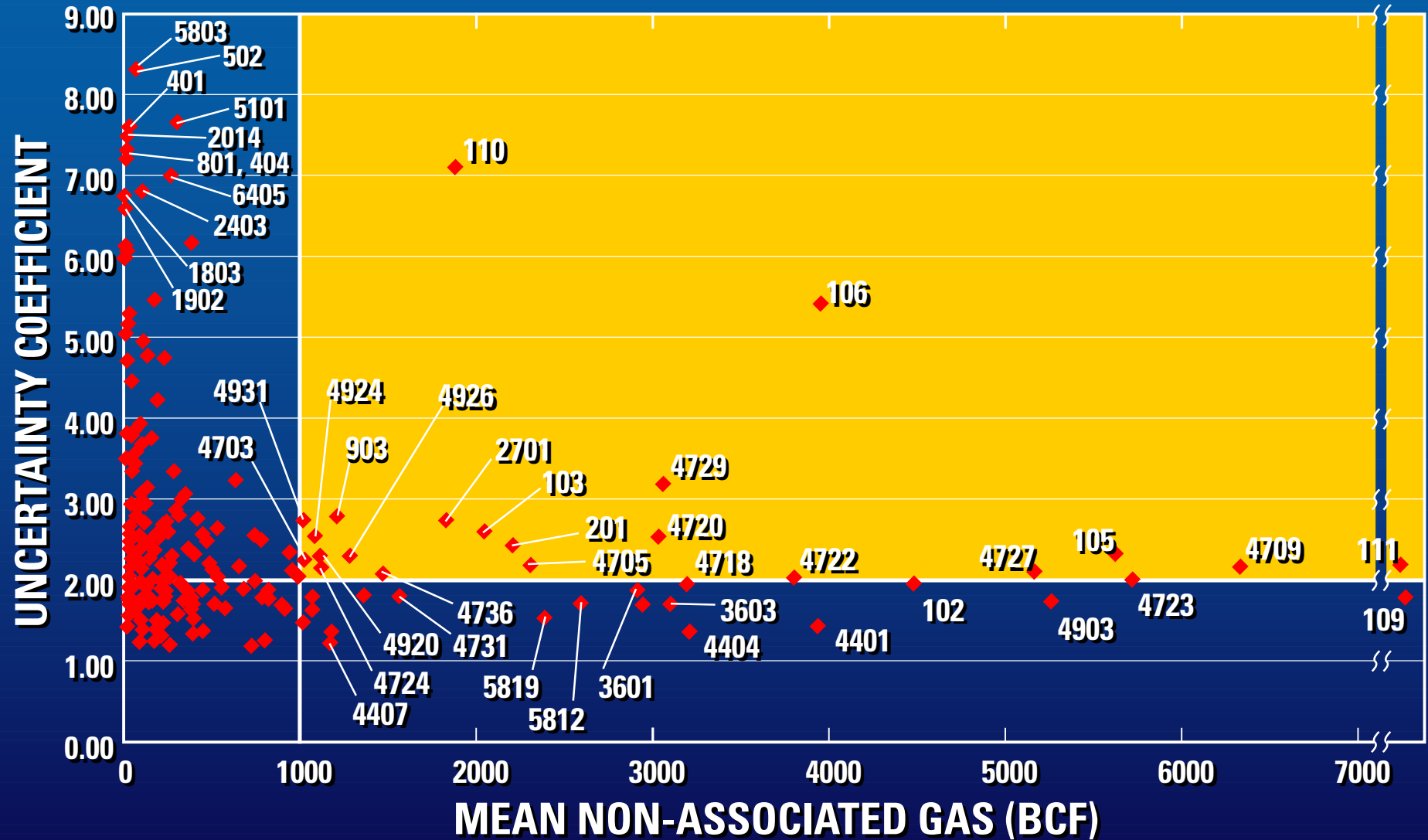
Figure 1. Generalized map of conterminous U.S. and Alaska showing basins containing sedimentary rocks deeper than 15,000 feet (about 4.5 km). Shaded areas represent entire basins.

Figure 2. Plot of uncertainty coefficient versus mean non-associated undiscovered conventional gas (in billions of cubic feet) for 236 gas-bearing plays from the USGS 1995 National Petroleum Assessment. Example plays identified by number. Refer to Gautier and others (1996) for play numbers. Shaded area represents plays with UC greater than 2.00 and mean undiscovered resource greater than 1,000 Bcf of gas. Play numbers 111 (23.8 Tcf of gas) and 109 (13.3 Tcf of gas) are off scale with respect to horizontal axis.

Figure 3. Summary crossplot of neutron porosity minus density porosity versus gamma-ray intensity, showing relative variation in porosity, water saturation, clay volume, bound water, and production potential, with plotted position of interval data. Heavy solid line is regression line of Figure 4 of Hester (1999). Dashed line is zero-production baseline of Figure 5 of Hester (1999).



HIGH PRIORITY GAS PLAYS FOR RE-EVALUATION



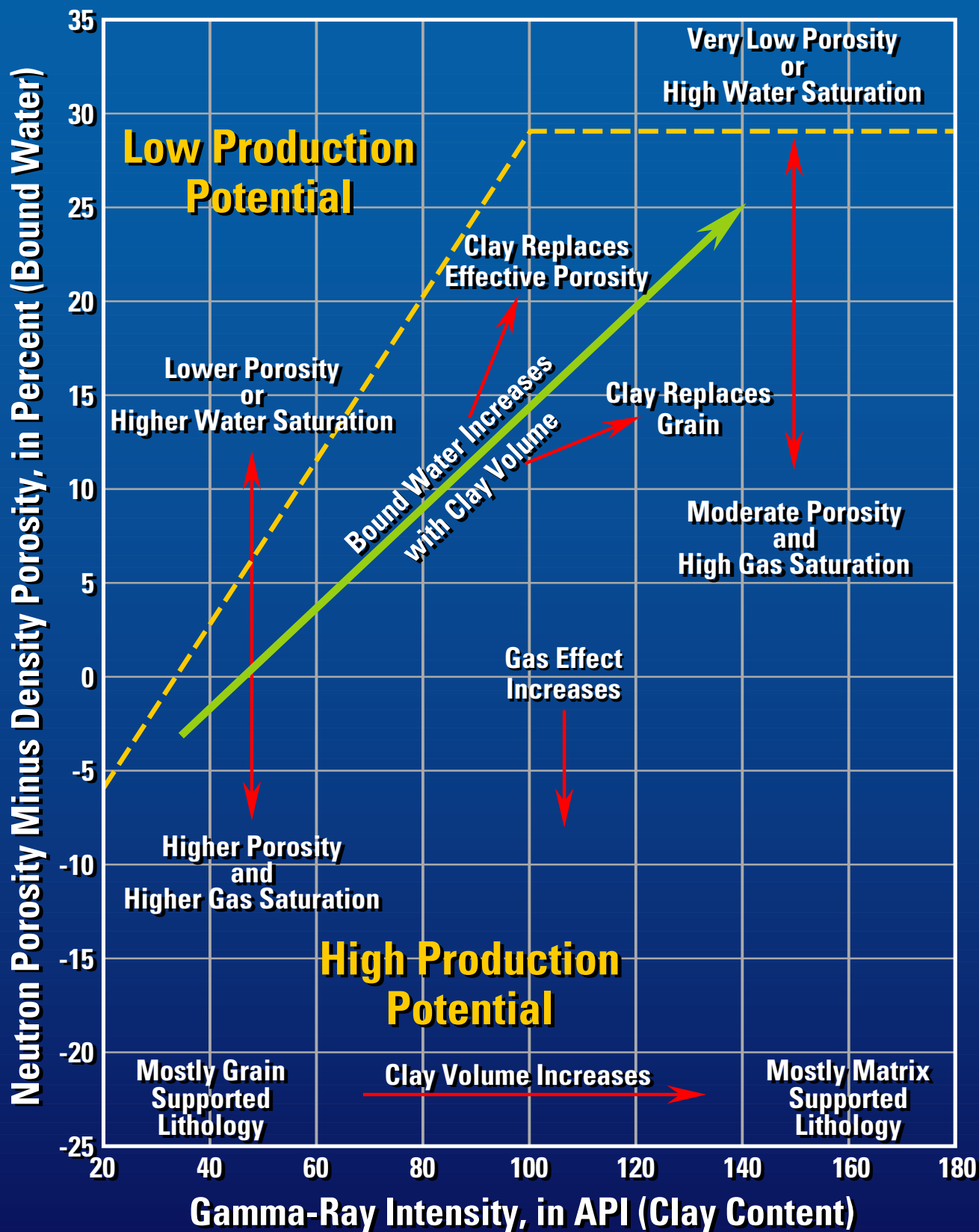


Table 1. List of basins/areas in each region of the U.S. with new potential basin-centered gas accumulations with respect to the USGS 1995 National Petroleum Assessment (Gautier and others, 1996). Ranking of each basin as high, medium, or low potential in parentheses is based on criteria discussed in report. Comments included with respect to evaluation in 1995 USGS National Assessment.

Alaska Region

Cook Inlet basin (medium-high)-- no continuous-type plays identified in 1995

Western Colville-Central Alaska basins (medium-high)—no continuous-type plays identified in 1995

West Coast Region

Columbia basin (medium)—one continuous-type gas play assessed in 1995

Willamette-Puget Sound trough (medium)-- one continuous-type gas play assessed in 1995

Hornbrook basin (low-medium)-- no plays defined in 1995

Los Angeles basin- seven conventional plays assessed (low)—one continuous-type gas play defined but not assessed in 1995

Salton Trough (low)-- no continuous gas plays defined in 1995

Rocky Mountains-Northern Great Plains Region

Hanna basin (high)-- no continuous-type gas plays defined in 1995

Snake River downwarp (low)-- no continuous-type gas plays defined in 1995

Midcontinent Region

Anadarko basin (high)-- two deep conventional plays assessed, one continuous-type play defined in 1995

Arkoma basin (medium)-- no continuous-type gas plays defined in 1995

Midcontinent Rift (low-medium)-- no continuous-type gas plays defined in 1995

Gulf Coast Region

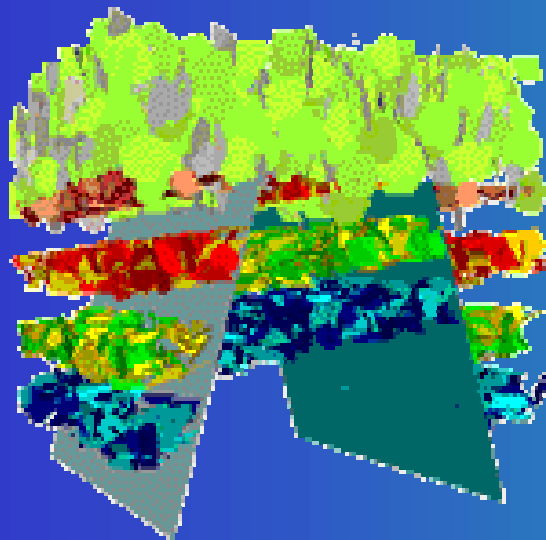
Western Gulf basin Austin Chalk (high)-- updip continuous-type Austin oil play assessed; no continuous gas plays identified in 1995

Louisiana-Mississippi Salt basins-Cotton Valley/Travis Peak (high)— 44 deep conventional gas plays and one continuous gas play assessed in 1995

Eastern Region

Black Warrior basin (medium)-- four conventional plays assessed, but no continuous-type gas plays defined in 1995

Discrete Feature Network Methods for IOR in Heterogeneous Reservoirs



**W. Dershowitz¹, T. Cladouhos¹,
P. LaPointe¹, and E. Wadleigh²**

¹Golder Associates, Inc, Redmond WA

²Marathon Oil, Midland TX

**NPTO Research Contract
DE-AC26-98BC15101**

- **Project Team**

Golder: DFN Technologies

Marathon: IOR Applications

MIT: DFN Data Analysis/Synthesis

- **Project Scope**

DFN Data Analysis Tools

DFN Model Development for Study Sites

IOR Design Using DFN Technologies

IOR/DFN Demonstration Application

Technology Assessment

Technology Transfer

Abstract of Paper for Presentation to DOE Reservoir Conference, Dallas, June 28-30, 1999

Discrete Feature Network Methods for IOR in Heterogeneous Reservoirs

W. Dershowitz¹, T. Cladouhos¹, P. LaPointe¹, and E. Wadleigh²

¹Golder Associates, Inc, Redmond WA

²Marathon Oil, Midland TX

Heterogeneities such as fractures, faults, sand/sandstone interbeds, and solution features play a key role in controlling the flow of reservoir fluids (oil and water) and injected materials (water, steam, surfactant and gel) to and from wells. Critical improvements in oil recovery efficiency can be achieved through an improved understanding of the connectivity of these features.

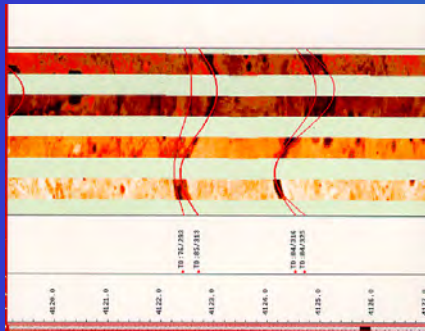
This paper describes the development of discrete feature network (DFN) methods to support IOR activities in heterogeneous and fractured dolomite and sandstone reservoirs. DFN models have been developed to identify the key discrete features that control flow and connectivity, such that the models can be used directly in the design of IOR activities.

This paper describes DFN approach to support IOR activities such as:

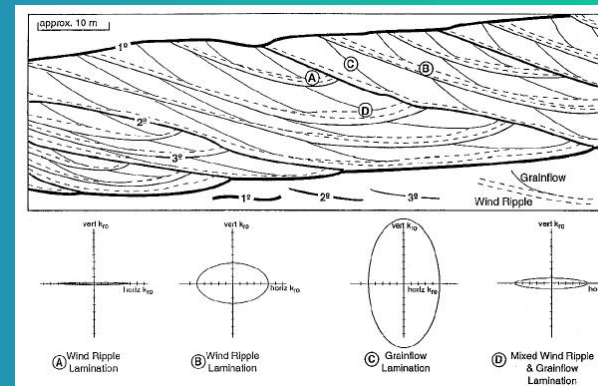
1. surfactant treatments to enhance a gravity stable recovery process,
2. waterflood displacement,
3. alternative gel treatments,
4. improved targeting of water injection,
5. horizontal drilling to connect with low recovery portions of the reservoir,
6. selective reduction in water cycling by improved gel conformance treatment design and placement, and
7. improved completion placement and stimulation for oil recovery under depletion mechanisms.

Examples are provided from project study sites in the Yates, Texas and Oregon Basin, Wyoming fields.

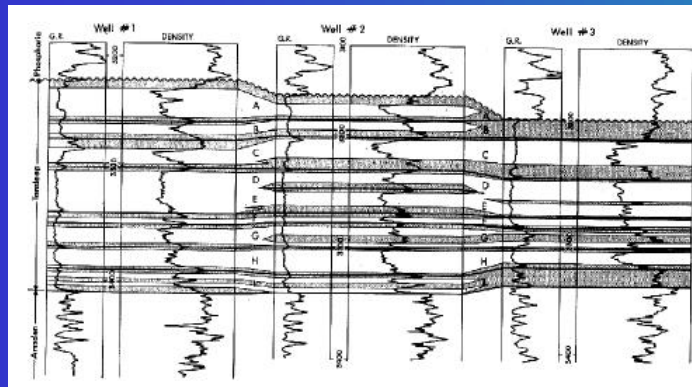
Discrete Features in Heterogenous Reservoirs



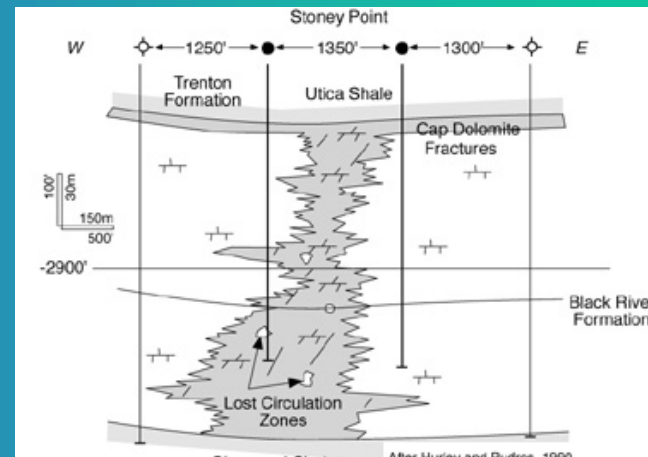
Fractures and faults



Bedding Features



Impermeable dolomite layers in sandstone



Carbonate Solution Features

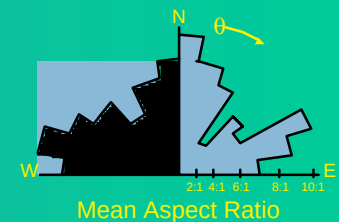
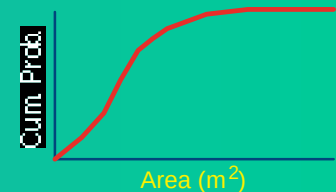
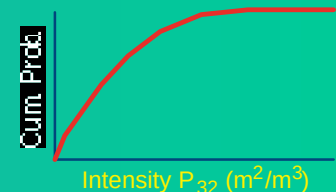
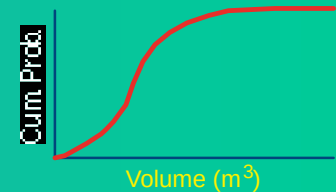
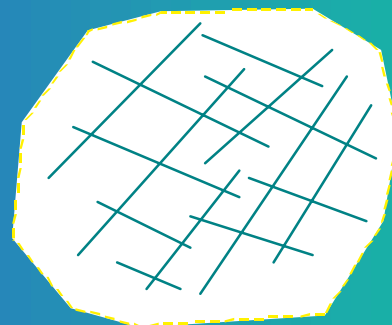
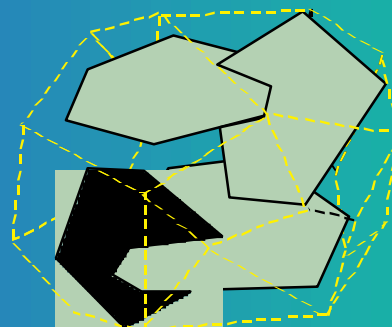
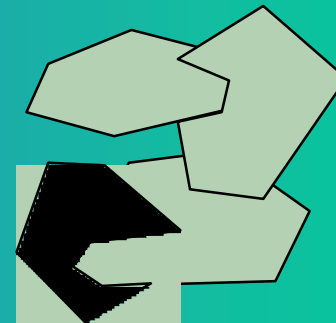
Discrete Feature Network Approach *for Heterogeneous Reservoir IOR*

- Identify Key Types of Discrete Features:
Conductors and Flow Barriers
- Analyse Data to Understand Key Discrete Features
Geology, Geophysics, Production, Well Testing
- Build Three Dimensional Discrete Feature Network Models
Spatial Structure, Orientation, Size, Shape, Porosity, Permeability Distributions
- Apply DFN Analysis Techniques to Design Appropriate IOR Strategies
Pathway, Compartmentalization, Connectivity Analyses, DFN Flow Simulations

Example DFN Application

Compartmentalization Analysis for Fractured and Heterogeneous Reservoirs

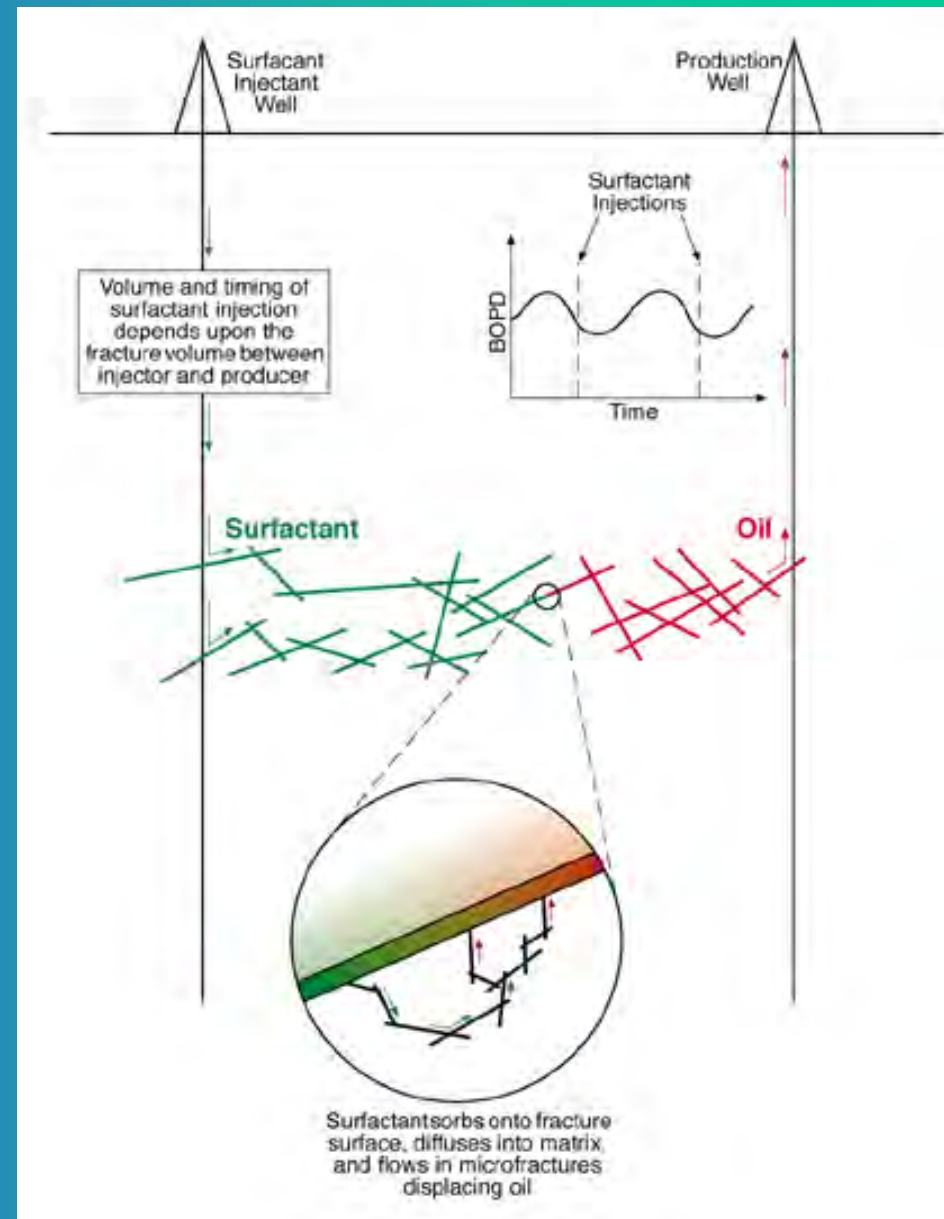
Fracture Network



IOR Issues Addressed by Discrete Feature Network Approaches

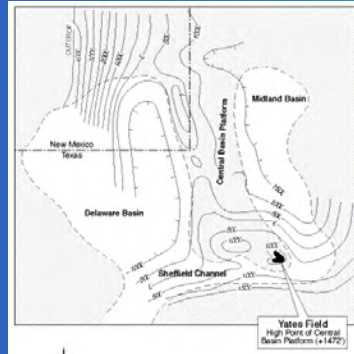
- Dewatering Fractures
to Access Bypassed Oil
- Directional Drilling and Hydraulic Fracturing
to Enhance or Reduce Fracture Connectivity
to Reduce Mud Loss
- Strategic Completion
to Access Fracture Connectivity
- Gel Placements
to Reduce Water Cycling
- Surfactant Flood
to Improve Matrix Oil Mobility
- TAGS Steam Flood
to Improve Mobility and Production Pressures

Surfactant Design in Fractured/ Heterogeneous Reservoirs

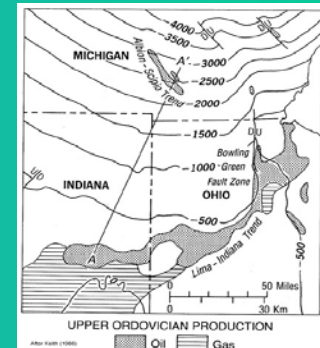


Heterogeneous Reservoir Project Study Sites

**Yates Field,
West Texas**



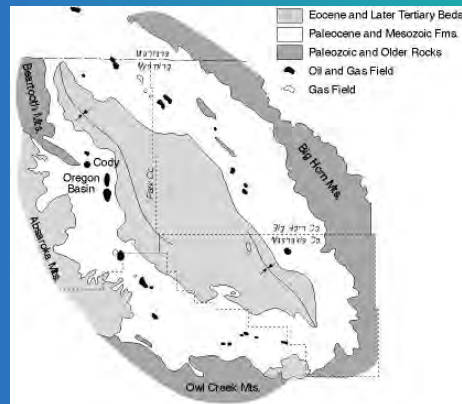
**Stoney Point,
Michigan**



Carbonate Solution Features

Dolomitization

**South Oregon
Basin, Wyoming**



Faults and Fractures

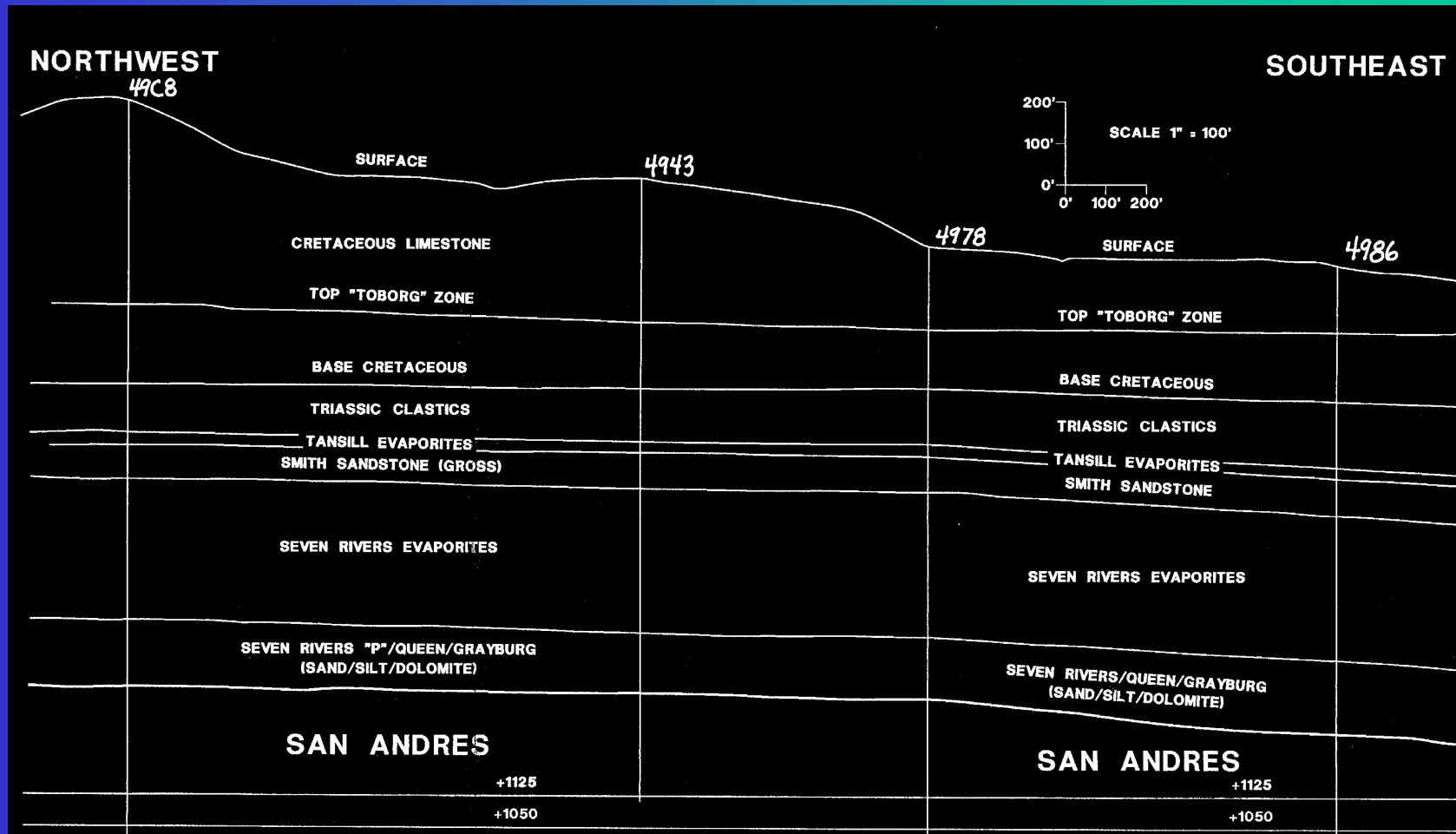
**North Oregon
Basin, Wyoming**

**Dolomite Interbeds, Eolian
Laminations**

DFN Applications for Project Study Sites

Field	IOR Design Issue	DFN Approach for IOF
Yates	Strategic Completion to Aid TAGS Steam Flood	DFN Simulation of Strategic Completions
North Oregon Basin	How much surfactant to inject?	DFN Compartmentalization and Pathway Analysis
North Oregon Basin	Best well orientation to minimize gel volume?	DFN Effective Permeability Tensor Calculation, Connectivity Analyses
South Oregon Basin	Best well orientation to access upper Phosphoria?	DFN Effective Permeability Tensor Calculation, Connectivity Analyses
Stoney Point	Well location and orientation for dewatering fractures?	DFN Simulation of Dewatering Operations

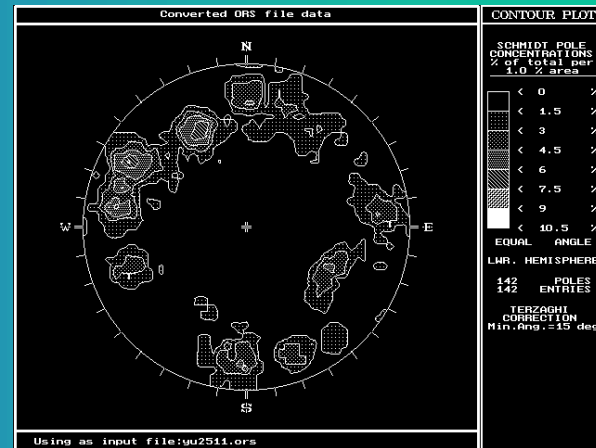
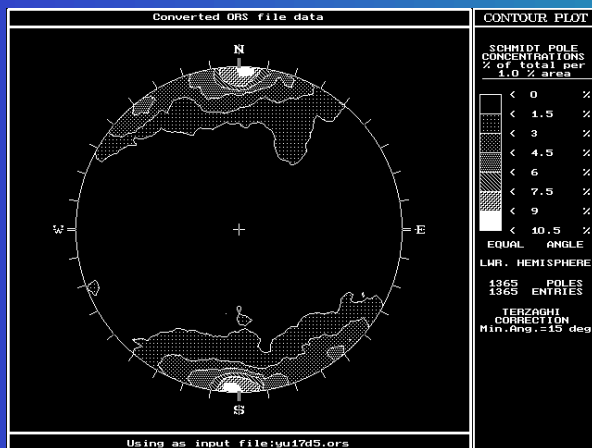
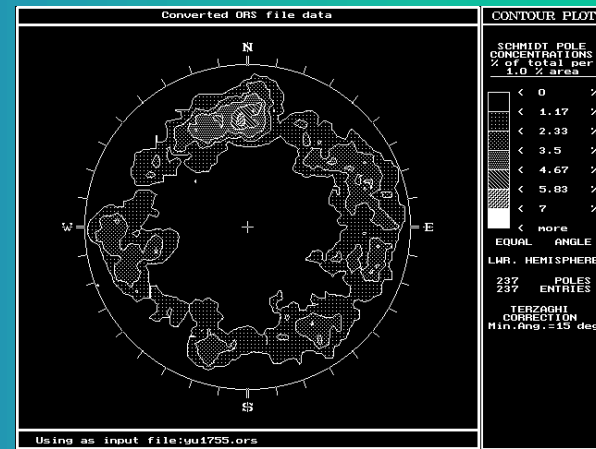
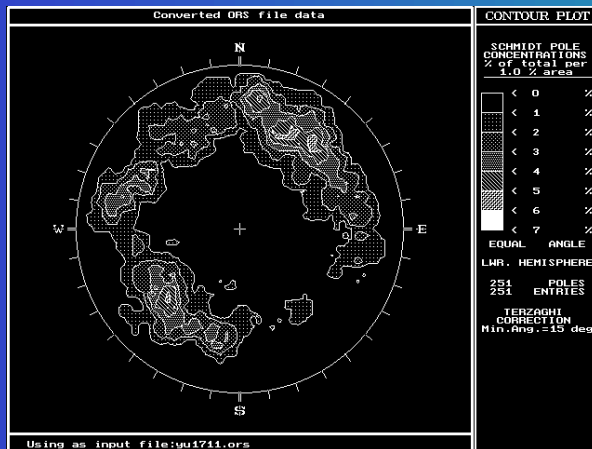
Yates Field, West Texas Study Site



DFN Model Implementation

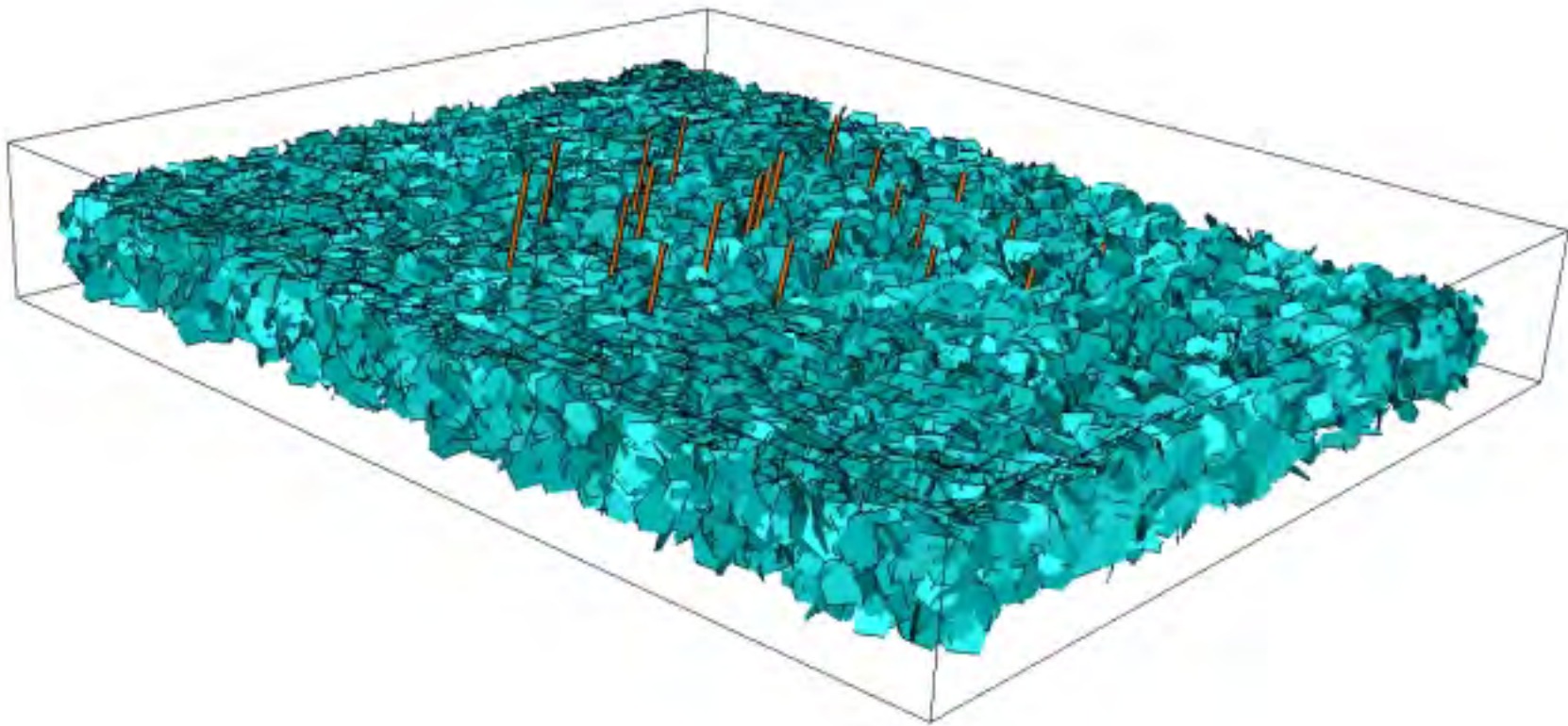
Fracture Orientation

Yates Field, West Texas



DFN Model Implementation

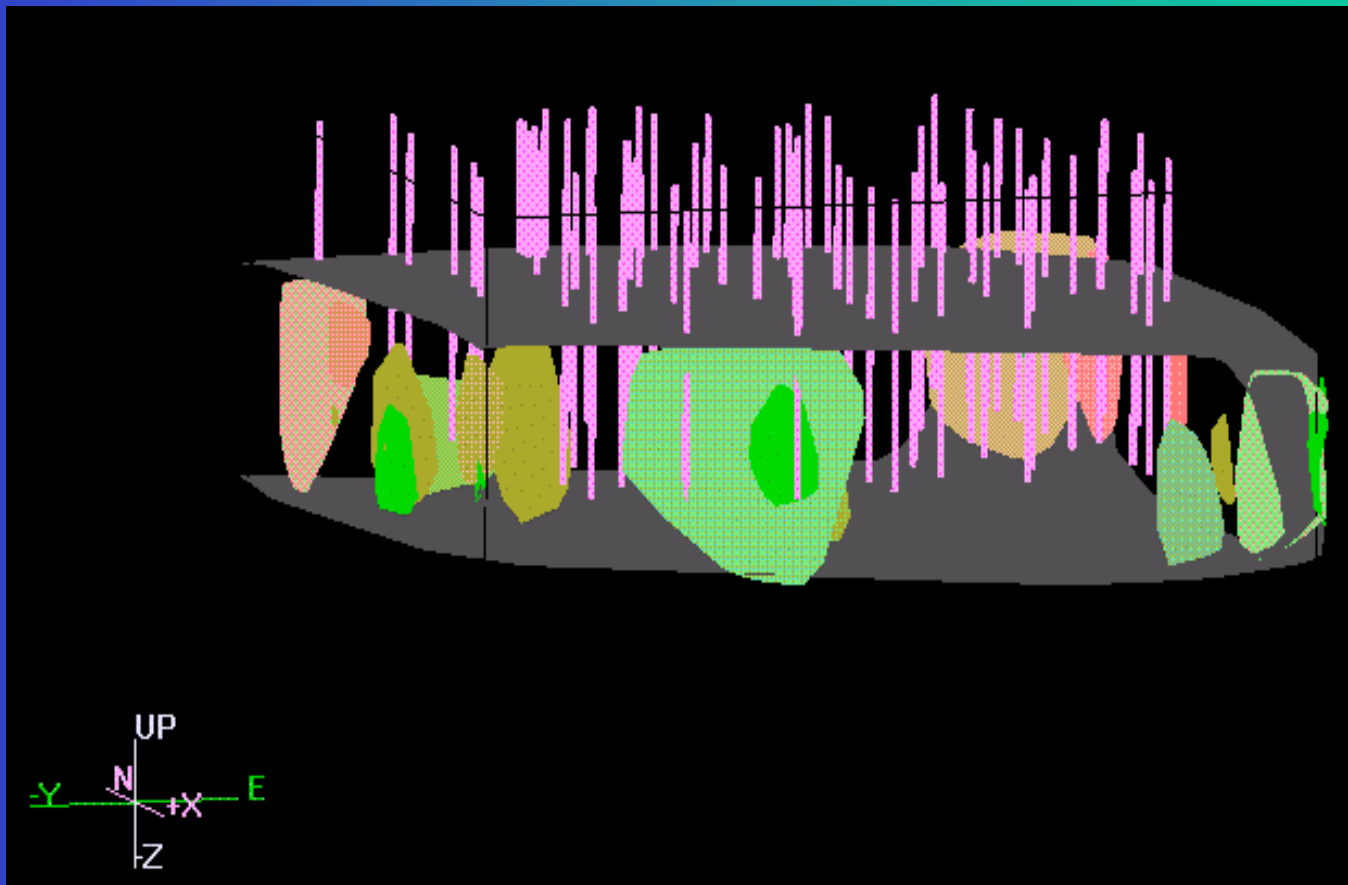
Yates Field, West Texas



DFN Model Application

Compartmentalization

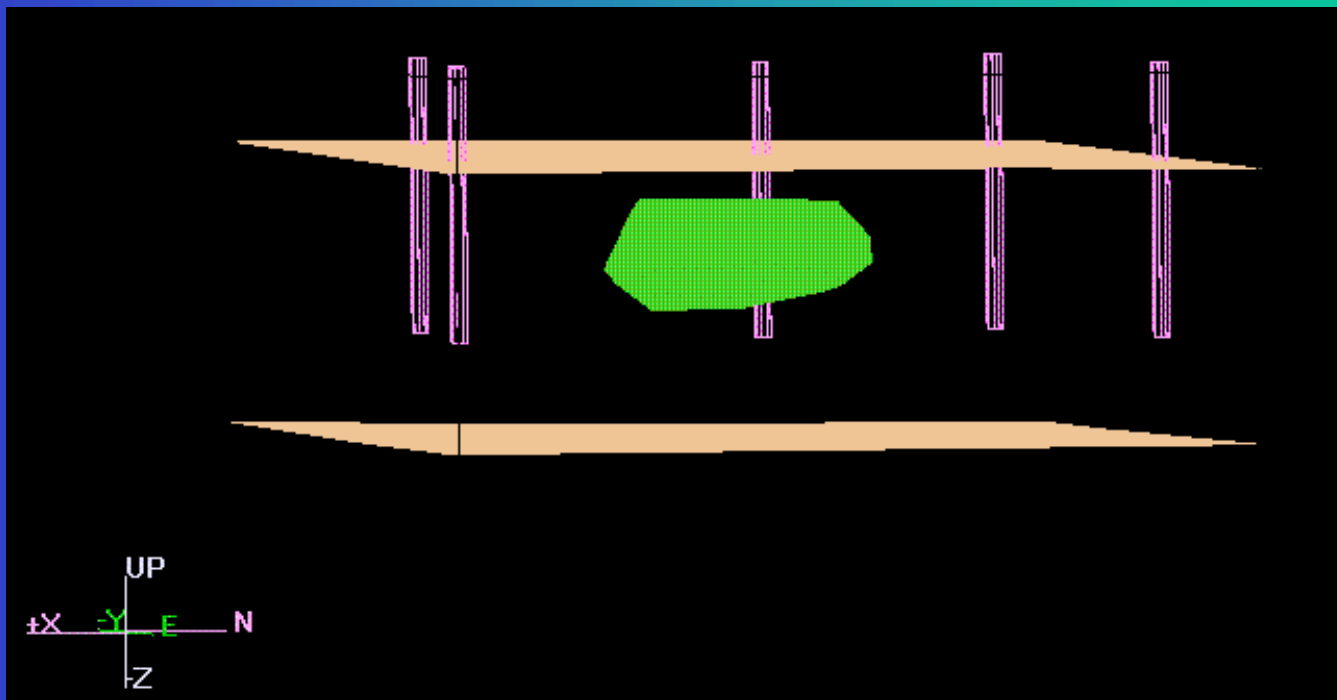
Yates Field, West Texas, Tract 49



Phase 2

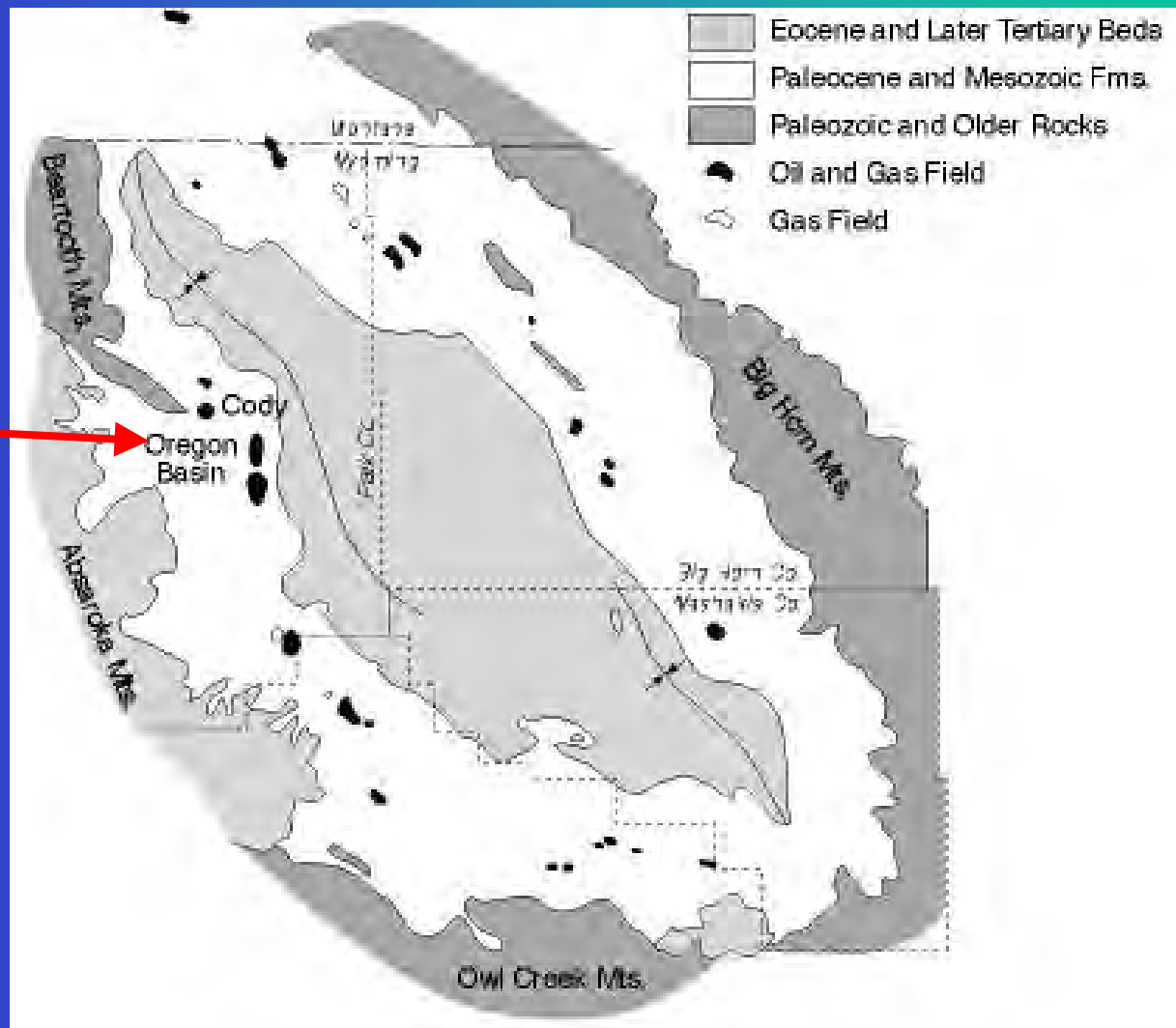
Strategic Completion Design

Yates Field, West Texas



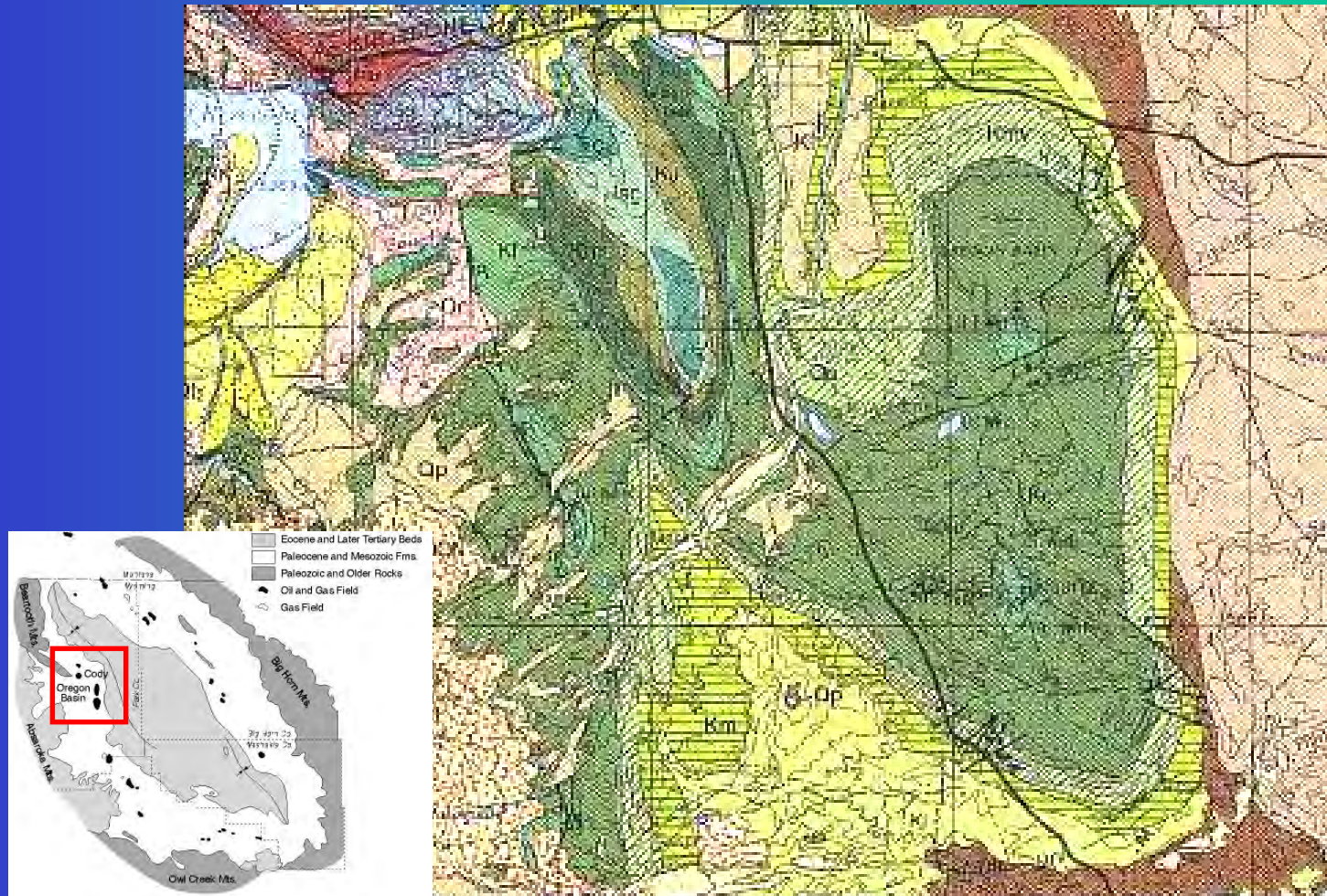
Oregon Basin Study Sites

North Oregon Basin/South Oregon Basin



Oregon Basin Study Sites

North Oregon Basin/South Oregon Basin



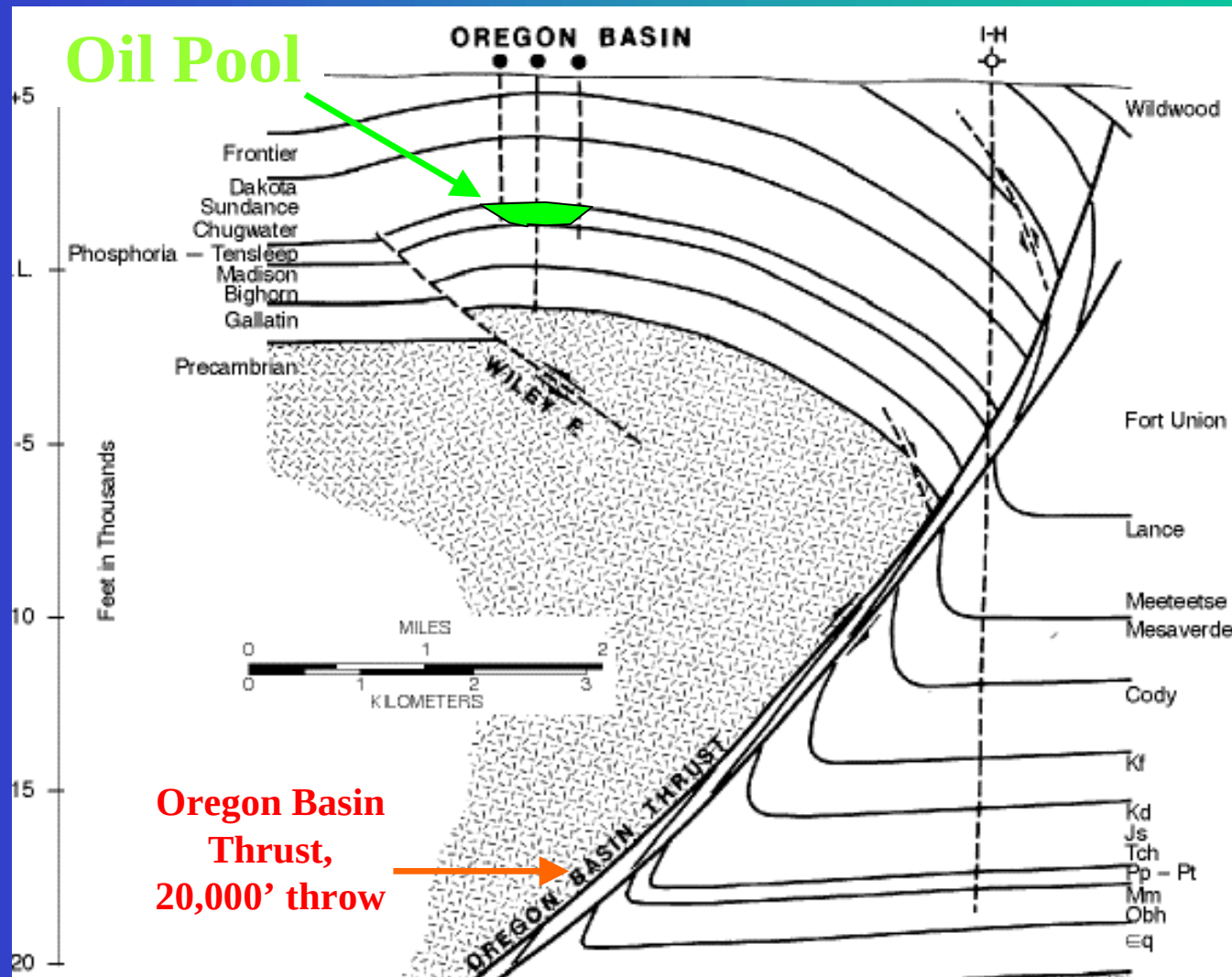
Surficial geology from Pierce, 1997

Relevant Stratigraphy at Oregon Basin

Symbol	Formation	thickness (south dome)	Lithology	Sed.Envir- onment
DINW	Triassic Dinwoody	30-45'	Shale and anhydrite	Marine or estuarine
PHOS	Triassic- Permian Phosphoria	250'	Carbonate (called Embar in old reports, Park City in new reports)	Marine
erosional unconformity				
TENS	Penn. Tensleep	20-190'	Cross-bedded and massive, well-sorted sandstone with dolomite interlayers	Marine/ eolian (coastal dune)
AMSD	Penn. Amsden	210'	Dolomite, shales and anhydrite. Basal sandstone	
erosional unconformity				
MADI MADB	Lower Miss. Madison	740'	Marine limestone, lower part dolomitized	Marine

Regional Structure at Oregon Basin Sites

North Oregon Basin/South Oregon Basin



North Oregon Basin Study Site

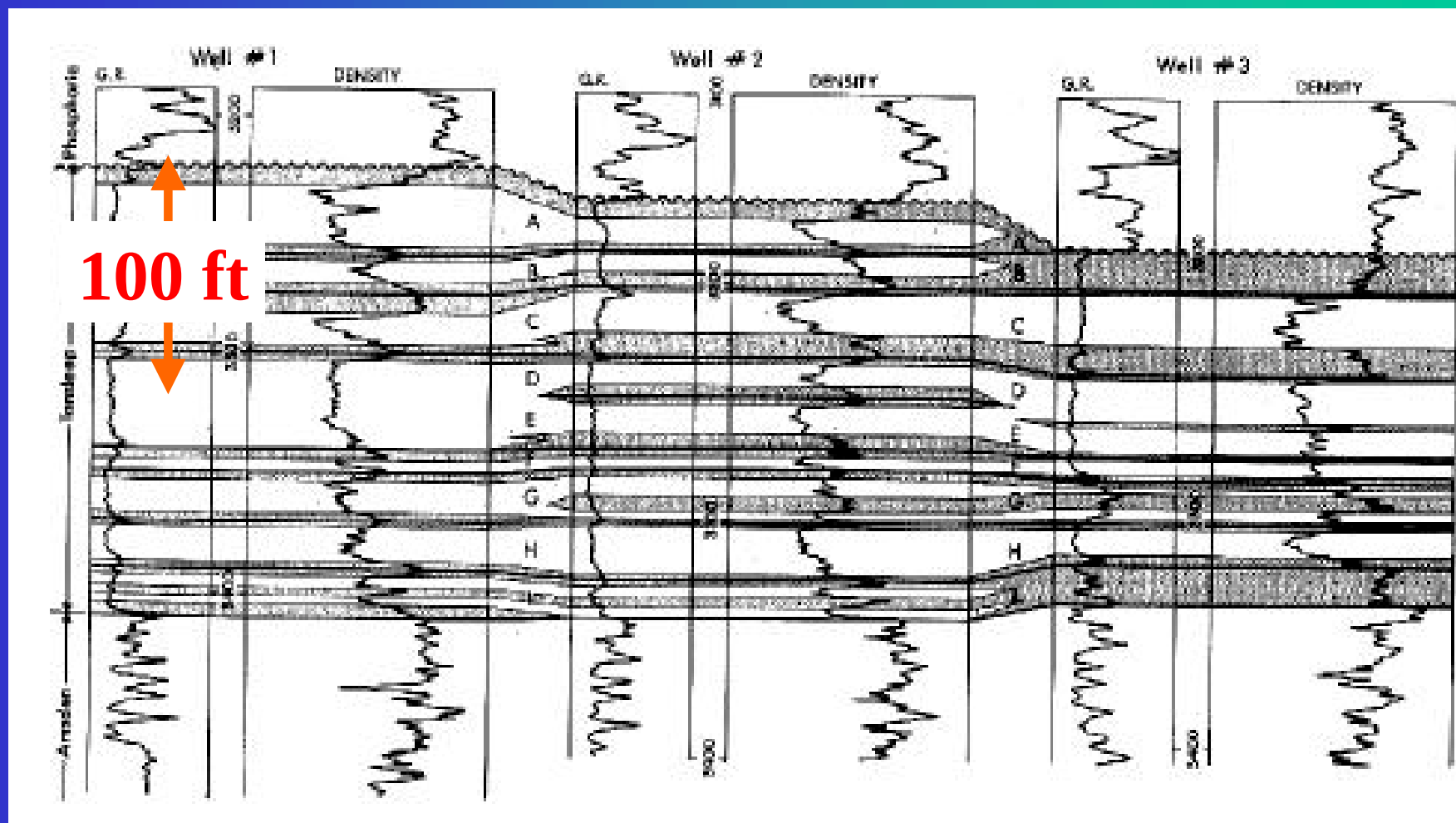
Reservoir development issues

- Upper Tensleep contains bypassed oil
- Coning from lower Tensleep prevents access
- Reservoir compartmentalized by dolomite layers

IOR strategies

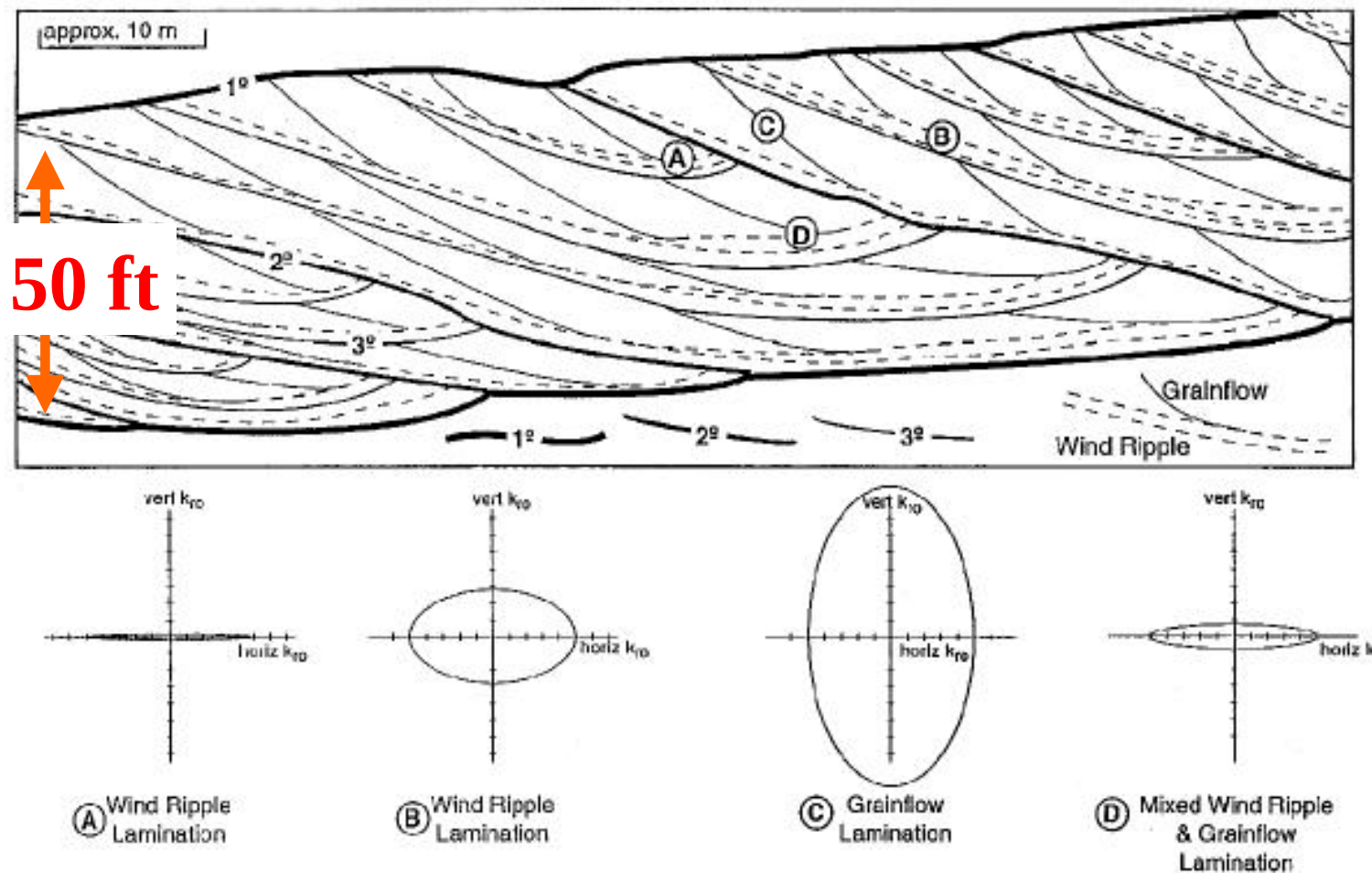
- Gel treatment of lower Tensleep
- Water injection in upper Tensleep
- Horizontal wells in upper Tensleep

Dolomite Layers at North Oregon Basin



from Morgan et al., 1977

Eolian Laminations at North Oregon Basin

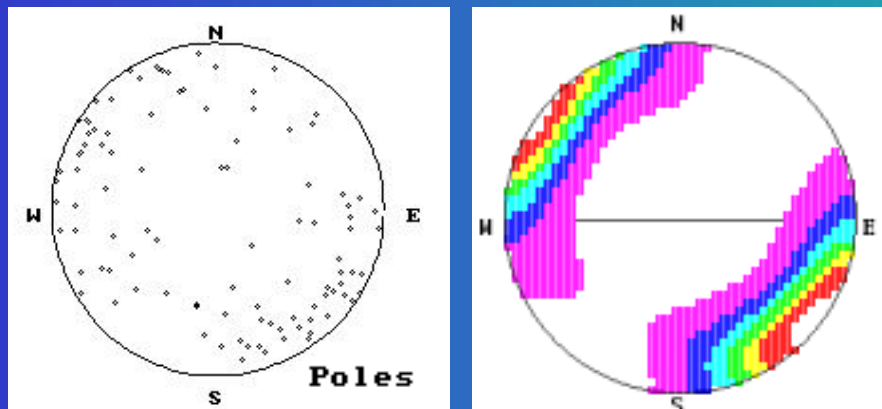


Directional Relative Permeability, K/K_h

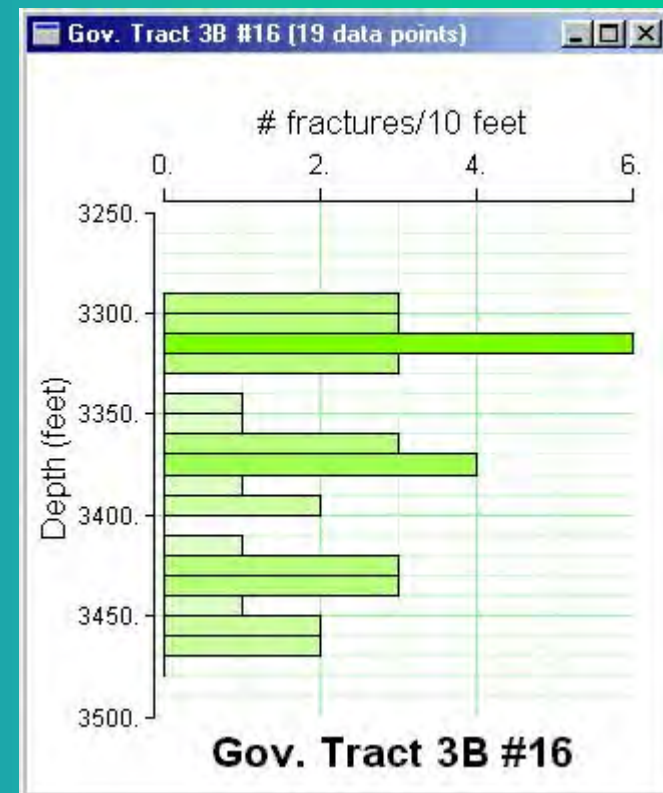
Dunn, 1997

Tensleep Fractures *North Oregon Basin*

NE-SW trending w/ scatter

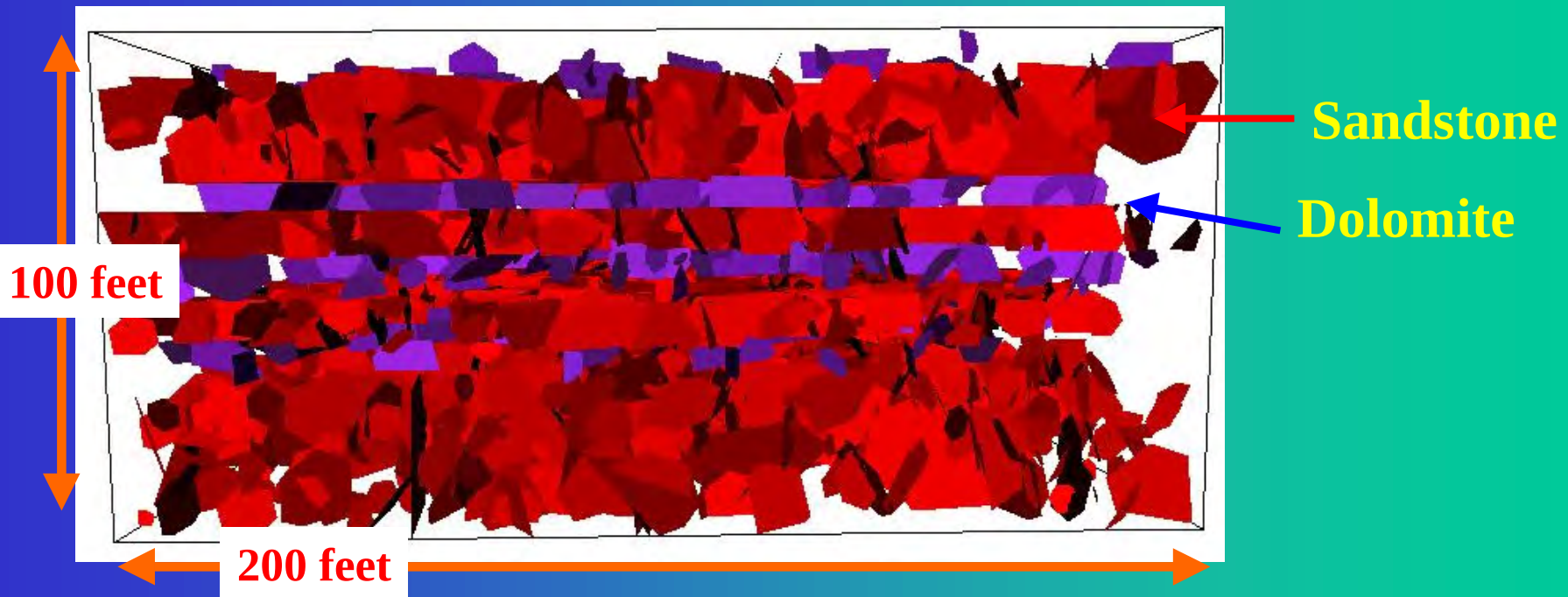


average spacing ~ 10'
no spatial correlation



DFN Model Implementation

Tensleep, North Oregon Basin



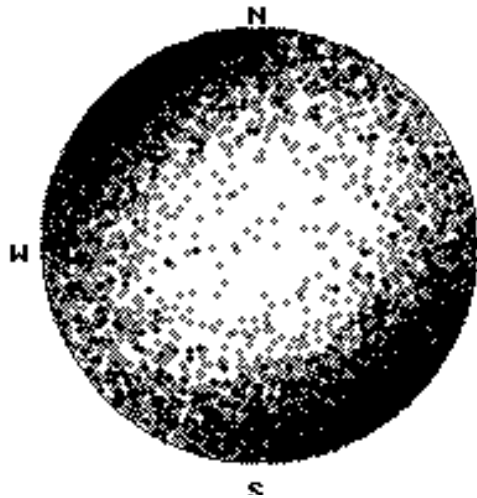
- Dolomites have 50% conductive fracture intensity as sandstones
- all fractures terminate on layer boundaries

DFN Model Verification

Fracture Orientations

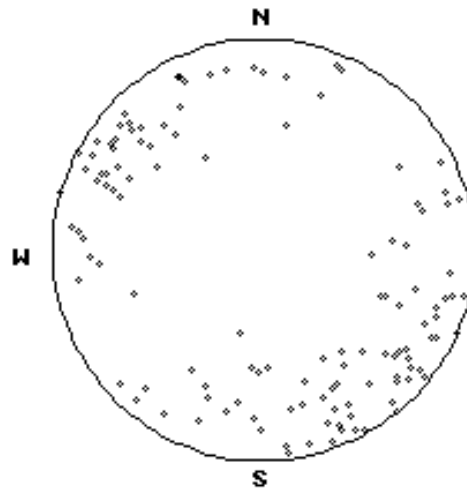
Tensleep, North Oregon Basin

All fractures in model



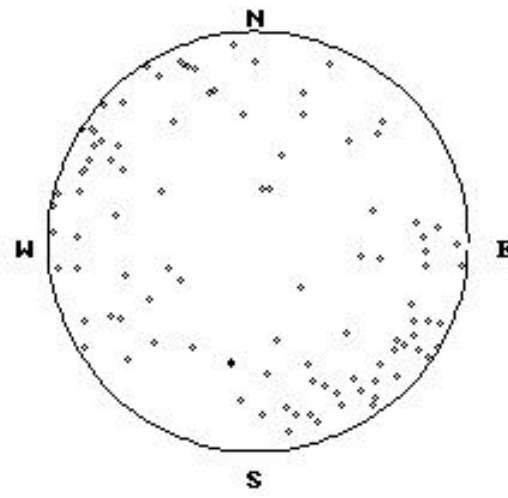
N = 2375

Simulated wells



N = 101

All Tensleep data



N = 101

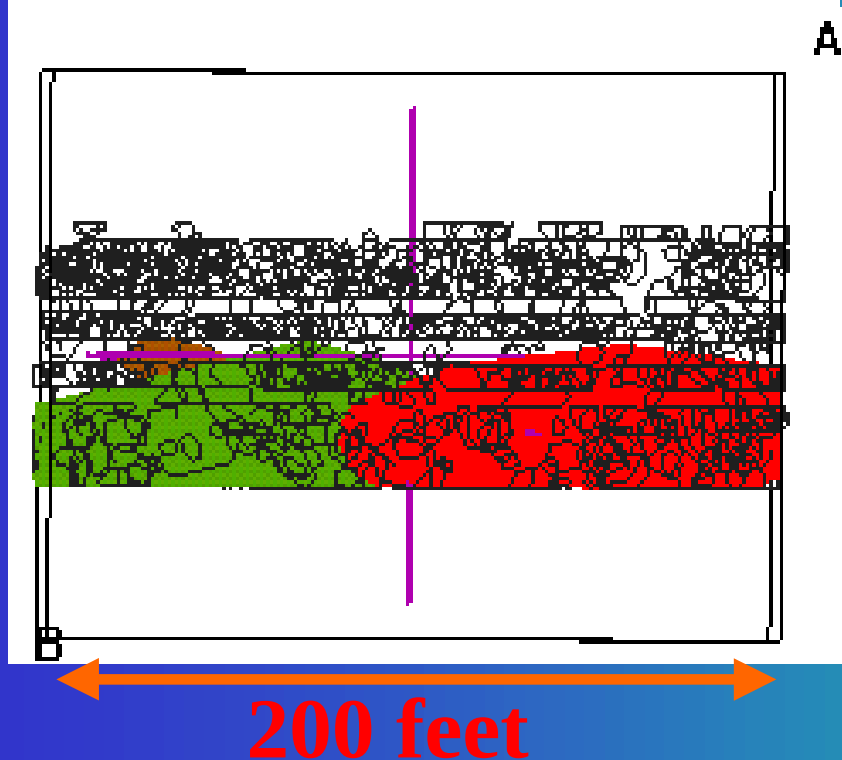
DFN Model Application

Compartment Analysis

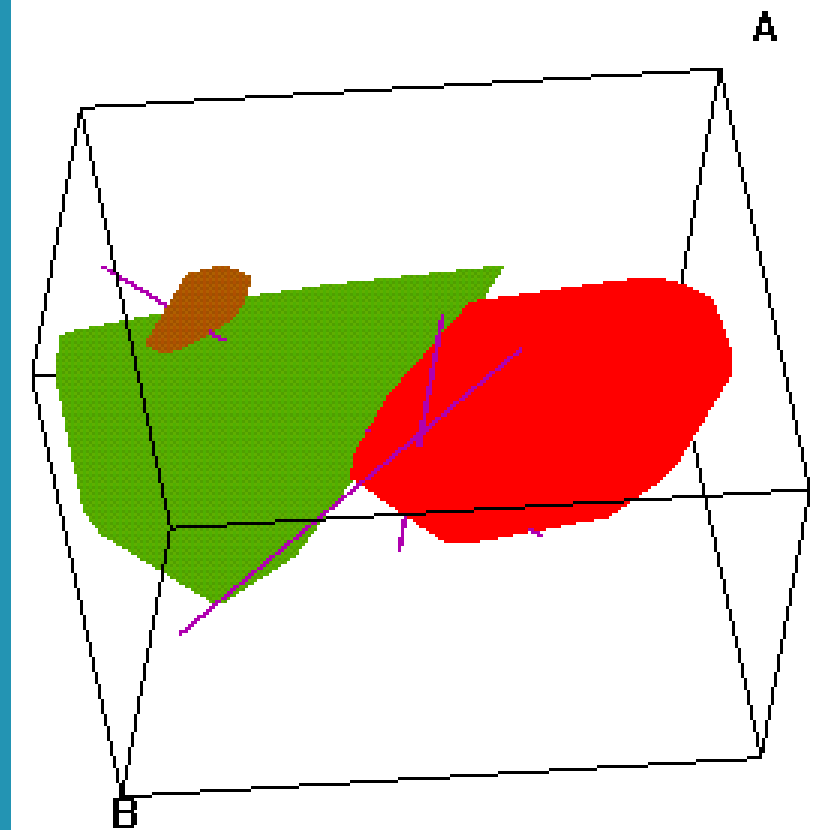
Tensleep, North Oregon Basin

Conductive $P_{32} = 0.4 \text{ m}^2/\text{m}^3$

Side view with fractures



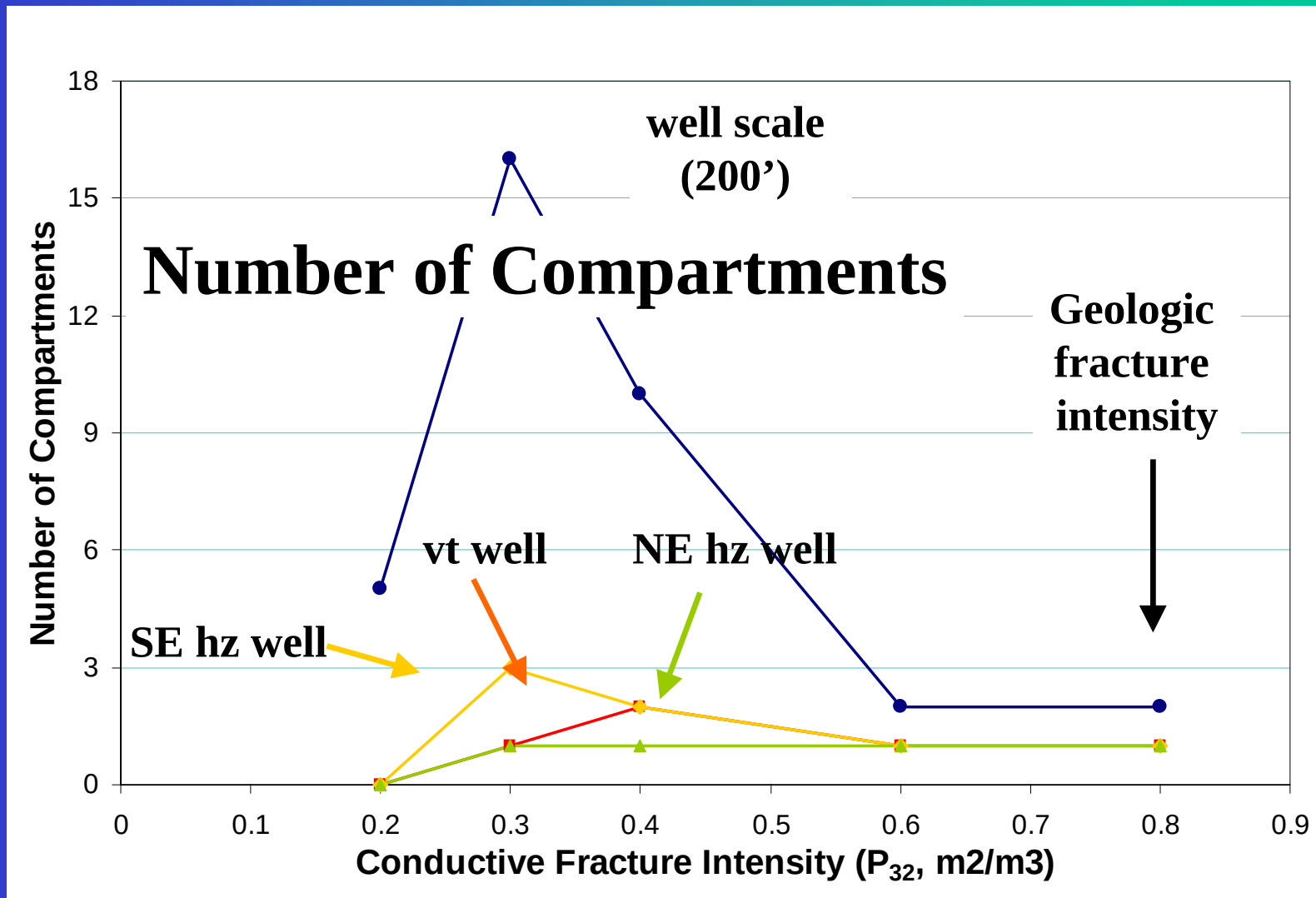
Top view w/o fractures



DFN Model Application

Compartmentalization

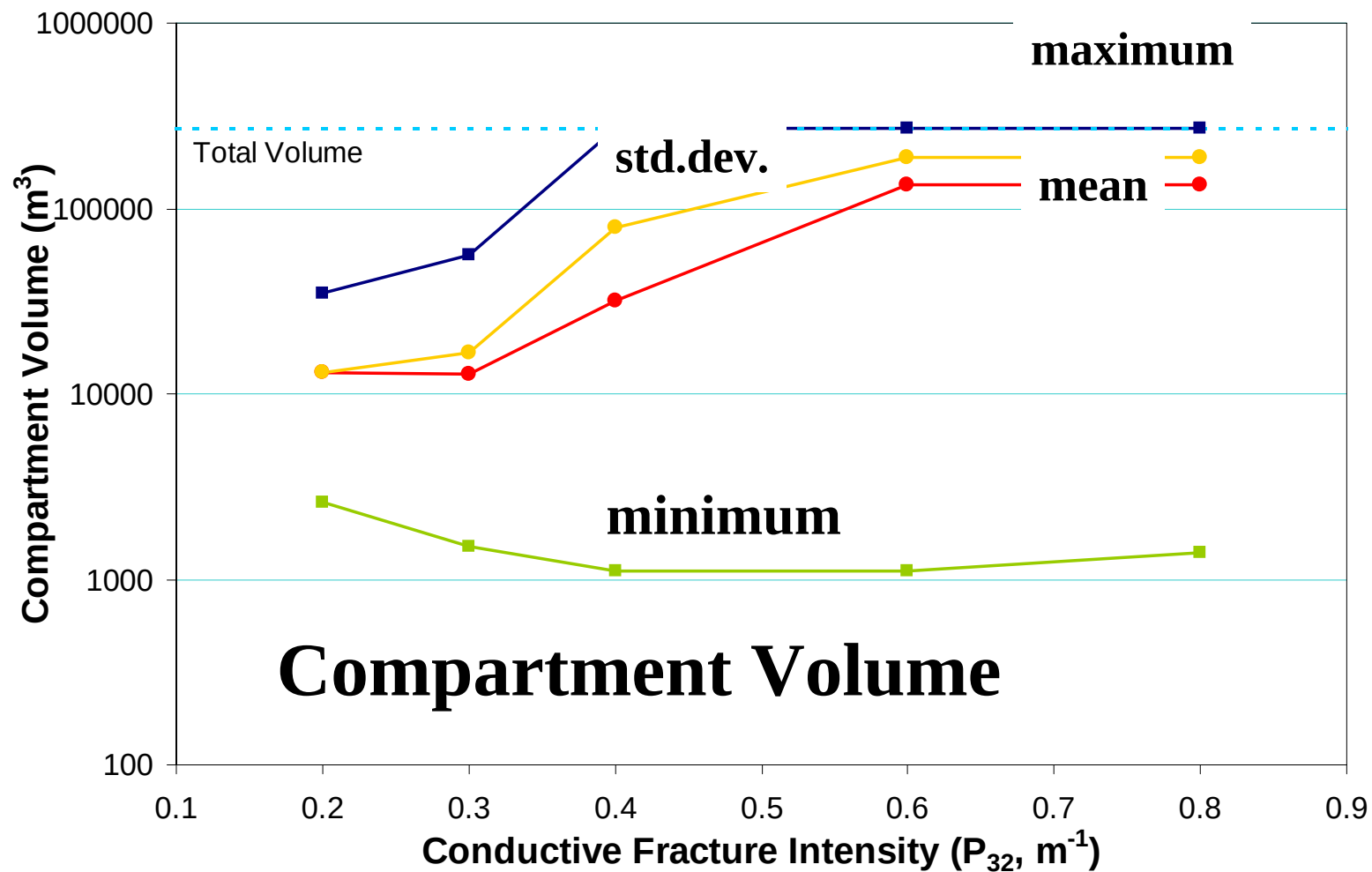
Tensleep, North Oregon Basin



DFN Model Application

Compartmentalization

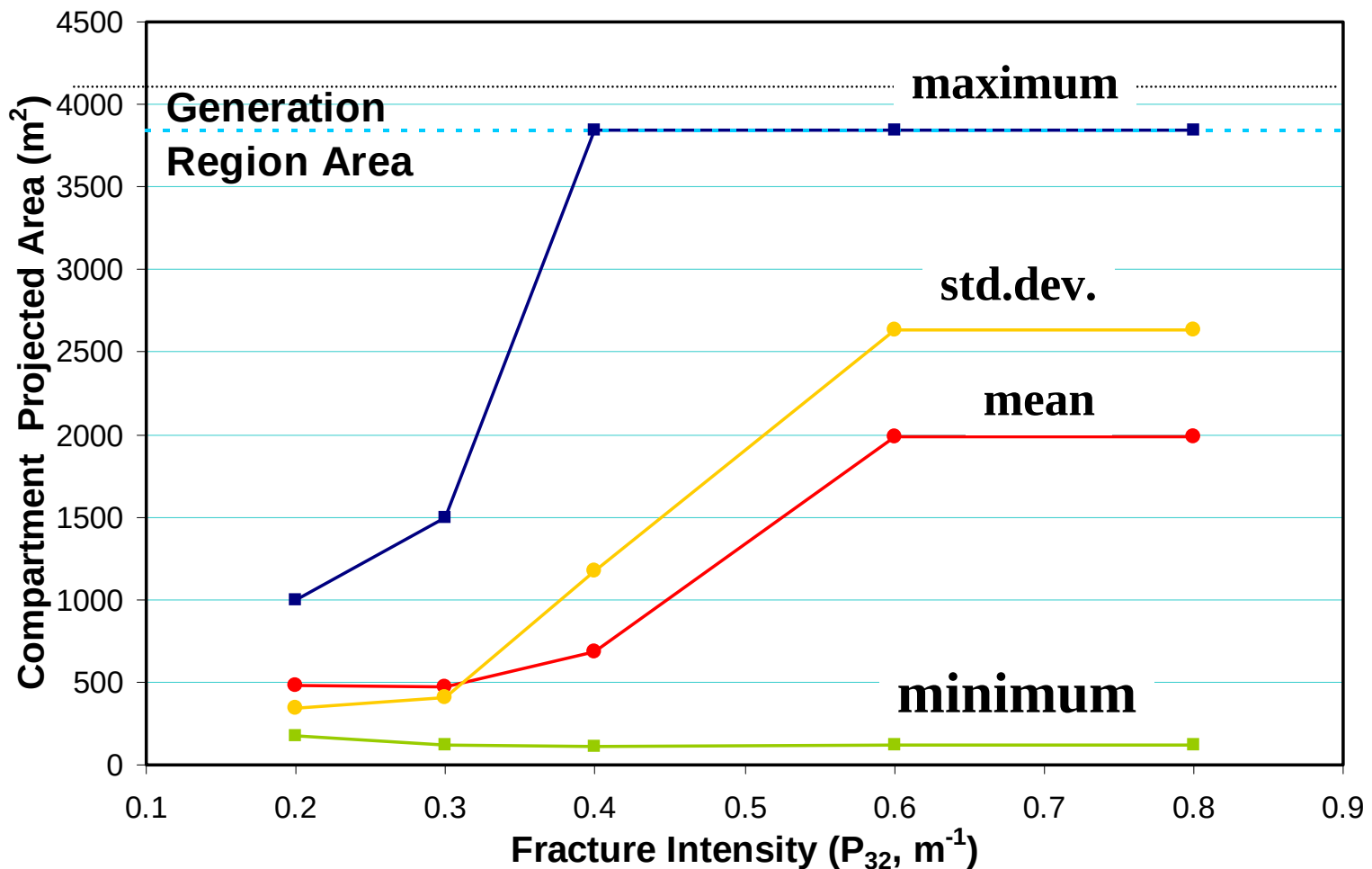
Tensleep, North Oregon Basin



DFN Model Application

Compartmentalization

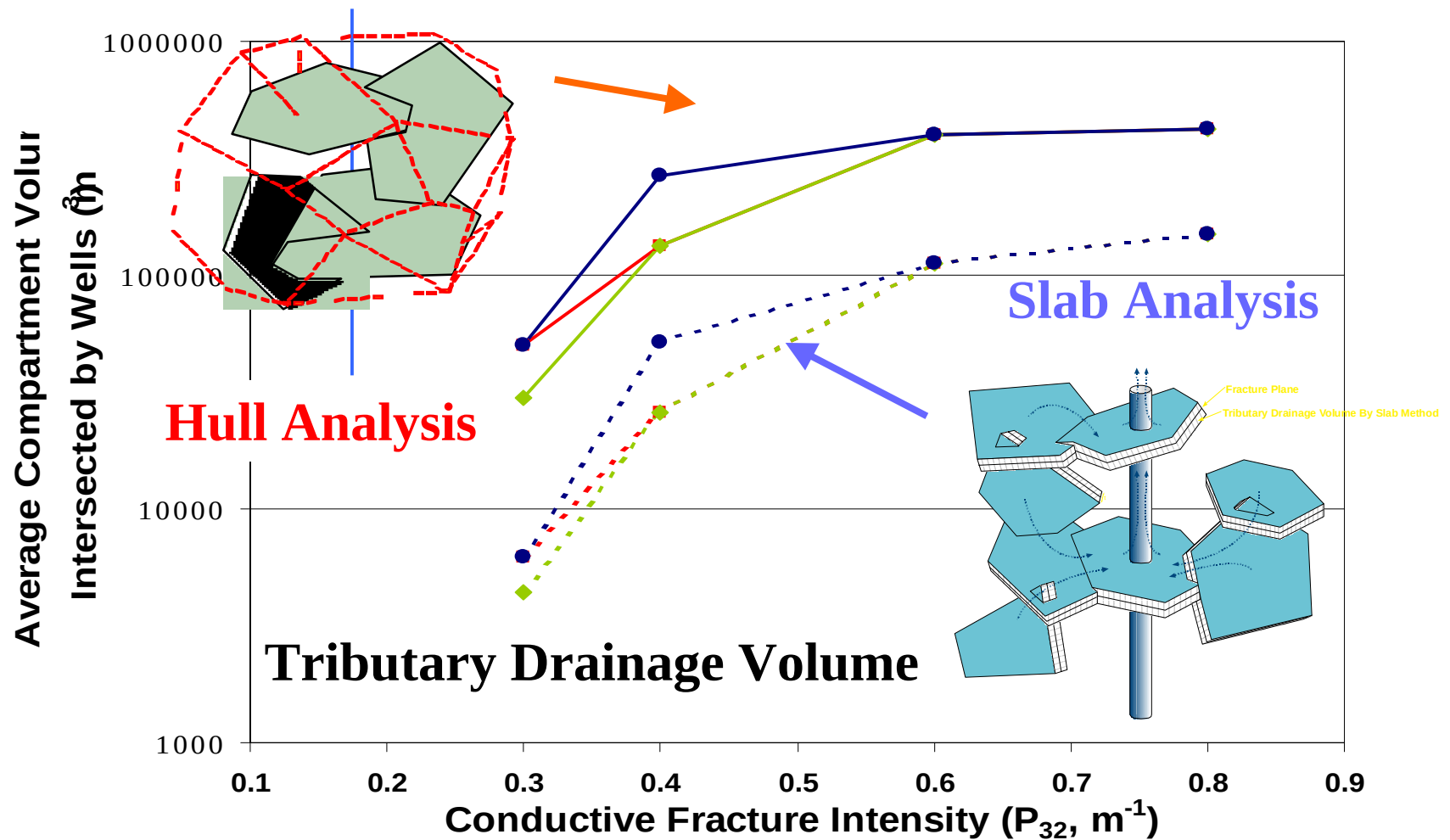
Tensleep, North Oregon Basin



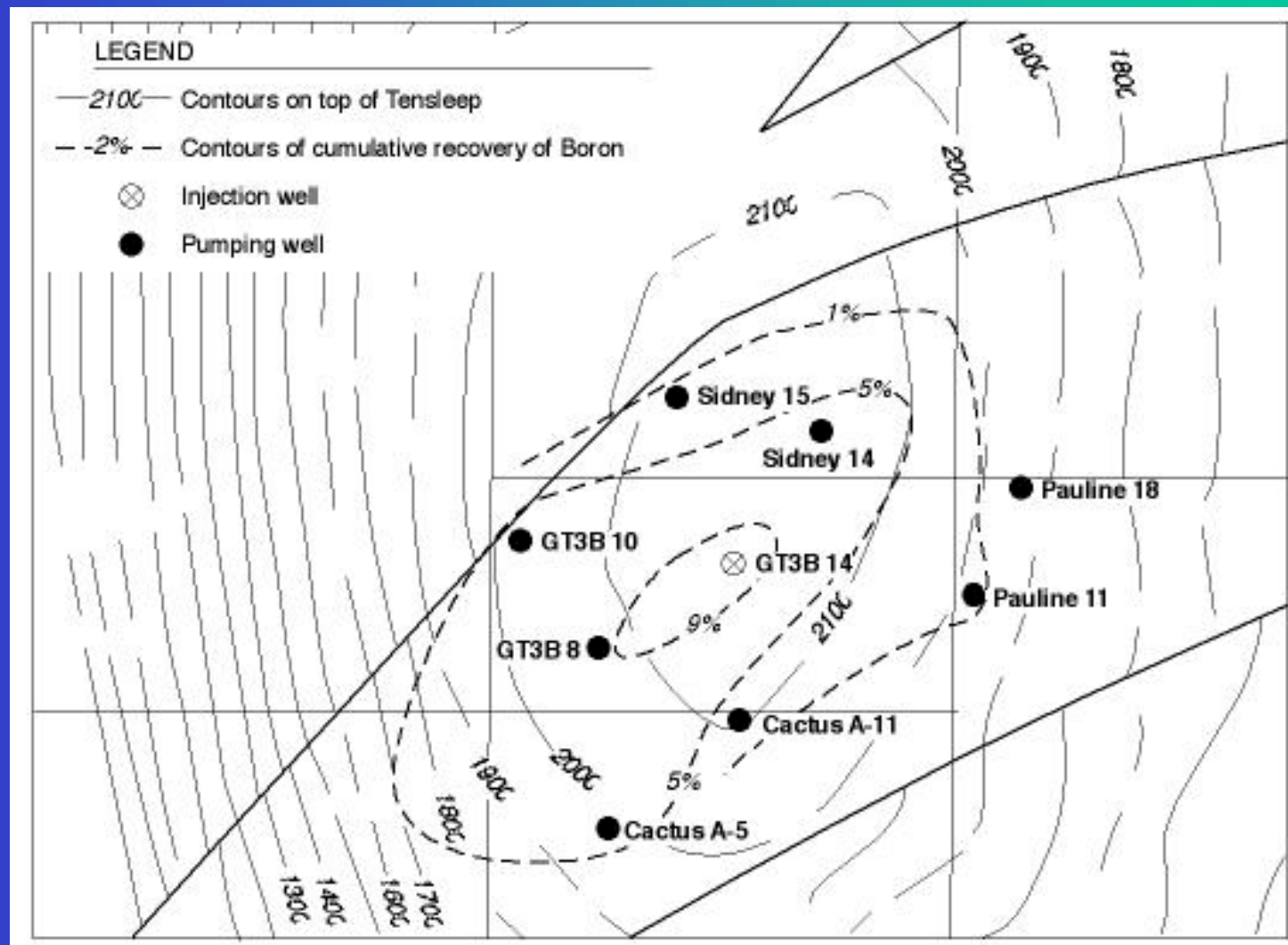
DFN Model Application

Compartmentalization

Tensleep, North Oregon Basin



Phase 2: Conditioning to Tracer Testing Tensleep, North Oregon Basin



South Oregon Basin Study Site

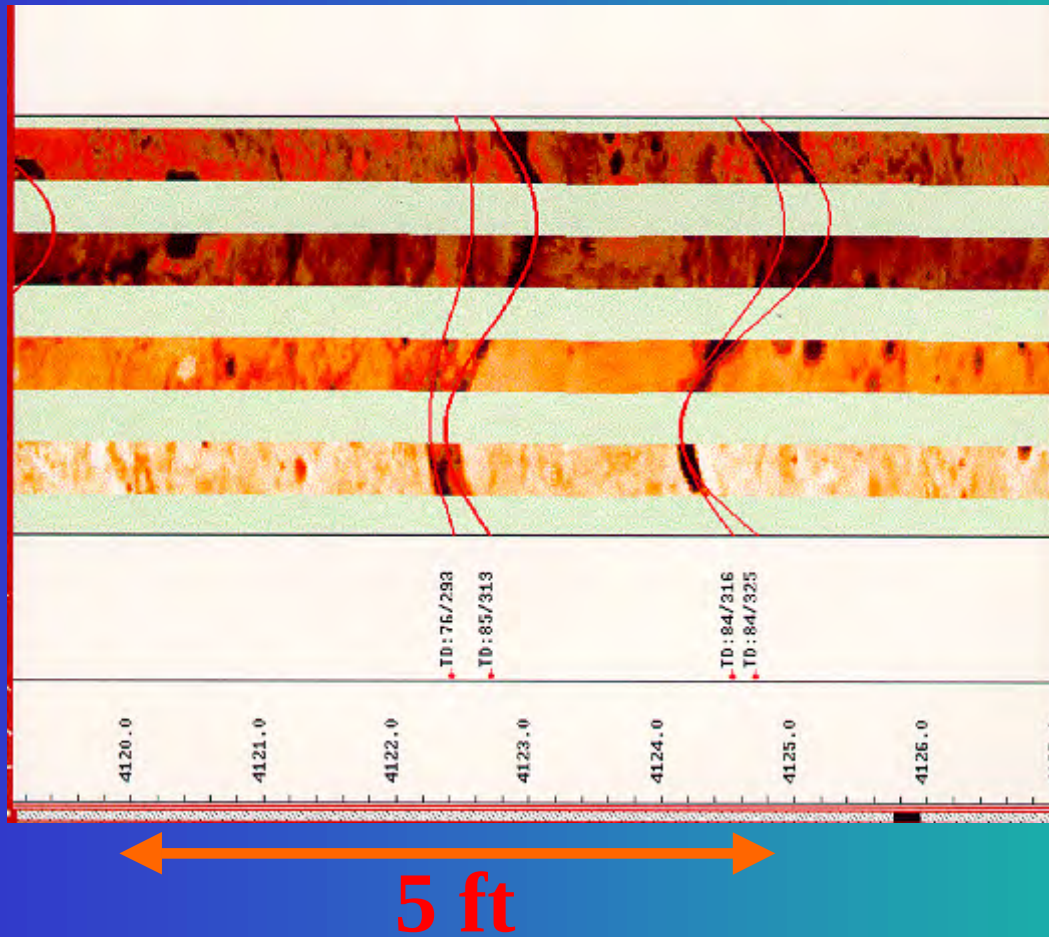
Reservoir Development Issues

- Oil saturation in upper Phosphoria is 80%
- Coning from lower Phosphoria prevents access

IOR Strategies

- Horizontal wells in upper Phosphoria
- Must avoid major faults/fractures to minimize mud loss in drilling

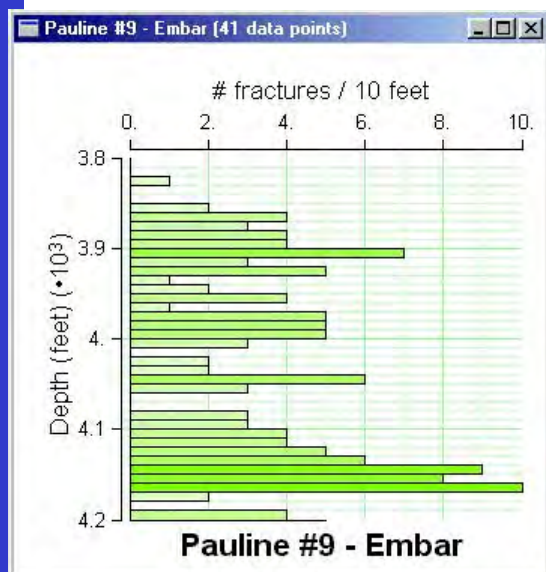
Directional drilling in South Oregon Basin



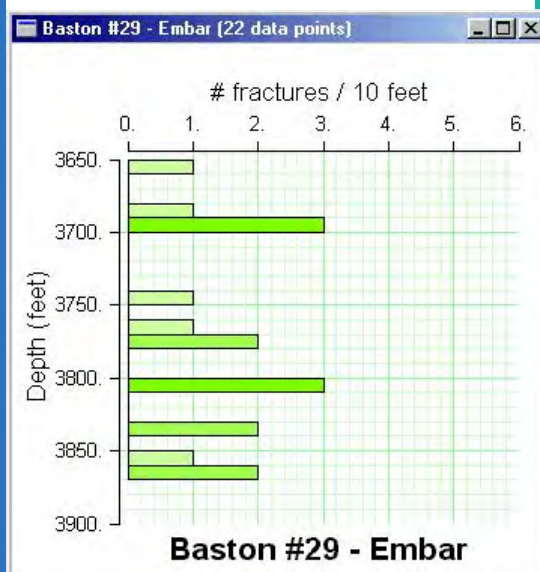
These fractures
accounted for
290 bbls/hr mud
loss during
drilling

Phosphoria Fractures, South and North Oregon Basin

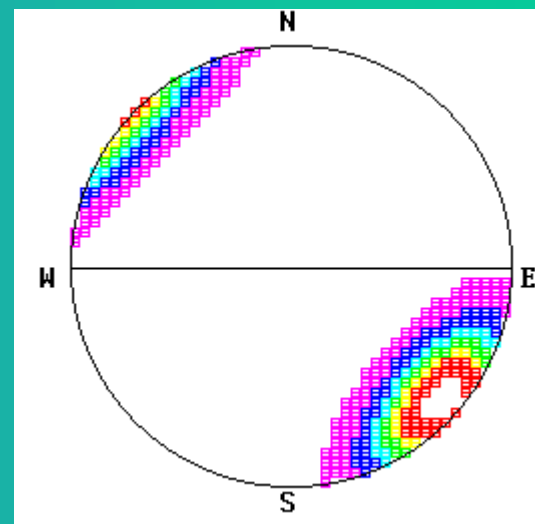
Horizontal Well



Vertical Well

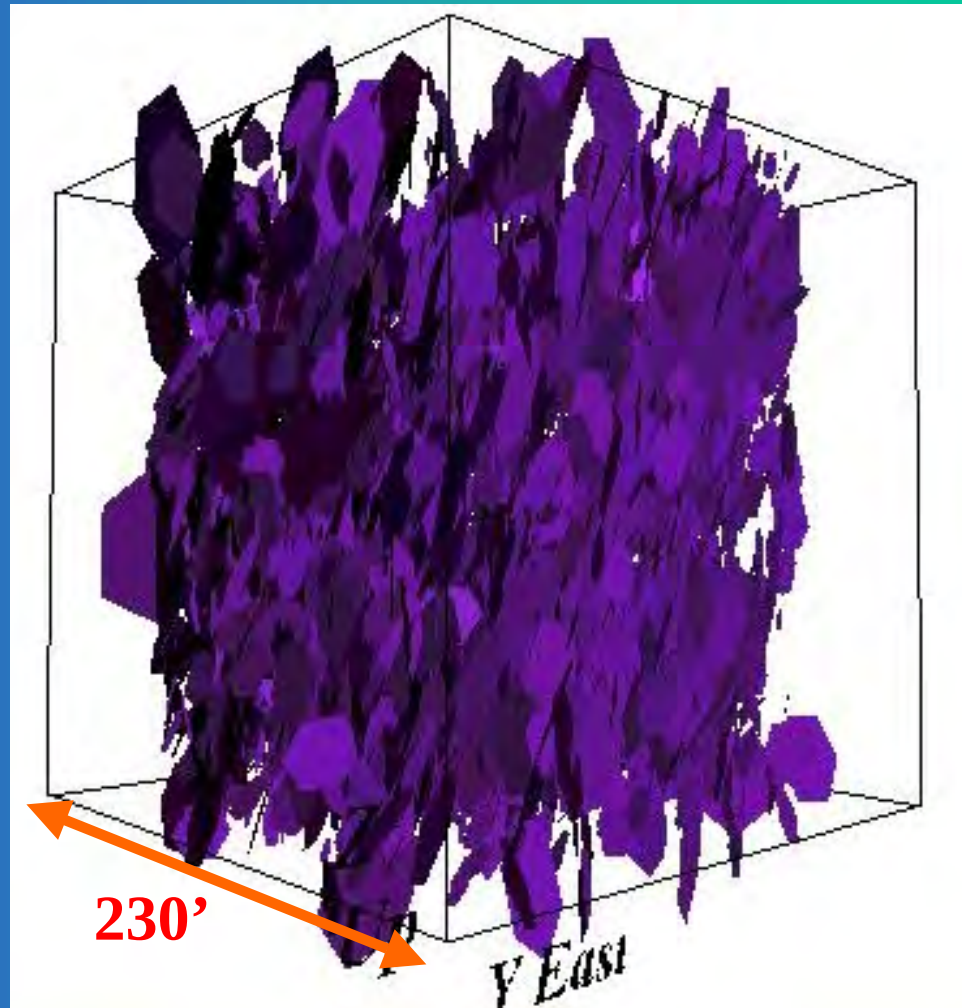


NE-SW trending



Fracture intensity = $1.6 \text{ m}^2/\text{m}^3$

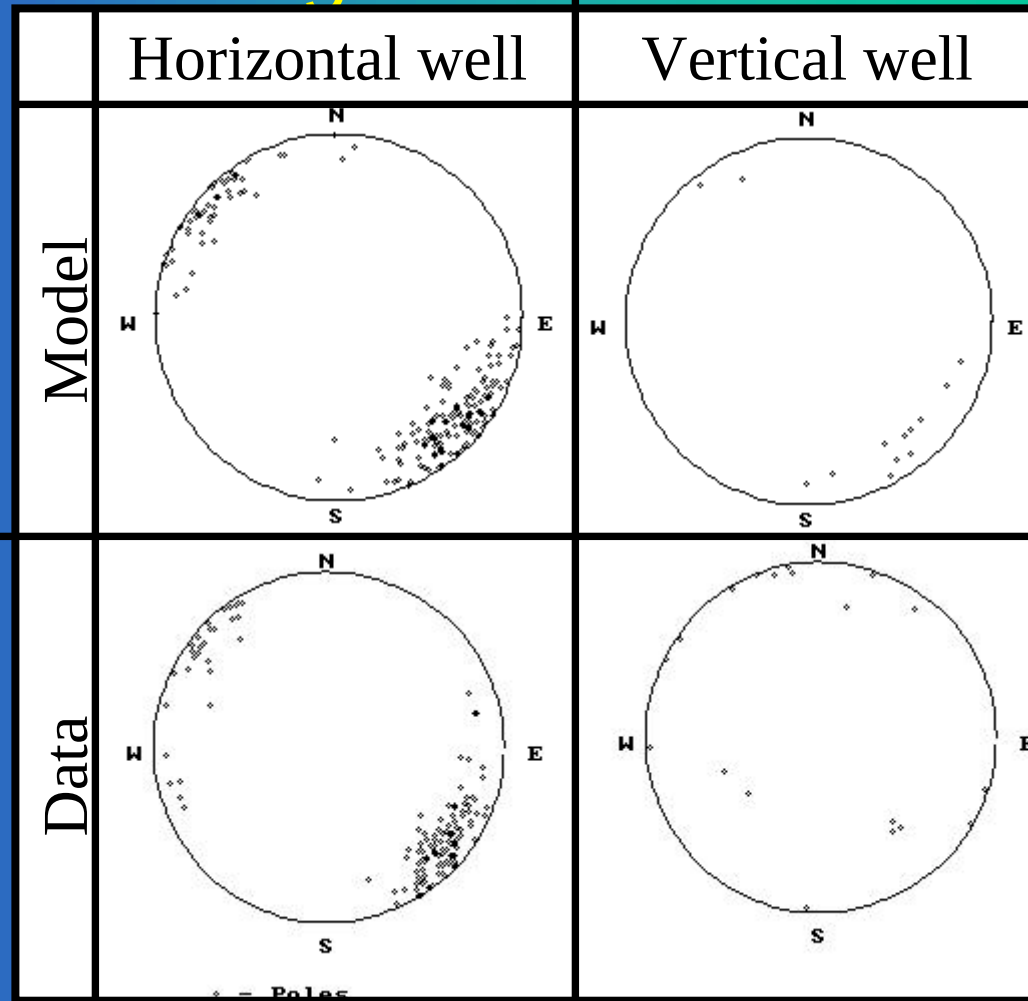
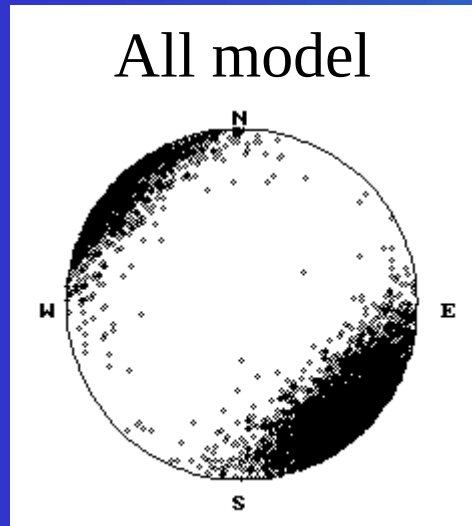
South Oregon Basin (Phosphoria) DFN Model



DFN Model Verification

Fracture Orientations

Phosphoria, *South Oregon Basin*

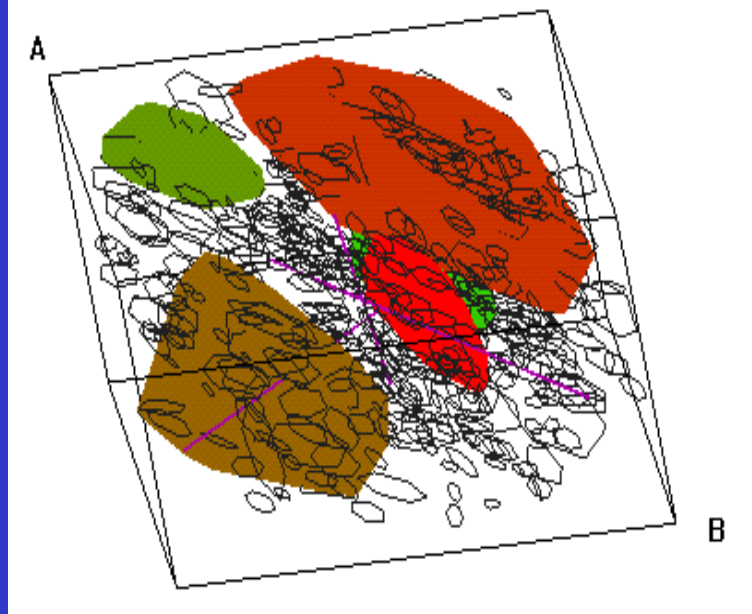


DFN Model Application

Compartmentalization

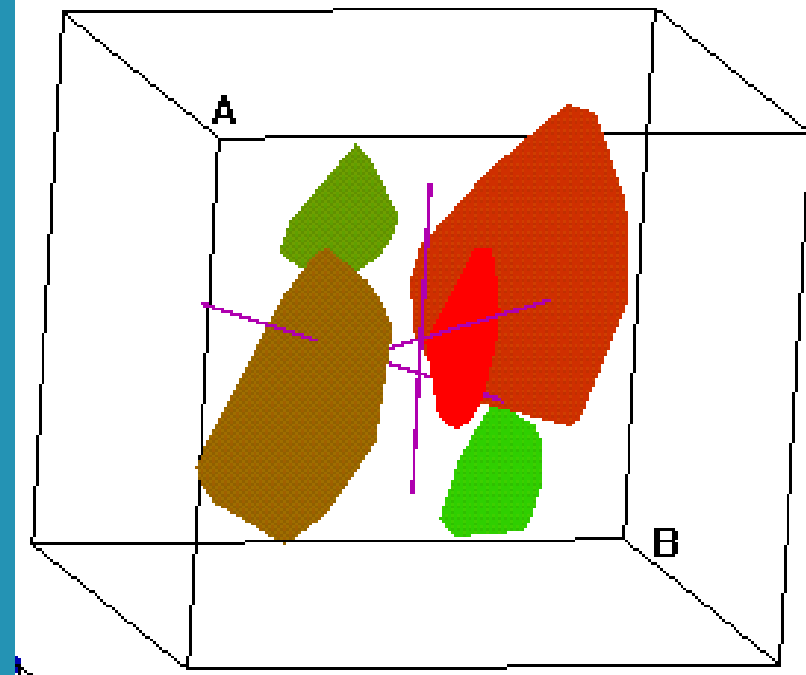
Phosphoria, South Oregon Basin

Top view w/ fractures



Conductive $P_{32} = 0.2 \text{ m}^2/\text{m}^3$

Side view w/o fractures

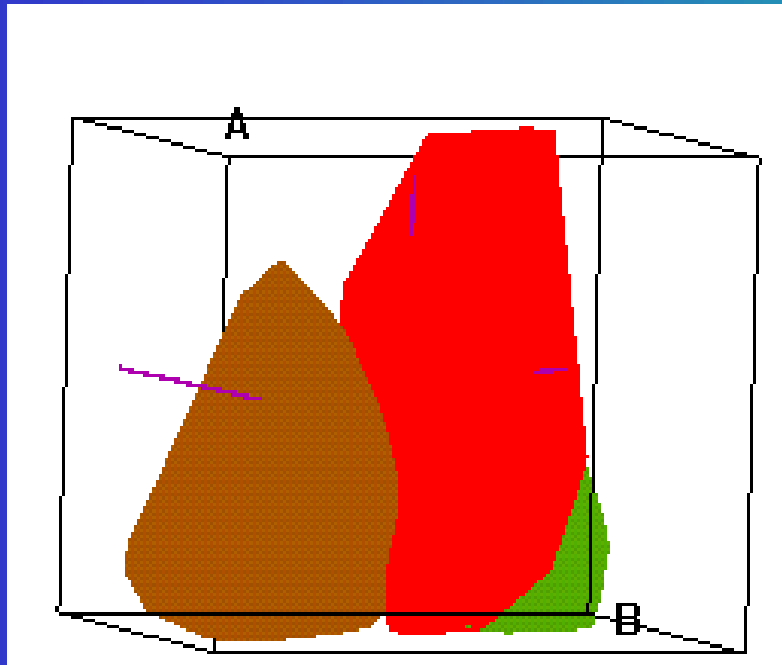


DFN Model Application

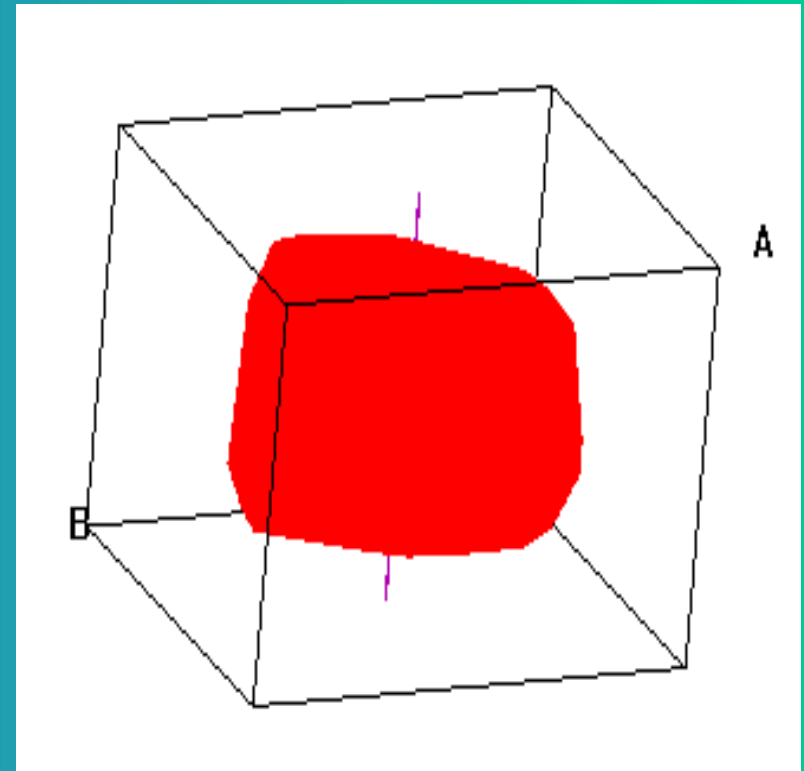
Compartmentalization

Phosphoria, South Oregon Basin

Conductive $P_{32} = 0.4 \text{ m}^2/\text{m}^3$



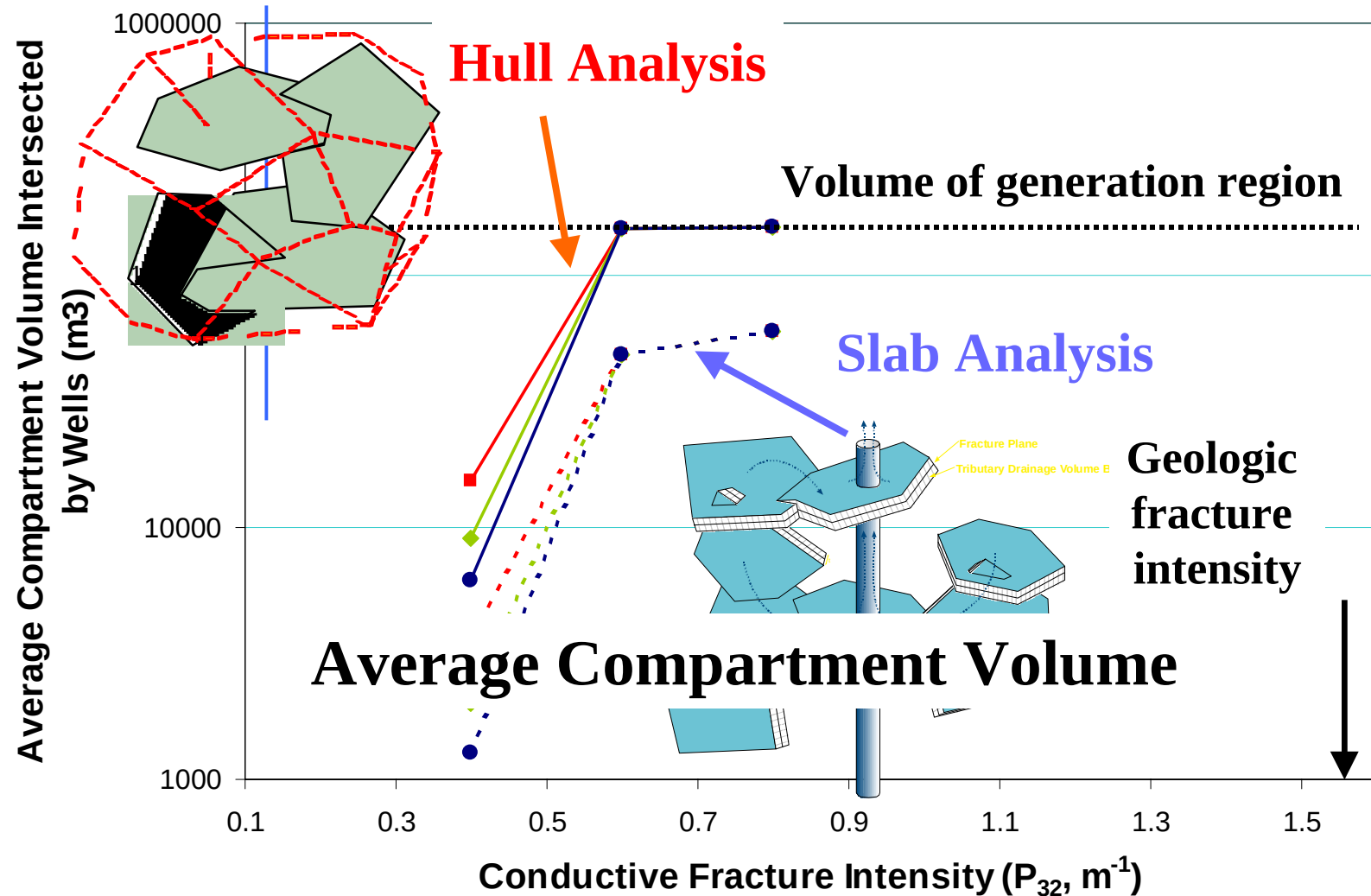
Conductive $P_{32} = 0.6 \text{ m}^2/\text{m}^3$



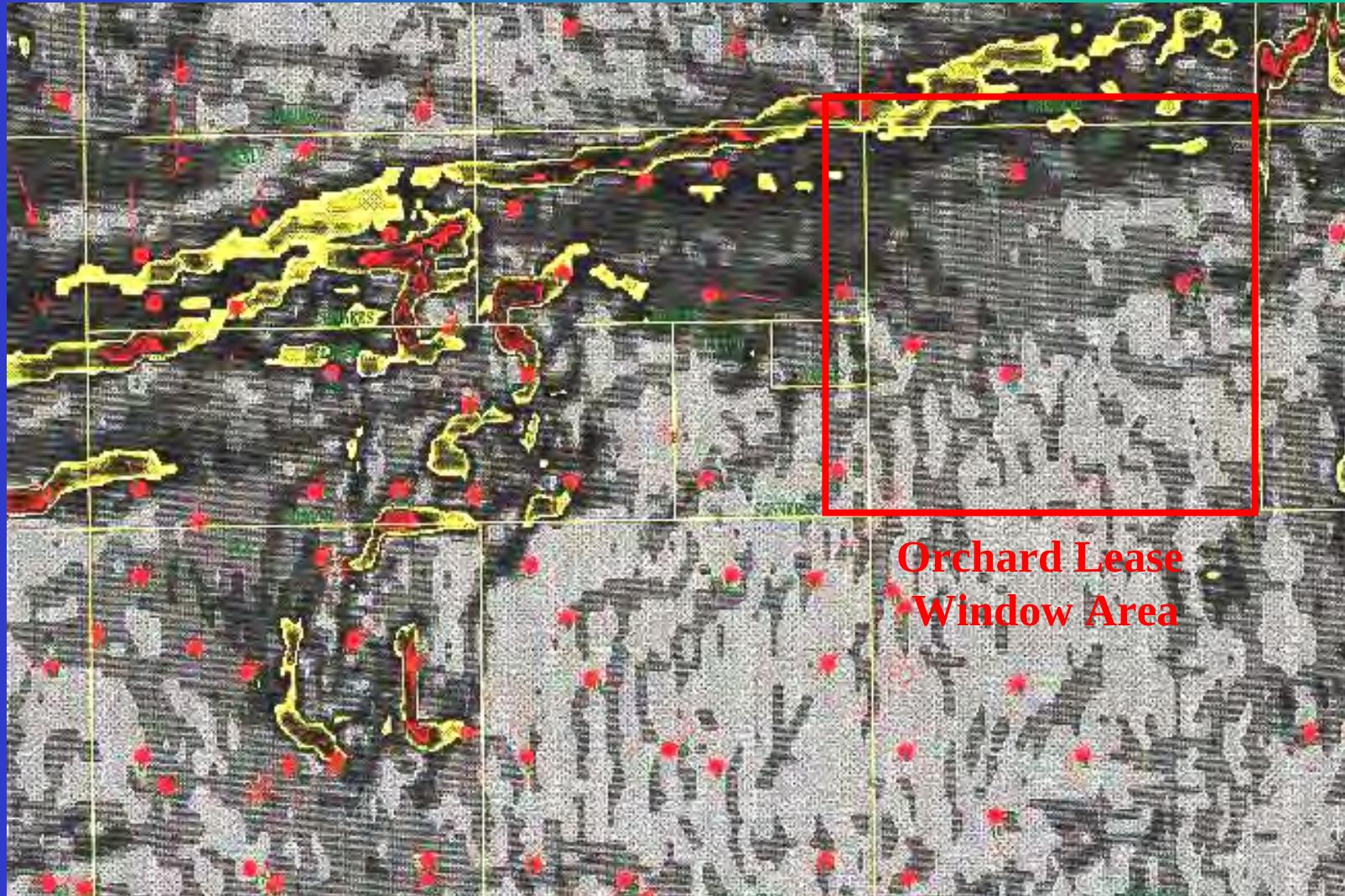
DFN Model Application

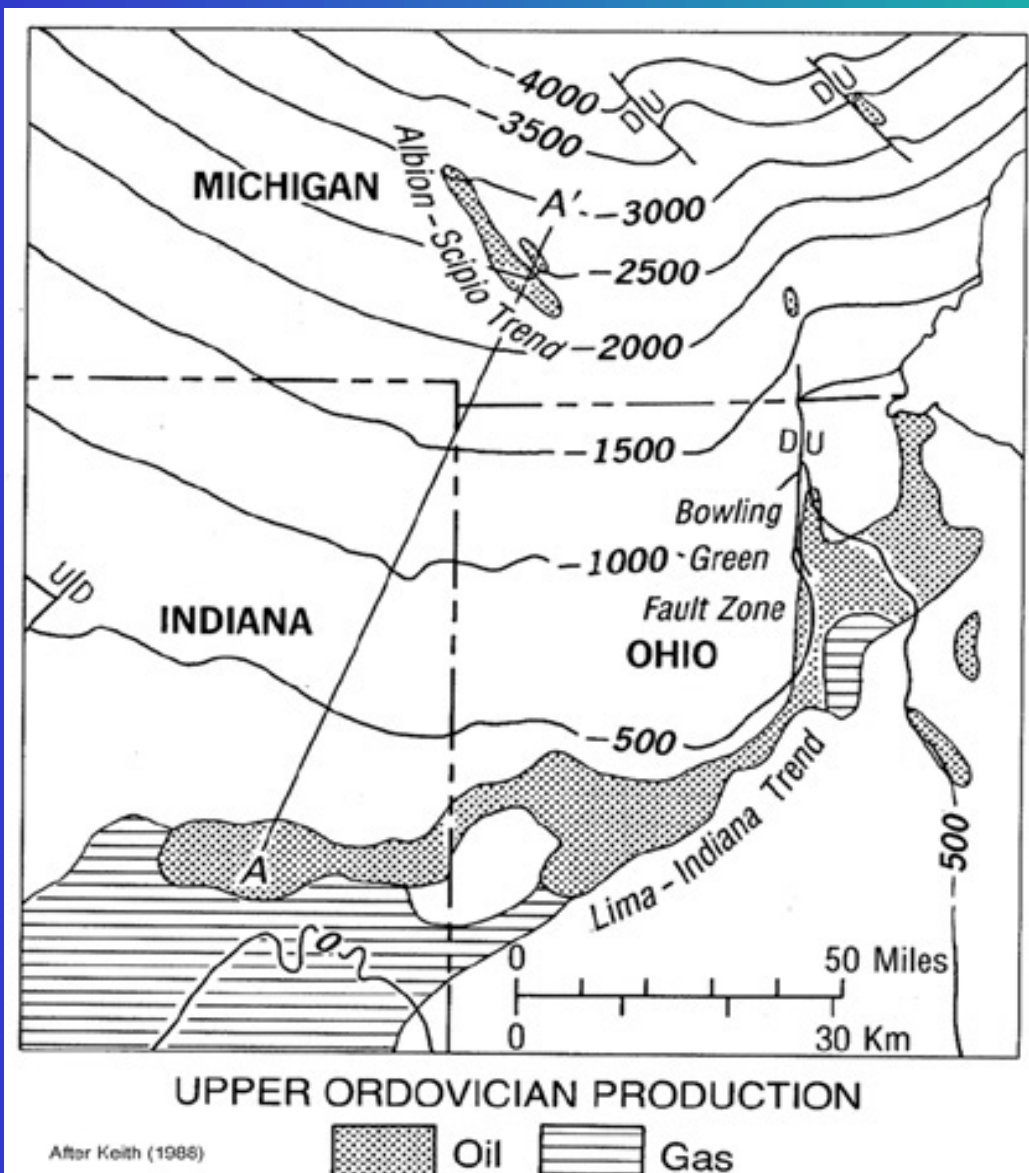
Compartmentalization

Phosphoria, South Oregon Basin



Phase 2: Incorporate Seismic Fault Interpretations South Oregon Basin

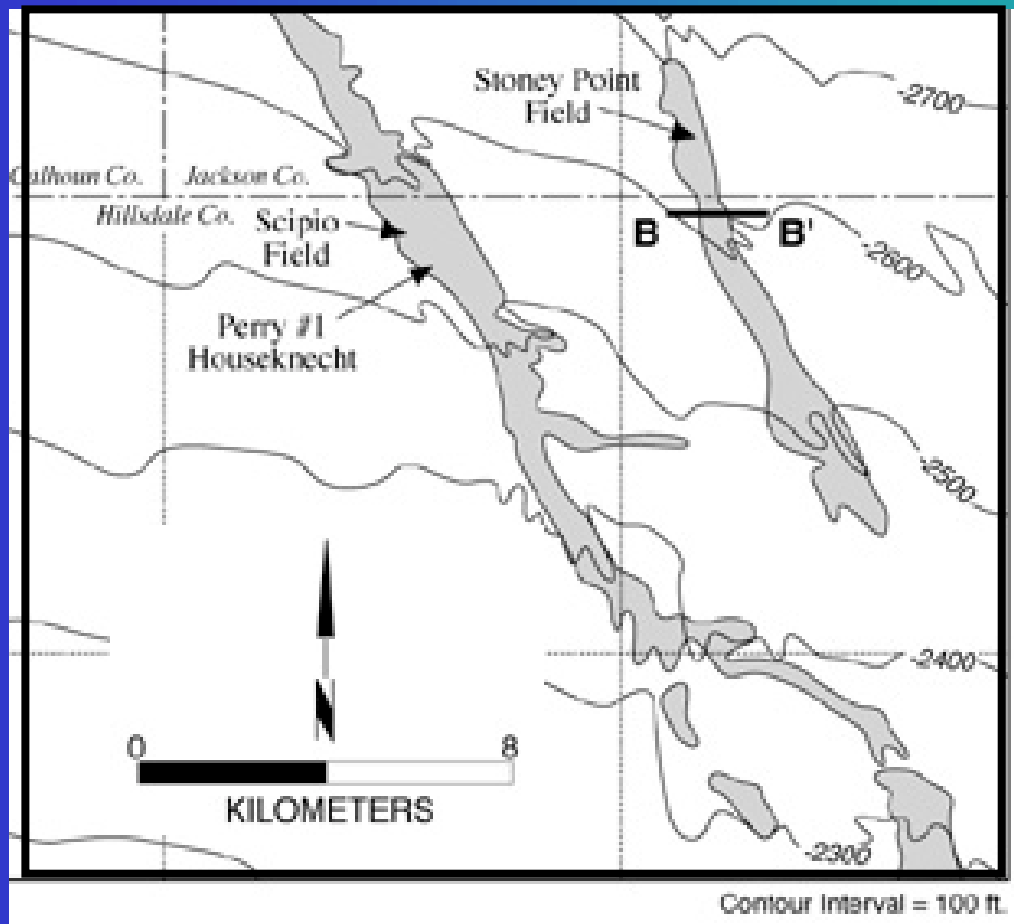




Trenton/Black River Oil: first US discoveries in 1885

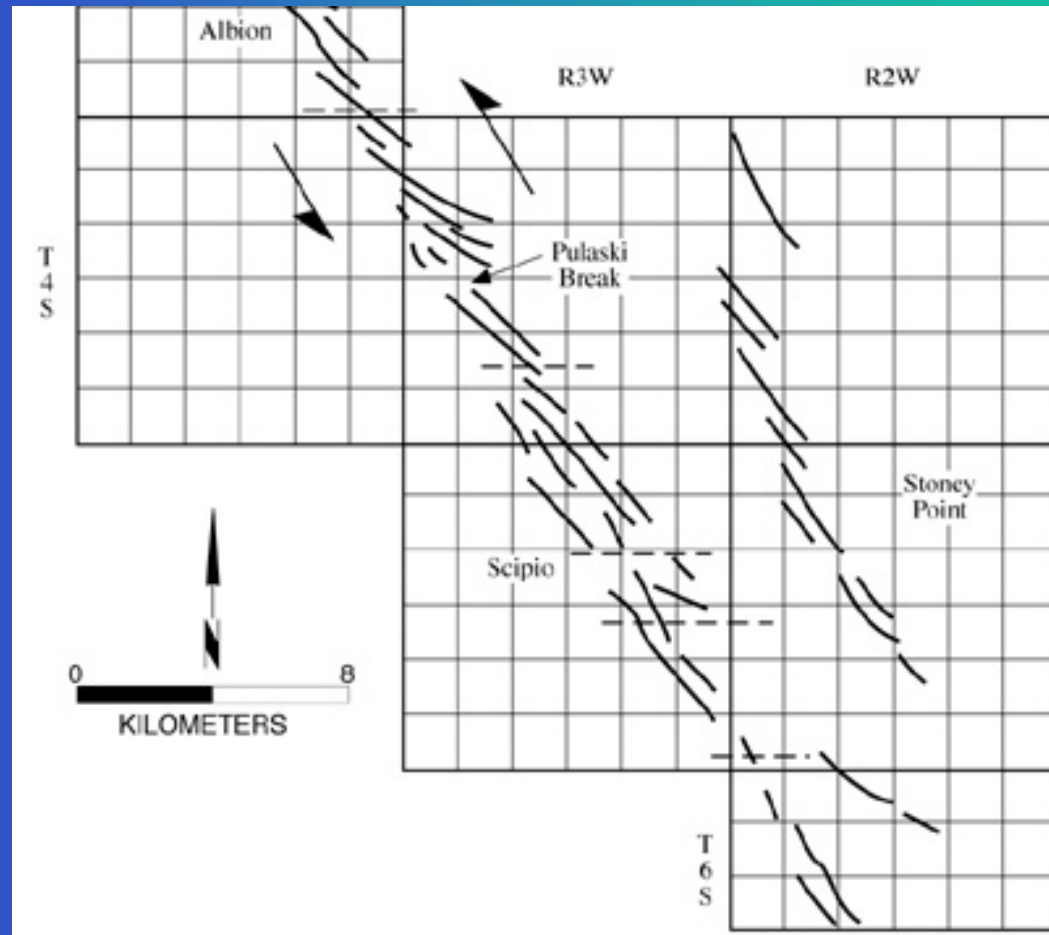
Oil production limited to areas of secondary porosity development (e.g. dolomite)

North Stoney Point, Southern Michigan

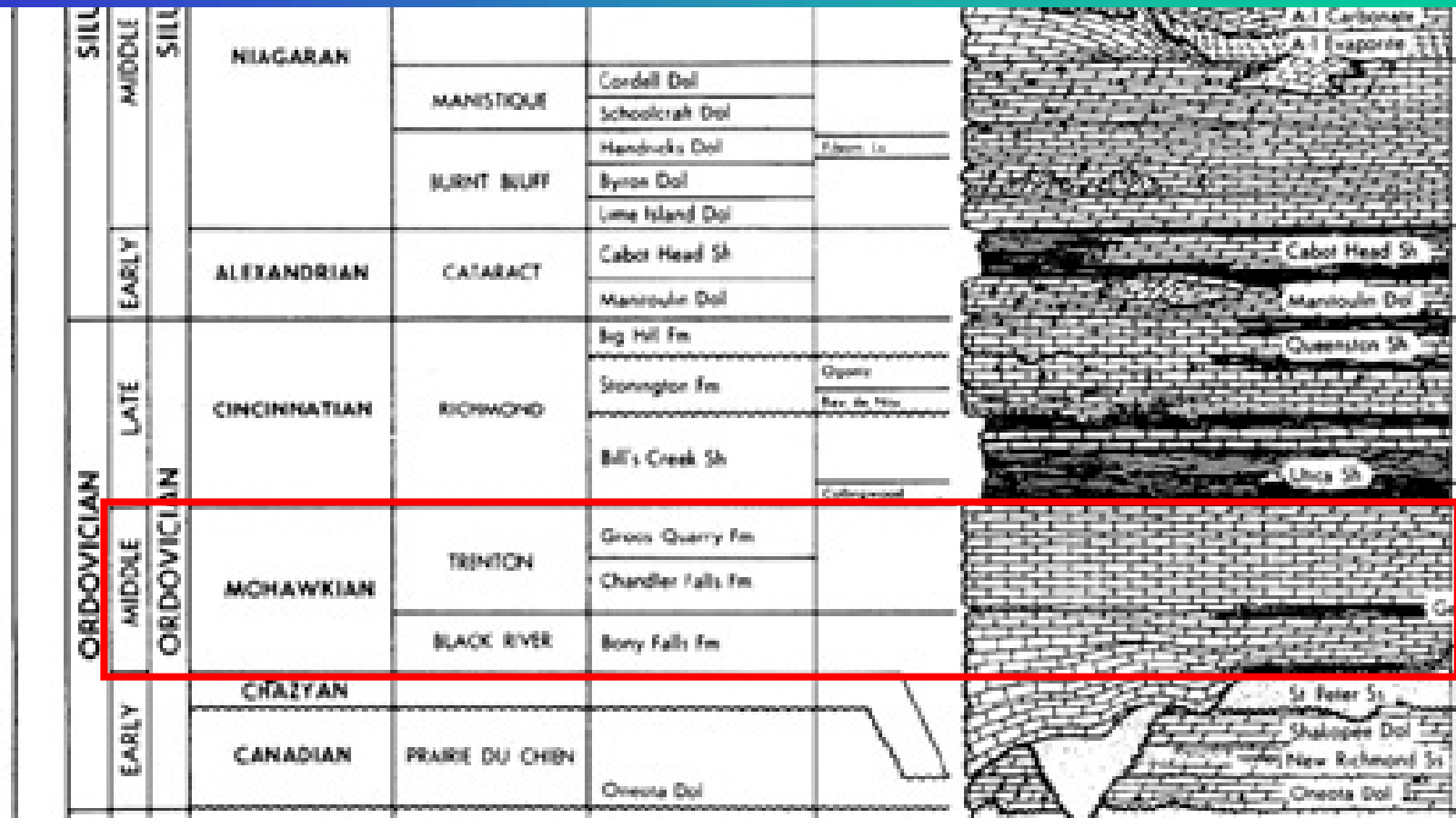


- Dolomitization occurred above NW trending basement shear faults
- Narrow, elongate vertical compartments
- Complex water/oil contacts
- Conceptual Model of fracturing

Faults in Paleozoic Cover Rocks at Stoney Point



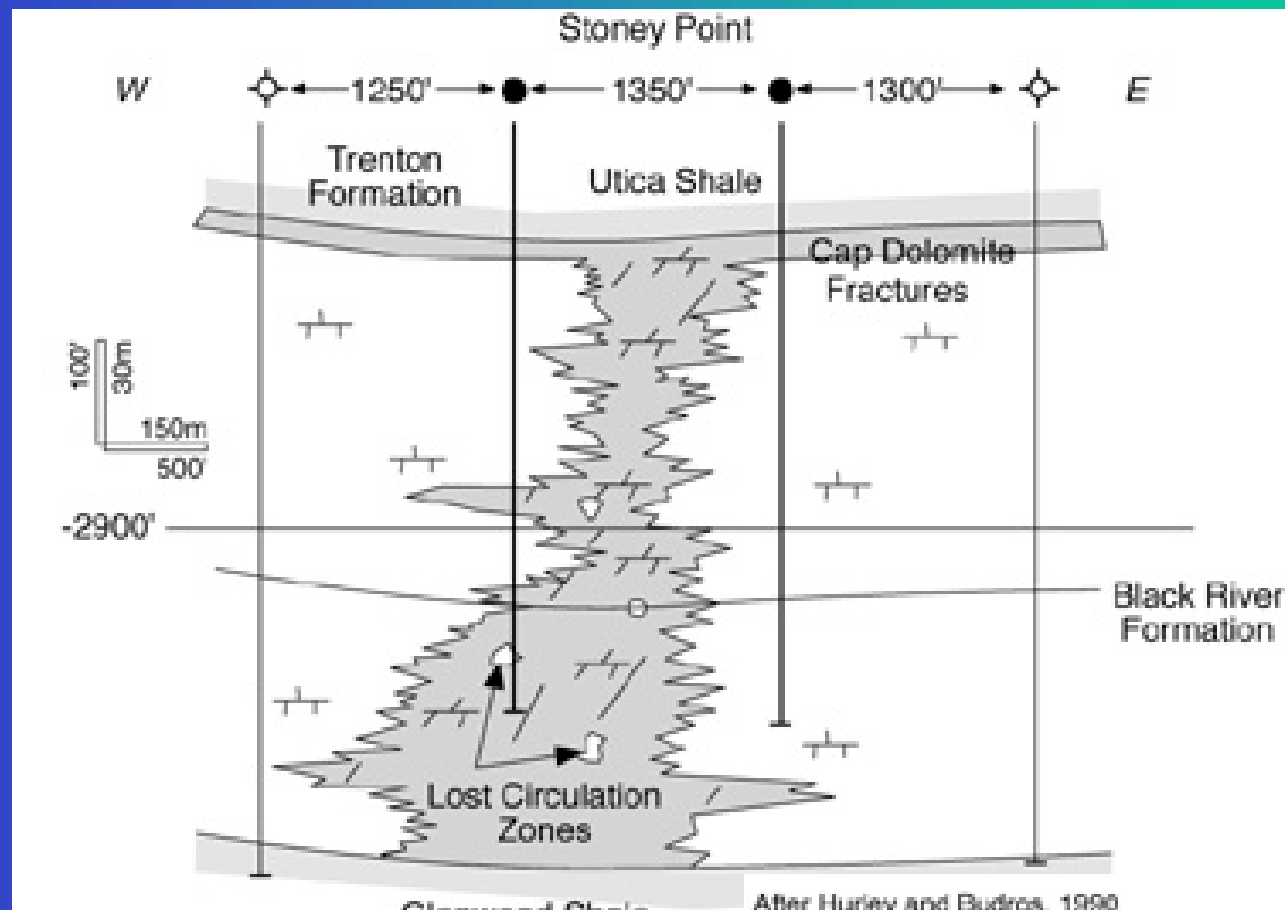
Stratigraphy at North Stoney Point



After Prouty (1988)

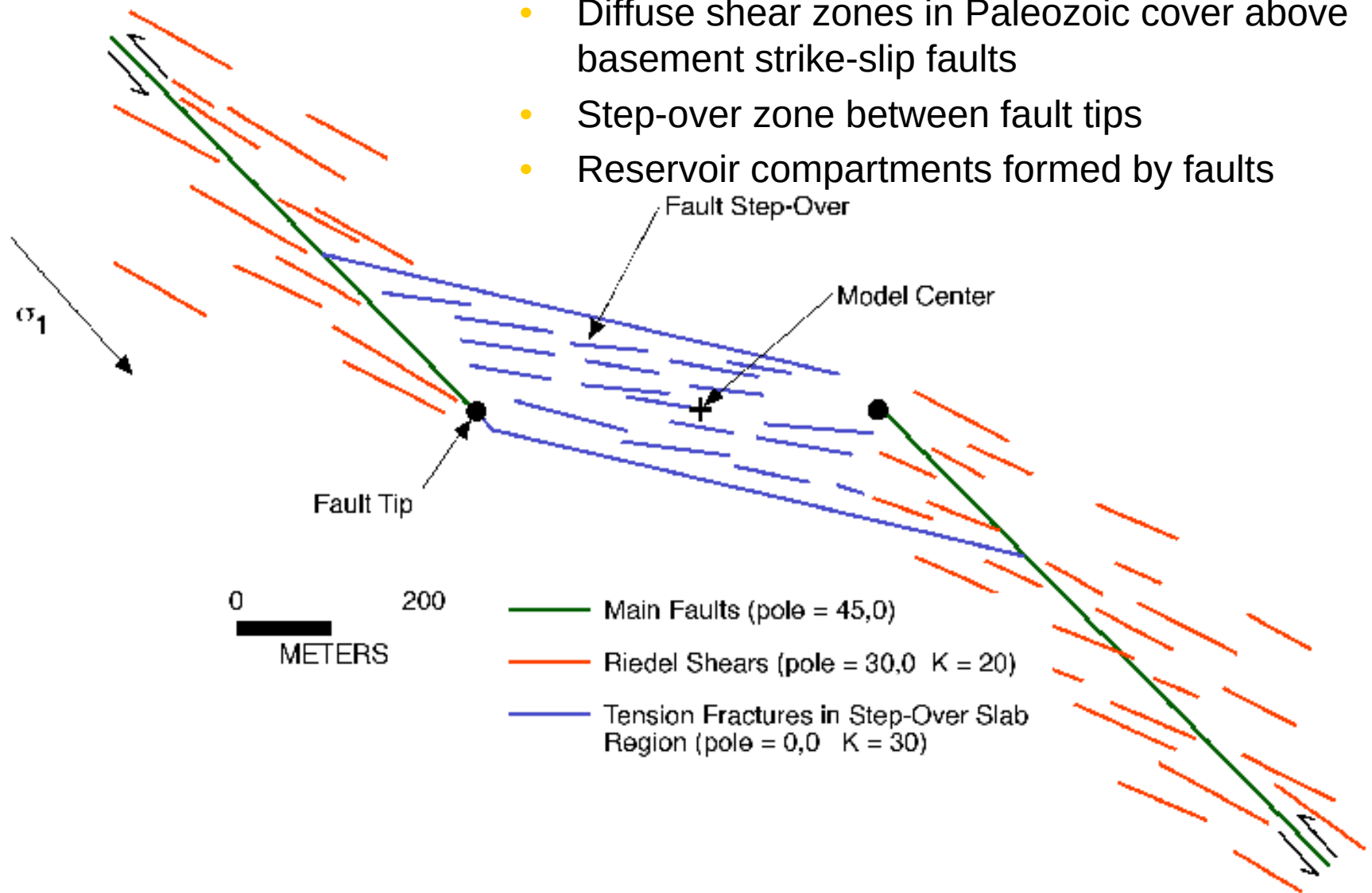
Carbonate Dissolution

North Stoney Point

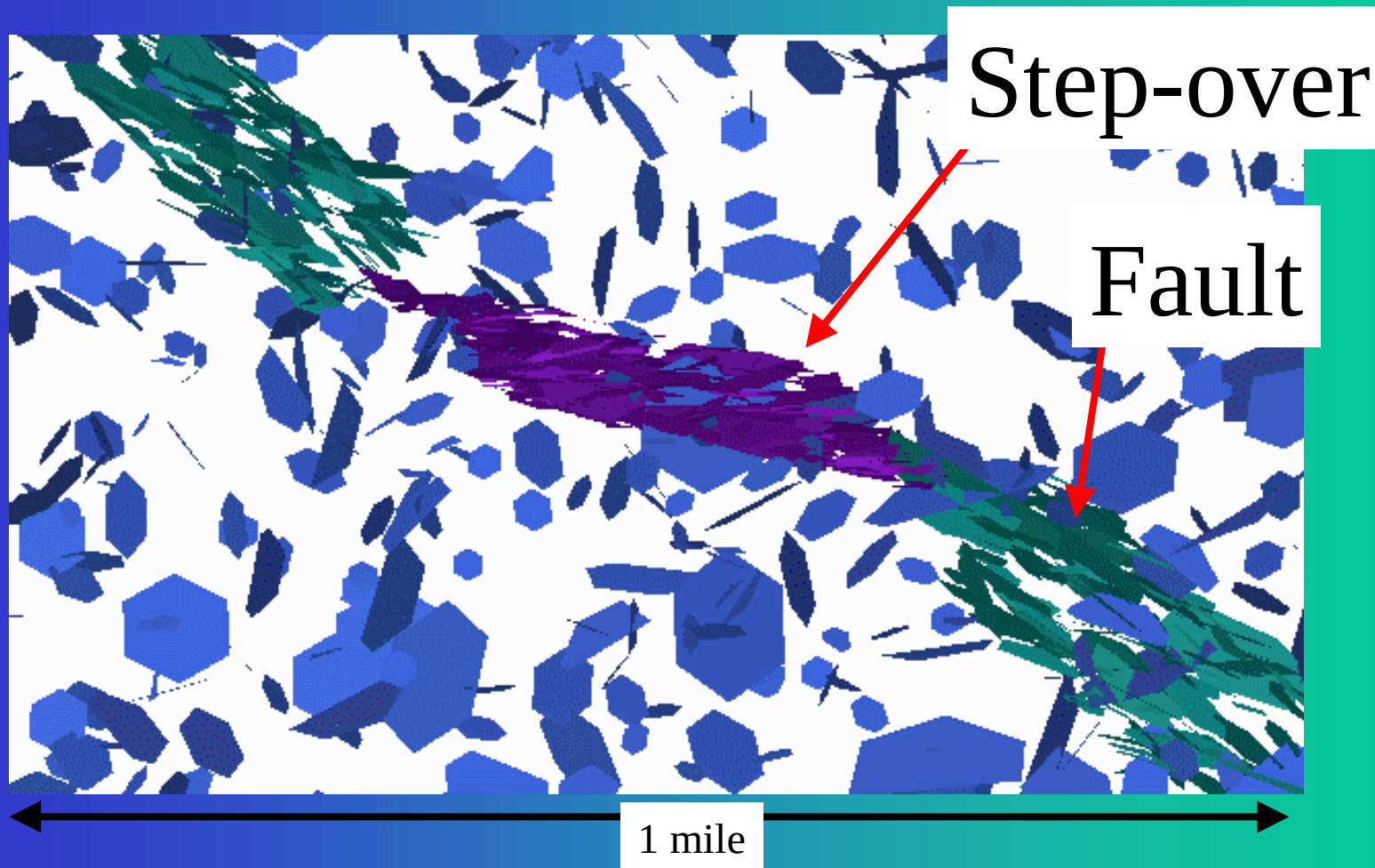


Conceptual Model *North Stoney Point*

- Diffuse shear zones in Paleozoic cover above basement strike-slip faults
- Step-over zone between fault tips
- Reservoir compartments formed by faults



Conceptual Model *North Stoney Point*

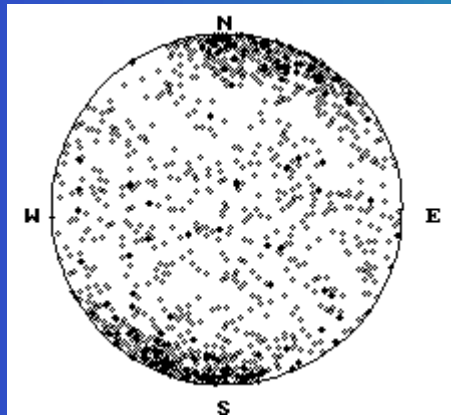


DFN Model Implementation

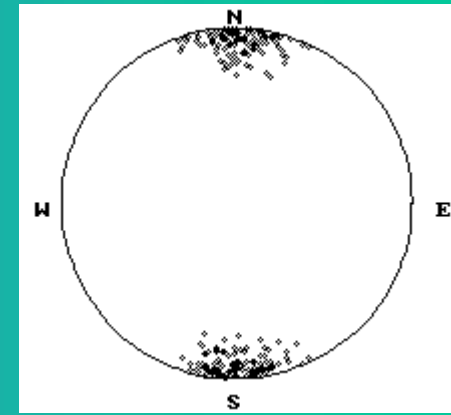
Fracture Orientations

North Stoney Point, Michigan

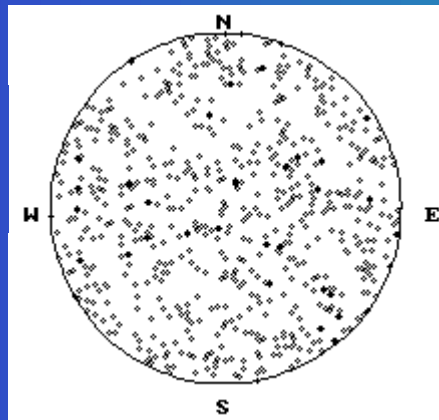
**All fracture
in model**



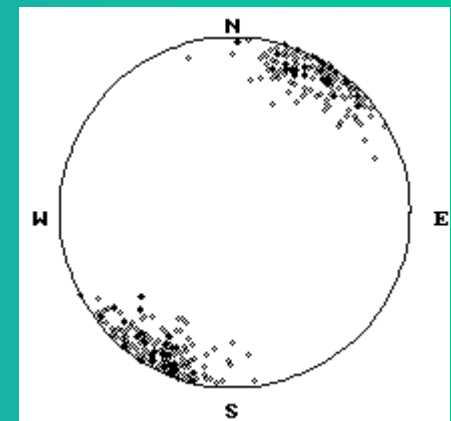
**tension fractures
in stepover**



**Background
fractures**



**Riedel shears
in shear zone**

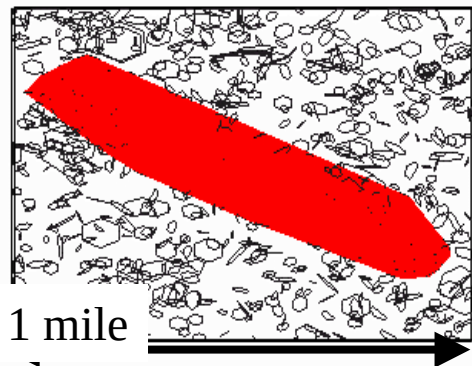


DFN Model Application

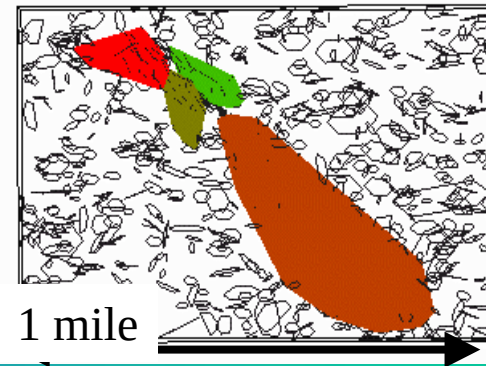
Compartmentalization

North Stoney Point

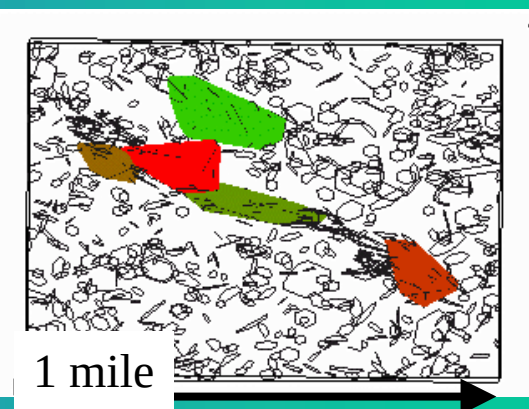
High intensity
($P_{32} = 0.05 \text{ m}^2/\text{m}^3$)



Medium intensity
($P_{32} = 0.01 \text{ m}^2/\text{m}^3$)



Low intensity
($P_{32} = 0.005 \text{ m}^2/\text{m}^3$)

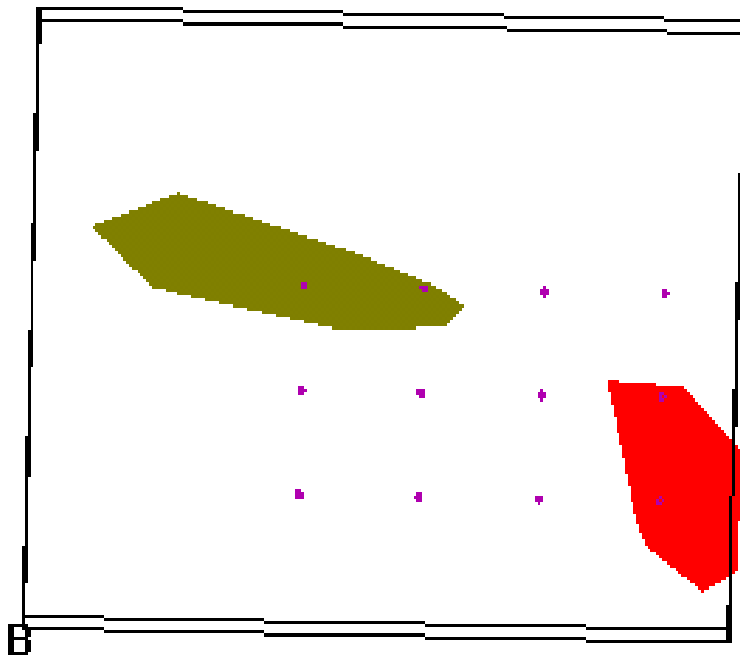


DFN Model Application

Well Field Design Based on Compartments

Phosphoria, South Oregon Basin

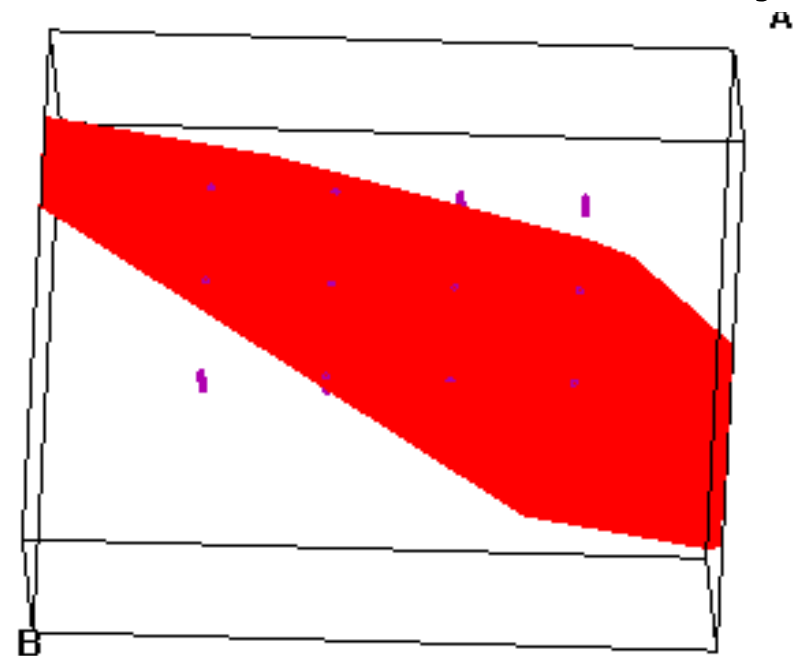
Low fracture intensity



4/12 hits

2 compartments

Medium fracture intensity



10/12 hits

1 compartment

FETC/NPTO Project Plans: Year 2

DFN Approaches for IOR in Heterogeneous Reservoirs

- Implement algorithms for heterogeneous reservoir DFN data analysis and modelling
- Create models based upon full reservoir structure and lithology
- Incorporate additional data as it arrives
- Determine conductive intensity
- Calibrate DFN Models to tracer and other field tests
- Directly address IOR design using DFN approaches

Analysis of Rift Basins for Optimum Development: Mississippi Interior Salt Basin

Ernest A. Mancini (emancini@wgs.geo.ua.edu; 205-348-4319)
William C. Parcell (parce001@bama.ua.edu; 205-348-9293)
T. Markham Puckett (mpuckett@wgs.geo.ua.edu; 205-348-7167)
Center for Sedimentary Basin Studies and Department of Geological Sciences,
The University of Alabama
Box 870338
Tuscaloosa, AL 35487-0338

Introduction

The domestic petroleum industry in the United States continues to change principally because of economic and regulatory reasons. Small- and medium-sized independent companies have evolved into major players in the drilling of new exploration wells in domestic basins. These companies do not have the exploration or research staffs of the major international companies; and therefore, their drilling decisions many times may not be made on the best available data.

Rift basins, including the Mississippi Interior Salt Basin, remain significant targets to explore for oil and natural gas. To date, however, comprehensive basin analysis and petroleum system modeling studies have not been performed in many of these basins. Further, small- and medium-sized independent companies that are drilling the majority of the wells do not have the resources to conduct basin studies. These companies maintain that the accessibility of oil and natural gas information is the single-most important factor critical to the search for new hydrocarbon resources.

Objectives

The objectives of this study have been to increase the amount of public information on domestic rift basins and enhance the understanding of petroleum systems operating in these basins. Attainment of these objectives is consistent with the goals of the 1998 Comprehensive National Energy Strategy. The discovery of new hydrocarbon resources in rift basins serves to support national economic and energy security by reducing the vulnerability of the U.S. economy to disruptions in oil supply by boosting domestic production in an environmentally superior manner.

Approach

To facilitate petroleum exploration efforts in rift basins, a comprehensive analysis of the Mississippi Interior Salt Basin has been undertaken. This basin was selected for study because it is the largest rift basin in the eastern Gulf Coastal Plain, extending from Louisiana eastward into Alabama, has produced the most petroleum in the region, has the highest potential for identifying underdeveloped plays and reservoirs in the area, and represents the largest subsurface well log, core and geophysical database of the basins in the eastern Gulf Coastal Plain. Further, the Mississippi Interior Salt Basin is an excellent analog for the study of offshore Gulf of Mexico basins, such as the Apalachicola-DeSoto Canyon Salt Basin. The purpose of this paper is to provide the information gathered and analyses performed relating to the tectonic, depositional, burial and thermal histories of the Mississippi Interior Salt Basin. These results represent the work performed during Year 2 of this 5-year study.

Project Results and Discussion

Regional Framework

The burial and thermal histories of the Mississippi Interior Salt Basin (Fig. 1) are directly linked to the tectonic and depositional histories of the basin which are closely related to the origin of the Gulf of Mexico (Wood and Walper, 1974). The Gulf of Mexico is a divergent margin basin characterized by extensional rift tectonics and wrench faulting (Pilger, 1981; Miller, 1982; Salvador, 1987; Winkler and Buffler, 1988). The history of the Gulf of Mexico includes a phase of crustal extension and thinning, a phase of rifting and sea-floor spreading and a phase of thermal subsidence (Nunn, 1984). The structural and stratigraphic framework of the region, including the Mississippi Interior Salt Basin, was established during the Triassic and Jurassic (Salvador, 1987).

Based on the distribution of crust type, Sawyer et al. (1991) proposed the following as a model for the evolution of the Gulf of Mexico and related Mississippi Interior Salt Basin. A Late Triassic-Early Jurassic early rifting phase is characterized by large and small half-grabens bounded by listric normal faults and filled with nonmarine siliciclastic sediments (red-beds) and volcanics. A

Middle Jurassic phase of rifting, crustal attenuation and the formation of transitional crust is characterized by the evolution of a pattern of alternating basement highs and lows and the accumulation of thick salt deposits. A Late Jurassic phase of sea-floor spreading and oceanic crust formation in the deep central Gulf of Mexico is characterized by a regional marine transgression as a result of crustal cooling and subsidence. Subsidence continued into the Early Cretaceous, and a carbonate shelf margin developed along the tectonic hinge zone of differential subsidence between thick and thin transitional crust. During the Early Cretaceous, erosional events are recognized during the Valanginian (base of the Hosston Formation), in the Aptian (base of the Pine Island Shale), in the Albian (base of the Mooringsport Formation), and in the Albian (base of the Washita Group) reflecting times of sea-level fall in the Gulf (Yurewicz et al., 1993).

This pattern of deposition was broken by a period of igneous activity and global sea-level fall during the Late Cretaceous (mid-Cenomanian) which produced a major lowering of sea-level in the region and resulted in the exposure of the shallow Cretaceous platform margin that rimmed the Gulf (Salvador, 1991). This mid-Cenomanian unconformity is most pronounced in the northern Gulf of Mexico area.

Mesozoic and Cenozoic strata of the northeastern Gulf of Mexico were deposited as part of a seaward-dipping wedge of sediment that accumulated in differentially subsiding basins on the passive margin of the North American continent (Martin, 1978). Basement cooling and subsidence resulted in filling of the accommodation space throughout the Jurassic. Structural elements that affected the general orientation of these strata include basement features associated with plate movement and features formed due to halokinesis of Jurassic salt. The basement surface is dissected by the regional basement rift system which consists of a rift-related trend of divergent wrench-type basement faults and associated grabens and half grabens (Mink et al., 1990). The major basement faults are the northwest-southeast trending Florida-Bahamas and Pearl River transfer faults. The graben system is a result of rifting and its geometry is a reflection of the direction of plate separation (MacRae and Watkins, 1996). The major positive basement features that influenced the distribution and nature of Mesozoic deposits onshore are the Wiggins Arch

complex, Choctaw ridge complex, the Conecuh ridge complex, the Pensacola ridge complex, and the Decatur ridge complex. These structural elements, such as the Choctaw, Conecuh, Pensacola, and Decatur ridge complexes, are associated with the Appalachian fold and thrust structural trend that was formed in the late Paleozoic by tectonic events resulting from convergence of the North American and African-South American continental plates. The Wiggins Arch complex may represent an elevated horst block associated with crustal extensional and rifting (Miller, 1982; Sawyer et al., 1991). This basement feature may be a remnant of the rifted continental margin of North America. The Wiggins Arch consists of pre-rift Paleozoic metamorphic and granitic rocks (Cagle and Khan, 1983).

Paleotopography had a significant impact on the distribution of sediment, and positive areas within basins and along basin margins provided sources for Mesozoic terrigenous sediments (Mancini et al., 1985b). The Mississippi Interior Salt Basin, which is a major negative structural feature in the northeastern Gulf of Mexico, is classified as the interior fracture portion of a margin sag basin, according to the classification of Kingston et al. (1983). This extensional basin was an actively subsiding depocenter throughout the Mesozoic and into the Cenozoic. Based on gravity data, Wilson (1975) interpreted the Mississippi Interior Salt Basin to be an area of attenuated granitic continental crust. Crustal thinning resulted from tectonic extension of the lithosphere during the rifting of the Gulf in the early Mesozoic. This attenuation of the crust established a subsiding basin cratonward of the rifted and elevated continental margin (Wood and Walper, 1974).

Halokinesis of the Jurassic Louann Salt has produced a complex of structural features in the northeastern Gulf of Mexico (Martin, 1978). Salt-related structures include diapirs, anticlines, and extensional fault and half graben systems. Structural elements resulting from salt movement include the regional peripheral fault trend, the lower Mobile Bay fault, the Mobile graben, Destin anticline, and numerous salt domes and anticlines. These features serve as petroleum traps in the region. Halokinetically-related structural deformation was initiated probably during the Late Jurassic and possibly as early as the Oxfordian (Dobson and Buffler, 1997). The Mississippi

Interior Salt Basin contains more than 50 documented salt domes with crests less than 6,000 ft from the surface and with two of the domes (Richton and Tatum salt domes) occurring less than 1,000 ft from the surface (Thieling and Moody, 1997).

The regional peripheral fault trend is comprised of a group of genetically related, *en echelon* extensional faults that are associated with salt movement. Onshore, this trend is composed of the Pickens, Gilbertown, West Bend, Pollard, and Foshee fault systems and offshore, the Pensacola-Destin fault system has been interpreted as part of this trend (Kemmer and Reagan, 1987). The trend approximates the updip limit of thick Jurassic salt (Martin, 1978). The faults of the regional peripheral fault trend are generally parallel or subparallel to regional depositional strike and are normal, down-to-the-basin or antithetic faults that form grabens that are generally 5 to 8 mi across (Murray, 1961). The faults are listric with fault dips ranging from 35° to 70° and with displacements on major faults ranging from 200 to 2,000 ft in the Jurassic section (Mancini et al., 1985a). The Mobile graben, which is considered to define the eastern limit of the Mississippi Interior Salt Basin, represents a more mature stage of halokinesis as evidenced by an association with diapiric features. The regional basement rift system influenced movement along the regional peripheral fault trend (Mink et al., 1990).

Sedimentation in the northeastern Gulf of Mexico was associated with rifted continental margin tectonics resulting from the breakup of Pangea and the opening of the Gulf of Mexico. Syn-rift Triassic graben-fill red-beds of the Eagle Mills Formation were deposited locally as the oldest Mesozoic strata above pre-rift Paleozoic basement during the early stages of extension and rifting (Tolson et al., 1983; Dobson, 1990).

The syn-rift middle Jurassic Werner Formation and Louann Salt are evaporite deposits that formed during the initial transgression of marine water into the Gulf of Mexico (Salvador, 1987). Basement structure influenced the distribution and thickness of Louann Salt with thick salt in the Mississippi Interior Salt Basin, and salt is absent over the Wiggins Arch (Wilson, 1975; Cagle and Khan, 1983). The updip limit of thick salt and the location of the extensional faults associated with

the regional peripheral fault trend coincide with a basement hinge line and occur in the northern part of the salt basin (Mancini and Benson, 1980; Mancini et al., 1985a).

The distribution of the Late Jurassic post-rift deposits of the Norphlet, Smackover, Haynesville and Cotton Valley were greatly affected by basement topography and progressively onlap the basement surface (Mancini and Benson, 1980; Dobson, 1990; Dobson and Buffler, 1997). The Norphlet Formation includes alluvial fan and plain, fluvial and wadi, eolian sheet, dune and interdune, and marine shoreface siliciclastic sediments (Mancini et al., 1985b). The Smackover Formation, which was deposited on a distally-steepened ramp surface during the major Jurassic marine transgression in the Gulf, consists of intertidal to subtidal laminated and microbial carbonate mudstones, subtidal peloidal wackestones and packstones, and subtidal to intertidal peloidal, ooid, oncoidal packstones and grainstones interbedded with laminated and fenestral carbonate mudstones (Mancini and Benson, 1980; Benson, 1988). This major transgression has been attributed to emplacement of oceanic crust in the Gulf and the resulting thermal subsidence due to crustal cooling (Nunn, 1984; Winkler and Buffler, 1988). Smackover microbial reefs developed updip of a basement hinge line detailing the boundary between continental crust and thick transitional crust and in association with horst blocks and salt structures in the zone of thick transitional crust (Dobson, 1990; Dobson and Buffler, 1997). The Haynesville Formation includes subaqueous to subaerial anhydrites, shelf to shoreline limestones, shales, and sandstones, and eolian, fluvial and alluvial sandstones (Tolson et al., 1983; Mann, 1988). The Cotton Valley Group consists of fluvial-deltaic and delta destructive sandstones and shales (Moore, 1983; Tolson et al., 1983).

The Early Cretaceous in the northeastern Gulf of Mexico was dominated by fluvial-deltaic to coastal siliciclastic sedimentation updip and the development of a broad carbonate shelf with a low relief margin downdip at the boundary between thick transitional crust and thin transitional crust (Eaves, 1976; Winkler and Buffler, 1988; Sawyer et al., 1991). The development of a carbonate shelf margin during the Early Cretaceous, which does not conform to the basement structure, is believed to be a combination of a change in the slope of the basement which is marked by a crustal

hinge zone and Jurassic sediment depositional patterns (Dobson, 1990; Sawyer et al., 1991). The hinge zone formed as a result of differential subsidence across the crustal boundary between thick and thin transitional crust (Corso, 1987). Although Norphlet, Smackover and Haynesville deposition patterns were greatly affected by basement topography, sediments deposited at the close of Cotton Valley times, such as the Knowles Limestone, reflect an infilling of the basement low areas and a general progradation (Dobson, 1990; Dobson and Buffler, 1997). This progradation has been interpreted by Dobson (1990) to produce the change from a carbonate ramp to a rimmed carbonate platform margin.

The Lower Cretaceous shelf margin was exposed during the early Late Cretaceous by a major lowering of sea level in the Gulf of Mexico. This sea-level fall has been attributed to a combination of regional igneous activity (Jackson Dome) and global sea level fall during the mid-Cenomanian (Salvador, 1991). A Late Cretaceous marine transgression followed this regional erosional event, and this transgression in combination with the Laramide orogeny affected deposition in the Late Cretaceous and into the Cenozoic (Salvador, 1991). Throughout the Cenozoic, the Mississippi Interior Salt Basin was the site of significant fluvial, deltaic and coastline siliciclastic sedimentation; the area experienced minor carbonate deposition (Salvador, 1991).

Burial History

Understanding burial history is important to interpreting the geohistory of a basin. Burial history is crucial in determining the generation, migration and preservation of hydrocarbons in the basin. This modeling is dependent upon a sound regional model for the geologic history of the basin (Waples, 1994a). Determination of the magnitude of depositional events, such as sedimentation and subsidence rates, are critical to interpreting burial history. The identification of erosion events and times of non-deposition are crucial in interpreting the burial and thermal histories of a basin. Burial history work for portions of the Mississippi Interior Salt Basin has been published by Nunn and Sassen (1986) and Driskill et al. (1988), but no comprehensive analysis has been published to date.

In this study, the tectonic and depositional histories of the Mississippi Interior Salt Basin form the foundation for interpreting the burial history of the basin. Five regional cross sections consisting of 48 key wells comprise the basis for the interpretation. The burial history for each well in the cross sections was determined using BasinMod® software. Information interpreted from these cross-sections, well logs, and other sources include biostratigraphic (geologic ages of selected units or horizons), paleoenvironmental (water depths), stratigraphic thickness of the units, lithologies, sediment accumulation and subsidence rates, unconformities and faulting.

The geologic ages for the Tertiary units in the Mississippi Interior Salt Basin were determined using the outcrop work of Mancini and Tew (1991) and for Upper Cretaceous strata using the outcrop work of Christopher (1982), Puckett (1995), Mancini et al. (1996) and the subsurface work of Mancini and Payton (1981). The geologic ages for the Lower Cretaceous units were estimated using the work performed in the western Gulf by Imlay (1940) and Young (1972). The geologic ages for the Upper Jurassic units were determined using the work done in the western Gulf by Imlay and Herman (1984) and Young and Oloritz (1993). Geologic age data published by Todd and Mitchum (1977) and Salvador (Salvador, 1987) were also used. Utilizing the geologic age data, the stratigraphic section was divided into five intervals: Jurassic (161-137 my), Early Cretaceous (137-99 my), Late Cretaceous (99-65 my), early Tertiary (65-30 my) and late Tertiary and Quaternary (30-0 my) for basin modeling. Major hiatuses were recognized in the Jurassic (195-176 my) and the Early Cretaceous (137-132 my). Fault displacements of 100 to 2,000 ft were found throughout the section in specific wells.

The total thickness of the sediment column was corrected for compaction utilizing the Sclater and Christie (1980) method. The thickness of key stratigraphic horizons was determined through well log study and by using BasinMod® software. The stratigraphic horizons were recognized by their characteristic well log signatures. Sediment accumulation rates and subsidence rates were determined based on these data by employing BasinMod® software. In these determinations, the following constants were used: average mantle density of 3.30 g/cm^3 ; average water density of 1.02 g/cm^3 ; and average sediment densities of 2.64 g/cm^3 for sandstone, 2.60 g/cm^3 for shale,

2.72 g/cm³ for limestone, 2.98 g/cm³ for anhydrite and 2.15 g/cm³ for salt. Paleowater depths ranged from 0-400 ft. These constants are consistent with those of Nunn and Sassen (1986).

Mean stratigraphic thickness, sediment accumulation rates, and tectonic subsidence rates were determined using BasinMod“ software. The mean stratigraphic thickness for the five intervals is as follows: Jurassic (4,746 ft), Lower Cretaceous (6,242 ft), Upper Cretaceous (3,858 ft), lower Tertiary (4,939 ft) and upper Tertiary (2,926 ft). Mean sandstone sediment accumulation rates range from 311 ft/my for Lower Cretaceous sandstones to 170 ft/my for Jurassic sandstones. Mean shale sediment accumulation rates range from 108 ft/my for Upper Cretaceous clays to 90 ft/my for lower Tertiary shales. Mean limestone sediment accumulation rates range from 122 ft/my for Jurassic limestones to 57 ft/my for Upper Cretaceous chalks. Mean anhydrite sediment accumulation rates are 85 ft/my for Lower Cretaceous anhydrites. Mean tectonic subsidence rates for the intervals are: Jurassic (130 ft/my), Lower Cretaceous (72 ft/my), Upper Cretaceous (46 ft/my) and lower Tertiary (45 ft/my).

The burial history modeling (Fig. 2) is consistent with the rift-related geohistory of the Mississippi Interior Salt Basin. Lithospheric extension occurred during the Early to Middle Jurassic and was followed by a long period of thermal subsidence. Nunn (1984) determined that the crustal thickness underneath the basin was 30-35 km (approximately 98,400-115,000 ft), while the crustal thickness to the north of the basin and underneath the Wiggins Arch to the south was greater. Tectonic subsidence rates were greatest during the Jurassic and decreased progressively from the Jurassic to the late Tertiary, reflecting the syn-rift and post-rift history of the basin. According to Driskill et al. (1988), 42% of the tectonic subsidence in the basin occurred within 32 million years following the onset of thermal subsidence and an equal amount of subsidence required an additional 68 million years. These authors report tectonic subsidence amounts of 1.26 to >1.76 km (approximately 4,100 to >5,780 ft) for the Mississippi Interior Salt Basin. Tectonic subsidence probably exceeded 1.95 km (approximately 6,400 ft) in the Perry sub-basin (Driskill et al., 1988). Therefore, the greatest accommodation space was generated during the Jurassic.

The sedimentary rock record of the basin indicates that the deepest water depths occurred during the Late Jurassic (Oxfordian), Early Cretaceous (Hauterivian-Albian), Late Cretaceous (Cenomanian-Turonian), and Late Eocene (Priabonian). These events correspond to global rises in sea level. Therefore, eustasy also contributed to the generation of accommodation space.

Sediment accumulation acts to reduce available accommodation space. Sediment supply in concert with tectonics and eustasy are the principal controls on sediment accumulation and cyclicity in the basin.

Thermal History

The thermal history of a basin is a crucial element as to whether the basin has hydrocarbons in commercial quantities and as to whether those hydrocarbons are oil, natural gas or both. Thermal maturity modeling has become a standard in basin analysis and petroleum exploration. Maturity modeling builds on burial history modeling. Determination of present-day heat flow, paleoheat flows, and thermal conductivities are vital criteria along with the amount and type of kerogen and the element of timing (Waples, 1994b). Thermal history work for portions of the Mississippi Interior Salt Basin has been published by Wilson (1975), Koons et al. (1974), Smith et al. (1981), Nunn (1984), Oehler (1984), Nunn et al. (1984), Nunn and Sassen (1986), Sassen (1989), Sassen and Moore (1988), Driskill et al. (1988), Claypool and Mancini (1989), and Mancini et al. (1993), but no comprehensive analysis has been published to date.

In this study, the tectonic, depositional and burial histories of the Mississippi Interior Salt Basin form the foundation for interpreting the thermal history of the basin. Five regional cross-sections consisting of 48 key wells comprise the basis for the interpretation. The thermal history for each well and cross-section was determined using BasinMod® software. Information utilized includes bottom hole temperature, present-day geothermal gradient, present-day heat flow, vitrinite reflectance, thermal alteration, Tmax, paleogeothermal gradient, paleoheat flow, thermal conductivity, total organic carbon and kerogen type.

The thermal history modeling indicates that effective source rocks in the basin include Upper Jurassic Smackover carbonate mudstones throughout the basin area and Upper Cretaceous Tuscaloosa shales in the south central portion (Perry sub-basin area) of the basin. Upper Jurassic and Lower Cretaceous shales are possible source rocks in the south central portion (Perry sub-basin area) of the basin given the proper organic facies. Tertiary shales have not been subjected to favorable burial and thermal histories required for petroleum generation in the basin.

These observations are consistent with previous studies, such as those by Nunn (1984), Oehler (1984), Nunn and Sassen (1986), Sassen and Moore (1988), Driskill et al. (1988), Claypool and Mancini (1989), and Mancini et al. (1993). These previous works have recognized that the Smackover is an effective regional source rock, that the Tuscaloosa is an effective local source rock in the south central portion of the Mississippi Interior Salt Basin, and that the Tertiary shales in the basin are thermally immature and are unlikely to have served as source rocks for crude oil. However, previous workers have not speculated on the possibility of Lower Cretaceous shales having acted as petroleum source rocks.

Organic geochemical source rock analyses performed as part of this study, in combination with those of Oehler (1984), Sassen et al. (1987), and Claypool and Mancini (1989), indicate that the petroleum source rock potential of the lower and middle Smackover carbonate mudstones of the Mississippi Interior Salt Basin has been optimized by the combination of favorable conditions of deposition, preservation, and subsequent burial and thermal histories.

Smackover samples from the lower and middle carbonate mudstones average 0.81% total organic carbon (Claypool and Mancini, 1989). Because much of the Smackover has experienced advanced levels of thermal maturity, the total organic carbon values were higher in the past prior to the generation of crude oil (Sassen and Moore, 1988). Organic carbon contents of up to 2.52% have been reported from these carbonate mudstones (Oehler, 1984). Thermally immature Smackover mudstones with pyrolysis T_{max} values of 422-424°C have hydrogen index values of 656 mg HC/g TOC, while mature Smackover mudstones with T_{max} values of 447-453°C have hydrogen index values of 50 mg HC/g TOC (Sassen and Moore, 1988).

The dominant kerogen types in the Smackover are algal (cyanobacteria) and amorphous (Oehler, 1984; Sassen et al., 1987; Claypool and Mancini, 1989). In updip areas near the paleoshoreline the Smackover includes herbaceous kerogen (Wade et al., 1987). In the basin area, Smackover samples exhibit thermal alteration indices of 2⁻ to 4 (Oehler, 1984; Sassen et al., 1987; Claypool and Mancini, 1989). These values represent an equivalent vitrinite reflectance (Ro) of 0.55 to 3.0% (Sassen and Moore, 1988).

The generation of crude oil from source rocks in the Mississippi Interior Salt Basin is interpreted to have been initiated at a level of thermal maturity of 0.55% Ro (435°C Tmax; 2 TAI) and concluded at a level of thermal maturity of 1.5% Ro (470°C Tmax; 3 TAI) (Nunn and Sassen, 1986; Sassen and Moore, 1988). This requires a depth of burial of 3 km or approximately 9,840 ft according to Driskill et al. (1988). Nunn and Sassen (1986) reported that the generation of crude oil in the Mississippi Interior Salt Basin was initiated at a depth of 3.5 km or approximately 11,500 ft. The generation of crude oil is believed to have been initiated from basinal Smackover carbonate mudstones in the Early Cretaceous, and the generation and migration of low to intermediate gravity crude oil is interpreted to have continued into the Tertiary (Nunn and Sassen, 1986; Driskill et al., 1988; Sassen and Moore, 1988). Updip Smackover carbonate mudstones are thought to have generated low gravity crude oil beginning in the Late Cretaceous or 20 my later than the basinal mudstones (Driskill et al., 1988). Post-Early Cretaceous shales (Tuscaloosa, Selma and Tertiary) have been interpreted as ineffective petroleum source rocks by Driskill et al. (1988) because of their thermal immaturity (0.4% Ro) in much of the Mississippi Interior Salt Basin area. However, the generation of crude oil is believed to have been initiated during the Tertiary locally from basinal Tuscaloosa shales, which have total organic carbon contents of up to 2.8% in the south central portion of the basin (Koons et al., 1974; Nunn and Sassen, 1986). Norphlet, Haynesville, Cotton Valley, and Rodessa shales analyzed by previous workers were found to have total organic carbon contents of less than 0.3% (Sassen and Moore, 1988; Claypool and Mancini, 1989). At a depth of burial of 5-6 km (approximately 16,400-19,700 ft), the Smackover mudstones are thought to be over-mature for the generation of crude oil (Nunn and Sassen, 1986; Driskill et al., 1988). The

low to intermediate crude oils that migrated into reservoirs were subjected to thermal cracking with depth of burial and time (Sassen and Moore, 1988; Claypool and Mancini, 1989). Most authors agree that the Jurassic and Early Cretaceous sediments experienced a rapid rise in temperature associated with rifting (190-165 my) and that for the past 60 to 75 my there has been little change in paleotemperature (Nunn, 1984; Driskill et al., 1988). This trend translates into a paleogeothermal gradient of 72°C/km during the Jurassic, of 58°C/km during the Early Cretaceous and of 28-33°C/km today (Smith et al., 1981; Nunn, 1984). Conductivities of $3\text{-}5 \times 10^{(-3)}$ cal/cm°C have been measured for strata in the basin (Smith et al., 1981; Nunn, 1984). Heat flows of $1.0 \mu\text{cal/cm}^2\text{-sec}$ are typical of the basin except in the vicinity of the Jackson Dome ($1.5 \mu\text{cal/cm}^2\text{-sec}$) (Smith et al., 1981). Bottom hole temperatures for strata buried to 21,000 ft are 380°F in the basin area, and the present-day geothermal gradient is 1.0-1.6°F/100 ft (Wilson, 1975). As a result of thermal maturity modeling and calibration with thermal maturation indices, elevated heat flows are evident in the south central (Perry sub-basin) and east central (Washington County, Alabama) portions of the basin and in the vicinity of the Jackson Dome.

From thermal maturation profiles for wells in the study area, a hydrocarbon generation and maturation trend can be observed. In wells in much of the basin, the generation of hydrocarbons from Smackover carbonate mudstones is initiated at 8,000-11,000 ft during the Early Cretaceous and continuing into the Tertiary throughout much of the Mississippi Interior Salt Basin (Fig. 3). Locally, hydrocarbon generation commenced at 7,000-8,000 ft from Tuscaloosa shales during the Tertiary in the area of the Perry sub-basin (Fig. 4). In the vicinity of the Jackson Dome, hydrocarbon gas generation begins at a depth of 15,000 ft. This hydrocarbon generation and maturation trend can be seen on the cross section in Figure 5.

Application and Conclusions

1. The burial and thermal histories of the Mississippi Interior Salt Basin are directly linked to the tectonic and depositional histories of the basin, which are closely related to the origin of the Gulf of Mexico. Active rifting persisted through the Middle Jurassic and crustal

cooling and subsidence which was initiated in the Late Jurassic continued into the Cretaceous. This basin is classified as an extensional basin. Basement topography had a significant influence on the distribution of sediments. Syn-rift deposits include the Jurassic Werner and Louann Salt. Post-rift deposits include Upper Jurassic, Cretaceous and Tertiary evaporites, carbonate and siliciclastic sediments. Deposition was dominated by a ramp margin during the Jurassic and a shelf margin during the post-Jurassic.

2. The burial history modeling for the Mississippi Interior Salt Basin is consistent with the rift-related geohistory of the region. Lithospheric extension occurred during the Early and Middle Jurassic and was followed by a long period of thermal subsidence. Tectonic subsidence rates were greatest during the Jurassic and decreased progressively from the Jurassic to the late Tertiary. The greatest accommodation space was generated during the Jurassic as a combination of subsidence and eustasy.
3. The thermal history modeling indicates that effective petroleum source rocks include Upper Jurassic Smackover carbonate mudstones throughout much of the Mississippi Interior Salt Basin and Upper Cretaceous Tuscaloosa black shales locally in the south central portion of the basin (Perry sub-basin area). Lower Cretaceous shales are possible source rocks in the south central portion of the basin (Perry sub-basin area) given the proper organic facies. Tertiary shales, although high in organic content, have not been subjected to favorable burial and thermal histories required for petroleum generation.
4. By utilizing a multidimensional burial and thermal history modeling approach, petroleum companies searching to extend known oil and gas plays in the Mississippi Interior Salt Basin should be able to generate new prospects and improve their ability to drill successful exploration wells.

Acknowledgements

This research has been funded by the National Petroleum Technology Office, Office of Fossil Energy, U.S. Department of Energy under DOE award number DE-FG22-96BC14946 for the

period 1996-2001. The contract is to The University of Alabama, Box 870338, Tuscaloosa, AL 35487-0338 (Telefax: 205-348-0818 and E-mail address: emancini@wgs.geo.ua.edu). The Project Manager is Virginia Weyland.

References

- Benson, D.J., 1988, Depositional history of the Smackover Formation in southwest Alabama: Transactions—Gulf Coast Association of Geological Societies, v. 38, p. 197-205.
- Cagle, J.W., and M.A. Khan, 1983, Smackover-Norphlet stratigraphy, south Wiggins Arch, Mississippi and Alabama: Transactions—Gulf Coast Association of Geological Societies, v. 33, p. 23-29.
- Christopher, R.A., 1982, Palynostratigraphy of the basal Cretaceous units of the eastern Gulf and southern Atlantic coastal plains, in D.D. Arden, B.F. Beck, and E. Morrow, eds., Proceedings of the Second Symposium on the Geology of the Southeastern Coastal Plain: Georgia Geologic Survey Information Circular 53, p. 10-23.
- Claypool, G.E., and E.A. Mancini, 1989, Geochemical relationships of petroleum in Mesozoic reservoirs to carbonate source rocks of Jurassic Smackover Formation, southwestern Alabama: American Association of Petroleum Geologists Bulletin, v. 73, p. 904-924.
- Corso, W., 1987, Development of the Early Cretaceous northwest Florida carbonate platform [unpublished Ph.D. dissertation]: The University of Texas, 136 p.
- Dobson, L.M., 1990, Seismic stratigraphy and geologic history of Jurassic rocks, northeastern Gulf of Mexico [unpublished M. S. thesis]: The University of Texas, 165 p.
- Dobson, L.M., and R.T. Buffler, 1997, Seismic stratigraphy and geologic history of Jurassic rocks, northeastern Gulf of Mexico: American Association of Petroleum Geologists Bulletin, v. 81, p. 100-120.
- Driskill, B.W., J.A. Nunn, R. Sassen, and R.H. Pilger, Jr., 1988, Tectonic subsidence, crustal thinning and petroleum generation in the Jurassic trend of Mississippi, Alabama and Florida: Transactions—Gulf Coast Association of Geological Societies, v. 38, p. 257-265.
- Eaves, E., 1976, Citronelle oil field, Mobile County, Alabama: American Association of Petroleum Geologists Memoir 24, p. 259-275.
- Imlay, R.W., 1940, Lower Cretaceous and Jurassic formations of southern Arkansas and their oil and gas possibilities: Arkansas Division of Geology Information Circular 12, 64 p.
- Imlay, R.W., and G. Herman, 1984, Upper Jurassic ammonites of the subsurface of Texas, Louisiana, and Mississippi, in W.P.S. Ventress, D.G. Bebout, B.F. Perkins, and C.H. Moore, eds., The Jurassic of the Gulf Rim: Proceedings of the Third Annual Research Conference, Gulf Coast Section, Society of Economic Paleontologists and Mineralogists Foundation, p. 149-170.
- Kemmer, D.A., and R.L. Reagan, 1987, Norphlet Formation (Upper Jurassic) sand erg—depositional model for northeastern DeSoto Salt Basin, eastern Gulf of Mexico: American Association of Petroleum Geologists Bulletin, v. 71, p. 576.
- Kingston, D.R., C.P. Dishroon, and P.A. Williams, 1983, Global basin classification system: American Association of Petroleum Geologists Bulletin, v. 67, p. 2175-2193.
- Koons, C.B., J.G. Bond, and F.L. Peirce, 1974, Effects of depositional environment and postdepositional history on chemical composition of Lower Tuscaloosa oils: American Association of Petroleum Geologists Bulletin, v. 58, p. 1272-1280.
- MacRae, G., and J.S. Watkins, 1996, Desoto Canyon Salt Basin: tectonic evolution and salt structural styles, in J.O. Jones, and R.L. Freed, eds., Structural Framework of the Northern Gulf of Mexico: Special Publication of Gulf Coast Association of Geological Societies, p. 53-61.

- Mancini, E.A., and D.J. Benson, 1980, Regional stratigraphy of Upper Jurassic Smackover carbonates of southwest Alabama: Transactions—Gulf Coast Association of Geological Societies, v. 30, p. 151-163.
- Mancini, E.A., R.M. Mink, and B.L. Bearden, 1985a, Upper Jurassic Norphlet hydrocarbon potential along the regional peripheral fault trend in Mississippi, Alabama, and the Florida Panhandle: Transactions—Gulf Coast Association of Geological Societies, v. 35, p. 225-232.
- Mancini, E.A., R.M. Mink, B.L. Bearden, and R.P. Wilkerson, 1985b, Norphlet Formation (Upper Jurassic) of southwestern and offshore Alabama: environments of deposition and petroleum geology: American Association of Petroleum Geologists Bulletin, v. 69, p. 881-898.
- Mancini, E.A., and J.W. Payton, 1981, Petroleum geology of South Carlton Field, Lower Tuscaloosa "Pilot Sand", Clarke and Baldwin Counties, Alabama: Transactions—Gulf Coast Association of Geological Societies, v. 31, p. 139-147.
- Mancini, E.A., T.M. Puckett, and B.H. Tew, 1996, Integrated biostratigraphic and sequence stratigraphic framework for Upper Cretaceous strata of the eastern Gulf Coastal Plain, USA: Cretaceous Research, v. 17, p. 645-669.
- Mancini, E.A., and B.H. Tew, 1991, Relationships of Paleogene stage and planktonic foraminiferal zone boundaries to lithostratigraphic and allostratigraphic contacts in the eastern Gulf Coastal Plain: Journal of Foraminiferal Research, v. 21, p. 48-66.
- Mancini, E.A., B.H. Tew, and R.M. Mink, 1993, Petroleum source rock potential of Mesozoic condensed section deposits of southwest Alabama, in B.J. Katz, and L.M. Pratt, eds., Source Rocks in a Sequence Stratigraphic Framework: American Association of Petroleum Geologists Studies in Geology, v. 37, p. 147-162.
- Mann, S.D., 1988, Subaqueous evaporites of the Buckner Member, Haynesville Formation, northeastern Mobile County, Alabama: Transactions—Gulf Coast Association of Geological Societies, v. 38, p. 187-196.
- Martin, R.G., 1978, Northern and eastern Gulf of Mexico continental margin: stratigraphic and structural framework: American Association of Petroleum Geologists Studies in Geology, v. 7, p. 21-42.
- Miller, J.A., 1982, Structural control of Jurassic sedimentation in Alabama and Florida: American Association of Petroleum Geologists Bulletin, v. 66, p. 1289-1301.
- Mink, R.M., B.H. Tew, S.D. Mann, B.L. Bearden, and E.A. Mancini, 1990, Norphlet and pre-Norphlet geologic framework of Alabama and panhandle Florida coastal waters area and adjacent federal waters area: Geological Survey of Alabama Bulletin 140, 58 p.
- Moore, T., 1983, Cotton Valley depositional systems of Mississippi: Transactions—Gulf Coast Association of Geological Societies, v. 33, p. 163-167.
- Murray, G.E., 1961, Geology of the Atlantic and Gulf Coastal Province of North America: New York, Harper & Brothers, 692 p.
- Nunn, J.A., 1984, Subsidence histories for the Jurassic sediments of the northern Gulf Coast: thermal-mechanical model, in W.P.S. Ventress, D.G. Bebout, B.F. Perkins, and C.H. Moore, eds., The Jurassic of the Gulf Rim: Proceedings of the Third Annual Research Conference, Gulf Coast Section, Society of Economic Paleontologists and Mineralogists Foundation, p. 309-322.
- Nunn, J.A., and R. Sassen, 1986, The framework of hydrocarbon generation and migration, Gulf of Mexico continental slope: Transactions—Gulf Coast Association of Geological Societies, v. 36, p. 257-262.
- Nunn, J.A., A.D. Scardina, and R.H. Pilger, Jr., 1984, Thermal evolution of the north-central Gulf Coast: Tectonics, v. 3, p. 723-740.
- Oehler, J.H., 1984, Carbonate source rocks in the Jurassic Smackover trend of Mississippi, Alabama, and Florida, in J.G. Palacas, ed., Petroleum Geochemistry and Source Rock Potential of Carbonate Rocks: American Association of Petroleum Geologists Studies in Geology, v. 18, p. 63-69.

- Pilger, R.H., Jr., 1981, The opening of the Gulf of Mexico: implications for the tectonic evolution of the northern Gulf Coast: *Transactions—Gulf Coast Association of Geological Societies*, v. 31, p. 377-381.
- Puckett, T.M., 1995, Planktonic foraminiferal and ostracode biostratigraphy of the late Santonian through early Maastrichtian strata in Dallas County, Alabama: *Geological Survey of Alabama Bulletin* 164, 59 p.
- Salvador, A., 1987, Late Triassic-Jurassic paleogeography and origin of Gulf of Mexico Basin: *American Association of Petroleum Geologists Bulletin*, v. 71, p. 419-451.
- Salvador, A., 1991, Origin and development of the Gulf of Mexico Basin, in A. Salvador, ed., *The Gulf of Mexico Basin: Geological Society of America, Decade of North American Geology*, v. J, p. 389-444.
- Sassen, R., 1989, Migration of crude oil from the Smackover source rock to Jurassic and Cretaceous reservoirs of the northern Gulf rim: *Organic Geochemistry*, v. 14, p. 51-60.
- Sassen, R., and C.H. Moore, 1988, Framework of hydrocarbon generation and destruction in eastern Smackover trend: *American Association of Petroleum Geologists Bulletin*, v. 72, p. 649-663.
- Sassen, R., C.H. Moore, J.A. Nunn, F.C. Meendsen, and E. Heydari, 1987, Geochemical studies of crude oil generation, migration, and destruction in the Mississippi salt basin: *Transactions—Gulf Coast Association of Geological Societies*, v. 37, p. 217-224.
- Sawyer, D.S., R.T. Buffler, and R.H. Pilger, Jr., 1991, The crust under the Gulf of Mexico, in A. Salvador, ed., *The Gulf of Mexico Basin: Geological Society of America, Decade of North American Geology*, v. J, p. 53-72.
- Sclater, J.G., and P.A.F. Christie, 1980, Continental stretching: an explanation of the post mid-Cretaceous subsidence of the central North Sea basin: *Journal of Geophysical Research*, v. 85, p. 3711-3739.
- Smith, D.L., W.J. Dees, and D.W. Harrelson, 1981, Geothermal conditions and their implications for basement tectonics in the Gulf Coast margin: *Transactions—Gulf Coast Association of Geological Societies*, v. 31, p. 181-190.
- Thieling, S.C., and J.S. Moody, 1997, Atlas of shallow Mississippi salt domes: *Mississippi Office of Geology Bulletin* 131, 328 p.
- Todd, R.G., and R.M. Mitchum, Jr., 1977, Seismic stratigraphy and global changes of sea level; Part 8, Identification of Upper Triassic, Jurassic, and Lower Cretaceous seismic sequences in Gulf of Mexico and offshore West Africa, in C.E. Payton, ed., *Seismic stratigraphy: applications to hydrocarbon exploration: American Association of Petroleum Geologists Memoir* 26, p. 145-163.
- Tolson, J.S., C.W. Copeland, and B.L. Bearden, 1983, Stratigraphic profiles of Jurassic strata in the western part of the Alabama coastal plain: *Geological Survey of Alabama Bulletin* 122, 425 p.
- Wade, W.J., R. Sassen, and E.W. Chinn, 1987, Stratigraphy and source potential of the Smackover Formation of the northern Manila Embayment, southwest Alabama: *Transactions—Gulf Coast Association of Geological Societies*, v. 37, p. 277-285.
- Waples, D.W., 1994a, Maturity modeling: thermal indicators, hydrocarbon generation and oil cracking, in L.B. Magoon, and W.G. Dow, eds., *The Petroleum System--From Source to Trap: American Association of Petroleum Geologists Memoir* 60, p. 285-306.
- Waples, D.W., 1994b, Modeling of sedimentary basins and petroleum systems, in L.B. Magoon, and W.G. Dow, eds., *The Petroleum System—From Source to Trap: American Association of Petroleum Geologists Memoir* 60, p. 307-322.
- Wilson, G.V., 1975, Early differential subsidence and configuration of the northern Gulf Coast basin in Southwest Alabama and Northwest Florida: *Transactions—Gulf Coast Association of Geological Societies*, v. 25, p. 196-206.
- Winkler, C.D., and R.T. Buffler, 1988, Paleogeographic evolution of early deep-water Gulf of Mexico and margins, Jurassic to middle Cretaceous (Cenomanian): *American Association of Petroleum Geologists Bulletin*, v. 72, p. 318-346.

- Wood, M.L., and J.L. Walper, 1974, The evolution of the interior Mesozoic basin and the Gulf of Mexico: Transactions—Gulf Coast Association of Geological Societies, v. 24, p. 31-41.
- Young, K., 1972, Cretaceous paleogeography: implications of endemic ammonite faunas: Texas Bureau of Economic Geology Geological Circular 72-2, 13 p.
- Young, K., and F. Oloriz, 1993, Ammonites from the Smackover Limestone, Cotton Valley field, Webster Parish, Louisiana, U.S.A.: *Geobios*, v. 15, p. 401-409.
- Yurewicz, D.A., T.B. Marler, K.A. Meyerholtz, and F.X. Siroky, 1993, Early Cretaceous carbonate platform, north rim of the Gulf of Mexico, Mississippi and Louisiana, *in* J.A.T. Simo, R.W. Scott, and J.P. Masse, eds., *Cretaceous Carbonate Platforms: Association of Petroleum Geologists Memoir 56*, p. 81-96.

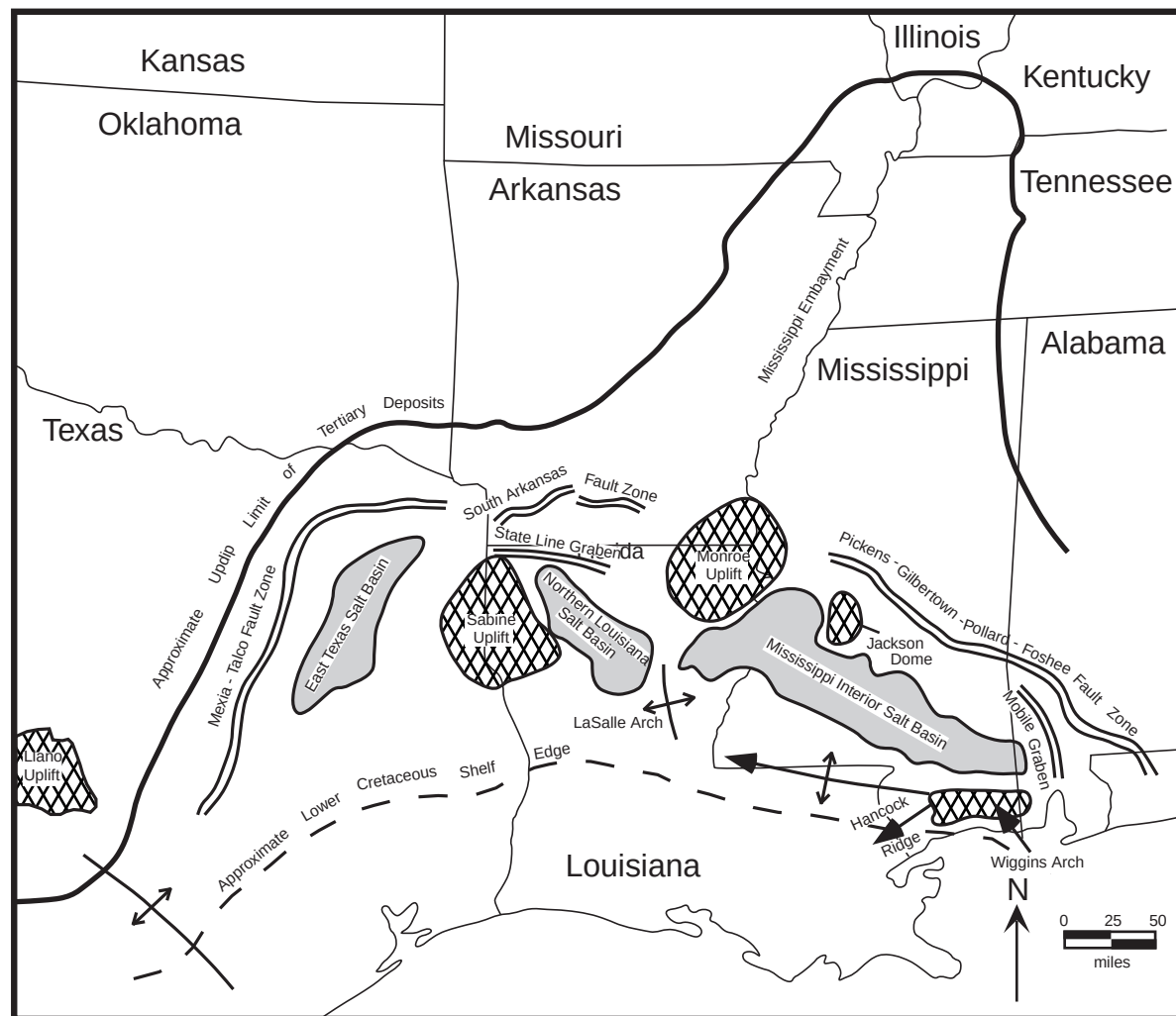


Figure 1. Basins and uplifts in the northern Gulf Coastal Plain. Modified from Pilger (1981).

23-153-20265 BUR HIST

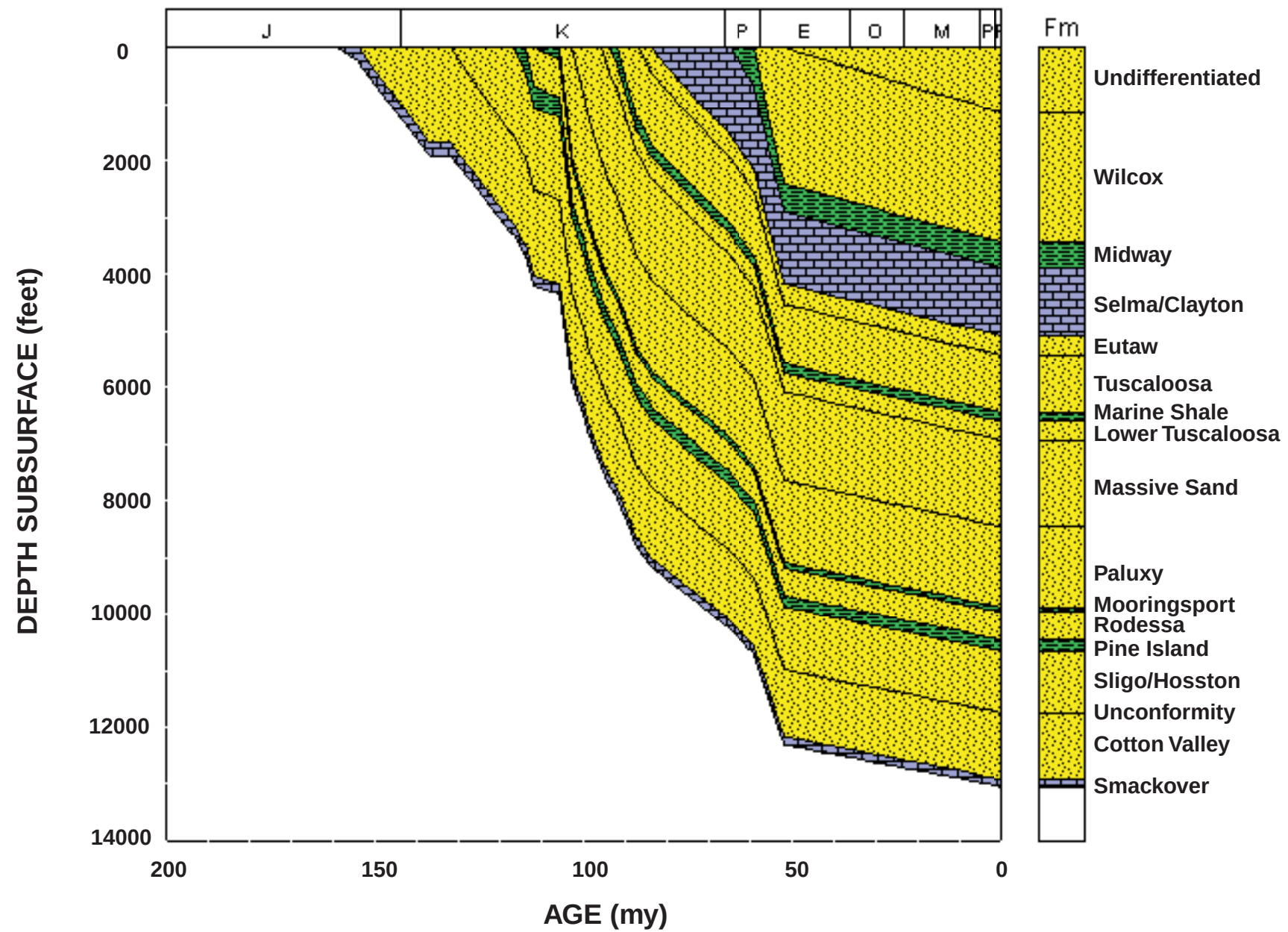


Figure 2. Burial history curve for well API 23-153-20265, located in Wayne County, Mississippi.

23-153-20265 MATURITY

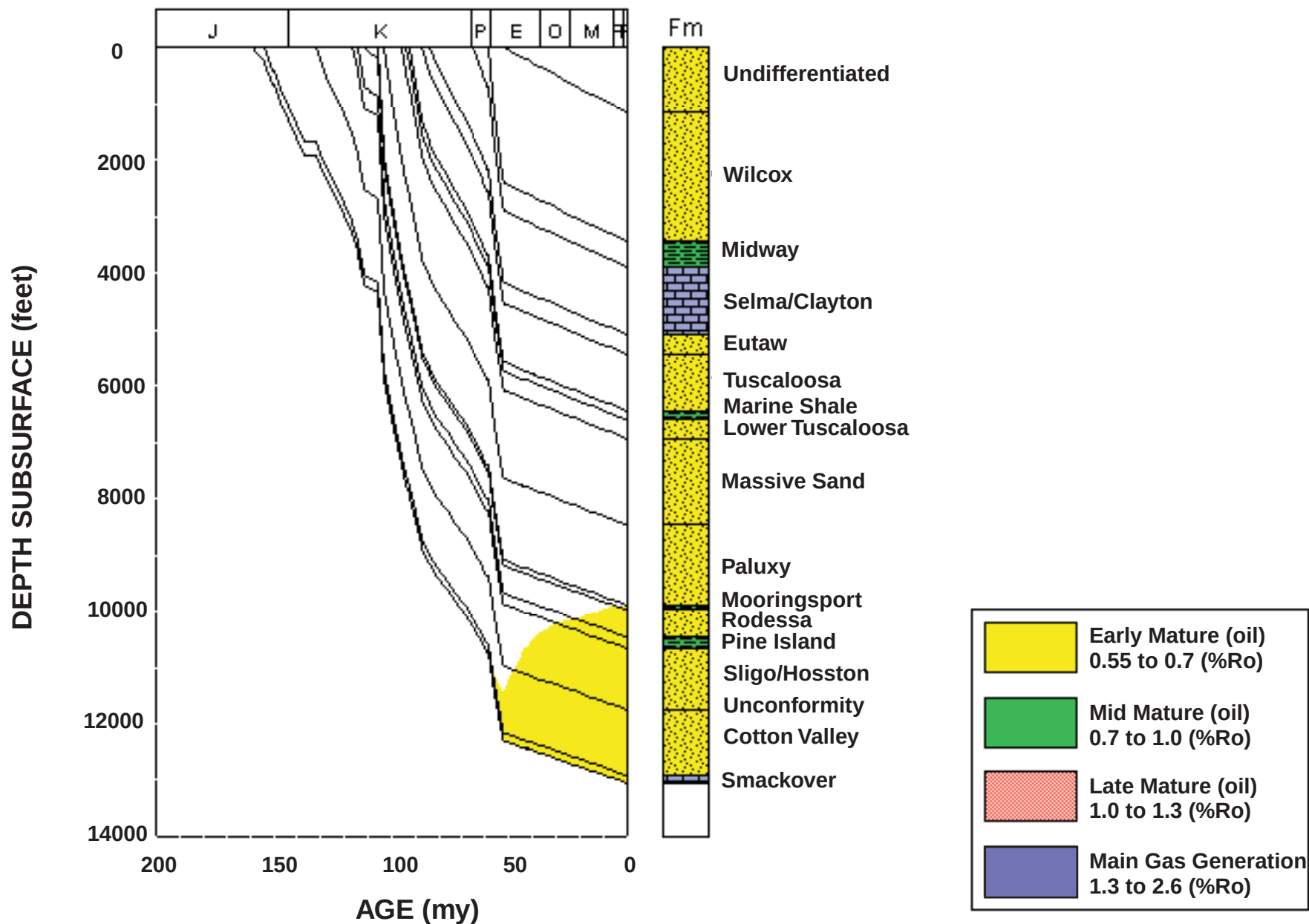


Figure 3. Hydrocarbon maturation curve for well 23-153-20265, located in Wayne County, Mississippi.

CMP=SC;TH=THF;MAT=LL
 TG=1;TI=4;EXP=None;PRM=MKC
 DI=3280.8

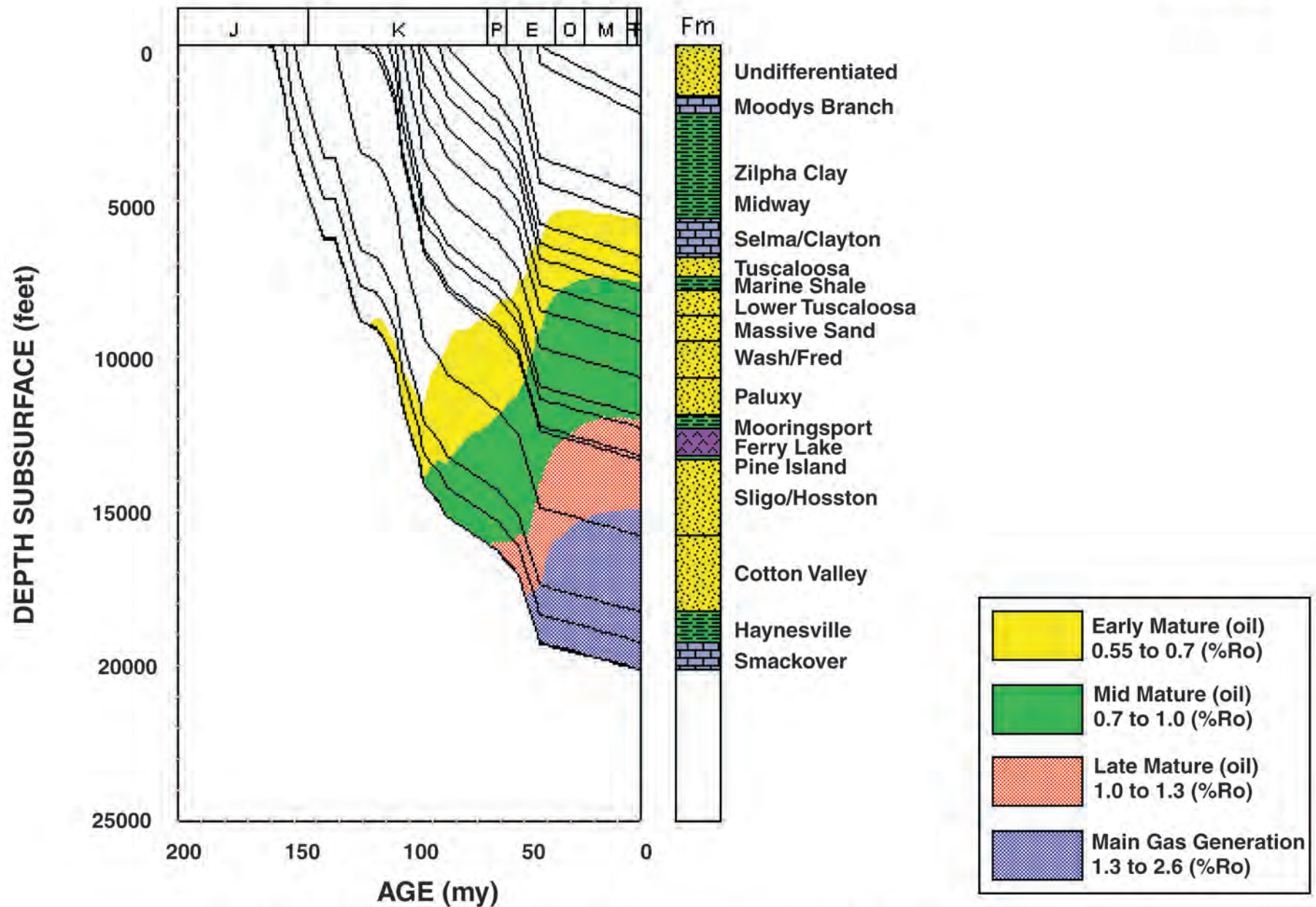


Figure 4. Hydrocarbon maturation curve for well API 23-111-00069, located in Perry County, Mississippi.

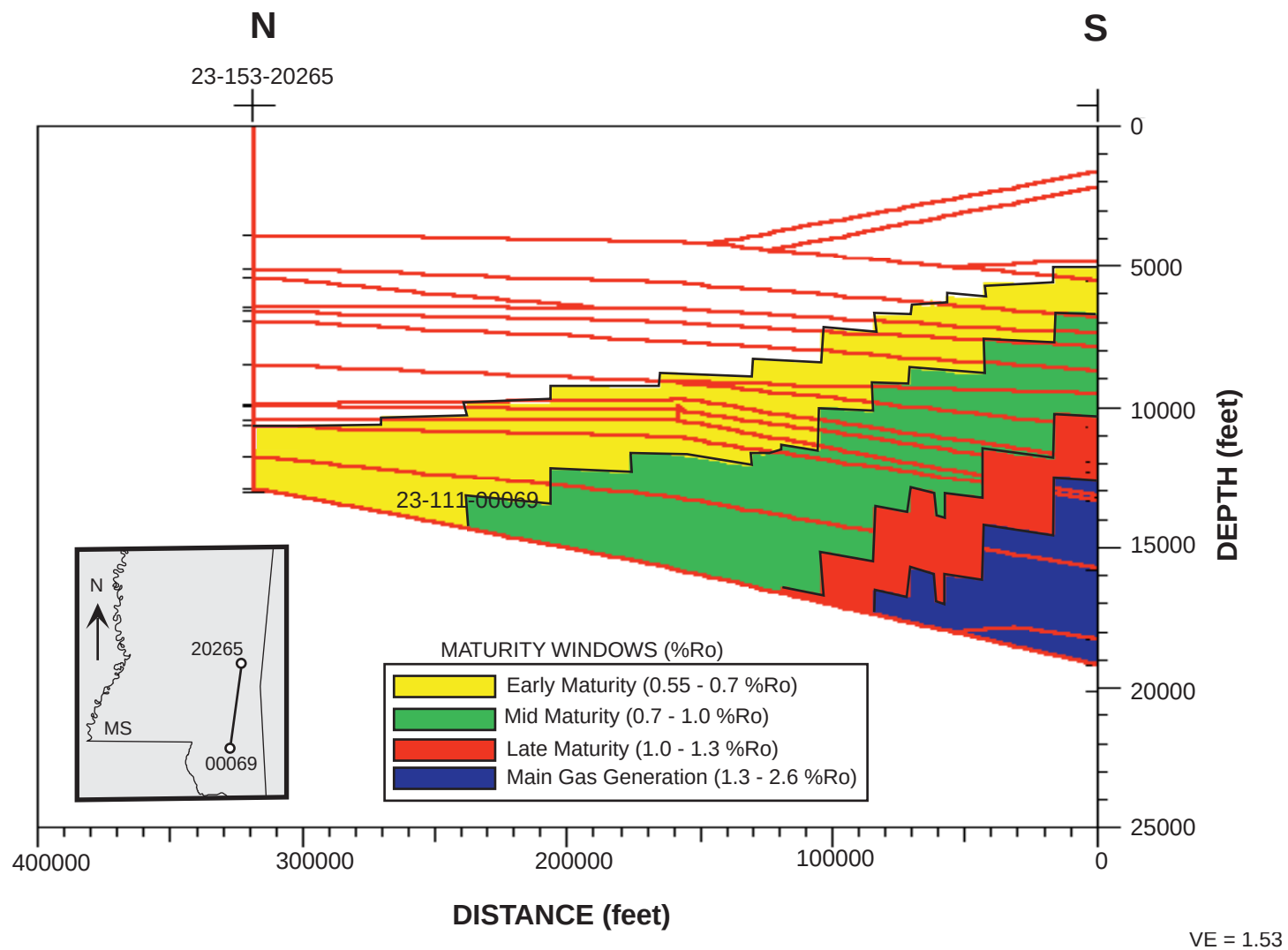


Figure 5. Hydrocarbon generation and maturation trend from Perry County to Wayne County, Mississippi.

Mapping and Visualization of Dolomite “Chimneys” in the Michigan Basin

James R. Wood (jrw@mtu.edu; 906-487-2894)
Michigan Technological University
Houghton, MI 49931)

William B. Harrison (william.harrison_iii@wmich.edu; 616-387-5488)
Western Michigan University
Kalamazoo, MI 49008

Introduction

In the Michigan Basin, long, linear dolomitized zones up to ½ mile wide and as much as 5 miles in length constitute major gas and oil reservoirs. These zones have enhanced porosities and permeabilities and have been referred to as dolomite “chimneys”. These are nearly vertical features, as far as can be determined by the drill, and are nearly 100% secondary (hydrothermal (?)) dolomite. Good examples are Deep River and N. Adams Fields in Arenac County, Michigan (Figure 1). Under favorable conditions these chimneys are prolific producers of hydrocarbons, typically reaching the 1-10 million-barrel range and occasionally much more, e.g. Albion-Scipio. This type of reservoir is not restricted to Michigan, but is found worldwide in carbonate terrain.

In the Michigan Basin these reservoirs are responsible for at least 50% of the reservoir oil (>300 million barrels) produced from the Dundee and Trenton Formations. They are often heavily fractured and occur either off-structure or cut across structure. One popular model for the Michigan chimneys is that they began to form on carbonate ramps under sub-aerial conditions in a karst environment. The joints were dolomitized by ascending hot saline fluids, which may have debauched onto the surface. Evidence for this includes mud-fills in the host carbonate, fluid inclusion data, diagenetic alteration (dolomitization), and lack of alteration in the overlying rock as well as the gross geometry. This study focuses on mapping and visualizing these unique reservoirs on basin and field scales using non-seismic data sources.

Objective

This report covers the first six months of a 36-month study partially funded by the U. S. Department of Energy to characterize fractures in sedimentary basins. The objective of this study is two-fold: (1) to re-examine the dolomite chimneys in Michigan, particularly with respect to fracture patterns, and (2) to develop tools to examine their spatial patterns and orientations on a basin scale.

The major problem with studying Michigan dolomite chimneys is obtaining data. The dolomite zones are difficult to image seismically, and rarely offer any clue to their presence prior to penetration by the drill. Historically, many of the Michigan fields were found by development drilling once a field had been discovered using conventional techniques. Deep River (Figure 2), for example, was “discovered” by deepening the

overlying Stray gas play down to the Dundee (Rogers City) Formation, discovering production in a small anticline there, and then stumbling onto the productive chimney during development. This was not atypical, and Michigan is fortunate that earlier generations of drillers and well-site geologists were expert in detecting these anomalous features and were diligent in recording their occurrence. What they recorded was the first occurrence of “top of porosity” on their scout tickets and driller’s reports. This was essentially the dolomite zone, but was reported as though it was a unique formation top pick. As a result, the data today are archived in hundreds of thousands of paper reports covering drilling activity from the early 1930’s to the present. These first had to be located and rendered into a manageable form. Consequently, a secondary objective of this study was to gather the data in a digital form and organize it in databases. Having done that, it was then necessary to develop means of displaying the data. Although commercial software packages (GeoGraphix, GeoQuest, etc.) are available, they are expensive and require considerable training and administrative overhead. It was decided to develop the visualization aspects of the study in ArcView, a standard GIS package that is versatile and affordable. It was also decided to develop a viewer that users could obtain as freeware or shareware to view the results of this project.

Approach

Data Acquisition

Approximately 55,000 wells have been drilled in Michigan through 1998. About 50-60% of these penetrate the main productive carbonate formations, the Dundee and Trenton Formations, so about 25,000 to 30,000 wells reports may contain references to “top of porosity” in dolomite zones. It is necessary to obtain copies of the scout tickets and driller’s reports for these wells and then go through them recording formation top picks and mentions of “top of porosity”. Sometimes a clue as to the presence of a chimney can be inferred from the geometry of the development wells in a field (Figure 2), but this is not infallible and the only recourse is to manually examine the records. This is complicated by the fact that companies often kept their own records and made annotations that are often the only reference to the dolomite zone. Thus the optimal approach often requires examination of more than one set of reports.

Our approach has been to scan in sets of scout tickets and driller’s reports donated by companies, then transfer the data to a digital database. We have included all relevant field information (operator, driller, dates, initial production, permit number, etc.) as well as all reported formation top picks. Progress to date includes complete information on 30+ fields, including over 3000 top picks. Scanned images of 17,000 scout tickets are available and work is in progress on the driller’s reports.

In addition to the field data, the USGS (U. S. Geological Survey) has over the years made much of their cartographic (roads, streams, cultural features, etc.) data available in digital form. This includes digital elevation models (DEMs) that show land elevation at various scales. We have obtained all the 1/24,000 (7.5 minute quadrangle data for Michigan, as well as all the 1/250,000 scale DEM data. We are in the process of building mosaics of the 1/24,000 data over the entire lower peninsula to help map fractures and fracture

patterns. The thought is that some subsurface lineations might have surface expressions. We intend to map the surface lineations and then overlay the trends of the dolomite chimneys.

Project Description

As mentioned, common practice in Michigan when developing prospects is to map the “Top of Porosity”, essentially the first encounter of the drill bit with diagenetic dolomite. In many Dundee Reservoirs, the main pay zone is altered limestone that occurs off structure. The Deep River Field (Figure 2). is a good example. Here the main reservoir is a diagenetic dolomite lying roughly NW – SE in a trend that is clearly off the structural highs mapped on the Dundee Formation. Tight, unaltered, limestone (“Tombstone”) forms a seal. Where the dolomitization has penetrated through to top of the limestone, the overlying Bell shale forms an effective seal. The discovery well was (the Basin Oil Company & Don Rayburn #1) was drilled as an extension to the previously discovered Brea gas field above. Earlier deepening of the Brea gas wells failed to encounter oil and bottomed in tight, non-productive limestone. Deep River Field was eventually found and developed along the dolomite trend and produced over 26 Mbbbls. of oil, an average of nearly 25,000bbbls per acre, over a period of 56 years from 1943 to present. The maximum number of producing wells was 105 developed on 1060 acres. The average depth to reservoirs was 2800 feet. Porosity averaged 8% with a 60 md permeability. The oil has an API gravity of 35°.

At Deep River, the main dolomite zone is approximately 5 ½ miles striking N 60 W. Detailed mapping (Figure 3) based on development wells shows that it is nowhere more than ½ mile in width. The dolomite strikes along a structural monocline that dips N 30 E and forms the NE flank of the Deep River dome. The dolomite is clearly secondary and is finely crystalline and vuggy. In core the dolomite is massive with sporadic vugs lined with small dark brown crystals and larger white rhombic crystals. Vugs are approximately 1-½ inches in diameter and as much as 5 inches long. There is no evidence of a measurable dip to the dolomite zone and it is assumed to be vertical. The dolomitization is known to continue downward at least 260 below the top of the Rogers City (Figure 4). Oil pay was encountered between 1 and 20 feet below the Bell shale and the original wells reported pay thickness of 11 – 12 feet. These wells were drilled with cable tools and generally flowed oil on the first few feet of penetration, occasionally out of control. Subsequent rotary drilling through the dolomite zone placed the OWC at near –2210 feet subsea and found an average pay thickness of 145 feet. The primary reservoir drive mechanism is thought to be a limited water drive primarily because the GORs are low and have remained fairly constant.

New mapping of the Top of Porosity at Deep River shows that the dolomite zone is more complex than previously realized (Figure 5). The primary dolomite zone lies North of structure as previously mapped, but several branches extend at nearly a mile at right angles to the main zone. The dolomitization pattern is clearly more complex than shown on earlier maps, but as before, none of the dolomitization shows any relation to present structure.

A number of fields similar to Deep River are known to exist, and we are in the process of mapping them in detail. Orientations, characteristic widths and lengths and details of the dolomitization are primary objectives. In addition, placing these features in context of the developing Michigan basin is a major objective. This involves collecting subsurface data on a large number of wells and displaying it in convenient forms. At present, ArcView, a commercial GIS software program and an electronic atlas, developed as parts of this project are the main visualization tools.

Results

The principal results of this project so far are the collection of data and the development of a computer program to work with the data. Both data and the program are available upon request from one of the authors (JRW) and both will be augmented and improved over the course of the project.

It is clear that at Deep River the main production is from fracture-controlled secondary dolomite. The orientation follows one of the principal stress directions in the basin and the porosity development is due entirely to the dolomitization.

Application

The goal of this project is to map the distribution of the known dolomite chimneys in the Michigan Basin and relate them to observed surface fracture patterns. Once this is done it may be possible to use the results to locate areas that might be prospective based on similar characteristics. If successful here, the results could conceivably be transferred to other basins where similar plays are known. As mentioned above, dolomite “chimneys” are not restricted to the Michigan Basin, but occur in many other carbonate-dominated basins.

Future Activities

Future activities include completion of data acquisition, including the scanning and archiving of the paper documents detailing the Michigan Basin wells. The ATLAS software package will be further developed to allow interactive editing of data from schout tickets and driller’s reports on-screen. Most importantly, fracture data, particularly on the field scale, will be compiled and analyzed with respect to chimney orientations and locations. All of these data will be archived and made available to the public on appropriate electronic media, FTP download or CD ROM.

Research sponsored by U. S. Department of Energy’s Federal Energy Technology Center under contract DE-AC26-98BC15100 with Michigan Technological University, 1400 Townsend Drive, Houghton, MI 49931. Mr. Purna Halder is the FETC Contract Officer. The period of performance is from October 1998 through September 2001.

Figure Captions

Figure 1. Index map for Lower Michigan showing location of Deep River and Adams oil fields in Arenac County.

Figure 2. Surface map of Deep River Field, Arenac County, Michigan showing well locations and section boundaries. The NW-SE trending set of wells outlines the dolomite “chimney”.

Figure 3. Detailed structure map of Deep River Field on top of Rogers City Formation. The secondary dolomite trend (labeled) clearly lies off structure. (After MBGS “Oil and Gas Fields of Michigan Basin”)

Figure 4. Cross section AA’ (see figure 3) across Deep River Field showing stratigraphic relations at Deep River and the narrow dolomite zone between the Bauer #7 and Mutch #2 wells. (After MBGS “Oil and Gas Fields of Michigan Basin”)

Figure 5. Contour map of “Top of Porosity” (filled, shaded contours) superimposed on top of structure map contoured on top of Dundee (a.k.a. Rogers City) Formation. The open circles represent IP (initial production) values (bbls/day).

Deep River, Adams, and North Adams Fields, Arenac County

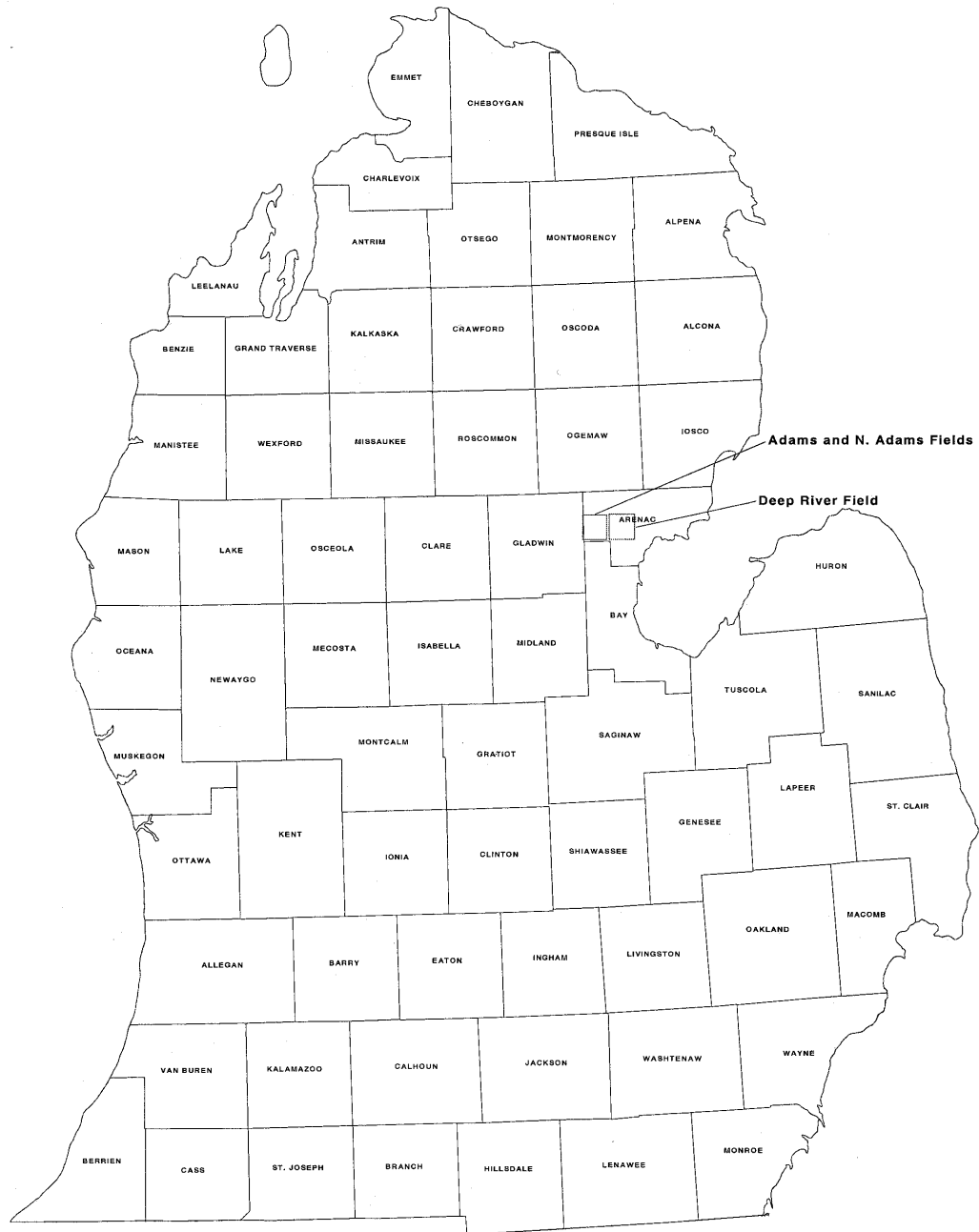


Figure 1.

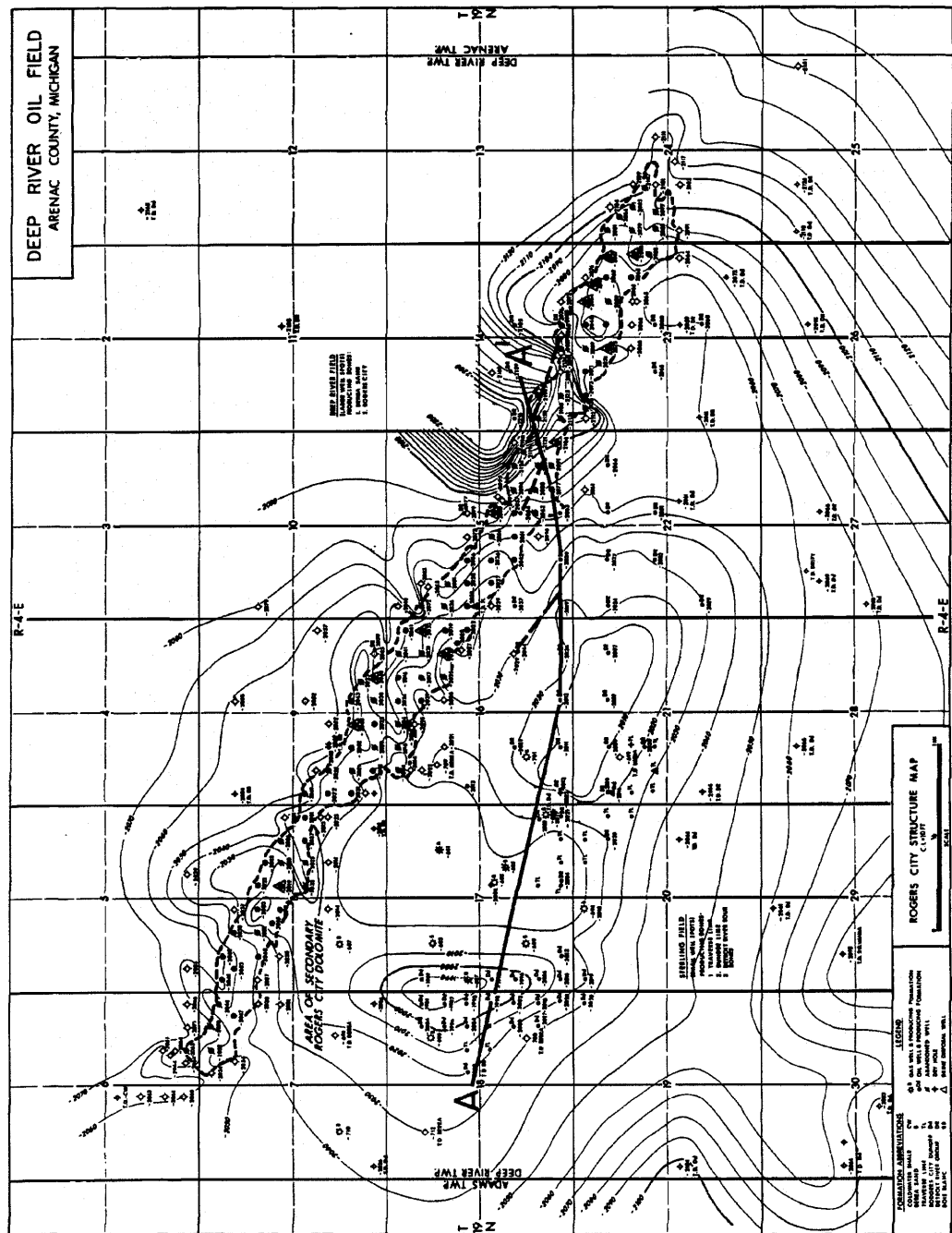


Figure 3.

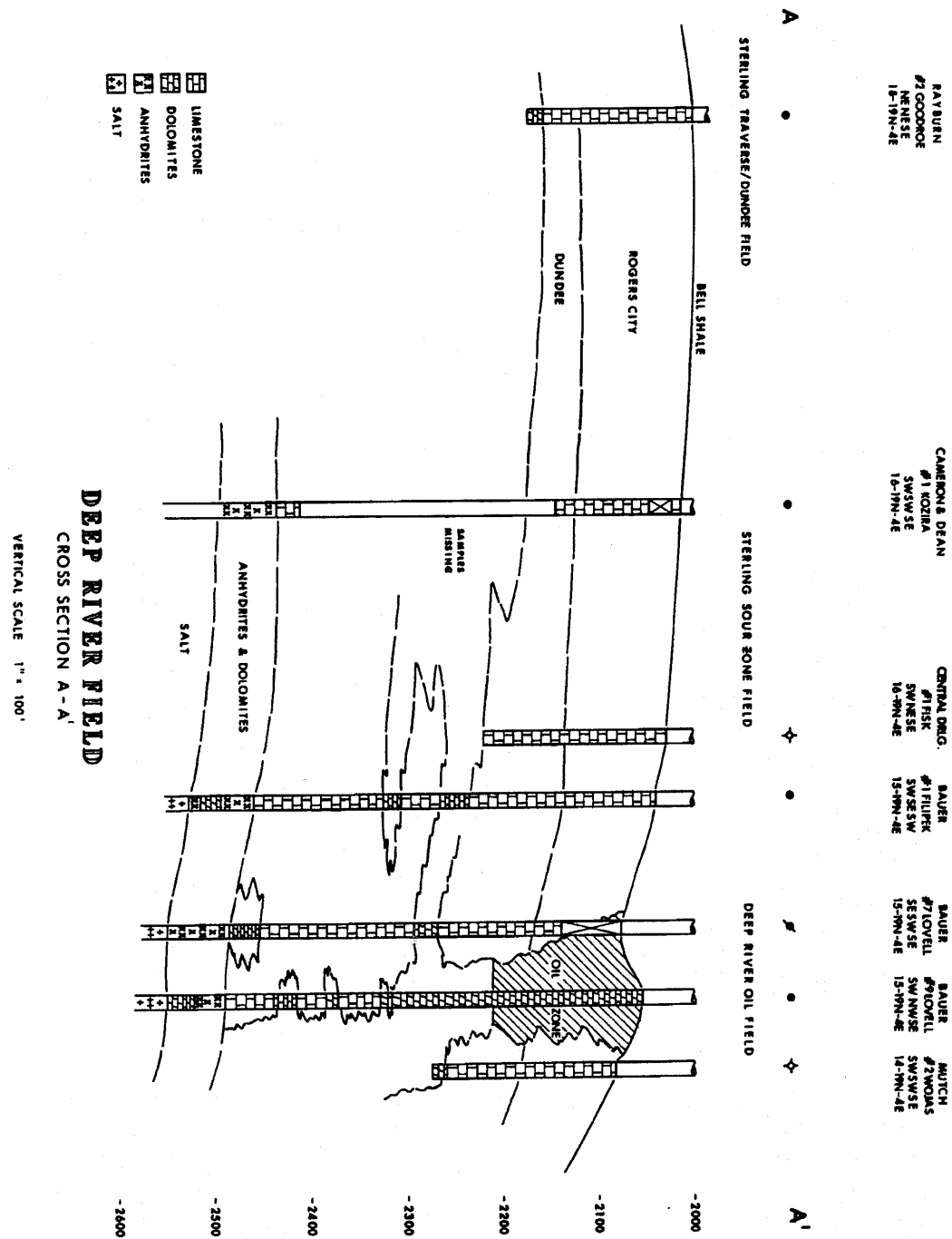


Figure 4.

Deep River Field, Arenac County: Top Porosity

Top Porosity (filled contours), Dundee IP (bubble),
Top Dundee (lines), and Deep River Field Wells

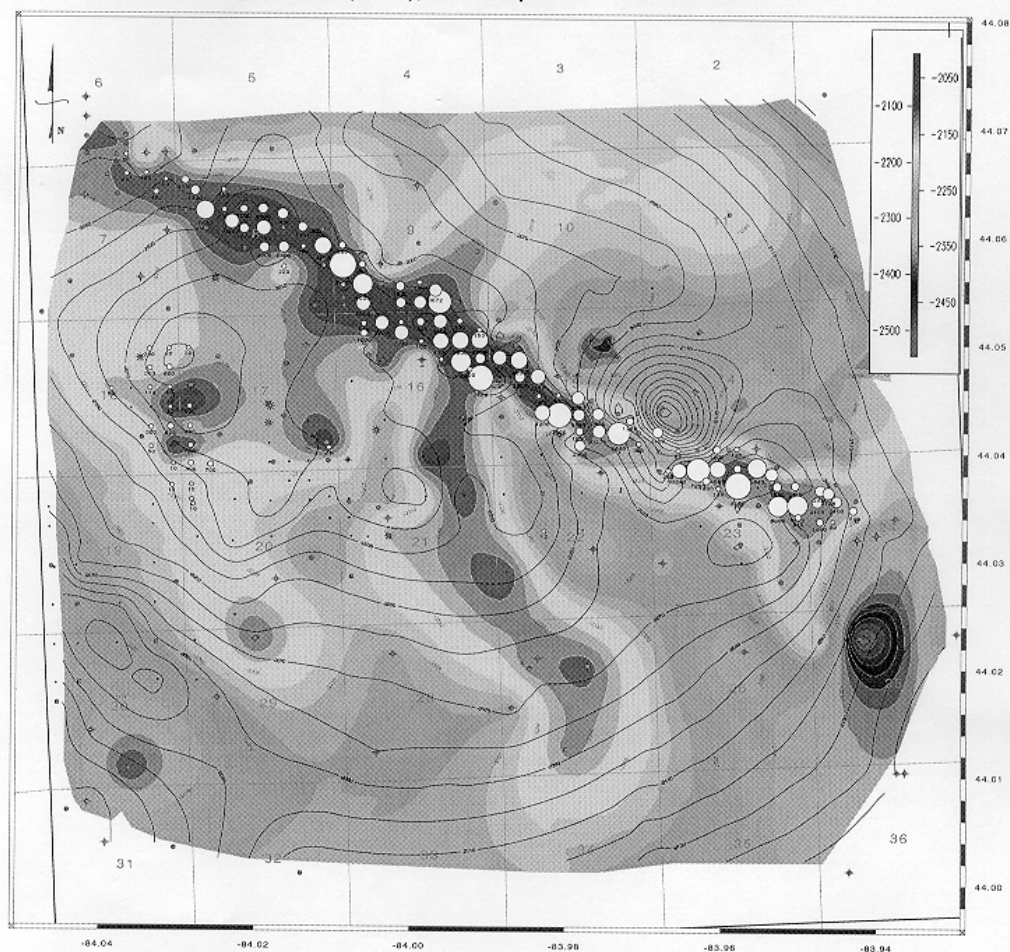


Figure 5.

New Techniques for Using Old Geophysical Logs in Reservoir Characterization: Examples from Bell Canyon Sandstones, Ford Geraldine and East Ford Units, Delaware Basin, Texas

Shirley P. Dutton (shirley.dutton@beg.utexas; 512-471-0329)
Bureau of Economic Geology
The University of Texas at Austin
Austin, TX 78713

George B. Asquith (gicga@ttacs1.ttu.edu; 806-742-3154)
Department of Geosciences
Texas Tech University
Lubbock, TX 79409

William A. Flanders (flanders@apex2000.net; 915-686-7209)
Transpetco Engineering of the Southwest, Inc.
Midland, TX 79701

Jose I. Guzman (jiguzman@mail.utexas.edu; 512-471-1534)
Helena H. Zirczy (hzirczy@mail.utexas.edu; 512-471-1534)
Bureau of Economic Geology
The University of Texas at Austin
Austin, TX 78713

Research sponsored by the U.S. Department of Energy's National Petroleum Technology Office, under contract number DE-FC22-95BC14936 with the Bureau of Economic Geology, The University of Texas at Austin, University Station, Box X, Austin, TX 78713-8924, telefax: 512-471-0140, begmail@beg.utexas.edu.

INTRODUCTION

Many mature oil fields in the United States have old, incomplete logging suites, and special techniques are required to maximize the information that can be derived from the old logs. In a study of the Ford Geraldine and East Ford units for a DOE Class III Oil Recovery Field Demonstration project, we developed a petrophysical approach that integrated traditional log-interpretation techniques with new methods in order to perform quantitative petrophysical interpretations using old logs. The ability to use the old logs was critical to characterizing the sandstone reservoir interval in these mature oil fields.

The Ford Geraldine and East Ford units produce from deep-water turbidite deposits of the Permian Delaware Mountain Group in Reeves and Culberson Counties, Texas (fig. 1). The main reservoir in both units is the Ramsey sandstone in the upper Bell Canyon Formation. The goal of the study is to demonstrate that reservoir characterization can optimize enhanced oil recovery (CO₂ flood) projects in slope and basin clastic reservoirs of the Delaware Mountain Group. The objective is to increase production and prevent premature abandonment of reservoirs in mature fields in the Delaware Basin of West Texas and New Mexico. Current production from Delaware Mountain Group reservoirs is only 14 percent of an original 1.8 Bbbl of oil in place, which provides a clear opportunity for improved recovery.

A key task of reservoir characterization was to quantify and map reservoir properties such as porosity, permeability, water saturation, and net pay in the two units. To accomplish this, we used traditional petrophysical methods combined with new techniques we developed in the Ford Geraldine unit. This petrophysical approach was then used to characterize the East Ford unit, providing an excellent opportunity to test the transferability of the log-interpretation methods to another field in the Delaware sandstone play.

OBJECTIVE

Primary recovery efficiency is low in Delaware Mountain Group reservoirs because of serious producibility problems, particularly low reservoir energy and high water production. Unless methodologies and technologies to overcome these producibility problems are applied, much of the remaining oil in Delaware sandstone fields will not be recovered. Our objective in conducting reservoir-characterization studies of the Ford Geraldine and East Ford units was to provide insights that are applicable to all slope and basin clastic fields in the Delaware Basin.

The technologies used for reservoir characterization included subsurface log, core-analysis, and petrophysical study. Petrophysical analysis was complicated by the incomplete nature of the logging suites in both units. In the Ford Geraldine unit, 118 wells have no porosity logs, and of the remaining 187 wells, 84 of them have only old neutron logs. Only 38 wells have both

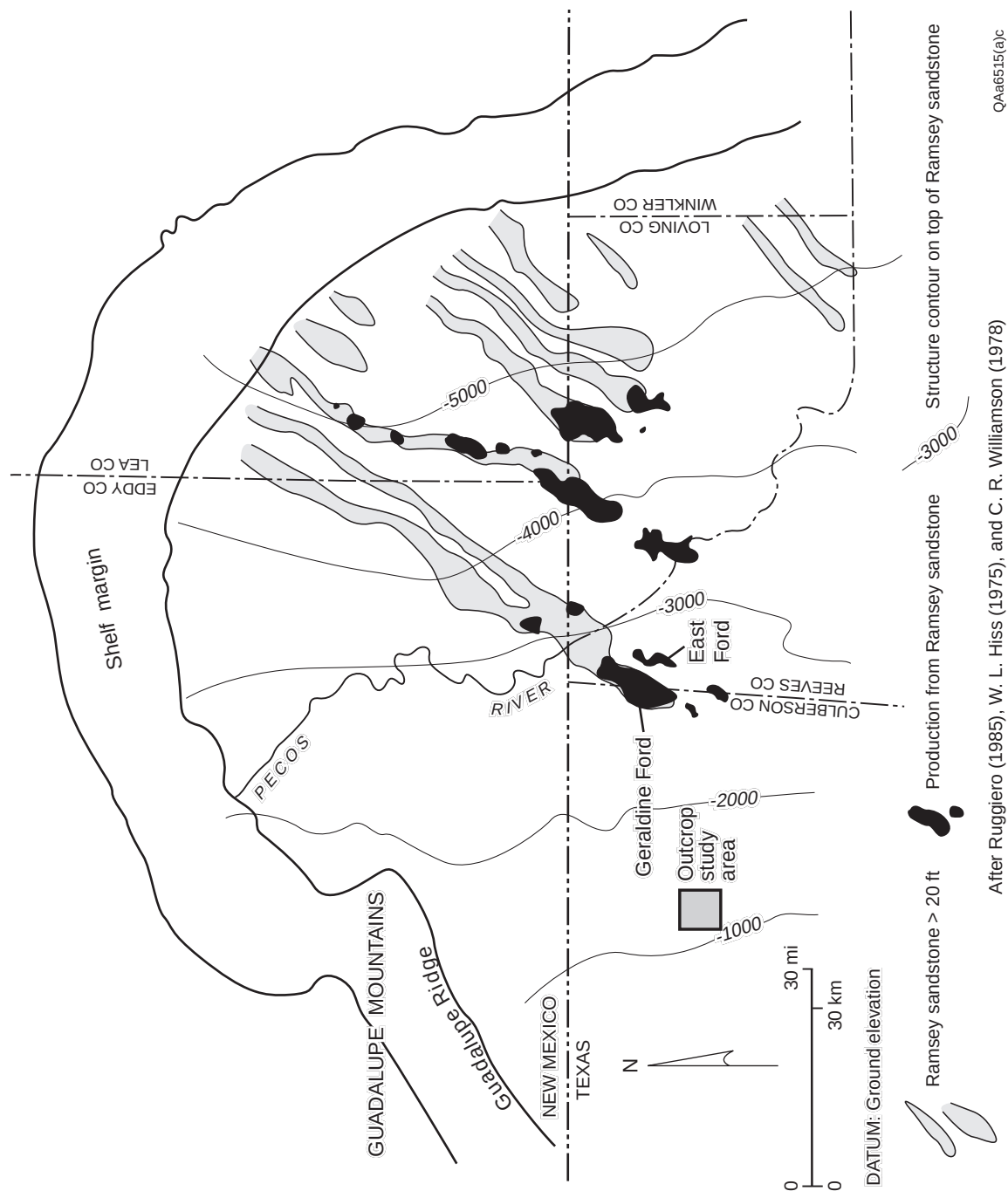


Figure 1. Location of East Ford and Geraldine Ford fields in Reeves and Culberson Counties, Texas. Production from these and other upper Bell Canyon fields in the Delaware Basin occurs from the distal (southwest) ends of east-dipping, northeast-oriented linear trends of thick Ramsey sandstone deposits. Modified from Ruggiero (1985), after Hiss (1975) and Williamson (1978).

porosity and resistivity logs. In the East Ford unit, only 26 of the 45 wells have porosity logs, and only 17 wells have both porosity and resistivity logs. The old gamma-ray and neutron logs were run by many different companies at different scales and sensitivities. Because of these problems, not all of the methods of a modern petrophysical analysis (Asquith and Gibson, 1982) could be used. Thus, the objective of the petrophysical characterization of the Ford Geraldine and East Ford units was to develop a method of log interpretation that would combine traditional techniques with some new methods and allow quantitative petrophysics to be accomplished with the old logs.

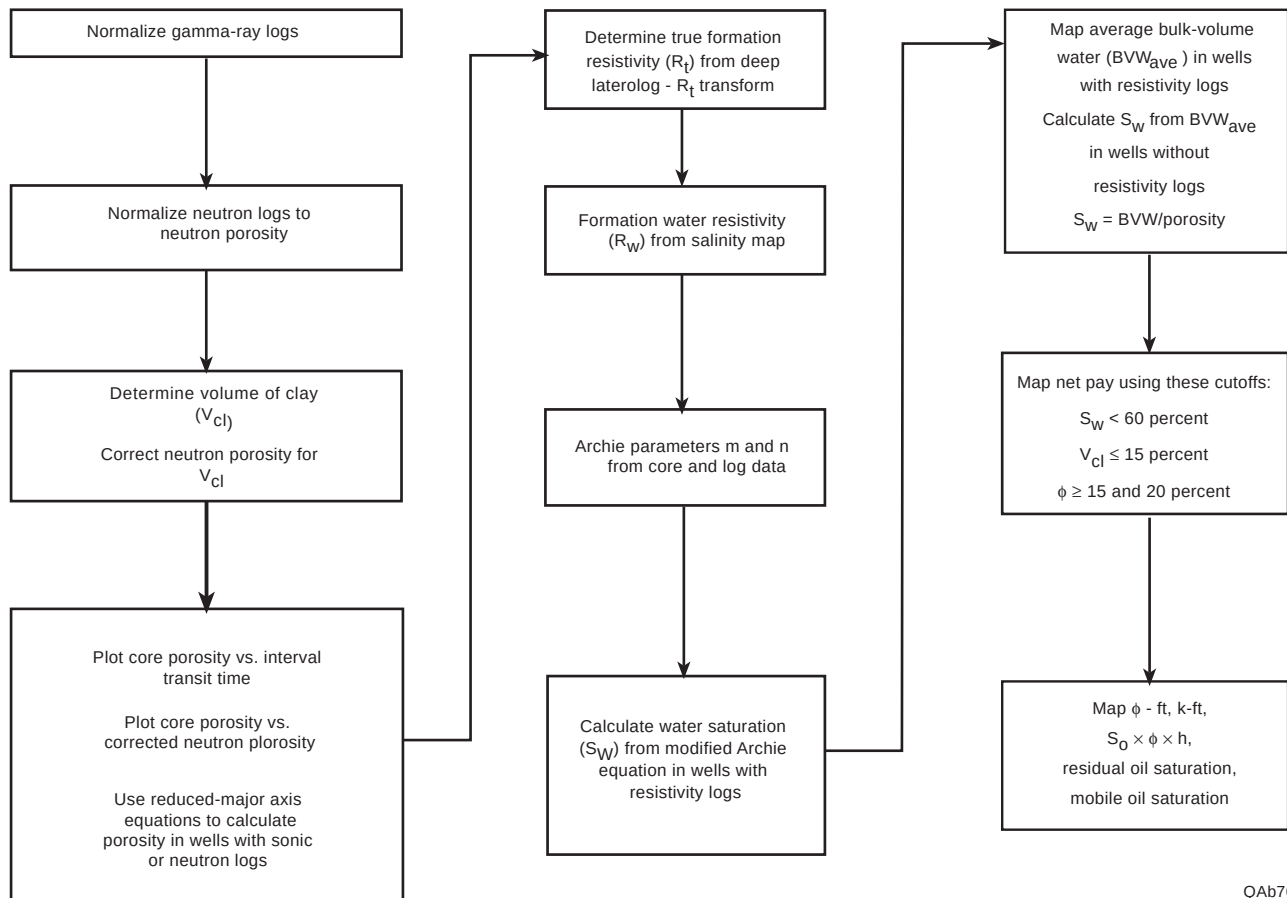
APPROACH

Our approach to quantitative petrophysical analysis using old log suites was developed in the Ford Geraldine unit because of the abundant core and core-analysis data available. We started from traditional methods of log interpretation (Asquith and Gibson, 1982) and integrated them with new methods for (1) determining true formation resistivity (R_t) from Deep Laterologs (LLD) and (2) calculating saturation exponent (n) using core porosity and water-saturation values from relative permeability curves. Much of the approach, but not all, was transferred successfully to the East Ford unit, where the technique was modified to calculate water saturation. In fields like those of the Delaware Mountain Group with poor, incomplete data, there is probably no unique solution to log interpretation that will always be successful. Instead, it is necessary to try a variety of techniques and to test their validity using all available information about the field.

PROJECT DESCRIPTION

Ford Geraldine Unit

Petrophysical characterization of the Ford Geraldine unit was accomplished by integrating core and log data and quantifying petrophysical properties from wireline logs (fig. 2); the goal



QAb7683c

Figure 2. Flow chart of petrophysical analysis of the Ford Geraldine unit.

was a set of maps of porosity, permeability, net pay, water saturation, porous hydrocarbon volume, and other reservoir properties across the unit. The first step in the petrophysical analysis was to construct cross plots of neutron porosity and interval transit time (ITT) versus core porosity in order to determine log-to-core porosity transforms. Core porosity was plotted versus core permeability to derive a porosity–permeability transform equation. Additional tasks included: (1) mapping formation water resistivity (R_w) across the unit, (2) determining the Archie Parameters m (cementation exponent) and n (saturation exponent), and (3) developing a transform for converting resistivity measured by the deep laterolog (LLD) to true formation resistivity (R_t) when a log measuring flushed-zone resistivity (R_{xo}) is unavailable (Asquith and others, 1997).

This approach combines traditional log-analysis techniques with new methods that were developed for this study to compensate for missing data. The approach is presented in detail in Asquith and others (1997) and is summarized later.

Porosity Transforms

Because the old gamma-ray and neutron logs were run by many different companies at different scales and sensitivities, the gamma-ray logs were normalized to API units and the neutron logs to porosity units. The procedure for normalization was similar to that outlined by Barrett (1995). High and low gamma-ray and neutron values were selected for each well, however, so that the normalizing transforms each had different slopes and intercepts.

Because the Ramsey sandstone contains authigenic clays and interbedded organic-rich siltstone, it was necessary to correct for the volume of clay and silt in the calculation of neutron porosity. The clay correction was obtained from gamma-ray responses in clean sandstones versus response in organic-rich siltstones, the closest lithology to shale available in the section. Gamma-ray cutoffs for organic-rich siltstone and clean sandstone were determined at 90 and 40 API units, respectively, by plotting gamma-ray response versus interval transit times (Asquith and others, 1997). The volume of clay (V_{cl}) was then calculated by the following equations:

$$\text{IGR} = (\text{GR} - 40) / (90 - 40);$$

$$V_{\text{cl}} = 0.33[2^{(2 \times \text{IGR})} - 1.0] \text{ (Atlas Wireline, 1985),}$$

where IGR = gamma-ray index and GR = gamma-ray value from log. The V_{cl} was used to correct the normalized neutron porosity by multiplying by $(1.0 - V_{\text{cl}})$ (Asquith and others, 1997).

Interval transit time (ITT) logs and normalized and clay-corrected neutron logs were then correlated to core porosity by reduced major axis regression (Asquith and others, 1997). The resulting equations for porosity are as follows:

$$\text{Porosity (percent)} = (0.59 \times \text{ITT}) - 31.5$$

$$\text{Porosity (percent)} = (1.11 \times \text{clay-corrected neutron porosity}) + 0.67$$

Calculation of Water Saturation

Resistivity logs are electric logs that are used to determine hydrocarbon-versus-water-bearing zones (Asquith and Gibson, 1982). Resistivity logs can be used to calculate water saturation in a formation if several parameters are known, including (1) formation water resistivity (R_w), (2) true formation resistivity (R_t), (3) Archie's cementation exponent (m), and (4) Archie's saturation exponent (n) (Archie, 1942). R_w values were calculated across the Ford Geraldine unit from a map of prewaterflood salinity (Ruggiero, 1985; Asquith and others, 1997). The R_w values at 75°F ranged from 0.11 to 0.18 ohm-m, with the highest values to the southwest.

True Formation Resistivity

Calculating accurate water saturations in the Ford Geraldine unit was difficult because a deep laterolog (LLD) was commonly run without an accompanying log to measure either flushed-zone resistivities (Microlaterolog, MLL or Microspherically Focused Log, MSFL) or invaded-zone resistivities (Shallow Laterolog). These additional logs make it possible to correct the resistivities of the partly invaded zone measured by the LLD to the true formation resistivity (R_t) needed for calculation of accurate saturations. Without our applying this transform, water

saturations in wells with only LLD logs would be overestimated. To overcome this problem, a linear regression transform was developed between R_t (as calculated in 12 Ford Geraldine unit wells having both shallow-resistivity measurement tools run as well as the LLD) and the LLD curve response (Asquith and others, 1997):

$$R_t = 1.3002 \times \text{LLD} + 0.3397.$$

To illustrate the importance of using this LLD– R_t transform to obtain R_t in wells having only an LLD log, hydrocarbon pore-feet thickness was calculated in the Ramsey sandstone in a typical well with and without the correction. When the transform is not used, original oil in place (OOIP) is underestimated by 155,000 barrels in a 40-acre tract (Asquith and others, 1997).

Archie Parameters m and n

Special core analyses from a well in the Ford Geraldine unit (FGU-156) included four measurements of the cementation exponent, m . The average of the measured m values was 1.88. To verify the measured values, log data were used to back-calculate m from ITT porosity and flushed-zone resistivity log values (Asquith and others, 1997). This method gave a value of m of 1.83, which was used in the modified Archie equation for the Ford Geraldine unit.

Special core analyses also measured saturation exponent (n), but the values were low (average =1.32) and probably not accurate. For this reason, a new technique was developed (Asquith and others, 1997) to calculate the value of n using core porosity and water-saturation values from relative permeability curves by the following equation:

$$n = \text{LOG}(F \times R_w/R_t)/\text{LOG}(S_w),$$

where:

n = saturation exponent,

$F = 1/\phi^{1.83}$ (ϕ is porosity),

R_w = formation water resistivity at formation temperature (0.092 ohm-m),

R_t = true formation resistivity ($R_t = 1.67 \times \text{LLD} - 0.67 \times \text{MLL}$), and

S_w = water saturation from relative permeability curves.

Values of water saturation and core porosity are from five samples on which relative permeability was measured (Asquith and others, 1997). The values of S_w represent the point where the relative permeability to water is equal to zero.

Obtaining a value for R_t in the FGU-156 well is impossible because resistivity logs were not run. Instead, R_t values were obtained from the FGU-153 well, which is 1/3 mi to the northeast of FGU-156. Obtaining R_t values from a different well was justified for the following reasons:

1) the wells are close and in the same R_w area; 2) R_t values were only selected from depths with similar porosities in both of the wells; and 3) R_t values in the Bell Canyon sandstones do not vary much.

The value of n that was calculated by using this method, 1.90, is more realistic than the core-measured average value of 1.32 (Asquith and others, 1997). Therefore, for the Bell Canyon sandstones in the Ford Geraldine area, water saturations should be calculated by the following modified Archie equation:

$$S_w = [(1/\phi^{1.83}) \times (R_w/R_t)]^{1/1.90}.$$

Net Pay Cutoffs

Cutoffs to define net pay for the Ramsey sandstone in the Ford Geraldine unit were established for V_{cl} , ϕ , and S_w on the basis of core and log data and published information. Accurate values for V_{cl} are difficult to determine for the Delaware sandstone because of the lack of adjacent shales. Therefore, the selection of a V_{cl} cutoff was based on the work of Dewan (1984), which suggests a V_{cl} cutoff of 15 percent for reservoirs with dispersed authigenic clay. This cutoff was used because of the common occurrence of authigenic clay in the Delaware sandstones (Williamson, 1978; Thomerson, 1992; Walling, 1992; Asquith and others, 1995; Green and others, 1996).

A plot of core porosity versus core permeability for the Ramsey sandstone in the Ford Geraldine unit resulted in the selection of the following ϕ cutoffs:

$\phi \leq 15$ percent for a permeability of 1.0 md

$\phi \leq 20$ percent for a permeability of 5.0 md

Normalization of five relative permeability curves led to the selection of a S_w cutoff for net pay at 60 percent, a value at which the relative permeability to oil is about eight times that of permeability to water. The relative permeability curves were normalized by using the method outlined by Schneider (1987).

East Ford Unit

Reservoir characterization of the East Ford unit provided an opportunity to test the transferability of the log-interpretation methods used in the Ford Geraldine unit to another Delaware sandstone field. Porosity transforms were developed for the East Ford unit, but the LLD- R_t transform and the Archie parameters calculated for the Ford Geraldine unit were used in the petrophysical analysis of the East Ford unit. It was not possible to develop these factors specifically for the East Ford unit because it has a more restricted log suite and no special core analyses.

Only 26 wells in the East Ford unit have usable porosity logs. Four other wells have cased-hole neutron logs (fig. 3), which were not used for quantitative petrophysical analysis. Because interval-transit-time (ITT) logs were the most common, only the 23 ITT logs were used for calculating porosity. Seventeen wells have both ITT and resistivity logs.

The gamma-ray logs in the East Ford unit were run in the early 1960's by several different companies at different sensitivities. They could not be directly compared, even though all but one of the logs were recorded in API units, so the gamma-ray logs had to be normalized. High and low GR values were selected for each well, giving them all different normalizing equations.

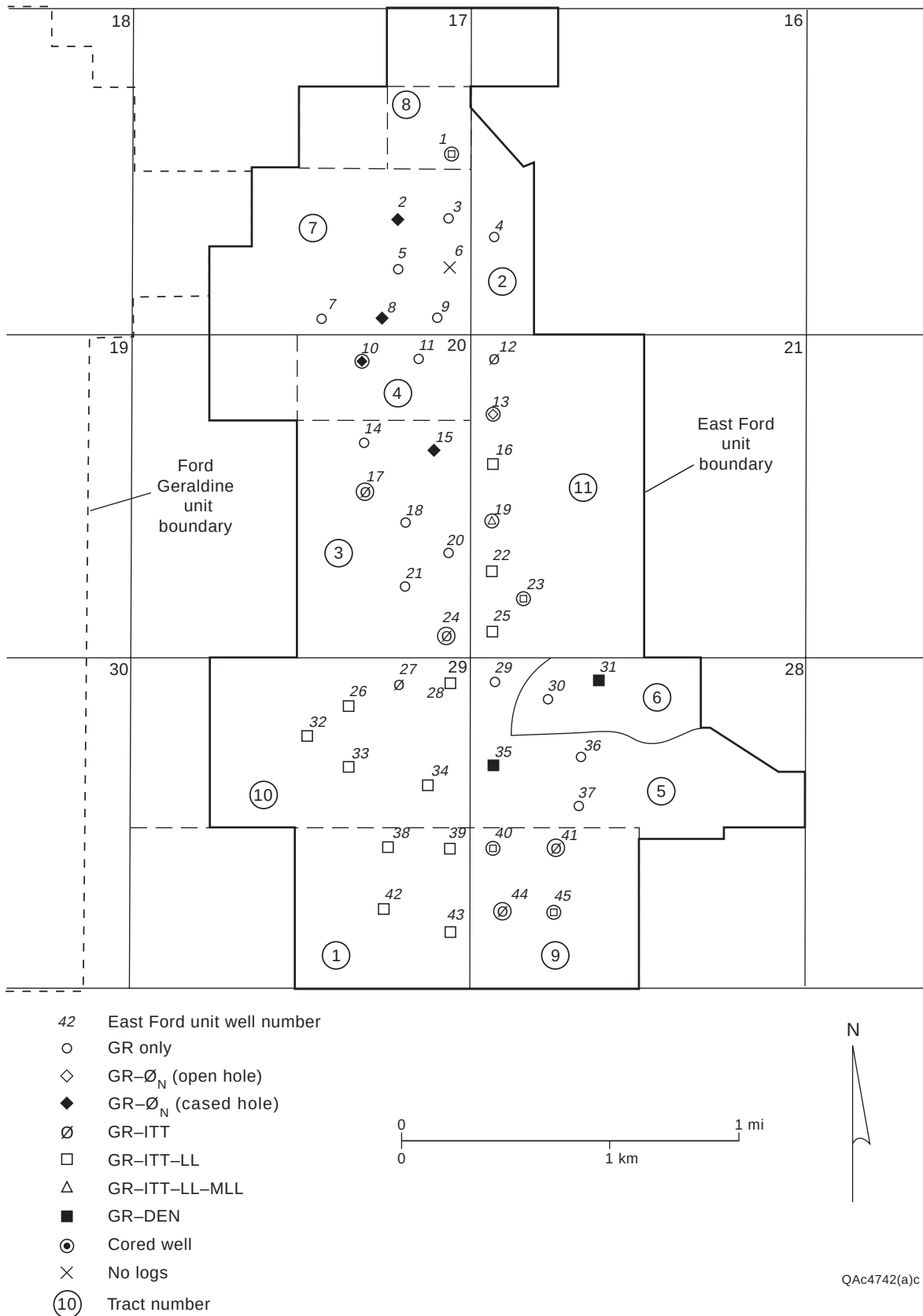


Figure 3. Distribution of geophysical log suites available in the East Ford unit.

Porosity Transforms

Core analyses from 334 samples of the Ramsey interval from 11 wells in the East Ford unit were available, so we derived new porosity transforms instead of using the equations developed in the Ford Geraldine unit. The least-squares linear regression line relating core porosity and permeability is

$$\text{Permeability (md)} = 0.014 \times 10^{(0.144 \times \text{porosity})} \text{ (fig. 4).}$$

Core depths were shifted to log depths by using core-to-log correction factors determined for each cored well. A cross plot of ITT versus core porosity was constructed to determine the ITT-log to core-porosity transform (fig. 5). Several of the ITT logs had zones where the readings went off scale ($>100 \mu\text{sec/ft}$) because of hole washout, and these intervals were omitted from the plot of ITT versus porosity. The reduced-major-axis (RMA) equation relating ITT and core porosity was used to determine porosity in wells having ITT logs. The RMA equation is

$$\text{Porosity (percent)} = 0.533 (\text{ITT}) - 26.5.$$

Because so few ITT logs were available in the East Ford unit, logs from wells with hole washout were used in the petrophysical analysis. ITT values were extrapolated into the washed-out zones from depths where the Ramsey sandstone had good log response, and these extrapolated values were used to calculate porosity from the RMA equation.

Volume of Clay

Volume of clay (V_{cl}) was calculated from gamma-ray logs by the same method as the one used in the Ford Geraldine unit. From a plot of ITT versus normalized gamma-ray response (GR) from 16 wells in the East Ford unit (fig. 6), a GR_{cl} value of 50 API and GR_{sh} of 89 API were selected. The V_{cl} for the Ramsey sandstone was then calculated by

$$IGR = (GR - 50)/(89 - 50), \text{ and}$$

$$V_{cl} = 0.33[2^{(2 \times IGR)} - 1.0] \text{ (Atlas Wireline, 1985),}$$

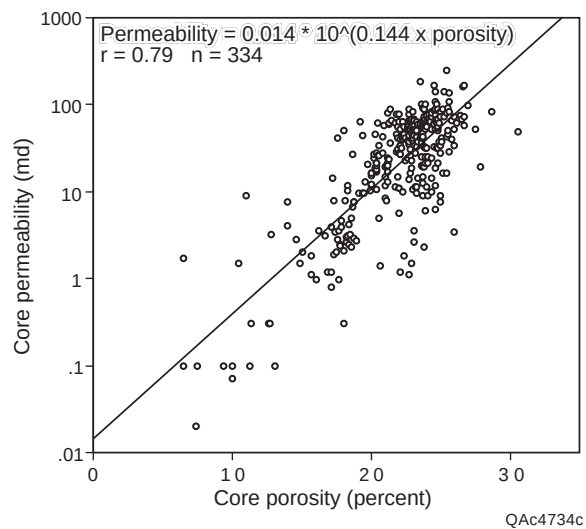


Figure 4. Cross plot of core porosity versus core permeability with porosity–permeability transform for the Ramsey sandstone in the East Ford unit, Reeves County, Texas.

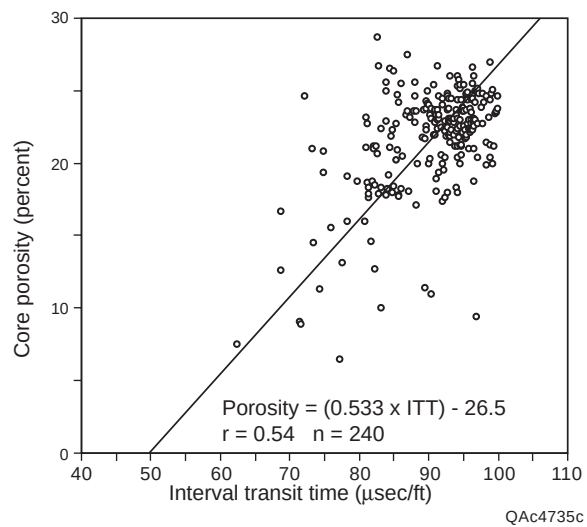


Figure 5. Cross plot of interval transit time (ITT) versus core porosity with porosity transform for the Ramsey sandstone in the East Ford unit.

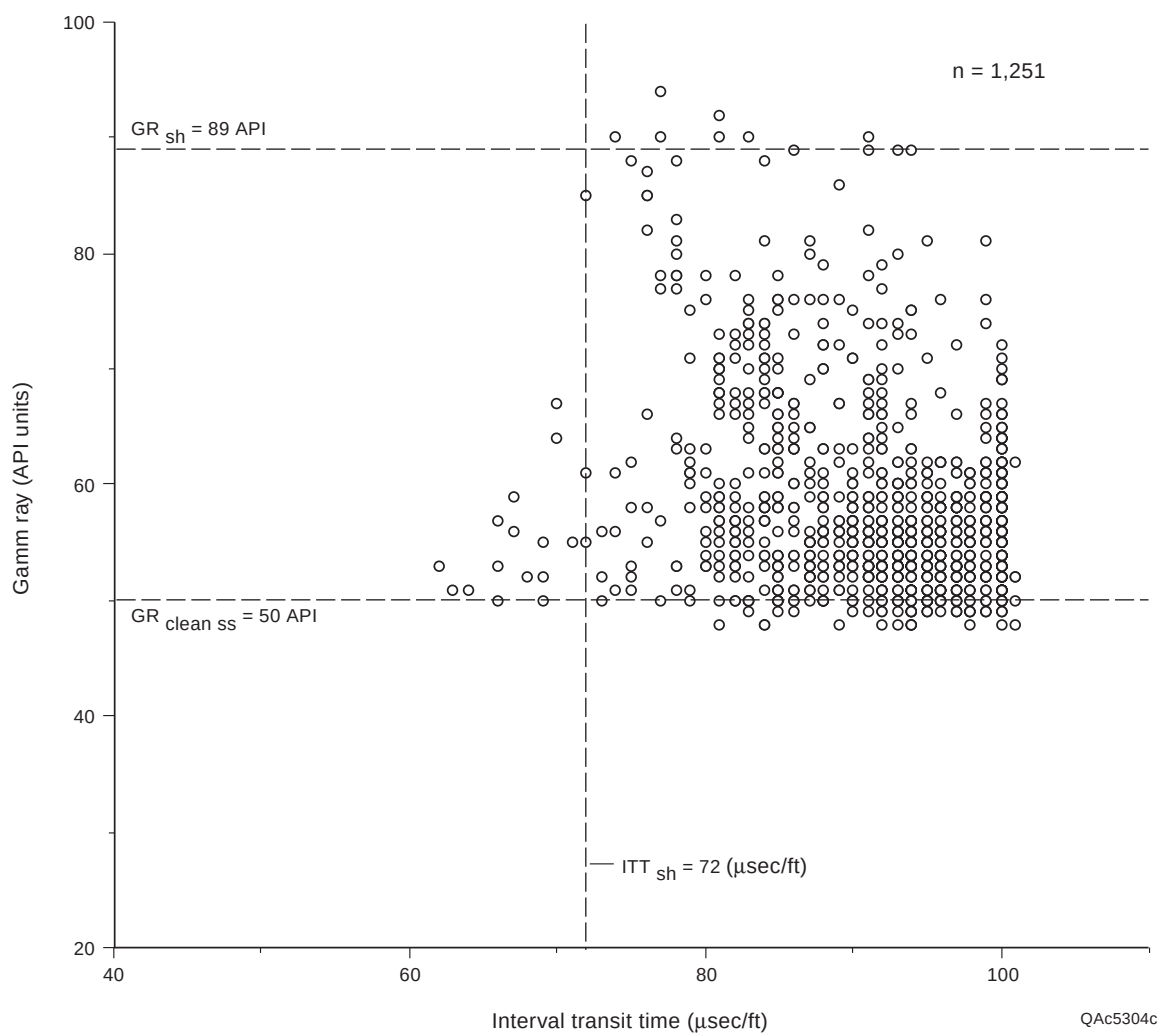


Figure 6. Cross plot of interval transit time (ITT) versus gamma ray (GR) for the Ramsey sandstone interval, East Ford unit. The data in this figure are from 16 wells, and the cross plot was used to determine GR_{cl} (50 API), GR_{sh} (89 API), and ITT_{sh} (72 μsec/ft).

where IGR is gamma-ray index. A map of V_{cl} distribution shows that low values occur in the center of the East Ford unit, and V_{cl} increases toward the margins of the unit, where the Ramsey sandstone pinches out into siltstone.

Calculation of Water Saturation

The same approach for calculating water saturation was followed in the East Ford unit as was developed in the Ford Geraldine unit. Because only one Microlaterolog was run in the East Ford unit, we used the transform developed in the Ford Geraldine unit, $R_t = 1.3002 \times LLD + 0.3397$, to correct LLD to R_t in East Ford wells.

Formation-Water Resistivity

In preparation for calculating water saturations (S_w), we estimated formation-water resistivities (R_w) across the Ford East unit from a contour map of formation-water salinities (fig. 7). Salinity data from four wells in the East Ford unit (EFU 1, 9, 24, and 37) were combined with those from the Ford Geraldine unit (Dutton and others, 1997a, b) to obtain a more regional view of water salinity. The contour map of salinity was used to assign salinity values for each of the East Ford wells. The formation-water resistivity at 75°F was then read from a chart relating NaCl concentration, temperature, and resistivity (Schlumberger, 1995, chart Gen-9, p. 1–5). Values of R_w at 75°F ranged from 0.10 to 0.12 ohm-m in the East Ford unit (fig. 7). Formation temperatures in each well were calculated from the geothermal gradient in the field and the depth of the middle of the Ramsey sandstone. Values of R_w at formation temperature were then calculated by Arp's formula (Asquith and Gibson, 1982): $R_{tf} = R_{temp} \times (Temp + 6.77) / (T_f + 6.77)$,

where

R_{tf} = resistivity at formation temperature,

R_{temp} = resistivity at a temperature other than formation temperature,

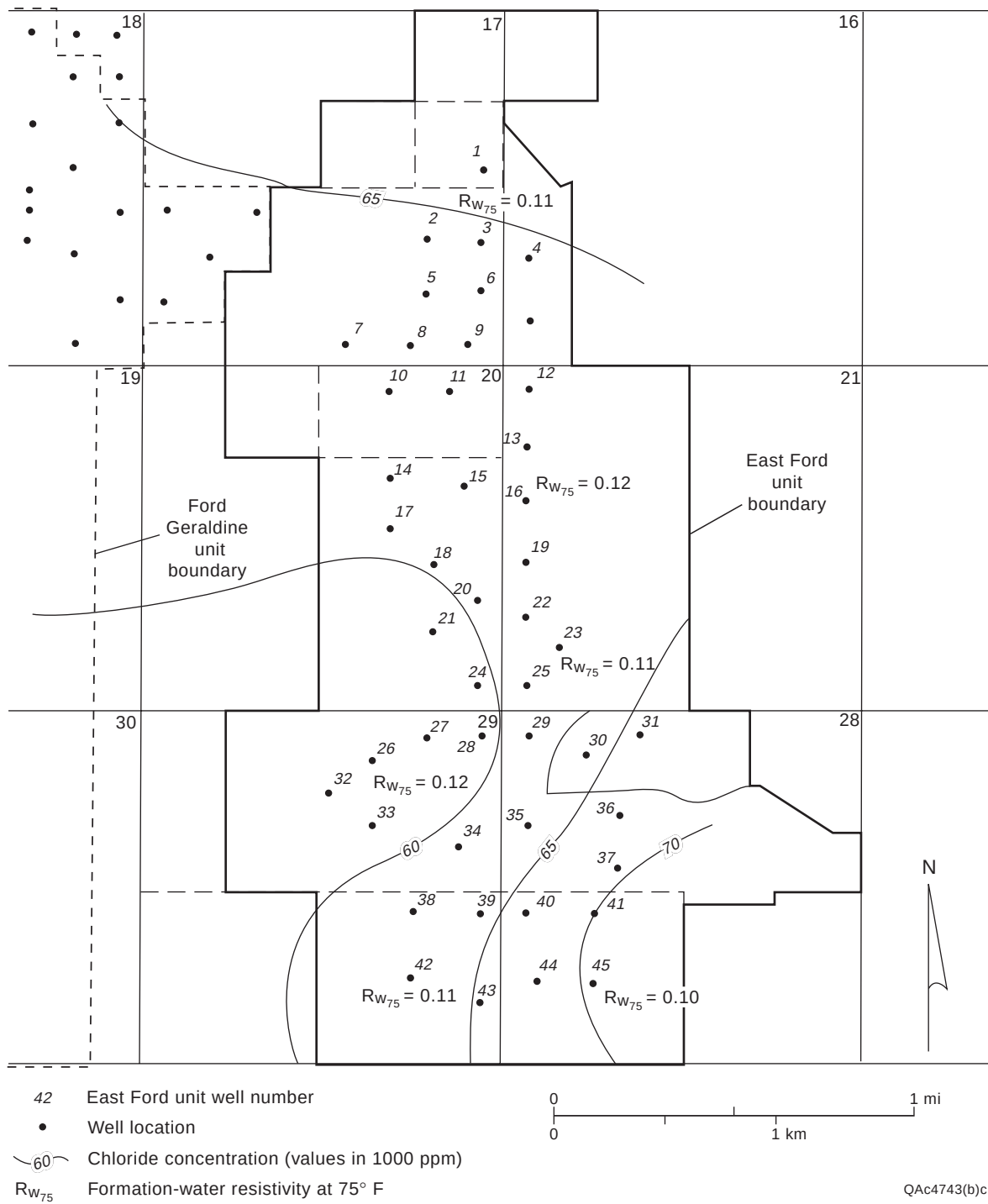


Figure 7. Isosalinity map with formation-water resistivities (R_w) at 75°F for the East Ford unit.

Temp = temperature at which resistivity was measured, and

T_f = formation temperature.

Archie Parameters m and n

No special core analyses of cementation exponent (m) or saturation exponent (n) were available from the East Ford unit, so the values of m and n determined for the Ramsey sandstone in the Ford Geraldine unit (Asquith and others, 1997) were used. Water saturations (S_w) in the East Ford unit were calculated by the same modified Archie equation that was developed for the Ford Geraldine unit:

$$S_w = [(1/\phi^{1.83}) \times (R_w/R_t)]^{1/1.90},$$

where ϕ is porosity.

Net-Pay Cutoffs

Net-pay cutoffs for the Ramsey sandstone in the East Ford Geraldine unit were selected for volume of clay (V_{cl}), porosity (ϕ), and water saturation (S_w). The same V_{cl} cutoff of 15 percent that was used for the Ford Geraldine unit was also applied to the Ford East unit. A porosity cutoff of 17.5 percent, corresponding to a permeability of 5 md (fig. 4), was selected. A change in the slope of the permeability distribution occurs at 5 md, and sandstones having permeability of ≥ 5 md probably represent the floodable Ramsey sandstones (Dutton and others, 1999b). No relative permeability curves were available for the East Ford unit, so the water-saturation cutoff of 60 percent was selected, the same cutoff that was used for the Ford Geraldine unit.

Saturation Distribution

As is common in Delaware sandstone reservoirs, the Ramsey sandstone at the East Ford unit had high initial S_w , and many wells produced some water at discovery. The Ford Geraldine

unit averaged 47.7 percent S_w at discovery, well above the irreducible water saturation of 35 percent (Pittaway and Rosato, 1991), and the Ramsey sandstone at the East Ford unit probably also had initial water saturation greater than irreducible. Average S_w measured in 334 core analyses of the Ramsey sandstones was 47.1 percent.

Areal distribution of S_w was mapped from geophysical log data supplemented by water-saturation data from cores. First, we mapped the areal distribution of bulk volume water (BVW) according to the formula $S_w = BVW_{ave}/\phi$ using log data from wells having both ITT and resistivity logs (method described in Asquith and others, 1997). On the basis of this map, BVW values were then assigned to wells having porosity logs but no resistivity logs. Average S_w values were calculated in these wells then combined with S_w data from resistivity logs to map S_w distribution in the East Ford unit. This approach resulted in many wells in the main producing trend of the field having calculated S_w greater than 50 percent. Such high water saturations were considered unreasonable because water cuts in these wells are low, so a new method for calculating water saturation was developed.

A plot of all log-calculated S_w values versus percent water cut in initial potential tests had a large scatter in the data. Data from some wells were thought to be invalid and were eliminated if the wells fell into one of the following categories: (1) Wells completed only in the Olds sandstone; these wells had high water cuts from the Olds sandstone that could not be equated to the S_w calculated from the Ramsey sandstone. (2) Wells completed in both the Olds and Ramsey sandstones having high water cuts; these wells probably produced mainly from the Olds sandstone. (3) Wells without resistivity logs, for which S_w was calculated from the BVW map; these wells had high calculated S_w values that were inconsistent with their low water cuts. (4) Other wells with inconsistent log S_w and water-cut data. For a few wells, it was unclear why the calculated S_w was high despite a low water cut, but these inconsistent wells were also eliminated from the data base. The remaining data were used to calculate a linear regression line relating water cut to S_w (fig. 8). A map of S_w across the East Ford unit (fig. 9) was then made from the valid log-calculated S_w data (fig. 8) combined with S_w data calculated from the water-

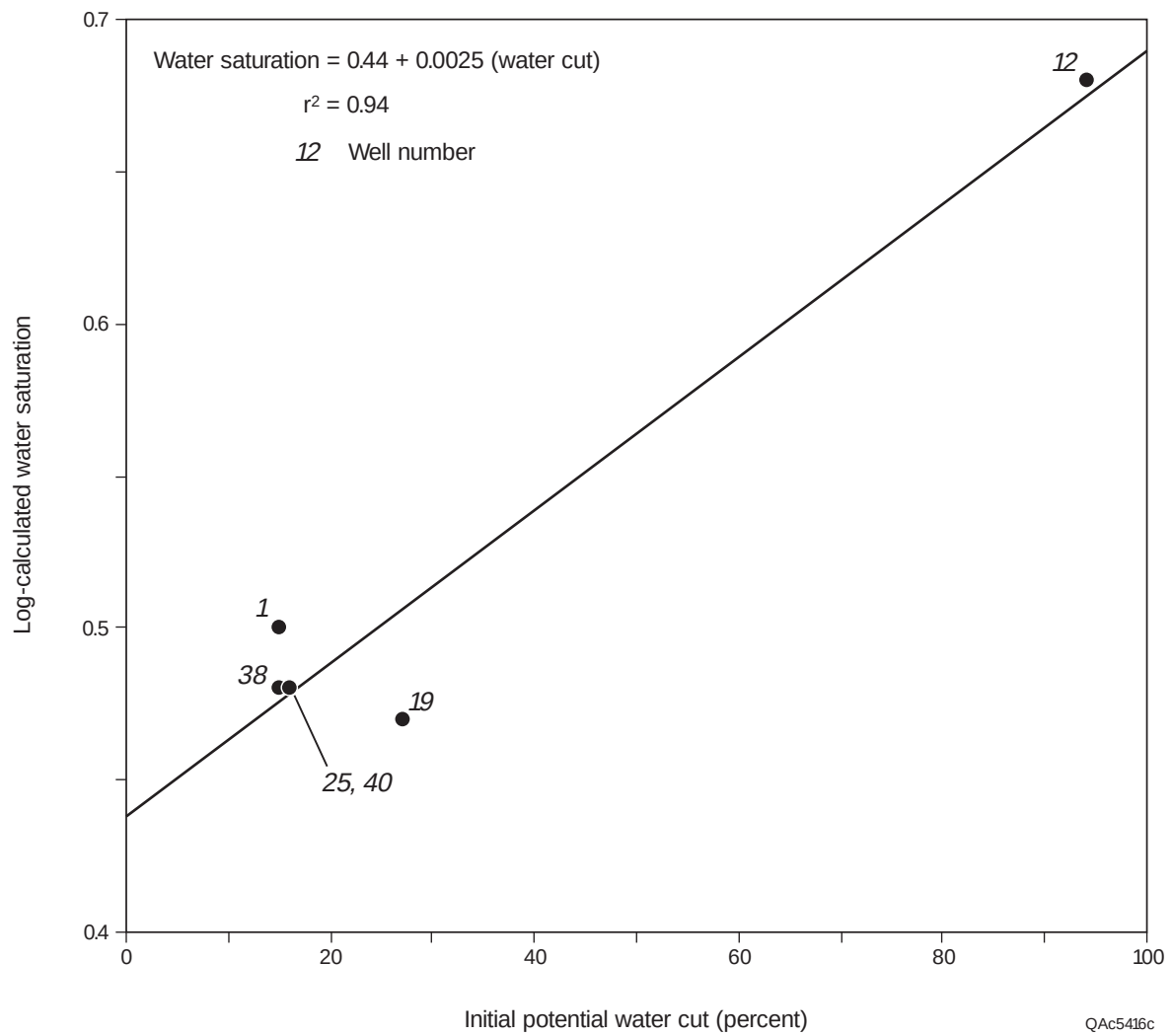


Figure 8. Plot of valid log-calculated water saturation (S_w) versus percent water cut in initial potential tests.

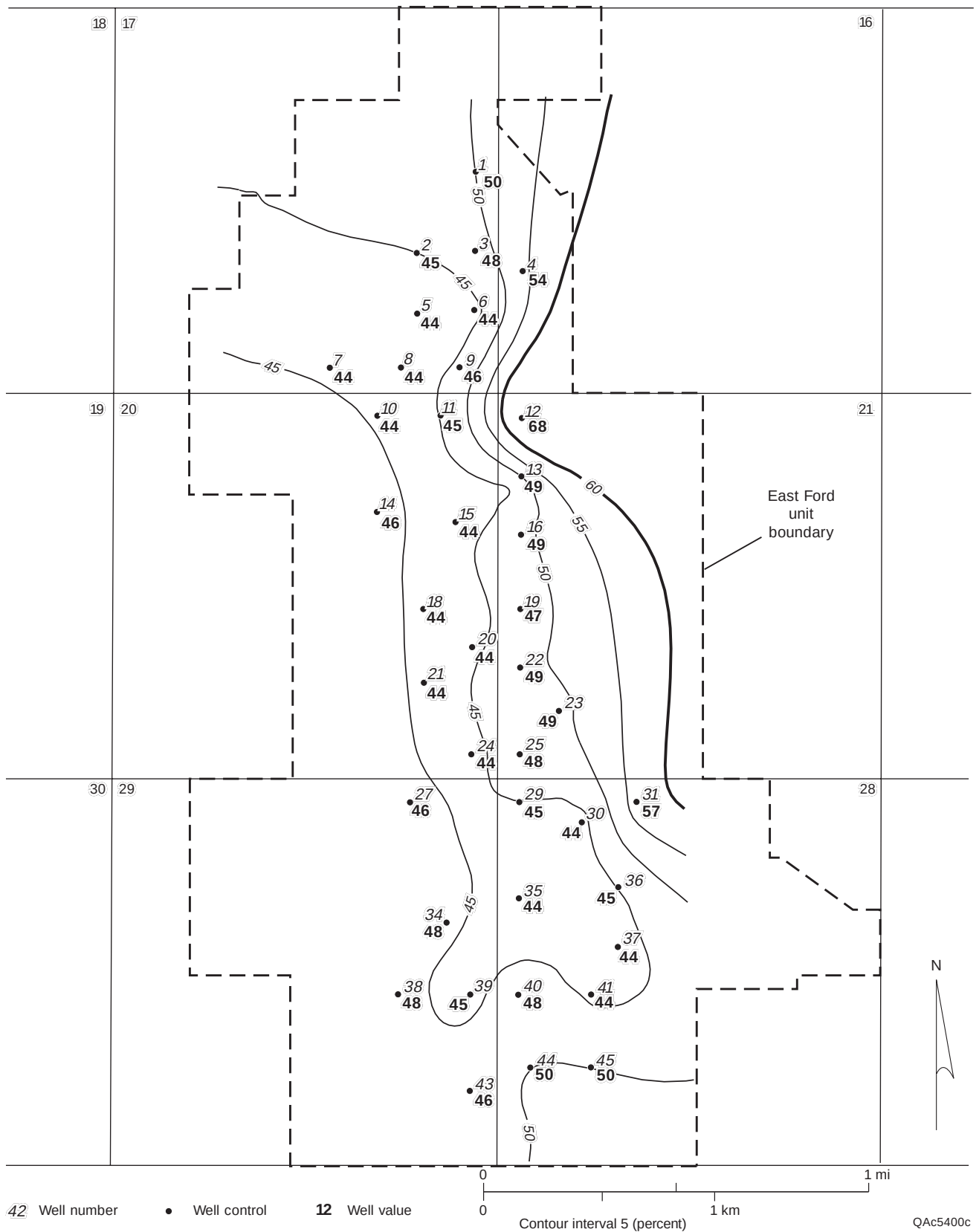


Figure 9. Map of water saturation (S_w) of the Ramsey sandstone in the East Ford unit. The S_w values are either valid log-calculated data (wells in figure 8) or calculated from the water-cut- S_w transform shown in figure 8.

cut– S_w transform. Values of S_w ranged from 44 to 55 percent across most of the field and averaged 48 percent. S_w increases to the east and northeast, which is to be expected because that direction is down structural dip.

RESULTS

Most aspects of the log-interpretation methodology developed for the Ford Geraldine unit were used successfully in the East Ford unit. The approach that was used to interpret water saturation from resistivity logs had to be modified because in some East Ford wells, the log-calculated water saturation was too high and inconsistent with the actual production. In addition, the use of bulk-volume water mapping to determine water saturation in wells having no resistivity logs did not yield results consistent with production. A cross plot of valid log-calculated water-saturation versus water-cut data provided a transform that was used to estimate water-saturation from water-cut data in wells without good resistivity logs.

The ability to do quantitative petrophysical analysis allowed us to map porosity, permeability, net pay, water saturation, porous hydrocarbon volume, and other reservoir properties in both units (Dutton and others, 1997a, b; 1999a) despite having old, incomplete log suites. This information, when combined with the primary production data, allowed us to determine the volume and distribution of remaining oil in place, which is the target of tertiary recovery.

APPLICATION

The approach to petrophysical analysis that was developed in the Ford Geraldine unit can be used in other fields in the Delaware sandstone play, as demonstrated by the successful transfer of the log-interpretation methods to the East Ford unit. Core-analysis and log data from the field being studied should be used to the greatest extent possible, but where they do not exist, the Ford Geraldine values provide a reasonable substitute. For example, if core-analysis data are

available, they should be used to develop core-porosity to log-porosity transforms specific to that field, but in a field having no core analyses, the transforms developed in the Ford Geraldine unit can be used instead. Similarly, if a field has both Laterologs (LLD) and accompanying Microlaterologs, Microspherically Focused Logs, or Shallow Laterologs, an R_t –LLD transform specific to that field should be developed, but if these logs are not available, the Ford Geraldine equation can be used instead. Unless special core analyses have determined m and n in a field, the values determined for these parameters in the Ford Geraldine unit are the best data available, and water saturations should be calculated by the following modified Archie equation:

$$S_w = [(1/\phi^{1.83}) \times (R_w/R_t)]^{1/1.90}.$$

When applying this method of petrophysical analysis to a new field, it is important to compare the results with other field information, such as production data. In fields with poor, incomplete data, there is probably no unique solution to log interpretation that will always be successful. Instead, it is necessary to try a variety of techniques and to test their validity using all available information about the field.

FUTURE ACTIVITIES

In the next phase of this project we will apply the knowledge gained from the reservoir characterization to increase recovery from the East Ford unit through an enhanced-recovery program (CO₂ flood). Detailed comparison will be made between production from the East Ford unit during the CO₂ flood with the predictions that were made during the reservoir-characterization phase on the basis of simulations. This comparison will provide an important opportunity to test the accuracy of reservoir characterization as a predictive tool in resource preservation of mature fields. Through technology transfer, the knowledge gained in the study of the East Ford and Ford Geraldine units can be applied to increase production from the more than 100 other Delaware Mountain Group reservoirs in West Texas and New Mexico, which together contain 1,558 MMbbl of remaining oil.

ACKNOWLEDGMENTS

This research was funded by the U.S. Department of Energy under contract no. DE-FC22-95BC14936 and by the State of Texas under State Match Pool Project 4201 and as part of the State of Texas Advanced Resource Recovery project. The NPTO Contracting Officer's Representative is Daniel Ferguson, and the period of performance is March 31, 1995, through August 31, 2000. The Bureau of Economic Geology acknowledges support of this research by Landmark Graphics Corporation via the Landmark University Grant Program. Drafting was by the Graphics staff of the Bureau of Economic Geology under the direction of Joel L. Lardon. Others contributing to the publication of this report were Susan Lloyd, word processing, and Lana Dieterich, editing.

REFERENCES

- Archie, G. E., 1942, The electrical resistivity log as an aid in determining some reservoir characteristics: *Petroleum Technology*, v. 5, p. 54–62.
- Asquith, G. B., Dutton, S. P., Cole, A. G., Razi, M., and Guzman, J. I., 1997, Petrophysics of the Ramsey sandstone, Ford Geraldine Unit, Reeves and Culberson Counties, Texas, *in* DeMis, W. D., ed., *Permian Basin oil and gas fields: turning ideas into production*: West Texas Geological Society, Publication No. 97-102, p. 61–69.
- Asquith, G. B., and Gibson, C. R., 1982, *Basic well log analysis for geologists*: American Association of Petroleum Geologists, *Methods in Exploration Series*, 216 p.
- Asquith, G. B., Thomerson, M. D., and Arnold, M. D., 1995, The recognition of possible oil and water wettability changes in the Permian Delaware Mountain Group sandstones from petrophysical well logs, *in* Martin, R. L., ed., *In search of new Permian Basin oil and gas fields*: West Texas Geological Society Fall Symposium, Publication 95-98, p. 39–50.
- Atlas Wireline, 1985, *Log interpretation charts*: Houston, Texas, Atlas Wireline Services, Western Atlas International, Inc., 203 p.
- Barrett, D. G., 1995, Use of computers to perform old log analysis, *in* Martin, R. L., ed., *In search of new Permian Basin oil and gas fields*: West Texas Geological Society Fall Symposium, Publication 95-98, p. 31–38.

- Dewan, J. T., 1984, Essentials of modern open-hole log interpretation: Tulsa, Oklahoma, PennWell Publishing Co., 345 p.
- Dutton, S. P., Asquith, G. B., Barton, M. D., Cole, A. G., Gogas, J., Malik, M. A., Clift, S. J., and Guzman, J. I., 1997a, Application of advanced reservoir characterization, simulation, and production optimization strategies to maximize recovery in slope and basin clastic reservoirs, West Texas (Delaware Basin): The University of Texas at Austin, Bureau of Economic Geology, annual report prepared for the U.S. Department of Energy, DOE/BC/14936-9, 187 p.
- Dutton, S. P., Barton, M. D., Asquith, G. B., Malik, M. A., Cole, A. G., Gogas, J., Guzman, J. I., and Clift, S. J., 1999a, Geologic and engineering characterization of turbidite reservoirs, Ford Geraldine Unit, Bell Canyon Formation, West Texas: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 255, 88 p.
- Dutton, S. P., Flanders, W. A., Guzman, J. I., and Zirczy, H. H., 1999b, Application of advanced reservoir characterization, simulation, and production optimization strategies to maximize recovery in slope and basin clastic reservoirs, West Texas (Delaware Basin): The University of Texas at Austin, Bureau of Economic Geology, annual report prepared for the U.S. Department of Energy, DOE/BC/14936-11, OSTI ID: 7432, 106 p.
- Dutton, S. P., Malik, M. A., Clift, S. J., Asquith, G. B., Barton, M. D., Cole, A. G., Gogas, J., and Guzman, J. I., 1997b, Geologic and engineering characterization of Geraldine Ford field, Reeves and Culberson Counties, Texas: The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for the U.S. Department of Energy, 115 p.
- Green, K. M., Frailey, S. M., and Asquith, G. B., 1996, Water-flood feasibility study of the Brushy Canyon K-2 zone Red Tank field, Lea County, New Mexico, in DeMis, W. D., and Cole, A. G., eds., The Brushy Canyon play in outcrop and subsurface: concepts and examples: Permian Basin Section, SEPM, Publication No. 96-38, p. 165–171.
- Hiss, W. L., 1975, Stratigraphy and groundwater hydrology of the Capitan aquifer, southeastern New Mexico and western Texas: University of Colorado, Ph.D. dissertation, 396 p.
- Pittaway, K. R., and Rosato, R. J., 1991, The Ford Geraldine unit CO₂ flood—update 1990: Society of Petroleum Engineers Reservoir Engineering, v. 6, no. 4, p. 410–414.
- Ruggiero, R. W., 1985, Depositional history and performance of a Bell Canyon sandstone reservoir, Ford-Geraldine field, west Texas: The University of Texas at Austin, Master's thesis, 242 p.
- Schlumberger, 1995, Log interpretation charts: Houston, Schlumberger Wireline & Testing, variously paginated.
- Schneider, F. N., 1987, Three procedures enhance relative permeability data: Oil and Gas Journal, March, p. 45–51.

- Thomerson, M. D., 1992, Petrophysical analysis of the Brushy Canyon Formation, Hat Mesa Delaware field, Lea County, New Mexico: Texas Tech University, Master's thesis, 124 p.
- Walling, S. D., 1992, Authigenic clay minerals in sandstones of the Delaware Mountain Group: Bell Canyon and Cherry Canyon Formations, Waha field, West Texas: Texas A&M University, Master's thesis, 63 p.
- Williamson, C. R., 1978, Depositional processes, diagenesis and reservoir properties of Permian deep-sea sandstones, Bell Canyon Formation, Texas-New Mexico: The University of Texas at Austin, Ph.D. dissertation, 262 p.

RIVERTON DOME GAS EXPLORATION AND STIMULATION TECHNOLOGY DEMONSTRATION, WIND RIVER BASIN, WYOMING

Ronald C. Surdam (rsurdam@uwyo.edu; 307-766-4200)

Zunsheng Jiao (jiao@uwyo.edu; 307-766-2703)

Nicholas K. Boyd (mzungu@uwyo.edu; 307-766-4211)

Institute for Energy Research, P.O. Box 4068

University of Wyoming, Laramie, Wyoming 82071

ABSTRACT

The new exploration technology for basin center gas accumulations developed by R.C. Surdam and Associates at the Institute for Energy Research, University of Wyoming, was applied to the Riverton Dome 3-D seismic area. Application of the technology resulted in the development of important new exploration leads in the Frontier, Muddy, and Nugget formations. The new leads are adjacent to a major north-south trending fault, which is downdip from the crest of the major structure in the area.

In a blind test, the drilling results from six new Muddy test wells were accurately predicted. The initial production values, IP, for the six test wells ranged from < one mmcf/day to four mmcf/day. The three wells with the highest IP values (i.e., three to four mmcf/day) were drilled into an intense velocity anomaly (i.e., anomalously slow velocities). The well drilled at the edge of the velocity anomaly had an IP value of one mmcf/day, and the two wells drilled outside of the velocity anomaly had IP values of < one mmcf/day and are presently shut in. Based on these test results, it is concluded that the new IER exploration strategy for detecting and delineating commercial, anomalously pressured gas accumulations is valid in the southwestern portions of the Wind River Basin, and can be utilized to significantly reduce exploration risk and to increase profitability of so-called basin center gas accumulations.

Most importantly, this study strongly suggests that a prime exploration prospect exists in the Riverton Dome 3-D seismic survey area. At this location, the new IER conceptual model and exploration technology can be tested in three tar-

geted formations (i.e., the Frontier, Muddy, and Nugget formations) in a single well. At the prospect, in each of the formations there is an intense velocity anomaly that is 1800 to 1900 ms slower than would be predicted by the regional velocity - depth gradient. A velocity anomaly of this magnitude can only be explained by the presence of significant gas accumulations. *Thus, it is concluded that a well drilled at CDP 124896 in the Riverton Dome 3-D seismic survey is not only an ideal test of the IER exploration technology, but also the highest priority drill site for so-called basin center gas accumulations within the survey area.*

INTRODUCTION

A primary objective of the Institute for Energy Research (IER)-Santa Fe Snyder Oil Company-DOE Riverton Dome project is to test the validity of a new conceptual model and resultant exploration paradigm for so-called "basin center" gas accumulations (Surdam, 1997; see Figure 1). This paradigm and derivative exploration strategy suggest that the two most important tasks crucial to the development of prospects in the deep, gas-saturated portions of Rocky Mountain Laramide Basins are (1) the determination and, if possible, three-dimensional evaluation of the pressure boundary between normal and anomalous pressure regimes (i.e., this boundary is typically expressed as a significant inversion in both sonic and seismic velocity-depth profiles), and (2) the detection and delineation of porosity/permeability "sweet spots" (i.e., areas of enhanced storage capacity and deliverability) in potential reservoir targets below this boundary (Figure 1). There are other critical

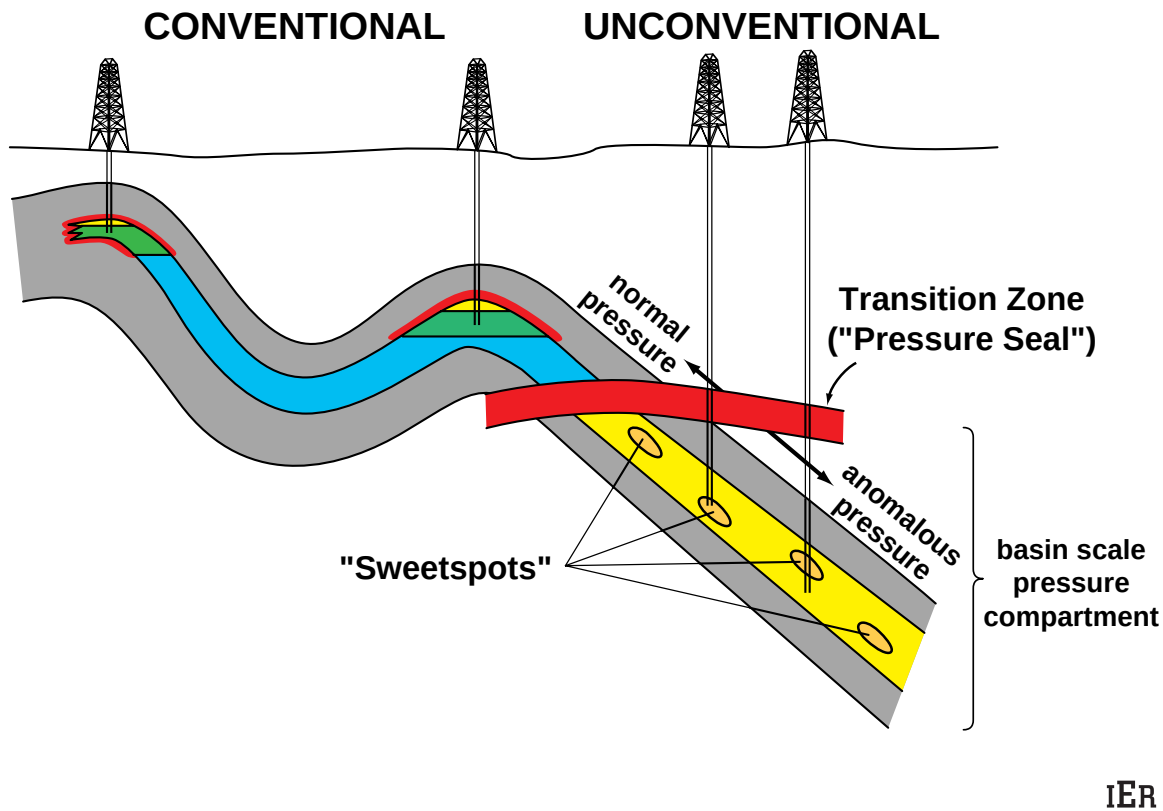


Figure 1. Conceptual model for basin-center, anomalously pressured gas accumulations. Key elements are (1) the regional pressure seal expressed as a sonic or seismic velocity inversion (i.e., regional boundary that separates normally pressured rocks above from anomalously pressured rocks below), and (2) production sweet spots below the regional pressure seal (i.e., domains characterized by enhanced porosity and permeability). Blue is fluid that is dominantly water (simple phase); yellow is fluid containing a significant free gas phase (multiphase) and red are capillary seals.

aspects in searching for basin center gas accumulations, but completion of these two tasks is essential to the successful exploration for the unconventional gas resources present in anomalously pressured rock/fluid systems in the Rocky Mountain Laramide Basins (RMLB).

The southern Wind River Basin, in particular the Riverton Dome area, is a neat location for testing this exploration paradigm (Figure 2). Preliminary work within the Wind River Basin has demonstrated that there is a regionally prominent pressure surface boundary that can be detected by inversions in sonic velocity-depth gradients in individual well log profiles (Figure 3) and that can be seen as a velocity inversion on seismic lines (Figure 4). Also, the Wind River Basin in general — and the Riverton Dome area specifically — are characterized by a significant number of anomalously pressured gas accumulations (Figure 5). Most importantly, Santa Fe Snyder Oil Company

has provided the study with sonic logs, a 3-D seismic study (40 mi²), and a variety of other necessary geological and geophysical information.

DATA SET AND METHODOLOGY

The most important portion of the available data set is the 3-D Riverton Dome seismic study, for it allows not only a three-dimensional velocity evaluation, but it also facilitates the application of new and/or modified existing technologies developed at IER to detect, visualize, and delineate basin center gas accumulations.

In this study, Echo Geophysical-processed seismic data were used as the basis for the velocity analysis. The processing stream included true amplitude recovery, surface consistent deconvolution, time variant spectral whitening, statics and applied residual statics. The data were summed in 500 × 550 ft bins with maximum offsets of 15,000 ft and then

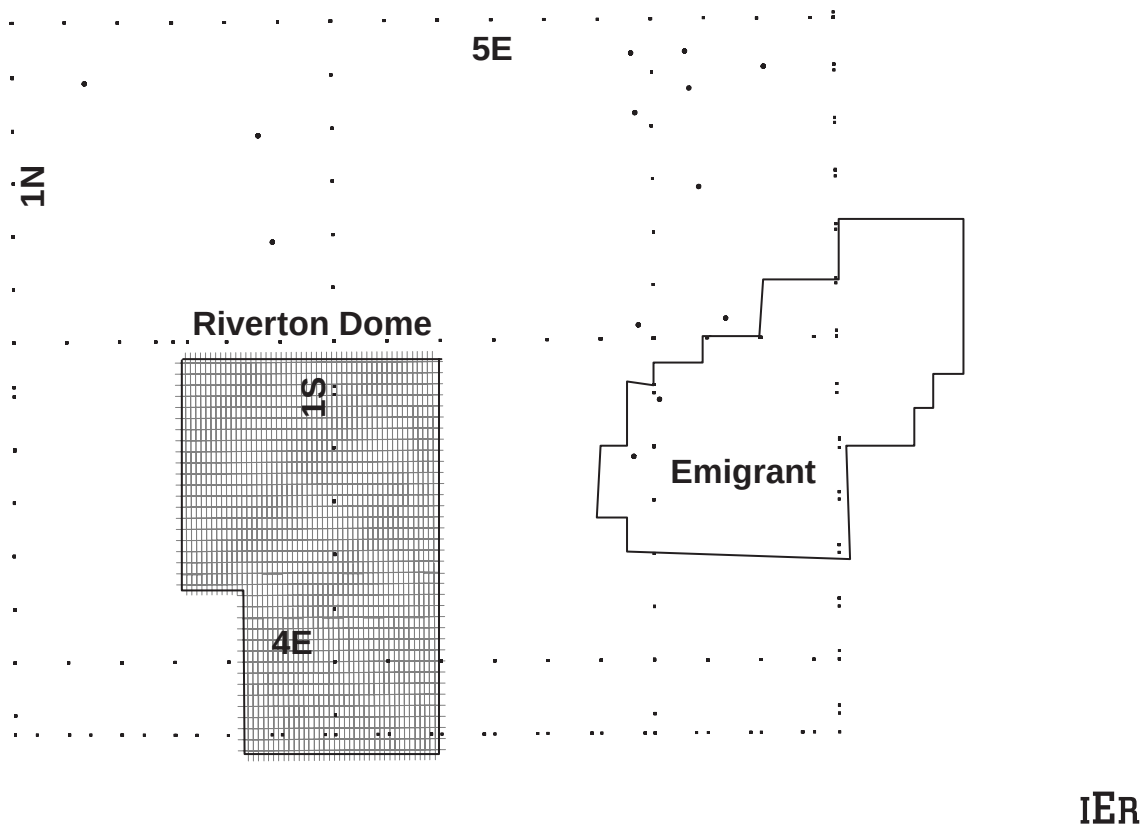


Figure 2. Index map for the Riverton Dome area, Wind River Basin, Wyoming.

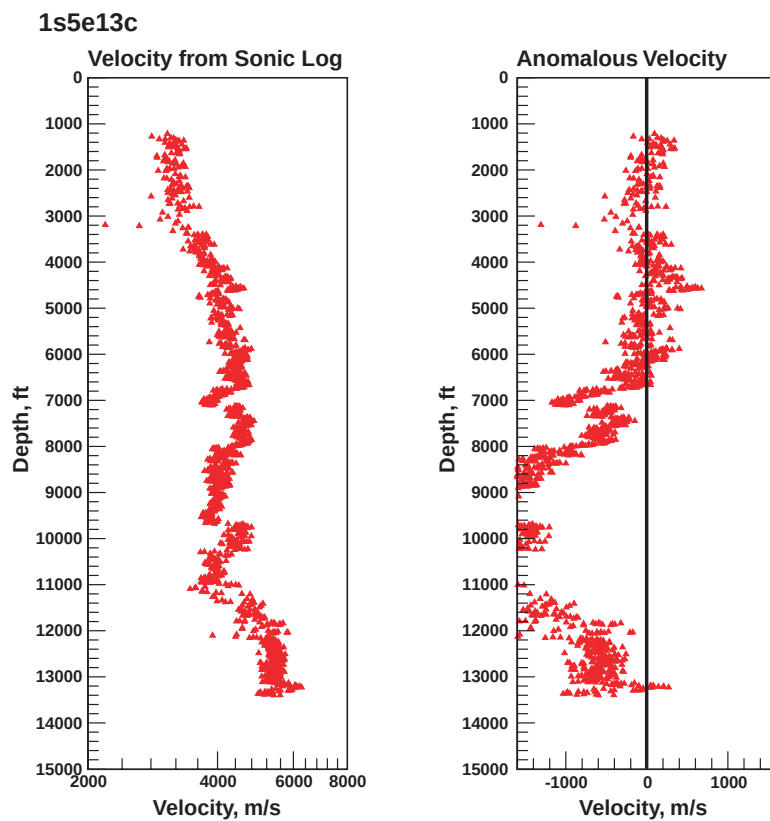


Figure 3. Sonic velocity log, and anomalous sonic velocity-depth profile after removal of normal regional velocity-depth gradient. This example is from within the Riverton Dome 3-D seismic survey area.

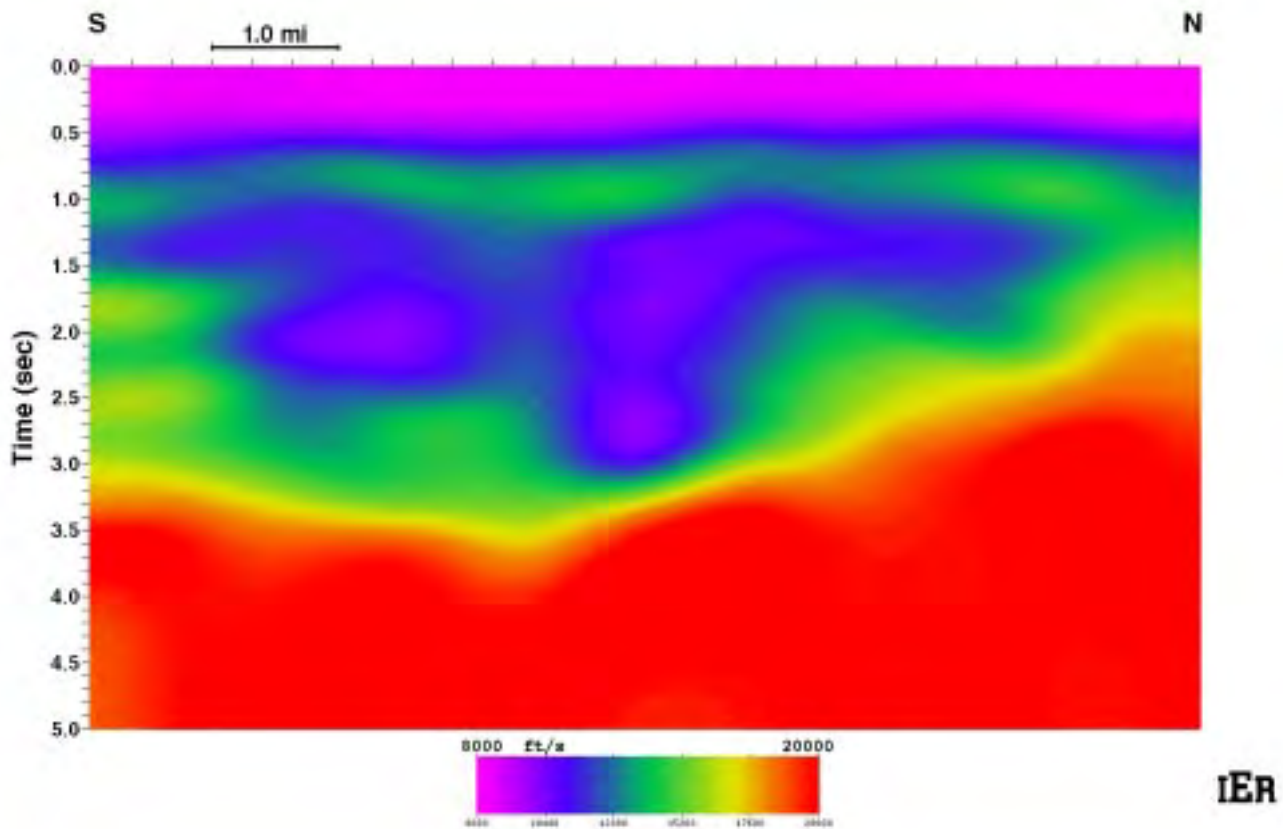


Figure 4. 2-D seismic interval velocity profile from a seismic line from the area north of the Riverton Dome area. Top of the regional pressure surface boundary is at the color change from green to blue at approximately 1.0 sec TWTT.

input into the ProMAX velocity analysis program.

In more detail, the Riverton Dome 3-D survey consists of 382 end lines and 577 cross lines. The end lines typically are separated by 100 ft and the cross lines are separated by 110 ft. For the purposes of this study, the velocity analysis was done on every tenth end line (i.e., 1000 ft intervals) and at every ninth cross line (i.e., 990 ft). The vertical sampling for the velocity study was done at 100 ms intervals. In contrast, commercial processing for velocity constructions typically utilize a grid of every 25th end line (i.e., every 2500 ft) and a sample point at every 50th cross line (5500 ft). Thus, the sampling grid utilized in this study (i.e., 60 points per end line) was considerably closer than in typical commercial processing (i.e., 10 to 11 samples per end line).

Thus far in the study, the two tasks accomplished include (1) the evaluation and construction of the velocity field in the Riverton Dome area

according to the sampling strategy outlined above, and (2) isolation of anomalously slow velocity domains. Task 2 was accomplished by subtracting the normal regional velocity-depth gradient from the observed velocity-depth profile at 1620 sample points (i.e., CDP's; see Figure 6) in the Riverton Dome 3-D survey. A typical normal velocity-depth gradient for the study area was determined by modelling the compaction trend-sonic velocity-depth profile relationships from nearby well logs from within or from nearby well logs in the study area (Figure 3). In summary, the anomalous velocity profiles (Figures 7A - 7C) and volume (Figure 8) are the result of removing the typical regional normal velocity-depth profile from the observed velocity-depth gradients at each of the 1620 sample points. As noted in Figures 7A through 7C, the match with depth (or time) between anomalous seismic interval velocity and anomalous sonic velocity are not exact. The velocity-time gradients shown in Figures 7A - 7C are from

Anomalous Velocity Model of the Mesaverde Group Southwest Wind River Basin

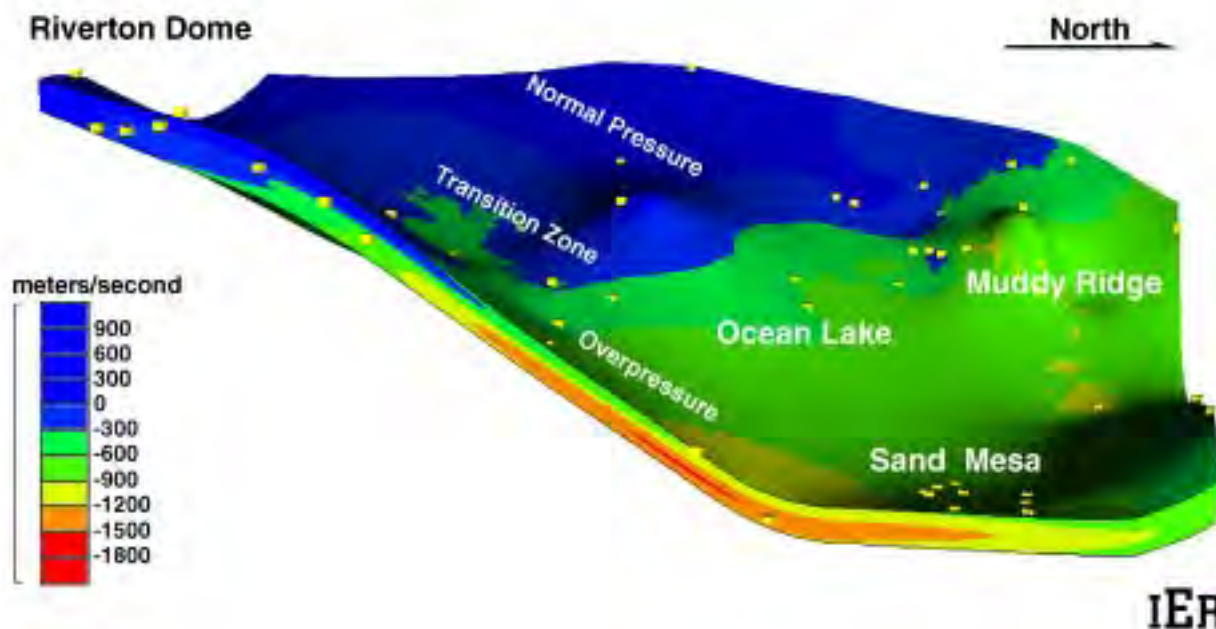


Figure 5. Three-dimensional anomalous sonic velocity model for the Mesaverde Group stratigraphic unit in the southwestern portion of the Wind River Basin, Wyoming. Model illustrates normal, transitional and anomalously pressured domains within the Mesaverde and locations of hydrocarbon fields. Yellow data are the well control for the figure.

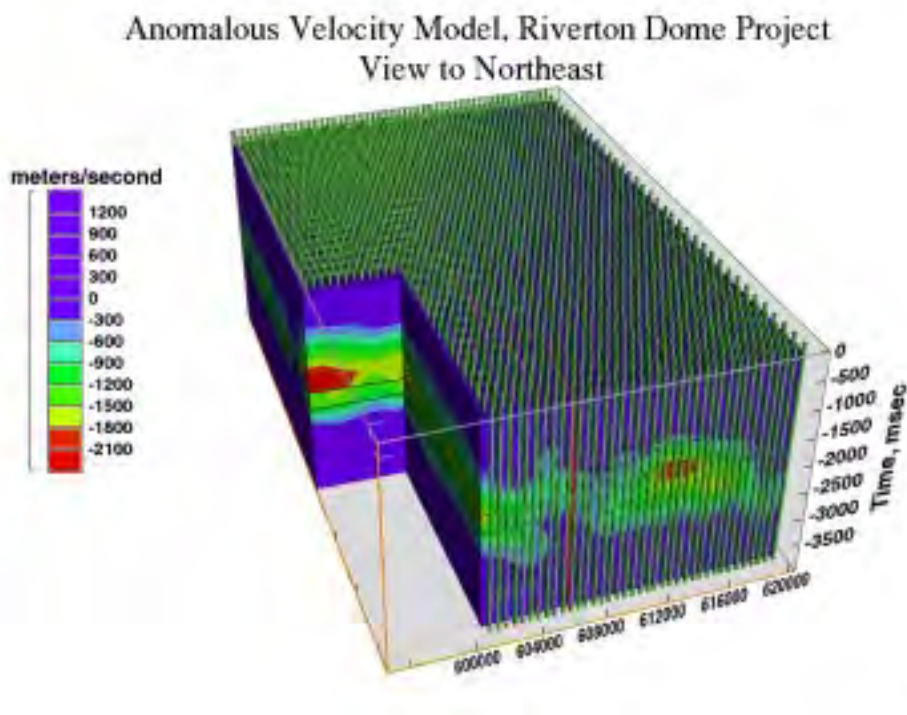
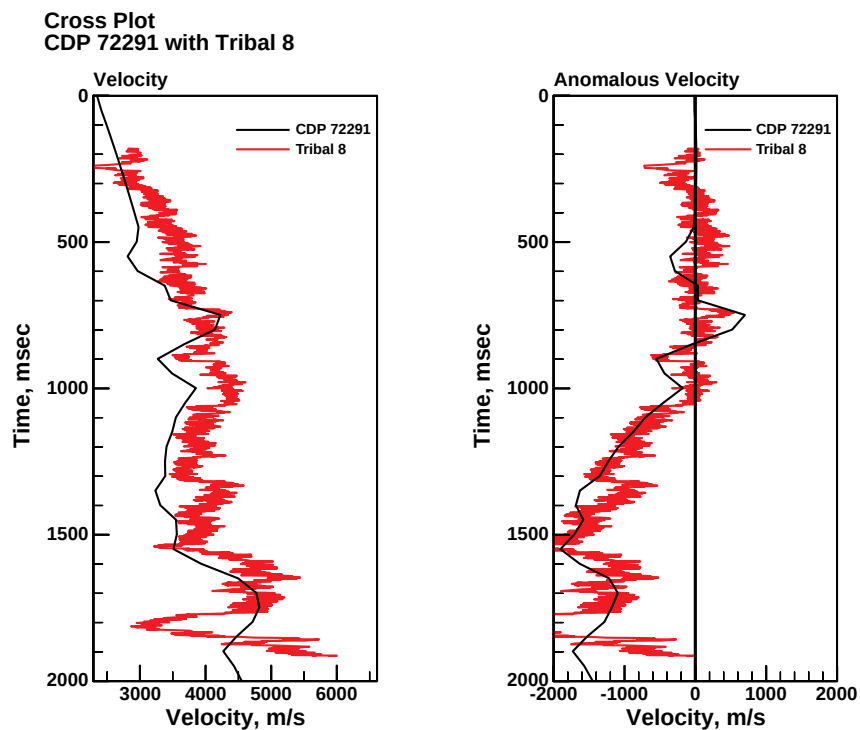


Figure 6. Anomalous seismic interval velocity volume derived from the Riverton Dome 3-D seismic survey. Figure shows location of 1620 CDP's used in this study; for each of the CDP's a velocity-depth (i.e., time) profile was constructed.

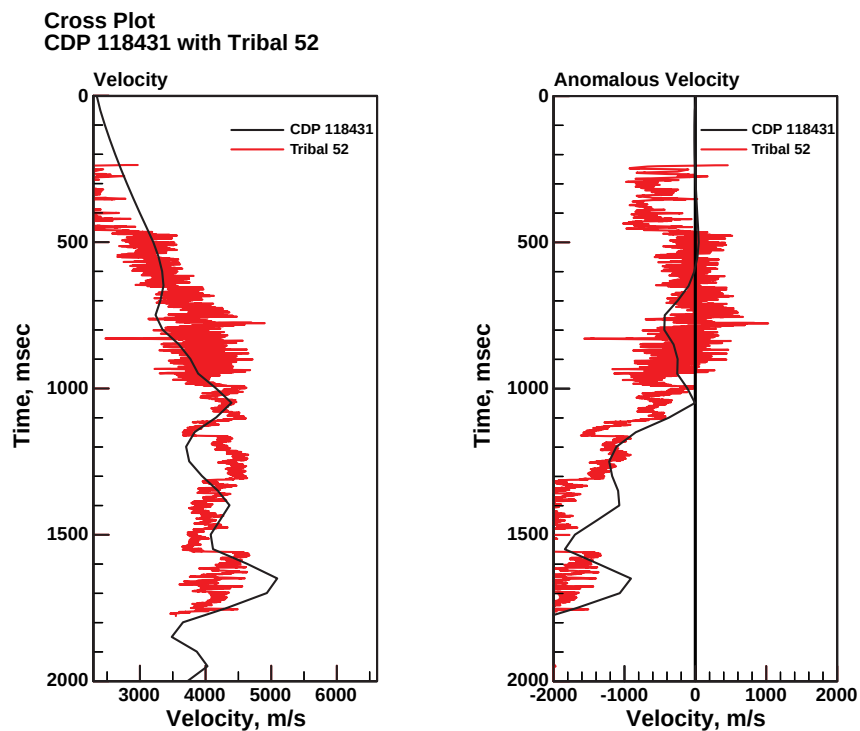
A.



IER

Figures 7A-C. Sonic and seismic interval velocity-depth profiles from coincident well logs and seismic line CDP's on the right side of the diagram (i.e., anomalous velocity profile) the typical velocity-depth gradient has been removed from both the sonic and seismic velocity profiles allowing for the isolation of anomalously slow velocity domains.

B.

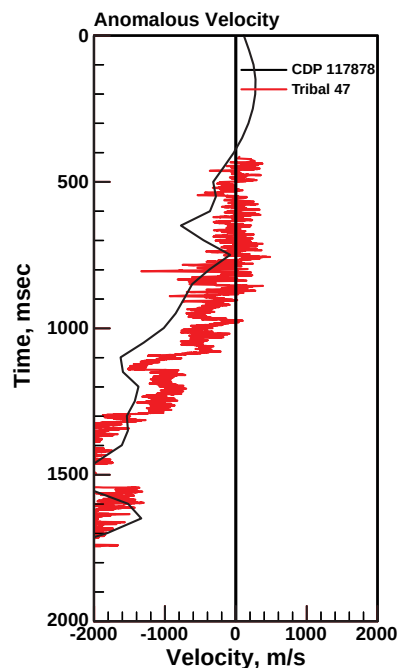
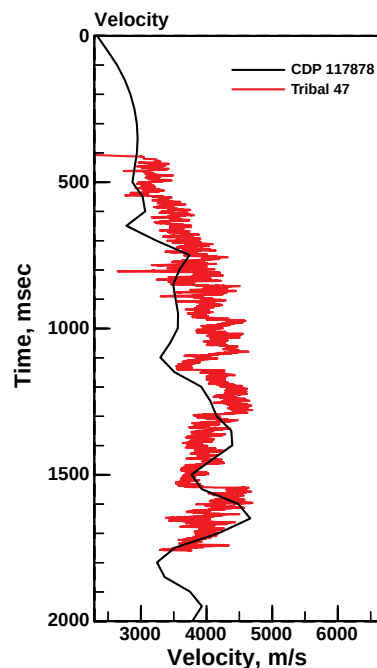


IER

Figure 7B.

C.

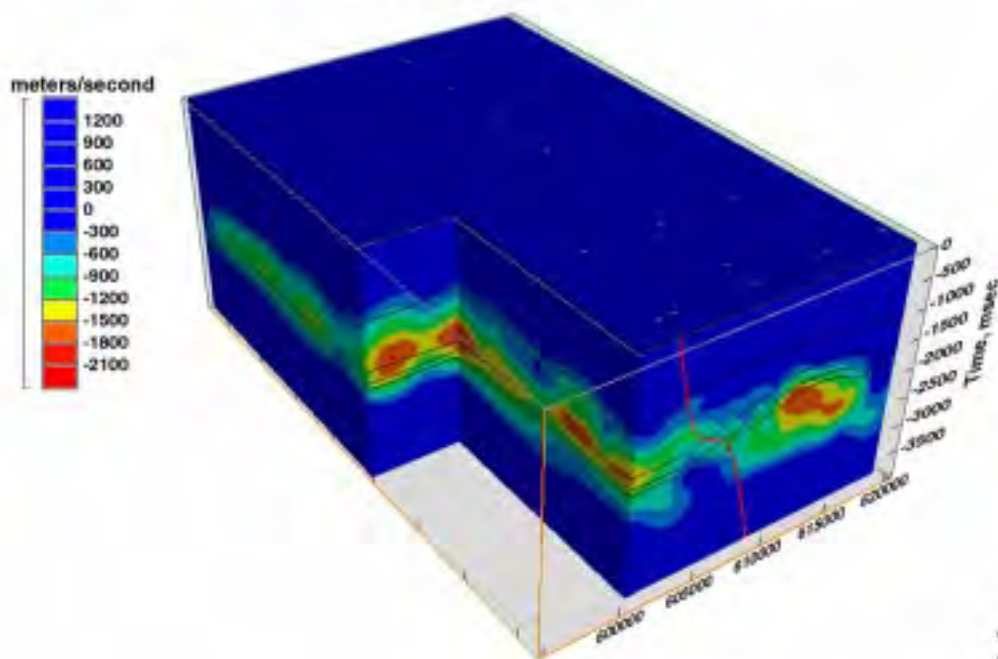
Cross Plot
CDP 117878 with Tribal 47



IER

Figure 7C.

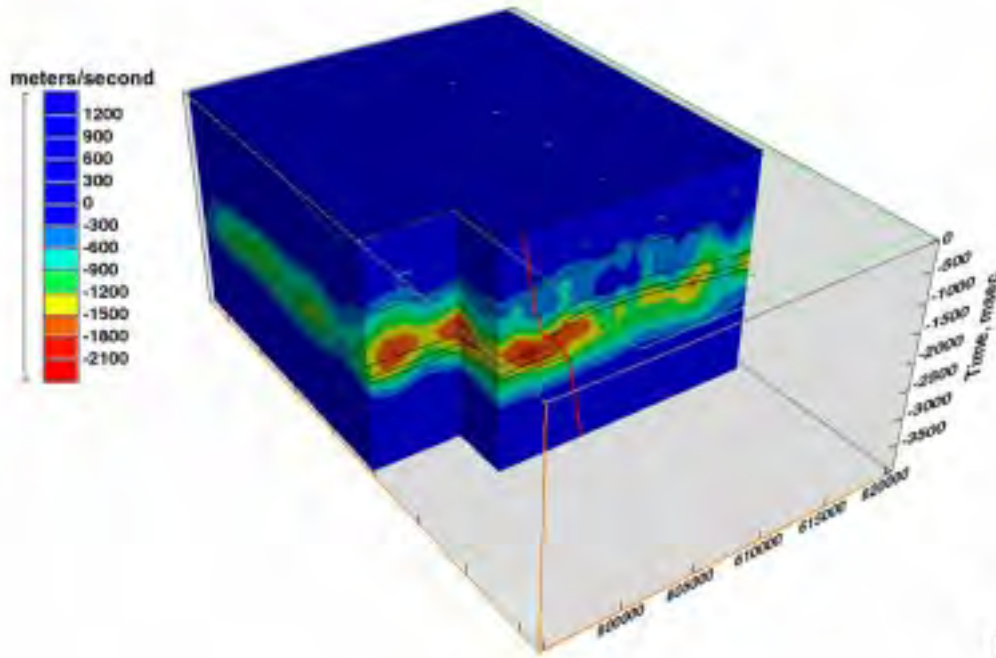
Anomalous Velocity Model, Riverton Dome Project
View to Northeast



IER

Figure 8. Anomalous seismic interval velocity volume for the Riverton Dome, 3-D seismic survey. That portion of the volume shown in dark blue consists of rocks with a fluid system following a hydrostatic gradient and a normal or typical velocity-depth gradient. In contrast, those rocks shown in light blue, green, yellow and orange have fluid systems that are anomalously pressured and that are characterized by anomalously slow seismic velocities (i.e., fall below the typical regional velocity-depth gradient).

Anomalous Velocity Model, Riverton Dome Project
View to Northeast

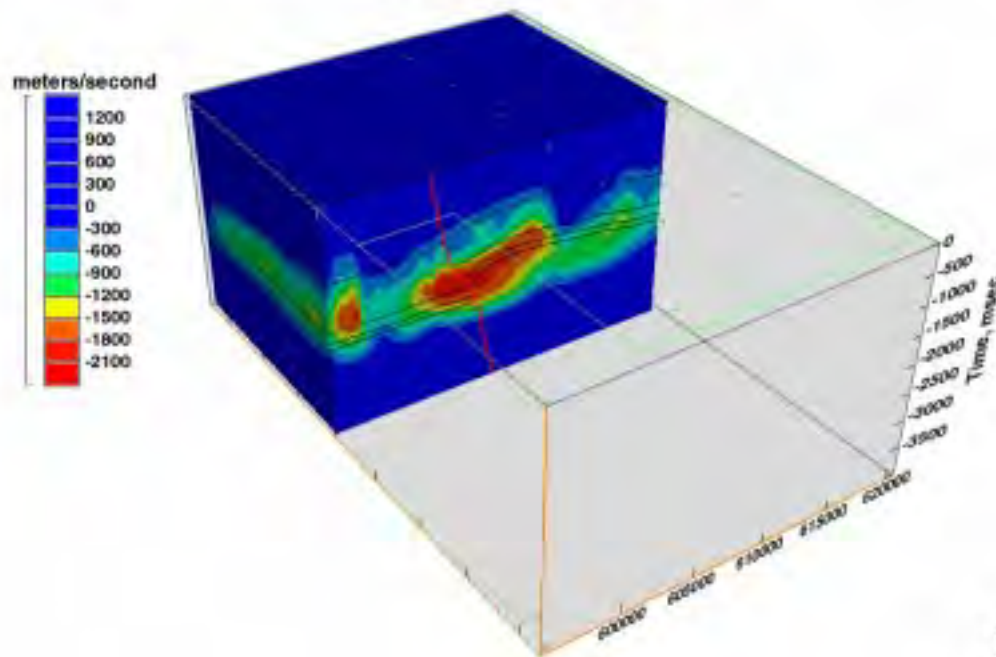


A.

IER

Figure 9A. East-west section through the anomalous velocity volume illustrated in Figure 8; the cross section is viewed from the southwest to northeast. Diagram demonstrates the intense velocity anomaly adjacent to the North-South fault running through the 3-D seismic survey area. Also note the topographic relief on the regional velocity inversion surfaces (i.e., color change from dark to light blue).

Anomalous Velocity Model, Riverton Dome Project
View to Northeast



B.

IER

Figure 9B. Same as Figure 9A, only the east-west cross section is farther to the north.

wells that deviate from vertical, so it is impossible to match exactly the geographic position of a well with a CDP from the seismic survey. The comparisons shown in Figures 7A - 7C are from geographic overlapping CDPs (seismic velocity) and well locations (sonic velocity). Therefore, most of the differences noted in Figures 7A - 7C when comparing the seismic and sonic velocities can be attributed to uncertainties resulting from the deviation of the drilled wells. Any velocity domain falling below the typical regional velocity-depth profile is considered to be anomalously slow and is assigned a negative sign to signify that it is anomalously slow.

PRELIMINARY RESULTS

Using the procedures outlined above, it is possible in the Riverton Dome 3-D seismic survey area to detect and to delineate anomalously slow velocity domains in 3-D visualizations, as well as the regional pressure surface boundary/velocity inversion surface (see Figures 9A,B). Figures 9A

and 9B are east-west cross sections through the anomalous velocity volume (Figure 8) in the study area viewed from the southwest to northeast. The red line shown in Figures 9A and 9B is a significant N-S fault in the Riverton Dome area; the position of the fault was determined from geological data provided to IER by Snyder Oil Company. Clearly illustrated in Figures 9A and 9B is the top of anomalous pressure (uppermost velocity inversion surface shown in the figures as a color change from dark to light blue) and domains of intense anomalously slow velocities (red color).

Figures 10 A-C are a series of north-south cross sections viewed from east to west through the anomalous velocity volume (Figure 8). Again the regional velocity inversion surface (i.e., pressure surface boundary) is clearly delineated, as are the intense velocity anomalies beneath the inversion surface. Note the significant topographic relief characterizing the regional velocity inversion surface (see especially Figures 10A - 10C). The topographic highs on the velocity inversion surface (Figures 10A - 10C) represent areas where

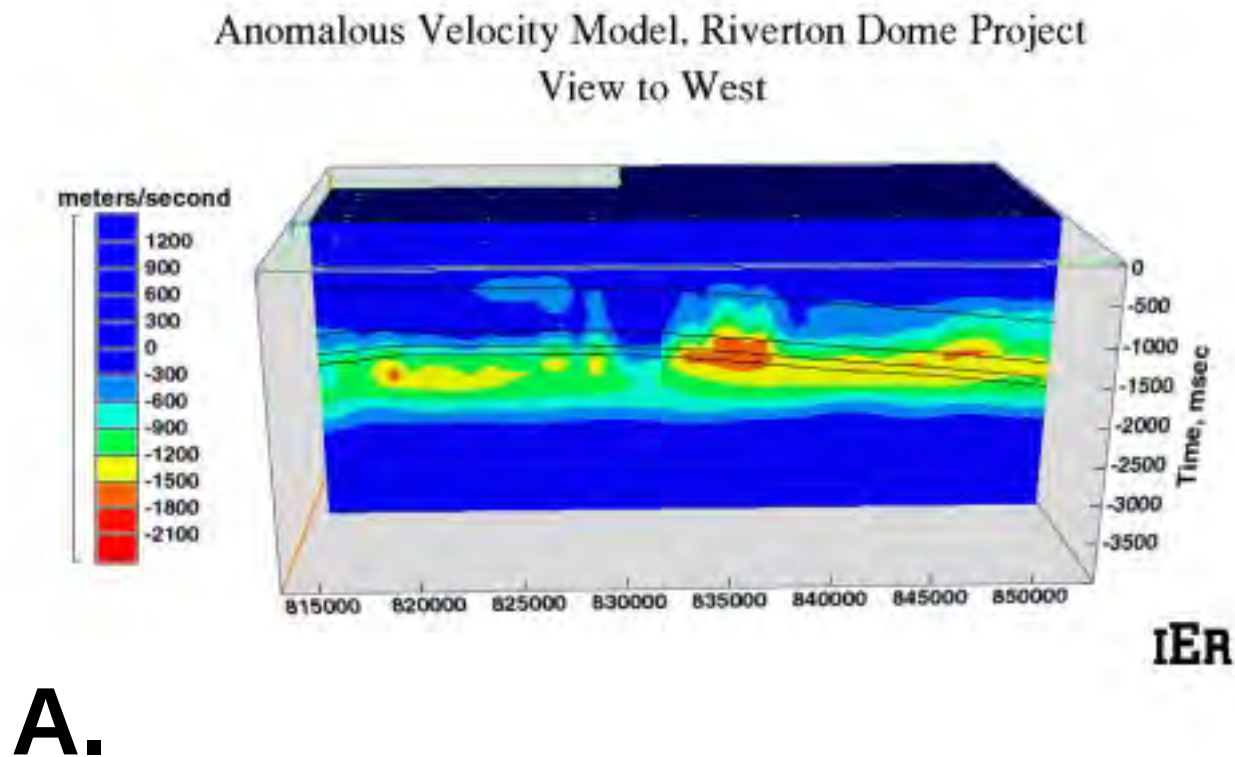
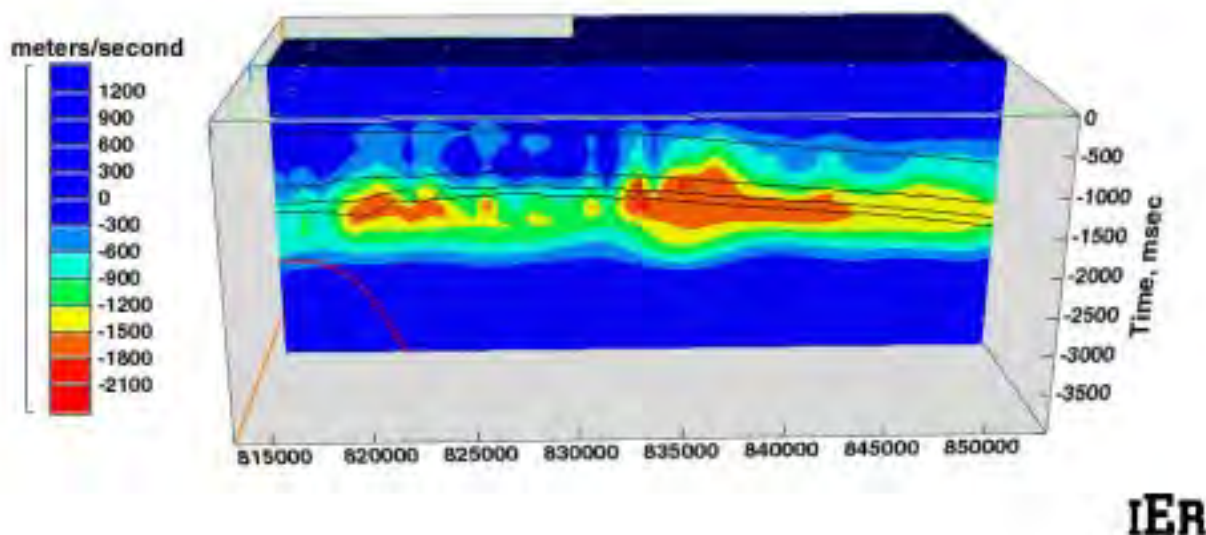


Figure 10A. North-south cross section, view from east to west, through the anomalous velocity volume shown in Figure 8.

Anomalous Velocity Model, Riverton Dome Project View to West



B.

Figure 10B. North-south cross section, view from east to west, through the anomalous velocity volume shown in Figure 8. Figure 10B is farther west than Figure 10A.

gas is penetrating up into the overlying stratigraphic section.

Figure 10C is a cross section cut very close to the place of the north-south fault mentioned previously. Based on the relationship between the fault plane and the velocity anomalies, it is concluded that the north-south fault plane is a controlling factor with regard to the distribution of anomalous velocity domains within the Riverton Dome velocity volume.

Also, it is possible to study the configuration of the regional velocity inversion surface by stripping away all of the overlying section to view the surface in three dimension (Figure 11A). The volume shown in Figure 11A represents not only the uppermost surface of the anomalous velocity volume, but also the whole anomalous velocity volume (both top and bottom). In Figure 11B, all anomalous velocity layers down to 1500 ms (anomalously slow) have been stripped off of the anomalous velocity volume; therefore Figure 11B is a representation of the most intense anomalously slow velocities in the

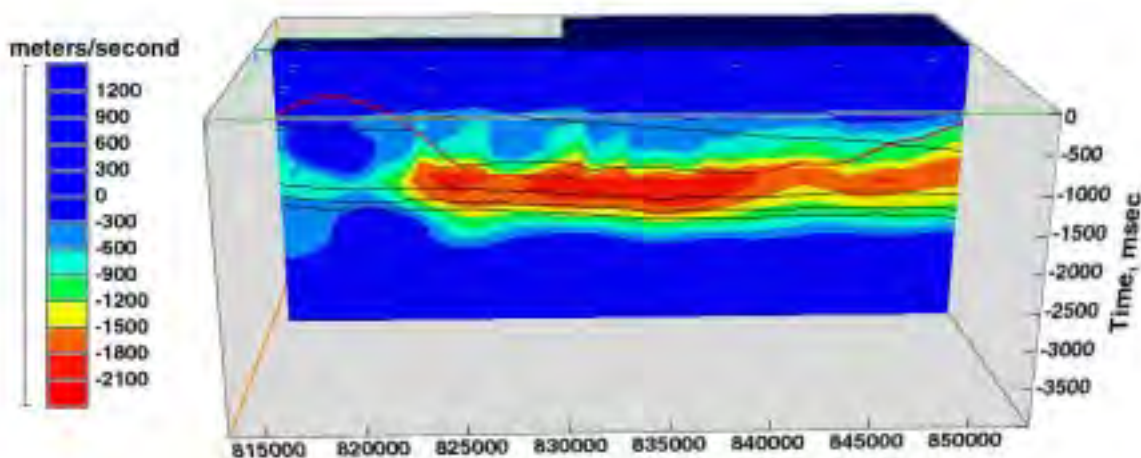
anomalous velocity volume. As a consequence, of the operations illustrated in Figures 9, 10, and 11, it is possible to more fully define in detail the distribution and configurations of all anomalous velocity domains in the Riverton Dome 3-D seismic survey.

Velocity Anomalies

In Figures 12A and 12B, the stratigraphic section above the Cody Formation has been removed from the anomalous velocity volume. Therefore, the viewer is looking at the velocity character of the anomalous velocity at the top of the Cody Formation in both inclined (Figure 12A) and map views (Figure 12B). From Figures 12A and 12B it is apparent that in the southern half of the study area, the Cody is characterized by normal seismic interval velocity, and presumably normal pressures; whereas in the northern half of the area, the Cody is characterized by anomalously slow seismic interval velocities, and presumably anomalous pressures.

Figures 13A and 13B are similar constructions

Anomalous Velocity Model, Riverton Dome Project View to West



C.

IER

Figure 10C. North-south cross section through the anomalous velocity volume (Figure 8) approximately parallel to the fault plane of the major North-South fault that is located down dip and west of the major structural closure in the area (i.e., doubly plunging north-south anticline).

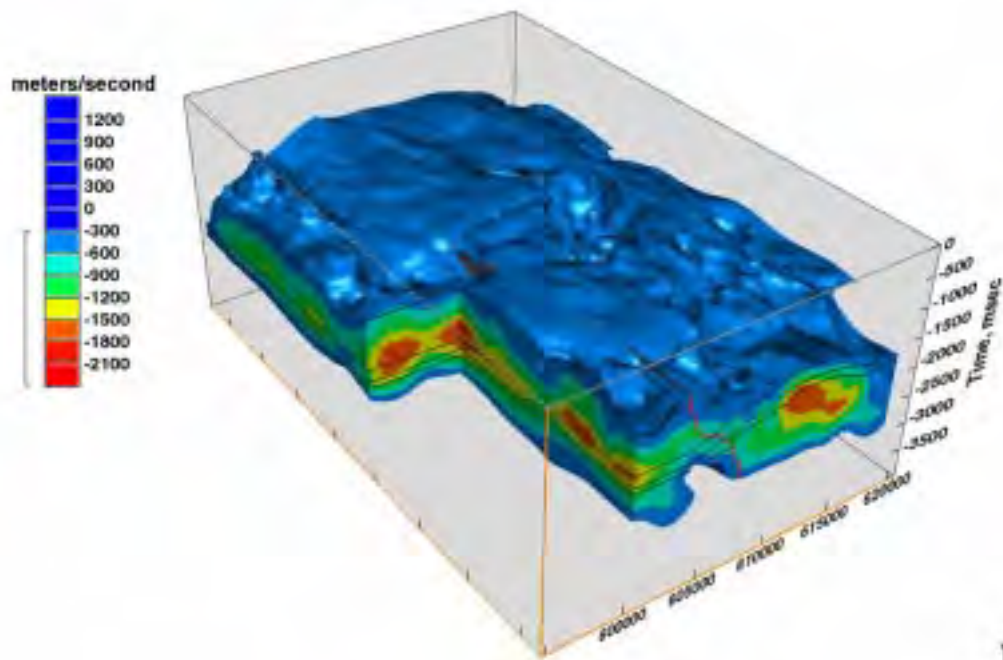
for the top of the Frontier Formation. It is clear from Figures 13A and 13B that there is a significant domain adjacent to the north-south fault that is anomalously slow. This particular velocity anomaly is observed in 10% or 160 of the 1620 CDP's shown in Figure 6. From Figure 9A it is concluded that this anomaly extends down into the main portion of the Frontier Formation.

East of the anomaly along the fault at the crest of the structure there is normally pressured hydrocarbon production in the Frontier Formation (see location of the Tribal 8 well on Figure 14B). Figures 14A and 14B clearly illustrate that at the crest of the structure east of the fault, a portion of the Frontier Formation is characterized by normal velocity (i.e., velocity values falling on the typical regional velocity-depth gradient). In both Figures 14A and 14B, the rocks within that part of the Frontier Formation characterized by normal velocity have been removed. Clearly, the removal of the rocks creates a canyon or topographic low on the Frontier anomalous velocity volume at the crest of the structure and trending from south to north. Production histories demonstrate that the Frontier

rocks that were removed (thereby creating the topographic low; Figure 14B) are normally pressured. From the geometry of the topographic low, it is speculated that the low represents a north-south channel-like sandstone within the Frontier Formation that is draped over the structure (i.e., north-south anticline plunging to the north). This "channel" sandstone is probably connected to the Frontier outcrop that occurs to the south of the Riverton Dome area. This scenario would explain how the Frontier Formation could be normally pressured (i.e., fluid system follows a hydrostatic gradient) at the crest of the structure, but with anomalously pressured rocks downdip to the west in the vicinity of the north-south fault. The sandstones within the channel probably are recharged by meteoric water from the south with hydrocarbons collecting at the crest of the structure due to a strong water drive. In strong contrast, the Frontier Formation down dip to the west is isolated from the outcrop and is being charged with hydrocarbons migrating up along the north-south fault.

Figures 15A and 15B represent inclined and map views of the Muddy Formation. The spatial

Anomalous Velocity Model, Riverton Dome Project View to Northeast

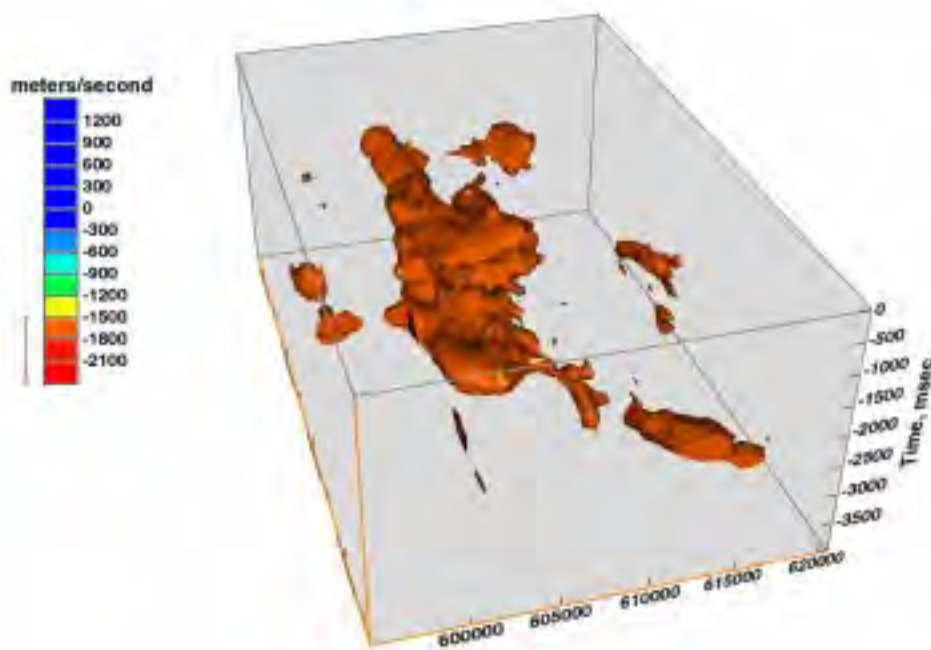


A.

IER

Figure 11A. Anomalous velocity volume where all the stratigraphic units above the top of the regional velocity surface (i.e., pressure surface boundary) have been removed. In addition the rocks with normal velocity characteristics below the anomalous velocity volume also have been removed.

Anomalous Velocity Model, Riverton Dome Project View to Northeast

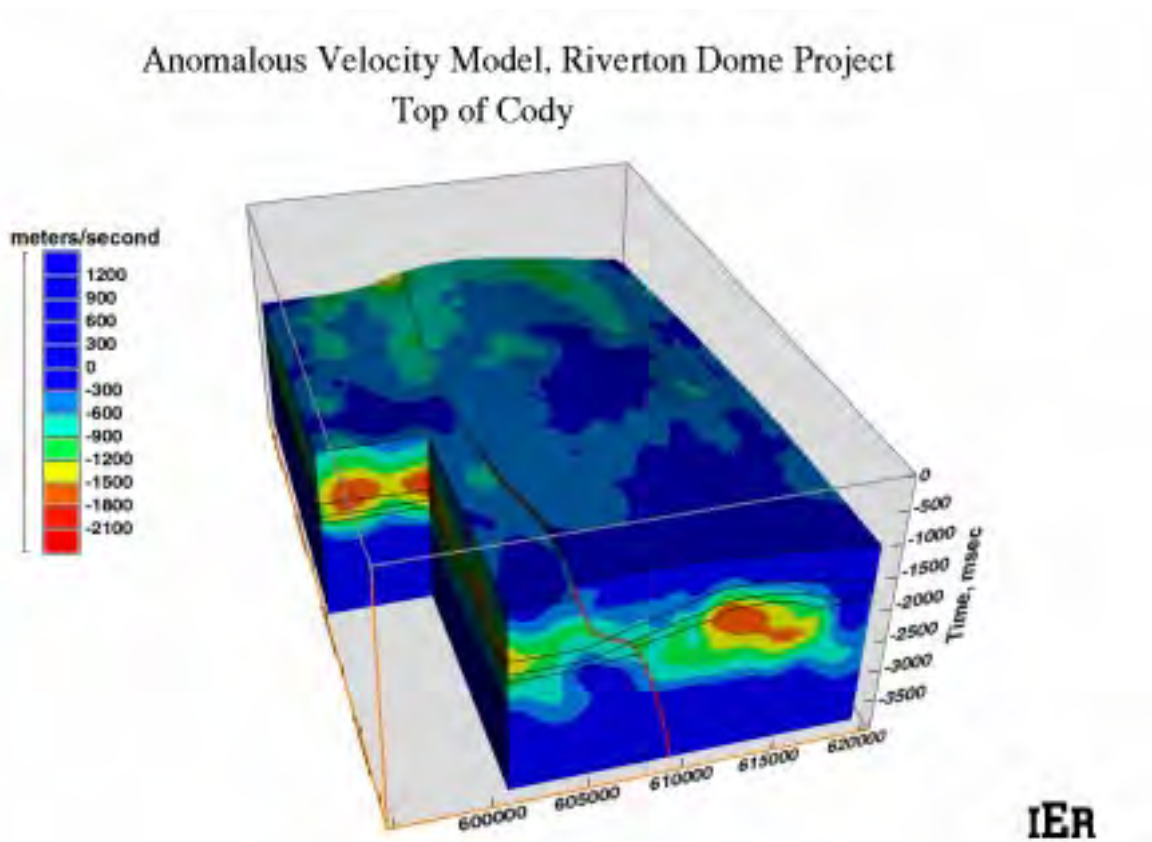


B.

IER

Figure 11B. Isolated anomalous velocity volume showing only rocks characterized by velocities at least 1500 ms slower than the regional velocity-depth gradient (i.e., intense anomalously slow velocities).

A.



B.

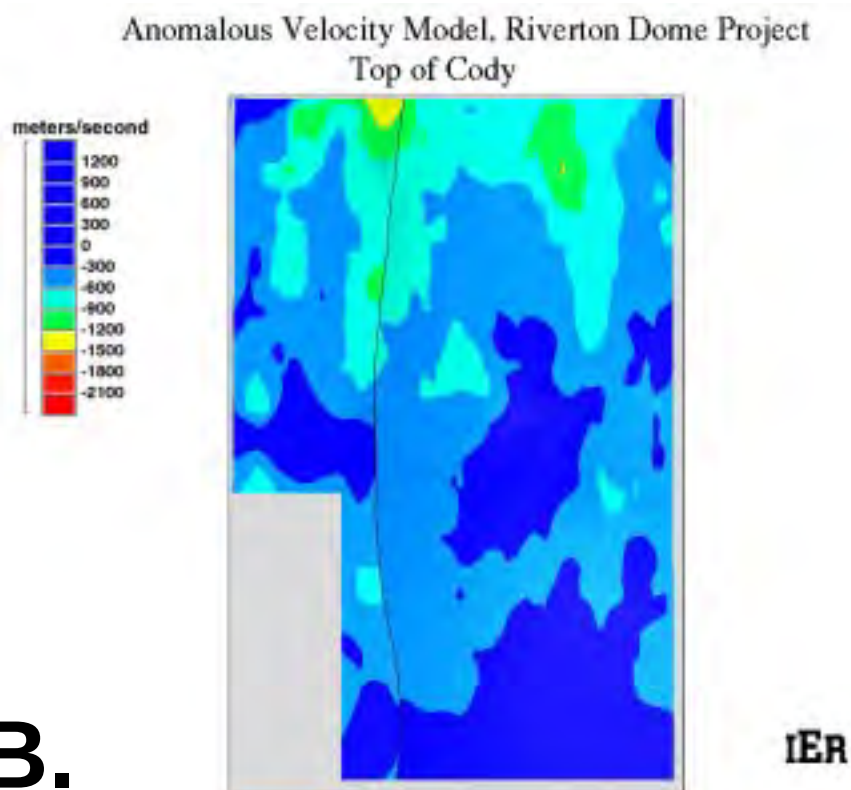
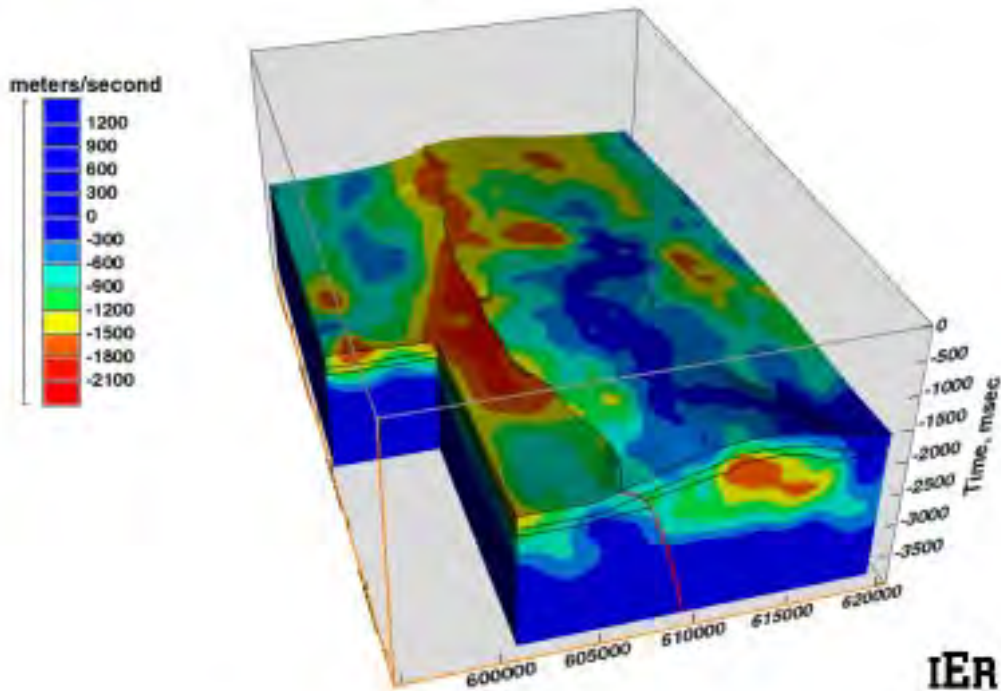


Figure 12B. Map view of the top of the Cody Formation showing the anomalous velocity distribution at the top surface of the Cody Formation.

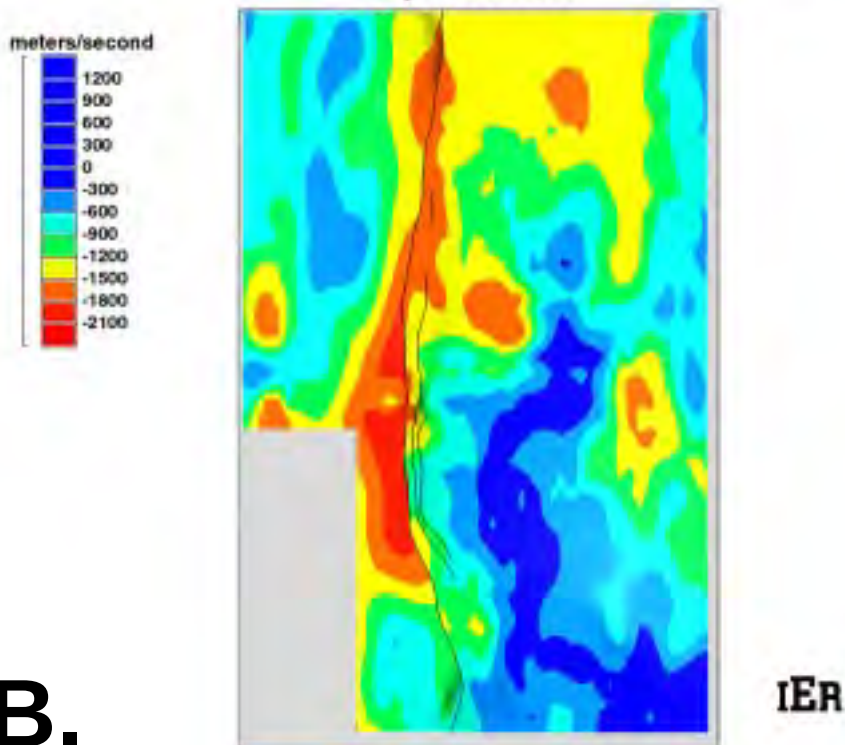
Anomalous Velocity Model, Riverton Dome Project Top of Frontier



A.

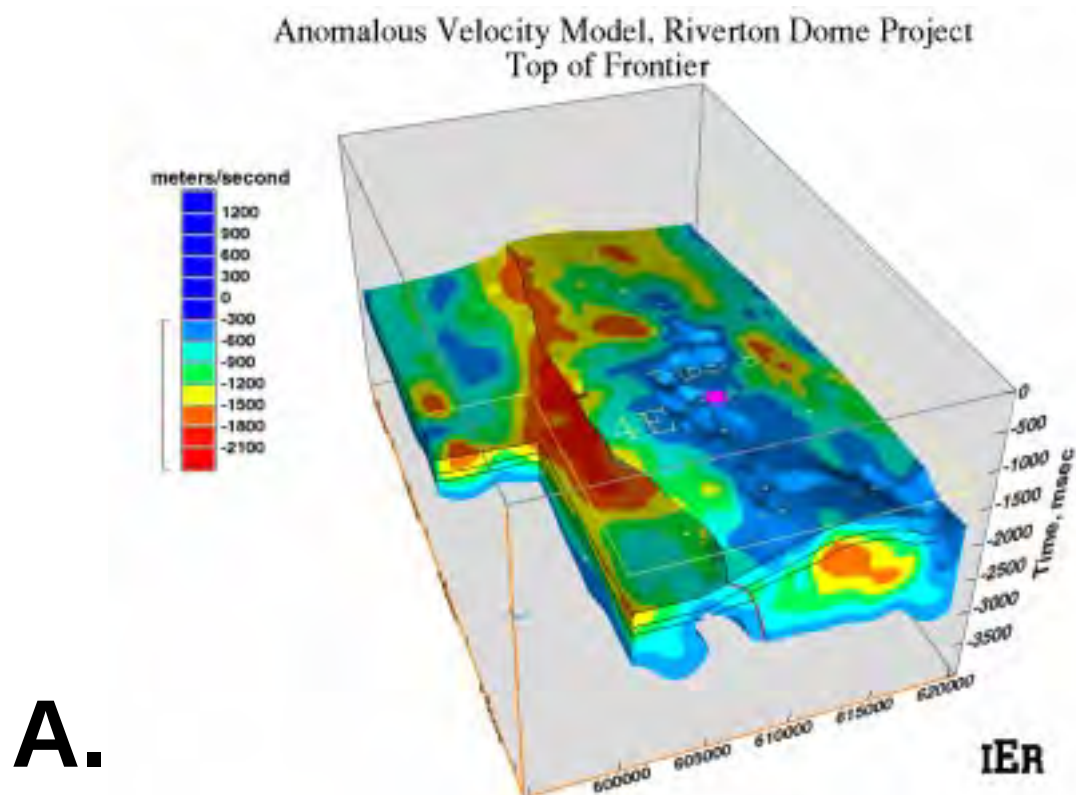
Figure 13A. Anomalous velocity volume in which all the stratigraphic units above the top of the Frontier Formation have been removed. The top of the volume in this figure is the top of the Frontier Formation.

Anomalous Velocity Model, Riverton Dome Project Top of Frontier

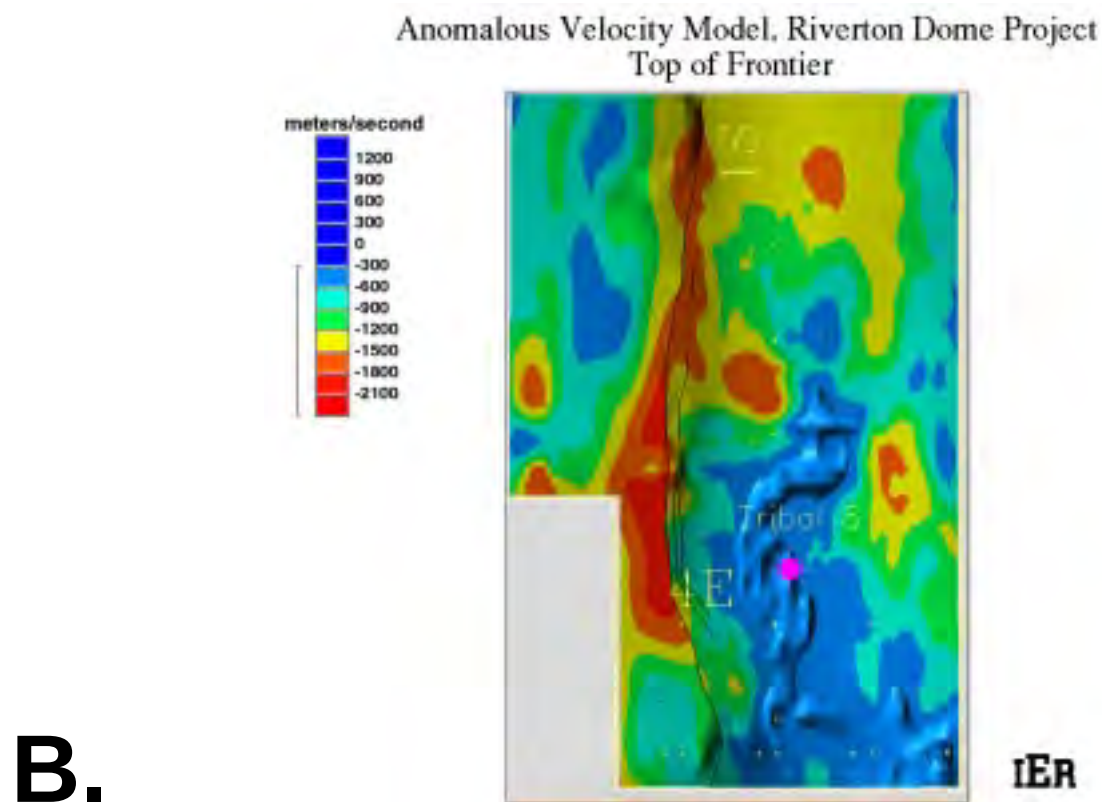


B.

Figure 13B. Map view of the top of the Frontier Formation showing the anomalous velocity distribution at the top surface of the Frontier Formation.



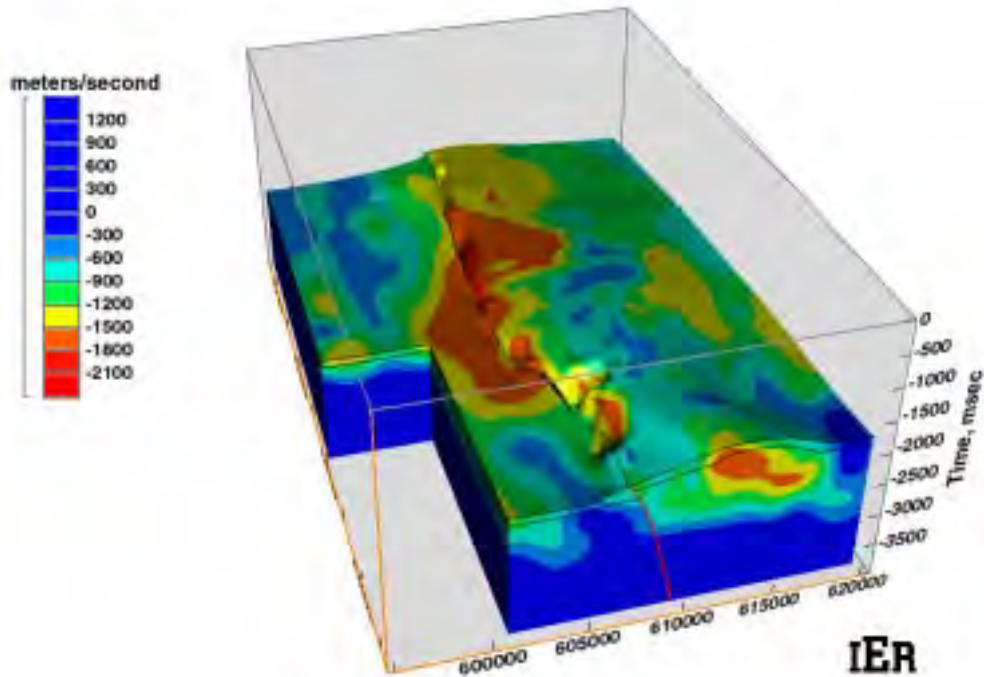
A.



B.

Figures 14A,B. Same as Figures 13A and 13B only all Frontier rocks characterized by normal velocities (i.e., probably normally pressured) have been removed. The Tribal 8 well is shown (pink dot) because it is producing normally pressured hydrocarbons from the Frontier Formation at the top of the structural closure.

Anomalous Velocity Model, Riverton Dome Project Top of Muddy



A.

Figure 15A. Anomalous velocity volume in which all the stratigraphic units above the top of the Muddy Formation have been removed. The top of the volume in this figure is the top of the Muddy Formation.

pattern of the anomalous velocities is similar to the pattern observed for the Frontier Formation. At the crest of the structure at the south end of the survey area, there is a significant velocity anomaly in the Muddy Formation (Figures 15A,B). The most intense and volumetrically important velocity anomaly in the Muddy Formation, like in the Frontier Formation, occurs along both sides of the north-south fault (Figures 15A,B). In summary, this velocity anomaly occurs on both the up and down thrown sides of the fault (Figures 9A,B); with the fault clearly controlling the distribution of the velocity anomaly, and presumably the gas saturated, anomalously pressured rocks within the Muddy Formation.

Figures 16A,B are similar velocity reconstructions for the Nugget Formation. Although the configuration of the Nugget Formation velocity anomaly is similar to that of both the Frontier and Muddy formations, there is one important difference; the most intense Nugget velocity anomalies are confined to the eastern side of the north-south

fault (Figures 16A,B). The intense velocity anomalies within the Nugget Formation are very important, for the Nugget is typically a porous sandstone, whereas the sandstones in the Frontier and Muddy formations commonly are relatively tight. So the velocity anomalies within the Nugget may represent significant gas accumulations in a porous sandstone reservoir. Elsewhere in the general area, the Nugget commonly is water-filled. Again it should be noted that the most intense velocity anomaly occurs along the north-south fault and downdip from the crest of the structural closure.

INTERPRETATION

The velocity anomalies demonstrated in Figures 13 through 16 can be isolated and visualized in three dimensions using the IER technology (Figures 11A,B). The importance of this operation is that the volume shown in Figure 11B is gas saturated and anomalously pressured. Core observations in the area show that the Cody, Frontier, Muddy, and Nugget formations are not

B.

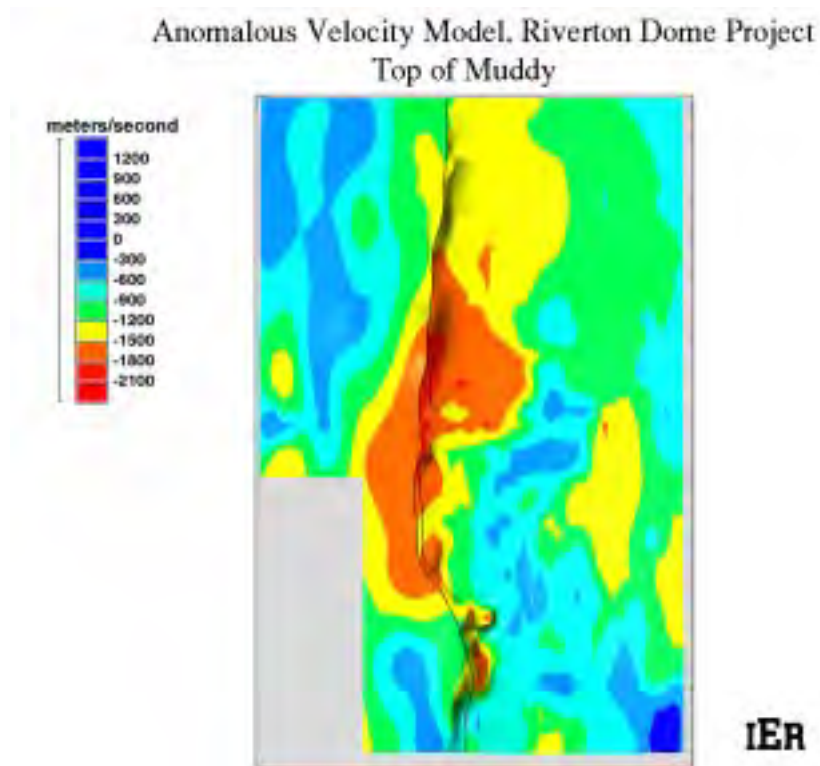


Figure 15B. Map view of the top of the Muddy formation showing the anomalous velocity distribution at the top surface of the Muddy Formation.

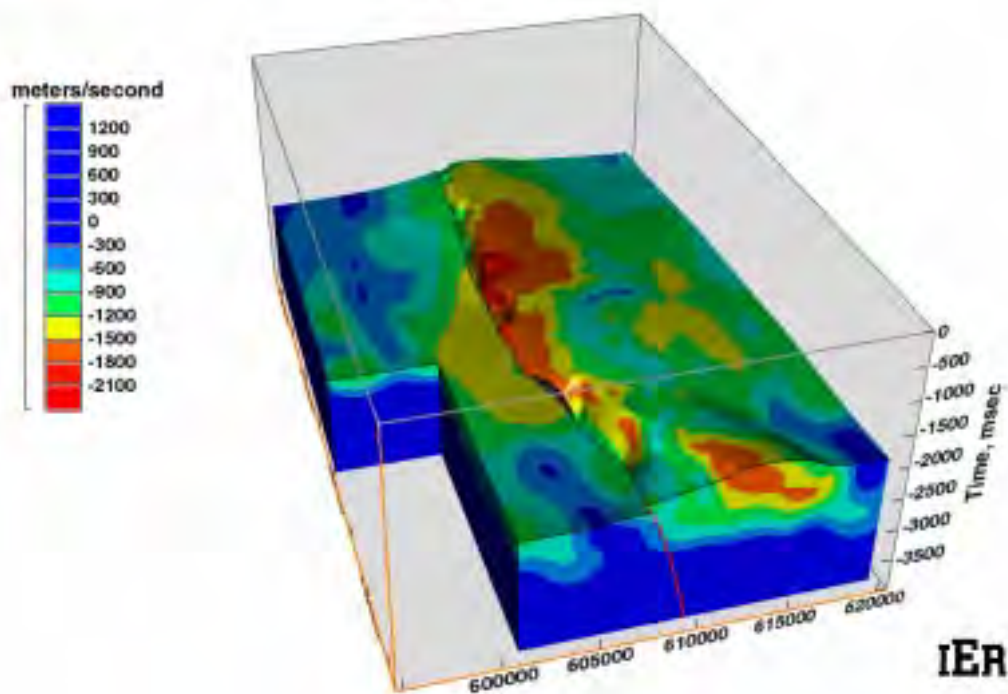
undercompacted. Therefore, the best explanation for the intensely slow velocities shown in Figure 11B is that the fluid system within the volume contain significant free gas in the fluid phase (Surdam et al., 1997). As a result the anomalous velocity volume shown in Figure 11B is an important lead as to where to explore for anomalously pressured gas accumulations in the Riverton Dome area. This exploration lead will evolve into a serious gas prospect if it can be shown that potential reservoir units with commercial porosity/permeability intersect the anomalous velocity volume shown in Figure 11B.

VALIDATION OF IER EXPLORATION TECHNOLOGY

During the time that the velocity field evaluation was progressing at IER, six Muddy Formation tests were completed by Santa Fe Snyder Oil Company. From the perspective of the IER researchers, these were blind tests of the exploration strategy. The test well results were made known

to IER only after the final results of the Riverton Dome velocity evaluation were presented to Santa Fe Snyder Oil Company by IER in Laramie, Wyoming on January 27, 1999. The range of initial gas production of the six wells was < one to four mmcf/day. Figure 17A is a map view of the anomalous velocity values at the top of the Muddy Formation. In Figure 17A, all anomalous velocity layers < 1200 ms slower than the regional velocity-depth (or time) gradient have been removed from the anomalous velocity volume. Thus, the anomalous velocity remnant shown in Figure 17A includes all rocks within the Muddy Formation that have anomalous velocities more than 1200 ms slower than the regional velocity-depth gradient. Also plotted on the anomalous velocity diagram (Figure 17A) are the positions of the six test wells and their characteristic initial production (IP) values in mmcf/day. Figure 17B is an enlarged display of the area of interest within the Riverton Dome survey area showing in detail the relationship between the anomalous velocity domain within the Muddy Formation and the IP values for

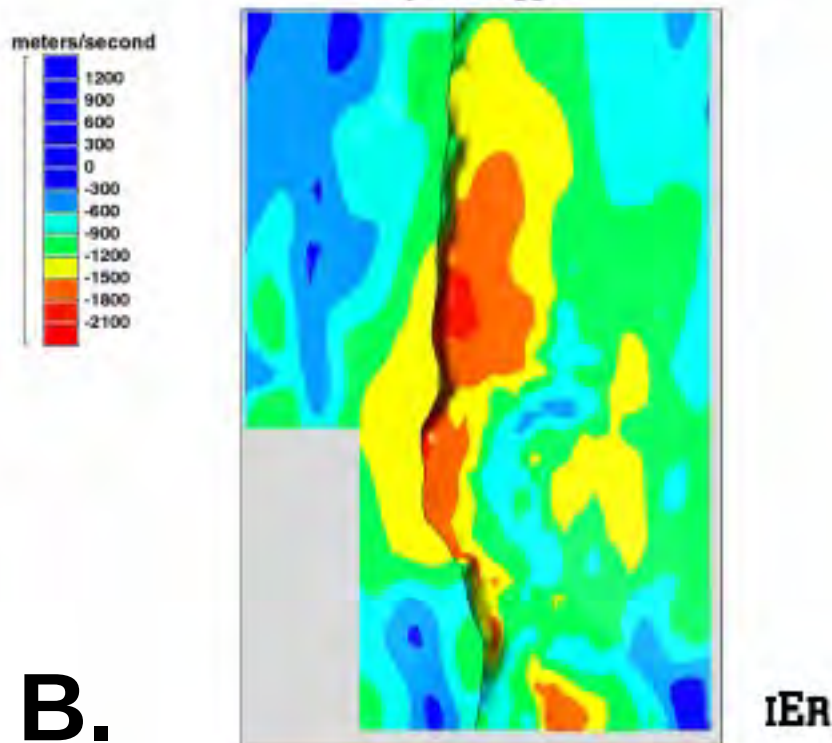
Anomalous Velocity Model, Riverton Dome Project Top of Nugget



A.

Figure 16A. Anomalous velocity volume in which all the stratigraphic units above the top of the Nugget Formation have been removed. The top of the volume in this figure is the top of the Nugget Formation.

Anomalous Velocity Model, Riverton Dome Project Top of Nugget



B.

Figure 16B. Map view of the top of the Nugget Formation showing the anomalous velocity distribution at the top surface of the Nugget Formation.

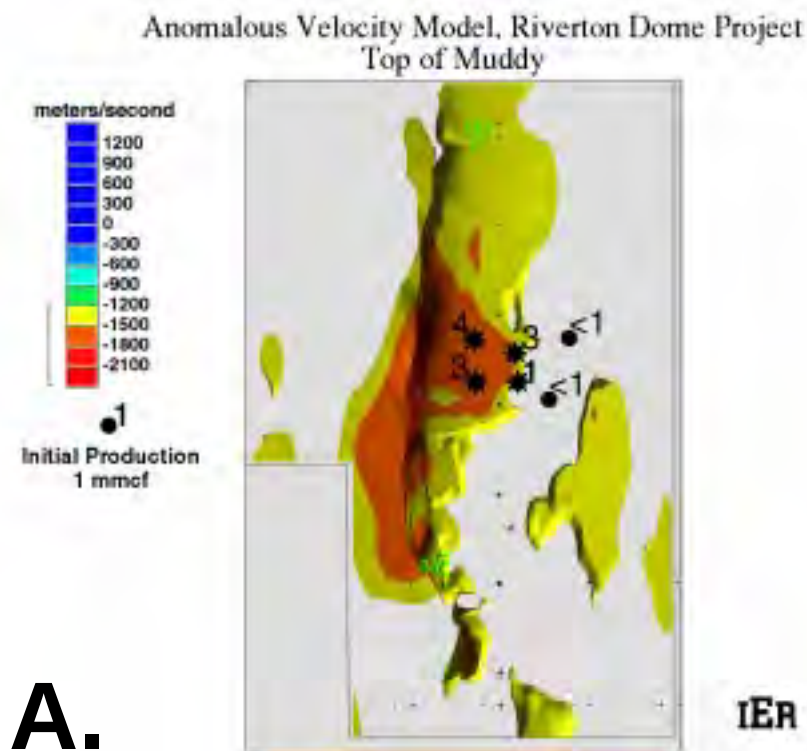


Figure 17A. Map view at the top of a targeted reservoir interval (i.e., Muddy Formation); map is derived from a 3-D anomalous velocity volume constructed from a 3-D seismic survey in the Wind River Basin. In a blind test five recent Muddy Formation wells are plotted on the anomalous velocity surface at the top of the Muddy Formation. The wells within the velocity anomaly (i.e., > 1500 meters/sec below the regional velocity-depth gradient) had initial production values of two to four mmcf/day; the well at the edge of the velocity anomaly (i.e., < 1200 meters/sec below regional gradient) had initial production of one mmcf/day; whereas the well drilled outside the velocity anomaly had initial production of < mmcf/day and presently is shut in.

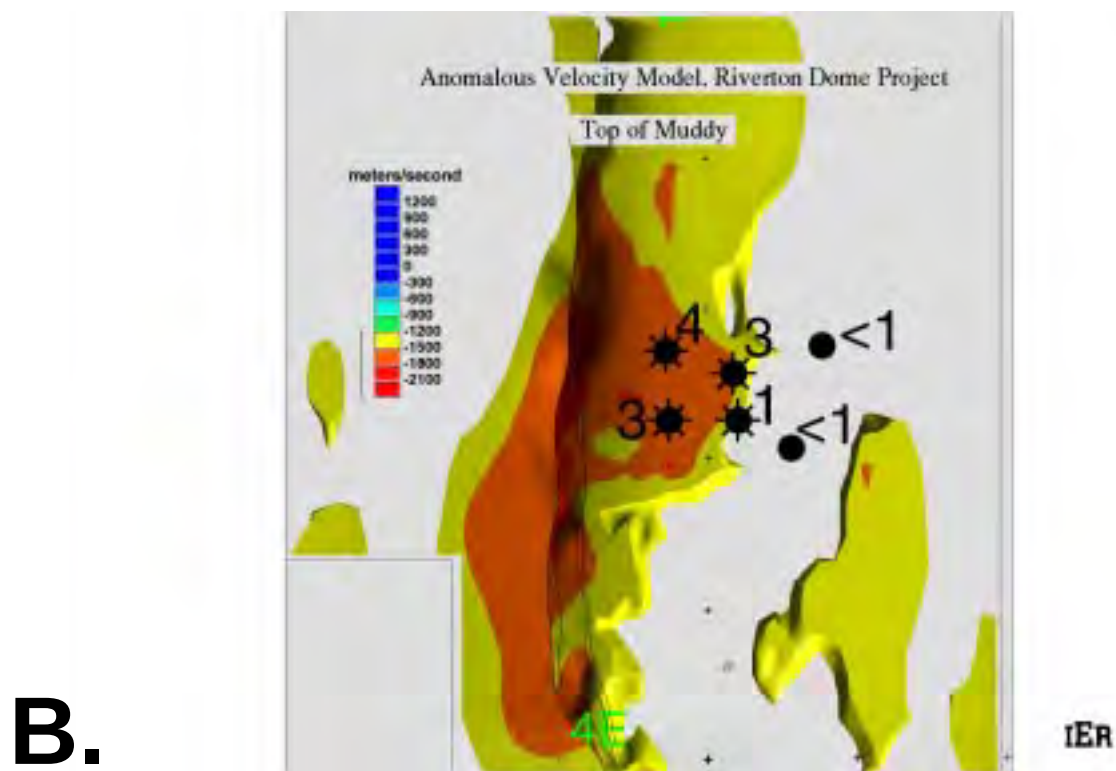


Figure 17B. Enlarged diagram showing the details of the area of interest in Figure 18A.

the six recent test wells. Wells completed in the Muddy Formation and in those rocks characterized by anomalous velocity values 1500 ms slower than the regional velocity-depth gradient (i.e., three wells) have IP values ranging from three to four mmcf/day. The one well at the edge of the velocity anomaly (i.e., anomalous velocity value of < 1200 ms below, or slower than the regional velocity-depth gradient) had an IP value of one mmcf/day. The two wells drilled into Muddy Formation rocks with a maximum anomalous velocity value of < 1200 ms have IPs of < one mmcf/day and at last notice were shut in. In fact, judging from Figure 15B, the Muddy Formation in the vicinity of the < one mmcf/day wells may have anomalous velocity values of only 300 to 600 ms (slow). The uncertainties associated with the velocity selections and resultant anomalous velocity values derived in this study are on the order of no more than 600 ms, and perhaps as low as 300 ms. It is concluded, with respect to the six recent Muddy test wells, that the IER exploration strategy for detecting and delineating commercial anomalously pressured gas accumulations is valid within the Riverton Dome 3-D seismic survey area, and can be utilized to sig-

nificantly reduce exploration risk and increase profitability of so-called deep basin accumulations.

CONCLUSIONS

The Ideal Test of the IER Exploration Technology

Armed with the new conceptual model and resultant exploration paradigm, plus the detection and delineation techniques discussed in this report, it should be possible to greatly reduce exploration risk in the Riverton Dome area and in other Rocky Mountain Laramide Basins. The ultimate value of the new technology will be determined by the degree to which it is able to predict in a forward fashion the distribution of basin-center gas accumulation. As such, the following final test is suggested. A careful review of all the results from this study suggest that a prime location exists in the Riverton Dome survey area where the new concept, IER exploration paradigm, technology, and detection techniques can be tested in three formations by a single well. The location is shown by a black dot on Figures 18A (i.e., Frontier anoma-

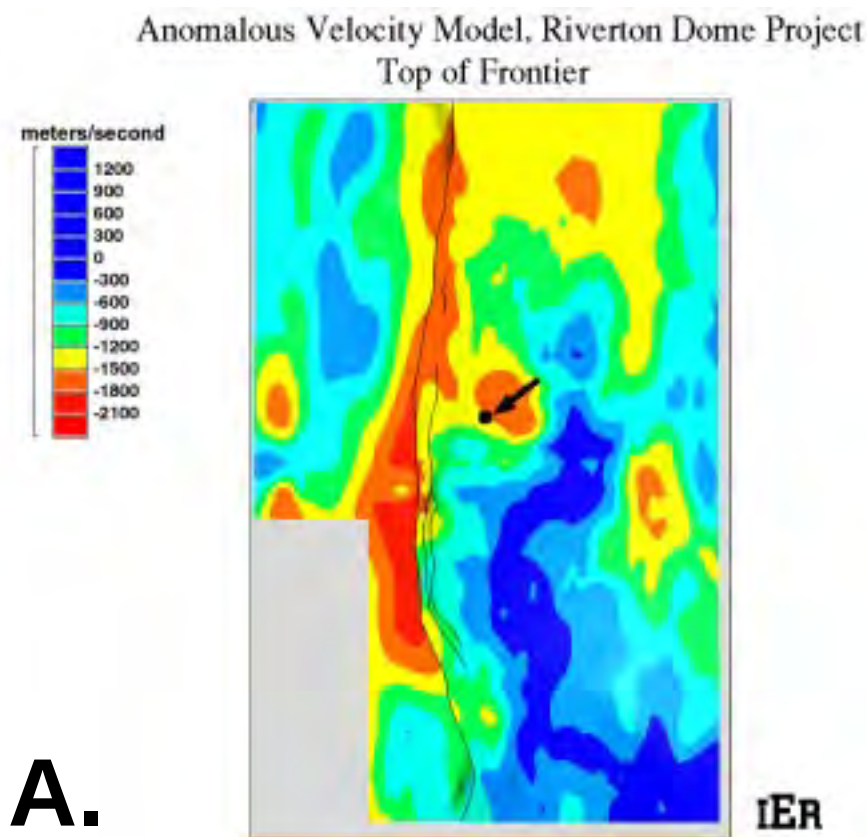
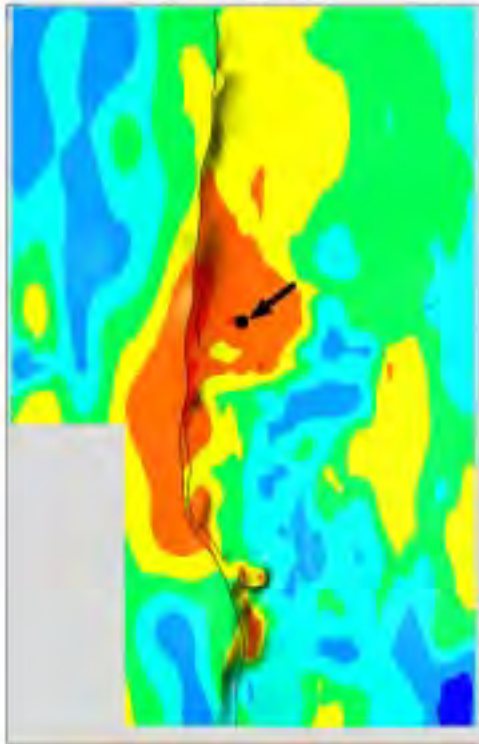
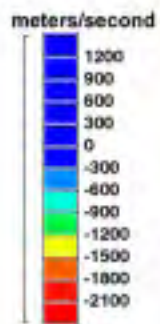


Figure 18A. Anomalous velocity map of top of Frontier Formation (Figure 13B) with the location of the proposed test well shown with a black dot (CDP 124896 in the Riverton Dome 3-D seismic survey area).

Anomalous Velocity Model, Riverton Dome Project
Top of Muddy

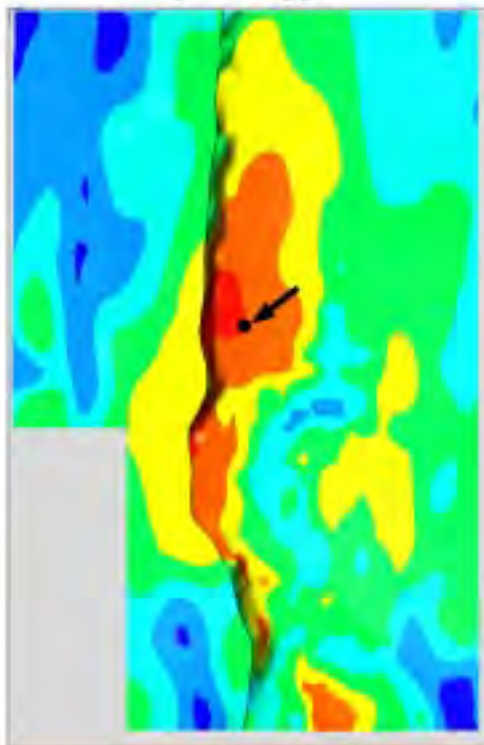
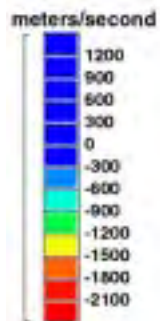


IER

B.

Figure 18B. Same as Figure 18A only map is of the anomalous velocity distribution on the top of the Muddy Formation.

Anomalous Velocity Model, Riverton Dome Project
Top of Nugget



IER

C.

Figure 18C. Same as Figure 18A and 18B only map is of the anomalous velocity distribution on the top of the Nugget Formation.

lous velocity map), 18B (i.e., Muddy anomalous velocity map), and 18C (i.e., Nugget anomalous velocity map). In each case, the drill site (the black dot) is located over an intense velocity anomaly in each of the respective formations. The drill site is located at CDP 124896 of the Riverton Dome 3-D seismic survey. Figure 19 is an interval velocity and anomalous velocity profile for the drill site (at CDP 124896). The anomalous velocity increases from -1100 ms to -1800 ms in the Frontier Formation; the anomalous velocity increases from -1800 ms to -1900 ms in the Muddy; and reaches -1900 ms in the upper portion of the Nugget Sandstone. These are truly significant anomalously slow velocities in each of the target reservoir intervals, and demonstrate that all three formations can be tested in a single well.

To further illustrate the velocity characteristics of the suggested drill site (i.e., CDP 124896), north-south and east-west anomalous velocity profiles that intersect at the drill site have been constructed [Figure 20A (north-south profile) and Figure 20B (east-west profile)]. Both Figures 20A and 20B

illustrate that the Frontier, Muddy, and Nugget potential reservoir intervals are characterized by intensely slow velocities beneath the drill site location. It is also important to note that the regional velocity inversion surface is characterized by a very significant topographic high, suggesting that at this location gas is migrating further up into the section than in most other parts of the survey area.

Thus, it is concluded that a well drilled at CDP 124896 in the Riverton Dome 3-D seismic survey is not only an ideal test of the IER exploration technology, but also the highest priority drill site for so-called basin center gas accumulations within the survey area.

ACKNOWLEDGMENTS

Sharon Kubichek, Henry Heasler, John Buggenhagen, and Peigui Yin, all scientists at the Institute for Energy Research, University of Wyoming, have contributed significantly to the ideas and concepts discussed in this report. Special acknowledgment goes to the Department of

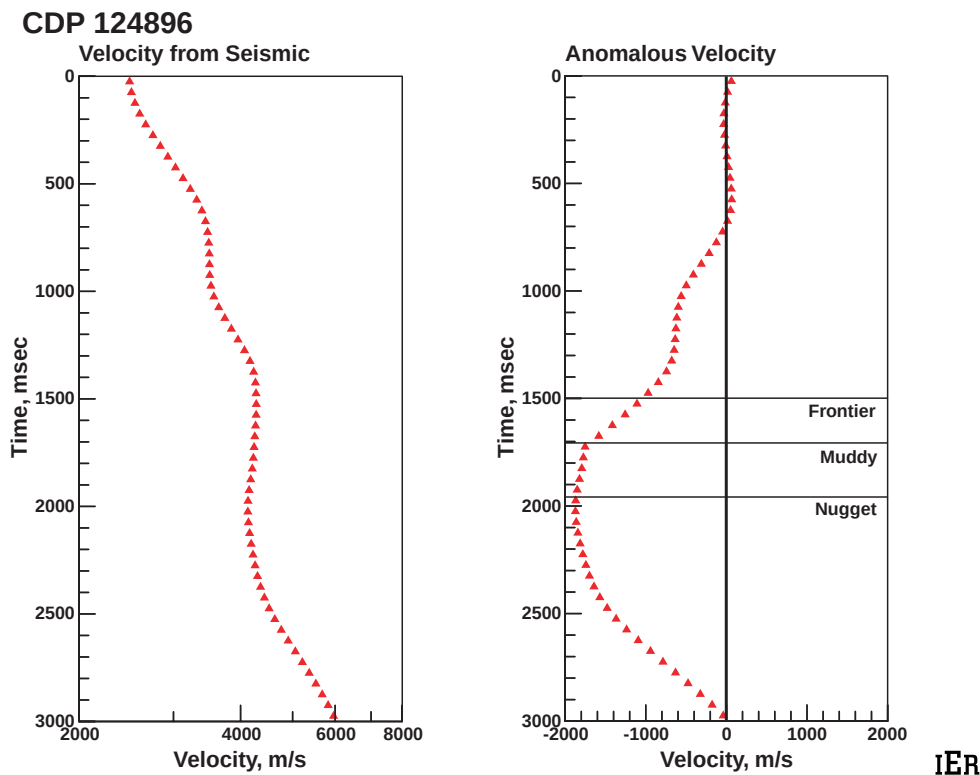


Figure 19. On the right the seismic interval velocity profile at CDP 124896, and on the left the anomalous velocity profile at CDP 124896.

Energy (Contract No. DE-FC26-97FT34181) for providing financial support of the work; to Gas Research Institute (Contract Nos. 5096-260-3833 and No. 5097-210-4085) for supporting the development of concepts explaining anomalously pressured gas accumulations in the Rocky Mountain Laramide Basins; and to Santa Fe Snyder Oil Company, Belco, and Tom Brown Company for supplying Wind River Basin data. Geodynamic Geographic EarthVision™ software was used in the geospatial modeling and visualization presented in this report. ProMAX seismic processing software and Landmark interpretation software provided to the Institute for Energy Research by Landmark Graphics Company were also used in these studies.

REFERENCES

Buggenhagen, John, 1999, Part 2: Understanding

Unconventional Reservoirs: Reservoir Characterization of the Frontier Formation Reservoirs in the Badger Basin field, Bighorn Basin, Wyoming: Ph.D. Dissertation, University of Wyoming, Laramie, WY.

Surdam, R.C., 1997, A New Paradigm for Gas Exploration in Anomalously Pressured “Tight Gas Sands” in the Rocky Mountain Laramide Basin, *in* R.C. Surdam, ed., Seals, Traps, and the Petroleum System: American Association of Petroleum Geologists, Tulsa, OK, Memoir 67, Chapter 17, pp. 283-298.

Surdam, R.C., Z.S. Jiao, and H.P. Heasler, 1997, Anomalously Pressured Gas Compartments in Cretaceous Rocks of the Laramide Basins of Wyoming: A New Class of Hydrocarbon Accumulation, *in* R.C. Surdam, ed., Seals, Traps, and the Petroleum System: American Association of Petroleum Geologists, Tulsa, OK, Memoir 67, Chapter 12, pp. 199-222.

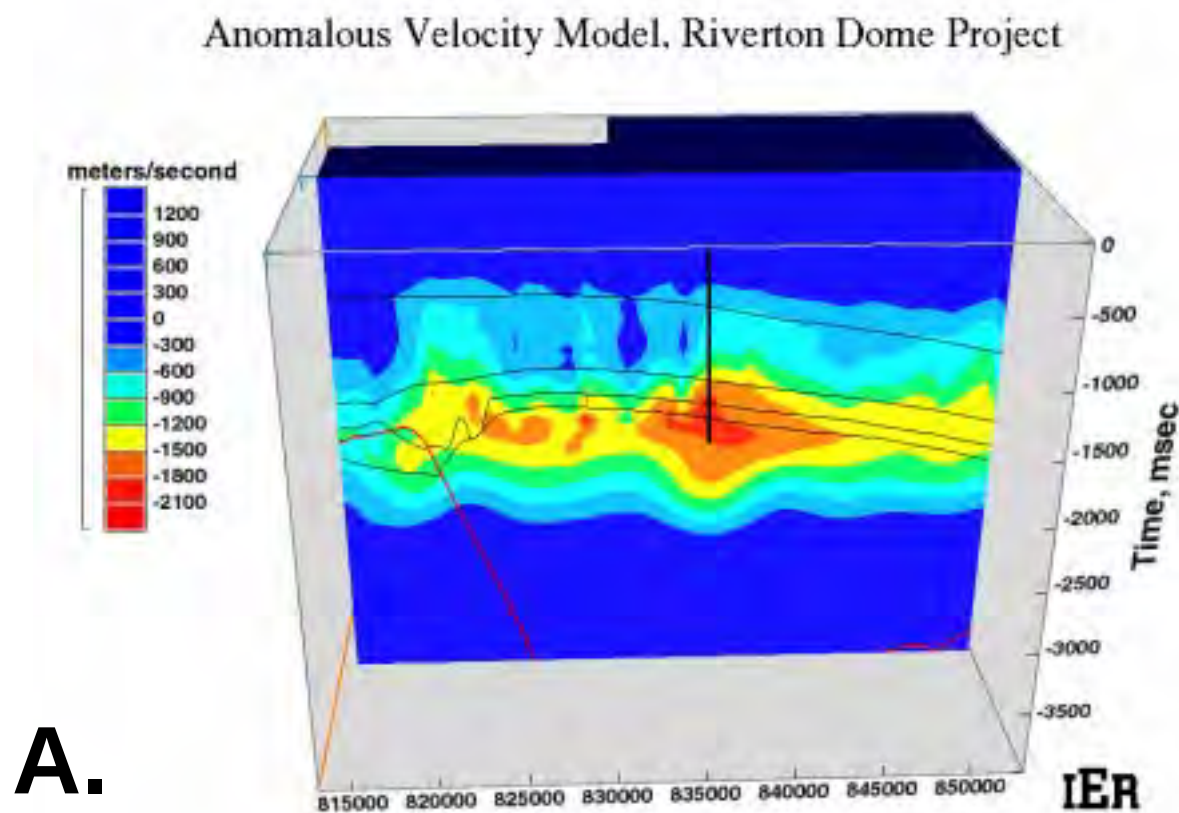
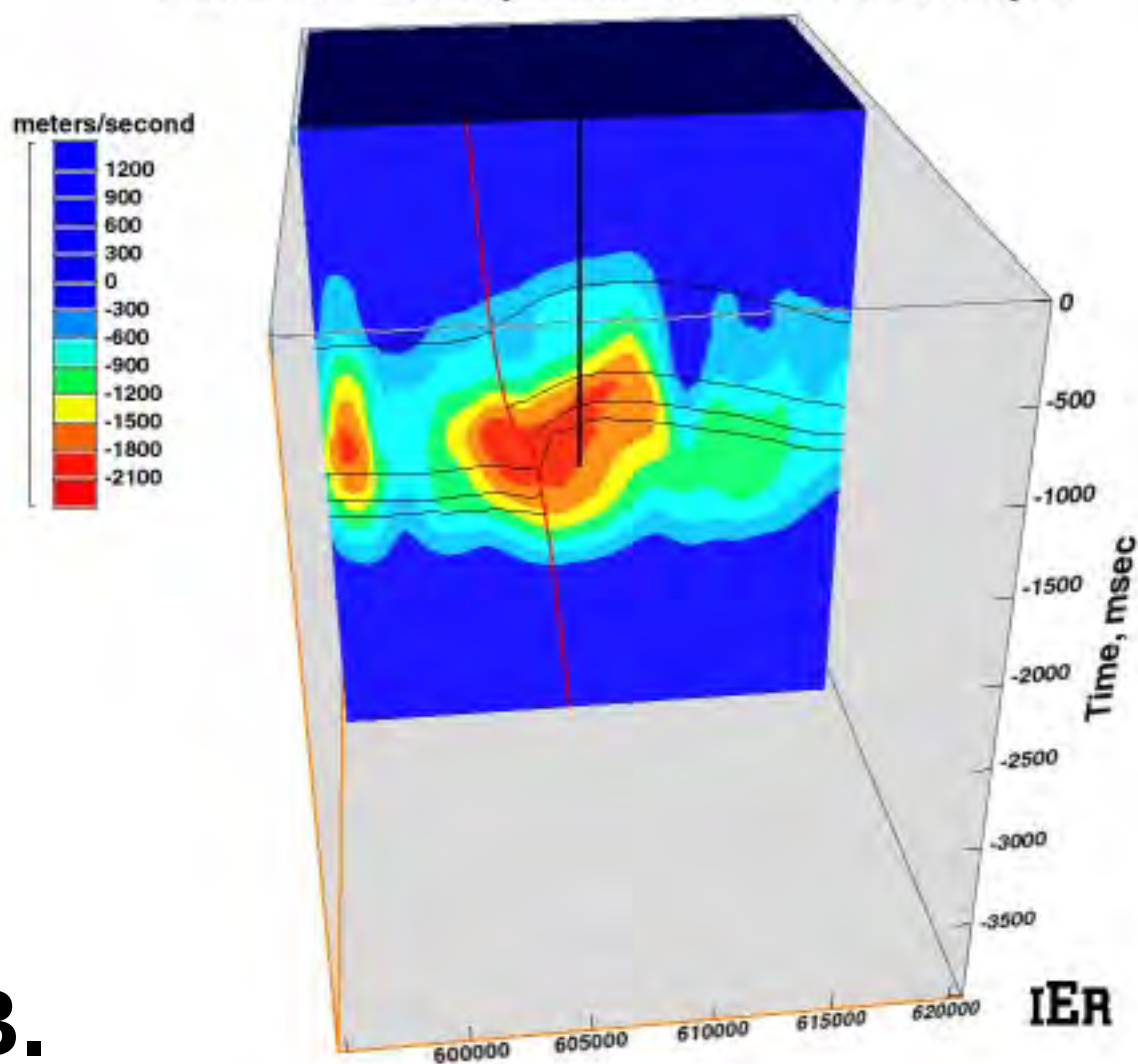


Figure 20A. North-south anomalous velocity cross section through the proposed drill site (i.e., CDP 124896). The black vertical line indicates location of proposed well on the cross section. Note that the Frontier, Muddy, and Nugget Formations all are characterized by anomalous velocities at least 1500 ms slower than the regional velocity depth gradient.

Anomalous Velocity Model, Riverton Dome Project



B.

Figure 20B. East-west anomalous velocity cross section through the proposed drill site (i.e., 124896). The black vertical line indicates location of the proposed well on the cross section (same location as in Figure 20A). Again note that the Frontier, Muddy and Nugget Formations are all characterized by intense velocity anomalies. For a more exact measure of the intensities of the anomalous velocities see Figure 19.

THE USE OF ADVANCED ACOUSTIC CAVITATION FOR APPLICATIONS IN THE OIL AND NATURAL GAS INDUSTRY

Michael L. Wilkey¹
Robert W. Peters¹
James C. Furness, Jr.²

¹Energy Systems Division
Argonne National Laboratory
9700 S. Cass Avenue
Argonne, IL 60439

²Furness-Newburge, Inc. (FNI)
376 Crossfield Road
Versailles, KY 40383

ABSTRACT

Argonne National Laboratory (ANL) has conducted research involving acoustic cavitation (sonication) combined with advanced oxidation techniques for several applications for the oil and natural gas industry. Acoustic cavitation involves the application of high intensity sound waves (having strong oxidation potential) to a liquid phase. Microbubbles form which grow to a critical size (on the order of a few angstroms) which then implode. At the collapsing bubble interface, temperatures in the order of $\sim 5,000^{\circ}$ K and pressures on the order of 500 to 1,000 atmospheres have been estimated, while the bulk solution stays near ambient. This creates conditions that are very effective for cleaning industrial equipment. This process can be enhanced by the combination with other advanced oxidation techniques such as ozone injection, vapor stripping, and/or the addition of hydrogen peroxide.

ANL has conducted research into mineral scale removal using this advanced acoustic cavitation technique. Barium sulfate (BaSO_4) scale was used as the surrogate scale. During these tests, ANL was able to break up scale with as large as 5/8-in thickness. Preliminary results to date indicate that better than 90% of surrogate scale was removed, after a 15-min application of sonication (20 kHz) at 20 W/cm^2 . Additional research (for the textile and forest products industries) conducted at ANL included the removal of solidified polyethylene from spinnerette heads and polypropylene from scaled glassware (for application to spinnerette heads). In these applications, the removal of the solidified waste form reached nearly 100% using sonication techniques. The sound waves effectively chiseled the waste forms from the equipment, breaking the scale into many, many fine particulates, effectively forming a slurry of the original solid "hockey-puck-like" monolith. The acoustic cavitation effectively scoured the equipment surface free of the solidified waste form.

ANL is currently investigating the use of this advanced acoustic cavitation technique to remove paraffin build-up from production wells and lateral piping in the field. FNI, ANL, and Nicor Technologies are currently examining the possibility of using this technique to remediate blocked or plugged underground natural gas storage wells. Other potential applications of this advanced acoustic cavitation technique being studied include: disablement and neutralization of land mines and unexploded ordinances, *in-situ* removal of chlorinated solvents (volatile organic compounds) from groundwater, enhanced oil/water separation, development of a hand held device for decontamination and decommissioning of buildings, and removal of oil and cutting lubricants from scrap aluminum.

ANL has been researching the combination of acoustic cavitation (sonication) with advanced oxidation (air, oxygen, ozone, and hydrogen peroxide) techniques for the past five years. Furness-Newburge, Inc. (FNI) has been working with the foundry industry to solve environmental emissions problems and optimize sand/clay/binder reuse for the past eight years. ANL and FNI joined forces in May of 1998 to begin examining the synergies of their independent work efforts and focus on new applications for the joint technology interests. The following text summarizes these efforts by application and give a brief summary of the approach.

Groundwater and Soil Remediation

ANL has been investigating an integrated (sonication coupled with vapor stripping) system in a current project funded by the U.S. Department of Energy's (DOE's) Environmental Management Science Program (EMSP) to partially degrade and/or destroy volatile organic compounds (VOCs). An experimental pilot-scale, in-well system is being designed and installed in a high-bay area at ANL. ANL and its industrial partner, FNI, are fabricating the test system for the pilot demonstrations.

Preliminary laboratory-scale results obtained from the EMSP project indicate the system is capable of partially degrading and destroying VOCs. The combination of sonication and vapor stripping can remove up to 97% of the chlorinated solvents with a 5-10 minute contact time. ANL believes that this system can destroy chlorinated solvents and petroleum hydrocarbon contaminants at a very high rate with minimum contact time.

ANL is currently working on a research project to determine the efficiency and economics of employing an integrated (acoustic cavitation combined with advanced oxidation) treatment system to destroy/remove hydrocarbons at levels encountered in contaminated groundwater at oil refineries. The objective of this effort is to conduct a pilot-scale demonstration of an integrated treatment system that couples in-well sonication and in-well vapor stripping augmented with ozone/hydrogen peroxide to effectively treat groundwater contaminated with petroleum hydrocarbons [e.g., polyaromatic hydrocarbons (PAHs), benzene, toluene, ethylbenzene and total xylenes (BTEX)]. This treatment scheme enables the contaminated water to be treated in well (i.e., below grade), thereby minimizing the regulatory concerns and economic issues associated with pump-and-treat technologies.

ANL and FNI have had discussions with personnel at McClelland Air Force Base in California; Warren Air Force Base in Cheyenne, Wyoming; and Badger Army Ammunition Plant in Wisconsin about the groundwater problems at their respective sites. These sites have typical groundwater problems with contamination due to chlorinated solvents such as 1,1,1-trichloroethane (TCA), trichloroethylene (TCE), dichloroethane (DCA), chloroethylene (DCE), carbon tetrachloride, vinyl chloride, and dinitrotoluene (DNT).

Scale Removal for the Oil and Gas Industry

Radioactive Scale (Naturally Occurring Radioactive Materials-NORM)

Within DOE's Gas Research Program, the management of naturally occurring radioactive materials (NORM) in natural gas production is a high priority environmental research area. Petroleum production NORM is generated in three waste streams: scale, sludge, and produced water. Scale and sludge accumulate primarily in water-handling equipment, such as pipelines, tubing, pumps, filters, oil/water separators, and storage vessels.

The purpose of this project is to examine a new technology involving sonication/dissolution aimed at treating naturally occurring radioactive materials (NORM) waste. Barium sulfate (BaSO_4) scale was used as the surrogate waste for this study. This project investigated the sonication/dissolution of NORM wastes. During the first part of this study, barium sulfate (BaSO_4) scale was formed in glass beakers; the BaSO_4 scale was spiked with various non-radioactive co-contaminant forms such as strontium and cesium. The strontium and cesium used in these studies were of the non-radioactive form. Future activities involve the sonication/dissolution of BaSO_4 -scale containing radium.

Barium-sulfate scale (potentially contaminated with radioactive materials) is a common byproduct of oil and natural gas production. The baseline technology for removing this scale from industrial equipment involves using a proprietary dissolver operated at a solution temperature of 190 to 200°F at pH ~13. A decrease of 20 to 30°F as a result of sonication would be extremely beneficial and would be more cost effective than the current operations for removing barium sulfate scale. This project also will determine whether the combination of sonication techniques coupled with the use of chelating agents could effectively remove NORM-type scale from industrial equipment. The focus of this study is to determine whether sonication techniques can enhance the dissolution of BaSO_4 scale either using sonication alone or using sonication in conjunction with chelating agents (such as ethylenediaminetetraacetic acid (EDTA), citric acid, etc.). The objective of this project is to determine whether sonication alone or using sonication in conjunction with chelating agents can enhance the dissolution of BaSO_4 scale. Preliminary results are shown in Fig. 1.

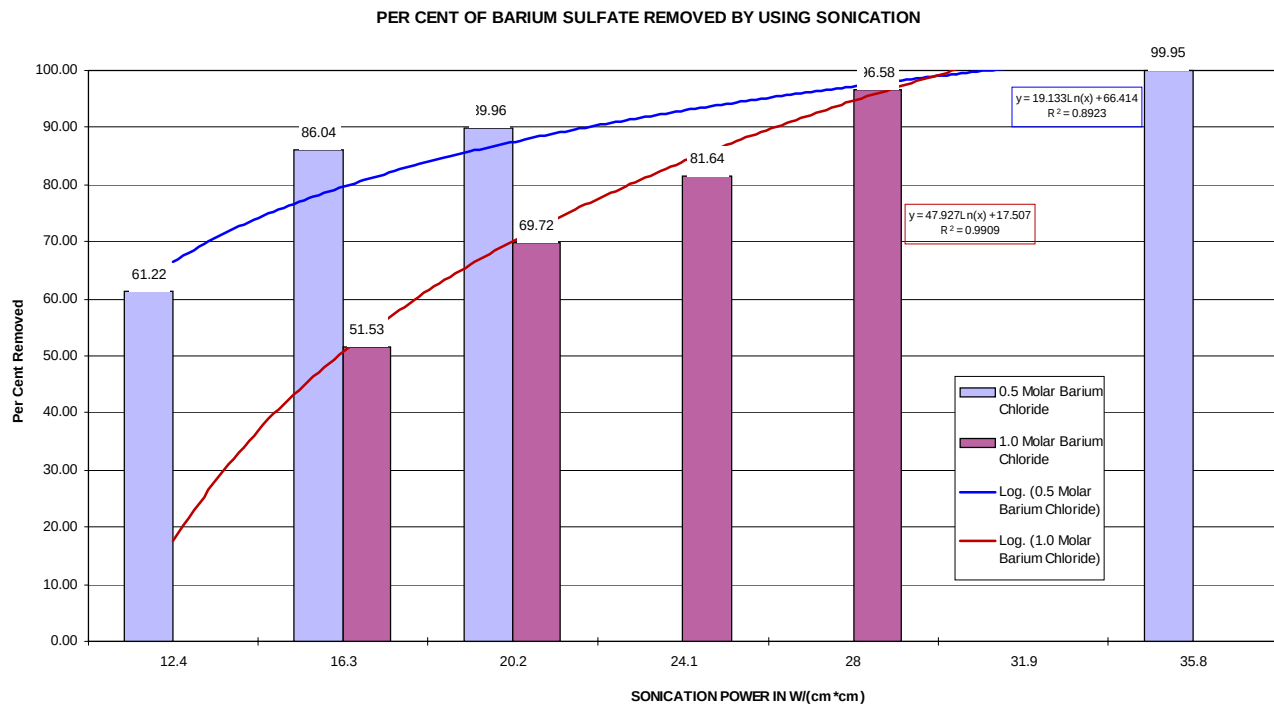


Figure 1 Preliminary results of barium sulfate removal using sonication.

Mineral Scale (Within Production and/or Storage Wells, Laterals, and Equipment)

FNI, ANL and Nicor Technologies are currently examining the possibility of utilizing sonication to locate and remediate underground natural gas storage well damage. The diagnostic portion of the research effort will utilize a high frequency transponder and a receiver to locate the damaged areas within the underground storage well. Once the problem area has been located, the actual remediation of the damage to the underground storage area will be conducted using sonic transducers contained within the same small (coffee cup size) unit used to locate the problem area. The acoustic waves generated by these transducers will actually break up any scale, inorganic precipitate, organic or hydrocarbon residue, fouling or plugging caused by either particulates or bacteria.

The use of sonic waves to locate, size, and identify objects is well known, mature technology. Sonication has also been shown to break up mineral scale and other scaling/fouling build-up within natural gas and oil field piping/wells. This project proposes to adapt sonication for the detection and remediation of damaged underground natural gas storage wells. Initially a "surrogate" underground storage well environment would have to be created in the lab. Both the locating and remedial functions of sonication would be tested in the "surrogate" storage well created in the lab. The ability of the sonicator to break-up the various types of blockages (inorganic, organic/hydrocarbon, and fouling/plugging caused by particulate and bacteria) will be tested in the lab. Additionally, more tenacious types of scale will be tested to determine the limits/capabilities of the various power intensities and frequencies used in the first year's efforts.

The field test partner, Nicor Technologies, will provide fouled/scaled tubing from actual underground storage wells. If the proposed system can remove the actual scale/fouling from the tubing provided, an actual down-hole "pre-field test" can be conducted in an actual observation well (located within a storage reservoir system) as the final test of the system prior to beginning the actual field trials scheduled as part of the second phase of activities.

Process Optimization within the Foundry and Steel Industries

In the production of iron castings, molten iron is poured into a "green" sand mold comprised of sand, clay, powdered coal, water, and organic binders. The heating of the coal and other organics in the mold during casting causes the release of volatile organic compounds (VOCs) such as benzene. In order to reduce these emissions, advanced oxidants (AO) were introduced as a "sand additive" to these molds by way of a Sonoperoxone™ (SP) system that uses ozone, hydrogen peroxide, and sonication. This SP/AO-containing water replaces ordinary water as a mold ingredient. These Sonoperoxone™ systems have been operating at more than four working foundries for the last 1 to 4 years.

Records from these foundries have shown reductions in VOCs and benzene emissions after installation of the Sonoperoxone™ system. FNI is working with the Pennsylvania State University to test and evaluate the emissions from green sand and green sand components using thermogravimetric analysis (TGA). In these TGA tests, sand samples were heated under nitrogen; and mass losses were tracked to determine the amount and temperature where emissions occur. Two full-scale foundry lines running the same casting types in parallel have been compared: one using AO/SP and one not using this AO/SP. Over a full year of operation, the AO foundry's sand had consistently lower mass losses that would translate into lower VOC emissions. In addition, pilot-scale casting trials were conducted on molds whose only difference was that one mold used this AO treated water and the other mold used ordinary water. Mold autopsies and TGA tests characterized the effect of AO on these emissions during the casting event, and generally found emission reductions with water containing AO.

Compaction and Stabilization of Wastes for Recycle/Reuse

The current disposal option of choice by the steel and foundry industry involves sending metal fines/particulates (called "swarfs") to either a landfill or to a scrap metal yard. Included in these wastes are manufacturing process "swarfs" (metallic particulates from grinding, polishing, honing, etc.); pollution control wastes (e.g., baghouse wastes and other pollution control residues); and mill scale or slags. Even though the landfills accept these wastes, the landfill owners recognize that these are really undesirable wastes, due to their tendencies to rapidly oxidize and create spot flare-ups (fires). Because of these problems, the steel industry often pays premium to dispose of the swarfs at a landfill. The "swarfs" typically contain high metallic content (>40% iron and other recyclable metals such as nickel, copper, etc.), and, therefore, have some intrinsic recyclable/reuse value. The handling of these metallic wastes (particulate and other solid forms) is difficult. By packaging these metallic wastes into a more manageable form, value is created where only cost existed before. These wastes need to be converted into a different form so that they can either be recycled or formed into a marketable byproduct.

This project investigates the use of various chemical-binding agents, used either singly or in combination with one another, in order to form dense, hard recyclable forms of the metallic particulates. The objective of this phase of ANL's work with Solvent Systems International, Inc. (SSI) is to "optimize" the compressive strengths of the newly formed by-products. ANL and SSI will examine how the additives (binders) can be combined with advanced oxidation techniques (including sonication) in order to maximize the compressive strengths of the recycled by-products.

FUTURE APPLICATIONS

The following two topic areas are applications that are not fully developed and need further study to bring them into the prototype/field testing phases of development.

Decommissioning and Decontamination of Buildings

The objective of this approach is to demonstrate the potential of multiple advanced oxidation delivery systems to deactivate viruses and kill bacteria in biological systems and to render less toxic in chemical warfare agents. The proposed delivery systems of advanced oxidants are as follows: (1) Foams or foamed gels with the bubbles containing advanced oxidants and the bubble wall structure designed in such a way to extend the stability of the advanced oxidants, such as UV/ozone/high humidity gases used to generate the microbubble structure (i.e., lamellae) in a foam or foamed gel; (2) Gas phase delivery of advanced oxidants in the form of high humidity, UV-irradiated ozone containing gas and/or the same device used as a recirculating biological or chemical destruction system; (3) Advanced oxidant containing steam-cleaning system for decontamination of buildings, rooms, or laboratories, or other structures containing chemical or biological agents. This would involve the use of advanced oxidants in the water used to generate steam. This would be a synergistic approach in that the steam in and of itself could be used to sterilize the bacteria, spores, viruses, or other microorganisms in a biological system directly and then due to the heat more rapidly decompose the toxic "skeleton" (i.e., the potentially more toxic daughter byproducts of biological death). In a chemical system employing an A/O steam decontamination approach, the A/O steam tends to speed chemical dissociation of the chemical agent. The potential use of reactive metals such as vanadium, titanium, and iron could further enhance A/O steam decontamination when finally irradiated with ultraviolet light. This creates a scenario of advanced oxidation chain reactions that have already been verified by the scientific/technical community familiar with advanced oxidation systems. The end state will be a building, facility, or site that is completely reusable, non-toxic, steam-cleaned, and in terms of public perception, "sterilized." A fourth objective would be in the creation of an advanced oxidant decontamination device to be used for hospital workers caring for victims of biological terrorism. A downdraft or side-draft device would capture the bacterial aerosol from breathing and coughing of a victim and kill the organism and hence deny a pathway for disease propagation.

The proposed approach to the problem of decontaminating chemically and biologically contaminated surfaces by deactivating viruses and killing bacteria in biological systems and rendering chemical warfare agents less toxic is unique because: (1) each sub-element of the proposed system has a proven technical basis in other applications; (2) the delivery system can

be deployed in a simple manner: and (3) the project team has both a strong scientific research and development track record and proven industrial successes.

Conventional treatment of solid structures generally includes chemical extractions such as with steam cleaning systems or chelating agents, and render to rubble contaminated structures. The approach being offered has the ability to completely remove the chemical or biological agents, and thereby enable the structure to once again be used. The technology of advanced oxidation has already been proven by the scientific community to kill pathogens and dissociate chemicals. What is being proposed is a focused expansion of existing technology into a technology that is adaptable, flexible, portable, and applicable to chemical and biological agents by relatively low-tech delivery systems and maintainable, reliable, and already proven components. Current approaches using advanced oxidation are already being used in extremely large-scale applications such as drinking water treatment and reduction of air pollutants such as benzene and other VOCs in the foundry industry.

Disablement and Neutralization of Ordinances/Land Mines/Explosives

The objective of this approach is to demonstrate the potential of multiple advanced oxidation delivery systems to deactivate viruses and kill bacteria in biological systems and to render less toxic in chemical warfare agents. The proposed delivery systems of advanced oxidants are as follows: (1) Foams or foamed gels with the bubbles containing advanced oxidants and the bubble wall structure designed in such a way to extend the stability of the advanced oxidants, such as UV/ozone/high humidity gases used to generate the microbubble structure (i.e., lamellae) in a foam or foamed gel; (2) Gas phase delivery of advanced oxidants in the form of high humidity, UV-irradiated ozone containing gas and/or the same device used as a recirculating biological or chemical destruction system; (3) Advanced oxidant containing steam-cleaning system for decontamination of buildings, rooms, or laboratories, or other structures containing chemical or biological agents. This would involve the use of advanced oxidants in the water used to generate steam. This would be a synergistic approach in that the steam in and of itself could be used to sterilize the bacteria, spores, viruses, or other microorganisms in a biological system directly and then due to the heat more rapidly decompose the toxic “skeleton” (i.e., the potentially more toxic daughter byproducts of biological death). In a chemical system employing an A/O steam decontamination approach, the A/O steam tends to speed chemical dissociation of the chemical agent. The potential use of reactive metals such as vanadium, titanium, and iron could further enhance A/O steam decontamination when finally irradiated with ultraviolet light. This creates a scenario of advanced oxidation chain reactions that have already been verified by the scientific/technical community familiar with advanced oxidation systems. The end state will be a building, facility, or site that is completely reusable, non-toxic, steam-cleaned, and in terms of public perception, “sterilized.”

This approach provides a very versatile compact transportable and low-tech decontamination family of processes that can be tailored to specific applications and locations such as targets of terrorism, triage centers, and extended care facilities. The operational personnel will require minimal training and relatively standard personal protective equipment. The maintenance personnel would require a slightly higher level of training but certainly not beyond what is considered normal and prudent in our relatively high-tech society. The transient

nature of advanced oxidation would also help to allay fears of long-term decontamination residuals, such as would be found in chlorine or other long-term potential high-risk chemical approach to chemical decontamination.

This approach focuses on the exact goals and needs of the current climate of terrorism because: (1) it focuses on a unique solution to the problem of decontaminating chemically and biologically contaminated surfaces by deactivating viruses and killing bacteria in biological systems and rendering chemical warfare agents less toxic; (2) each sub-element of the proposed system has a proven technical basis in other applications; (3) the delivery system can be deployed in a simple manner; and (4) the project team has both a strong scientific research and development track record and proven industrial successes.

Conventional treatment of solid structures generally includes chemical extractions such as with steam cleaning systems or chelating agents, and render to rubble contaminated structures. The approach being offered has the ability to completely remove the chemical or biological agents, and thereby enable the structure to once again be used. The technology of advanced oxidation has already been proven by the scientific community to kill pathogens and dissociate chemicals. What is being proposed is a focused expansion of existing technology into a technology that is adaptable, flexible, portable, and applicable to chemical and biological agents by relatively low-tech delivery systems and maintainable, reliable, and already proven components. Current approaches using advanced oxidation are already being used in extremely large-scale applications such as drinking water treatment and reduction of air pollutants such as benzene and other VOCs in the foundry industry.

In summary, seven different applications of combining advanced acoustics (sonication) with advanced oxidation techniques have been presented. At least three of these applications have direct linkages to oil and gas industry applications: (1) mineral scale removal (paraffins, underground storage well remediation, improving performance of stripper wells, etc.); (2) radioactive scale removal (NORM); and (3) groundwater and soil remediation (e.g., at oil or gas processing plants). Two other applications have been discussed that have applications in the steel and foundry industries (process optimization and compaction/stabilization of wastes for recycle/reuse). Finally two more futuristic application in the decommissioning and decontamination (D&D) areas (disablement/neutralization of ordinances and D&D of buildings) have been presented as areas that need more development work. ANL is working closely with their industrial partners (FNI, Nicor Technologies, and Solvent Systems, Inc.) in all of these areas to further advance the technology of combining acoustic cavitation with advanced oxidation techniques.

Ruggedized Optical Fiber Sensors for Downhole Monitoring

Russell G. May (rmay@vt.edu; 540-231-1837)

Anbo Wang (awang@vt.edu; 540-231-4355)

Hai Xiao (hxiao@vt.edu; 40-231-7070)

Jiangdong Deng (jdeng@vt.edu; 540-231-3829)

Photonics Laboratory

Bradley Department of Electrical and Computer Engineering

Virginia Tech

Blacksburg, VA 24061-0111

Contract Information: This research was sponsored by the U.S. Department of Energy's Federal Energy Technology Center, under Contract DE-FG26-988C15167 with the Virginia Polytechnic Institute and State University, Blacksburg, VA, and in collaboration with Chevron Research and Technology Company.

Introduction

Efficient and complete recovery of petroleum reserves is difficult in part due to a lack of robust instrumentation for characterization of physical conditions in the downhole environment. Accurate evaluation of pressure, temperature, and volumetric flow would permit optimization of oil recovery processes. Unfortunately, sensors currently used for downhole characterization have demonstrated limited lifetimes in the harsh environment that are typical for this application. Development of ruggedized instrumentation engineered specifically for the downhole environment will accelerate the adoption of technology leading to intelligent completions.

Under the sponsorship of the U.S. Department of Energy National Petroleum Technology Office, and in collaboration with Chevron Research and Technology Company, the Photonics Laboratory at Virginia Tech is investigating the application of optical fiber sensor technology to the development of ruggedized sensors for the downhole environment. Using a new sensor configuration which has been labeled the Self-Calibrating Interferometric/Intensity-Based (SCIIB) sensor, designs for the measurement of pressure, temperature, flow, and acoustic waves are being evaluated. The SCIIB configuration combines the best features of both interferometric and intensity-based optical sensors, resulting in a sensor that demonstrates the high sensitivity of interferometry, together with the simple signal processing of intensity-based sensors. In addition, the sensor probe generates two signals, which can be combined to realize self-calibrating operation. Undesired perturbations such as fluctuations in the optical source power or losses due to bends in the optical fiber are common-mode. Ratiometric processing of the two signals eliminates the common-mode perturbations and yields the desired measurand. Tests, as described below, have shown that the SCIIB sensor has a low cross-sensitivity to undesired physical effects.

Objective

Measurement and characterization of physical conditions in the downhole oil production environment will not only enable adoption of completion strategies based on expanded data from recovery processes, but also provide enhanced characterization of existing reserves. To this end, the objective of this research program is to develop and evaluate sensors for downhole measurement of pressure, temperature, volumetric flow, and acoustic waves (for seismic applications), and to develop technology to enable survival of the sensors over extended periods of time. This paper describes preliminary research in the development of a miniaturized fiber optic pressure sensor for downhole use.

Approach

Several methods have been demonstrated for the measurement of physical phenomena using optical fiber sensors. In general, some parameter of the lightwave guided by the optical fiber is modified by the measurand, and the magnitude of the measurand is inferred from the amount of change of the lightwave parameter. Some of the changes in the lightwave that can be related to applied external effects include changes in intensity (optical power), wavelength, phase, and polarization. Of these, sensors employing either changes in lightwave intensity or phase have been the most widely researched.

Intensity-based sensors are relatively simple to implement. Low-cost light sources such as light emitting diodes (LEDs) can be used, and simple photodetectors may be employed to determine the intensity of the optical power in the sensor output. An example of one type of intensity-based fiber optic sensor configured as a pressure sensor is a microbend sensor, shown in Figure 1a. A length of optical fiber connecting a source and detector is sandwiched between two plates in which ridges have been machined. When a pressure is applied to one of the plates, the resulting force deforms the fiber in a quasi-sinusoidal pattern. From experience with the design of optical fiber cables for telecommunication, it is well known that periodic deformations of an optical can generate sizable optical losses, even if the amplitude of the deformation is only a small fraction of the fiber diameter. Therefore, the pressure applied to the plate can be correlated to the reduction in optical power transmitted through the fiber, either through theoretical analysis or by experimental calibration.

However, other effects can also cause a reduction in the optical power output by the sensor, resulting in possible misinterpretation of the change as due to applied pressure. For example, bends in the optical fiber connecting the source to the sensor, which may result from routing the fiber around an obstacle, generate attenuation in the fiber. This reduction in optical power transmitted through the fiber may be erroneously interpreted as an increase in pressure applied to the sensor. In a similar manner, fluctuations in the power output by the optical source, perhaps arising from changes in the temperature of the source, also result in a change in the power incident on the photodetector. Again, the change in optical power spoofs a change in the applied pressure.

In contrast, interferometric fiber optic sensors, in which the measurand produces a change in the phase of the lightwave, are largely insensitive to optical losses in the fiber. In a typical interferometric sensor, light from a source with high coherence, such as a laser diode, is split into two paths. One type of fiber optic interferometer, a Mach-Zehnder, is illustrated in Figure 1b. One path (the reference leg) is isolated from the physical effect to be measured, while the other (the sensor leg) is subjected to the effect. The sensor is engineered so that the applied measurand effects a change in the optical path length of the sensor leg, either by elongation of the leg, or by a change in the refractive index of the leg. In the example shown, pressure applied to matched plates generates a deformation in the fiber, which elongates the fiber. At the output of the sensor, the light in the two legs is combined. Since the light is coherent, the two paths interfere, with the state of the interference depending on the relative phase difference between the interfering lightwaves; if the waves are in phase, they interfere constructively, producing strong optical power, and if they are out of phase, they interfere destructively, with a reduction in optical power.

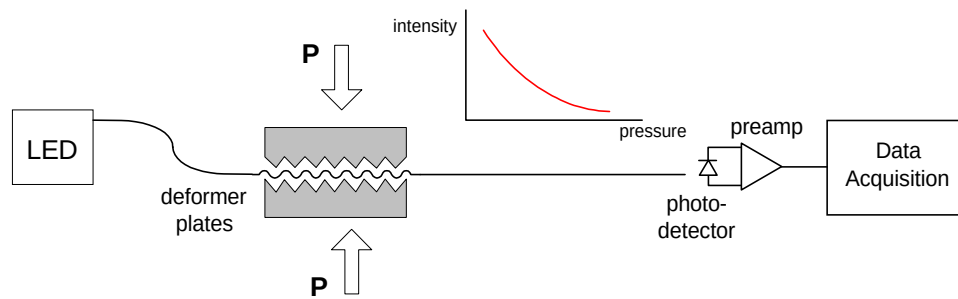


Figure 1a. Fiber optic intensity-based sensor for the measurement of pressure through microbends.

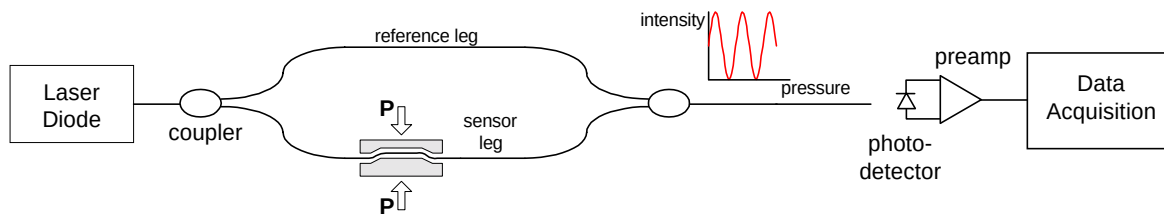


Figure 1b. Fiber optic interferometric sensor for the measurement of pressure through elongation of fiber.

Figure 2 displays the output intensity of a typical interferometric sensor as a function of the change in optical path length (the product of the physical length and the refractive index of the sensor leg). Since the interferometer output changes dramatically for changes in optical path length of less than the wavelength of light (on the order of 10^{-6} meter), the interferometer yields highly sensitive measurements of fiber elongation or

refractive index change. However, as the figure illustrates, changes in optical path length longer than a wavelength yields periodic changes in the power output by the sensor. The term commonly used for each peak in intensity is a “fringe.” The periodic output of the interferometer complicates the interpretation of the output, requiring additional equipment or algorithms to yield an output that is a monotonically varying function of the applied pressure. Some of the techniques used include counting of fringes, and use of more than one wavelength to derive an unambiguous measurement of the interference state.

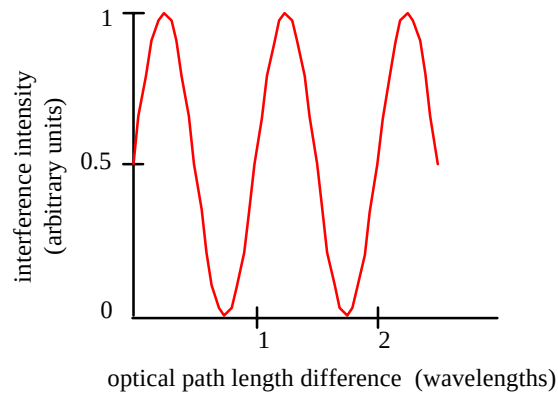


Figure 2. Typical output of an interferometric sensor for an increase in optical path length.

The Self-Calibrating Interferometric/Intensity-Based (SCIIB) sensor configuration, recently invented at the Virginia Tech Photonics Laboratory, combines the high sensitivity of interferometry with the simple signal processing of intensity-based sensors. The sensor, illustrated in Figure 3, employs a structure known as a Fabry-Perot interferometer cavity, formed by aligning two polished fiber ends inside a capillary tube. When light is injected into the sensor’s input fiber, it propagates through the fiber until it reaches the end of the fiber. Due to the discontinuity in refractive index, approximately 4% of the optical power is reflected at the fiber end as a result of Fresnel reflections (reflection R_1 in the figure). The remaining 96% of the light continues across the air gap of the cavity, until 4% of that light is reflected from the end of the second (reflector) fiber. This second reflection (R_2) travels back across the air gap and into the first (input) fiber, where it combines with the first reflection. If the optical source is coherent enough, the reflections interfere, and the intensity of the optical output of the sensor depends on the relative phase difference of the two reflections.

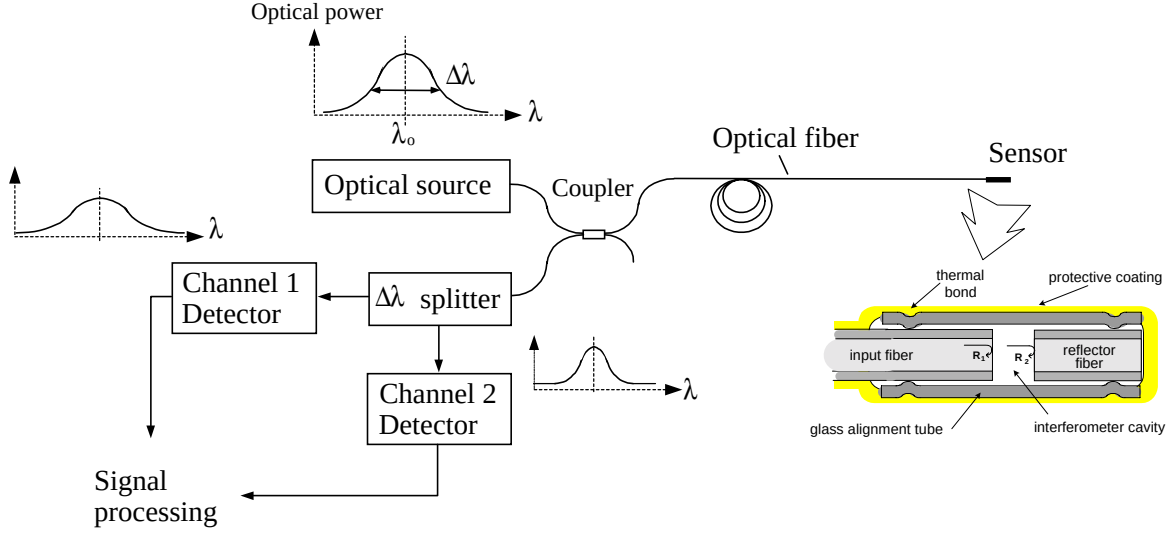


Figure 3. Schematic of Self-Calibrating Interferometric/Intensity-Based (SCIIB) sensor system, showing detail of sensor configured as a pressure sensor.

For the configuration presented in Figure 4, hydrostatic pressure applied to the sensor probe results in a deformation of the glass capillary alignment tube. When the applied pressure exceeds the pressure of the air trapped in the sensor, the radius of the tube decreases, causing an increase in the separation of the two fibers. From the principles of mechanics, an analytical expression relating the change ΔL in air gap separation to the applied pressure p is found to be

$$\Delta L = \frac{L p r_o^2}{E(r_o^2 - r_i^2)} (1 - 2\mu) \quad (1)$$

where

p is the applied pressure,
 μ is the Poisson's ratio of the glass, and
 E is the Young's modulus of the glass.

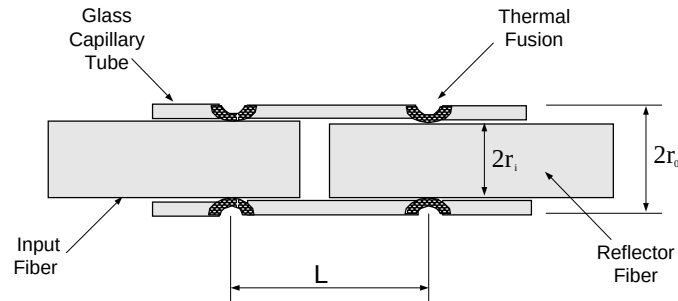


Figure 4. Schematic illustrating geometry of SCIIB pressure sensor.

To simplify the processing and interpretation of the sensor output, the sensor probe is designed so that the optical intensity of the output over the expected full range of the applied pressure remains within the quasi-linear part of the sinusoidal output. This is accomplished by controlling the length, diameter, wall thickness, and the modulus of elasticity of the capillary alignment tube during sensor fabrication. When properly designed, the excursion ΔL of the gap during the application of pressure can be limited so that the sensor output is constrained to the quasi-linear portion of the interferometric function, corresponding to the bold highlight in Figure 5. In this way, complicated signal processing involving fringe counting or spectral decomposition can be avoided, and a simple photodetector may be used, since the optical power output is then linearly related to the applied pressure through Equation 1.

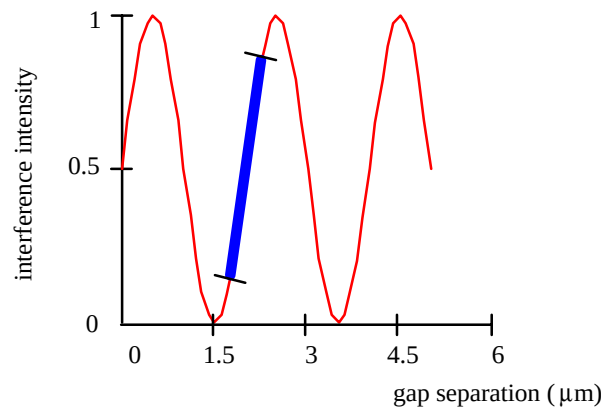


Figure 5. Intensity output of Fabry-Perot cavity, highlighting the quasi-linear region of the sensor output.

However, since the sensor's output signal is now processed like an intensity-based sensor, changes in the attenuation of the input fiber or in the output power of the source may generate errors. To eliminate this possibility, an optical beamsplitter is used to split the sensor output into two channels. Optical filters are then used to adjust the coherence of the light in the two channels. In the reference channel, the light is adjusted to have a short coherence length; in the sensor channel, the light is changed to have a long coherence length.

When the coherence length of the light source is longer than the path length difference of the two legs in an interferometer, interference is observed when the light from the two legs are combined. Conversely, when the source coherence length is less than the path length difference, interference does not take place, and the result of combining the two beams is that their intensities add arithmetically. In the SCIIB system, the coherence length of the sensor channel (Channel 2 in Figure 3) is engineered to exceed the path length difference in the Fabry-Perot cavity (the path length difference is twice the gap length, since the reflection R_2 in Figure 3 has to traverse the gap twice). Therefore, the output of Channel 2 will exhibit interference fringes as the gap length is changed due to

changes in applied pressure. As explained above, the output of the sensor channel will be constrained so that the output will be a linear function of pressure. However, changes in bends or connectors in the input fiber will also yield changes in the output of the signal channel. The function of the reference channel is to eliminate these undesired changes.

The coherence length of the reference channel (Channel 1 in Figure 3) is adjusted to be much shorter than the path length difference in the Fabry-Perot cavity; therefore no interference takes place in the output of the reference channel. The power output by Channel 1 is therefore only the sum of the optical power of the two reflections R_1 and R_2 , with no interference. The power of those reflections, however, is affected by changes in loss of the fiber or connectors. So both the sensor channel and the reference channel exhibit changes in output due to fiber loss, connector loss, or fluctuations in source output power; only the sensor channel exhibits changes in output due to gap length changes from pressure. The undesired fluctuations in power are common-mode to both signal and reference channels. By taking the ratio of the outputs of the two channels, the undesired fluctuations are canceled out, leaving only the interferometric variations, which contain the desired information about pressure measurements.

Figure 6 contains two plots generated by a theoretical simulation of the SCIIB system, and show the optical power outputs of both the reference and sensor channels. In this example, an optical source with a peak wavelength of 850 nm is assumed. The top plot, corresponding to the reference channel with an optical bandpass of 70 nm, shows that

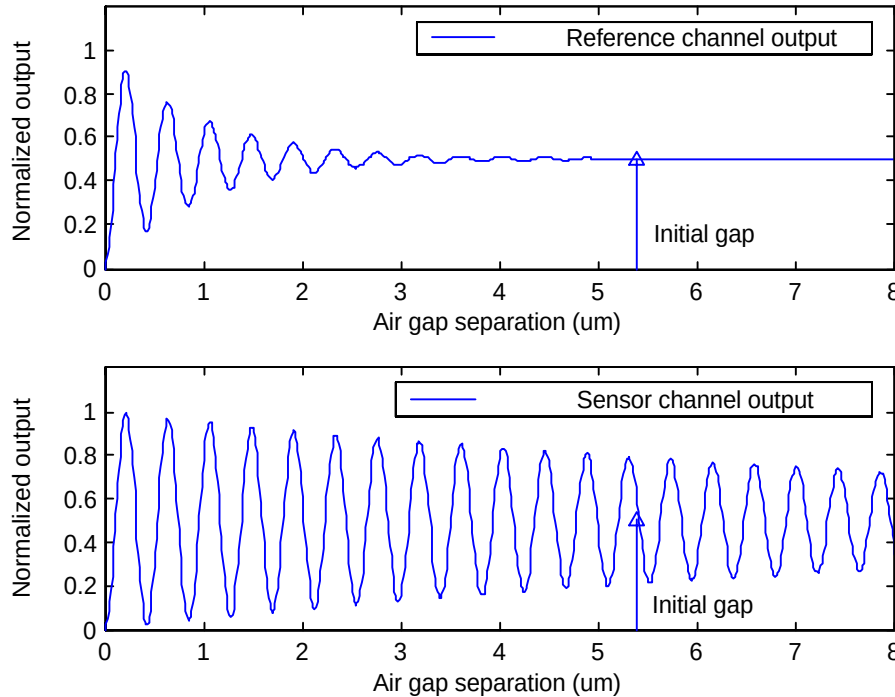


Figure 6. Outputs of two SCIIB channels, demonstrating the difference in interference effects due to coherence filtering.

interference effects are rapidly diminished as the gap increases from zero to a few microns. For gaps greater than five microns, interference effects are absent, and the output intensity equals the sum of the intensities of the two reflections R_1 and R_2 . Therefore, for the source assumed for this analysis, the initial gap of the SCIIB Fabry-Perot cavity should be set to at least 5 μm . In contrast, the sensor channel output, with a bandpass of 10 nm, exhibits strong interference effects over the entire range of air gap shown.

Results

To test the validity of the sensor system, a prototype SCIIB pressure sensor was fabricated using a one centimeter long silica tube to form a gap between two single-mode optical fibers. The optical fibers had cladding diameters of 125 μm with core diameters of 62.5 μm , and the silica tube had an inner diameter 130 μm . The outside diameter of the tube was 365 μm . The tube was bonded to the fibers by using a carbon dioxide laser to fuse the glass elements. Using a deadweight pressure calibrator, hydrostatic pressures up to 5000 psi were applied to the probe after it was connected to a laser diode and photodetector. By measuring the output intensity and counting the number of interferometric fringes in the output, the gap displacement could be determined within an accuracy of 0.1 μm . In Figure 7, the measured gap of the sensor probe as the pressure was varied is compared with the gap change predicted by Equation 1. The close match confirms that the change in gap can be used to determine the applied hydrostatic pressure. The discrepancies at higher pressures probably result from the estimate used for the value of Young's modulus of the tube in Equation 1.

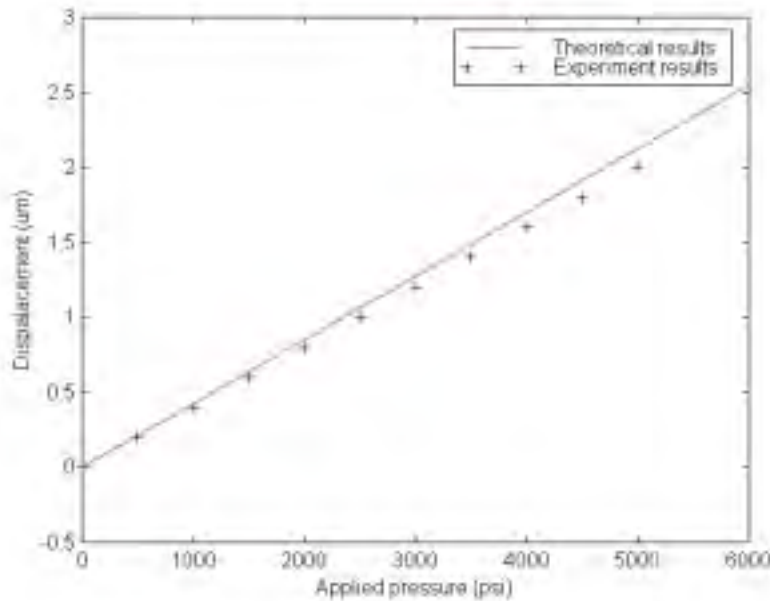


Figure 7. Comparison of experimental results with analytically predicted results for SCIIB pressure sensor.

To test the cross-sensitivity of the SCIIB pressure sensor to temperature, a new sensor was fabricated using 62.5/125 μm (core/cladding) optical fiber inside a 130/365 μm (inside diameter/outside diameter) glass capillary tube. The tube was thermally fused to the fibers so that the distance separating the fused points (parameter L in Equation 1) was 630 μm . The sensor was then connected to a two-channel optoelectronic system, similar in design to the system illustrated in Figure 3. An analog-to-digital converter was used to digitize the outputs of the two SCIIB channels, and a personal computer was then employed to calculate the ratio of the sensor channel to the reference channel. Using the deadweight pressure calibrator, the sensor probe was subjected to hydrostatic pressures varying from 0 to 2000 psi. The applied pressure was limited in this test to constrain the sensor output to remain within its quasi-linear region.

The output of the SCIIB system was compared with the pressure applied by the deadweight calibrator to determine the calibration constant for the sensor. Next, the pressure vessel of the calibrator was wrapped with electrical heating tape, so that the temperature applied to the sensor could be varied during the pressure test. A thermocouple was used to monitor the temperature. The temperature was adjusted to 50°C, 100°C, 145°C, and 196°C, in turn. At each temperature, the hydrostatic pressure was increased from 0 to 2000 psi in steps of 100 psi, with the output of the SCIIB sensor recorded for each pressure increment. Figure 8 displays the result of the tests at the four temperatures, and indicates that the temperature changes have an almost negligible effect on the sensor output. The temperature effect was calculated to be 0.04% $^{\circ}\text{C}^{-1}$ over the full range of the sensor output.

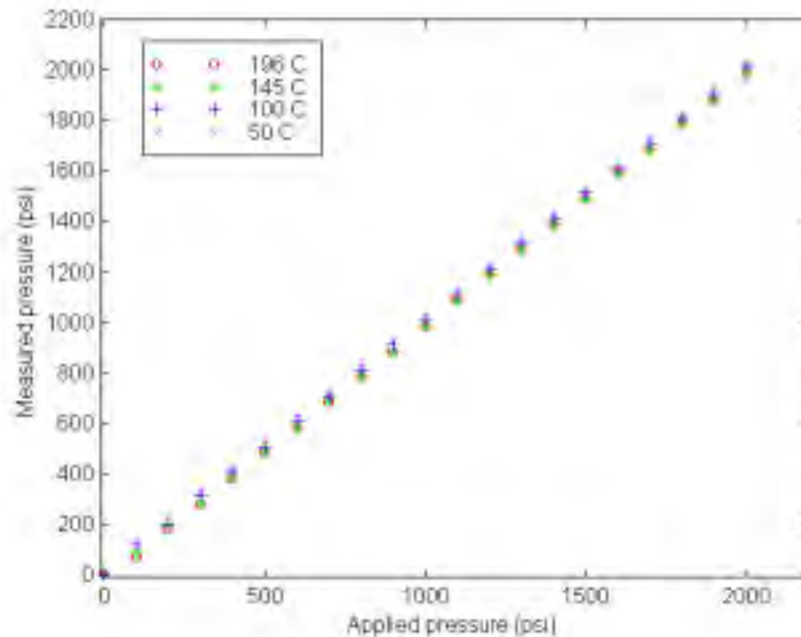


Figure 8. Output of SCIIB pressure sensor for applied pressure at different temperatures.

An experiment was undertaken to investigate the SCIIB system's ability to compensate for undesired changes in the fiber loss or source power. For this test, a 62.5/125 μm (core diameter/cladding diameter) multimode fiber was connected to a two-channel optoelectronic system similar to the one illustrated in Figure 3. The free end of the fiber was not terminated with a Fabry-Perot cavity; in this way, the reflection from the end of the fiber would be absent of interference effects. Under these conditions, the output of the SCIIB system should be constant, even if the source optical power or the fiber attenuation is changed.

To generate a change in the optical loss of the fiber, it was wrapped one turn around a cylindrical mandrel to induce bend losses. Since the magnitude of the optical loss increases as the radius of the bend in the fiber decreases, it is possible to introduce varying amounts of loss by using mandrels of different diameters. The amount of loss induced was calculated by measuring the voltage output by the reference channel when the fiber was bent. This measurement was divided by the output of the reference channel recorded before the fiber was bent. After subtraction of this ratio from a value of one, the loss was then expressed as a normalized value,

$$\text{normalized fiber loss} = 1 - \frac{P_{\text{bent}}}{P_{\text{straight}}}. \quad (2)$$

The output of the SCIIB system, found by taking the ratio of the two channels, was plotted as a function of normalized fiber loss as the loss was increased from zero to 0.5 (3dB). The results in Figure 9 indicate that the SCIIB system is very effective in rejecting changes in optical power that are common mode to both the reference and sensor channels.

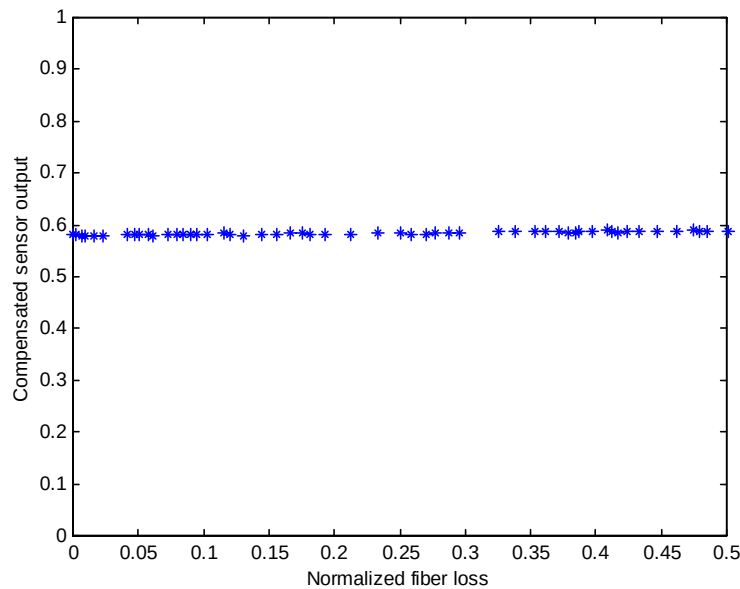


Figure 9. Plot of SCIIB system output as fiber loss was increased up to 3 dB through bending of input fiber.

Future Activities

While the preliminary results presented here validate the optical principles of the SCIIB sensor and suggest a promising future for the application of the sensor in the oil industry, much work remains before the sensor could be considered practical for downhole applications. Currently, our laboratory is developing methods for the automated assembly of the pressure sensor probe. Computer controlled fabrication is expected to enhance sensor repeatability and reliability.

The downhole environment is a particularly harsh one for glass fibers. Water, present in many wells, attacks the amorphous network in silica-based glass, and promotes failure of the fiber through stress corrosion. The high pressures and temperatures present in the downhole environment will only serve to accelerate this process. The polymers that are typically used to coat optical fibers for telecommunications uses are permeable to water under high pressures, due to free volume in the polymers. One of the goals of this research program is to identify coatings that will protect the glass fiber in high-temperature, high-pressure environments. Towards this end, we will evaluate commercially available polymer, metallic, and ceramic coatings for optical fibers, as well as experimental coatings that can be applied to the fibers using Virginia Tech's optical fiber draw tower.

Prototype sensors will be tested in the latter part of the program, first at the University of Tulsa in conditions simulating a typical downhole environment, and then in an actual well in Chevron's Coalinga, CA oil field.

Acknowledgement

The authors gratefully acknowledge the Contracting Officer's Representative, James L. Barnes, of the National Petroleum Technology Office.

Electrical resistance tomography using steel cased boreholes as long electrodes

Robin L. Newmark (newmark@llnl.gov; 925-423-3644)

William D. Daily (daily1@llnl.gov; 925-422-8623)

Abelardo L. Ramirez(ramirez3@llnl.gov; 925-422-6909)

Lawrence Livermore National Laboratory,

P.O. Box 808

Livermore, Ca., 94550

Abstract

Electrical resistance tomography (ERT) using multiple electrodes installed in boreholes has been shown to be useful for both site characterization and process monitoring. In some cases, however, installing multiple downhole electrodes is too costly (e.g., deep targets) or risky (e.g., contaminated sites). For these cases we have examined the possibility of using the steel casings of existing boreholes as electrodes. Several possibilities can be considered. The first case we investigated uses an array of steel casings as electrodes. This results in very few data and thus requires additional constraints to limit the domain of possible inverse solutions. Simulations indicate that the spatial resolution and sensitivity are understandably low but it is possible to coarsely map the lateral extent of subsurface processes such as steam floods. The second case uses an array of traditional point borehole electrodes combined with long-conductor electrodes (steel casings). Although this arrangement provides more data, in many cases it results in poor reconstructions of test targets. Results indicate that this method may hold promise for low resolution imaging where steel casings can be used as electrodes but the merits depend strongly on details of each application. Field tests using these configurations are currently being conducted.

Background

Electrical resistance tomography (ERT) has been demonstrated to be a useful characterization tool, providing details of the lithostratigraphy between wells (e.g., Newmark *et al.*, 1994). ERT has previously been used to map subsurface processes such as fluid infiltration (Daily *et al.*, 1992), steam injection and ohmic heating (Ramirez *et al.*, 1993, 1995) by mapping the spatial and temporal changes in soil resistivity resulting from changes in liquid saturation and temperature. It has also been used to monitor the removal of DNAPL chemical during pumping (Newmark *et al.*, 1998). The presence of appreciable amounts of separate-phase, electrically insulating fluids locally increase electrical resistivity. The removal of these fluids during pumping produces a drop in electrical resistivity, as the insulating fluids are displaced by relatively conductive formation fluid.

In general, ERT has been conducted using a cross-borehole geometry, using multiple electrically-isolated electrodes placed in vertical arrays. This geometry has the potential to

produce relatively high quality, high resolution images when the aspect ratio of vertical to horizontal spacing is equal to or greater than 1.5:1.0. Typical electrode installations involve multiple electrodes strung on nonconductive casing (e.g., plastic or fiberglass) in conventionally-installed boreholes, or as instrumentation strings installed using cone penetrometers. Both designs have been effective in shallow to moderate depths (most recently up to 1300 ft), but deeper installations require significant and more costly modifications. The ability to obtain ERT images using existing conventional casings as electrodes would increase the applicability of the technique. In this context, we undertook a study to examine the possibility of using the steel casings of existing boreholes as electrodes.

The method of ERT data collection and processing has been described in detail by Ramirez and his colleagues (e.g., Ramirez *et al.*, 1995). The forward and inverse modeling codes are described by LaBrecque *et al.*, (1996). The forward solution is implemented using the finite difference technique with Newman boundary conditions at the ground air interface and Dirichlet boundary conditions along the other faces of the cube. The inverse solution employs an objective function which aims to minimize data misfit and model roughness. The minimization of the objective function is done iteratively.

Case 1: Crosswell ERT

In the first case, we modeled ERT data acquired using a standard crosswell configuration. The model simulates a typical layered sand and shale sequence common in many oil fields (Figure 1). It is composed of a series of various thickness, 40 ohm-m units (sands) imbedded in a 4 ohm-m matrix (shales). The sand units range in thickness from 2.3 m to 9.1 m thick. These 2D simulations include two ERT electrode strings separated by 30.5 m, each consisting of 30 electrodes. Vertical electrode spacing is set to 4.6 m, so the 2.3 m thick sand is half the electrode spacing. In all models, there are two pixels per electrode spacing (each pixel in this first case is about 2.3 m square). The modeled region is larger than the image plane alone, so boundary effects are minimized. Synthetic data generated using the forward model is inverted, producing an image indicative of a typical baseline image one might obtain in the field. In the baseline inversion, the shape of the sands are well represented, even the one whose thickness is only half the electrode separation. The amplitudes are also well reconstructed except for the thinnest sand layer, whose amplitude reflects the averaging expected over the electrode spacing.

We next decrease the resistivity in the sand units, as we simulate the passage of steam through the sands. Over time, the sand units fill with steam, decreasing their resistivity to that of the surrounding shale (4 ohm m). As the steam fills the sands, the inverted images clearly indicate the location of the steamed region. Amplitudes are similarly reproduced as for the baseline image. The location and extent of the region in which resistivities are decreased is well reproduced in all but the thinnest sand, where it appears to be somewhat smeared laterally beyond the zone of change in the model. The absolute value of the difference is well represented in all but the thinnest sand as well.

Case 2: Point electrode to casing configuration.

As an intermediate step toward a pure casing-to-casing configuration, we next simulated a hybrid configuration utilizing both point electrodes and vertical casings as long electrodes (Figure

2). These simulations were computed in 3D. We assume two electrode arrays, 23.3 m apart, with a vertical casing outboard on each side, an additional 23.3 m out. Two surface electrodes were included, each located an additional 94 m outboard of the two casings. The finite difference mesh width is 1554 m in the direction co-planar with the casings and electrode arrays, 1508 m in the direction perpendicular to the image plane, and 786 m deep. The imaged plane lies in the center. The point electrode arrays are shown schematically in the figure; they are located in the same 98 m interval as in the first case. The model is only permitted to change between 348 and 446 m; this assumes changes only occur in the pay zone.

In this simulation, we permit the resistivities of the initially 40 ohm-m sand units to decrease to 10 ohm-m, simulating the progress of steam through the sands over time. The lower sand unit reaches only partway across the image plane. Steam fills from right to left. The decrease in resistivity due to the passage of steam is apparent in the time progression of the inverted difference images (with respect to baseline) (Figure 2). The location and amplitude of the steam front is well reproduced between and near the point electrodes. Resolution is lost (the image appears smeared) near the vertical casings.

Case 3: Casing to casing configuration.

In the casing to casing configuration models, we modeled the electrode array as a simple 9-spot pattern of vertical casings acting as electrodes (Figures 3 and 4). The casings define a square pattern which is 140 m on a side. Twelve surface electrodes were included, located halfway between each of the nine casings, in the x and y directions. The complete model width is 2270.28 m in both the x and y directions, and is 956.24 m deep. The imaged volume lies in the center, in the depth interval from 348 to 446 m.

We considered two cases. In the first, the entire 445 m long casings were utilized as a “long” electrode (Figure 3). In the second, only the lower 70 m of each casing was energized, simulating a “short” electrode over the lower portion of the casing (Figure 4). This latter configuration reflects engineering considerations for limiting current flow over the upper portion of the casing above the region of interest. In both cases, the model is only permitted to change between 348 and 446 m. As before, the model consists of 40 ohm-m sands, filling over time with 10 ohm-m steam, surrounded by a 4 ohm-m shale. Steam fills from right to left, and only fills part of the volume (plane in and out of the page). All changes are constrained to the lower portion of the model.

In both the “long” and “short” casing to casing simulations, no vertical resolution is available. However, there is useful horizontal resolution. The movement of steam across the field is readily apparent, particularly in the difference images. The lateral extent in both the along- and across- steam front directions is well reproduced. The long model predicts a smaller difference amplitude than expected. The short model results in a greater predicted amplitude of the difference, closer to the expected value.

Summary

We have evaluated the use of metal casings as long electrodes with which to perform electrical resistance tomography. The results of these simulations suggest that it may be possible to monitor steam flood using this approach. Conventional crosswell ERT provides good lateral

and vertical images of resistivity changes resulting from steam progress. In the hybrid case, using both vertical casings and point electrode arrays, overall resolution was degraded with respect to the crosswell electrode string case, yet better than that using casings alone, as expected. Using vertical casings alone, there is distinct signature indicative of the changing resistivity across the field, which is well above the noise level in the simulations. Given these indications, field surveys in an oil field undergoing steam flood are underway.

Acknowledgements

This work was funded by the U.S. Department of Energy's Office of Fossil Energy, Natural Gas and Oil Technology Partnership program. We appreciate the efforts of Rhonda Lindsey, the National Petroleum Technology Office Program Manager for this project. We gratefully acknowledge the support of our industrial partners, Aera Energy LLC, Chevron Production, Inc. and SteamTech Environmental Services, Inc., in this effort. Work performed under the auspices of the U.S. Department of Energy by the Lawrence Livermore National Laboratory under Contract W-7405-ENG-48.

References

- Daily, W., A. Ramirez, D. LaBrecque and J. Nitao, 1992. Electrical Resistivity Tomography of Vadose Water Movement, *Water Resources Research*, v. 28, no. 5, 1429-1442.
- LaBrecque, D.A., G. Morelli and P. Lundegard, 1996. 3-D electrical resistivity tomography for environmental monitoring, Symposium on the Application of Geophysics to Engineering and Environmental Problems (SAGEEP) '96, Keystone, Co., April 28 - May 2, 723-732.
- Newmark, R.L., S. Boyd, W. Daily, R. Goldman, R. Hunter, D. Kayes, K. Kenneally, A. Ramirez, K. Udell, and M. Wilt, 1994. Using geophysical techniques to control in situ thermal remediation, Symposium on the Application of Geophysics to Engineering and Environmental Problems (SAGEEP) '94, Boston, Ma., March 27-31, 195-211.
- Newmark, R.L., W.D. Daily, K.R. Kyle and A. L. Ramirez, 1998. Monitoring DNAPL pumping using integrated geophysical techniques, *Journal of Environmental and Engineering Geophysics*, v. 3, no.1, 7-14.
- Ramirez, A., W. Daily, K. LaBrecque, E. Owen and D. Chesnut, 1993. Monitoring an Underground Steam Injection Process Using Electrical Resistance Tomography, *Water Resources Research*, v. 29, no. 1.
- Ramirez, A., W. Daily and R. L. Newmark, 1995. Electrical resistance tomography for steam injection monitoring and process control, *Journal of Environmental and Engineering Geophysics*, v. 0, no. 1, p. 39-51.

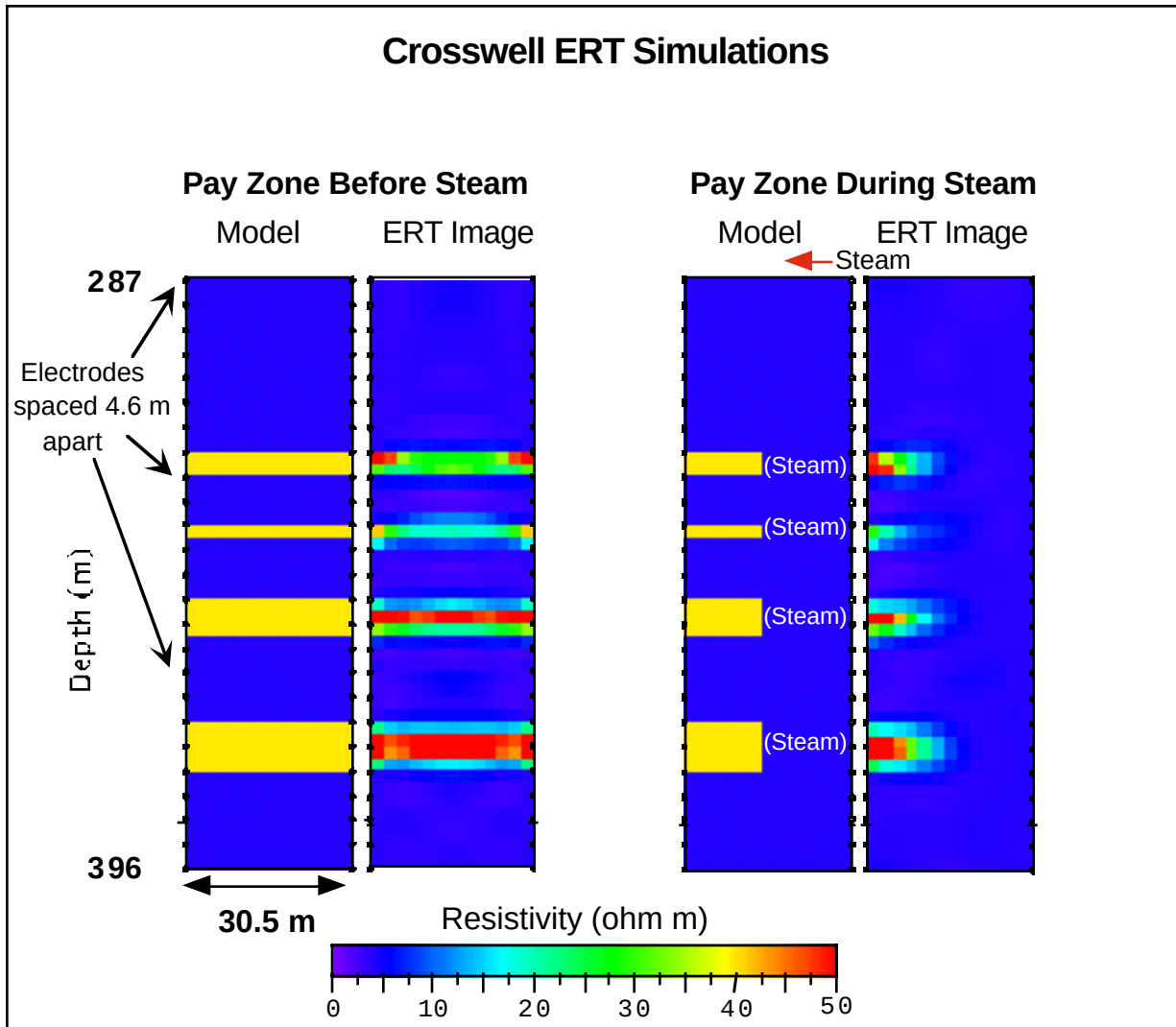
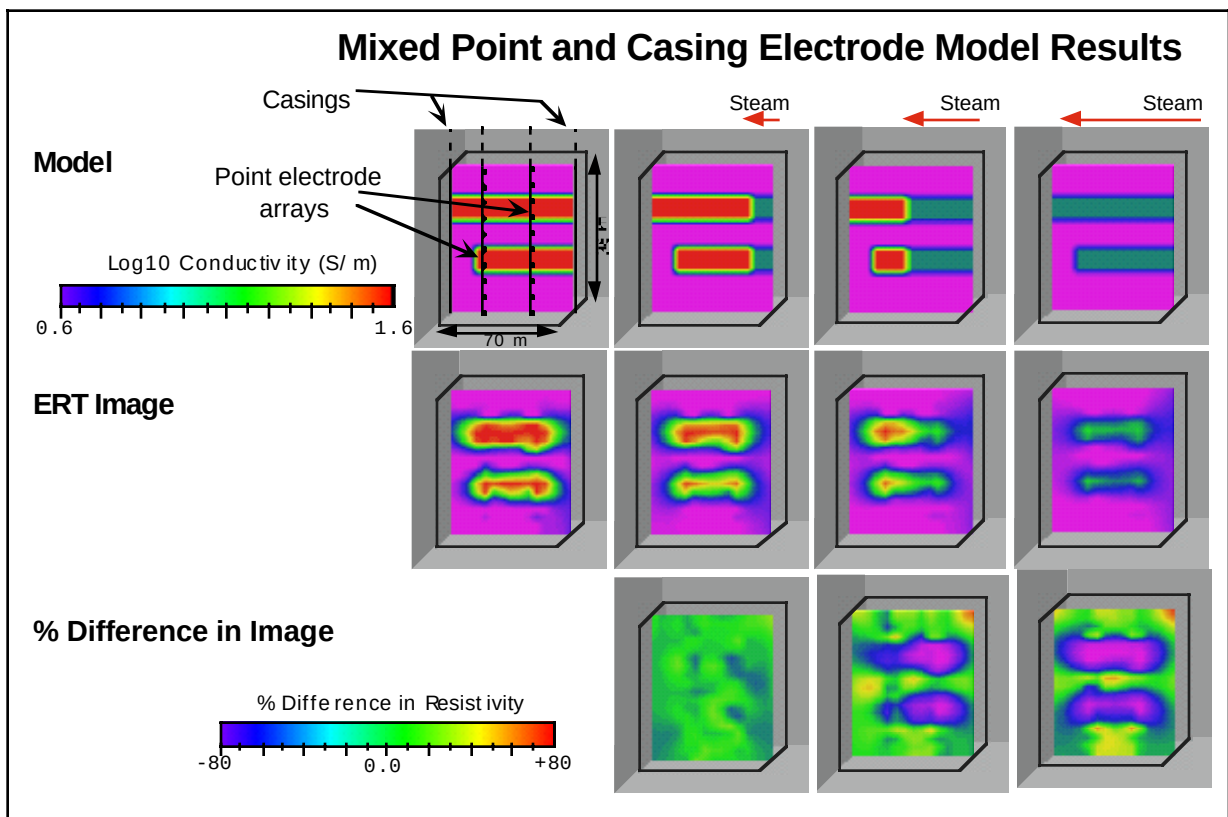


Figure 1. Crosswell ERT simulations, showing the effect of various thickness sand units filling time, decreasing their resistivity to that of the surrounding shale. On the left are shown the model and the inverted ERT image. On the right are shown the model and inversion assuming that the steam has passed halfway through the image plane, in all the sand units.

Figure 2. Results of simulating mixed point and casing electrodes. Top: 3D model, with 40 ohm m sands, filling over time with 10 ohm m steam, surrounded by a 4 ohm m shale. Steam fills from right to left; the lower sand unit reaches only partway across the image plane. Center: Simulated inversions. Bottom: Difference images (with respect to baseline) over time.



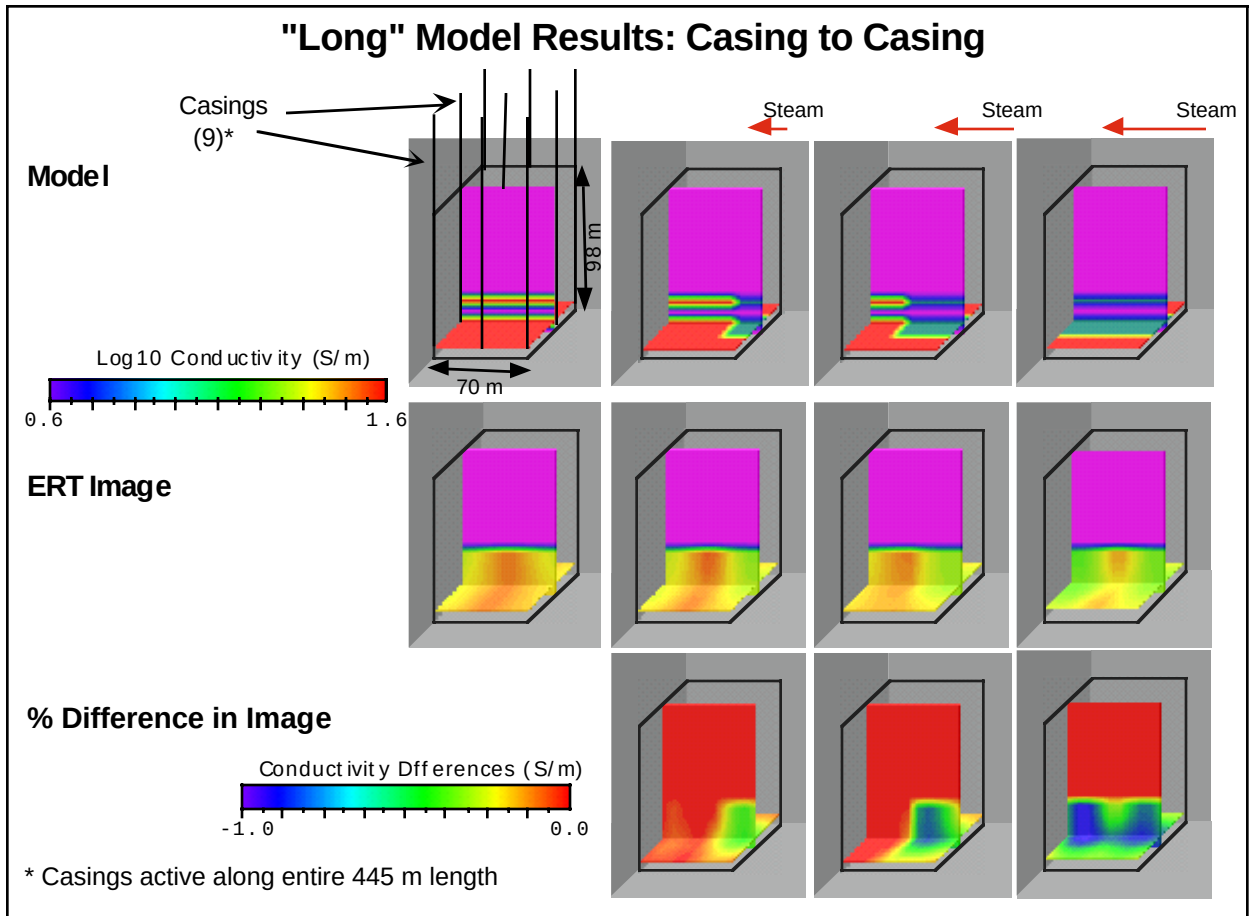


Figure 3. Results of "long" casing-to-casing simulations, assuming the entire casing length has electrical contact with the formation. Steam fills from right to left, and only fills part of the volume (plane in and out of the page). Center: Simulated inversions. Bottom: Difference images (with respect to baseline) over time. All changes are constrained to the lower portion of the model.

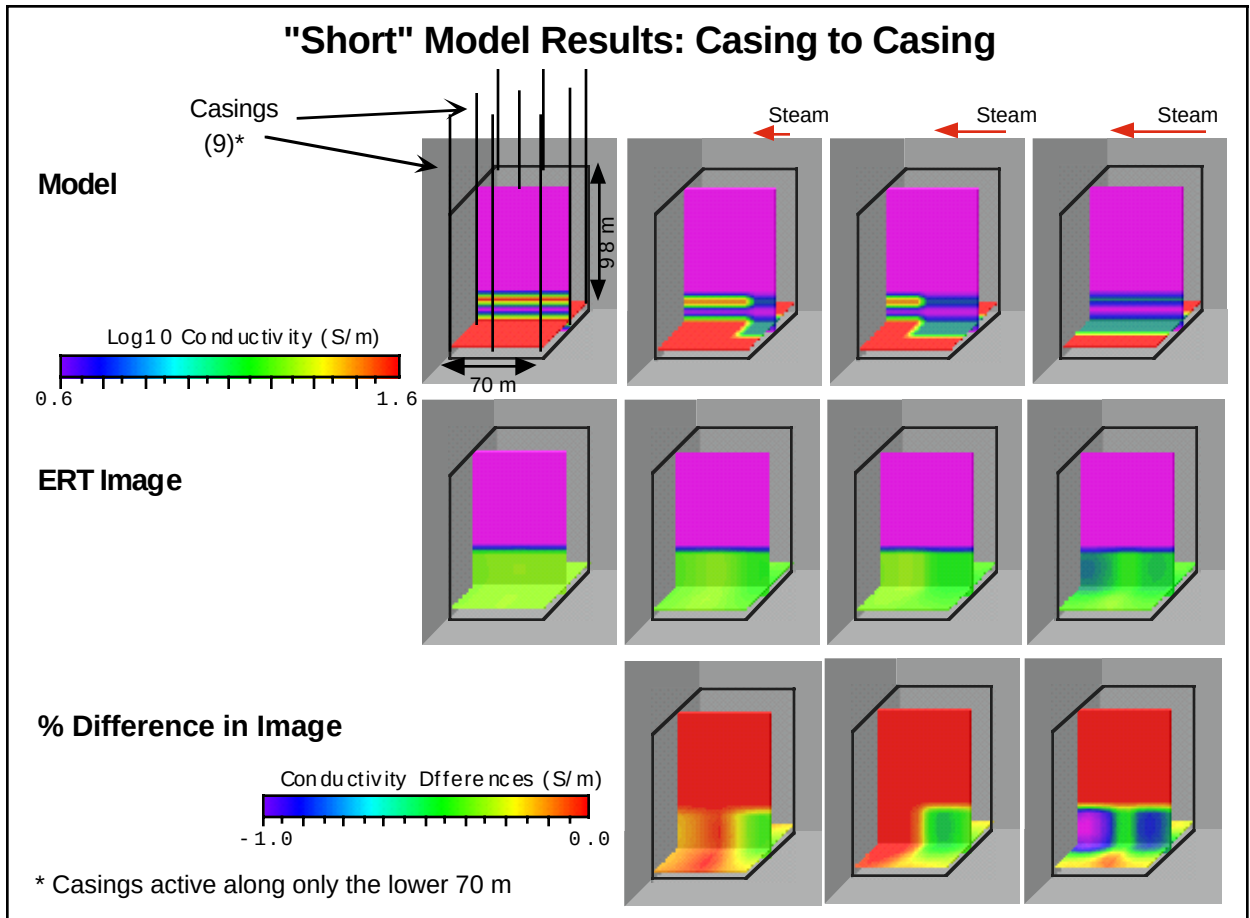


Figure 4. Results of "short" casing-to-casing simulations, assuming only the lower 70m of casings have electrical contact with the formation. Same presentation as in Figure 3.

James N. Albright and Donald S. Dressen
Los Alamos National Laboratory

Abstract

At Los Alamos, we have embarked upon a broad-based technology integration and development program. Our goal is to demonstrate the feasibility of obtaining geotechnical information in the subsurface by combining miniaturized conventional drilling technologies with contemporary electronics and advanced sensors assembled in very small-diameter borehole instrumentation packages. Using this approach, we expect to achieve a substantial reduction in the cost of oil and gas exploration and to increase the quantity and quality of subsurface data by using instruments specifically designed for data acquisition in microholes drilling at critical locations.

Advances in Crosswell Electromagnetics: Steel Cased Boreholes

Barry A. Kirkendall (kirkendall1@llnl.gov; 925-423-1513)

Phillip E. Harben (harben1@llnl.gov; 925-422-3571)

Lawrence Livermore National Laboratory

P.O. Box 808 L-206

Livermore, CA 94550

Work performed under the auspices of the Department of Energy by the Lawrence Livermore National Laboratory under contract W-7405-Eng-48. University of California - COR William Daubenspeck, P.O. Box 808, Livermore CA 94550. Telefax: (925) 422-1100. Ongoing period of performance.

Nearly 400 billion barrels of oil are estimated to remain in US reserves; as a result, new geophysical technologies for assessing the practicality and cost of extended oil recovery are urgently needed. The crosswell electromagnetic (EM) induction technique allows precise, high resolution mapping of the spatial conductivity distribution between fiberglass (i.e. nonconductive) cased boreholes, thus providing high resolution reservoir characterization as well as steam and water flood tracking. Potential conductivity contrasts may occur, for example, between oil sands and water sands, during spatial variability of gas-water contacts, or from loss of steam due to incidental fractures. The predominant amount of casing encountered in the oil patch, however, is carbon steel, which significantly attenuates and disperses the inductive electromagnetic energy due to its surface conductivity. The extension of the crosswell EM technique to single and dual steel cased wells would not only greatly expand this technique, but would allow rapid, efficient, and versatile reservoir characterization in the oil field. As this expansion is contingent on a practical and economical solution of EM induction through carbon steel casing, Lawrence Livermore National Laboratory (LLNL) has recently made significant progress towards this end and is continuing to investigate further this technique.

Wu and Habashy (1994) established a foundation for this study with experimental and modeling results regarding the effect of laboratory steel casing on the electromagnetic signals transmitted through such casing. Although the conductivity, magnetic permeability, and the casing wall thickness all affect the induced EM field, it was found that casing thickness and conductivity of carbon steel do not vary significantly. It is therefore the relative change in the magnetic permeability which most affects the EM energy. Wilt et al. (1995) suggest that the casing effect is localized within the pipe section that includes the sensor and that the effect of the casing can be separated. Recent data acquired by LLNL at a site in Richmond, California quantify the effect of steel casing on induction measurements and demonstrate this effect to be separable, as well as a method of separation. This unique site contains adjacent steel and plastic wells in which frequency soundings demonstrate low spectrum (1.0 - 200 Hz) measurements an effective method of isolating the casing response from the formation response. It is shown that the steel casing effect on the induction coil is highly localized, and limited to a maximum of 0.60 meters above

and below the coil. Additionally, operating frequencies are optimized in the single steel case, as well as quantification of the difficulties caused by electrical property spatial variations in steel casing. Concerning the dual steel well scenario, preliminary studies suggest a method to weight the effect of each individual carbon steel well. The presence of dual steel collars is easily mapped, and with prior knowledge of their limited spatial effect, it is shown that the effect can be subtracted from the formation response.

Future steel casing research at LLNL concerns the development of new processing methods to quickly and accurately remove steel casing effects, to investigate and use rapid, more efficient methods of tomographic inversion in the presence of high attenuation and dispersion due to carbon steel, and the increase of model resolution in a complex subsurface such as typically encountered at petroleum fields.

DISCLAIMER

This document was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor the University of California nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by tradename, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or the University of California. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or the University of California, and shall not be used for advertising or product endorsement purposes.



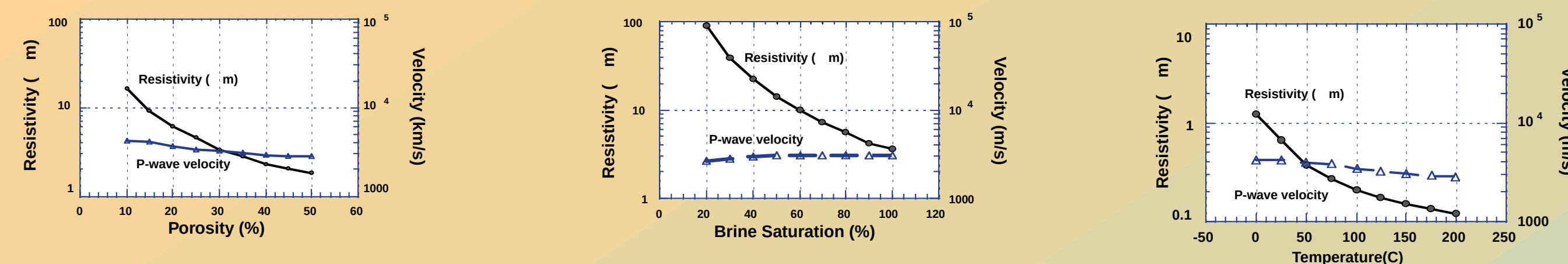
Advances In Crosswell Electromagnetics: Steel Cased Boreholes



Nearly 400 billion barrels of oil are estimated to remain in US reserves; as a result, new geophysical technologies for assessing the practicality and cost of extended oil recovery are urgently needed. The crosswell electromagnetic (EM) induction technique allows precise, high resolution mapping of the spatial conductivity distribution between fiberglass (i.e. nonconductive) cased boreholes, thus providing high resolution reservoir characterization as well as steam and water flood tracking. Potential conductivity contrasts may occur, for example, between oil sands and water sands, during spatial variability of gas-water contacts, or from loss of steam due to incidental fractures. The predominant amount of casing encountered in the oil patch, however, is carbon steel, which significantly attenuates and disperses the inductive electromagnetic energy due to its surface conductivity. The extension of the crosswell EM technique to single and dual steel cased wells would not only greatly expand this technique, but would allow rapid, efficient, and versatile reservoir characterization in the oil field. As this expansion is contingent on a practical and economical solution of EM induction through carbon steel casing, Lawrence Livermore National Laboratory (LLNL) has recently made significant progress towards this end and is continuing to investigate further this technique.

What are the advantages of Electromagnetics?

Electromagnetics can be more sensitive to changes in porosity, temperature, and brine saturation than through the use of seismic methods. This translates into excellent resolving ability for tracking steam floods, water floods, and fracture detection.



New LLNL Crosshole Field System

Receive

- Pentium - based Ethernet / LABVIEW acquisition and operation
- GPIB Instrument control
- Fiber - Optic Voice Communication



Logging mast fully extended on the LLNL receiver truck with the rear hydraulic stabilizer system activated. The large fuel capacity allows over 140 hours of operation in remote field sites. The transmitter truck is shown to the far right of the figure at the Richmond Field Station, California - a separation distance of 52 meters.

Transmit

- Analog Transmit Coil
- Pentium / LABVIEW based digital acquisition system
- Fiber Optic Ethernet and
- Analog Link with Receive truck
- Transmitter operable up to 125 C



Rear view of the LLNL transmitter truck. The mast is controlled by a hydraulic boom for positioning over boreholes. The site is at the Richmond Field Station, California

→ 175 C with new transmitter

Summary

- Crosswell EM can be used to image through single and dual steel casings
 - An experiment this August at Seneca Resources, California, will attempt to better constrain the dual steel casing problem
 - Numerical models of a segmented casing in a layered medium are needed to better understand the electrical properties of variable pipe sections
- The effect of the steel casing is a linear shift in amplitude and phase which can be subtracted in the frequency domain
- The steel casing effect on the induction coil is limited to 0.60 meters above and below the coil
- To achieve the best balance between formation sensitivity and attenuation, the most effective frequencies for use in induction through steel casing are between 100 Hz and 300 Hz

Future work

Modeling resolution

The necessary resolution is already in the data, the problem is getting it out, since the conductive earth disperses the crosswell signal energy.

- sensitivity analysis
- q-domain wavefield imaging techniques.

Expansion of applications

Crosswell EM through single- and dual-steel casing is clearly the primary focus of this section, although other applications of crosswell EM to be investigated are

- Development of a segmented casing forward modeling code for both vertical and horizontal dipoles in a layered medium

Methods for removal of steel casing effects

Designing a device capable of measuring properties of the steel casing

Measurement while drilling - the process of placing a transmitting antenna behind the drilling terminus would vastly broaden this technique

Natural gas field applications which would measure changes in the water-gas contact.

Using permanent sensors, cemented down-hole

Coupling Data to Reservoir Characteristics and Rock Properties

The LLNL petrophysical laboratory is simultaneously working on several relevant issues regarding the micro effects of steam flooding during enhanced oil recovery processes. These experiments, concerning temperature, conductivity, and pressure, can produce results to help constrain our inversion processes, within steel cased wells.

Figure One
Comparative Amplitude Response of Steel and Plastic Cased Wells

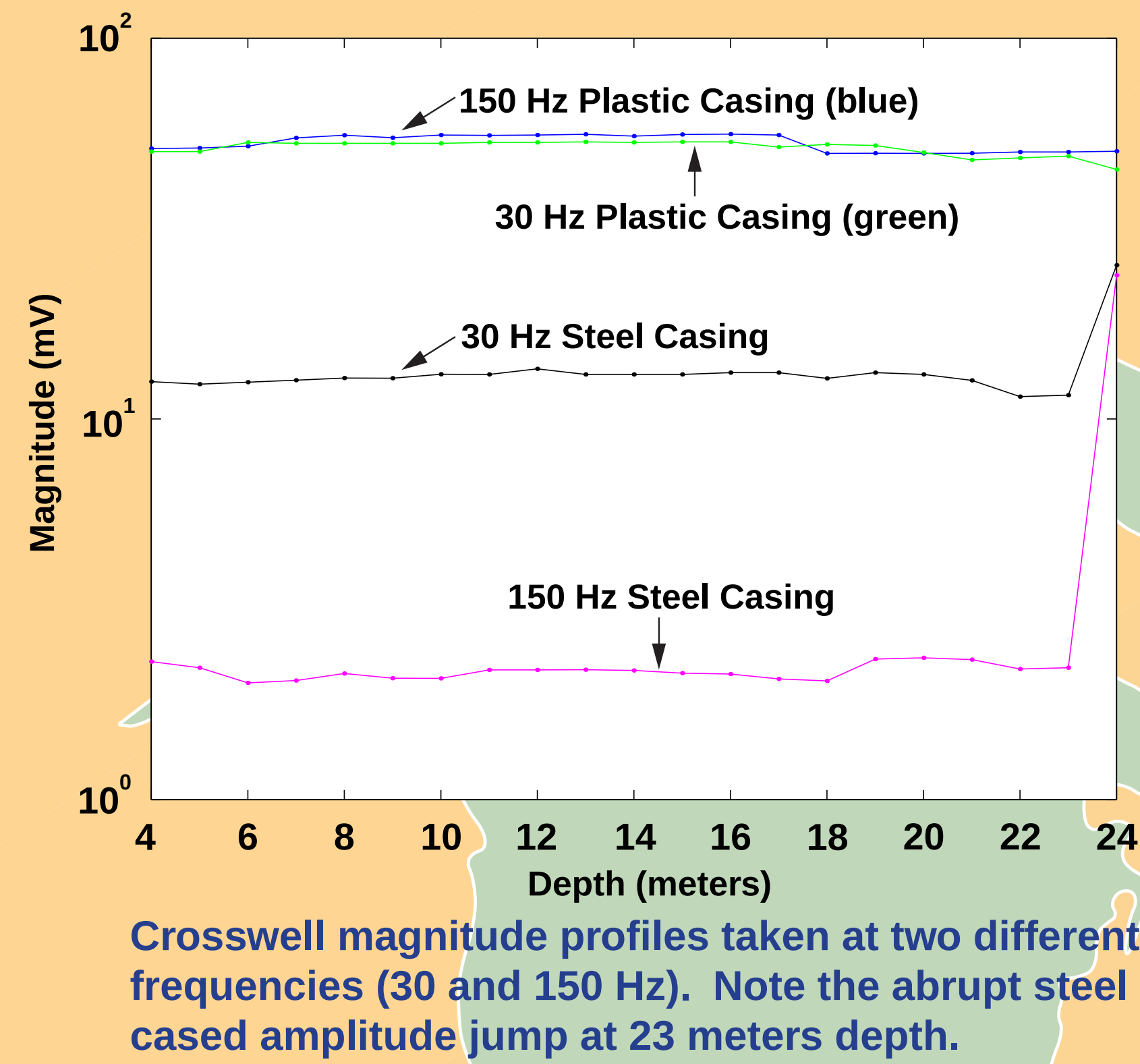


Figure Two
Crosshole EM Data, 2 Steel Casings

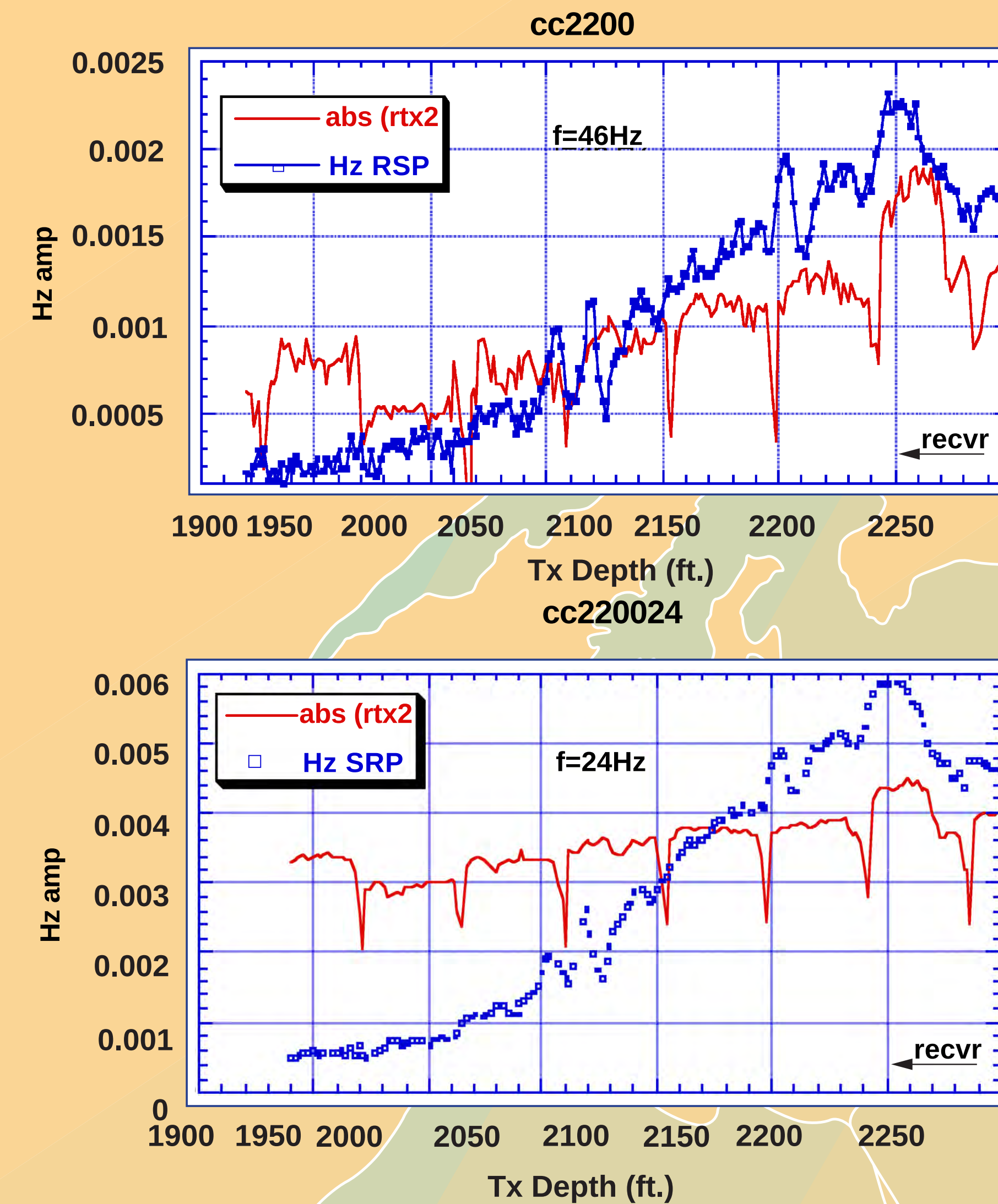


Figure Three
Comparative Phase Response of Steel and Plastic Cased Wells

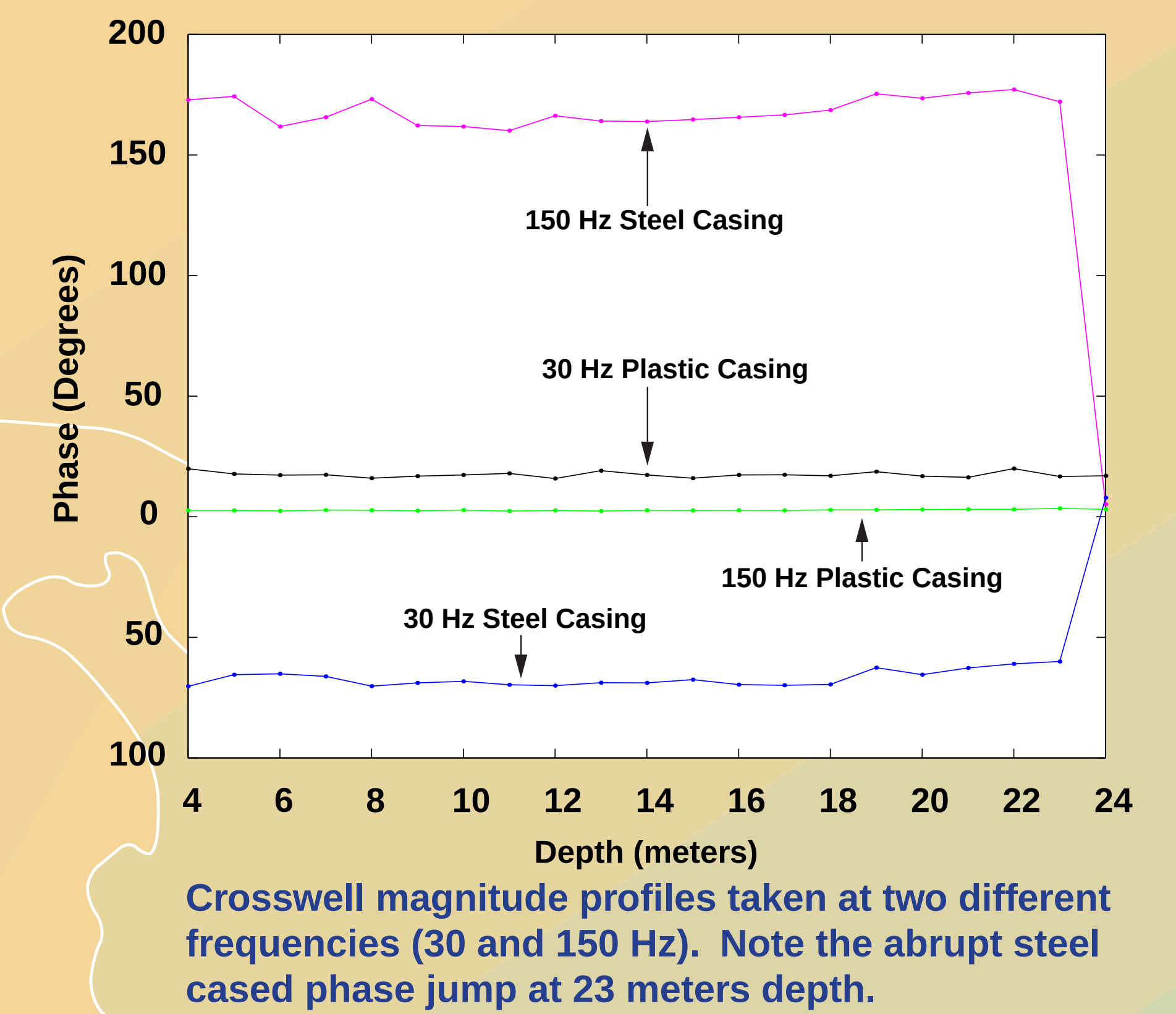


Figure Four
Amplitude Comparison of Frequency soundings at Variable Depth

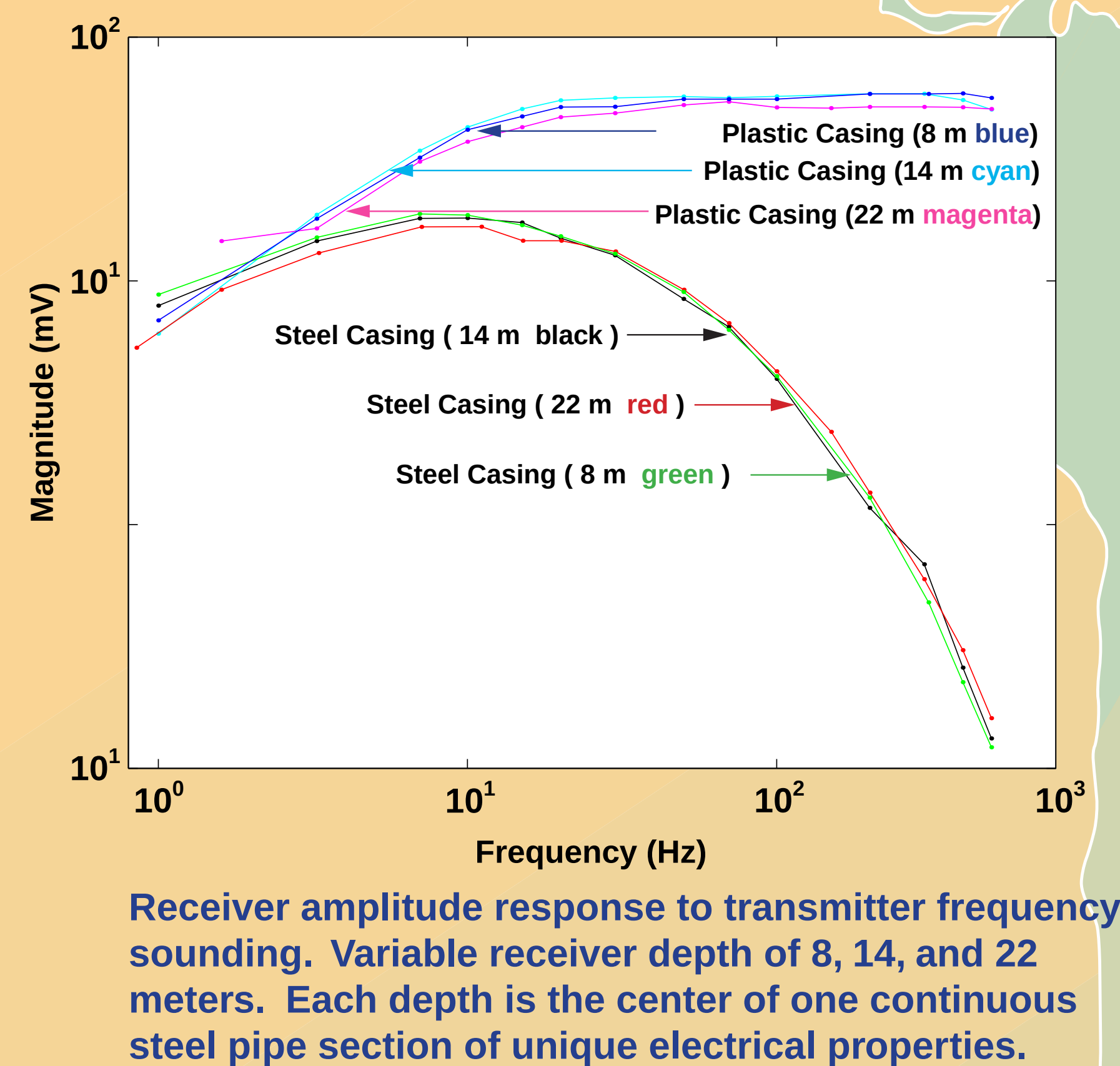


Figure Five
Crosshole EM Phase 2 Steel Casings

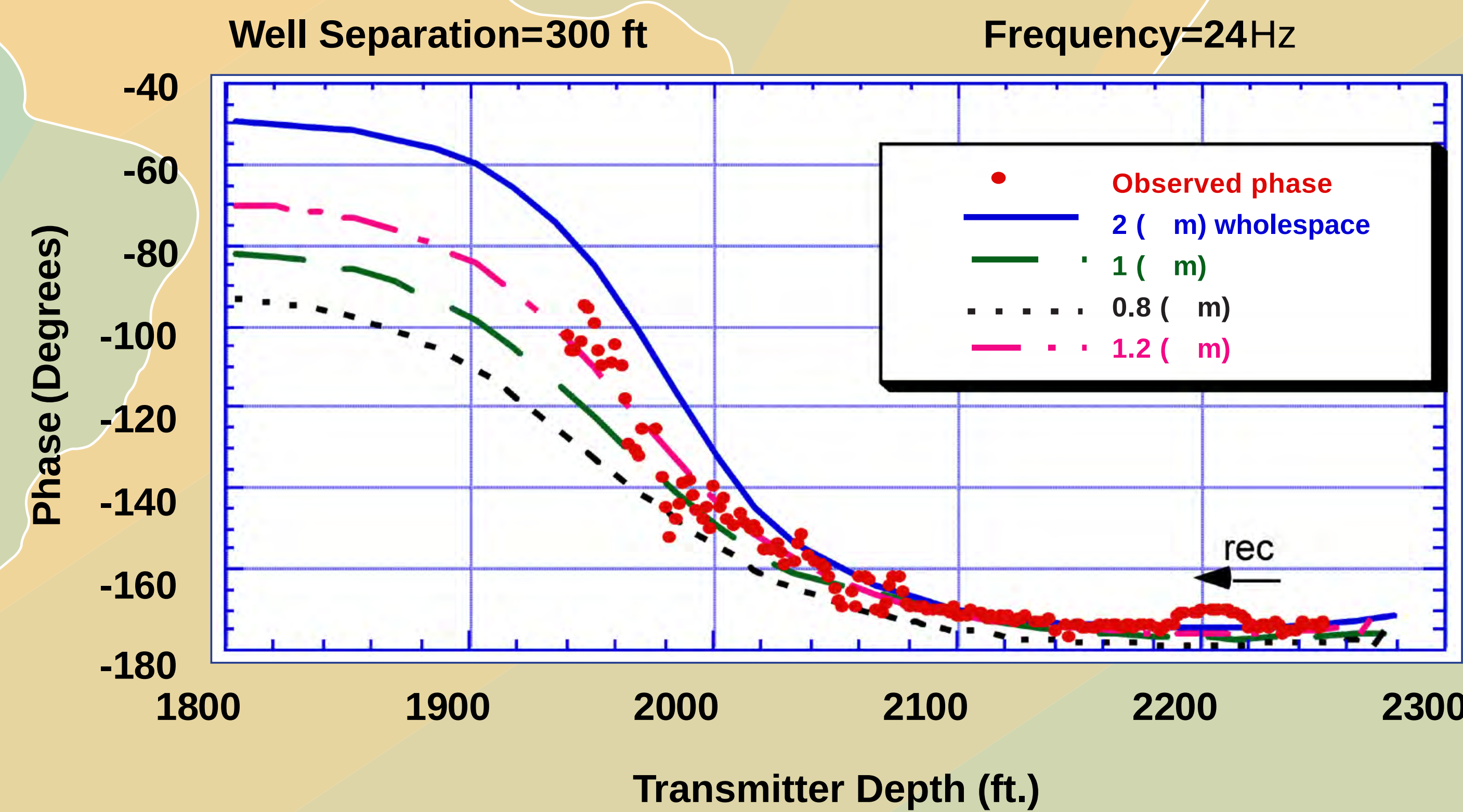
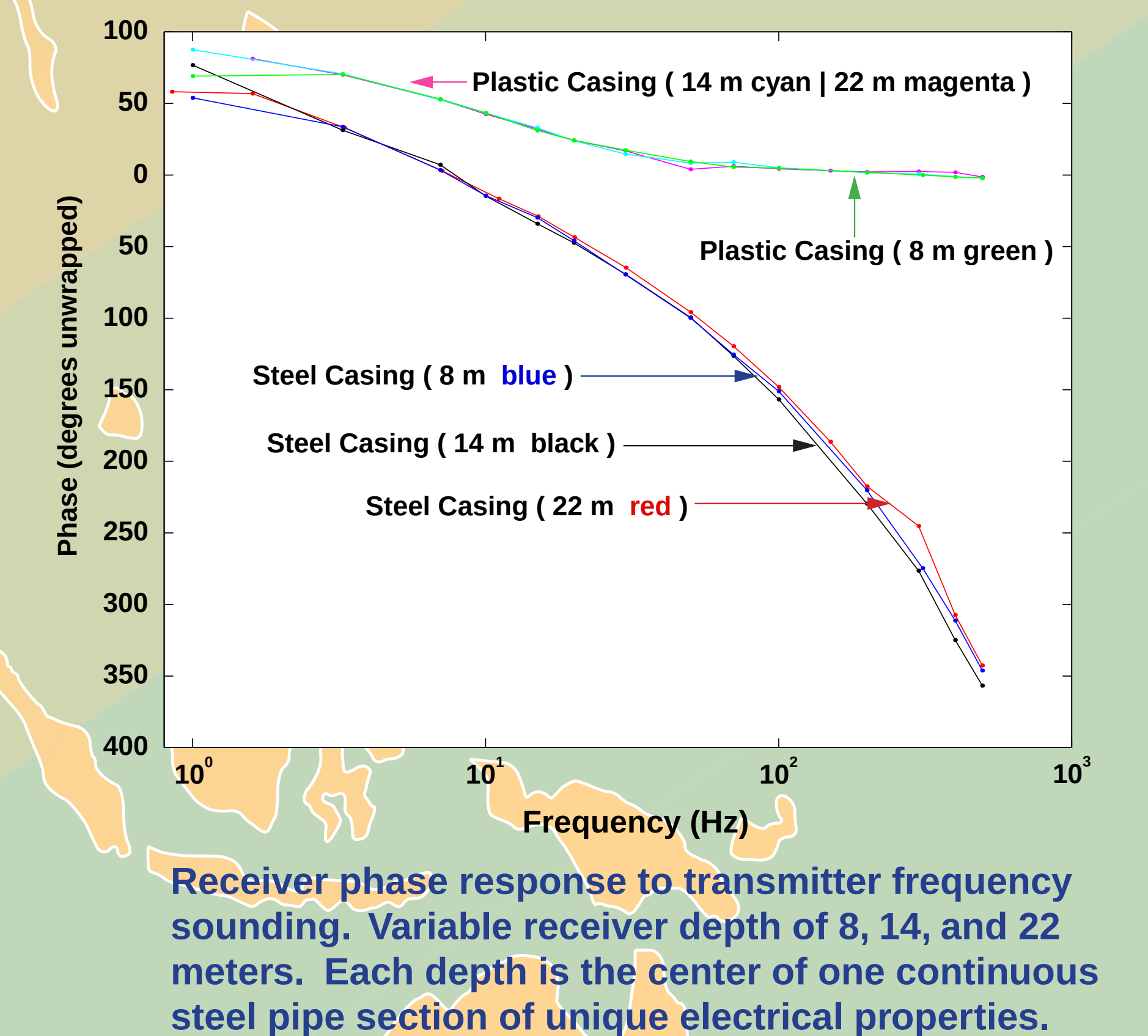


Figure Six
Phase Comparison of Frequency soundings at Variable Depth



As the steel cased well is open at the hole bottom, the sharp amplitude and phase jump at 23 m as seen in figures 1 and 3, demonstrate that the induction coil is only affected by the casing 0.60 meters above and below the downhole tool. This result is allowing forward and inverse models to be run with more efficient and accurate results.

When conducting crosswell EM surveys within one fiberglass observation well and one steel cased well, the effect of the steel casing is seen as a constant filter, with attenuation dependent on frequency, as shown in figures 4 and 6. The amplitude and phase effects may linearly be subtracted.

Crosswell EM surveys within dual steel casing suffer from high signal attenuation and seen in figures 2 and 5. The major problem, however, with subtracting the dual steel cased wells, is the relative contribution of each well in the received signal. The solution to this problem suggests knowledge of the electrical properties of the casing. Efforts are currently underway in determining the design of such a tool.

Technologies Under Development:

**"Design and Development of Gas-Liquid Cylindrical Cyclone
Compact Separators for Three-Phase Flow"**

Paper presented at:

1999 Oil and Gas Conference – Technology Options for Producers' Survival

June 28-30, 1999, Dallas, TX

Co-Sponsored by DOE and PTTC

by

**Ram S. Mohan, Ph.D., Assistant Professor of Mechanical Engineering and
Ovadia Shoham, Ph.D., Professor of Petroleum Engineering**

The University of Tulsa

600 South College Avenue

Tulsa, Oklahoma 74104-3189

Phone: (918) 631-2075

Email: Ram-Mohan@utulsa.edu



June 1999

Design and Development of Gas-Liquid Cylindrical Cyclone

Compact Separators for Three-Phase Flow

Ram S. Mohan, Ph.D. (Ram-Mohan@utulsa.edu, 918-631-2075)
Ovadia Shoham, Ph.D. (os@utulsa.edu, 918-631-3255)
Tulsa University Separation Technology Projects (TUSTP)
The University of Tulsa
600 South College Avenue
Tulsa, Oklahoma 74104-3189

BACKGROUND

Multiphase separation technology has advanced slowly and incrementally for several years. A new look and infusion of novel ideas and concepts are now needed to develop breakthrough technologies in this area for the 21st century. In the past, the petroleum industry has relied mainly on the conventional vessel-type separator, which is bulky, heavy and expensive, to process wellhead production of oil-water-gas flow. Economic and operational pressures continue to force the petroleum industry to seek less expensive and more efficient separation alternatives in the form of compact separators, such as the gas liquid cylindrical cyclone (GLCC[®]). The compact dimensions, smaller footprint and lower weight of the GLCC has a potential for cost savings to the industry, especially in offshore applications. Also, the GLCC reduces the inventory of hydrocarbons significantly, which is critical for environmental and safety considerations.

A lack of understanding of the complex multiphase hydrodynamic flow behavior in the GLCC inhibits complete confidence in its design and necessitates additional research and development. Most of the studies on compact separators have been carried out for simple gas/liquid flows, usually utilizing air and water. There has been considerable progress, recently, in the research conducted in this area under the leadership of the Tulsa University Separation Technology Projects (TUSTP), mainly for two-phase separation in the GLCC. The significance of the research conducted by TUSTP has been highly appreciated by the industry, as shown by their continuing support to the consortium. TUSTP research team provides expertise in several essential areas, such as multiphase flow measurement and instrumentation, mathematical modeling, fluid mechanics, computational fluid dynamics, process control and high pressure field applications. Due to the much needed interdisciplinary nature of the research team, no other industry/university research consortium exists in the area of compact multiphase separation technology at the present time.

The objective of the proposed project is to expand the research activities of TUSTP to multiphase oil/water/gas separation. This project will be executed in two phases. Phase I (1997 - 2000) will focus on the investigations of the complex multiphase hydrodynamic flow behavior in a three-phase GLCC. The activities of this phase will include the development of a mechanistic model, a computational fluid dynamics (CFD) simulator, and detailed experimentation on the three-phase GLCC. The experimental and CFD simulation results will be suitably integrated with the mechanistic model. In Phase II (2000 - 2002), the developed GLCC separator will be tested under high pressure and real crudes conditions. This is crucial for validating the GLCC design for field application and facilitating easy and rapid technology deployment. Design criteria for industrial applications will be developed based on these results

and will be incorporated into the mechanistic model by TUSTP. These essential ingredients will ensure the development of the state-of-the-art technology in compact separation technology for the 21st century.

INTRODUCTION

For many years, the Petroleum Industry has relied mainly on the conventional vessel-type separators. They are bulky, heavy and expensive in capital, installation and operation. Due to economic and operational pressures, the petroleum industry has recently shown interest in the development of innovative alternatives to the conventional separators. One such alternative is the Gas-liquid Cylindrical Cyclone (GLCC). Unlike the conventional vessel type separators, the GLCC is simple, compact, low weight, low-cost, requires little maintenance, and is easy to install and operate. It is therefore gaining popularity as an easy-to-operate economically attractive, alternative to the conventional separator. The development ranking of the various separation technology alternatives are shown schematically in Fig. 1. As shown in this figure, conventional vessel-type separators have reached their maturity, except for some minor improvements that are being incorporated, such as new developments of internal devices and control systems. Large diameter vertical cyclones and hydro-cyclones have also been used by the industry for some time. However, recent trends in development are focused towards new type of compact separators such as the GLCC.

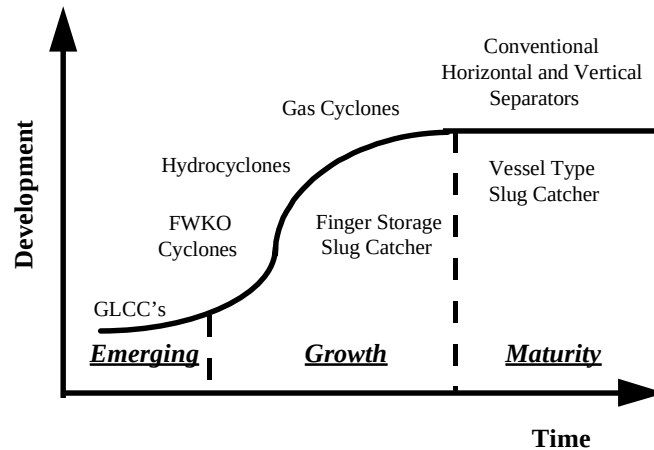


Fig. 1 - 'S' Curve for Developmental Ranking of Separation Technology

A schematic of the GLCC separator is shown in Fig. 2. It is a vertically installed pipe mounted with a downward inclined tangential inlet, with outlets provided at the top and bottom of the pipe. It has neither moving parts nor internal devices. Due to the tangential inlet, the flow forms a swirling motion producing centrifugal forces. The two phases of the incoming mixture are separated due to centrifugal and gravity forces. The liquid is forced radially towards the walls of the cylinder and is collected from the bottom, while the gas moves to the center of the cyclone and is taken out from the top. Currently, the GLCC finds its potential applications as a gas knockout system upstream of production equipment. Through the control of Gas Liquid Ratio (GLR), it enhances the performance of multiphase meters, multiphase flow pumps, and de-sanders. Other applications are portable well testing equipment, flare gas scrubbers, and slug

catchers. The GLCC is also being considered for down hole separation, primary surface separation (onshore and offshore) and sub sea separation.

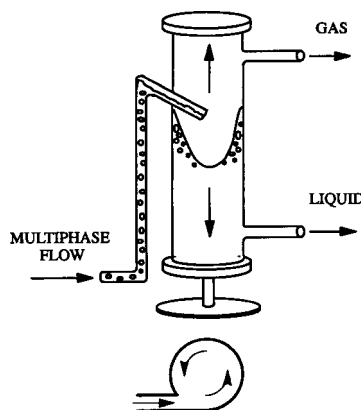


Fig. 2 - Gas-Liquid Cylindrical Cyclone Configuration

GLCC's that have already been installed and put to use in the field have successfully demonstrated their applicability as two-phase separators. The concept is bound to have a pronounced impact on the petroleum industry. However, a lack of understanding of the complex, multiphase, hydrodynamic flow behavior inside the GLCC inhibits complete confidence in the GLCC design and necessitates additional research and development. Knowledge of the hydrodynamic behavior would enable GLCC users to correctly predict the performance of the GLCC and to carry out appropriate design for all configurations and applications.

Most of the studies on compact separators have been carried out for simple gas/liquid flows, usually utilizing air and water. The fluid system existing in the industry is much more complicated with oil/water/gas three-phase flow. In this project, we propose to develop compact separators for oil/water/gas flow and conduct detailed investigations of the three-phase flow behavior. Initially, oil/water two-phase flow will be studied, utilizing a non emulsifying oil to avoid emulsions and dispersions. By all means, this will not be a trivial extension of gas/liquid flow due to the close densities of the two liquids, water and oil. Later, the gas phase will be added to investigate whether compact separators will be effective as a water knockout device to remove the majority of the free water from multiphase mixtures.

OBJECTIVES

The overall objective of this five-year project (October, 1997 – September, 2002) is to expand the state-of-the art of compact separation technology research from two-phase (gas-liquid) flow separation to multiphase oil/water/gas flow production systems. The research aims at making compact separators predictable, reliable and a viable economical alternative to conventional vessel type separators. Long-term cooperation with petroleum industry is envisaged in conducting this project to better understand, analyze and design compact separators for field application, and facilitate easy and rapid technology deployment.

PROJECT DESCRIPTION

This project will be executed in two phases. Phase I (1997 - 2000) will focus on the investigations of the complex multiphase hydrodynamic flow behavior in a three-phase GLCC[®] separator. The activities of this phase will include the development of a mechanistic model, a computational fluid dynamics (CFD) simulator, and detailed experimentation on the three-phase GLCC[®]. The experimental and CFD simulation results will be suitably integrated with the mechanistic model. In Phase II (2000 - 2002), the developed GLCC[®] separator will be tested under high pressure and real crudes conditions. Design criteria for industrial applications will be developed based on these results and will be incorporated into the mechanistic model.

Major Project Milestones:

- Initial modeling, design, fabrication and preliminary data acquisition (Year 1)
- Gas carry-under measurements, model refinement and design improvement (Year 2)
- Liquid carry-over measurements, model refinement and design improvement (Year 3)
- High-pressure field pilot plant GLCC[®] design (Year 4)
- High-pressure data acquisition and field design guidelines (Year 5)
- Interim and final reports preparation (ongoing).

PROJECT STATUS

This report presents a brief overview of the activities and tasks accomplished during Year 1 of the project (budget period, October 1, 1997 – September 30, 1998). The total tasks of the budget period are given initially, followed by the technical and scientific results achieved till date. The report concludes with a detailed description of the plans for the conduct of the project for the upcoming budget period (October 1, 1998 – September 30, 1999).

Tasks of the Current Budget Period (Oct. 1, 1997 – Sept. 31, 1998)

Objective - Initial Modeling and Data Acquisition:

- a. Initial development of the mechanistic model for three-phase separation.
- b. Design and expansion of two-phase test facility for three-phase loop.
- c. Preliminary experimental data acquisition of global separation efficiency.
- d. Preliminary simulation of three-phase flow using CFX code.
- e. Interim reports preparation.

As a part of the tasks identified for the current budget period, the following specific activities have been completed:

1. Plans for detailed experimental investigations for GLCC[®] control are in progress. Preliminary data acquisition is in progress for control strategy formulation. The experimental investigations are being conducted in the out-door experimental facility using a dedicated GLCC[®] capable of withstanding higher pressures. The newly fabricated GLCC[®] with state-of-the-art control valves and new data acquisition system have already been installed. This GLCC[®] has a new aluminum inlet, designed for high-pressure (200-psi) conditions, with sector/slot plate configuration.
2. Identified a new indoor project location for the experimental facility for three-phase flow in the North Campus of The University of Tulsa and allocated the area. Updated the

preliminary floor layout drawing to scale of the three-phase flow loop consisting of the three-phase separator, oil and water tanks, metering section, test section and, related valves and fittings. Construction of the three-phase flow loop is in progress and expected to be completed by November-December, 1998.

3. Started development activities to identify strategies for mechanistic modeling for multiphase flow behavior in GLCC[®]. Literature review in progress to identify the issues related to behavior of oil-in-water and water-in-oil dispersions. Several oil/water-mixing strategies formulated based on Computational Fluid Dynamics (CFD) simulation studies. Investigation in progress to identify techniques for integration of GLCC[®]s with hydrocyclones for building three-phase compact separation systems. This is very critical for elevating the compact separation technology from bulk separation to fine separation of three-phase flow.
4. Several items for the flow loop partially received. Procurement of components needed for the flow loop such as pipes and fittings, gate valves, pumps, and control valves is completed. Three-phase separator, oil and water tanks, two sets of centrifugal pumps for oil and water, flexible piping and the upstream metering section have been installed. Fabrication of the flow loop, support structure for the experimental facility, test GLCCs and downstream metering section are underway.
5. Designated four graduate students to perform the research and experiments. One more student is expected to join in Spring '99.

It is essential to develop an appropriate control strategy for proper operation of a three-phase GLCC. Hence initial experimental investigations are planned for evaluating the GLCC control system performance for different possible control strategies. The layout of the experimental facility for conducting the controls experiments is given in Fig. 3. Construction of the dedicated GLCC for controls investigation is completed in the existing outdoor GLCC flow loop and the experiments are in progress.

A schematic of the floor layout of the three-phase flow loop consisting of the metering and test section are shown in Figs. 4 and 5. Air is supplied from a compressor and is stored in a high-pressure gas tank. The air flows through a metering section consisting of micro-motion mass flow meter and control valves. The liquid phases (water and oil) are pumped from the respective storage tanks and are metered with two sets of micro-motion mass flow meters and control valves, before being mixed. Several mixing sections have been designed to evaluate and control the oil-water mixing characteristics at the inlet. The liquid and gas phases are then mixed at a tee junction and sent to the test section. State-of-the-art micromotion net oil computers (NOC) will be used to quantify the watercut, GOR, and mixture density. The test section consists of 2 dual stage GLCCs. Initially the test section will be equipped with one dual stage GLCC and later it will be upgraded to 2 dual stage GLCCs. The three-phases from the GLCC outlets will also metered using micro-motion mass flow meters. The test section construction will be modular so that in place of GLCC any other separators such as hydro-cyclones could be used in series to form compact separation systems.

Investigations have been initiated in collaboration with the TUSTP member companies and other universities such as Michigan State University to formulate mechanistic models for integrated compact separation systems. Control valves placed along the flow loop control the flow into and out of the test sections. The flow loop is also equipped with several temperature

sensors and pressure transducers for measurement of the in-situ pressure and temperature conditions. Installation of the data acquisition system will follow as soon as the construction of the flow loop is completed. A schematic of the typical data acquisition system for the flow loop is shown in Fig. 6.

Three types of GLCC configurations will be considered for single stage GLCC and dual stage GLCC as shown in Fig. 7. The above flow loop can be used for both configurations. These two types of configurations will aid in investigating the function of GLCC as a bulk separator and a full separator. Non-emulsifying oil will be used as the experimental fluid. Flow runs will be conducted initially by using oil-water two-phase and gas will be added as the third phase later. Two types of oil-water interface are possible as shown in Fig. 8. Initial investigation will focus on identifying the nature of oil-water interface and formulation of appropriate separation strategies for the GLCC. Several literature have been identified to provide more information into the nature of the oil-water interface for cyclonic separators of low G-forces such as the GLCCs.

As an essential component of the mechanistic model development for three-phase flow, preliminary Computational Fluid Dynamic simulations have been conducted to investigate the oil-water separation in a two-phase liquid-liquid mixture with water (denser liquid) as the medium. The results of CFD flow-simulation studies using the computer code CFX 4.1 are shown in Fig. 9 for three different oil droplet sizes. The simulation time was 20 seconds, the oil specific gravity was 0.885, and the GLCC lower part length and diameter were 4-ft and 3-inches respectively. The magnitudes of radial, axial and tangential velocity components are also given in Fig. 9, which is typical of normal GLCC operating conditions. The simulation results of the droplet trajectory indicate that, it is much easier to separate oil droplets of diameters 1000 micron (1mm) and above from the denser water medium. It is also observed that at diameters of 100 microns and below there is a much higher probability of oil particle carry-under into the water stream. This is a very significant initial result as it gives a basis for oil droplet monitoring, predicting the oil carry-under and developing strategies for ensuring separation efficiency of three-phase separators. Detailed investigations are planned in the second project year (October, 1998 – September, 1999) to conduct simulation studies for other operating conditions, namely different flow velocities, different fluid densities, and also verification with experimental results.

Tasks of the Second Project Year Activities (Oct. 1, 1998 - Sep. 31, 1999)

Objective - Gas Carry-under and Model Refinement:

- a. Measurement of the operational envelope of the GLCC for gas carry-under.
- b. Detailed measurement of gas carry-under beyond the operational envelope.
- c. Development of constitutive models for CFD code for simulation of gas carry-under.
- d. Refinement of mechanistic model for gas carry-under.
- e. Investigation of three-phase separator configurations and verification with experimental results.
- f. Interim reports preparation.

Contract Information: Grant No.: DE-FG26-97BC15024, Project Period: 10/1/97 to 09/30/02, Recipient Project Director: Dr. Ram S. Mohan, The University of Tulsa, Ph: 918-631-2075, Fax: 918-631-2397, Email: Ram-Mohan@utulsa.edu.

Acknowledgement: The authors wish to acknowledge the Federal Energy Technology Center (FETC), U.S. Department of Energy for the above grant and specifically the DOE Project Officers, Ms. Rhonda P. Lindsey and Mr. James L. Barnes at the National Petroleum Technology Office (NPTO), Tulsa. This report is prepared for the project period 10/1/97 to 09/30/98.

Note: GLCC[®] - Gas-Liquid Cylindrical Cyclone - copyright, The University of Tulsa, 1994.

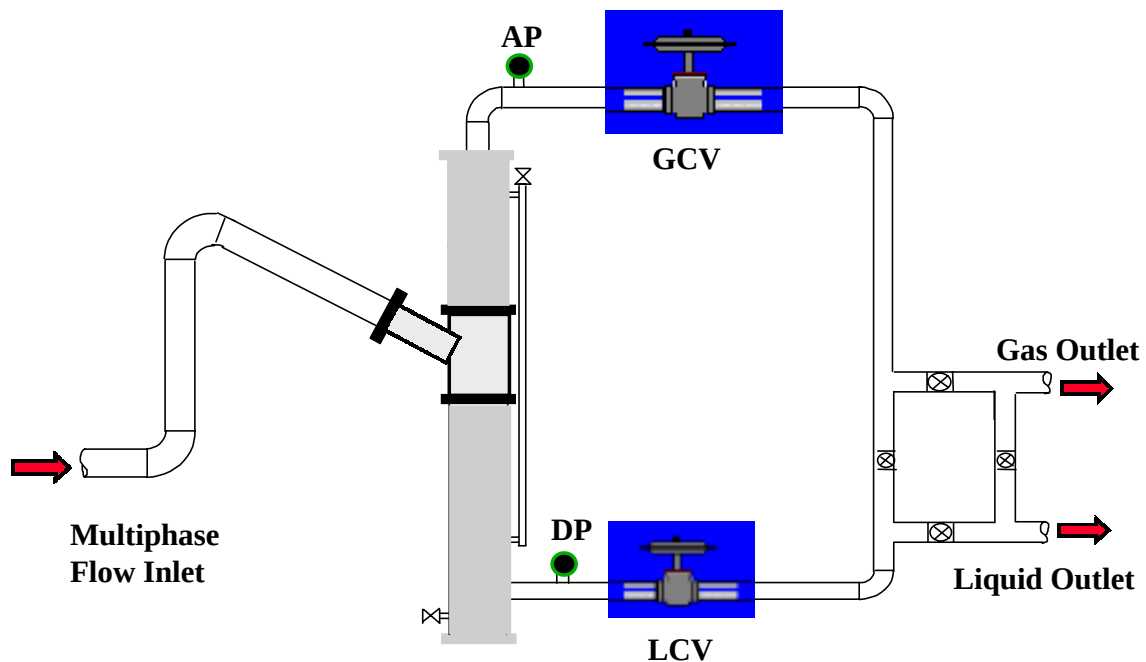


Fig. 3. GLCC Experimental Facility for Controls Experiment

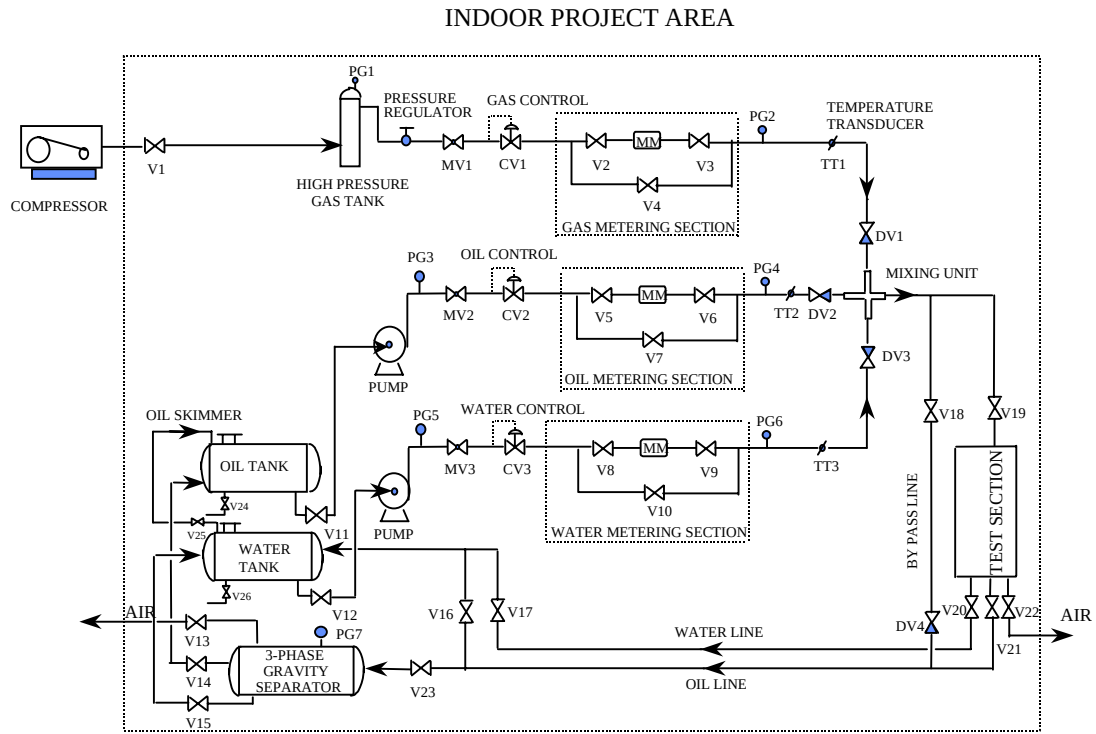


Fig.4. Three-Phase Experimental Flow Loop

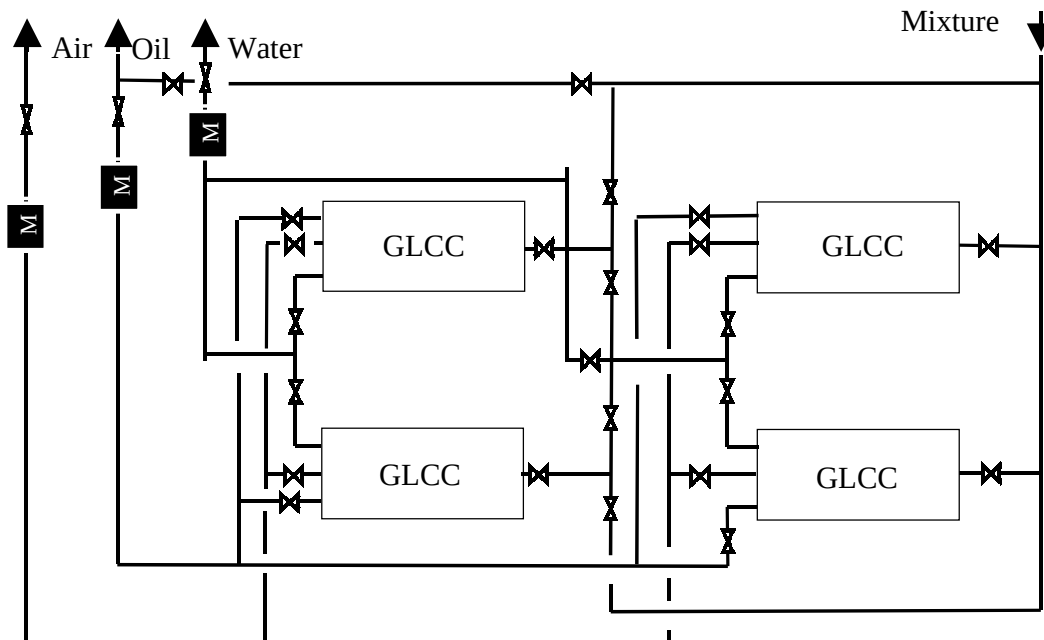


Fig. 5. GLCC Test Section

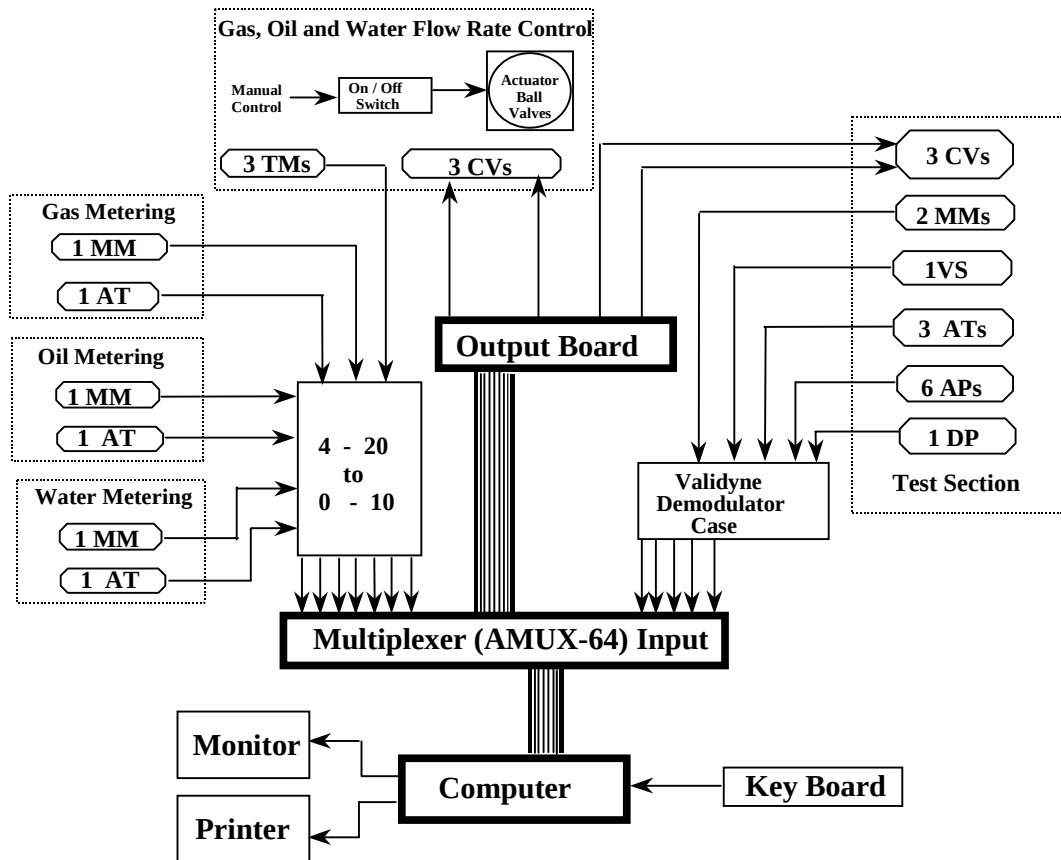


Fig.6 Instrumentation and Data Acquisition Flow Chart (3-PHASE)

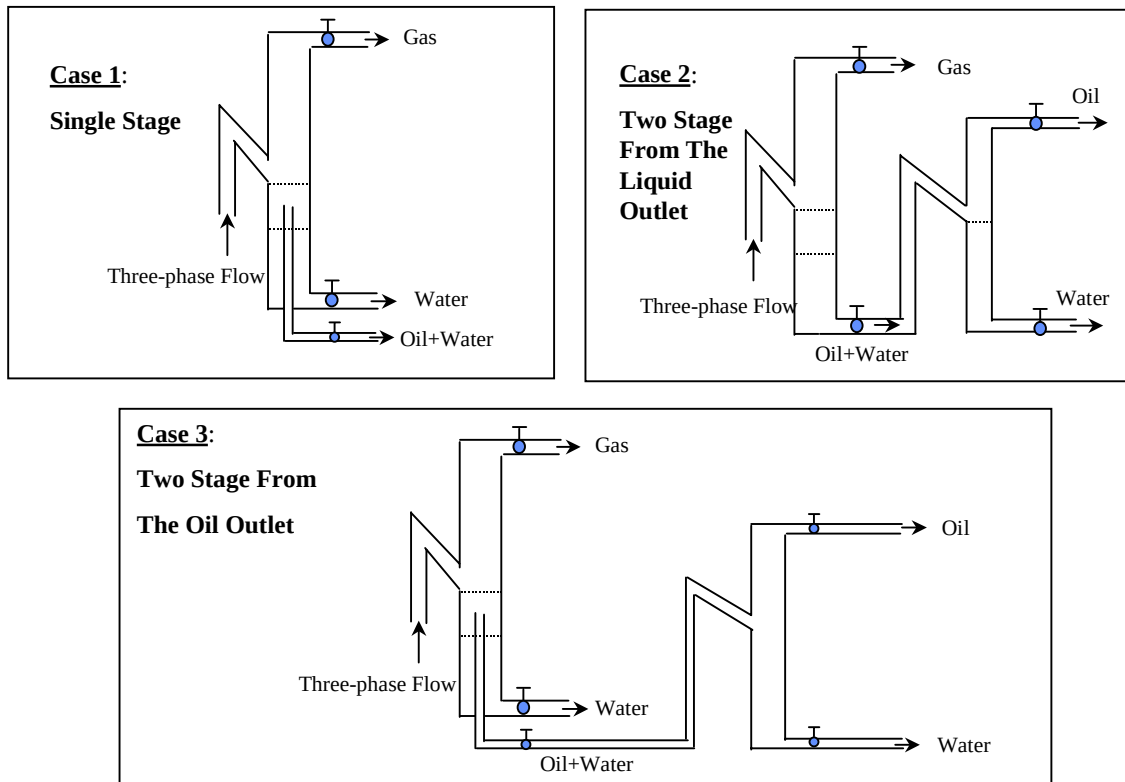


Fig. 7 Test section configurations (separated outlets)

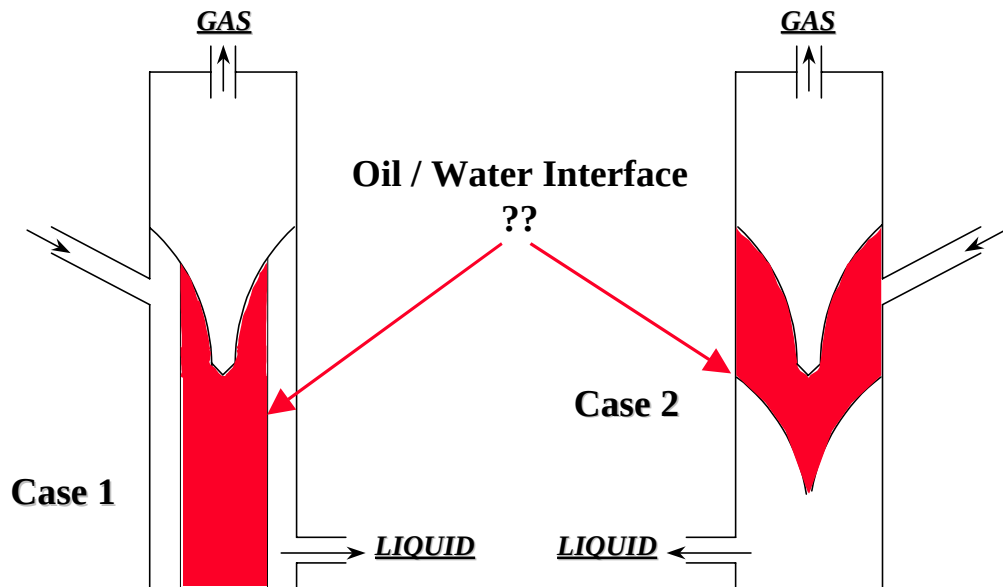
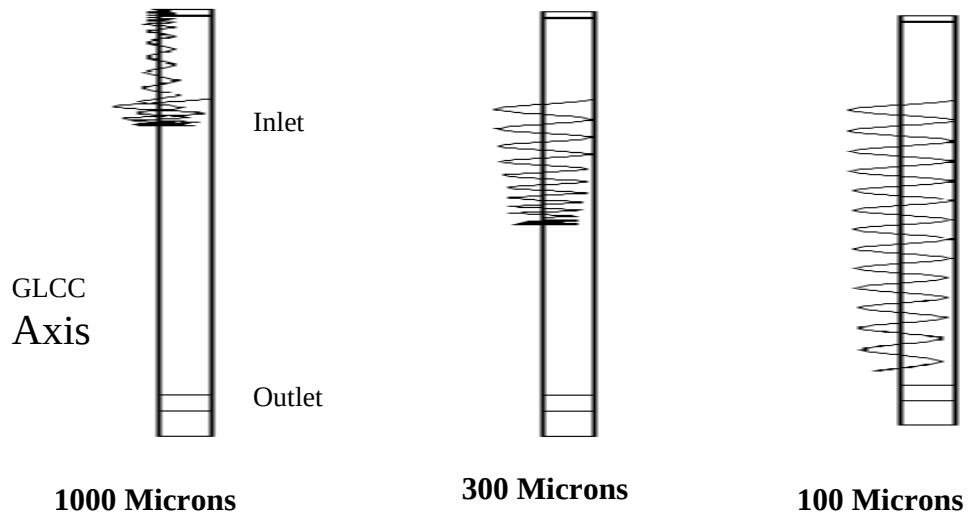


Fig. 8 Oil/Water Interface



Simulation Time : 20 seconds, **GLCC diameter:** 3 inches,
GLCC Lower length: 4 Ft, **Radial Velocity:** 0.18 m/s,
Axial Velocity: 0.75 m/s, **Tangential Velocity:** 1.66 m/s,
Oil Density: 885 Kg/m³,

Fig. 9 Preliminary Droplet Trajectory Analysis



1999 Oil & Gas Conference

Design and Development of Gas-Liquid Cylindrical Cyclone Compact Separators for Three-Phase Flow

by

Ram S. Mohan and Ovadia Shoham

The University of Tulsa

June 28-30, 1999



Introduction

- ❖ **Past Studies on Compact GLCC[©] Separators Have Been Carried Out for Two-Phase Gas/Liquid flow**
- ❖ **Partial or Full Separation of Gas and Liquid Successfully Demonstrated by the GLCC[©]**
- ❖ **Extension of GLCC[©] Capabilities for Oil/Water/Gas Three-Phase Separation.**
- ❖ **Feasibility for Bulk Separation of Water and Oil Phases.**



Objective

- ❖ **Study Oil/Water/Gas Three-Phase GLCC Compact Separators:**
 - **Design and Construct Three-Phase Flow Loop**
 - **Acquire Experimental Data**
 - **Develop a Mechanistic Model**
 - **Test at High Pressure and Real Crude Field Conditions**
- ❖ **GLCC as Bulk Separator?**



Project Scope and Schedule ***- Phase I***

- **October 1997 - September 2000 at The University of Tulsa (TU)**
- **Design and Construct Three-Phase GLCC Loop**
- **Acquire Experimental Data on Oil-Water Separation Efficiency**
- **Conduct CFD Simulation and Develop Mechanistic Model**
- **Develop User Friendly Computer Code for Design**



Project Scope and Schedule - Phase II

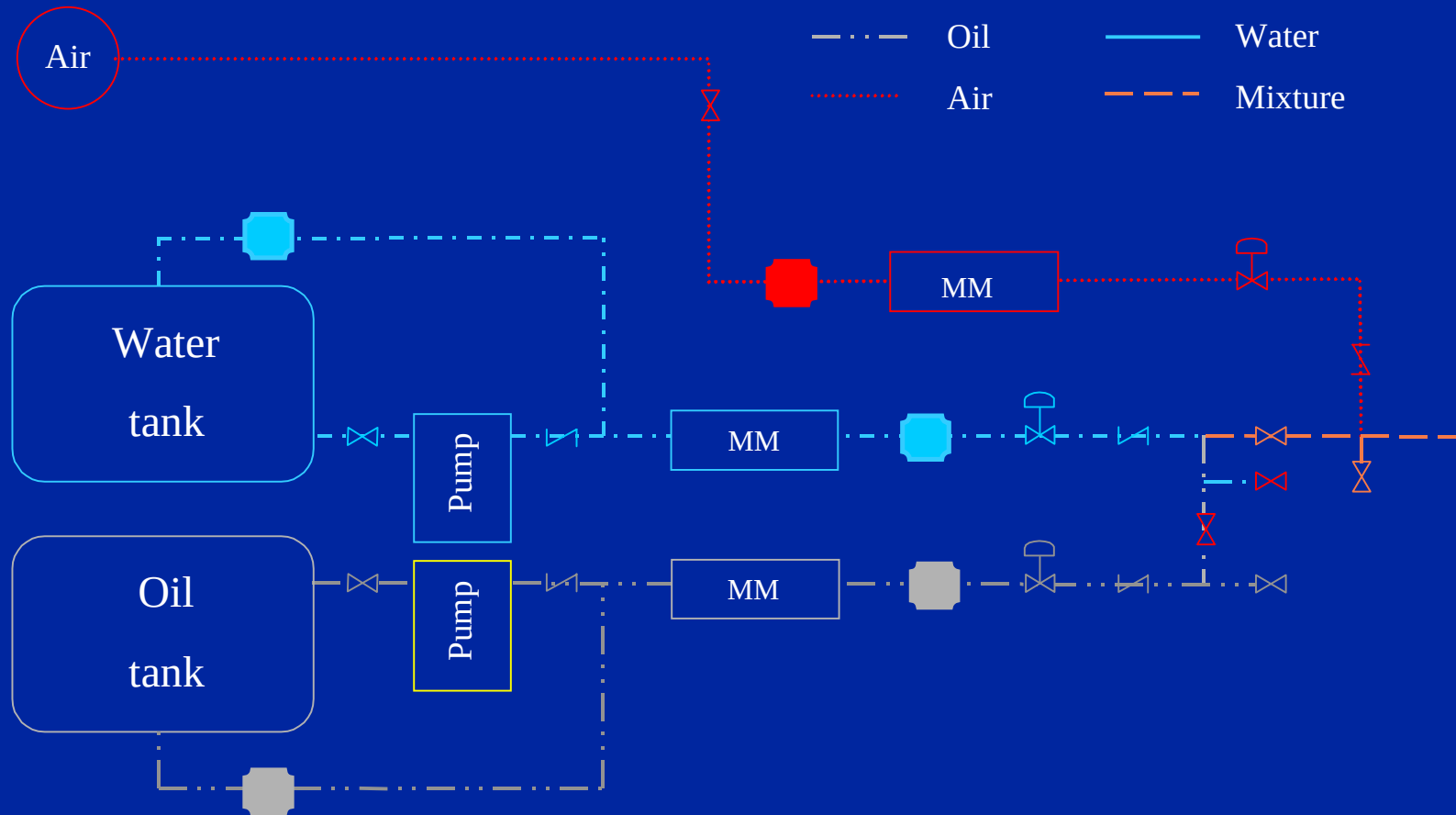
- ❖ **October 2000 - September 2002 at TU and Texas A&M**
 - **Test New GLCC Under High Pressure, and Real Crudes - Texas A&M**
 - **Modify Mechanistic Model, Design Criteria and Computer Code - TU**



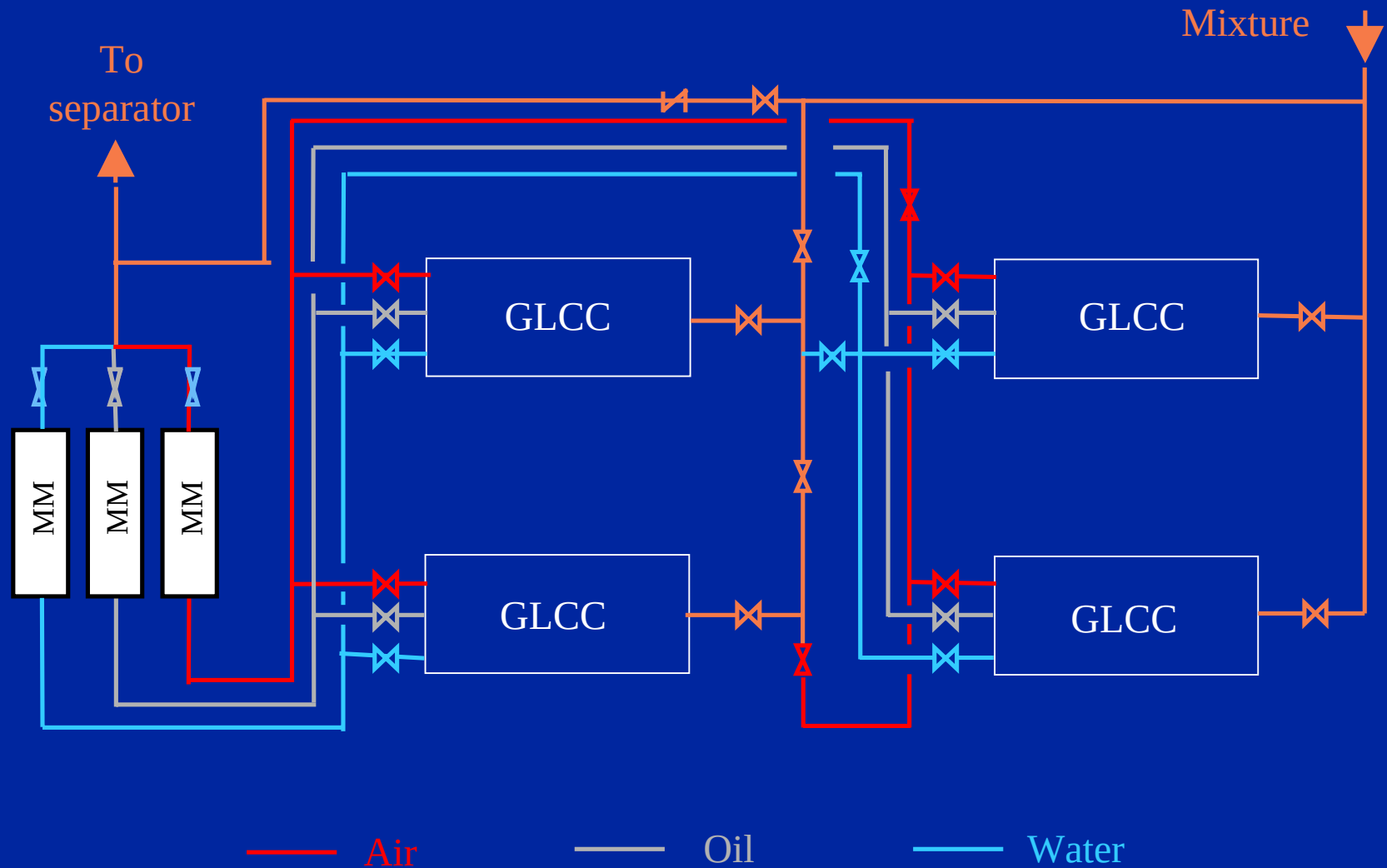
Experimental Program

- ❖ **Experimental Facility**
 - **Metering and Mixing Section**
 - **Test Section**
- ❖ **Three-Phase GLCC Design**

Metering and Mixing Section

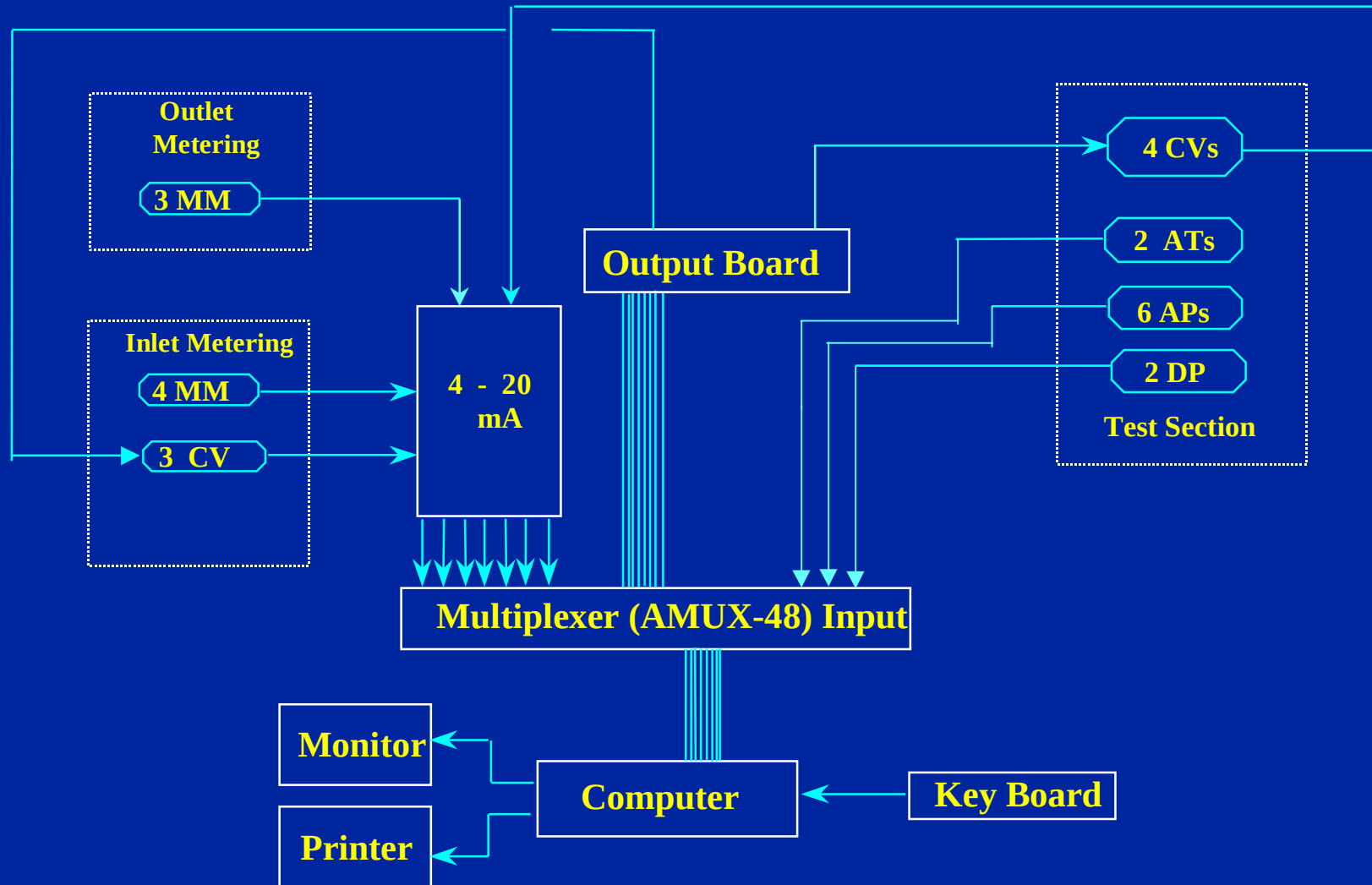


GLCC Test Section





Data Acquisition System



Data Acquisition System



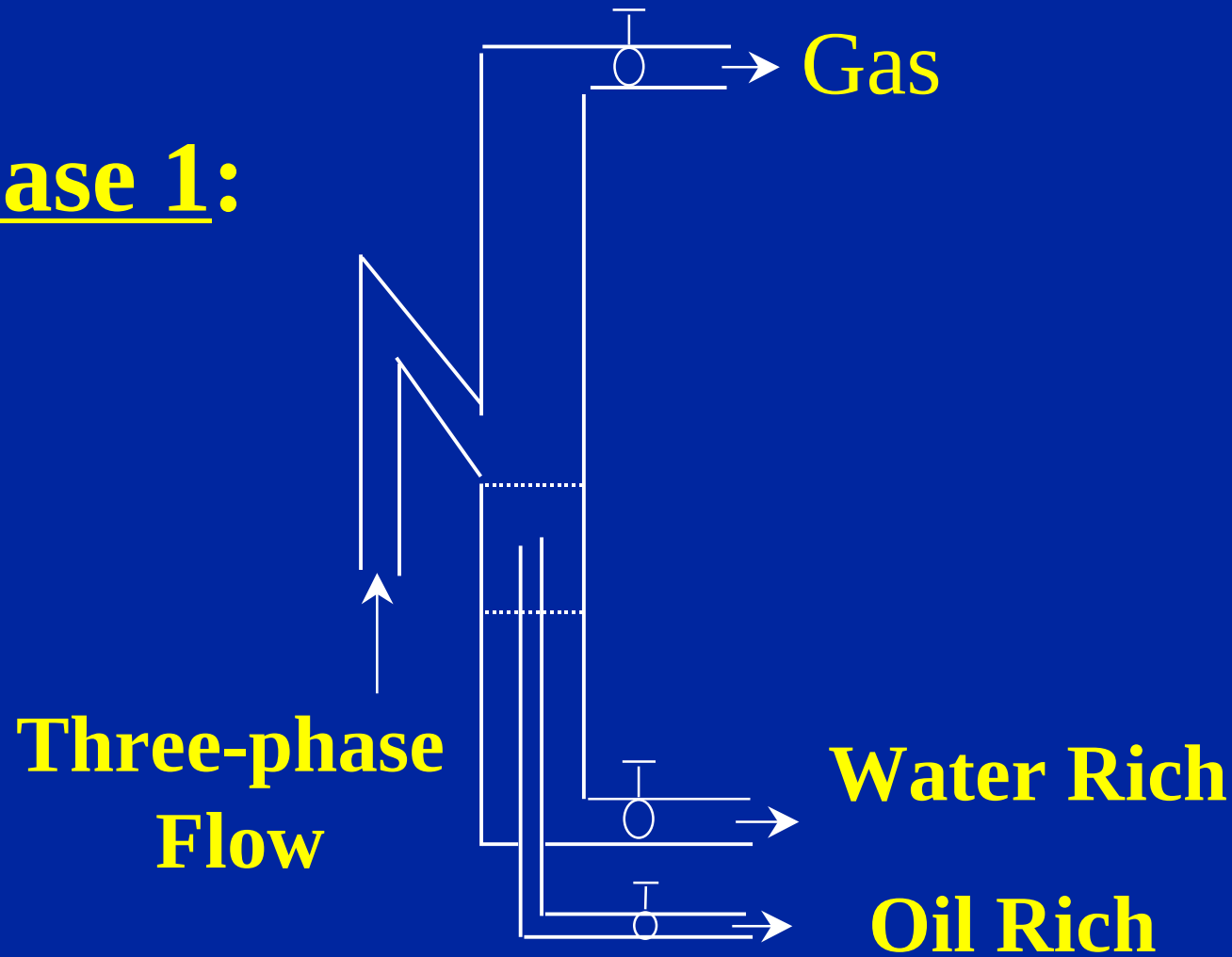


GLCC Configurations

- ❖ Two types of configuration will be considered
 - Single-Stage GLCC
 - Two-Stage GLCC

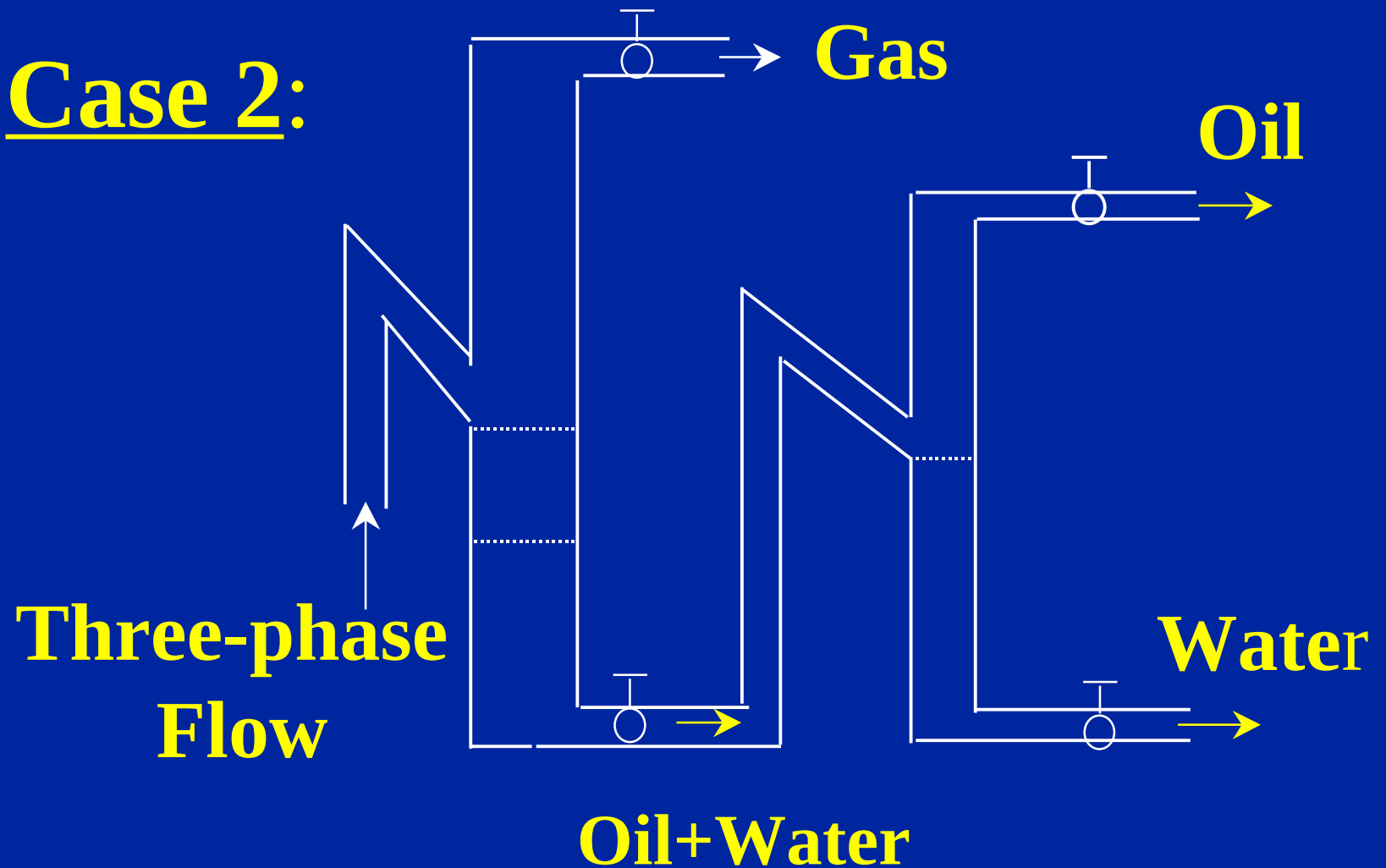
Single-Stage GLCC

Case 1:

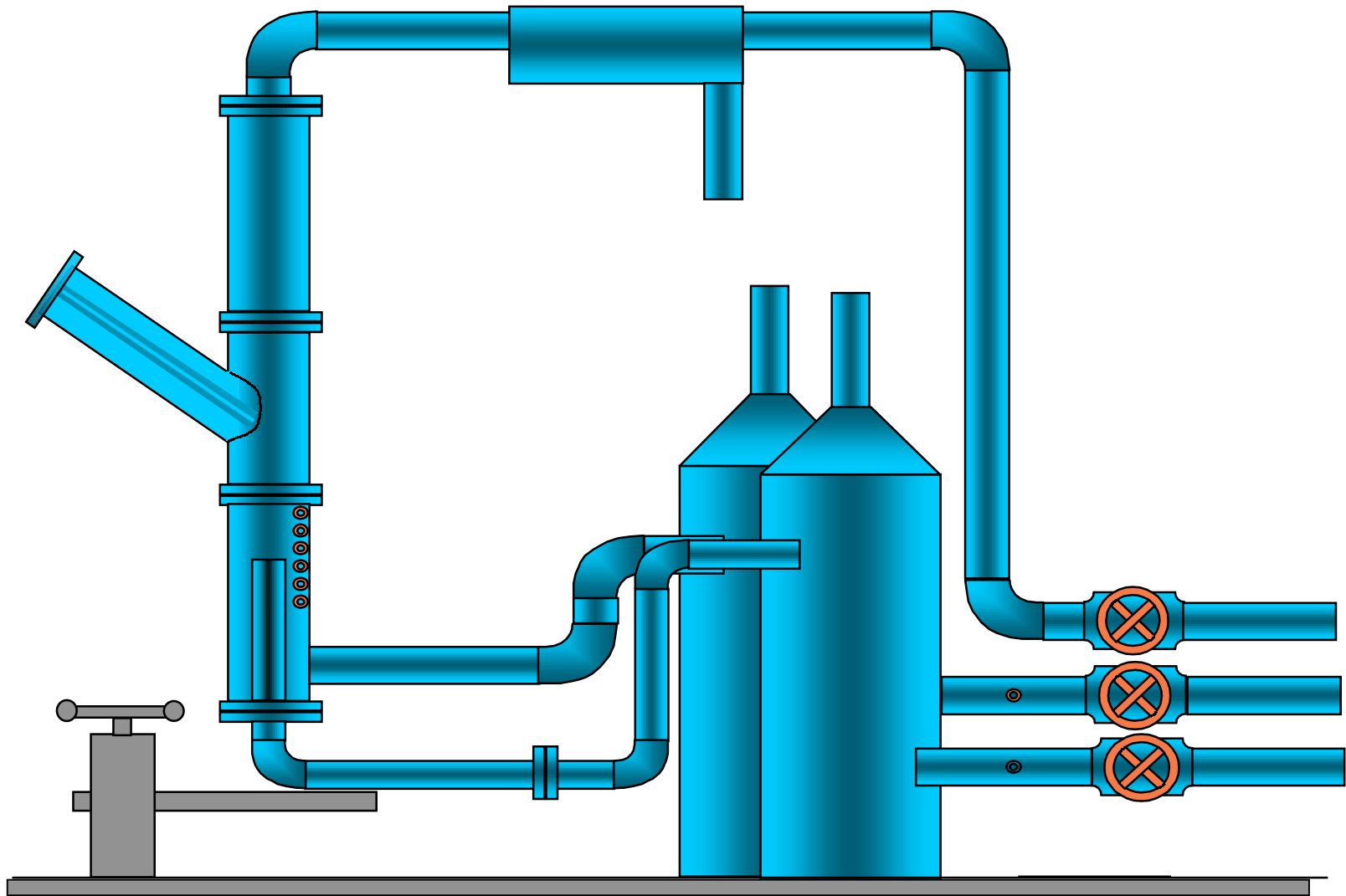


Two-Stage GLCC[®] / LLCC[®]

Case 2:



Three-Phase GLCC Design





Project Status

- ❖ **Design and Construction of New Three-Phase Flow Loop - Completed**
- ❖ **Instrumentation and Data Acquisition System - Completed**
- ❖ **Oil-Water Runs - In Progress**
- ❖ **Three-Phase GLCC Design - In Progress**



Overview of Three-Phase Flow Loop





Oil, Water and Gas Lines



Oil-Water Mixing



Downstream Metering





LLCC[®] in Place





Oil/Water Separation in LLCC[®]





Conclusions & Near Future Work

- ❖ **Oil/Water Mixtures Can be Separated in the LLCC[©] with Efficiencies Greater than 80%.**
- ❖ **Summer 1999**
 - **Construction and Installation of Three-Phase GLCC**
 - **Preliminary Data Acquisition**
- ❖ **Fall 1999**
 - **Completion of Data Acquisition**
 - **Initial Mechanistic Model**

Performance Characteristics of an Extended Throat Flow Nozzle for the Measurement of High Void Fraction Multi-Phase Flows

J. R. Fincke

Lockheed Martin Idaho Technologies Company
Idaho National Engineering and Environmental Laboratory, USA

C. Ronnenkamp, D. Kruse, J. Krogue, D. Householder
Perry Equipment Corporation, USA

ABSTRACT

An extended throat flow nozzle has been examined as a device for the measurement of very high void fraction ($\alpha \geq 0.95$) multi-phase flows. Due to its greater density and partial contact with the wall, the equilibrium velocity of the liquid phase appreciably lags that of the lighter gas phase. The two phases are strongly coupled resulting in pressure drops across the contraction and in the extended throat that are significantly different than those experienced in single-phase flow. Information about the mass flow rates of the two phases can be extracted from the measured pressure drops. The performance of an extended throat flow nozzle has been evaluated under multi-phase conditions using natural gas and hydrocarbon liquids at 400 and 500 psi. Two hydrocarbon solvents were used as the test liquids, Isopar M[®] (sp = 0.79) and Aromatic 100[®] (sp = 0.87). These data are compared to prior air-water data at nominally 15 psi. The high and low pressure data were found to be consistent, confirming that the temperature, pressure, and size scaling of the extended throat venturi are correctly represented. This consistency allows different sized devices to be applied under different fluid conditions (temperature, pressure, gas and liquid phase composition, etc) with confidence.

INTRODUCTION

In recent years, the metering of multiphase fluid streams prior to separation using flow nozzles or other pressure drop devices¹ has received increased attention. Significant progress has been made in the metering of multiphase fluids by first homogenizing the flow in a mixer then metering the pseudo single phase fluid in a venturi in combination with the measurement of fluid density obtained by a gamma densitometer or other device. This approach relies on the successful creation of a homogenous mixture with equal phase velocities. Under these conditions the mixture approximates a single phase fluid with density $\bar{r} = \alpha r_g + (1 - \alpha) r_l$ where α is the volume fraction of the gas phase, and ρ_k , $k=g,l$ is the gas and liquid phase density, respectively. This technique works well for flows which, after homogenizing, the continuous phase is the liquid phase. While the upper limit of applicability of this approach is ill defined, it is generally thought that for void fractions greater than about 90-95% a homogenous mixture is difficult to create or sustain. The characteristic undisturbed flow regime in this high void fraction range is that of an annular or annular mist flow. The gas phase flows in the center of the channel while the dense liquid phase flows in a film on the inner surface of the channel. Depending on the geometry, pressure and the flow rates of each phase, significant amounts of the denser phase may also become entrained in the gas phase and be transported as dispersed

droplets. While the liquid generally occupies <5% by volume, the mass flow rate of the liquid can be comparable to that of the gas phase due to its greater density.

The presence of the liquid phase complicates the measurement, causing conventional meters, such as orifice plates or venturi meters, to overestimate the flow rate of the gas phase. Figures 1 and 2 illustrate this problem. The venturi meter used is of conventional design following ASME guidelines². The upstream piping is 2 inch inside diameter and the throat diameter is 1.4 inch for a contraction ratio of $\beta=0.7$. The gas mass flow rate is obtained in the usual manner from

$$(1) \quad m_g = \frac{AC_c Y}{\sqrt{1 - b^4}} \sqrt{2 r_g \Delta P}$$

where m_g is the gas mass flow rate, A is the area of the throat, ΔP the measured pressure differential, ρ_g the gas density at flow conditions, C_c the discharge coefficient ($C_c=0.995$), and Y is the expansion factor. The test pressure was 400 psi, the gas phase was dry pipeline natural gas and the liquid phase was Isopar M[®] a hydrocarbon solvent with specific gravity of 0.79. The test temperature was approximately 80 °F. The liquid mass loading, defined as m_l/m_g , ranged from a low of 1.4 % to a high of 30 %. And the corresponding void fraction ranged from 0.997 to 0.95. The test configuration, which is shown in Figure 8, will be described in more detail in the following section. Figure 2 is a comparison of the apparent gas mass flow rate to the reference gas mass flow rate obtained by metering the dry pipeline gas using a conventional orifice meter and flow computer, before the introduction of the liquid phase. The presence of the liquid phase clearly increases the pressure drop in the venturi and results in the meter over predicting the true gas mass flow rate. The resulting error, in percent of reading, is shown in Figure 2. The error in the gas mass flow rate measurement ranges from around 7 % of reading for a mass loading of 1.4 % to a maximum of 27 % for a mass loading of 30 %.

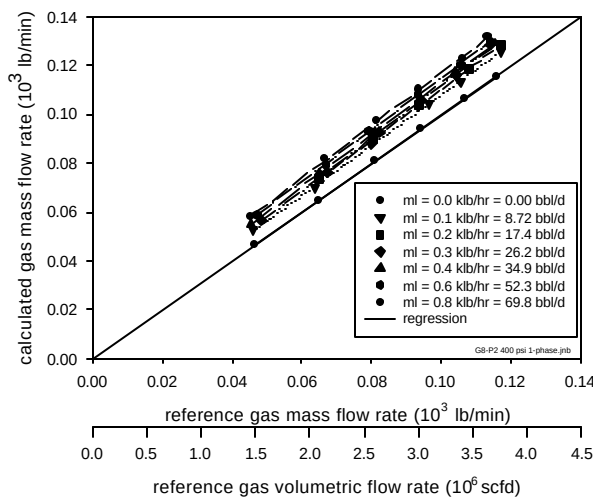


Figure 1. Venturi performance using the single phase calibration under multi-phase test conditions.

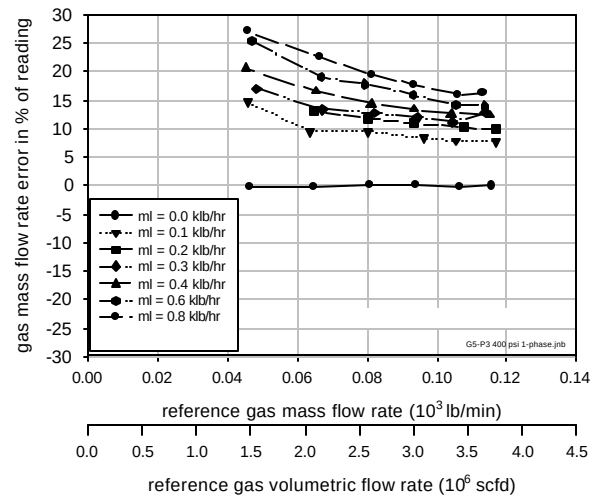


Figure 2. Mass flow rate error in percent of reading using single phase calibration under multi-phase test conditions.

The over prediction of the gas mass flow rate by the venturi meter is due to an increase in the pressure drop under multi-phase conditions. The increase in pressure drop is caused by the interaction between the gas and liquid phases. Liquid droplet acceleration by the gas, irreversible drag force work done by the gas phase in accelerating the liquid film and wall losses determine the magnitude of the observed pressure drop. The flow field is characterized and complicated by the continuous deposition and entrainment of liquid along the venturi length and by the presence of surface waves on the liquid film. The continuous deposition and entrainment process contributes to the overall pressure drop through the loss of momentum caused by the acceleration of the newly entrained droplets. The surface waves present an effectively roughened surface over which the gas must flow increasing the momentum loss due to the addition of form drag to the interfacial shear stress.

A simple, semi-empirical solution to the overestimation of gas mass flow rate under multi-phase conditions has been proposed by Murdock³. Murdock's analysis, which ignores any interaction (momentum exchange) between the gas and liquid phases yields an equation, which, if the ratio of gas to liquid mass flow rate is known *a priori*, proposes to correct the apparent reading to the actual value. The resulting equation is given below, where M is an empirically determined constant:

$$(2) \quad m_{g(Murdock)} = \frac{m_{g(apparent)}}{1 + M \left(\frac{m_l}{m_g} \right) \frac{C_g Y}{C_l} \sqrt{\frac{r_g}{r_l}}}.$$

The subscript (*apparent*) denotes the value of m_g obtained from equation (1) under multi-phase conditions, and the subscript (*Murdock*) denotes the corrected value according to Murdock's equation. The C_k , $k=g,l$ are the discharge coefficients for the gas and liquid phases respectively. Murdock³ recommended a value of 1.26 for M. The results of applying equation 2 to the data of Figure 1 appear in Figures 3 and 4. The ratio of the liquid to gas mass flow rate used in equation 2 was taken from the measured values obtained by metering the single phase fluids independently before mixing. As seen in Figures 3 and 4 the correction is insufficient to adjust the apparent reading to the actual reference value.

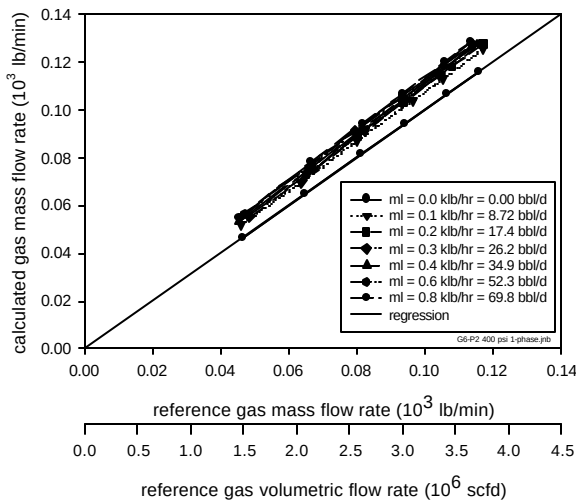


Figure 3. Venturi performance under multi-phase conditions using the Murdock correction, M=1.26.

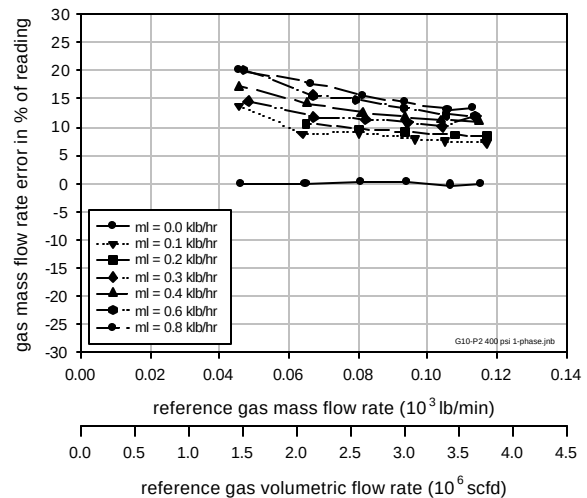


Figure 4. Gas mass flow rate error in percent of reading using the Murdock correction, M=1.26.

The approach suggested by Jamieson and Dickinson⁴ was to adjust the value of M to fit the data. For the data examined here the value of M required to obtain agreement for the $\dot{m}_l = 100$ lb/hr data is 25.2, twenty times the original recommended value of 1.26. The results of applying equation 2 to the data of Figure 1 using $M = 25.2$ appear in Figures 5 and 6. Clearly M is not a universal constant. While the $\dot{m}_l = 100$ lb/hr data is adequately corrected the $\dot{m}_l > 100$ lb/hr is significantly over compensated.

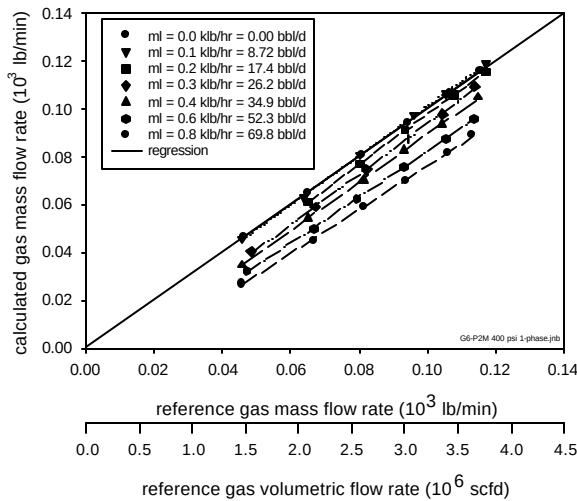


Figure 5. Venturi performance under multi-phase conditions using the Murdock correction, $M=25.2$.

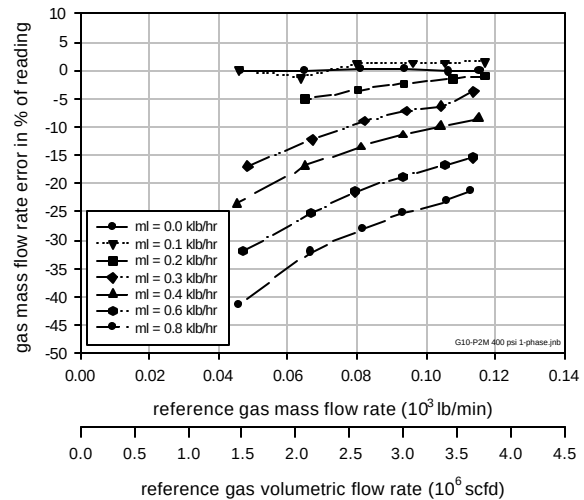


Figure 6. Gas mass flow rate error in percent of reading, using the Murdock correction, $M=25.2$.

Reliable metering of high void fraction multi-phase flows over a wide range of conditions (liquid loading, pressure, temperature, and gas and liquid composition) without prior knowledge of the liquid and gas mass flow rates requires a different approach than the simple modification of single phase meter readings. Conceptually, a method of metering such a flow is to impose an acceleration or pressure drop on the flow field via a constriction or expansion and to observe the pressure response of the device at several locations. Because the multi-phase pressure response differs significantly from that of a single-phase fluid, it is likely that the measured differentials will be a unique function of the mass flow rates of each phase. We have explored the performance of an extended throat venturi meter with multiple differential pressure measurements under high void fraction conditions. A schematic of the types of devices whose performance is examined is shown in Figure 7. The flow is from left to right.

TEST APPARATUS AND TEST CONDITIONS

Testing has been conducted at nominally atmospheric pressure using air-water flows in a laboratory apparatus at the Idaho National Engineering and Environmental Laboratory and at 400 and 500 psi using dry pipeline natural gas and hydrocarbon liquids in the test fixture shown schematically in Figure 8. Elevated pressure testing was conducted at the Hydrocarbon Training & Development Center in Houston, TX.

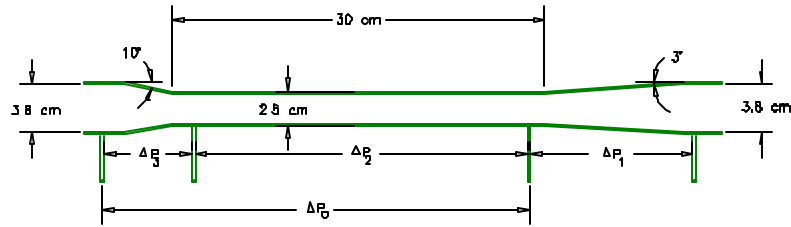


Figure 7. Schematic of extended throat flow nozzle, flow is left to right.

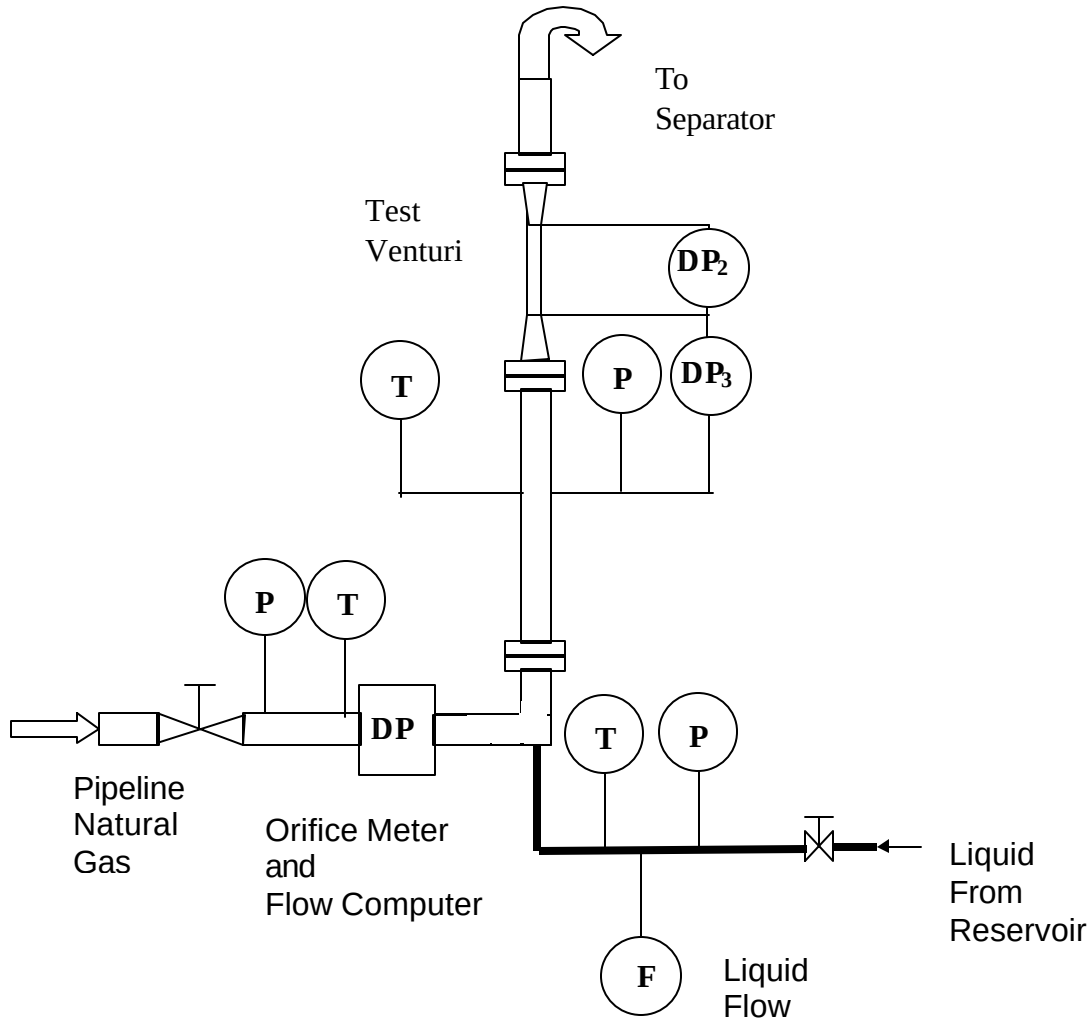


Figure 8. Schematic of test apparatus.

Pipeline natural gas is diverted, metered by an orifice and PECO Corp. Smart Computer, then introduced to the test apparatus at the mixing elbow. Similarly, the test liquid is metered by a turbine meter and a PECO Corp. Smart Computer. The fluid is introduced to the flow stream through a concentric tube in the center of the elbow. All testing was conducted in vertical, upward flow. Test section piping is nominally 2 inch inside diameter. Appropriate pressure and temperature measurements are provided for the single-phase fluids and for the multi-phase mixture just upstream of the test venturi. After flowing through the venturi the gas and liquid

phases are separated, the liquid is re-circulated through the test apparatus and the gas phase is returned to the pipeline.

Three differential pressure measurements are recorded for the extended throat flow nozzle, Figure 7. The measured differentials are ΔP_3 across the contraction, ΔP_2 in the extended throat, and ΔP_0 , which should equal $\Delta P_3 + \Delta P_2$, as a consistency check. The complete range of test conditions is summarized in Table 1. Extended throat venturi with two throat diameters and three contraction ratios have been tested over pressures ranging from nominally atmospheric to 500 psi using two gases and four liquids with specific gravity ranging from 0.79 to 1.2.

Table I. Summary of Venturi Geometry and Test Conditions

	INEEL 1" Venturi	PECO 1.4" Venturi	PECO 1" Venturi
Pressure	15 psi	400, 500 psi	400, 500 psi
Fluids	Air-Water Air-Salt Water	<i>Isopar M</i> $\hat{a}$ - Natural Gas	<i>Isopar M</i> $\hat{a}$ <i>Aromatic 100-</i> Natural Gas
Liquid specific gravity	1.0 1.2	0.79	0.79 0.87
Throat diameter	1.0 "	1.4 "	1.0 "
Contraction ratio $\beta=d/D$	0.656	0.677	0.484
Gas mass flow rate range	0 – 0.015 10^3 lb/min	0 – 0.135 10^3 lb/min	0 – 0.135 10^3 lb/min
Gas volumetric flow rate range	0 – 0.5 10^6 scfd	0 – 4.3 10^6 scfd	0 – 4.3 10^6 scfd
Liquid mass flow rate range	0 – 0.15 10^3 lb/hr	0 – 0.8 10^3 lb/hr	0 – 0.8 10^3 lb/hr
Liquid volumetric flow rate range	0 – 20 bbls/day	0 – 70 bbls/day	0 – 70 bbls/day
Liquid mass loading range m_l / m_g	0 – 30 %	0 – 30 %	0 – 30 %
Estimated void fraction range	0.99 – 1.0	0.94 – 1.0	0.95 – 1.0

ONE-DIMENSIONAL THEORY AND GAS MASS FLOW RATE

One-dimensional theory can not yield an exact description of meter performance, however it can provide insight into the observed behavior under multi-phase conditions. As described in the introduction the gas and liquid phases are strongly coupled. As the gas phase accelerates in the converging section of the nozzle, the denser liquid phase velocity appreciably lags that of the lighter gas phase. In the extended throat region the liquid phase continues to accelerate, ultimately approaching its equilibrium velocity with respect to the gas phase. Even at equilibrium significant velocity differences or slip will exist between the gas and liquid phases. Conservation of mass and energy for each phase is written below where the subscript (1) denotes

the upstream condition and (2) the throat. ΔP_{gl3} is the pressure drop experienced by the gas-phase due to irreversible work done by the gas phase in accelerating the liquid phase between locations 1 and 2. It is assumed that only the liquid phase is in contact with the wall, f_w is the wall friction coefficient and G_c is a geometry factor which accounts for the acceleration of the fluid in the contraction and the surface area of the contraction.

$$m_g = a_1 r_g u_{g1} A_1 = a_2 r_g u_{g2} A_2$$

$$m_l = (1 - a_1) r_l u_{l1} A_1 = (1 - a_2) r_l u_{l2} A_2$$

$$3) \quad P_1 + \frac{1}{2} r_g u_{g1}^2 = P_2 + \frac{1}{2} r_g u_{g2}^2 + P_{gl3}$$

$$P_1 + \frac{1}{2} r_l u_{l1}^2 = P_2 + \frac{1}{2} r_l u_{l2}^2 - P_{gl3} + G_c f_w \frac{1}{2} r_l u_{l2}^2$$

The gas phase energy equation can be rewritten using the equation for the gas phase mass flow rate, where D is the diameter of the upstream piping, d is the throat diameter, $\beta = d/D$ is the contraction ratio, and ΔP_3 is the pressure drop across the contraction.

$$4) \quad \Delta P_3 = \frac{1}{2} \frac{m_g^2}{r_g a_2^2 A_2^2} \left(1 - \left(\frac{a_2}{a_1}\right)^2 b^4\right) + \Delta P_{gl3} :$$

With the approximation that α_1 and $\alpha_2 \cong 1$, the modified orifice equation results.

$$5) \quad \Delta P_3 \approx \frac{1}{2} \frac{m_g^2}{r_g A^2} (1 - b^4) + \Delta P_{gl3}$$

For single-phase flow ΔP_{gl3} is equal to zero and the equation is solved directly for the mass flow rate m_g . In practice, the single-phase result is modified by the addition of an empirical constant C_c which accounts for the true discharge characteristics (non-ideal one-dimensional behavior and friction losses) of the nozzle and Y which takes compressibility effects into account.

$$6) \quad m_{g1f} = \frac{C_c A Y}{\sqrt{1 - b^4}} \sqrt{2 r_g \Delta P_3}$$

As shown in the introduction if equation 6 is used under multiphase conditions the mass flow rate of the gas phase can be significantly overestimated. Under multiphase conditions the mass flow rate of the gas phase is given by:

$$7) \quad m_g = \frac{C_{2f} a_2 A_2 Y}{\sqrt{1 - \left(\frac{a_2}{a_1}\right)^2 b^4}} \sqrt{2 r_g (\Delta P_3 - \Delta P_{gl3})}$$

where $\alpha_2 A_2$ represents the cross sectional area occupied by the gas phase. For ΔP_3 large with respect to ΔP_{gl3} the quantity under the radical can be approximated by

$$8) \quad \sqrt{\Delta P_3 - \Delta P_{gl3}} \approx \sqrt{\Delta P_3} - C_{gl3} \times \sqrt{\Delta P_{gl3}}$$

where C_{gl3} is a constant to be determined. Empirically we have found that ΔP_{gl3} can be replaced by ΔP_2 , the pressure rise in the extended throat, with appropriate choice of constants. The mass flow rate of gas under both single phase and multiphase conditions now becomes

$$9) \quad m_g = \frac{C_{2f} A Y}{\sqrt{1 - b^4}} \sqrt{2 r_g} \left[\sqrt{\Delta P_3} - C_2 \times \sqrt{P_2} \right],$$

where we have assumed that $\alpha_2 \approx \alpha_1 \approx 1$. The constants $C_{2\phi}$ and C_2 have been determined empirically and the validity of the equation has been tested over a wide range of conditions.

Figures 9 and 10 show the 1 inch low pressure air-water mass flow rate data plotted with the 1.4 inch 400 and 500 psi natural gas-Isopar M data. Overall, two throat diameters, 1" and 1.4", representing three contraction ratios, at pressures ranging from atmospheric to 500 psig using two gases, and four fluids have been experimentally examined. A single universal set of constants has been found to yield gas mass flow rates with a accuracy of $\pm 2\%$ of reading for liquid mass loading $m_l/m_g < 10\%$ and $\pm 4\%$ of reading for $10\% < m_l/m_g < 30\%$. This liquid loading range covers the void fraction range from $0.95 < \alpha < 1.0$, where α is the volume fraction of the gas phase.

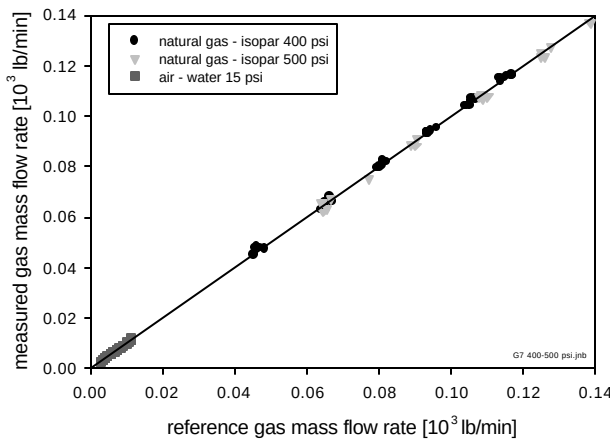


Figure 9. Comparison of measured and reference gas mass flow rates.

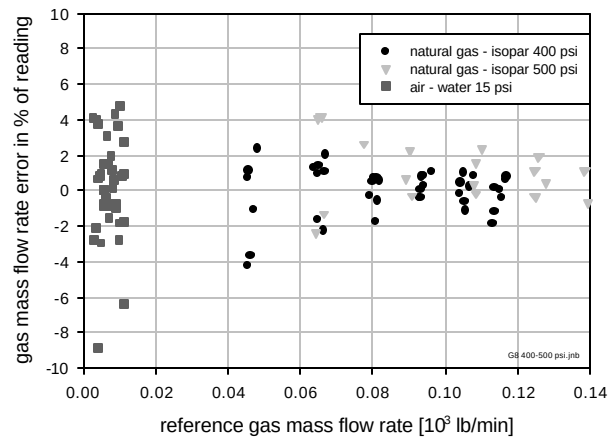


Figure 10. Gas mass flow rate measurement error in percent of reading.

We have assumed that $\alpha_2 \approx \alpha_1 \approx 1$, making equation 9 only approximate. The statistical fitting procedure used to determine the constants $C_{2\phi}$ and C_2 implicitly determines a weighted mean value of α . Hence, because α does not appear explicitly and is unknown there is an uncertainty of $\pm 1-2\%$ over the void fraction range $0.95 < \alpha < 1.0$, implicit in the equation. If α or $(1-\alpha)$ is independently measured the observed measurement uncertainties can be significantly reduced. The uncertainty can also be significantly reduced if, at installation, the actual flow rates are accurately known. If this measurement is available then the meter reading can be adjusted to reflect the true value and the uncertainty in the gas phase mass flow rate measurement can be reduced to less than 0.5% of reading if the flow rates change by less than 50% or so over time. The repeatability of the measurement is essentially the random uncertainty in the pressure measurements, less than about 0.5% of reading.

TOTAL AND LIQUID MASS FLOW RATE

If the ratio of liquid to gas flow rate is known *a priori* with certainty then the mass flow rate of the liquid phase can be directly obtained from $m_l = m_g (m_l / m_g)_{\text{known}}$. Note that because the liquid mass flow rate is only a fraction (0-30%) of the gas mass flow rate the uncertainty in the measurement is magnified. For instance, if $m_l/m_g = 0.01$, a 1% error in m_g is magnified to

become a 100% of reading error for the liquid phase. An additional fixed error of 1% in the ratio m_l/m_g results in a 200% of reading total error for the liquid phase. This approach, of course, assumes that the m_l/m_g ratio remains constant over time.

Unfortunately, without accurate, independent knowledge of α or $(1-\alpha)$ the liquid mass flow rate cannot be obtained directly from one-dimensional theory. The velocity of the liquid phase can, however, be estimated directly as follows: Once the mass flow rate of the gas phase is determined the ΔP_{gl3} term can be estimated from the gas phase energy equation:

$$10) \quad \Delta P_{gl3} \approx \Delta P_3 - \frac{1}{2} \frac{m_g^2}{r_g A^2} (1 - b^4)$$

Rearranging the liquid phase energy equation yields

$$11) \quad \Delta P_3 + \Delta P_{gl3} = \frac{1}{2} r_l u_{l2}^2 \left(1 - \frac{u_{l1}^2}{u_{l2}^2} \right) + G_c f_w \frac{1}{2} r_l u_{l2}^2$$

and using the expression for the mass flow rate of liquid results in

$$12) \quad \Delta P_3 + \Delta P_{gl3} = \frac{1}{2} r_l u_{l2}^2 \left(1 - \frac{(1 - a_2)^2}{(1 - a_1)^2} b^4 \right) + G_c f_w \frac{1}{2} r_l u_{l2}^2$$

With the assumption that $\frac{(1 - a_2)^2}{(1 - a_1)^2} b^4 \ll 1$ the liquid velocity u_2 can be estimated. If $(1-\alpha)$ is

known then the liquid mass flow rate could be estimated directly from $m_l = (1 - a_2) r_l u_{l2} A$. Unfortunately, $(1-\alpha)$ cannot be accurately estimated from the differential pressure data, it must be independently measured to pursue this approach.

If we consider the gas and liquid phases together but allow their velocities to differ, the total mass flow rate can be written as

$$13) \quad m_t = m_g + m_l = \left(a r_g + \frac{(1 - a)}{S} r_l \right) u_g A$$

where the density term in brackets is the effective density, ρ_{slip} . Since m_t is constant throughout the venturi allows us to write the pressure drop ΔP_3 as

$$14) \quad \Delta P_3 = \frac{1}{2} \left(a r_g + \frac{(1 - a)}{S} r_l \right) u_g^2 (1 - b^4) + G_c f_w \frac{1}{2} r_l u_{l2}^2$$

The second term on the right hand side is the friction loss assuming that only the liquid phase is in contact with the wall. The equation can be rearranged to yield the total mass flow rate

$$15) \quad m_t = \left(a r_g + \frac{(1 - a)}{S} r_l \right) u_g A = \frac{2 \left(\Delta P_3 - G_c f_w \frac{1}{2} r_l u_{l2}^2 \right) A}{(1 - b^4) \cdot u_g}$$

If the assumptions leading to this equation are approximately correct then $\dot{m}$ can be obtained directly from ΔP_3 once u_g is estimated from the measured value of $\dot{m}_g$, $u_g = \dot{m}_g / r_g A$ and u_2 is calculated from equation 12. The results of this calculation for the 400 and 500 psi 1.4-inch venturi data appear in Figures 11 and 12. The friction factor $G_c f_w$ is taken to be 0.062. While the friction term is small it should not be ignored. The total mass flow rate is obtained with a measurement uncertainty of $\pm 4\%$ of reading.

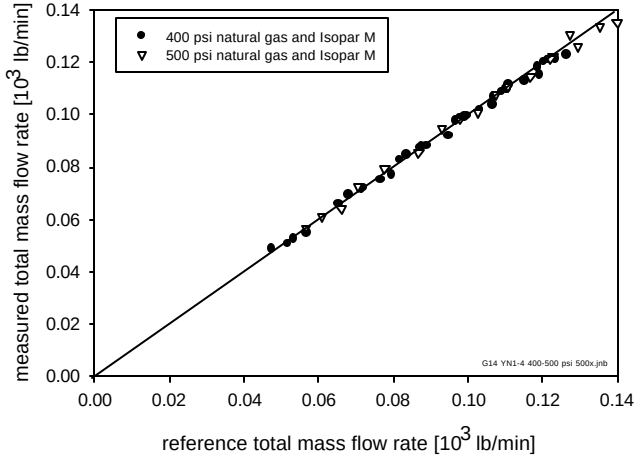


Figure 11. Measured total mass flow rate.

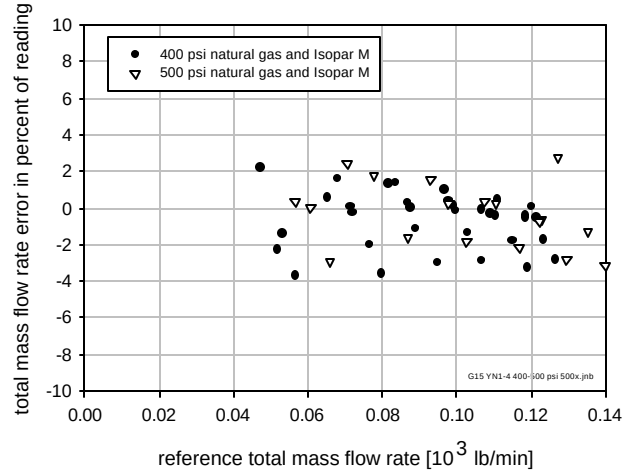


Figure 12. Total mass flow rate error in percent of reading.

In principle, (since the total mass flow rate is the sum of the gas and liquid mass flow rates) the liquid mass flow rate can now be obtained directly from, $\dot{m}_l = \dot{m}_t - \dot{m}_g$. The result of this calculation for the 400 psi data is shown in Figures 13 and 14. When attempting to deduce a small number, $\dot{m}_l$, from the difference of two large numbers the resulting uncertainty is also

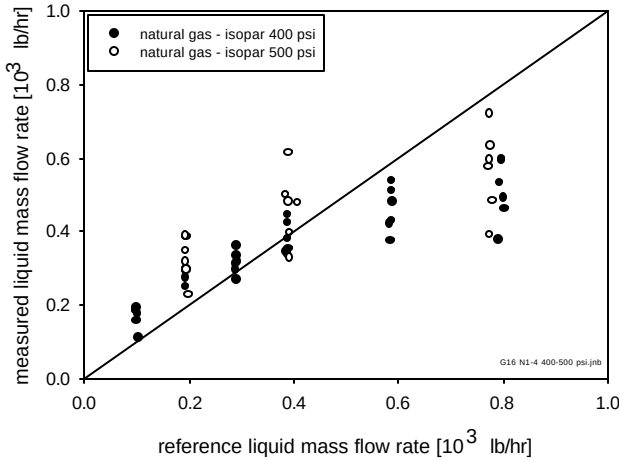


Figure 13. Comparison of measured and reference liquid mass flow rates.

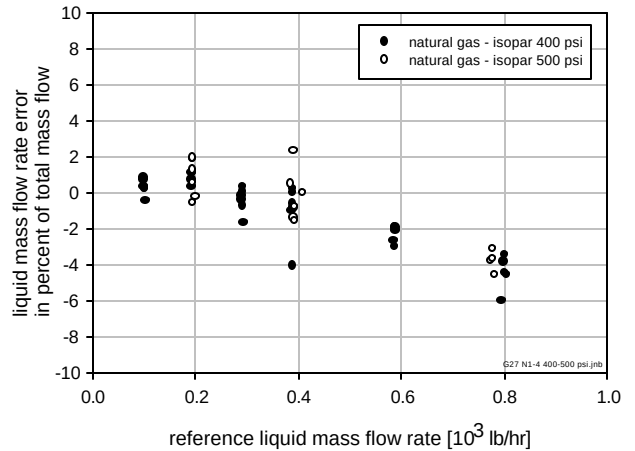


Figure 14. Liquid mass flow rate error in percent of reading of total mass flow rate.

large, this is evident in Figure 13. Realistically this error should be quoted in terms of the total mass flow rate, Figure 14. The liquid mass flow rate can be obtained within $\pm 5\%$ of the total mass flow rate.

INSTALLATION BENCHMARKING

As previously noted in the discussion of the measurement of the gas mass flow rate, if the flow rates of each phase are accurately known at the time of installation, measurement performance over a reasonable range of mass flow rates can be significantly enhanced. The data suggest that the uncertainty in the gas mass flow rate measurement can be reduced to $< 0.5\%$ of reading by benchmarking even if the gas and/or liquid mass flow rates change by $\pm 50\%$. Similarly the uncertainty in the total mass flow rate can be reduced to $< 2\%$ of reading for the same $\pm 50\%$ changes in gas and/or liquid mass flow rates. The corresponding improvement in accuracy of the liquid phase measurement is also significant. Because the liquid mass flow rate measurement is dependent on both the gas phase and total mass flow rate measurements (equation 16), the uncertainty is also sensitive to changes in both gas and liquid mass flow rate. If the liquid mass flow rate measurement is benchmarked at an initial value, the data indicate that the accuracy attainable is $\pm 20\%$ of reading for changes in gas mass flow rate in the range of $\pm 15\%$ and/or changes in liquid mass flow rate in the range of $\pm 25\%$. The uncertainty in the liquid mass flow rate quoted in terms of percent of total mass flow rate becomes $\pm 1\%$.

CONCLUSIONS

The mass flow rate measurement performance of the extended throat flow nozzle is summarized in Table I below. The uncertainty in the measurement of the mass flow rate of each phase and the total mass flow rate is expressed in percent of reading of the total mass flow rate $m_t = m_g + m_l$. The “benchmarking” columns are specified as both percent of reading of the mass flow rate of the measured phase and percent of reading of the total mass flow rate. Measurement uncertainties can be significantly reduced if flow rates are accurately known at time of meter installation or periodically measured by separation and separate metering during the service life of the meter and the well. Because the liquid phase is only a small fraction of the total mass flow rate the uncertainty in its measurement is inherently high.

Table I. Mass flow rate measurement performance summary.

	Uncertainty in % of total mass flow	Benchmarked uncertainty in % of reading*	Benchmarked uncertainty in % of total mass flow*
Gas phase	$\pm 4\%$	$\pm 0.5\%$	$\pm 0.5\%$
Total mass flow	$\pm 4\%$	$\pm 2\%$	$\pm 2\%$
Liquid phase	$\pm 5\%$	$\pm 20\%$	$\pm 1\%$

* see section on “INSTALLATION BENCHMARKING”

ACKNOWLEDGMENTS

This work was performed under the auspices of the U.S. Department of Energy under DOE field Office, Idaho, Contract DE-AC07-94ID13223. Support was provided by Laboratory Directed Research and Development funds and by Perry Equipment Corporation.

REFERENCES

- 1) Hewitt, G. F. (1998) Differential Pressure, Dual Energy Gamma Densitometry and Cross Correlation in Multiphase Flow Measurement, International Conference on the Future of Multiphase Metering, London, UK.
- 2) Avallone, E. A. and Baumeister (1987). Mark's Standard Handbook for Mechanical Engineers, McGraw Hill, New York, pp. 3.62 – 2.63.
- 3) Murdock, J. W. (1962). Two Phase Flow Measurement with Orifices, ASME Journal of Basic Engineering, December, 419-433.
- 4) Jamieson, A. W. and Dickinson, P. F. (1993). High Accuracy Wet Gas Metering, Proceedings, North Sea Flow Measurement Workshop, Bergen, Norway.

LARGE DOWNHOLE SEISMIC SENSOR ARRAY

Fincke, J. R. (jf1@inel.gov; 208-526-2031)

West, P. B. (west@inel.gov; 208-526-1538)

Weinberg, D. M. (weinbe@inel.gov; 208-526-4274)

Lockheed Martin Idaho Technologies Company
Idaho National Engineering and Environmental Laboratory
P.O. Box 1625
MS 2211
Idaho Falls, Idaho 83415-2211

Walter, L. A. (lwalter@oyo.com; 281-494-8282)

OYO Geospace Instruments
12750 S. Kirkwood, Suite 10
Stafford, Texas 77477

Contract Number: N/A

Contractor name: LMITCO

Address: P.O. Box 1625, Idaho Falls, ID 83415

Telefax Number: 208-526-5327

NPTO Contracting Officer's Representative: Robert Lemmon

Period of Performance: FY95-FY00

Subcontract Information: N/A

Since the days of the very first reflection seismic line acquired for petroleum exploration, geologists and geophysicists have wanted better quality reflection data and more resolution of the subsurface. As technology improved from single-channel analog recorders to multi-channel digital recording, so did the ability of explorers to find more reserves in shorter periods of time. Borehole seismic surveys started two decades ago with vertical seismic profiles (VSPs). However, despite their success, geophysicists continue to demand more from borehole surveys. In the mid-1980s, several research teams within the major companies designed and tested various systems of borehole seismic receivers and sources. Such surveys promised to allow companies to shoot from one well to another, thereby providing what amounted to a seismic "catscan" of the earth between the two wells. While potentially useful in exploration ventures, the real promise of these so-called cross-well surveys lies in their ability to image producing horizons within existing fields, thereby enabling production and injection strategies to be optimized. Unfortunately, cross-well surveys suffer from high data acquisition costs. Based on the experience of several operators active in the field, there is a direct correlation between the number of receivers one puts into the well bore and the cost of the survey. For cross well seismic to achieve its real potential, a major change in data-acquisition technology had to be found.

To solve this problem, the INEEL under a CRADA with OYO Geospace Instruments is developing a large downhole seismic sensor array (LDSSA) that can be scaled to >100 sensor locations (3-axis using either geophones or accelerometers) and can be clamped, unclamped, and moved to a new borehole location. Systems developed in this effort along with evolving

computational techniques will be able to collect and interpret data in ways that will greatly enhance the industries' capability to find and extract oil and gas.

This project will provide the oil and gas industry with a more economic, higher-fidelity, three- (or four-) component, subsurface, seismic survey system. Successful development of the LDSSA requires unconventional clamping and deployment technology and a downhole electronic architecture that is significantly different from approaches currently employed on available 5-12 sonde arrays. It is our objective to design, fabricate, and test various downhole prototype seismic sensor modules, compatible with a large downhole seismic sensor array. The developed hardware is compatible with state-of-the-art electronics and fiber-optic telemetry technologies.

The Idaho National Engineering and Environmental Laboratory is funded to develop prototype seismic sensor modules scalable to at least a 300-channel system. The modules will be deployable in vertical and deviated well bores using conventional wireline and/or coiled tubing. The array can contain 100 three-component sensors, and will quickly and verifiably clamp to well casing. The hardware contains state-of-the-art electronics and fiber-optic technologies. With this new tool, subsurface seismic data can be collected and transmitted to the surface in real time where it can be recorded and processed. This system will help industry more economically acquire high quality, high frequency, three-component subsurface seismic data.

To date, the INEEL has fabricated and tested prototype packer-type and magnetically clamped modules in the borehole environment. Upon final design and testing, packer-clamped modules will be fabricated and mated to OYO's new proprietary electronics that provides full 24-bit data acquisition. This advanced electronics design will enable the original goal of 100 levels to not only be met, but also exceeded. Currently, OYO is using this new system with a previous-generation receiver module to acquire data in several areas. Issues associated with co-deployment of packer-clamped systems with production tubing in place are also being examined. The final task in this project is the fabrication and testing of a fully integrated fieldable prototype system. This task will demonstrate deployment, clamping, and operation of acquisition and telemetry systems in an integrated manner.

Using an early prototype, OYO Geospace Instruments ran a cross-well survey for a major producer in New Mexico. The results included: improved borehole seismic resolution by 9 times, provided nearly 10 times more data in 1/50th of the time, and helped replace a 10 BOPD well with a 130 BOPD well. Getting more oil out of existing fields either by enhanced production techniques or producing previously unseen "new" reserves, borehole seismic surveys hold great promise for producers, majors and independents alike.

As the INEEL's CRADA partner, OYO Geospace Instruments has the first right-of-refusal to license any of the designs being created at the INEEL. As a manufacturer of geophysical instrumentation, OYO is in a position to build borehole systems to any service supplier who wants them.

P.9 Biological Oxidation of Sulfides in Oilfield Brines

G. A. Bala (GB3@inel.gov; 208-526-8178)
Lockheed Martin Idaho Technologies Company
Idaho National Engineering and Environmental Laboratory
P.O. Box 1625
Idaho Falls, Idaho 83415-2203

G. E. Jennema (gejenne@tpco.com; 918-661-8797)
Phillips Petroleum Company
224 Geoscience Building
Bartlesville, Oklahoma 74004

K. L. Sublette (che_ks@centum.utulsa.edu; 918-631-3085)
McComas, C. B. (918-631-3085)
600 South College Avenue
The University of Tulsa
Center for Environmental Research and Technology
Tulsa, Oklahoma 74104-3189

Contract Number: n/a

Contractor Name: LMITCO

Address: P.O. Box 1625, Idaho Falls, ID 83415

Telefax Number: 208-526-9822

FETC Contracting Officer's Representative (CPR): NPTO - David Alleman

Period of Performance: 4/1/98 - 3/31/02 (tentative)

Subcontract Information: University of Tulsa, #K98-179829

Abstract

The presence of sulfides in reservoirs and produced fluids is a function of microbial, electro-chemical, and geochemical processes. Problems presented by sulfides include environmental compliance, toxicity, corrosion, reduced well performance, offensive odor, reduced monetary value of products, and increased operating costs. Technologies for the removal and control of sulfides include the use of biocides, scavenging agents, corrosion inhibitors, Claus reactors, amine plants, etc. Problems with these technologies include: ineffectiveness, use of toxic chemicals, cost, and generation of toxic wastes requiring disposal.

To overcome some of these problems, biocontrol strategies (generally termed biocatalysis) are being developed that rely on bacteria that oxidize sulfides in the presence of oxygen or nitrates to produce elemental sulfur or sulfate. In addition, these bacteria can out-complete Sulfate Reducing Bacteria (SRB) for nutrients needed for generation of sulfides thereby controlling further sulfide production. These biocatalytic processes have the advantages of being less costly and more acceptable since they utilize inexpensive, non-hazardous chemicals and generate low toxicity products.

We are developing and plan to demonstrate biocatalysis of sulfides in bioreactors integrated into production infrastructure. Specific objectives are to optimize the growth and sulfide scavenging capacity of a proven nitrate-reducing, sulfide oxidizing consortium of microorganisms and develop appropriate bioreactor platforms for scale design and technology demonstrations.

Biocatalytic processes rely on the ability of sulfide-oxidizing bacteria to remove sulfides while utilizing inexpensive, non-hazardous chemicals that result in the generation of low toxicity products. Most known sulfide biocatalysts require oxygen which in many cases is undesirable. However, a few sulfide-oxidizing biocatalysts such as *Thiobacillus denitrificans* use nitrate as an oxidant under anoxic conditions. Unfortunately, sulfide oxidation by *Thiobacillus* forms sulfate which can be inhibitory to further sulfide oxidation, is difficult to remove from the process stream, and readily reduced back to sulfide by SRB.

The novel biocatalyst system we propose oxidizes sulfide to elemental sulfur using nitrate as an oxidant. This results in less energy consumed per mole of sulfide removed and the production of an insoluble end product, sulfur, that can be removed and sold. Other by-products include biomass and a small amount of nitrogen gas. Furthermore these novel sulfide oxidizing bacteria have simple nutritional requirements for growth and can potentially out-compete SRB for trace nutrients needed for generation of sulfides thereby controlling further biogenic sulfide production.

The INEEL and Phillips Petroleum Company recently performed a successful in-situ proof-of-principle field trial (Coleville Field, Saskatchewan Canada) of sulfide removal by manipulating an indigenous population of nitrate-reducing, sulfide-oxidizing bacteria. A 19 well field-pilot of sulfide removal from produced oilfield brines by sulfide-oxidizing, nitrate-reducing bacteria is reported. Over a period of 50 days, ammonium nitrate (400 mg/L) and monosodium phosphate (12 mg/L) were co-injected upstream of two injection wells flowing 1,412 and 283 barrels (bbl) of water per day. Within 10 days of injection, sulfide levels at the injectors were reduced by 42 to 100% while sulfide levels at producers declined by as much as 50 to 60%. Sulfide oxidation rates greater than 373 mg/L/hr were calculated. These reductions in sulfide were accompanied by increases in the sulfide-oxidizing bacteria at both injectors and producers while slight reductions in sulfate-reducing bacteria were noted. The organisms responsible for the sulfide reduction are indigenous to the Coleville Operations Unit, Saskatchewan, Canada and incompletely oxidized sulfide to elemental sulfur in produced brine under the laboratory conditions tested. The major metabolic end products are elemental sulfur and nitrogen gas. The organisms have been isolated from the field and are being evaluated as potential biocatalysts for sulfide mitigation.

If successful, this technology will mitigate air and liquid sulfide effluents originating in aqueous field output, reduce corrosion facilitated by sulfides, reduce sulfide concentrations in produced fluids, and reduce the toxicity of produced water. Additionally, it has the potential to minimize the application of biocides and corrosion inhibitors.

The goal is to develop technology for application in existing water handling infrastructure. Application of technology is not dependent on the mechanism of sulfide formation (microbial, electrochemical, or geochemical). Potentially this technology can also be used to remove H₂S from gas streams.

Additional information on this project can be found in "Sulfide Removal in Reservoir Brine by Indigenous Bacteria," G. E. Jenneman, P. D. Moffitt, G. A. Bala, and R. H. Webb. 1999. SPE Prod. and Facilities 14 (3):219-225.

SUCTION PULSE DRILLING SYSTEM

RESULTS OF A PHASE I FEASIBILITY STUDY

Jack J. Kollé (jkolle@tempresstech.com; 253-872-1982)

Mark M. Marvin (mmarvin@tempresstech.com; 253-872-1986)

Tempres Technologies Inc.

19308 – 68th Avenue South

Kent, WA 98032

INTRODUCTION

Conventional rotary drilling is slowed by the confining pressure exerted by the column of mud in the borehole. The bottom hole pressure in a hole drilled for oil or gas is typically maintained at a value which is equal to, or slightly higher than the pore pressure of fluids (water, oil or natural gas) in the formation being drilled. The confining pressure of the mud increases the strength and plasticity of rock, reducing the efficiency of indentation and shear cutting (Kollé, 1996). The greatest effect of confining pressure occurs in shale, which also accounts for most of the rock encountered during drilling for oil and gas. Drilling experience has demonstrated that significant increases in drilling rate can be achieved by underbalanced drilling (in which the borehole pressure during drilling is smaller than the formation pressure). This is achieved by reducing the amount of weighting material added to the drilling mud or by using light-weight drilling fluids such as gas or foam to drill. The problem with underbalanced drilling is that the entire open section of the hole is subject to low pressure, which reduces borehole stability and increases the risk of a gas kick.

OBJECTIVE

An ideal drilling system would create a low-pressure region that is limited to the hole bottom while normal or overbalanced conditions are maintained above the bit to control formation fluids. The HydroPulse™ system shown in Figure 1 provides a means of generating intense cyclic suction pressure pulses that overcome the effects of borehole pressure and increase drilling penetration rate in deep formations. This system would be mounted on a conventional drill string and powered by mud hydraulics. The bottomhole assembly is compact and the system is compatible with downhole motors. The suction pulses could be used to enhance the penetration of conventional roller-cone, PDC or diamond bits. In many situations, such as horizontal drilling, it is difficult to apply a high mechanical thrust to the bit. The hydraulic thrust generated by a suction pressure pulse provides a means of drilling with minimal applied thrust. The suction pulse generator could also be used as a downhole seismic source or for a variety of workover operations such as removal of fines from damaged formations.

APPROACH

Drilling mud is normally pumped through a drill bit to remove cuttings from the hole bottom and transport them to the surface. When directed through high-speed flow courses, the mud flow contains significant kinetic energy, which can be converted into a suction pressure pulse by momentarily interrupting the flow with a valve as shown in Figure 2. This generates a suction pressure pulse downstream of the flow interruption. The suction pulse magnitude can be quite high because of the low compressibility of water-based drilling mud. The pulse results in an impulsive thrust on the bit at the same instant that the fluid pressure at the bit face is reduced. Suction pulse drilling results from the simultaneous combination of high indentation force on mechanical cutters and the reduced confining pressure.

The HydroPulse™ system employs a self-cycling poppet valve to generate the appropriate pulse magnitude and time history. The poppet valve design ensures that flow through the bit is maintained at a constant high velocity up to the instant that the valve closes. Instantaneously stopping the flow of water (or mud) in a closed conduit results in a suction pressure pulse downstream of the valve.

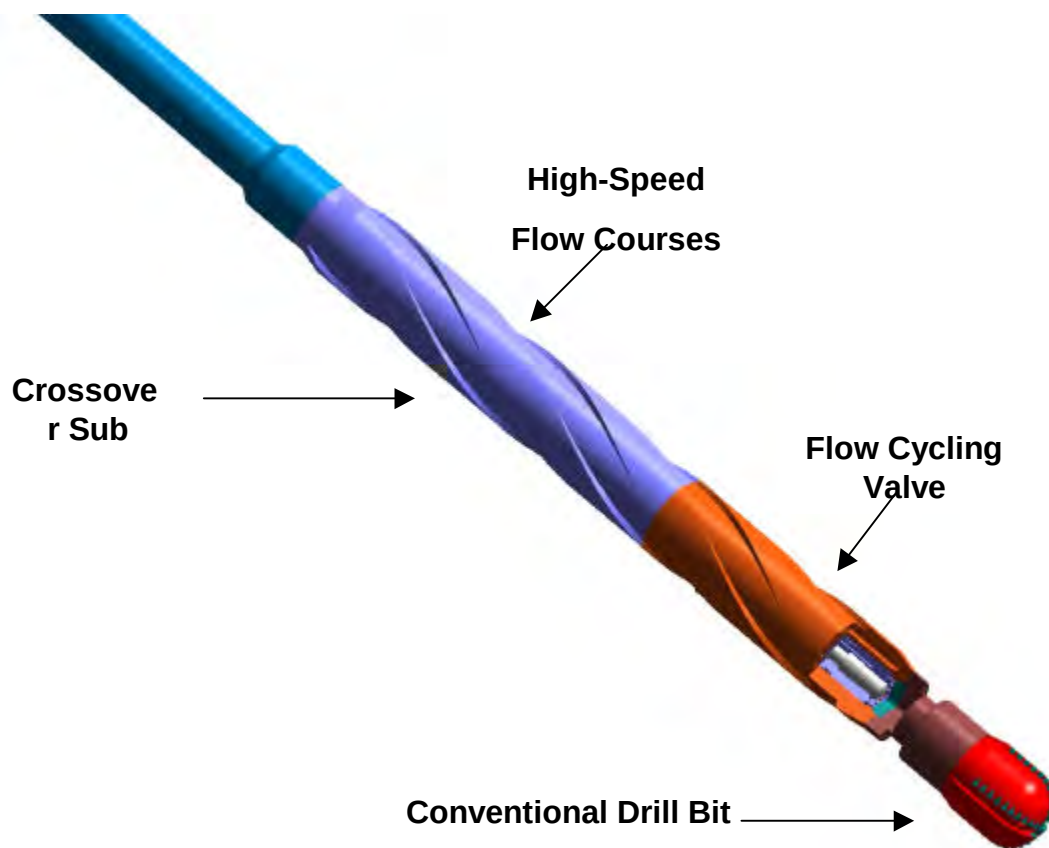


Figure 1. HydroPulse™ drilling system

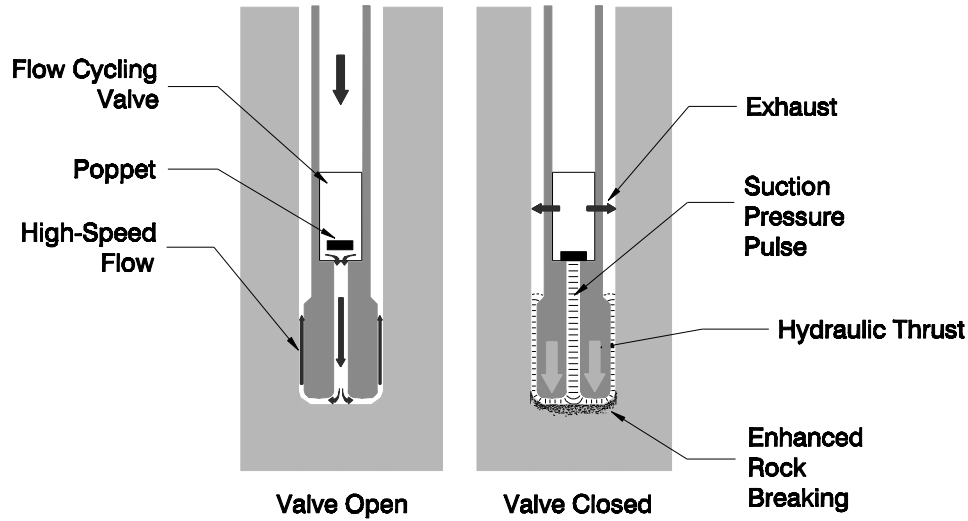


Figure 2. Suction pulse drilling.

The magnitude of the suction pulse can be evaluated by equating the kinetic energy of flow in a closed conduit to the elastic potential energy of the decompressed fluid volume. If the initial flow velocity is v , the magnitude of the water-hammer pressure pulse is

$$\Delta P = v \sqrt{r K_f} , \quad (1)$$

where K_f is the bulk modulus of the fluid and r is the density (Troostmann 1996). In water ($K_f = 2.4$ GPa at 35 MPa), the pressure pulse has an amplitude of about 1.5 MPa per m/s flow velocity. The pressure magnitude increases with the square root of the mud density. Flow velocities of 10 to 20 m/s are common in the flow courses of carbide body drill bits, so pressure pulses of 15 to 30 MPa (2000 - 4000 psi) or more can be generated. The duration of the pressure pulse is determined by the two-way travel time of acoustic waves in the flow conduit. The speed of sound in water is about 1500 m/s so the duration of a pressure pulse in a high-speed flow course with a length of 1 m would be about 1.3 milliseconds.

RESULTS

The Phase I project discussed here involved the development and testing of a small-scale prototype suction pulse valve. This valve was used for a series of pressure drilling tests demonstrating the effect of suction pulses on drilling performance. This section discusses the results of small scale drilling tests.

Prototype Flow Cycling Valve and Test Setup

Figure 3 shows an engineering prototype flow cycling valve designed for a flow rate of 2×10^{-4} m³/s (3.4 gpm). The discharge from this valve is directed through the pressure drilling test stand shown in Figure 4. The flow cycling valve periodically interrupts the flow from the drill to the bit and diverts it to an exhaust port. When the cycling valve poppet is open, flow enters through the drill rod and is discharged through open ports on the bit. The high speed flow is directed through flow courses around the bit into a 1-m long suction pressure line. The intensity of the pressure pulse is related to the flow velocity in the suction pulse line while the pulse duration is related to

the length of the line. High pressure is maintained in the pressure vessel by directing the flow from the suction pressure line and cycling valve exhaust through an adjustable choke.

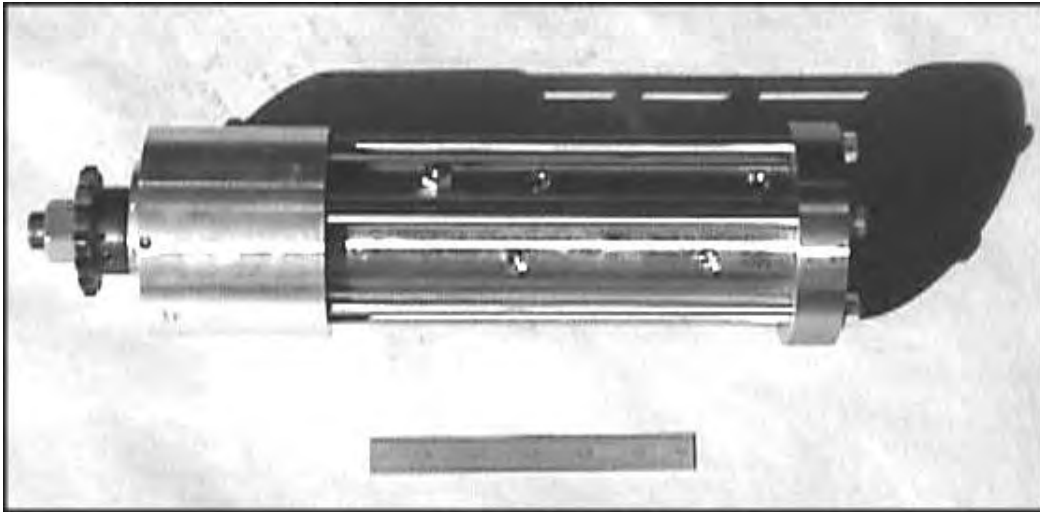


Figure 3. Engineering prototype flow cycling valve - ruler is 150 mm (6").

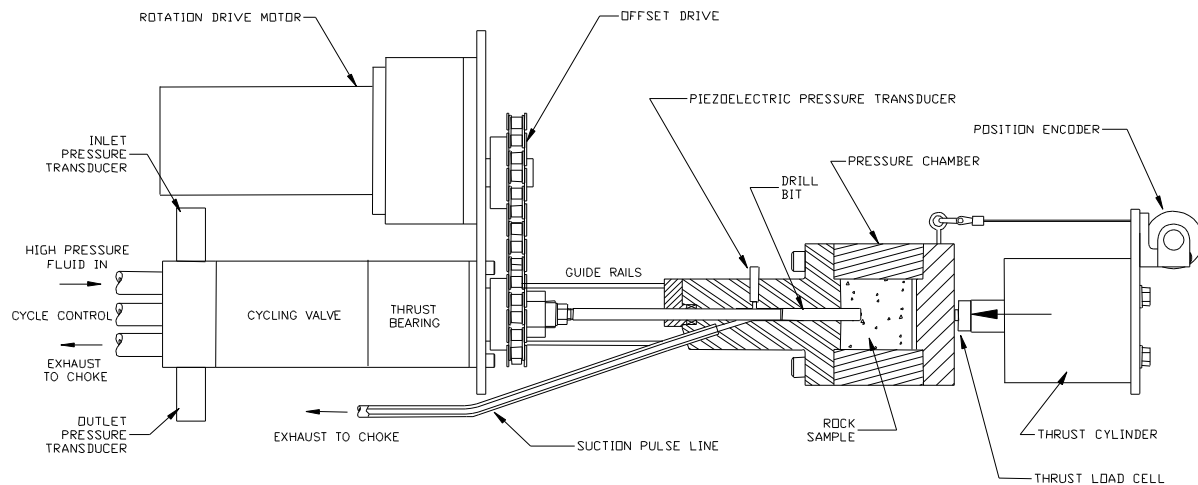


Figure 4. Small-scale pressure drilling test stand layout.

Figure 5 shows an example of a series of suction pressure pulses generated in a borehole in shale by the engineering prototype with a 1 m suction pulse flow line. The pressure pulses occur at a cycle rate of 47 Hz and each pulse has a duration of about 1.3 milliseconds. The hydraulic power associated with each pulse is .75 J and the power level is 35 W in this example. Figure 6 shows the pressure upstream of valve. There are no water hammer pressure spikes upstream of the valve because the flow is never interrupted. This means that this cycling valve could be located downstream of a downhole motor without affecting motor performance.

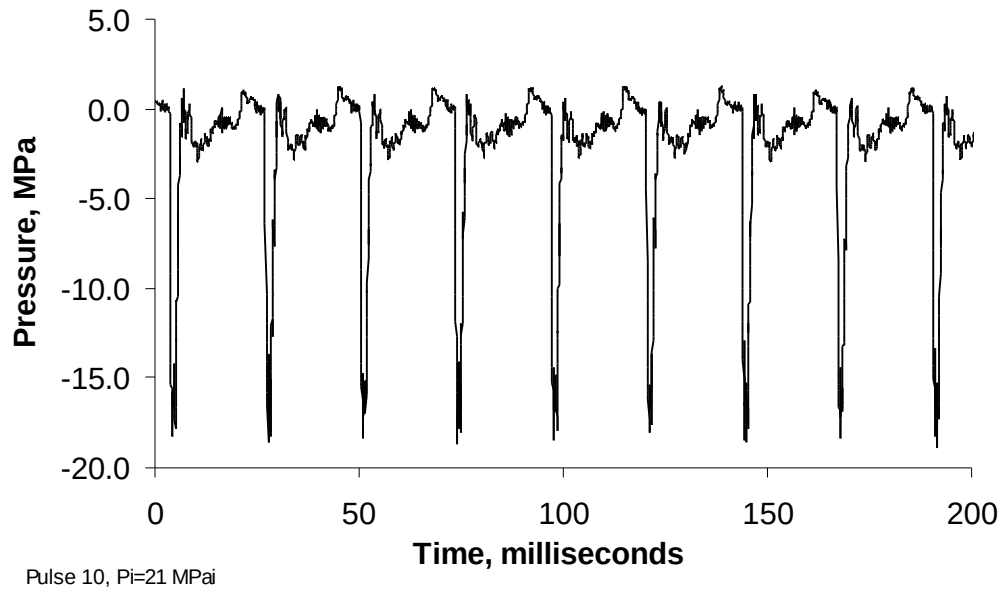


Figure 5. Example of 35 W suction pulse train generated by a flow interruption valve in combination with a high speed flow course. (1000 psi = 6.9 MPa).

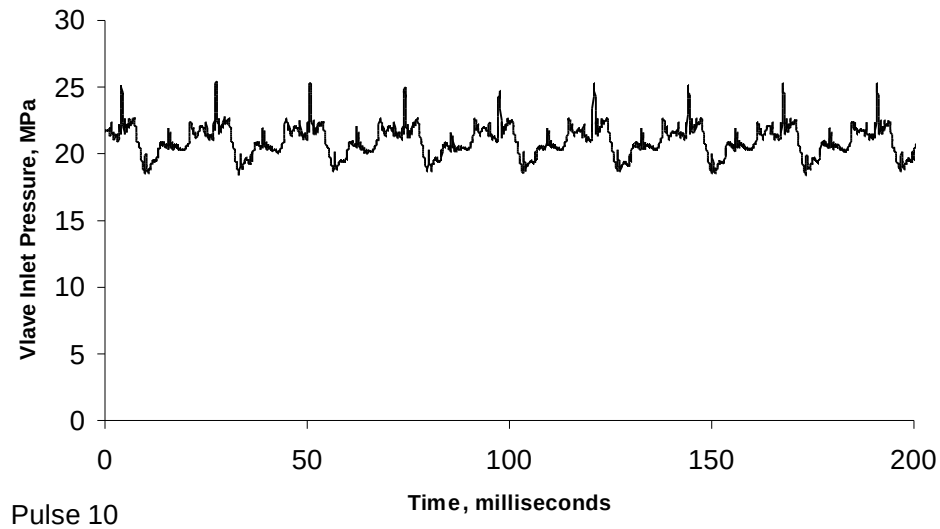


Figure 6. Upstream pulse profile on valve inlet pressure manifold.

The power spectrum of the suction pressure pulse signal is shown in Figure 7. This is the amplitude of the pressure that would be received at a range of 1 m from the source. The pulse energy has strong peaks at the basic cycle frequency and its higher harmonics. The power at 1 kHz is only 20 dB below the peak at 43 Hz indicating that this pulse would provide an intense source of high frequency seismic energy. Despite its tiny size, the power level of this source at harmonics of the repetition frequency is comparable to that of a moderate size airgun array (Dragoset 1990). A 200 mm diameter source would 27 dB higher in power.

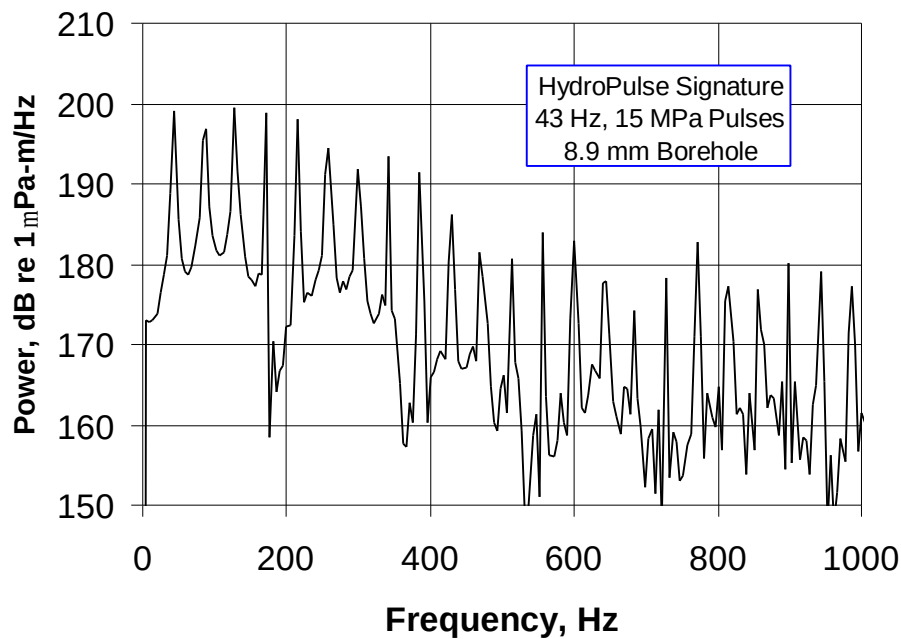


Figure 7. Amplitude spectrum of small scale (35 W) pulse signal (see Figure 5)

Small-Scale Drilling Tests

A series of small-scale drilling experiments were carried out to demonstrate the concept of suction pulse drilling. These experiments involved rotary drilling with a small, 8.7 mm (.343”) diameter drill into a pressurized rock sample. Drill bits with and without mechanical cutting elements were used. Drilling tests were carried out with and without the application of underbalance pressure pulses in order to allow a direct observation of the effect. As shown in Figure 8, the application of suction pressure pulses causes a sharp increase in penetration rate.

Figure 9 shows a carbide bit that was fabricated by grinding a 20 degree negative backrake on the carbide. The cutter edge was ground to a 90 degree angle to provide clearance on the face. The backrake cutter bit was used to drill two samples of Mancos Shale. Tests were carried out at two thrust levels. When suction pulses are applied at zero thrust, the penetration rate of the backrake cutter is essentially the same as with 200 N thrust. The drilling rate with 200 N thrust shows a step increase by a factor of four at around 10 MPa suction pulse pressure.

A similar test was carried out in Colton Sandstone at relatively low thrust. The application of 16 MPa suction pulses causes the penetration rate to triple.

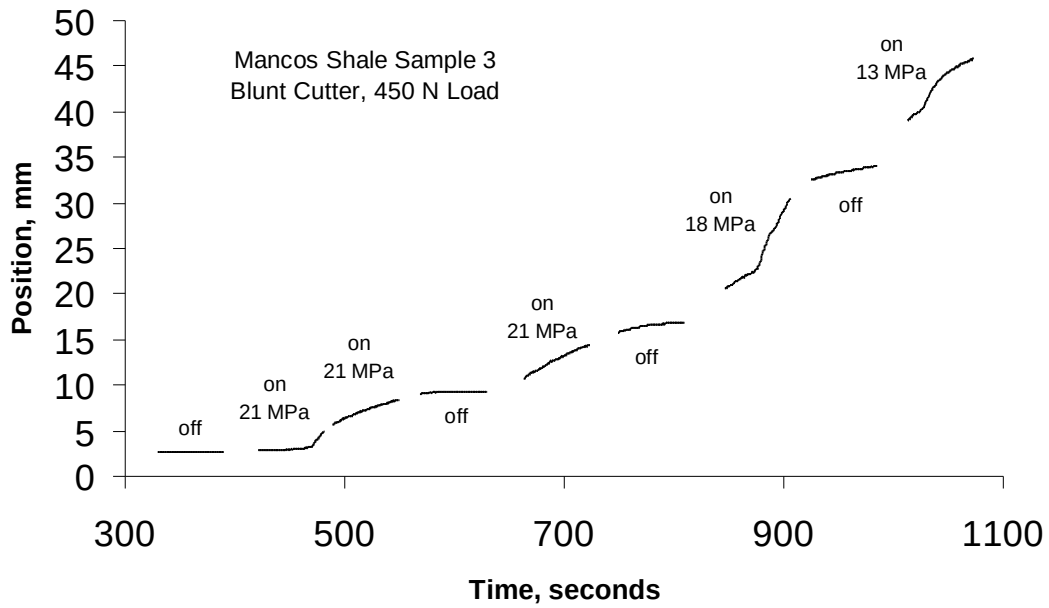


Figure 8. Example test record showing bit penetration with cycling on and off.

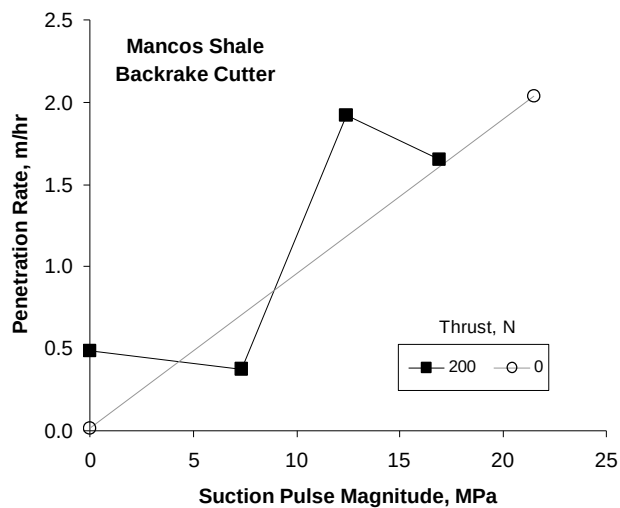


Figure 9. Mancos Shale drilling with backrake cutter at 60 rpm, 21 MPa ambient pressure.

An indenter bit with a 120 degree included angle carbide cutter was used to carry out suction pulse drilling tests in Sierra White Granite (Figure 10). The application of 9 MPa suction pulses at a frequency of 20 Hz caused the penetration rate to triple in the granite sample.

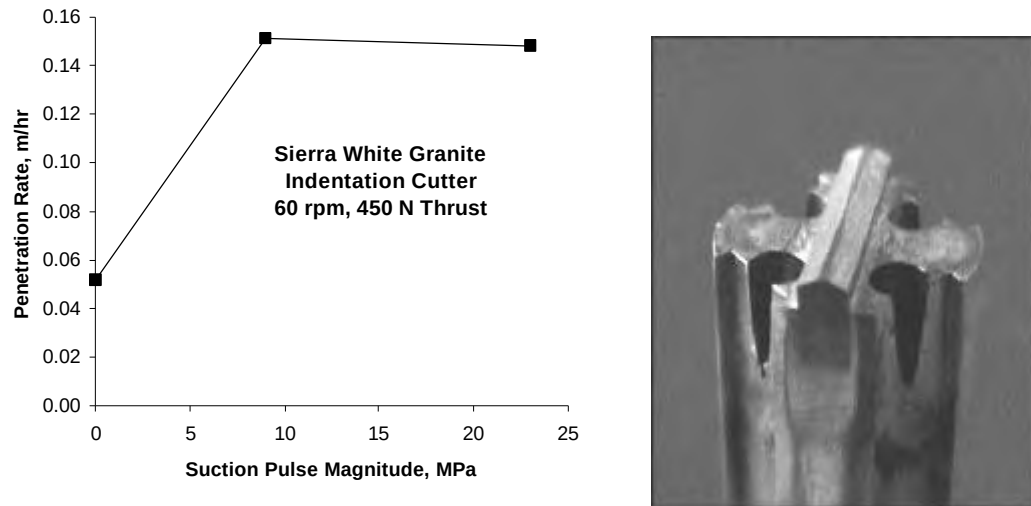


Figure 10. Indentor bit drilling rates in Sierra White Granite. Ambient pressure = 23 MPa.

The drilling rate data obtained during the feasibility study are summarized in Table 1. All of the drilling tests in shale, sandstone and granite indicated a significant increase rate of penetration as a result of the application of suction pulses. The increased penetration rate was observed at pulse magnitudes of around 10 MPa and a frequency of 20 Hz in Mancos Shale. Application of a 10 MPa suction pressure pulse, causes the mechanical load to increase by 250 N for about 1.5 milliseconds. The pulses do not have the short duration or high amplitude characteristic of an impact. The pulse rate is 20 Hz so the time-averaged thrust increase is only 8N. The increased thrust can only account for a small part of the observed effect on drilling rate. An analysis of suction pulse propagation in rock has shown that these pulses will induce effective tensile stresses in the rock that are comparable or greater than the tensile strength of the rock (Kollé 1998). We conclude that the increased drilling rate results from the combined effects of effective tensile stresses and mechanical indentation.

Table 1. Drilling rate summary; all data at 60 rpm, 21 MPa ambient pressure.

Bit	Rock	Thrust N	No Cycling ROP m/hr	Cycling ROP m/hr	ROP Ratio	Cycling Pressure MPa
Blunt	Mancos Shale	450	0.05	0.3	6	12
	Colton Sandstone	450	0.17	0.34	2	18
Backrake	Mancos Shale	0	0	2.1	∞	22
		200	0.5	2.0	4	7
	Colton Sandstone	40	1.2	4.6	4	16
Indentation	Granite	450	.05	.15	3	9

APPLICATIONS

The Phase I work described here has demonstrated the feasibility of a suction pulse generator and its application to drilling. This system would significantly enhance the rate of penetration and reduce the cost of deep drilling. The technology demonstrated here has significant other applications including horizontal drilling, seismic-while-drilling and workovers in open hole and tubulars.

Drilling

The primary application of the HydroPulse™ system is faster drilling in deep formations. The suction pulses will reduce the drilling strength of formations such as shale that become strong and highly plastic in deep boreholes. The pulses will also reduce formation balling and bit balling by overcoming the differential pressures that cause formations to stick together. The pulse technique provides the advantages of underbalanced drilling at the bit while allowing formation pressure control above the bit.

Seismic

Seismic investigation provides an important tool for characterizing oil and gas reservoirs. Seismic work is normally carried out separately from drilling although seismic analysis of the signal from a roller cone bit has been used for velocity profiling. The suction pulse generator provides an intense, periodic acoustic signal that can be used for seismic-while-drilling. The suction pulse drilling system discussed above would generate a pulse power of 7 kW with significant energy at frequencies greater than 1 kHz compared to peak frequencies of around 10 Hz for drill bit seismic. In this application a seismic receiver would be located on the surface, in a parallel borehole or on the drill string above the bit. Seismic interpretations of formation properties may be used to locate the bit and oil or gas bearing formations. Reflections of pulses from formations ahead of the bit can be used for high-resolution imaging while drilling. The intense signals generated by the suction pulse system are particularly well-suited for determining pore pressures in the formation ahead of the bit. High formation pore pressure or the presence of gas causes strong attenuation of seismic signals (Mavko and Nur 1979). Drill bit seismic cannot be used for attenuation measurements because the source signals are not well-characterized. Knowledge of formation pore pressure provides enhanced safety during drilling particularly in deep water drilling and in gas-pressurized formations.

Formation Damage Removal

The suction pressures generated by this tool could also be used to remove fine-grained materials which can clog the pores of oil and gas producing zones. Formation damage commonly occurs during overbalanced drilling because fine-grained materials are forced into the formation by the differential pressure. Near-wellbore formations may also become blocked during drilling or production by fine-grained minerals and other materials. The suction pressure pulses produced by the invention will remove fines from the formation in order to enhance oil and gas production rates. The pulses could also be used to clean out perforations following casing penetration with shaped charges.

FUTURE ACTIVITIES

Tempress Technologies is now engaged in the development of a full-scale HydroPulse™ valve that is designed to operate on drilling mud. The valve design shown in Figure 11 would fit into a 150-mm diameter (6") subassembly and is designed for full scale suction pulse drilling operations. The valve circuit is similar to engineering prototype shown in Figure 2. This valve will operate at 85% volumetric efficiency – that is 15% of the flow is used to actuate the valve and is exhausted.

Specifications for a 150-mm diameter (6") HydroPulse™ drilling system are provided in Table 2. At a flow rate of 300 gpm the cycling valve would operate at 60 Hz. The cycling frequency and suction pulse magnitude are proportional to flow rate. Intermediate scale systems suited for operation on coiled tubing are also possible. The pulse power level on the face of a 200 mm diameter bit would be 165 kW/m^2 (0.14 HSI). The subassembly would be installed above a conventional PDC or roller cone bit that is equipped with jet nozzles. Surge and swab pressures were calculated as a function of mud weight and viscosity using a turbulent Bingham fluid model (Monicard 1982). The surge pressures are insignificant compared to normal pressure fluctuations during tripping with conventional drilling tools (Bourgoyne et al. 1986).

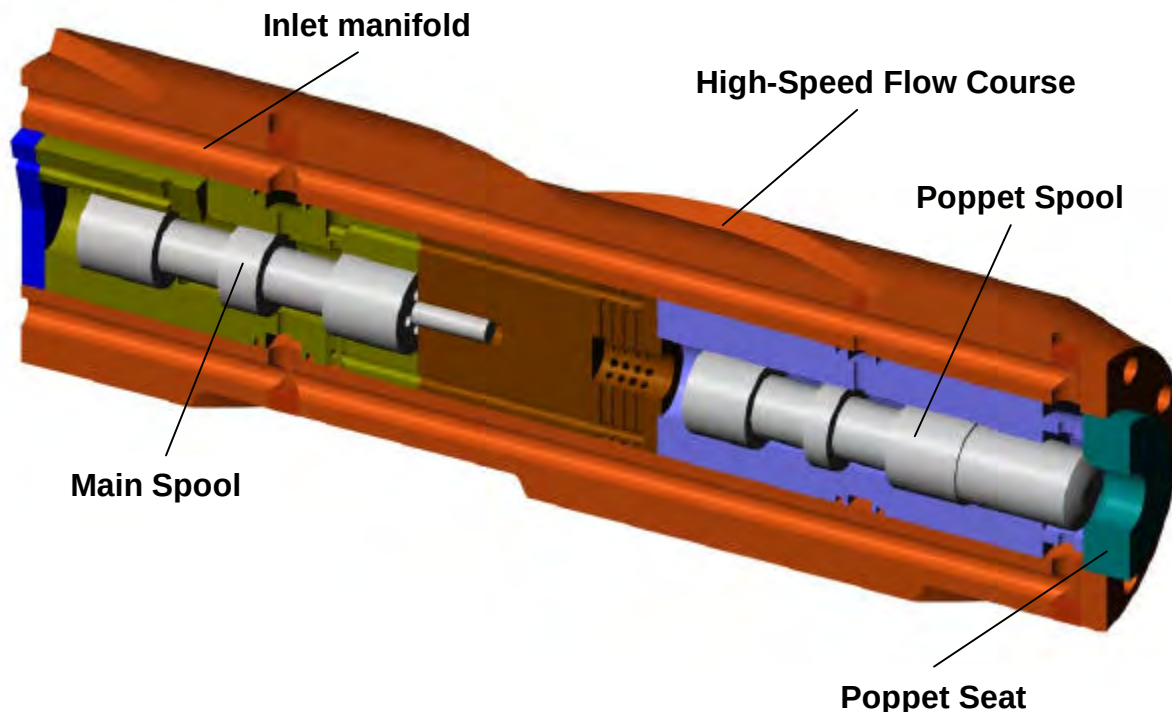


Figure 11. Full-scale HydroPulse™ cycling valve assembly configured for borehole applications.

Table 2. Specifications for a 150-mm (6") HydroPulse™ system.

Cycling Valve Diameter	150 mm (6")
Cycling Valve Length	600 mm (24")
Volumetric Efficiency	85%
Flow Course Length	1.5 m (60")
Flow Rate	.019 m ³ /s (300 gpm)
Pulse Frequency	60 Hz
Flow Course Area	.0032 m ² (5.0 in ²)
Flow Velocity	6 m/s (20 ft/s)
Pulse Amplitude	9 MPa (1300 psi)
Pulse Power	5.2 kW (7 hp)
Hydraulic Thrust Force on 200 mm (7-7/8") Bit	283 kN (64,000 lbf)
Maximum Hydraulic Liftoff (11 ppg, 100 cp mud)	< 2 kN (400 lbf)
Surge Pressure (tripping @ 1m/s in 11 ppg, 100 cp mud)	< 140 kPa (21 psi)

ACKNOWLEDGEMENTS

This research was sponsored by the U.S. Department of Energy's Federal Energy Technology Center under Cooperative Agreement No. DE-FC26-97FT34367 with Tempres Technologies Inc.. The period of performance for Phase I of this project was October 1, 1997 through December 31, 1998. We gratefully acknowledge the support and encouragement offered by the DOE contracting officer, Mr. William Gwilliam, during the course of this work.

REFERENCES

- Bourgoyne Jr., A.T., M.E. Chenevert, K.K. Millheim and F.S. Young Jr. (1986) *Applied Drilling Engineering*, Society of Petroleum Engineers, Richardson Texas.
- Dragoset, W.H. (1990) "Air-gun array specs: A tutorial," *Geophysics: The Leading Edge*, January, pp. 24-32.
- Kollé, J.J (1996) "The effects of pressure and rotary speed on the drag bit drilling strength of deep formations," *SPE 36434*, Proceedings of the 71st Annual Technical Conference and Exhibition, Denver, May 6-11, Society of Petroleum Engineers, Richardson, Texas.
- Kollé, J.J. (1998) "Underbalance pulse drilling rock mechanics analysis," TR-003, Tempres Technologies Inc., Kent, Washington.
- Mavko, G. and A. Nur (1979) Wave attenuation in partially saturated rocks, *Geophysics*, 44, 161-178.
- Monicard, R. (1982) *Drilling Mud and Cement Slurry Rheology Manual*, Editions Technip, Paris.
- Trostmann E. (1996) *Water Hydraulics Control Technology*, Marcel Dekker, Inc., New York.

DEVELOPMENT OF AN ADVANCED CUTTINGS TRANSPORT FACILITY AND OPTIMIZATION OF WELLBORE HYDRAULICS AT ELEVATED TEMPERATURES AND PRESSURES

**Ergun Kuru, Stefan Miska, Nicholas Takach, Mark Pickell
The University of Tulsa**

ABSTRACT

Recently, a new research initiative, Advanced Cuttings Transport Study (ACTS), has been undertaken by the University of Tulsa. The ACTS research program calls for the construction of a new research facility, Advanced Cuttings Transport Facility (ACTF), which will allow investigation of cuttings transport with compressible drilling fluids at elevated temperature (200 °F) and elevated pressure (2000 psi). The basic construction of the facility is completed and currently the loop is operational under elevated pressure. Modification to the ACTF will continue by adding elevated temperature capability (1999), aeration and foam capability (2000), cuttings transfer capability (2001), pipe rotation capability (2002) and finally, elevation capability (2003). Development and utilization of the ACTF will offer the industry a unique insight into the complex processes that govern fluid flow during drilling and production phases. The Tulsa University ACTS research program will provide valuable information to optimize underbalanced drilling technologies.

INTRODUCTION

Declining US oil production and stricter environmental regulations have resulted in a search for improved technologies to reduce cost and improve recovery from existing hydrocarbon reserves. One of the most effective methods of cost reduction relies on improvements in drilling technologies, in particular, development of directional, horizontal, and multilateral wells. Because many reservoirs in the lower 48 States are partially depleted (low reservoir pressure), to effectively drill re-entry horizontal or multilateral wells, one may have to use aerated drilling fluids (gas assisted, foam, mist, etc.) to minimize formation damage and increase the rate of penetration. Energized (compressible) drilling fluids are also of considerable importance in offshore, deep water drilling to avoid fracturing of unconsolidated formations.

The major advantage of foams and aerated muds is their flexibility in controlling the mud "effective density", which influences the borehole pressure. Yet, when compared to conventional (incompressible) drilling fluids, very little is known about the hydraulic and rheological properties of aerated drilling fluids and even less is known about their cuttings transport capabilities.

Hole cleaning (cuttings transport) is one of the major factors affecting cost, time and quality of directional, horizontal, extended reach, and multilateral oil/gas wells. Inadequate hole cleaning can result in expensive drilling problems such as pipe sticking, premature bit wear, slow drilling, formation fracturing, and high torque and drag.

The important advantages inherent to drilling with compressible fluids (increased rate of penetration, decreased formation damage, reduced environmental impact, and minimized lost circulation) can be hindered by inefficient cutting transport to the surface.

That is, these advantages depend on understanding the interaction between fluids and the drill cuttings.

Currently, our understanding of this complex interaction is very limited because the vast majority of research in cutting transport has been conducted with conventional drilling fluids. A new research initiative has, therefore, been undertaken at the University of Tulsa to investigate multiphase (gas, liquid and solids) drilling fluid systems for overbalanced and underbalanced drilling operations under elevated temperature and elevated pressure conditions. The purpose of the Advanced Cuttings Transport Study (ACTS) is to determine non-Newtonian fluid characteristics and cuttings transport performance of compressible fluids (aerated mud and foam) as well as conventional (incompressible) and synthetic drilling fluids under elevated temperature and pressure in a large-scale experimental facility.

Development of the Advanced Cuttings Transport Facility (ACTF)

To offer industry new insights into the complex processes that govern multi-phase fluid flow during drilling, the University of Tulsa proposed to develop and construct a large-scale experimental facility. The Advanced Cuttings Transport Facility (ACTF) will allow investigation of the hydraulics and cuttings transport properties of both compressible and incompressible fluids at elevated temperatures and pressures. Furthermore, the “drilling section” will include a rotating drillpipe that will be coupled to an articulated mast. This will make it possible to transport simulated cuttings through an annular space at any wellbore inclination angle with variable drillpipe rotational speeds.

Construction of the ACTF is currently planned through in six phases. Basic design concepts for the new facility and Phase I construction (single-phase flow at high pressure) have been completed. Operational parameters for this phase are pressures up to 2000 psi at ambient temperature utilizing water and various drilling fluids. Key areas of the loop include a rheology section consisting of 2- and 3-inch pipes, and a drilling section consisting of a 6-inch casing and 3 ½-inch drill pipe. Various instrumentation measures flow rate, pressure, and pressure differential.

In 1999, high temperature (up to approximately 200 °F) capability is planned to be added to the basic flow loop (Phase-II). The ability to operate at temperatures higher than 200 °F may be attempted in the future if requested by industry.

Aeration facilities at elevated temperature and pressure is planned to be added to the flow loop as Phase-III.

The cuttings transport capacity is planned for Phase IV. The introduction of cuttings will require some novel approaches with a pressurized loop.

Phase V plans include drillpipe rotation capability. This will be a significant enhancement following the introduction of cuttings into the flow loop to study the effect of drillpipe rotation on cuttings transport.

Current plans extend through Phase VI with the addition of the loop elevation (from horizontal to vertical including intermediate angles) capability. Elevation of the flow loop will have its biggest impact on cuttings transport studies.

Completion of the sixth phase will make it possible to study the flow of compressible drilling fluids and cuttings transport in a full-scale flow loop at pressures up to about 2000 psi and temperatures up to 200 °F; with inclination angles anywhere from 0° to

90°; with and without drillpipe rotation. Figure 1 shows the general configuration of the ACTF. The process and instrumentation diagram of the ACTF is given in Figure 2.

Scope of the Advanced Cuttings Transport Study (ACTS) Research Program

The specific goals of the proposed project are:

1. Provide the design for and construct ACTF, Phases II through VI, and operate the cuttings transport facility;
2. Conduct studies that will lead to the development of instrumentation to quantitatively determine cuttings location, height, and concentration in the annulus of the drilling section and to measure the bubble size, distribution, and shape during the cuttings transport experiments;
3. Conduct experiments and develop an experimental data-base for cuttings transport under elevated temperature and pressure conditions;
4. Develop models and computer programs for optimization of cuttings transport phenomena at elevated temperatures and pressures.

Successful completion of the study is contingent on accomplishment of several key tasks. Some critical tasks are (but not limited to):

1. The ability to achieve and maintain an approximately constant temperature environment.
2. The ability to handle foams and two-phase flow, and the ability to characterize bubbles.
3. The ability to monitor real-time location of cuttings in an elevated pressure and temperature (EPET) environment.
4. To provide for drillpipe rotation in a pressurized environment.

Eighty percent of the project funds will come from the U.S. Department of Energy. Twenty percent will come from the Industrial members.

Acknowledgments

Authors wish to thank U.S. Department of Energy for supporting this project.

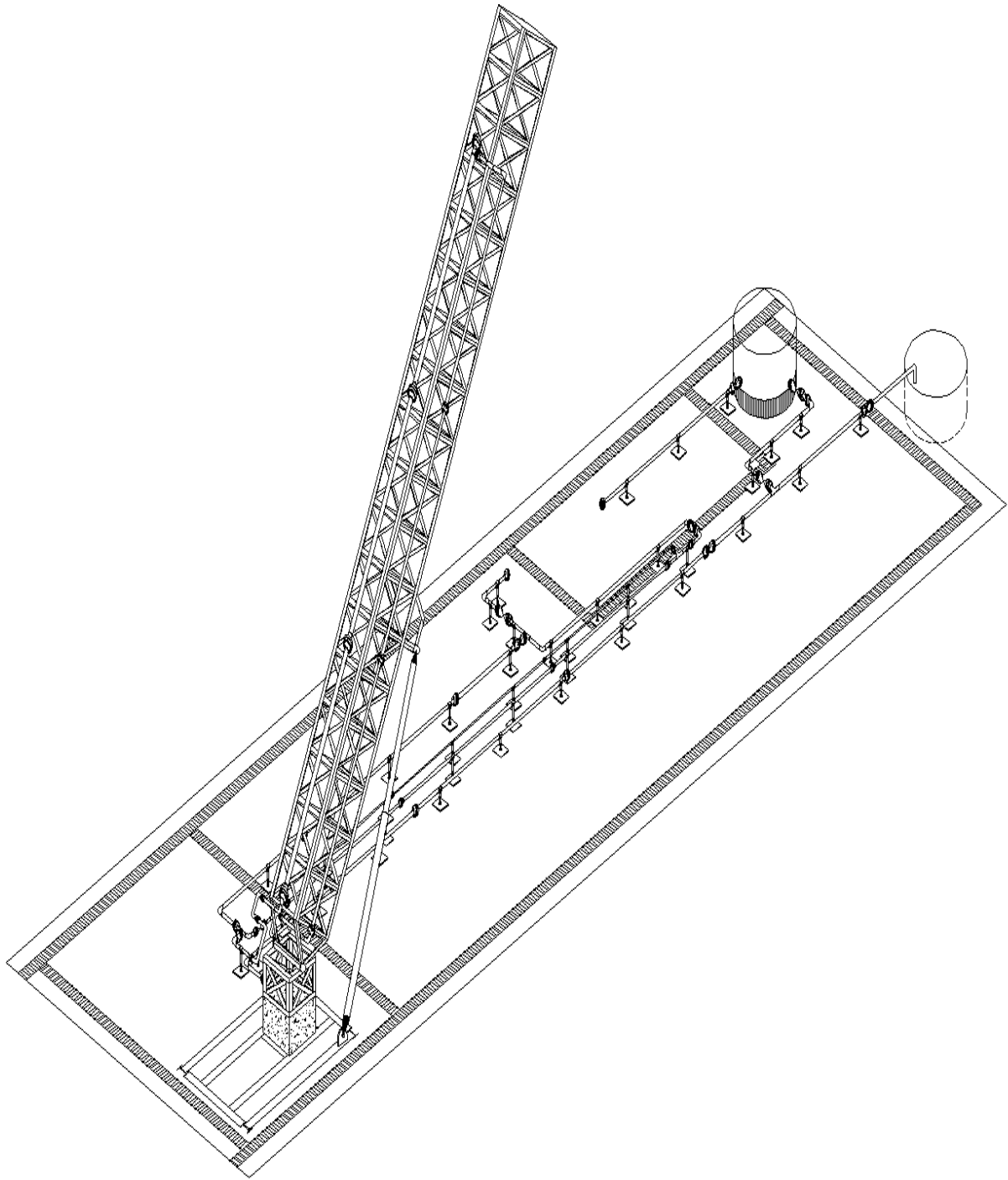


Figure 1 General Configuration of the Advanced Cuttings Transport Facility

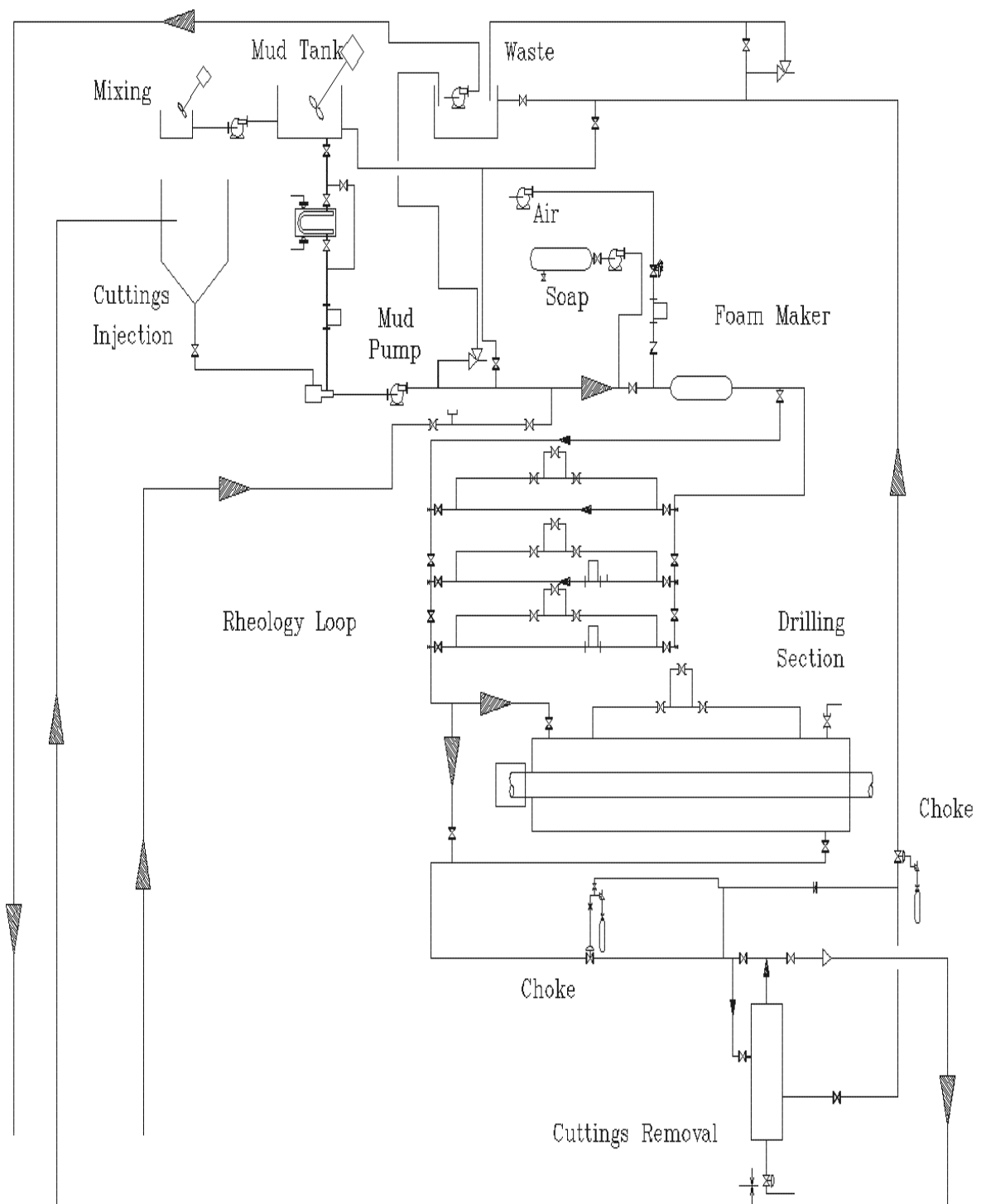


Figure 2 Process and Instrumentation Diagram of the Advanced Cuttings Transport Facility

Interpretation of Deep Complex Structure in a Limited-Quality 3-D Seismic Image

Bob A. Hardage (bob.hardage@beg.utexas.edu; 512-471-0300)

Bureau of Economic Geology
The University of Texas at Austin
Austin, TX 78713-8924

Abstract

A study funded by the U.S. Department of Energy, the Gas Research Institute, Mobil Exploration and Producing U.S., and Altura Energy was done to determine geologic controls on deep, prolific Ellenburger gas reservoirs at Lockridge, Waha, West Waha, and Worsham-Bayer fields in Pecos, Reeves, and Ward Counties in West Texas. A major component of the data base amassed for the study was a 176-mi² 3-D seismic survey extending across these fields. Ellenburger (Ordovician) reservoirs occurred at depths of 17,000 to 21,000 ft (5200 to 6400 m) over most of the study area. The eastern half of the 3-D seismic survey was covered with a thick (500 to 2000 ft [150 to 600 m]) variable layer of low-velocity Tertiary fill underlain by a varying thickness of high-velocity salt/anhydrite. These near-surface conditions attenuated seismic reflection signals from deep targets and made static corrections of the data difficult.

The 3-D seismic data acquired in this study are thought to be some of the best quality data produced over these fields, yet the 3-D image of the deep pre-Pennsylvanian targets was of limited quality because of the combined effects of complex, attenuating, near-surface layers and weak reflection signals from deep seismic targets. The principal interpretation objective was to construct the complicated tectonic structure related to these fields to determine genetic relationships between faults and deep gas production. The challenge was to construct this structural picture from a 3-D seismic image that did not provide a clear, unambiguous picture of the fault systems.

Petrophysical analyses of logs from wells drilled at key structural locations were invaluable in interpreting fault geometry by identifying overturned beds and repeated sections. Once 3-D seismic horizon and fault interpretations were done across the complete 176-mi² area, depth maps of key pre-Pennsylvanian horizons were made, and vertical depth sections were constructed across critical structural areas. The seismic interpreted structures were then restored to pre-deformation conditions to verify that the pre- and post-deformation lengths of these key horizons were consistent, and thereby determined if the seismic fault interpretations were structurally valid.

These methods of integrating petrophysical analyses and section reconstructions into the interpretation of 3-D seismic data should be helpful to others who are confronted with the challenge of constructing complex structural models from limited-quality 3-D seismic images.

This work was done as a part of DOE contract DE-FG21-88MC25031, titled *Integrated Strategies for Carbonate Reservoir Reserve Growth: An Example from the Ellenburger Group, Permian Basin, West Texas*, by the Bureau of Economic Geology, The University of Texas at Austin, Austin, TX (Fax: 512-471-0140). The funding period was August 1, 1995, through March 31, 1998; the Contracting Officer's Representative was Charles Byrer (304-285-4547).

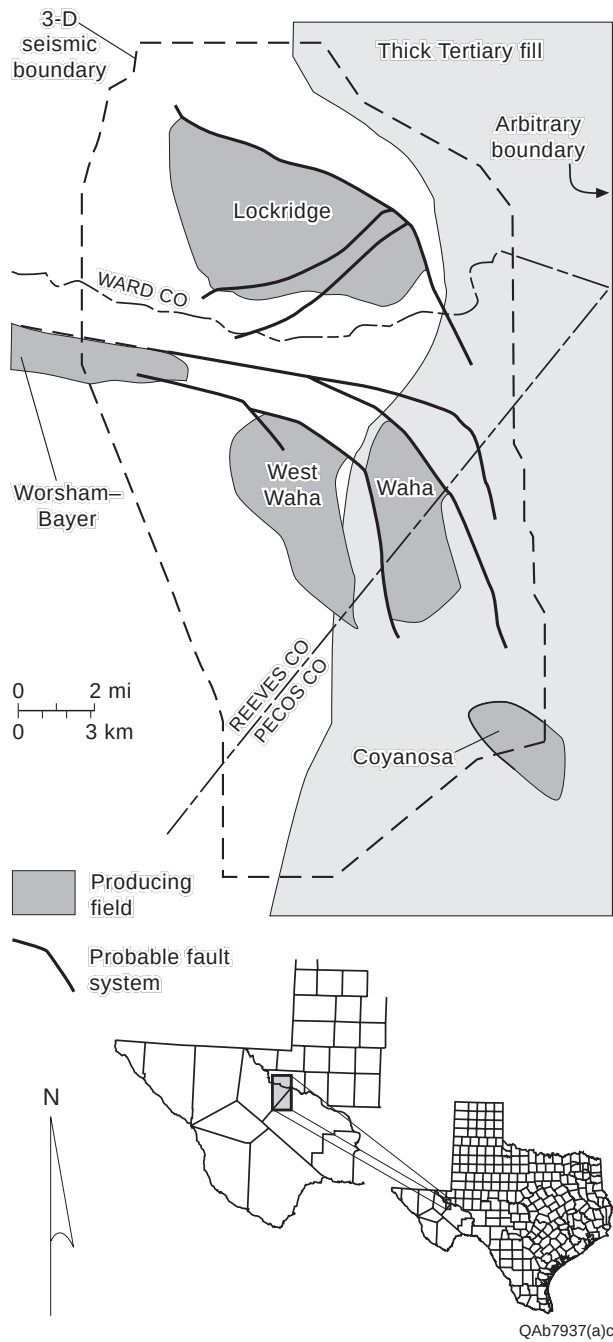


Figure 1. Location map of study area. The eastern portion of the study area was covered by a thick, complex surface layer that creates difficult static corrections that are referred to the Tertiary-Fill Problem. The labeled stippled areas are gas fields. The dark lines bounding, or crossing, these labeled gas fields identify where fault systems were suspected to be before this study was done.

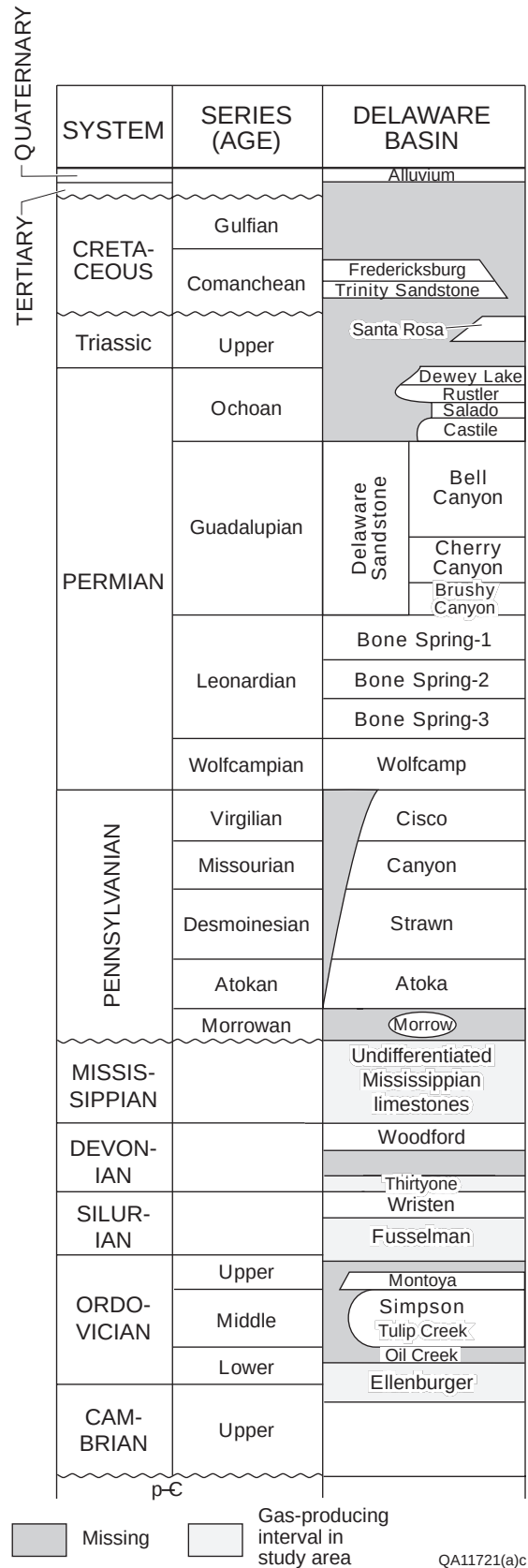


Figure 2. Stratigraphic column of the Delaware Basin. Gas production in the study area comes from reservoirs of the Ellenburger Group, Fusselman Formation, Thirtyone Formation, and Mississippian limestones. Note the missing section from the late Permian through Cretaceous, which is filled with Tertiary alluvium to form a thick, complex, near-surface layering.

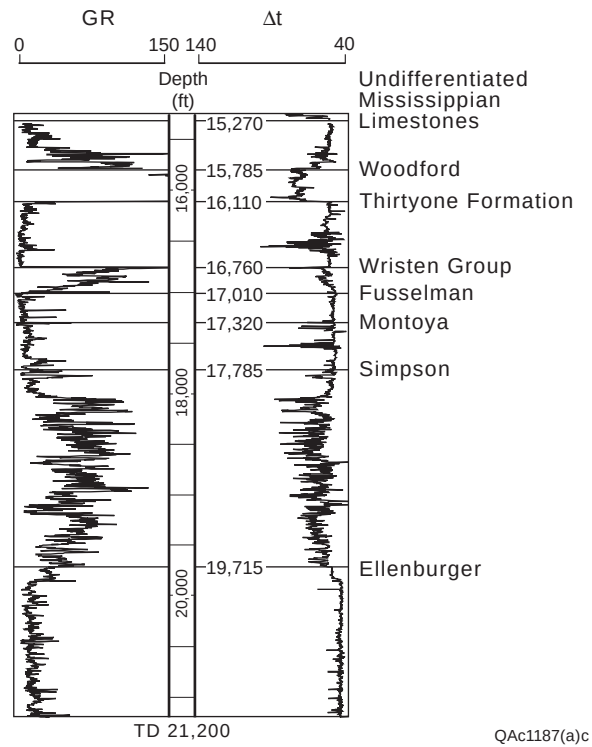


Figure 3. Type log from well no. 29 (Fig. 4) through deep imaging targets within the area of the 3-D seismic image. Note the gradual ramp increase in formation velocity associated with the top of the Ellenburger, the principal gas-producing interval that was to be studied.

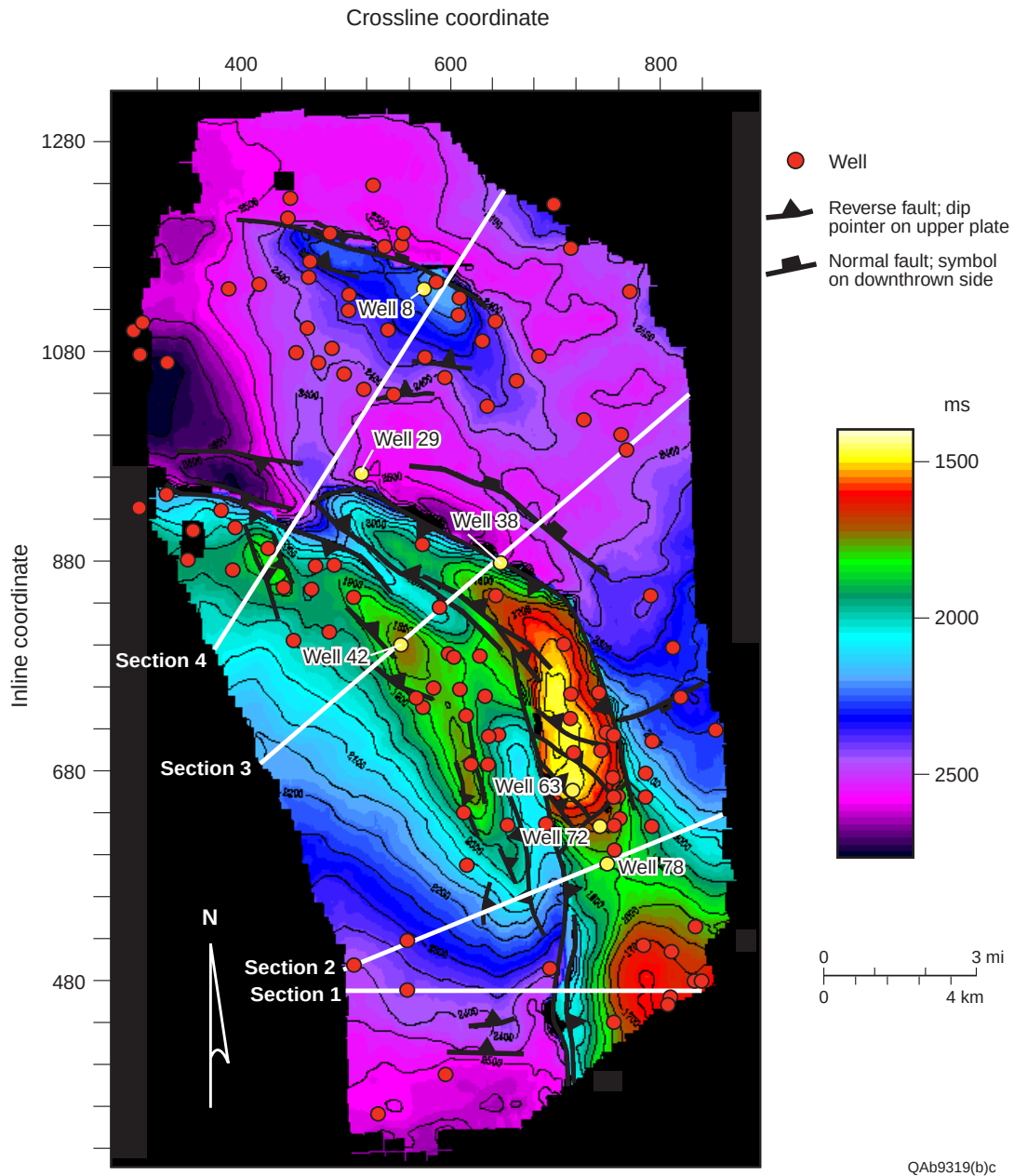


Figure 4. Locations of key wells and restoration cross-sections 1 through 4. The background map is the time structure of the interpreted Devonian surface.

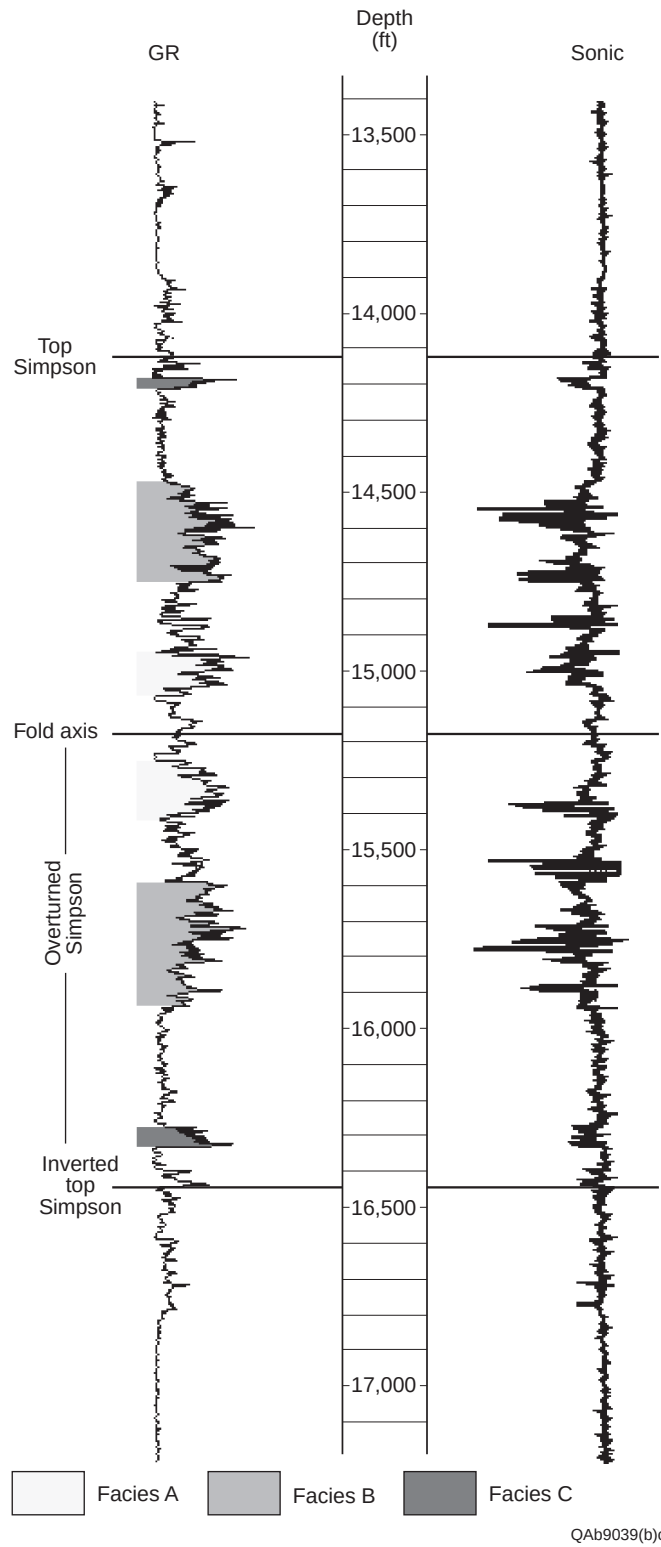
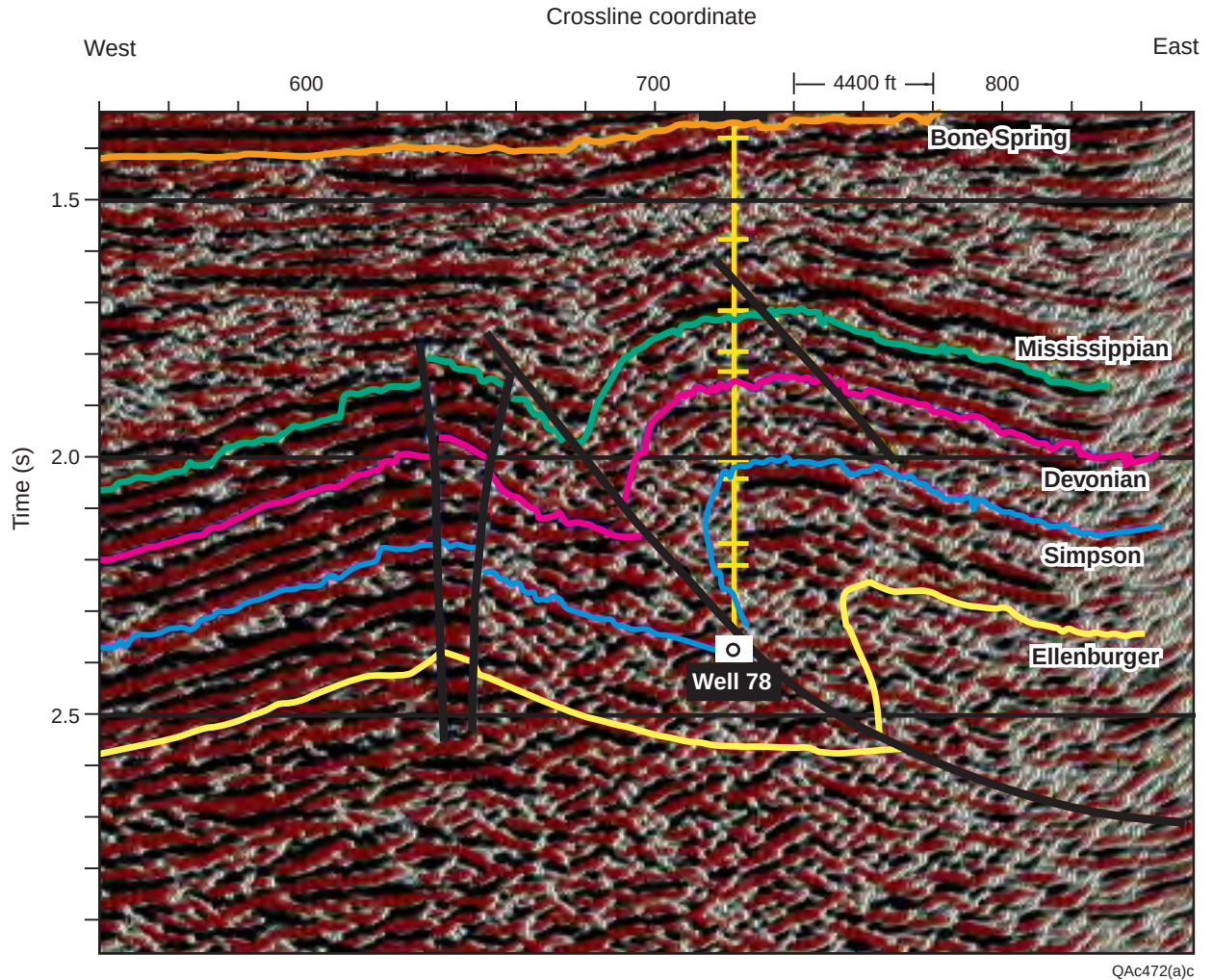


Figure 5. Example of overturned Simpson section, well 78 (Fig. 4).



QAc472(a)c

Figure 6. Seismic section (inline 576) passing through well 78. This seismic profile illustrates the overturned Simpson section that would have to be incorrectly interpreted as Ellenburger if the industry-provided formation tops were honored. The original (and incorrect) log-defined top of Ellenburger is the well tic at 2.22 seconds. Each labeled horizon identifies the top of that particular unit, regardless of whether the label is above or below the horizon. Phantom horizons have to be constructed across poor image areas.

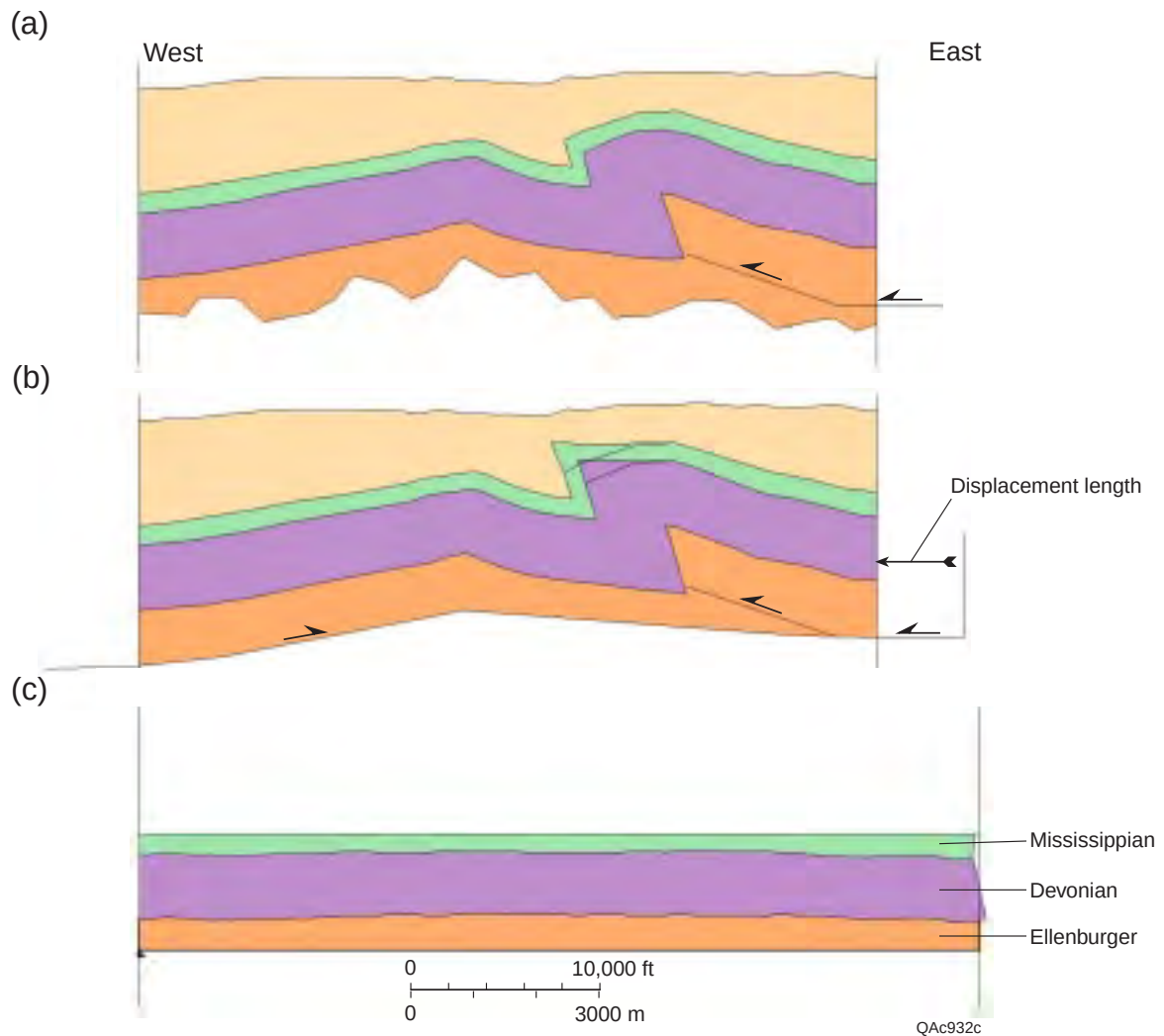


Figure 7. (a) Section 2 (Fig. 4) converted to depth with minor structures removed and overturned Mississippian and Devonian horizons added on front limb of fold to match deeper overturned beds recorded in well logs. The blind thrust shown is the type that formed the overturned fold. Base of section chosen at an arbitrary level. (b) Section shown in (a) modified to include thrust beneath the west part of the section and Mississippian and Devonian horizons inferred from forward modeling of folding above the blind thrust. Full arrow on east end of section indicates displacement needed to produce the fold shown. (c) Section in (b) restored to an undeformed Mississippian horizon. The section was pinned at the west boundary, so the uneven restored east boundary shows the deviation from constant bed lengths.

Seismic Data Acquisition Through Tubing

Michael Buettner (buettner2@llnl.gov; 925-422-7888)
Lawrence Livermore National Laboratory
7000 East Avenue
Livermore, CA 94550

Michael Jervis (michael.jervis@tomoseis.com; 713-461-4620)
Tomoseis
1650 W Sam Houston Parkway N
Houston, TX 77043-3115

Abstract

We have collected good quality crosswell seismic data through production tubing in active oil fields at realistic interwell distances (300 ft). The data were collected at the Aera Cymric field (1998) and at a Chevron site (1997); both located in the Central Valley of California. The Aera data were used to produce travel-time tomographic images of the interwell region. Both sites have similar geology, namely siliceous shale (diatomite) with moderate to highly-attenuating reservoir rocks. In addition we confirmed modeling predictions that typical tubing attenuation losses are on the order of 12 dB. We expect that the use of stronger sources and tube wave suppression will allow for crosswell imaging at realistic distances even for low Q or high noise situations. We are searching for an industrial partner now for a data collection in the gas wells of the San Juan Basin or South Texas.

Introduction

Cross borehole seismic imaging (tomography) has been demonstrated to be a useful tool for the characterization of oil producing reservoirs (Paulsson *et al.*, 1992, Lines, *et al.*, 1993, Bair, *et al.*, 1999). Some of the benefits derived from the use of cross borehole imaging are: 1) enhanced definition of the reservoir, 2) better reservoir management (resulting in increased production, lower costs, and less risk), 3) ability to do time-lapse monitoring of EOR processes (e.g. steam flooding), and 4) enhanced spatial resolution compared to surface seismology.

The application of cross borehole seismic imaging has been somewhat limited in producing oil fields because of the need to remove the production tubing (stopping production and adding cost) before data could be collected. However, with the advent of newer, more powerful sources and advanced data processing techniques, it is now possible to collect quality crosswell seismic data with the production tubing in place.

With overall direction from the Lawrence Livermore National Laboratory (LLNL), and as part of the DOE Borehole Seismic Forum, a partnership which also included Aera, Chevron, Tomoseis, and Lawrence Berkeley National Laboratory (LBNL) was formed to do modeling, and collect

and process crosswell seismic data in producing oil fields to demonstrate that quality crosswell seismic data could be collected and processed into useful images (velocity tomograms).

Crosswell Seismic Processing

The crosswell seismic processing flow is illustrated in Figure 1. Initial trace edit and data pre-processing is followed by travel time picking for producing 2-D or 3-D tomograms or velocity “maps” between the wells. This can be considered as a 2-D or 3-D “sonic” log of the reservoir. TomoSeis does not use a standard discretized or pixelated model as has been used in the past due to the inferior resolution afforded by such models. The velocity images derived from the data shown here use a layered model with lateral variations which can handle large dips and large lateral velocity variations. In addition, a full 3-D tomographic solution is available where the structure is extreme. The velocity image produced is depth referenced and no time-to-depth conversions are necessary.

The velocity information is used in reflection imaging, analogous to the way stacking velocities are used in surface seismic processing. As in VSP processing, wavefield separation is used to separate upgoing and downgoing wavefields allowing for a much cleaner stack. The data need to be mapped into the offset-angle domain following ray tracing and wavefield separation. This is performed using the VSP-CDP transform. Final velocity analyses are done to refine and improve the stacked section. Other information, such as shear, mechanical properties, anisotropy, or guided wave (continuity logging) modes can be analyzed as appropriate, and integrated into the overall reservoir model.

Field experiments and results

Crosswell data were collected at the Aera Cymric field (1998) and at a Chevron site (1997); both located in the Central Valley of California. Both sites have similar geology, namely siliceous shale (diatomite) with moderate to highly-attenuating reservoir rocks. In both cases the data were collected and processed by Tomoseis under contract to LLNL.

The signal source was a second generation RCP, or Resonant Cavity Piezo-electric, source. This source uses dual cavities with cylindrical ceramic vibrators to generate a broad bandwidth linear response signal. The source is not clamped to the borehole allowing data to be rapidly logged with the source in constant motion, similar to marine seismic acquisition. We used the Tomoseis “TARS” slim-hole, multi-level receiver system whose characteristics are detailed in Table 1. The data acquisition parameters are outlined in Table 2.

Data were collected at the AERA Cymric site for several configurations of the receiver well including: single casing, double casing, triple casing, and single casing plus production tubing. Figures 2 and 3 show the full wave fields (common receiver gather) and velocity tomogram respectively for a single casing in the receiver well. The first p-wave arrivals are well-defined, and no tube waves are in evidence. The interwell spacing is about 300 ft.

Figures 4 and 5 show the full wave fields (common receiver gather) and velocity tomogram respectively for a double casing in the receiver well. The first p-wave arrivals are not as well-

defined as for the single casing, but are nonetheless adequate to produce the tomogram of Figure 5. The interwell spacing is also about 300 ft.

Figures 6 and 7 show the full wave fields (common receiver gather) and velocity tomogram respectively for a triple casing in the receiver well. The first p-wave arrivals are not as well-defined as for the single casing, and tube waves are present, but it is possible to produce the tomogram of Figure 7. The interwell spacing is also about 300 ft.

Figures 8 and 9 show the full wave fields (common receiver gather) and velocity tomogram respectively for a single casing plus production tubing in the receiver well. The first p-wave arrivals are well-defined and no tube waves are in evidence. The interwell spacing is also about 300 ft.

It is evident that high quality data can be gathered at moderate Q sites like Cymric, and that tomographic imaging is possible, even through production tubing.

Data were also collected at the lower Q Chevron site. Figures 10 and 11 show the full wave fields (common receiver gather) and velocity tomogram respectively for the no-tubing case. The first p-wave arrivals are well-defined, followed by s-wave arrivals and tube waves. The interwell spacing is about 120 ft.

Figure 12 shows the full wave fields (common receiver gather) for the with-tubing case. Note that the p-wave arrivals are absent, and tube waves dominate. The difficulty here was very high noise from gas in the well. It was noted that the noise levels here in the 300-1000 Hz band were higher than in typical gas wells. It was not possible to produce a tomogram for this case.

Conclusions

Our results show that it is possible to collect high quality crosswell seismic data through production tubing at realistic distances (300 ft) in moderate Q geologies, and that tomographic imaging is possible for these cases. Lower Q or higher noise scenarios will make this more difficult. However, through the use of stronger sources and tube wave suppression it should be possible to do crosswell imaging at realistic distances even for low Q or high noise situations.

Future Activities

We are searching for an industrial partner now for a data collection in the gas wells of the San Juan Basin or South Texas. We expect improved performance by 1) using a stronger source with extended low frequency response, 2) suppressing tube waves in both source and receiver wells, and 3) by developing algorithms for smaller source-receiver vertical offsets. In addition we would like to investigate the use of shear waves (Sv) to investigate fractures and anisotropy, and collect data in higher temperature wells.

Acknowledgements

This work was funded by the U.S. DOE Natural Gas and Oil Technology Partnership Program. We gratefully acknowledge the support of our industrial partners, Aera Energy, Chevron, Inc, and Tomoseis. Work performed under the auspices of the U.S. Department of Energy by Lawrence Livermore National Laboratory under contract No. W-7405-Eng-48.

References

- Paulsson, B., M. Smith, K. Tucker, J. Fairborn, 1992. Characterization of a steamed oil reservoir using cross-well seismology, *The Leading Edge*, v. 11, no. 7, 24-32.
- Lines, L., M. Miller, H. Tan, R. Chambers, S. Treitel, 1993. Integrated interpretation of borehole and crosswell data from a west Texas field, *The Leading Edge*, v. 12, no. 7, 13-16.
- Bair, J., S. Johnson, D. Julander, R. Langan, J. Meyer, J. Washbourne, 1999. Time-lapse imaging of steam and heat movement in the Cymric 36W Cyclic Steam Pilot using crosswell seismology, SEG Expanded Abstracts, Oct., 1999.

Levels:	5 or 10
Diameter:	1 11/16"
Bandwidth:	150 - 2000 Hz
Depth:	15,000 feet
Temperature:	150°C (300°F)
Conveyance:	12 conductor wireline
Pressure Cntl:	grease injector/ lubricator
Sensitivity:	-182 dB

Table 1. TARS receiver specifications

Sample Period:	250 ms
No. of Samples:	6400 (pre-correlation)
No. of Samples:	1600 (post-correlation) or 400ms of data
Sweep frequencies:	150-1000 Hz (low Q formations) 150-1500 (medium Q formations)
Sweep function:	Linear
Shot Stacks:	4
Receiver Spacing:	2.5 ft
Shot Spacing:	2.5ft
Receiver System:	10 level

Table 2. Data Acquisition Parameters (Aera)

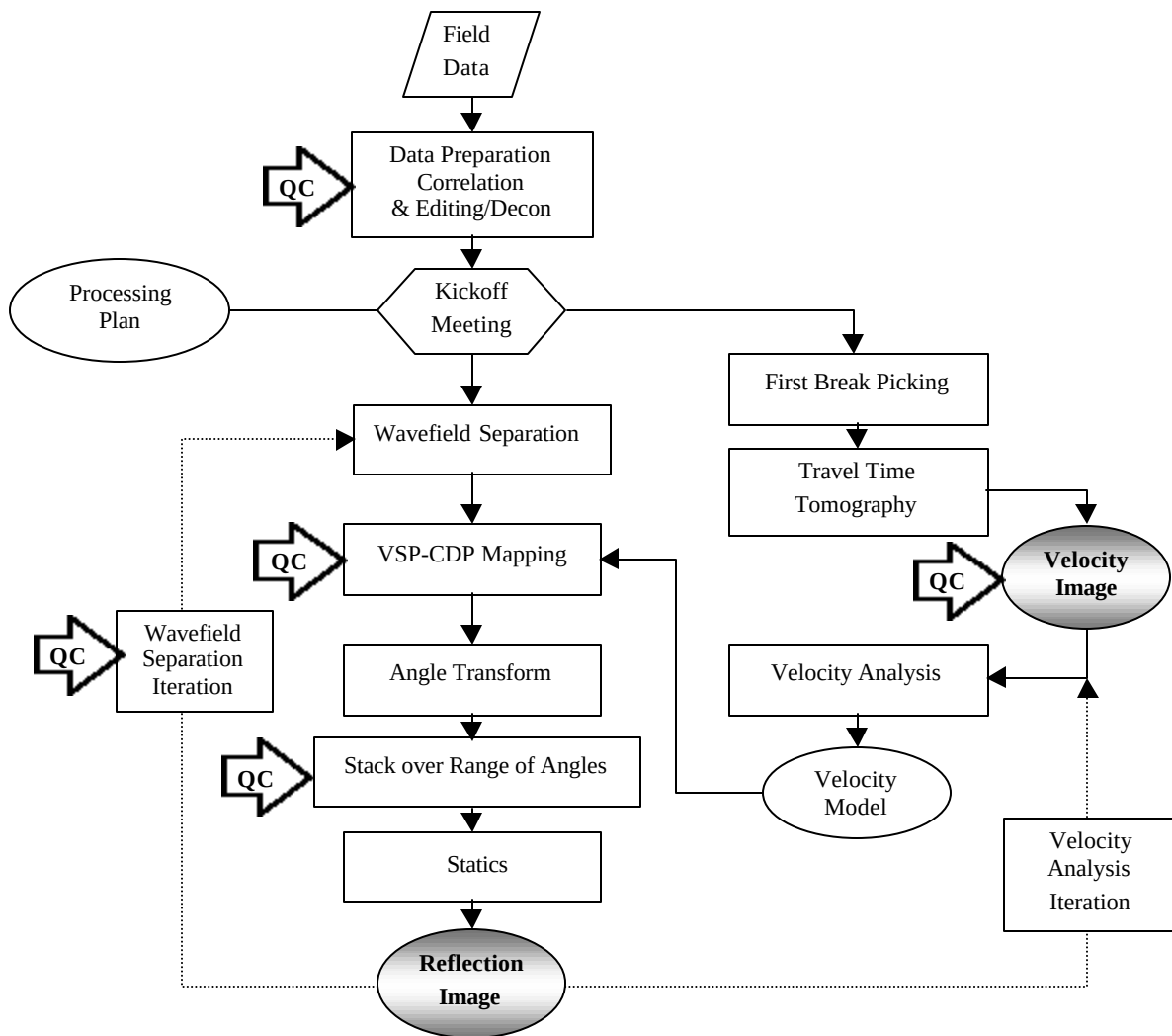


Fig. 1 Crosswell Seismic Processing Flow

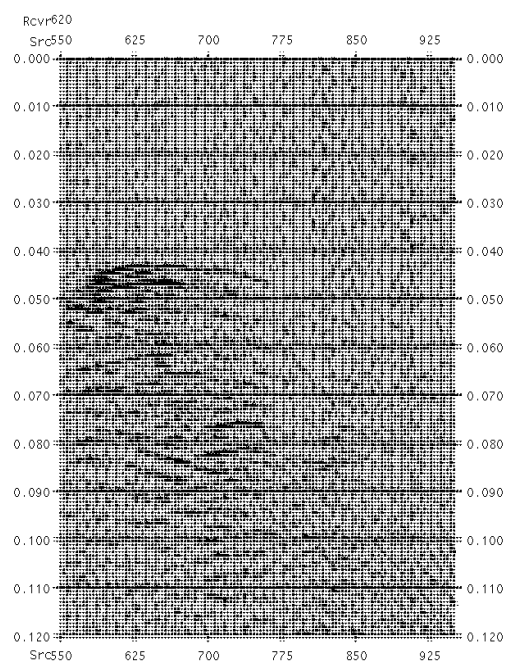


Figure 2. Full wave fields for a single casing at Aera

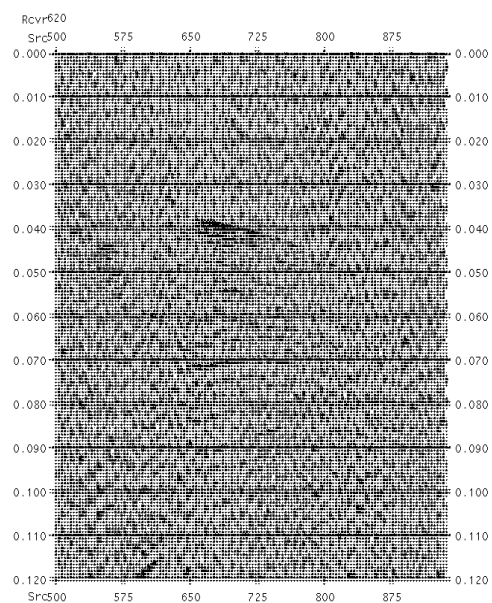


Figure 4. Full wave fields for a double casing at Aera

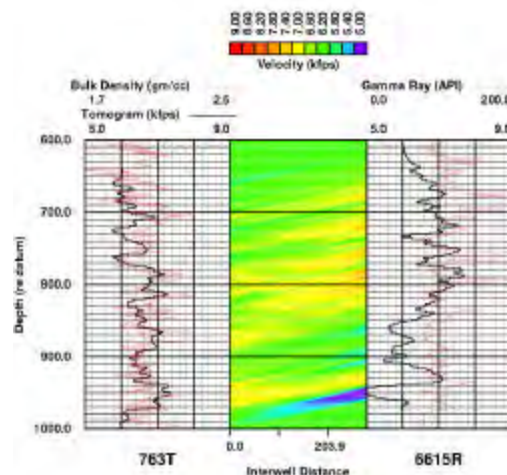


Figure 3. Tomogram for a single casing at Aera

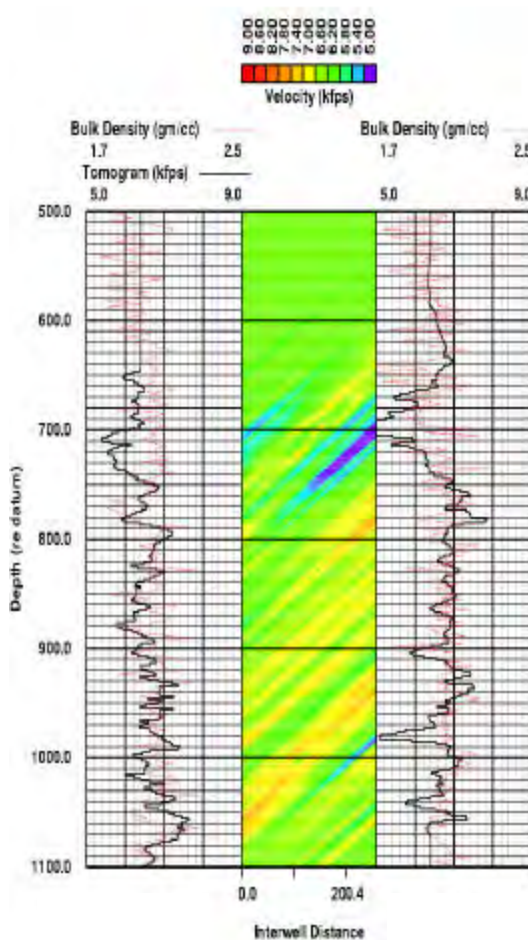


Figure 5. Tomogram for a double casing at Aera

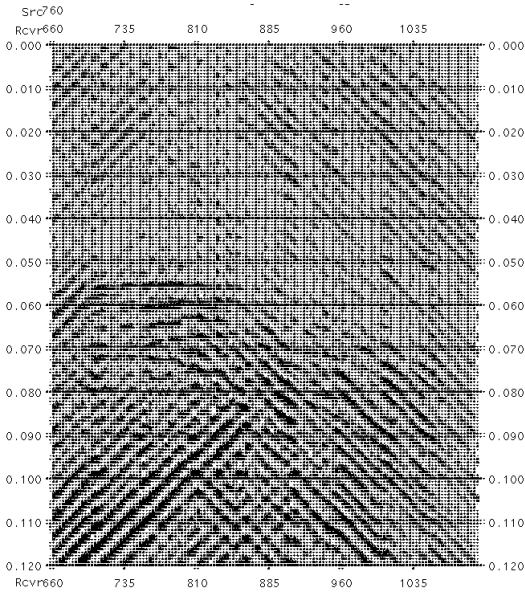


Figure 6. Full wave fields for a triple casing at Aera

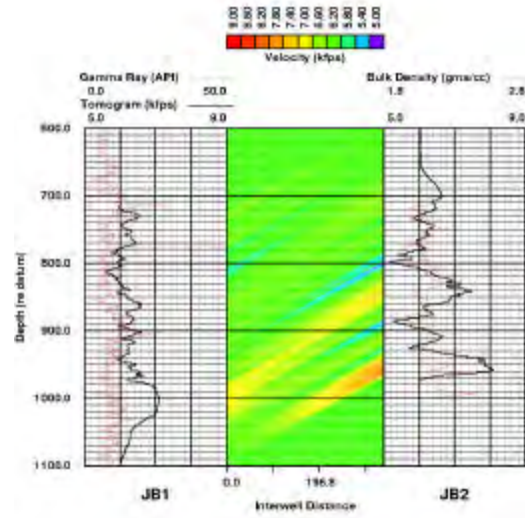


Figure 7. Tomogram for a triple casing at Aera

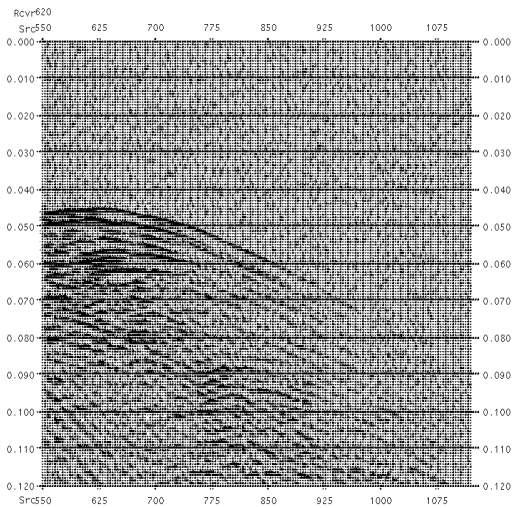


Figure 8. Full wave fields for a single casing plus production tubing at Aera

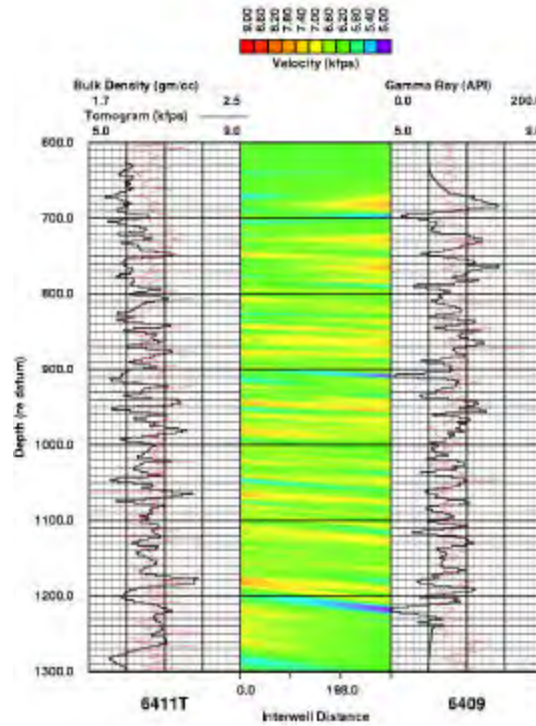


Figure 9. Tomogram for a single casing plus production tubing at Aera

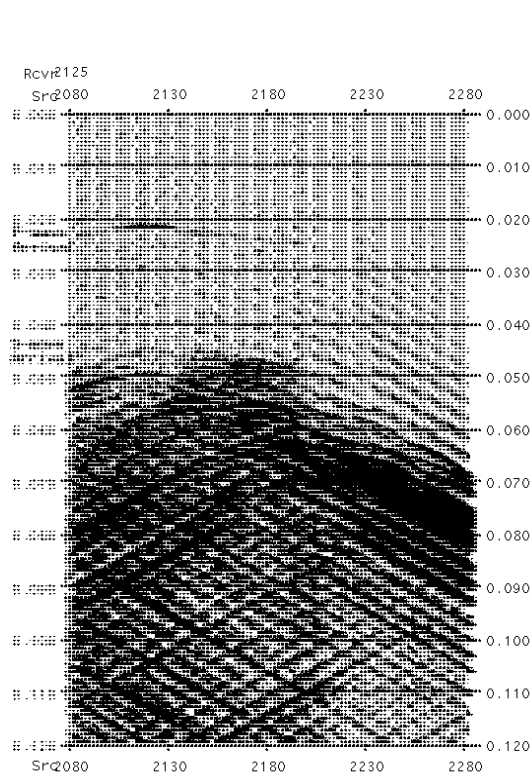


Figure 10. Full wave fields for the no-tubing case at the Chevron site

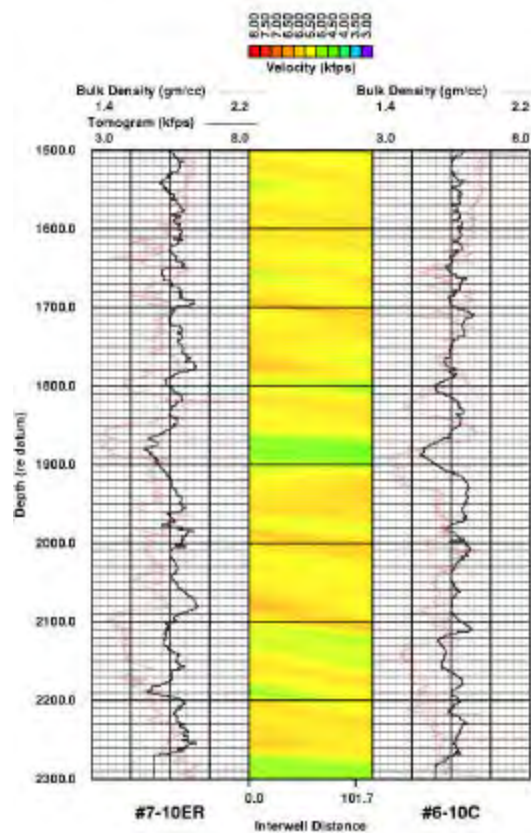


Figure 11. Tomogram for the no-tubing case at the Chevron site

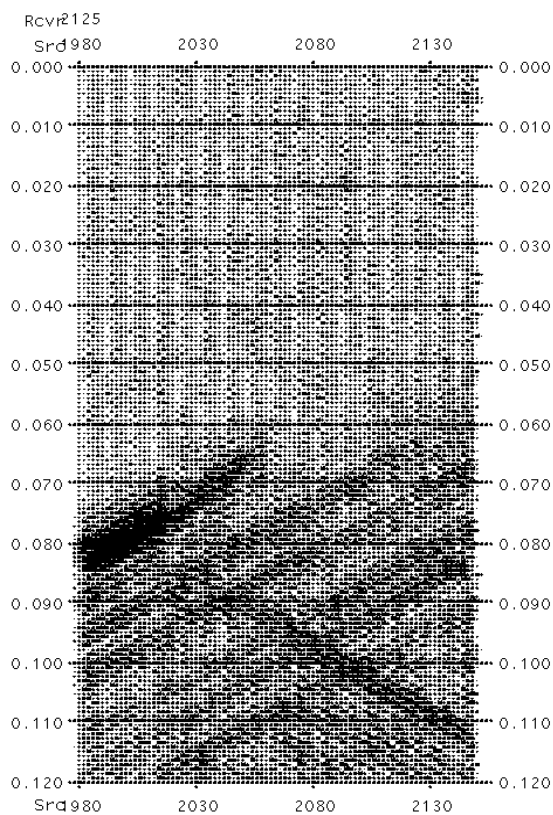


Figure 12. Full wave fields for the with-tubing case at the Chevron site

Application of High Resolution Seismic Imaging Methods for Fracture Quantification

E.L. Majer, T.M. Daley, L.R. Myer, K. Nihei, M. Feighner, J.E. Peterson,
V. Korneev, R. Gritto, B. Kaelin
Earth Science Division, Lawrence Berkeley National Laboratory, Berkeley CA

J. Queen, D. Cox and P. D'Onfro
Conoco Inc., Ponca City, OK

T. Mroz
Federal Energy Technology Center, Morgantown, WV

Abstract

Over the past several years as part of the Department of Energy's FETC fractured gas program, we have been developing and applying the use of high resolution seismic methods to define and map the permeable pathways in naturally fractured gas reservoirs. This work involves an iterative approach between theoretical, laboratory, modeling, controlled field work and large scale field work to develop and validate the appropriate seismic methods for not only determining the existence of fractures but for defining the fractures that control transport. The work has been focused on single and multiple component borehole sources in crosswell and single well configurations to record multicomponent data at frequencies from fifty to several kilohertz. Work to date shows that while surface methods provide broad characterization of fractures, borehole methods are necessary for providing the resolution necessary for inferring actual transport properties in fractured media. Although direct imaging of fractures is possible, other effects such as anisotropy, scattering and guided waves are also diagnostic of fracture characteristics in both velocity and amplitude analysis.

Theory

During the past several years there has been considerable effort in developing seismic imaging methods for fracture characterization. Most of these methods have focused on surface techniques using P-wave (for a comprehensive state of the art review see Tsvankin and Lynn, 1999) and occasionally S-wave methods (Schoenberg and Sayers, 1995). The result of many of these applications has been mapping of P-wave anisotropy, presumably due to fractures. However, due to limited bandwidth and resolution few if any of the surface based techniques have been able to derive the resolution to map the fracture(s) actually responsible for transport. Recent theoretical work, however, at Lawrence Berkeley National Laboratory (LBNL)(Kalen 1998, Nihei et al,1999, Nakagawa et al 1999) suggest that using higher resolution methods it may be possible to image fracture properties beyond anisotropic effects. These studies suggest that crosswell and single well data acquisition configurations would be appropriate for gathering the data required to image fracture properties.

One theoretical model for a fracture replaces the fracture by a zero thickness compliant layer. The compliance (inverse of stiffness) of the layer is related to the porosity of the fracture as well as

what fills the porosity. The key characteristics of the model is that phase and amplitude change can be related to measurable fracture stiffness even though a layer of zero thickness is assumed. Results for a plane wave normally incident upon a fracture are shown in Figure 1. As fracture stiffness (k) decreases, frequency dependent decreases in amplitude and velocity are predicted. The theoretical model also predicts that energy can be trapped by a fracture, propagating as a generalized Rayleigh wave. Figure 2 is numerical simulation showing a snapshot of the wavefields generated by vertical and horizontal point sources. The trapped waves are designated by RIW. Snapshots of the wavefield with no fracture present are shown for comparison. In order to characterize fractured reservoirs, effects of multiple fractures must be modeled. Figure 3 is a snapshot of the wavefield for an explosion source in a medium containing equally spaced fractures of infinite extent for high fracture stiffness (top) and low fracture stiffness (bottom). Figure 4 is a snapshot of the wavefield for a case of a plane wave incident on a single layer containing fractures of finite length and irregular spacing. Reflected and transmitted waves, as well as diffracted waves are observed.

Field Scale Application

In order to test these theories LBNL has performed several different scale experiments under controlled conditions at several different fractured sites. The main site was the Conoco borehole test facility near Newkirk Oklahoma. The site (Queen et al., 1992), contains six deep and five shallow wells used for geophysical and hydrological tests. The site occupied for the subject experiments consists of the five shallow groundwater wells (GW) in a "5-spot" pattern with the outside wells approximately 50 meters from the center well (Figure 5). The shallow wells penetrate a fractured shale and limestone sequence of the Lower Permian Chase Group (Queen and Rizer, 1990). Considering the pump test data, (Sheely, 1991) the fracture orientations/character of fractures mapped in the near by out-crops, and the seismic anisotropy together, we felt that there was strong evidence for a fracture controlled transport system. Therefore, both crosswell and single well surveys were carried out in the wells before, during, and after air was injected in well GW-5 (to enhance seismic visibility over a fully saturated fracture). Frequencies from 1,000 to 10,000 Hz were used.

Applying the theories above, one would expect a significant effect on the crosswell data if air had migrated between any of the crosswell pairs (the stiffness of the fracture had significantly changed due to air displacing water, thus making the fracture less stiff and more of a filter and reflector to a seismic wave). The crosswell results were quantified by calculating a summed spectral amplitude over a specified frequency band (4000 to 6000 Hz) in 0.08 millisecond time steps along each trace at each depth. This band was chosen because this is the band in which we had maximum power. The result is a time-amplitude plot for each trace. Figure 5 shows the crosswell spectral amplitude data between well pairs GW-3/GW-1 and GW-3/GW-4 before and after air injection. For GW-3/GW-1 path almost for all traces show a sharp decrease in the amplitude of the first arrival. However, the GW-3 to GW-4 crosswell first arrival signals look virtually identical before and after the air injection. The only significant difference between the before and after data from GW-3 to GW-4, is the increase in amplitude of a secondary arrival at 17 milliseconds. The large decrease in seismic energy produced when introducing air into the fracture is easily seen in these plots. The crosswell pairs GW-3 to GW-5 and GW-3 to GW-2 are similar to GW-3 to GW-1. We assume this is due to effects of air being injected at GW-5, and the water level in GW-2 being drawn down.

The single well data in GW-3 also showed a large change in reflectivity before and after the air injection, indicating that the fracture was acting as a reflector, i.e. the reflectivity increased when air was injected into the fracture, Figure 6. This was consistent with the transmission decreasing as shown in the crosswell data (Figure 1).

From the crosswell data it was determined that there was a fracture somewhere between GW-3 and GW-1, from the single well data it was determined that the distance to the fracture was 17 meters. A slant well was drilled on the seismic data and a fracture was encountered at the predicted place. To determine if that indeed was the permeable fracture, GW-5 was injected with air to see if the air was observed directly in the fracture encountered in the slat well. Air was observed, therefore giving proof that this was "the" fracture. It should be added that no other fractures were encountered in the slant well. In a related follow-up experiment a seismic source (same piezoelectric source used in the crosswell and single well) was placed in GW-5 to "shoot down the fracture" to confirm the fracture location and to explore such diagnostics as guided wave and other seismic diagnostics. Shown in Figure 7 is the result of this guided wave experiment. This figure shows that the wave that travels along the fracture changes amplitude as the air content changes, again confirming the fracture stiffness theory.

Another approach to interpreting the data was to apply a mixing theory to the results. That is treat the fracture as a air-water medium (Kalen 1999). Shown in Figure 8 are the predicted seismograms, moduli and phases for different air concentrations ranging from 0 to 50 percent air if one assumes this model. This implies that the velocity drops to very low values in the fracture thus making the wavelength small at the high frequencies used, on the order of the fracture dimensions of a few centimeters. Also, shown in Figure 8 are estimates of the fracture aperture and content using this approach. These values agree very well with the observed values in core across the fracture.

Discussion and Conclusions

Before this work began we were uncertain that seismic methods could map fracturing, or heterogeneity at a fine enough scale to provide useful information for fluid transport models. Although we by no means claim to have solved the problem, we feel that we have taken a step towards providing an approach to characterizing fractured heterogeneous environments. The high frequency approach described in this paper is the end result of starting out with conventional low resolution methods (VSP and surface reflection, which yielded little useful information) and ending up with a combination of seismic methods (crosswell and single well) to map conductive features. We feel that there are several significant results from this work.

1. We have demonstrated that single well reflection surveys can provide useful information on vertical features a significant distance from the well. Single well surveys hold great promise in characterizing fine scale reservoir heterogeneity, but due to operational issues (tube waves, horizontal velocity gradients, lack of commercial systems) the method has not been extensively used.
2. This work has shown that relatively small fractures can account for significant fluid flow. Methods such as VSP and surface reflection may provide clues to general fracture directions and

anisotropy but to accurately locate and characterize such features is a difficult task and requires high resolution subsurface methods. Using standard processing techniques, fracture zones were located which could be detected, but not located, by other means. This was accomplished by utilizing high frequency energy in a combination of crosswell and single well approaches.

3. From a rock physics point of view, we have shown that replacement of water with a gas (in this case air) produces large changes in the P-wave signal, even in such small features as a fracture with a width on the order of a millimeter. This is significant because although our wave lengths were on the order of one half to one meter, we still "saw" the fracture. This lends field evidence support for the displacement discontinuity theories that predict such effects, (Schoenberg, 1980, Pyrak-Nolte et. al, 1990a, 1990b).

Future work will pursue field and laboratory scale experiments to explain why and how such small features cause such large seismic anomalies, using S-waves as well as P-waves. Just as importantly, we will also take the high frequency crosshole and single well methods to larger scales with surveys in production environments. We feel that only in this joint basic/applied approach can we make true progress in developing useful methods for characterizing heterogeneous reservoirs.

Acknowledgments

This work was supported by the Assistant Secretary for Fossil Energy, Office of Oil Gas and Shale Technologies, U. S. Department of Energy under Contract No. DE-AC03-76SF00098. We are grateful to personnel at Conoco Inc. for their support of this project. All computations were carried out at the Center for Computational Seismology, the field work was supported by the Geophysical Measurement Facility at the Ernest Orlando Lawrence Berkeley National Laboratory.

References

Kaelin, B., 1998, Seismic imaging of the shallow subsurface with high frequency seismic measurements, Ph.D. Thesis, University of California Berkeley.

Nakagawa, S., Nihei, K.T., and Myer, L.R., 1999, Stop-pass behavior of acoustic waves in a 1-D fractured system, Acoustical Society of America, in press.

Nihei, K.T., Yi, W., Myer, L.R., Cook, N.G.W., and Schoenberg, M., 1999, Fracture channel waves, Journal of Geophysical Research, 104, No. B3, 4769-4781.

Pyrak-Nolte, L.J., Myer, L.R., and Cook, N.G.W., 1990a, Anisotropy in seismic velocities and amplitudes from multiple parallel fractures, Journal of Geophysical Research, 95, No. B7, 11345-11358.

Pyrak-Nolte, L.J., Myer, L.R., and Cook, N.G.W., 1990b, Transmission of seismic waves across single fractures, Journal of Geophysical Research, 95, No. B6, 8617-8638.

Queen, J. H., and Rizer, W. D., 1990, An integrated study of seismic anisotropy and the natural fracture system at the Conoco Borehole Test Facility, Kay County, Oklahoma: J. Geophys. Res., 95, 11255-11273.

Queen, J. H., Rizer, W. D., Liu, E., Crampin, S., and Lines, L. R., 1992, A review of downhole Source Effects at the Conoco Borehole Test Facility: in Symp of the Geophysical society of Tulsa, eds, L. Lines and J. Queen, Geophys. Soc. of Tulsa, Tulsa, OK. 62-63.

Schoenberg, M., 1980, Elastic wave behavior across linear slip interfaces, Journal of the Acoustical Society of America, 68, No. 5, 1516-1521.

Schoenberg, M. and Sayers, C., 1995, Seismic anisotropy of fractured rock, Geophysics, 60, 204-211.

Sheely, C. Q., 1991, Tracer survey conducted in the shallow wells of the Fort Riley formation at the Newkirk Borehole Test Facility during October 1990: Conoco Research Report, 56 p.

Tsvankin, I. and Lynn, H.B., Special section on azimuthal dependence of p-wave seismic signatures -- Introduction, Geophysics, 64, No. 4, 1139-1142.

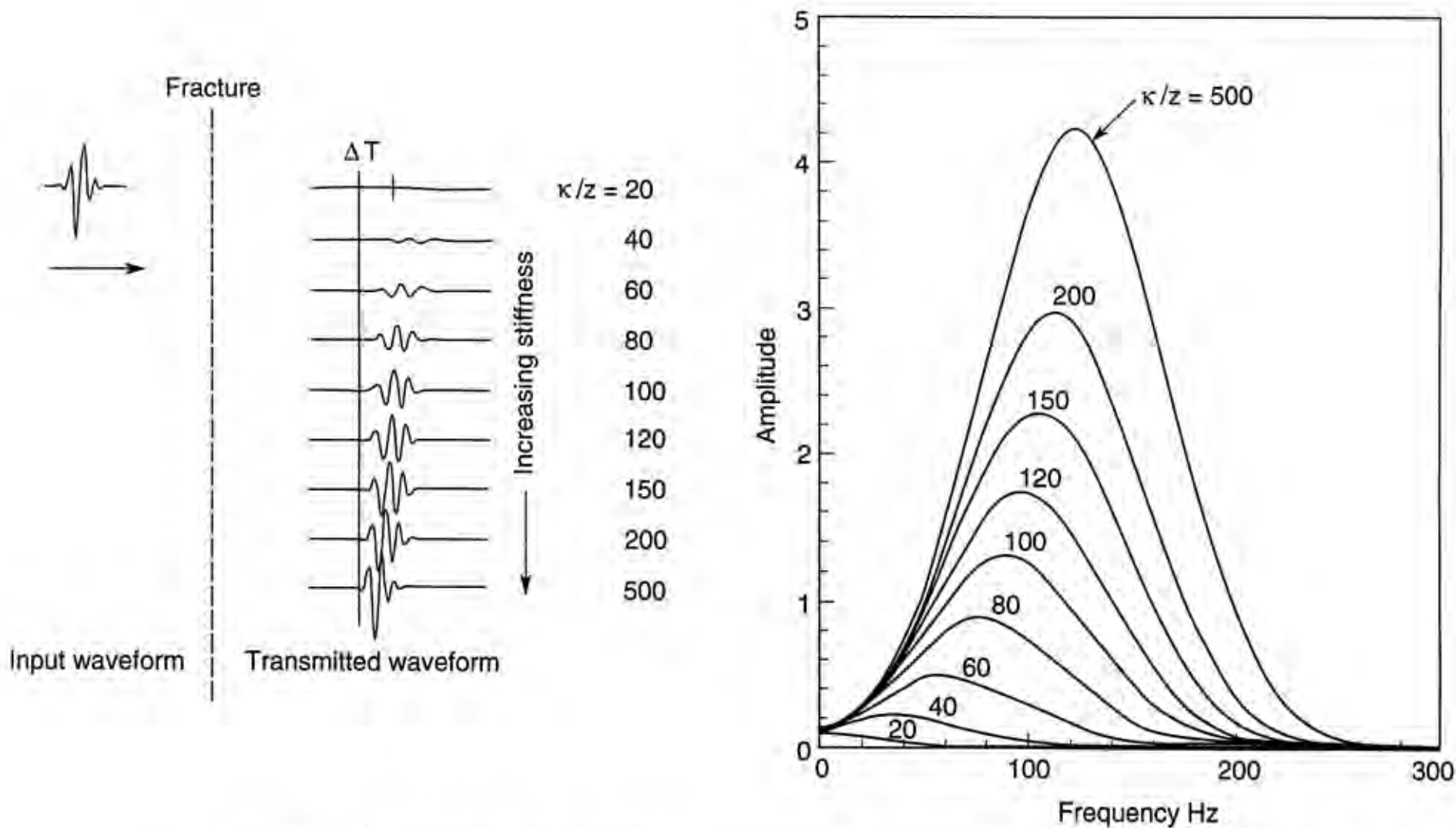
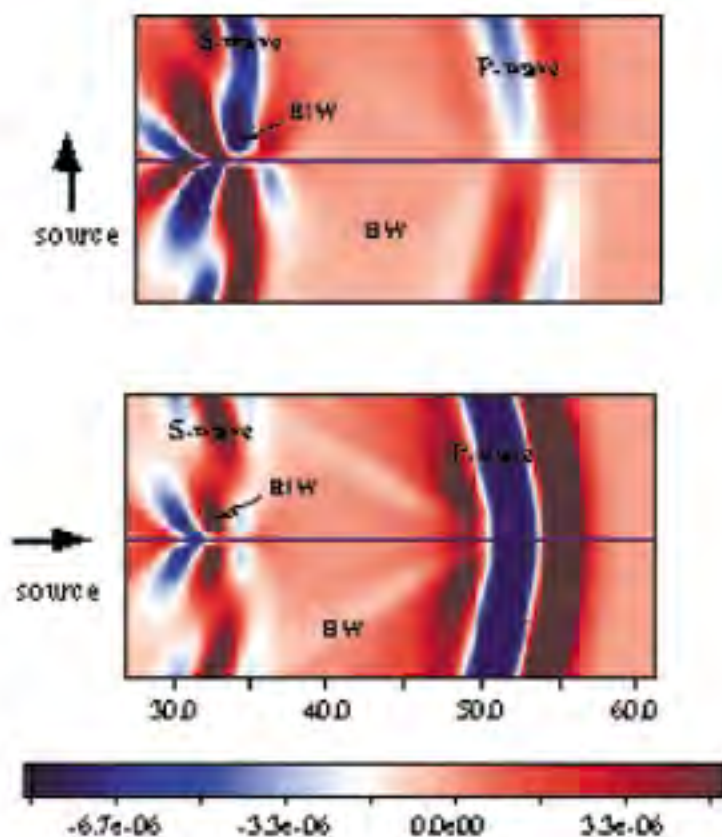
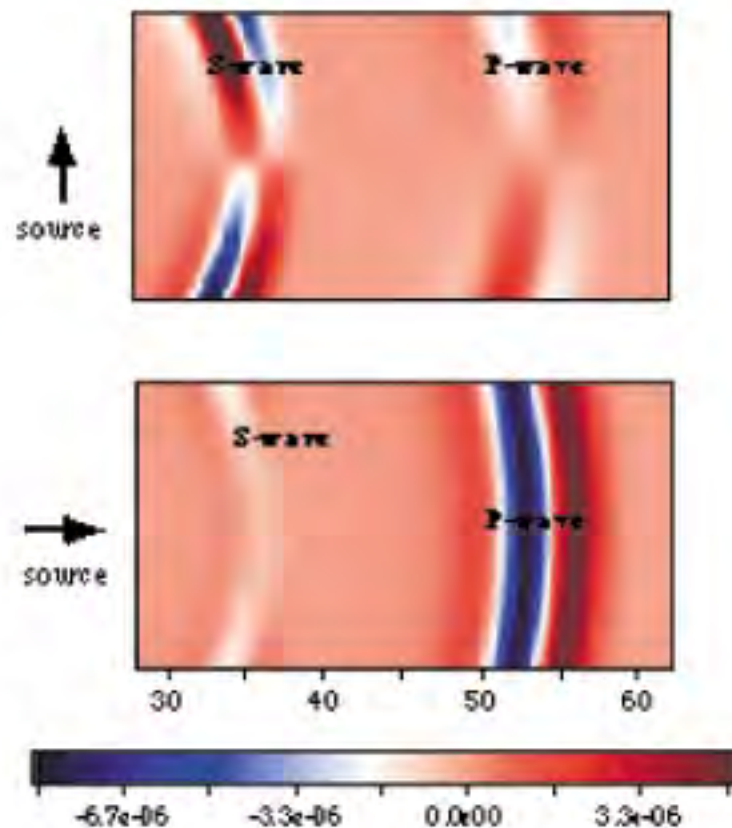


Figure 1. As fracture stiffness (k) decreases, frequency dependent decreases in amplitude and velocity are predicted.



**Homogeneous medium
with one interface**



Homogeneous medium

Figure 2. Numerical simulation showing a snapshot of the wavefields generated by vertical and horizontal point sources.

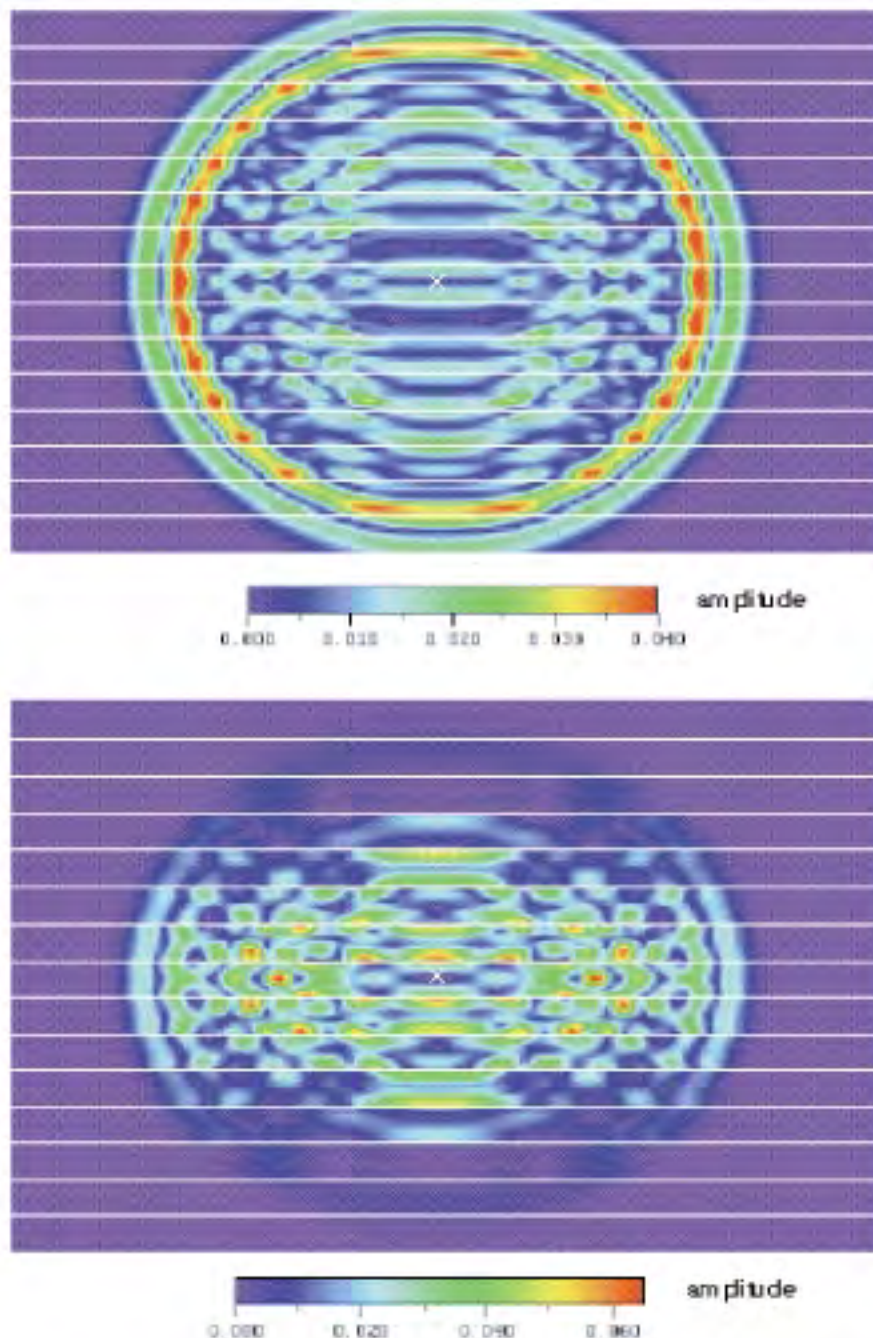


Figure 3. A snapshot of the wavefield for an explosion source in a medium containing equally spaced fractures of infinite extent for high fracture stiffness (top) and low fracture stiffness (bottom).

P-wave Reflection off a Vertically Fractured Layer

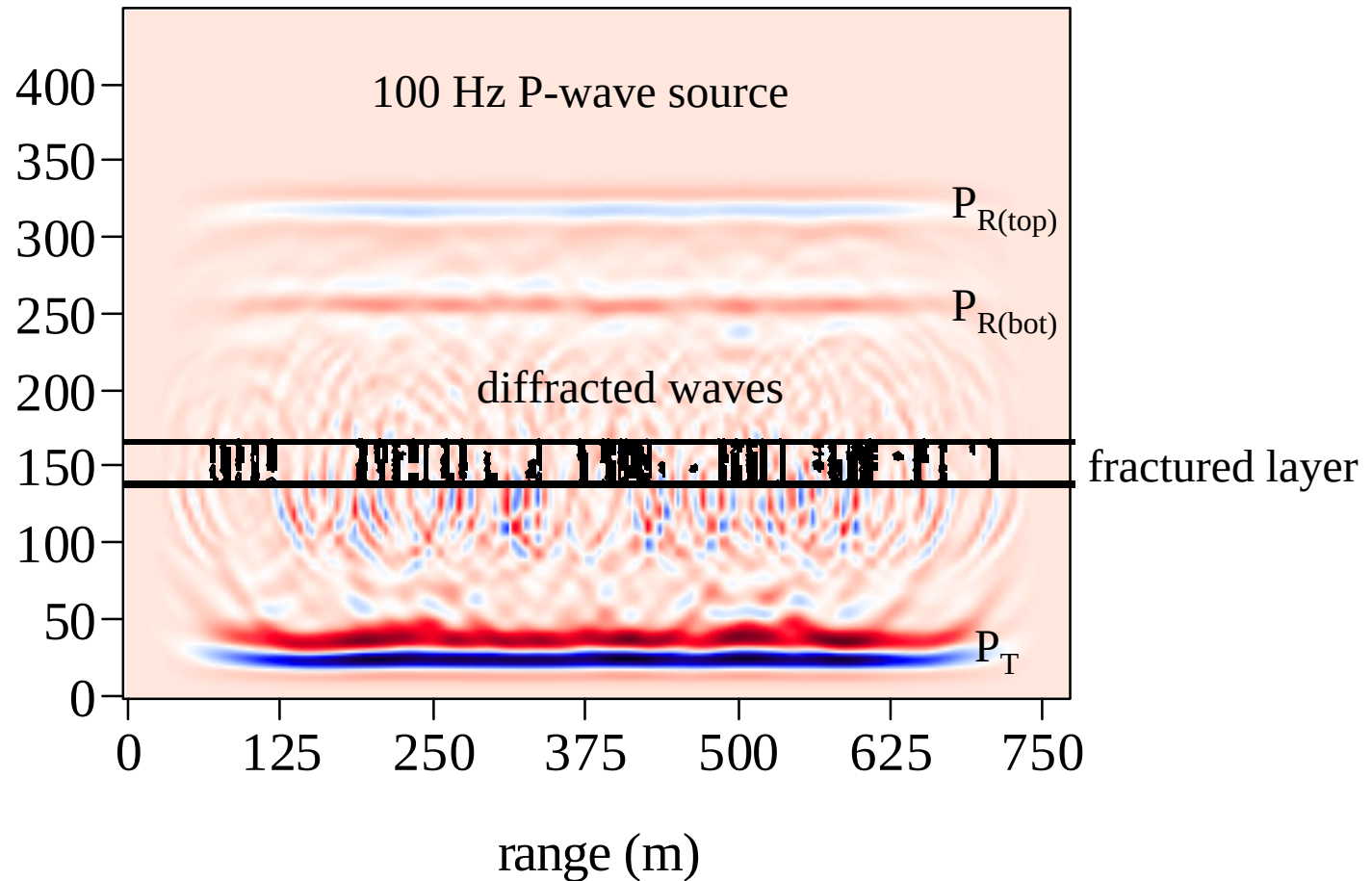


Figure 4. A snapshot of the wavefield for a case of a plane wave incident on a single layer containing fractures of finite length and irregular spacing. Reflected and transmitted waves, as well as diffracted waves, are observed.

Before and After Crosswell Air Injection Imaging

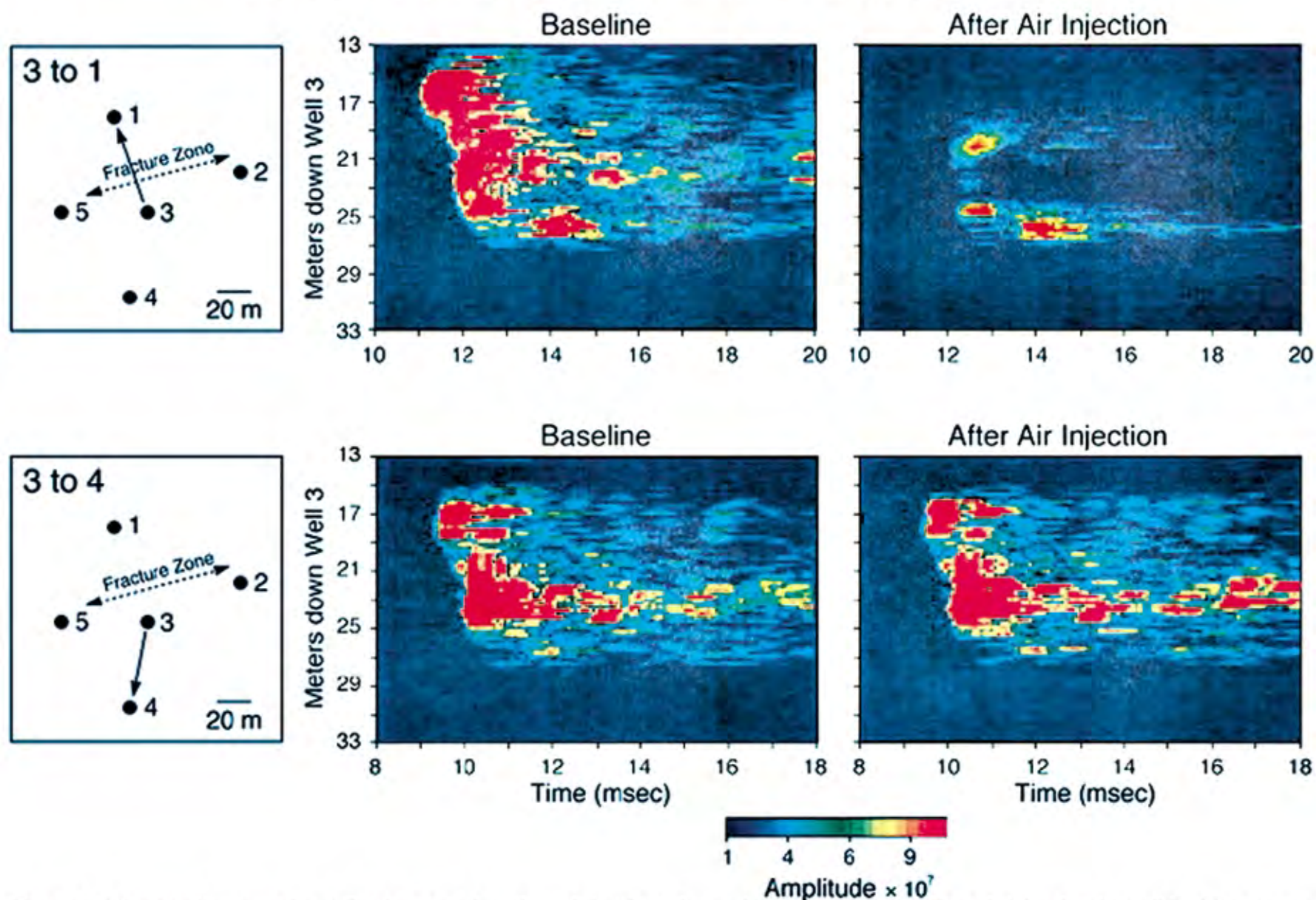


Figure 5. Crosswell spectral amplitudes as a function of depth and travel time before and after air injection in well 5. The energy transmitted between wells 3 and 1 (top row) shows clear change in amplitudes while the energy transmitted between wells 3 and 4 does not change amplitude. The fracture zone connecting wells 5 and 2 was also identified by hydrologic inversion and by singlwell reflection imaging.

SINGLE-WELL: GW-3

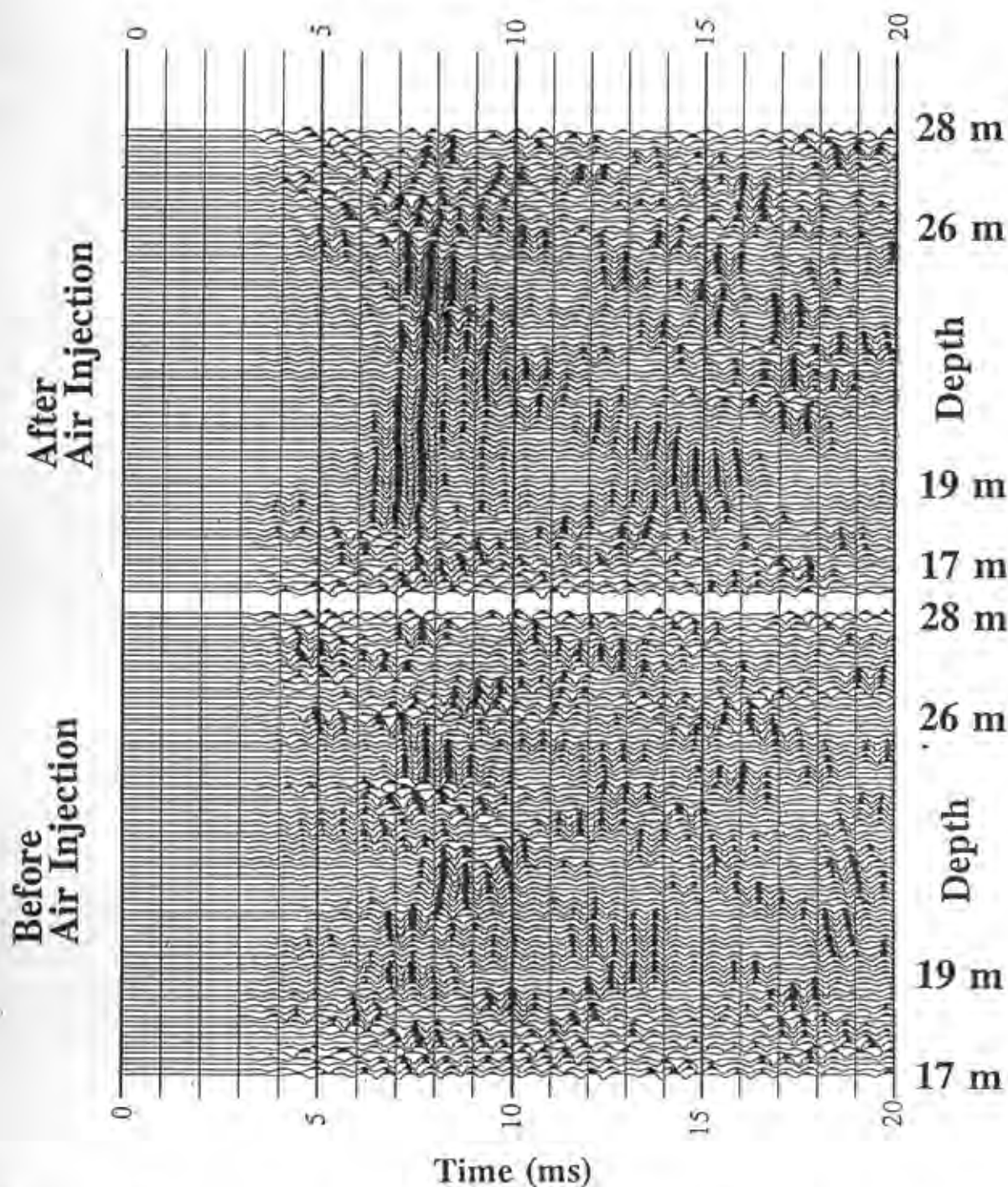


Figure 6. Crosswell monitoring during air injection. The source in well 5 generated a trapped fracture interface wave (generalized Rayleigh wave) which traveled along the fracture. The change in amplitude can be related to the change in fracture stiffness as air displaces water in the fracture.

Conoco Zero-Offset Crosswell: 5 to 2 Air Injection Monitor (Expanded View of FTW)

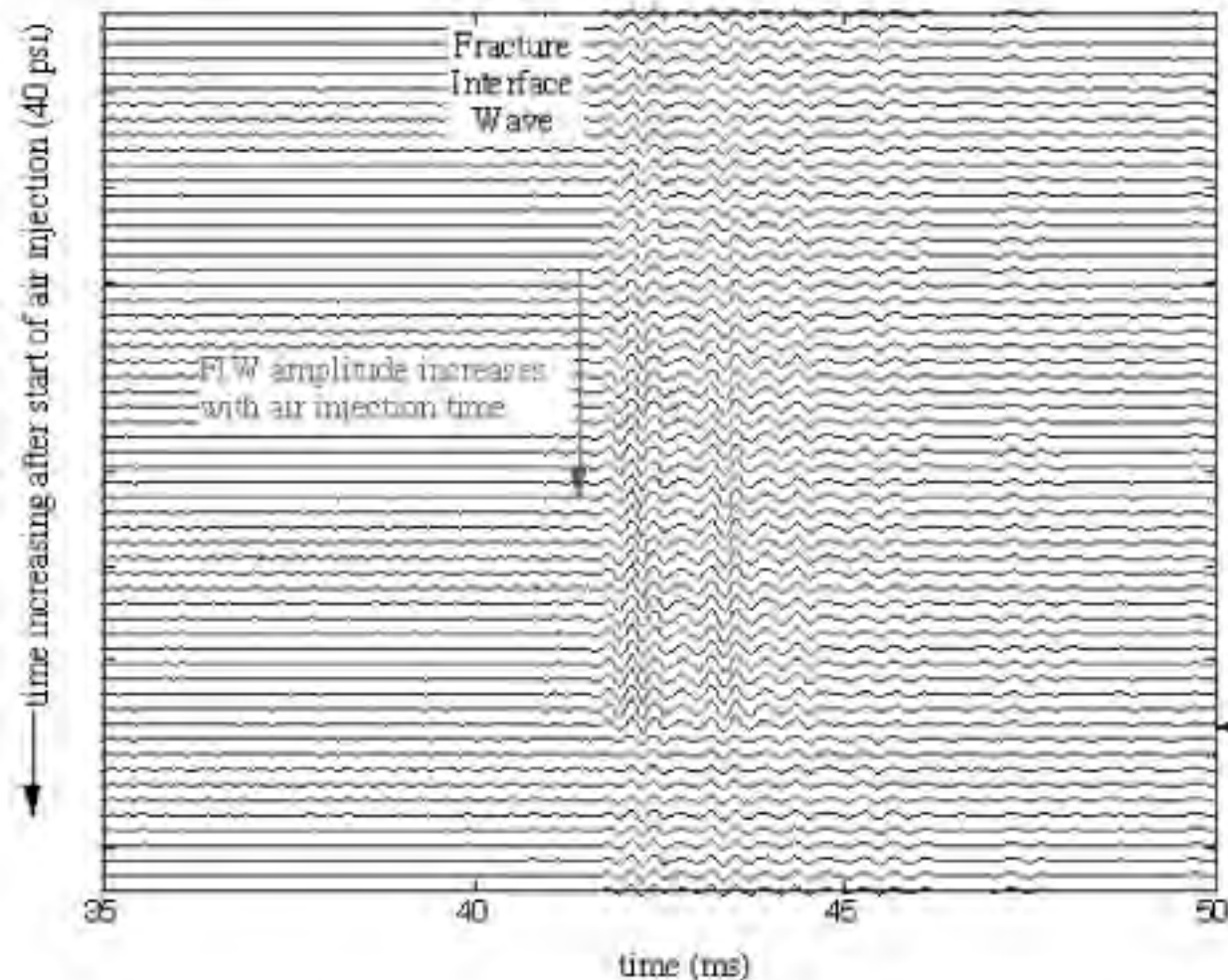
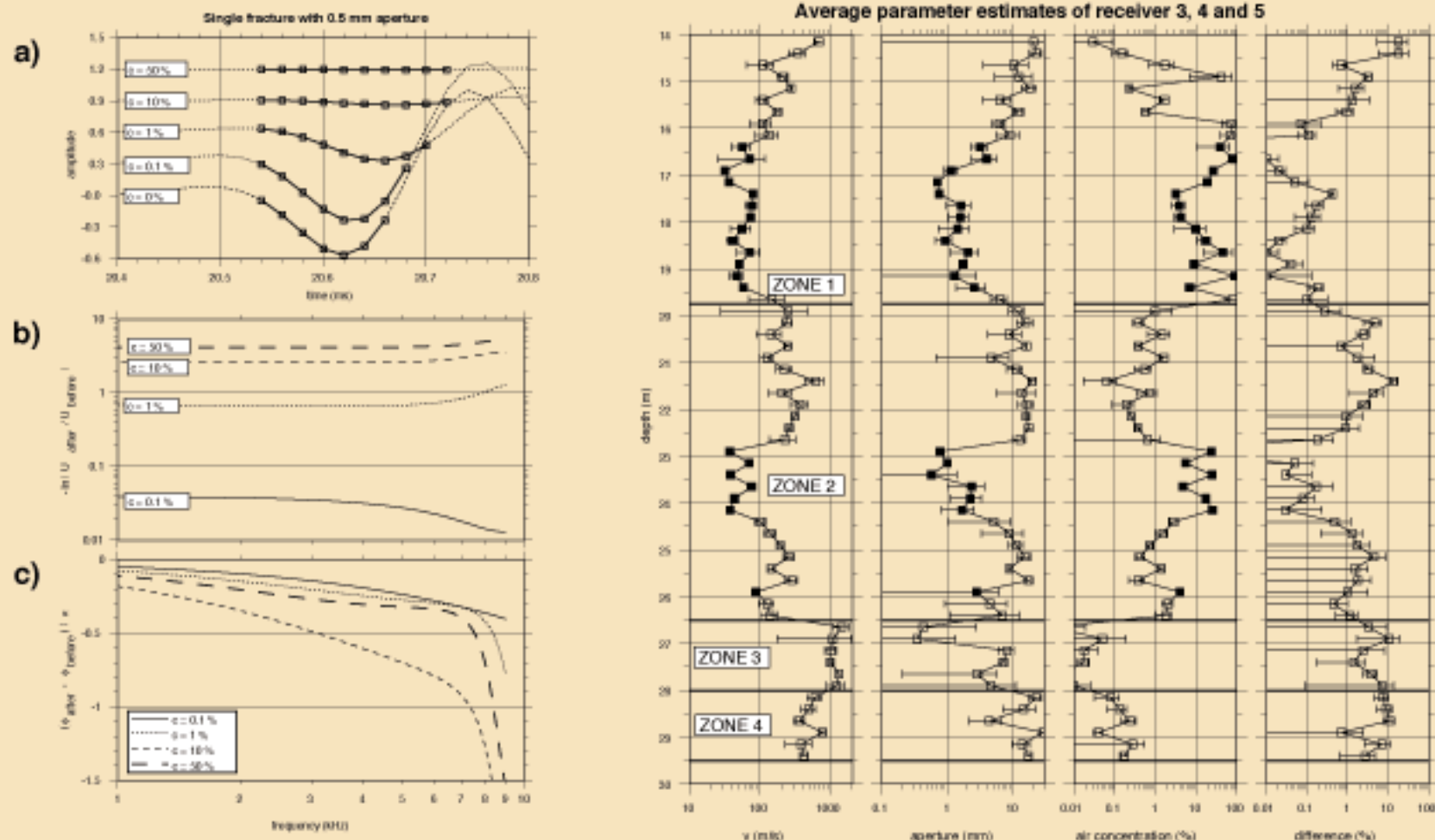


Figure 7. Crosswell monitoring during air injection. The source in well 5 generated a trapped fracture interface wave (generated Rayleigh wave) which traveled along the fracture. The change in amplitude can be related to the change in fracture stiffness as air displaces water in the fracture.

Modeling and inversion of crosswell seismic data for properties of the fracture zone between wells 2 and 5.



a) Seismograms, b) moduli and c) phase changes for different air concentrations.

Estimates of fracture aperture and air concentration. Reliable aperture estimates are only obtained if the velocity is below 100 m/s.

Figure 8

**BED-ISOLATION TREATMENTS OF A MATURE WELL IN THE BLUEBELL FIELD
OF THE UINTA BASIN, UTAH, THAT HAS UNDERGONE NUMEROUS HIGH-
VOLUME SHOTGUN COMPLETIONS**

Craig D. Morgan (nrugs.cmorgan@state.ut.us; 801-537-3370)

Utah Geological Survey

P.O. Box 146100

Salt Lake City, Utah 84114-6100

and

Milind D. Deo, Ph.D. (mddeo@eng.utah.edu; 801-581-7629)

University of Utah

Dept. of Chemical & Fuels Engineering

50 S. Central Campus Dr., Rm 3297 MEB

Salt Lake City, Utah 84112-9203

Class I Field Demonstration Program contract number DE-FC22-92BC14953 (1993-1999)
entitled *Increased oil production and reserves from improved completion techniques in the
Bluebell field, Uinta Basin, Utah*, Contracting Officer Representative Dan Ferguson NPTO, Tulsa
Oklahoma.

ABSTRACT

The purpose of the Class I field demonstration program was to increase primary oil production and reserves through improved completion techniques in the Bluebell field, Uinta Basin, Utah. Significant hydrocarbon reserves are believed to remain untapped due to insufficient characterization of the reservoir properties and less-than-optimal well-completion practices. Over one-quarter of the wells drilled in the Bluebell field have been abandoned, and the well abandonment rate is expected to increase as water production increases and oil production declines.

Wells in the Bluebell field typically have been completed in a shotgun fashion where 40 or more beds are perforated within a 1,500-foot vertical section of the Tertiary Green River and Colton Formations. During the life of most wells, additional perforated intervals are added and shotgun acid stimulations are applied to all the perforations every few years. The large acid jobs are expensive and the financial return generally declines with each successive treatment.

Part of the well demonstration program involved analyzing a mature well using dual burst thermal decay time (TDT) and dipole shear anisotropy (anisotropy) cased-hole logs and then acidizing four beds individually, attempting to avoid treating oil-depleted water-producing beds. Anisotropy and isotope tracer logs were run for post-treatment analysis. The first two acid treatments resulted in communication with intervals above and below the test interval. Swab tests recovered acid water from both intervals. The third and fourth treatments were confined within the test intervals, and oil and water were recovered during swab testing. A bridge plug was placed between the second and third test intervals, eliminating the first two (lowermost) intervals from production. The daily oil production rate was doubled and reservoir modeling indicates that 27,000 barrels of oil was added to the recoverable reserves from a previously perforated but nonproductive bed.

This project found the bed-isolation completion technique can be an effective and economic treatment if good cased-hole data are gathered, especially for older wells where the potential incremental increase in oil production no longer justifies the expense of the larger shotgun acid completion. Beds should be selected for treatment using anisotropy and TDT logs to identify beds that are fractured and have relatively low water saturation. The bed-isolation completions should be conducted using a dual packer tool to reduce cost. Both the upper and lower packer should be placed between perforated beds with at least 50 feet of vertical separation between them to reduce the risk of communication behind the casing during the treatment. The isotope tracer log can be useful in evaluating the mechanical aspects of the acid treatment, identifying thief beds, and detecting communication problems behind the casing which can be avoided in future treatments.

INTRODUCTION

The Bluebell field demonstrations were intended to test techniques to complete new wells and recomplete old wells in order to increase primary production and extend the life of many wells that might otherwise be prematurely abandoned. While the Bluebell field has produced large amounts of oil, indications are that significant reserves remain untapped due to lack of detailed characterization of the reservoir properties and current completion practices. More than one quarter of the wells drilled have been abandoned, and as water production increases and oil rates decline, the abandonment rate is expected to increase.

Wells in the Bluebell field are typically completed by perforating 40 or more beds over 1,000 to 3,000 vertical feet (300-900 m), then stimulating the entire interval with a single hydrochloric acid treatment. This technique is often referred to as a “shotgun” completion. The shotgun technique is believed to leave many potentially productive beds damaged and/or untreated, while allowing water-bearing and low-pressure (thief) zones to communicate with the wellbore. This practice has been used primarily because of the difficulty in identifying fracture zones and correlating reservoirs between wells.

Dual-porosity, dual-permeability, single-well, numerical simulation modeling indicate that fracturing is essential for good reservoir performance in the Bluebell field. Model sensitivity analyses of block size, fracture porosity, fracture frequency, and fracture permeability were conducted. Increased fracture porosity and frequency resulted in increased gas production. Increasing the fracture permeability increased the oil and gas production from a well for fracture permeabilities up to 5 milliDarcys (mD). Fracture permeability above 5 mD has less of an effect because the production is limited by the matrix permeability.

Two recompletion techniques were tested, a staged-completion, and bed-isolation completion technique. The staged-completion technique involves acidizing the entire productive interval (typically 1,500 feet [450 m] or more) in stages of about 500 vertical-feet (150 m) each. When the treatments are applied in stages, more of the perforated beds receive acid. Larger intervals or single stage treatments do not effectively get acid into all of the perforated beds. The large staged-completion technique becomes less effective as a well matures and many of the perforated beds become depleted of oil and increase in water production. The bed-isolation completion technique involves isolating and acidizing only beds with remaining oil potential. Cased-hole logs are effective tools for identifying changes in reservoir properties and remaining oil potential over the life of a well.

Identification of The Problems

The Bluebell field study was developed after extensive consultation with Uinta Basin operators and service companies on what completion and production problems are believed to be the most significant in the Uinta Basin oil fields. The consensus opinion identified the following problems:

1. A larger than necessary gross interval is typically perforated because of a lack of detailed understanding of the properties in the highly heterogeneous, multiple-reservoir complex spanning the Green River and Colton Formations.

2. Perforating a very large gross interval opens up water zones, thief zones, and low- to non-productive beds.
3. Effective treatments are difficult to design because of the large gross perforated interval, and the complex heterogeneity of the multiple reservoirs opened to the wellbore.
4. Heavy drilling mud, necessitated by overpressured reservoirs, invades the producing beds causing formation damage and reducing near-wellbore permeabilities.

Approach and Project Description

A two-year characterization study of the Bluebell field consisted of 12 separate, yet related tasks. The characterization tasks were: (1) well log analysis and petrophysical investigations, (2) outcrop studies, (3) cuttings and core analysis, (4) subsurface mapping, (5) acquisition and analysis of new logs and cores, (6) fracture analysis, (7) geologic characterization synthesis, (8) analysis of completion techniques, (9) reservoir analysis, (10) best completion technique identification, (11) best zones or areas identification, and (12) technology transfer.

The objective was to improve the geologic characterization of the producing formations, and develop completion techniques for specific producing beds or facies as opposed to the non-specific shotgun approach of stimulating all the beds with a single acid treatment. The characterization did not identify predictable-facies or predictable-fracture trends within the vertical stratigraphic column as hoped. But much was learned about the Green River and Colton reservoirs that is applicable to other individual wells, and when combined with advanced cased-hole logs may help to improve completions of new wells, and recompletion of old wells.

A three-well demonstration was developed. First, two different completion techniques on older wells; then one of the methods was selected for use in completing a new well. The recompletion of the Michelle Ute 7-1 well (section 7, T. 1 S., R. 1 W., Uintah Baseline and Meridian) (figure 1) was the first demonstration. The Michelle Ute 7-1 recompletion was designed as a three-stage, high-diversion, high-pressure, acid treatment. Each stage covered about a 500-foot (150-m) vertical interval with over 10 perforated beds. The Michelle Ute 7-1 treatment failed because of mechanical problems during the recompletion attempt. The second well demonstration was a recompletion of the Malnar Pike 17-1 well (section 17, T. 1 S., R. 1 E.). The Malnar Pike 17-1 recompletion was designed to be an acid treatment at the bed scale, by isolating and treating four individual beds. The third demonstration was the completion of a new well, the John Chasel 3-6A2 (section 6, T. 1 S., R. 2 W.), using the staged completion technique.

GEOLOGIC SETTING

The Uinta Basin is a topographic and structural trough encompassing an area of over 9,300 square miles (24,000 km²) (Osmond, 1964). The basin is sharply asymmetrical with a steep north flank bounded by the east-west trending Uinta Mountains and a gently dipping south flank bounded by the northwest-plunging Uncompahgre and north-plunging San Rafael uplifts. The basin is bounded on the east by the north-plunging Douglas Creek arch and on the west by the north-south-trending Wasatch Mountains (figure 2). The dominant regional fracture systems trend northwest to southeast and west to east, parallel to the major structural features that border or extend into the basin (Stearns and Friedman, 1972). Faults with large displacement and anticlinal folds are uncommon within the Uinta Basin.

The basin contains as much as 32,000 feet (7,960 m) of sedimentary rock ranging in age from Late Precambrian to Oligocene (figure 3). More than half of the sedimentary sequence (>16,000 feet [3,980 m]) consists of Paleocene- and Eocene-aged rocks (Anders and others, 1992). In Paleocene to Eocene time, the Uinta Basin downwarped relative to the rising Uinta Mountains. The basin had internal drainage forming ancestral Lake Flagstaff and Lake Uinta. Deposition in and around the lakes consisted of open- to marginal-lacustrine facies that make up the Green River Formation. Alluvial redbed deposits that are laterally equivalent and intertongue with the Green River, make up the Colton and Wasatch Formations.

The Uinta Basin of northeast Utah is the most prolific petroleum province in the state. More than 439 million barrels (61,000 MT) of oil and 1 trillion cubic feet (28,000,000 m³) of gas have been produced from deposits in the Paleocene/Eocene Green River and Colton (Wasatch) Formations. The 104 fields in the basin range in size from the giant Altamont-Bluebell-Cedar Rim field complex (three contiguous fields each with a defined legal boundary) in the northwest and north-central part, to scattered single-well fields throughout the basin (figure 1).

In the Altamont-Bluebell-Cedar Rim field area, the Green River and Colton Formations contain an oil-bearing section up to 8,000 feet (2,400 m) thick of which 2,500 feet (750 m) is locally overpressured. Production occurs from multiple, generally low matrix porosity, thin-bedded sandstone deposited in and around the shores of Lake Flagstaff and Lake Uinta during Paleocene through Eocene time. Permeability is commonly enhanced by vertical fractures.

The Bluebell field has produced over 141 million barrels (19,700,000 MT) of high gravity (38-42 degrees API) oil. The field was discovered in 1959 and is the third largest oil field (based on cumulative production) in Utah with more than 300 active wells. Approved well spacing is two wells per square mile, but much of the field is still produced at one well per square mile.

The Bluebell, Altamont, and Cedar Rim fields are located in the north-central portion of the Uinta Basin, near the structural axis (figures 1 and 2). The generation of hydrocarbons in the low-porosity and low-permeability rocks of the Flagstaff Member of the Green River Formation resulted in an overpressured, fractured, Colton/Flagstaff reservoir. Shallower, hydrostatically pressured hydrocarbon accumulations are found in the upper and lower Green River reservoirs. These reservoirs are enhanced by tectonic fractures which commonly make them more porous than the Colton/Flagstaff reservoir.

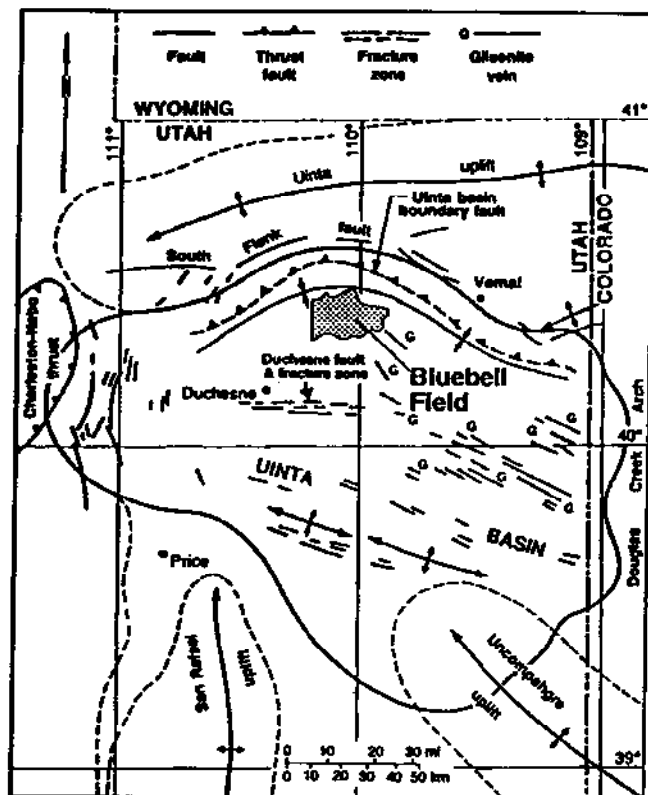


Figure 2. Major structural features, surface faults, and gilsonite veins, in and around the Uinta Basin.

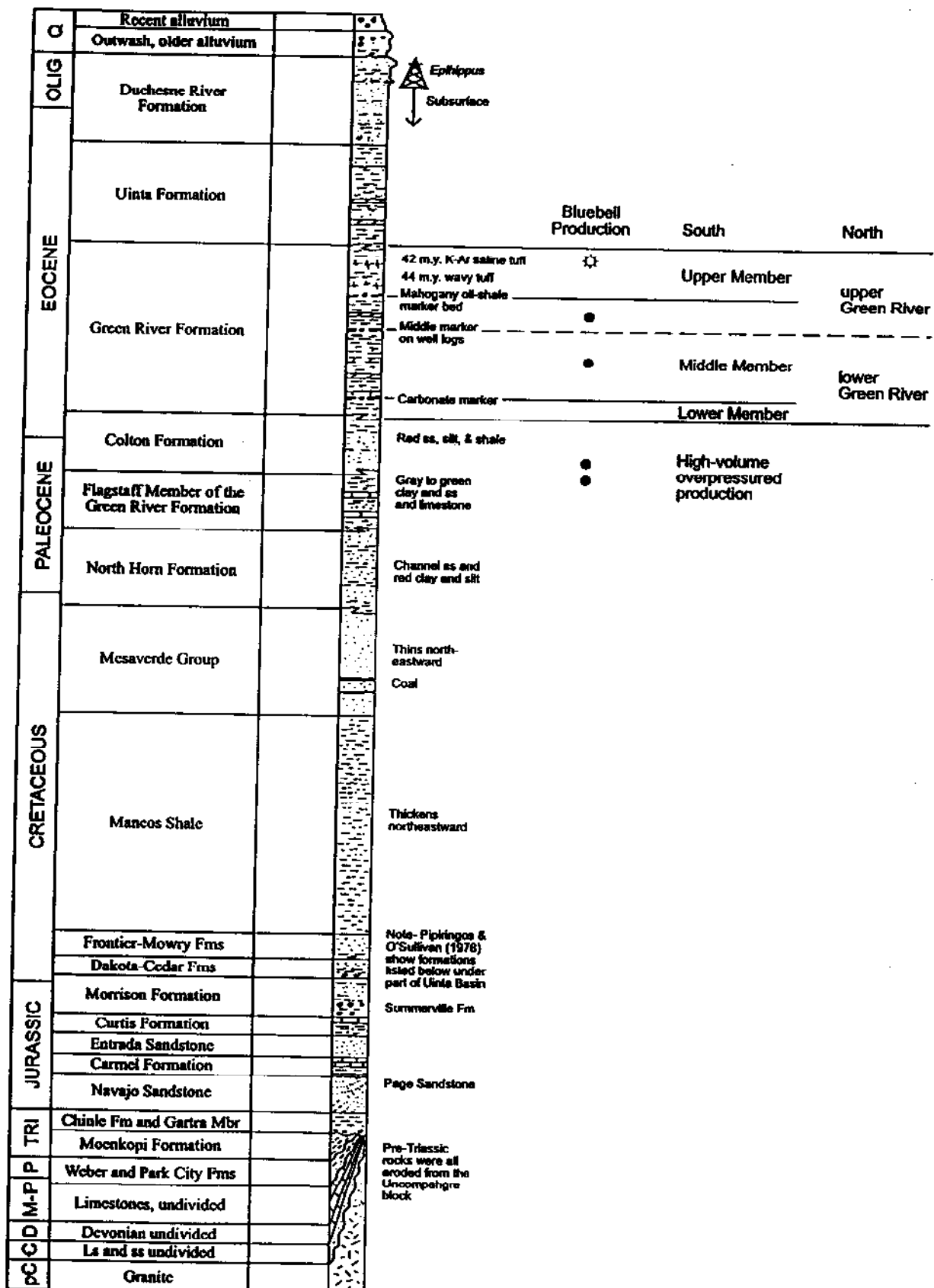


Figure 3. Stratigraphic section of the Uinta Basin modified from Hintze, 1988. The section illustrates the stratigraphic locations of the upper and lower Green River Formation as well as the Colton Formation and Flagstaff Member of the Green River which make up the Colton/Flagstaff reservoir.

SINGLE-WELL NUMERICAL SIMULATION MODELS

Single-well models were developed for both the Michelle Ute 7-1 and Malnar Pike 17-1 wells. The perforated intervals span thousands of feet in both the wells. Geological properties were calculated for all the perforated beds. The information was used to develop models for both wells, but only the Malnar Pike model is discussed here. These were comprehensive models since they took into account all the perforated beds.

Model Parameters

The Malnar Pike 17-1 well is perforated in 55 beds. The model was developed for a 40 acre (16.2 h) (1,320 feet [402.3 m] in the x and y directions) area surrounding the well. The reservoir properties observed at the well bore were assumed to be continuous over the entire 40-acre (16.2-h) area surrounding the well. The numerical values used for various parameters are listed in table 1.

The model was divided into 64 blocks with length and width dimensions of 165 feet (50.3 m). Low-porosity, low-permeability blocks separated the blocks representing perforated beds. This resulted in 109 layers in the vertical direction for the Malnar Pike 17-1 model. The thickness of the grid blocks varied according to the log calculated thickness data. The initial saturation of the perforated beds varied according to the values calculated from logs. The initial reservoir pressure was varied with depth using a gradient of 0.5 pounds-per-square-inch per foot (psi/foot) (115 grams/cm²/m). The bottom-hole pressure was 3,000 psi (21,000 kPa) for the first year of production and 2,000 psi (14,000 kPa) in subsequent years of production. The initial gas-oil-ratio (GOR) was set to the average GORs observed during the first month of actual production in the well.

Initial Production History Match

The perforating history of the well was duplicated in the production history match model. Even though the well was perforated in multiple beds, all the beds were not perforated at the same time. This factor was incorporated into the model by opening up the respective beds at appropriate times. However, it is not clearly understood which of the perforated beds in the well are responsible for the oil production. The permeabilities of the grid blocks representing the perforated beds were adjusted to match the field oil and gas production. Initially, only the permeabilities of the beds perforated at that time were adjusted until the next set of perforations were added. When the new set of perforations were added, only the permeabilities of newly perforated beds were adjusted. The permeabilities of the set of perforations previously open were not changed. In order to match the production data, the overall permeabilities were reduced after the last set of perforations were added for the well. As a result, the overall permeabilities were reduced to one percent of the original value.

The model predictions for the cumulative oil and gas productions for the Malnar Pike 17-1 well were compared with the field data. The model predictions were in close agreement with the field data. The oil production match is better than the gas production, though the gas production predictions are not significantly different than the field data.

The permeabilities and the fracture properties used to obtain the history match are listed in table 1. Extremely low permeability values were needed to obtain the production history match. The matrix permeability for the Malnar Pike 17-1 model varied between 0.1 and 2.5 mD, and the fracture porosity was only 0.02 percent of the reservoir volume. The fracture frequency was 1 per 125 feet (38.1 m). The fracture permeability varied between 0.02 and 0.22 mD. These were adjusted when evaluating the performances of treatments in the well.

The numerical models (four-section, as well as the single-well) do a reasonably good job of matching the field production data. The numerical parameters used for the rock matrix permeability and the fracture properties are extremely low. The low values of the matrix permeability are close to the experimentally observed values. Other researchers also have observed extremely tight (low porosity and low permeability) reservoir rocks in the Bluebell Field (Bredehoeft and others, 1994; Lucas and Drexler, 1976). Because of the tight nature of the reservoirs, production from the Altamont and Bluebell fields is dependent on naturally occurring fracture networks (Bredehoeft and others, 1994; Lucas and Drexler, 1976; Narr and Currie, 1982). The low fracture permeabilities in the model suggests that the fractures are not fully contributing to the production. Wagner (1996) analyzed fractures in some of the cores from the Bluebell field and found that a large number of the fractures were filled with calcite, pyrite or clay. Another reason for non-contributing fractures could be formation damage near the wellbore caused by the frequent acid treatments. The overall permeability values in the model had to be reduced significantly to match the production. The permeability reductions were applied only to the wellbore blocks and not to the entire model. The values were reduced after the final sets of perforations were added to the well. These extreme reductions in the permeability values (99 percent for the Malnar Pike 17-1) suggest that the near-wellbore formation has been damaged over the life of the well. The reductions required can be used to quantify the level of damage.

Table 1. Parameters for the comprehensive models for the Malnar Pike 17-1 well.

PARAMETER	<i>Malnar Pike 17-1</i>
Reservoir extent (ft)	9,582-14,360
Grid size	8*8*99
Grid block size (x and y) (ft)	165
Porosity	0.0-0.21
Matrix permeability mD	0.1-2.5
Fracture porosity	0.000002
Fracture frequency	1 per 125 ft

fracture permeability	0.02-0.22
Pressure (psi/ft)	0.5
Oil gravity (API)	35
Gas gravity	0.75
Initial GOR (scf/stb)	1100
Initial bubble point pressure (psi)	4,795
Initial oil saturation	0.1-1.0
Bottom hole pressure (psi)	3,000

RECOMPLETION OF THE MALNAR PIKE 17-1 WELL

The recompletion of the Malnar Pike 17-1 well was the second step in the three-well field demonstration. The Malnar Pike 17-1 recompletion involved isolation, stimulation, and testing of much smaller intervals than normal, treating at the bed scale, or as close to bed scale as was practical. The intervals were isolated using a bridge plug at the base and a packer at the top of the test interval.

Four separate acid treatments and tests were applied. The first two treatments resulted in communication above and below the test interval. Swab tests recovered acid water from both intervals after the treatment. The third and fourth treatments were mechanically sound and resulted in an increase in the daily oil production.

The TDT log was run before the treatment, anisotropy logs were run before and after the treatment, and an isotope tracer log was run after the treatment. These logs were used to identify beds for treatment and for post-treatment testing and evaluation.

Test Number 1

The first interval stimulated and tested was at a log depth from 13,366 to 13,470 feet (4,073.9-4,105.7 m) (figure 4a). A temperature and spinner survey run early in the life of the well, showed the perforations from 13,434 to 13,438 feet (4,094.7-4,095.9 m) were responsible for 17 percent of the oil production at that time. The TDT log shows this bed has a water saturation from 63 to 79 percent. The pre-treatment anisotropy log shows little to no fracturing in this bed. The perforated intervals 13,402 to 13,412 feet (4,084.9-4,087.9 m), and 13,486 to 13,494 feet (4,110.5-4,112.9 m), were identified as thief zones by the earlier temperature and spinner survey. The pre-treatment anisotropy log shows good fracture development in both thief zones. The perforated bed 13,414 to 13,418 feet (4,088.6-4,089.8 m), has a water saturation of 25 to 40 percent. All the other perforated beds in the test interval have water saturation ranging from 62 to 79 percent as indicated on the TDT log.

Figure. 4A-4D. Portions of the cased-hole logs ran in the Malnar Pike 17-1 demonstration well. Column A is a portion of the dipole shear anisotropy log ran before acid treatment. The greater the separation of the two lines (shaded in) the greater the density of fractures. Column B is a gamma-ray curve for correlation and bed identification. Column C is the anisotropy log ran after the acid treatments. Column D is from the isotope tracer log with the different tracers labeled 1, 2, and 3. The larger the curve, the more isotope left behind the casing, which helps determine where the acid went. The TDT log shows percent water saturation (S_w) in column E and column F diagrammatically shows oil (black) and water (white) in the pore volume of the rock. (4A) test number 1, (4B) test number 2, (4C) test number 3, and (4D) test number 4.

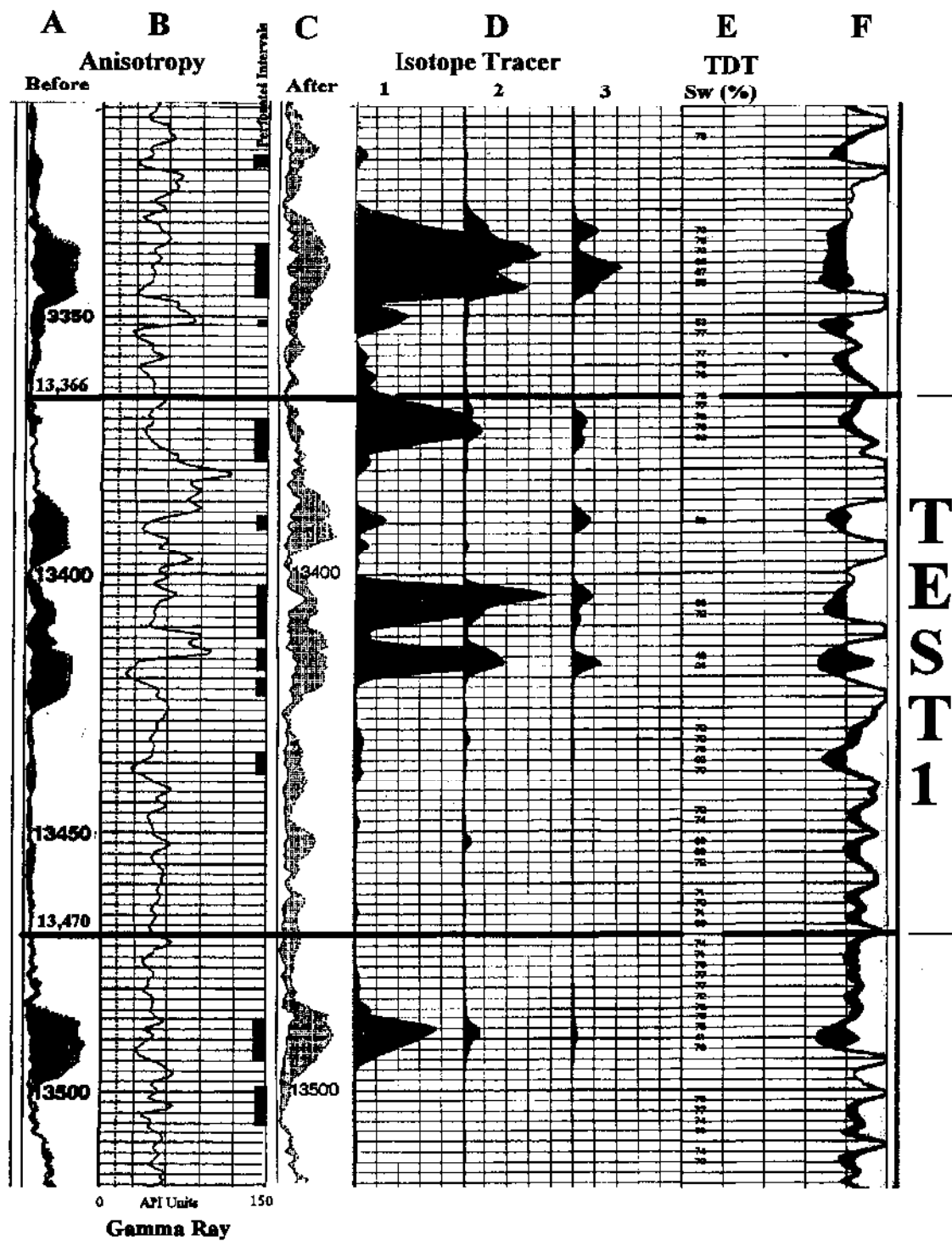


Figure 4A.

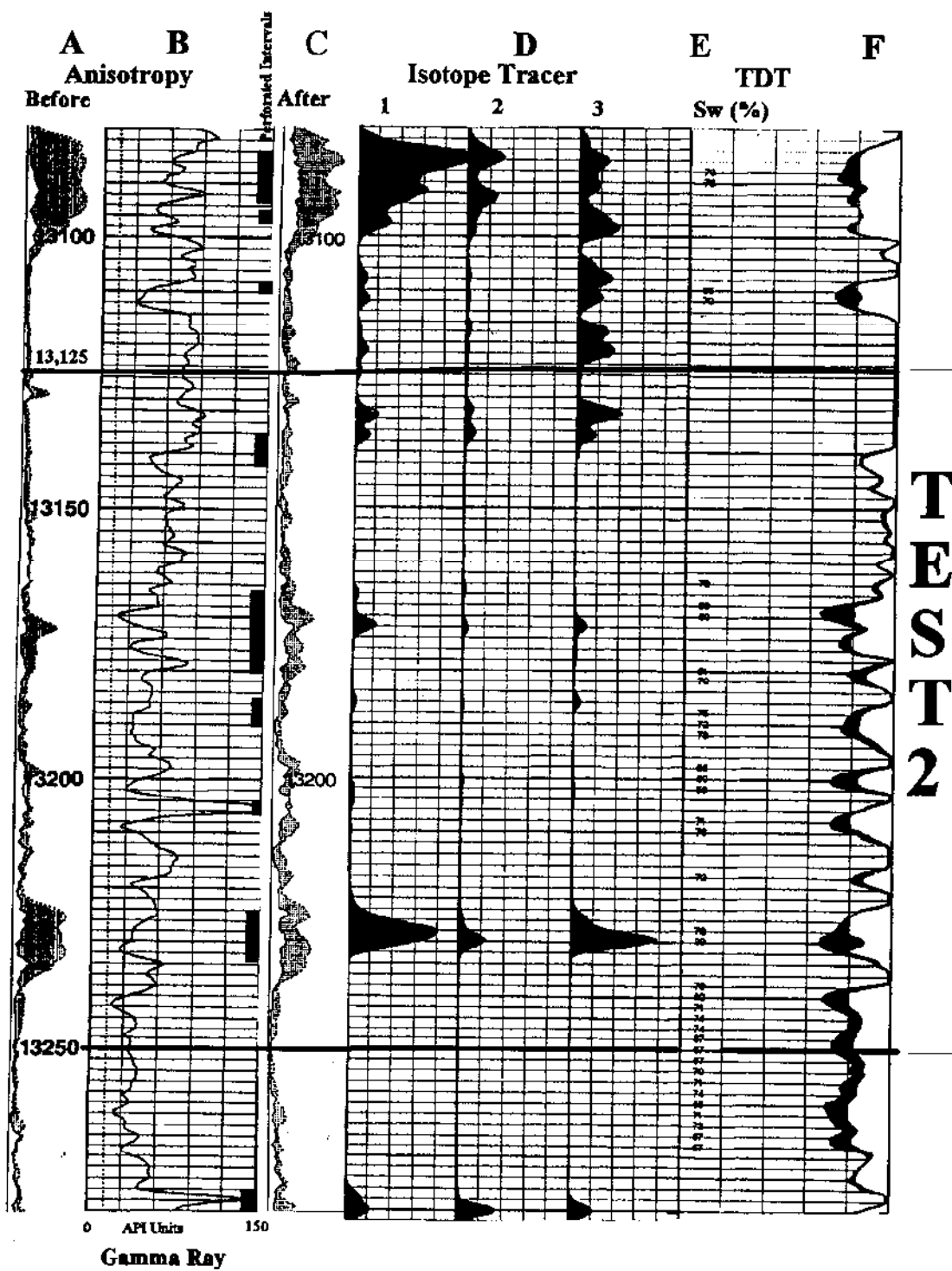


Figure 4B.

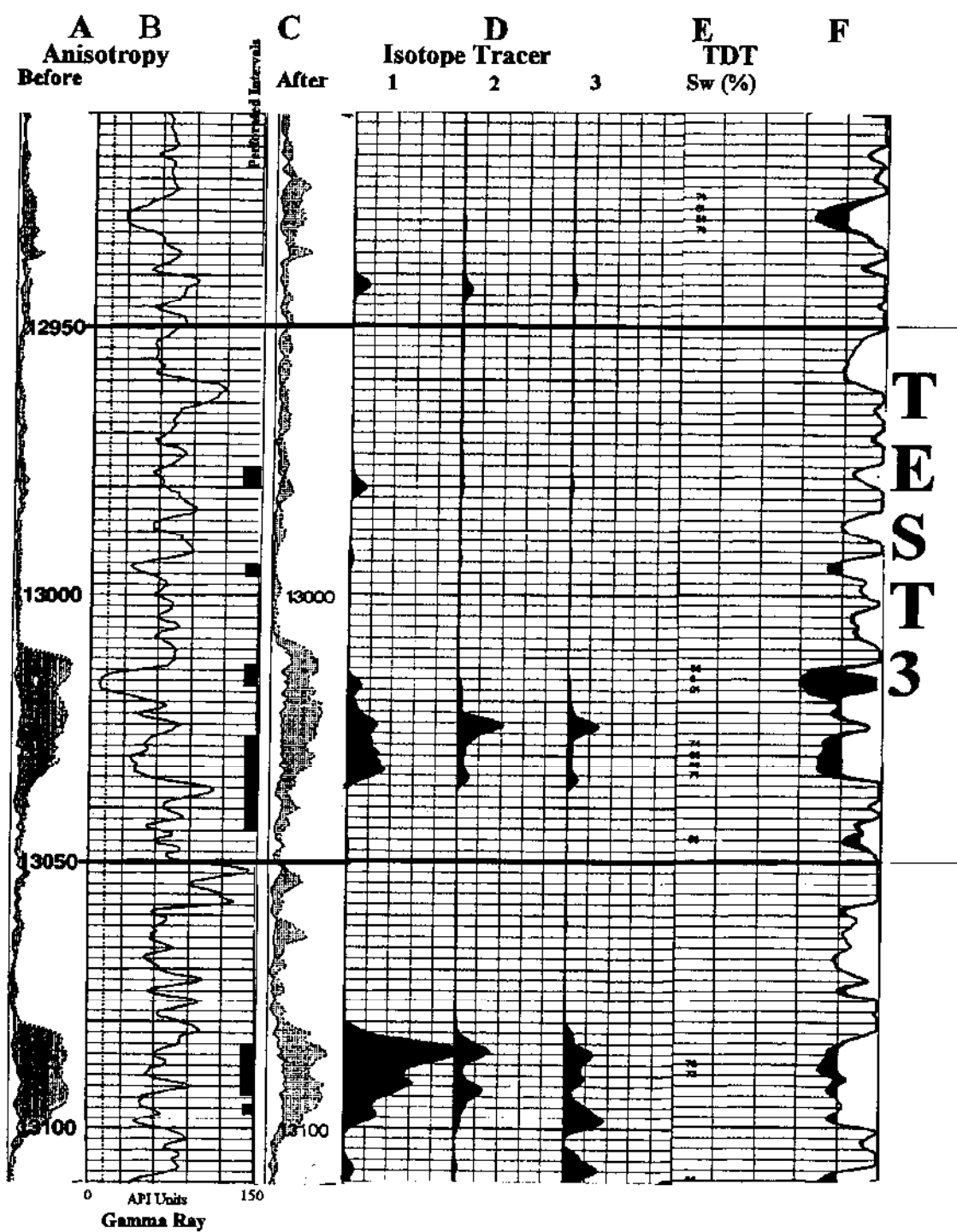


Figure 4C.

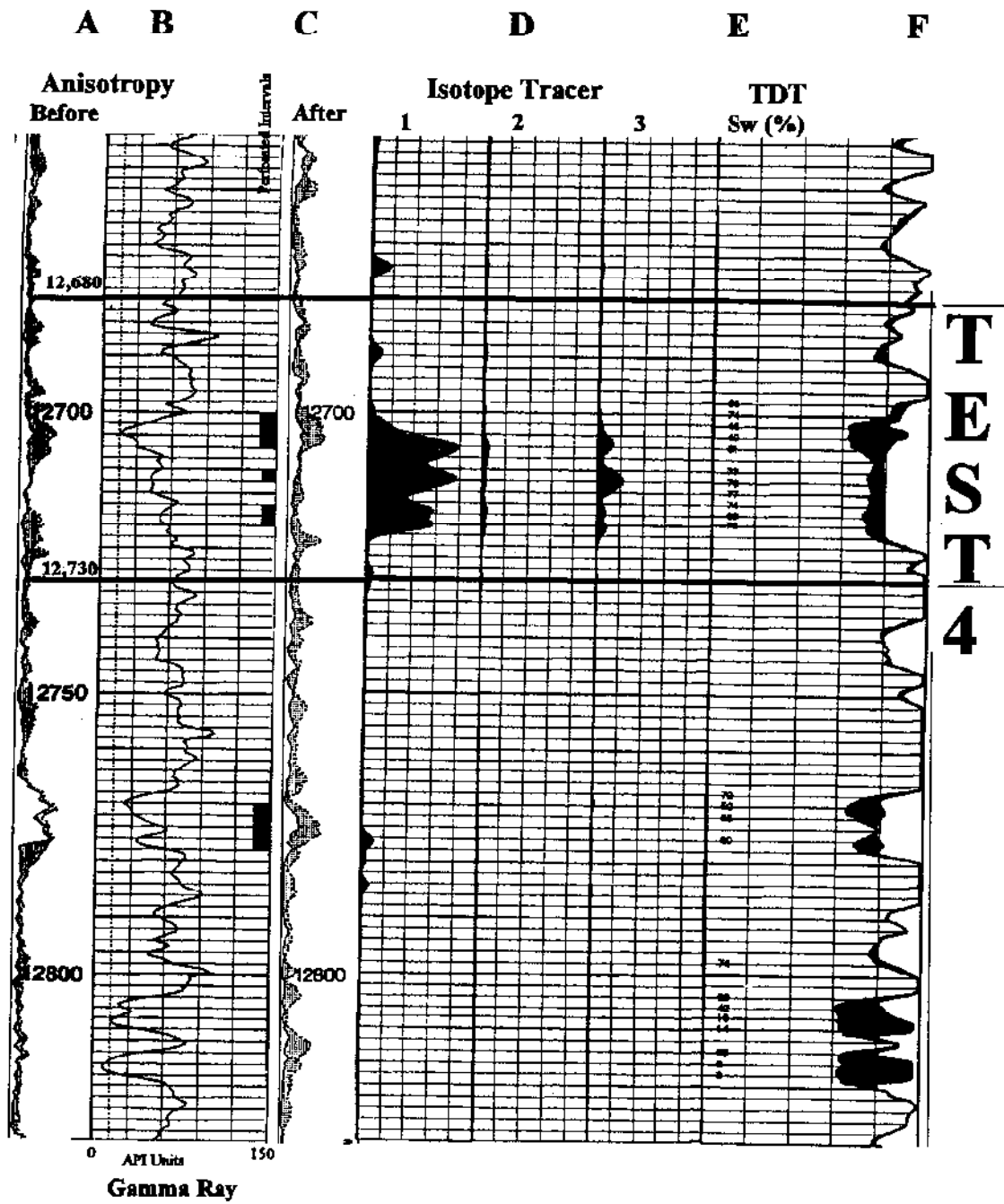


Figure 4D.

The interval was treated with 357 bbl (56,800 L) of hydrochloric (HCl) acid pumped at a maximum pressure of 7,214 psi (49,700 kPa), an average pressure of 5,500 psi (38,000 kPa), and at a maximum rate of 10 bpm (1,600 Lpm). Communication occurred behind the casing (probably in the cement between the casing and the formation) above the packer and below the bridge plug. The communication can be identified on the isotope tracer (tracer number 1) and the post-treatment anisotropy logs. The communication greatly reduced the effective delivery of the treatment to the intended beds. Limited swab testing after the treatment recovered acid water.

Test Number 2

The second interval stimulated and tested was at a log depth from 13,125 to 13,250 feet (4,000.5-4,038.6 m) (figure 4b). The pre-treatment anisotropy log showed two perforated intervals with well developed fractures at 13,224 to 13,233 feet (4,030.7-4,033.4 m) and 13,165 to 13,180 feet (4,012.7-4,017.3 m). A two-foot (0.6-m) layer (13,228 to 13,230 feet [4,031.9-4,032.5 m]) has a water saturation of 39 percent. The other perforated intervals have a water saturation ranging from 59 percent to more than 79 percent based on the TDT log.

The interval was stimulated with 95 bbl (15,100 L) of HCl acid pumped at a maximum pressure of 6,810 psi (46,900 kPa), an average pressure of 6,000 psi (41,000 kPa), and at a maximum rate of 10.2 bpm (1,600 Lpm). Communication occurred behind the casing (probably in the cement between the casing and the formation) above the packer and possibly below the bridge plug. The communication can be identified on the isotope tracer (tracer number 3) and the post-treatment anisotropy logs. The communication greatly reduced the effective delivery of the treatment to the intended beds. Limited swab testing after the treatment recovered acid water.

Test Number 3

The third interval stimulated and tested was at a log depth from 12,950 to 13,050 feet (3,947.2-3,977.6 m) (figure 4c). The perforated interval 13,013 to 13,017 feet (3,966.4-3,967.6 m) has a water saturation ranging from 8 to 56 percent, and the perforated interval 13,026 to 13,044 feet (3,970.3-3,975.8 m) has a water saturation range from 66 to 71 percent based on the TDT log. Although these two perforated intervals appear to be separate beds based on the gamma-ray log, the pre-treatment anisotropy log showed the beds were in communication with each other via fractures. Perforated intervals 12,994 to 12,996 feet (3,960.6-3,961.2 m) and 12,976 to 12,980 feet (3,955.1-3,956.3 m) have more than 80 percent water saturation and no fractures.

The interval was stimulated with 72 bbl (11,400 L) of HCl acid pumped at a maximum pressure of 8,203 psi (57,000 kPa), an average pressure of 6,000 psi (41,000 kPa), and at a maximum rate of

10 bpm (1,600 Lpm). A minor amount of communication occurred below the bridge plug. The communication is identified on the isotope tracer (tracer number 2) and the post-treatment anisotropy logs. The upper perforated intervals do not appear to have taken any acid. The tracer log shows that the perforated intervals 13,013 to 13,017 feet (3,966.4-3,967.6 m) and 13,026 to 13,044 feet (3,970.3-3,975.8 m) are in communication as indicated on the pre-treatment anisotropy log. Limited swab testing after the treatment recovered a minor amount of oil, gas, and acid water.

Test Number 4

The fourth interval stimulated and tested was at a log depth from 12,680 to 12,730 feet (3,864.9-3,880.1 m) (figure 4d). The perforated intervals 12,700 to 12,706 feet (3,870.9-3,872.8 m); 12,710 to 12,712 feet (3,874.0-3,874.6 m); and 12,716 to 12,720 feet (3,875.8-3,877.1 m); are in a coarsening-upward sequence with the best developed fracturing (pre-treatment anisotropy log) and lowest water saturation (TDT [40 to 48 percent] log) near the top of the sequence. The lower portion of the sequence has water saturations ranging from 69 to 78 percent.

The interval was stimulated with 71 bbl (11,300 L) of HCl acid pumped at a maximum pressure of 7,200 psi (49,600 kPa), an average pressure of 6,700 psi (46,200 kPa), and at a maximum rate of 9.6 bpm (1,500 Lpm). The isotope tracer (tracer number 1) and post-treatment anisotropy logs showed little to no communication above or below the test interval. Limited swab testing after the treatment recovered a minor amount of oil, gas, and acid water.

Preliminary Production Results

The Malnar Pike 17-1 well was completed in 1987 flowing 640 BOPD (89.6 MT) and 550 MCFGPD (15,600 m³). The cumulative production before the demonstration (September 31, 1997) was 111,304 BO (15,582.6 MT) and 95,970 MCFG (2,717,900 m³). The Malnar Pike 17-1 was producing at an average rate of 18 BOPD (2.5 MT) prior to the treatment. After the treatment, a bridge plug was placed at a depth of 13,060 feet (3,980.7 m), above the first and second intervals, because the operator felt they would produce water. The Malnar Pike 17-1 well has produced 20,663 BO (2,892.8 MT) in 17 months since the recompletion, averaging 41 BOPD (5.7 MT).

REVISED NUMERICAL SIMULATION MODEL AND PREDICTION OF THE PERFORMANCE OF THE TREATMENT

The two test intervals producing in the Malnar Pike 17-1 well are test interval three, between 12,950 and 13,050 feet (3,947.2-3,977.6 m), and test interval four between 12,680 and 12,730 feet (3,864.9-3,880.1 m). A bridge plug was set at 13,060 feet (3,980.7 m) so that the perforations below this depth would not contribute to the production. Because of the treatment, oil production increased from about 18 BOPD (2.5 MT) to about 40 BOPD (5.6 MT).

The dual-porosity, dual-permeability model employed previously to match oil and gas production from Malnar Pike 17-1 was modified to assess the treatment. Relevant matrix and fracture properties used in the model are presented in table 1. The aerial extent of the model was 40 (16.2 h) acres. The well intersected 109 layers; 55 oil-bearing layers separated by 54 non oil-bearing layers. Each of the layers were assigned appropriate depths.

When measured water saturations were used in the model, water produced from the model was two times the actual water produced from the well. In order to match the actual water production, relative water permeabilities were altered. The new set of relative permeabilities are shown in table 2. The cumulative oil, gas, and water production to October 1997, as predicted by the model, are compared with the field totals in table 3. As can be seen from the table, the agreement between the model predictions and field data is excellent. Even though the cumulative production match is reasonably good, the monthly oil, gas, and water production results from the model differ considerably from the field results (figures 5, 6, and 7). The oil production from the field is still reasonably well matched; however water and gas predictions could be improved. Considering the complexity of the data set and the interdependency of data types, the history match is reasonable.

The model predicted a total oil rate of 16 BOPD (2.2 MT) in October 1997. Several different strategies were attempted to match the post treatment rate of about 40 BOPD (5.6 MT). Only the properties in the affected zones were changed at the treatment time. All of the strategies and corresponding rates after treatment are listed in table 4. It was hypothesized that the treatment would have increased fracture permeabilities, extent of fracturing and or frequency of fracturing. Each of the options was examined, either in isolation, or in combination with other options, as well as the option of adding a new layer.

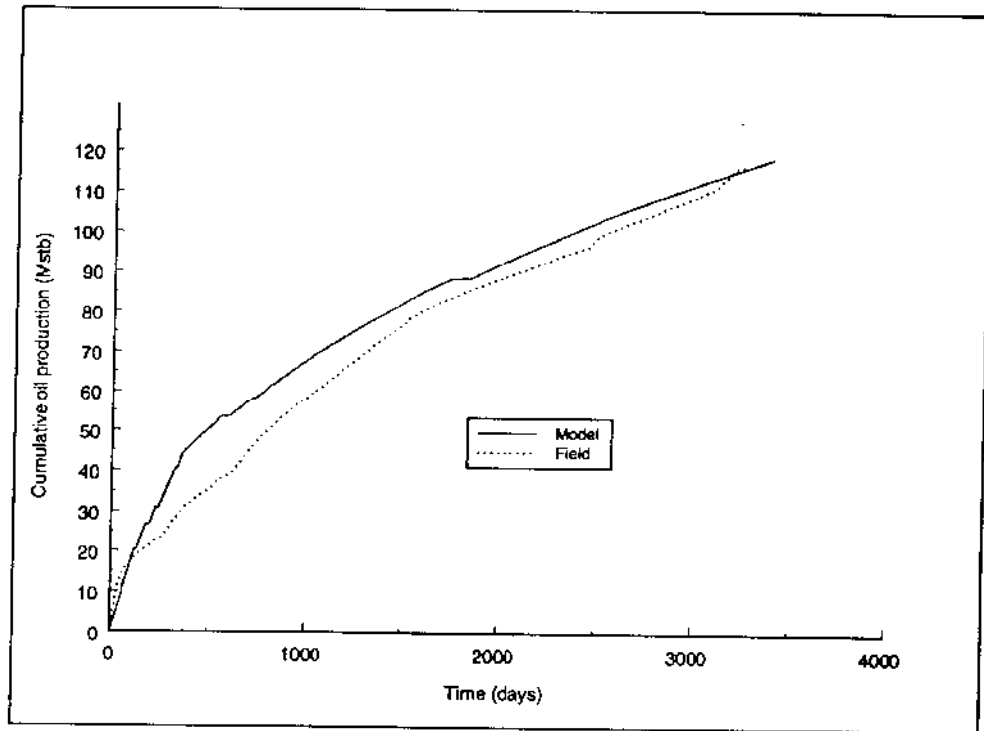


Figure 5. Comparison of cumulative oil production from the Malnar Pike 17-1 well with the modified model predictions.

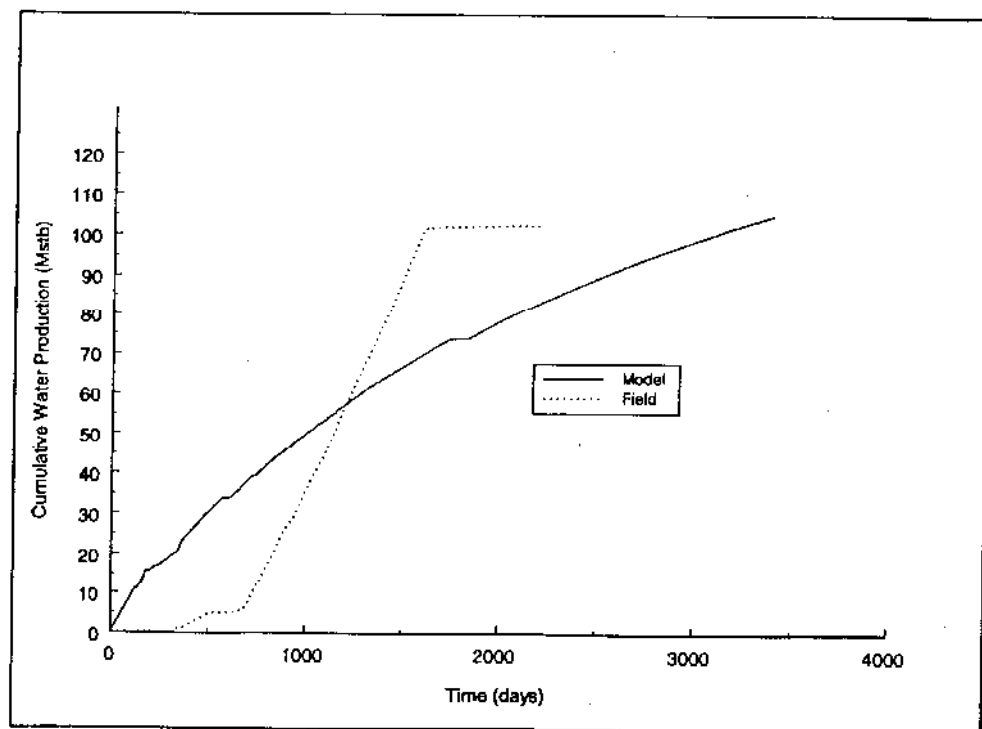


Figure 6. Comparison of cumulative water production from the Malnar Pike 17-1 well with the modified model predictions.

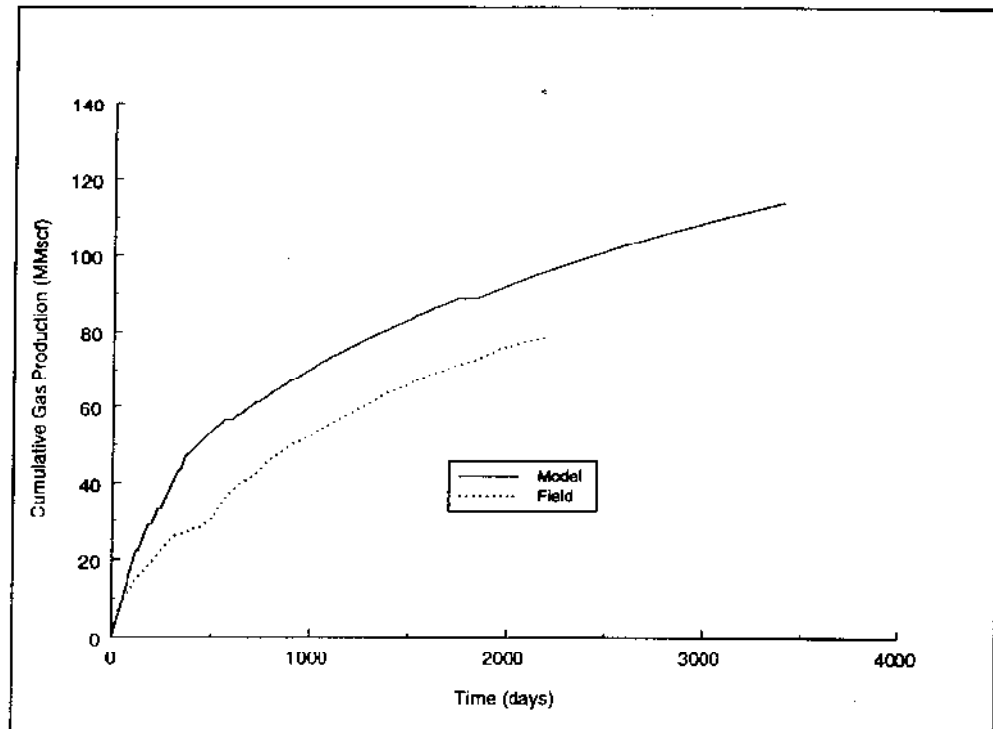


Figure 7. Comparison of cumulative gas production from the Malnar Pike 17-1 well with the modified model predictions.

As seen in table 4, it is possible to realize the gains in production by a variety of methods. Increasing the fracture permeability to 22 mD appeared to provide the most realistic increase in production. However, in most of the strategies examined, the production rate decreased to about 25 BOPD (3.5 MT) after about 6 months. Only in the scenario where an equivalent new layer was added to the reservoir did the production remain steady at around 31 BOPD (4.3 MT) well after the layer was opened. The layer was 30 feet (9.1 m) thick with a porosity of 0.14 and an initial oil saturation of 0.7. The layer had a matrix permeability of 1.5 mD and fracture permeability of 2.2 mD (properties of the older layers). Assuming only three percent recoverable oil from the layer (based on the performance of the well) we calculated that net reserves of about 27,000 BO (3,780 MT) were added to the well.

Table 2. Relative permeabilities used to obtain the history match for the Malnar Pike 17-1 well.

<i>Water Saturation</i>	<i>Relative Permeability to Water</i>	<i>Relative Permeability to Oil</i>
0.22	0.0	1.0
0.3	0.05	0.1
0.35	0.1	0.05
0.4	0.15	0.0175
0.5	0.5	0.0073
0.6	0.7	0.005
0.8	0.9	0.003
0.9	0.96	0.001
1.0	1.0	0.0

Table 3. Production match between the model and actual data from the Malnar Pike 17-1 well.

	<i>Production as of December 1993</i>		<i>Production as of October 1997</i>	
	<i>Actual Production</i>	<i>Model Prediction</i>	<i>Actual Production</i>	<i>Model Prediction</i>
<i>Oil (Mstb)</i>	93	100	113	125
<i>Gas (MMscf)</i>	79	87	96*	119
<i>Water (Mstb)</i>	100	102	122*	110

Mstb = thousand stock tank barrels

MMscf = Million standard cubic feet

* = value extrapolated from available data

Table 4. Different strategies used in emulating the treatment in the Malnar Pike 17-1 well.

<i>Strategy</i>	<i>Production Rate Immediately after Treatment (Stb/day)</i>	<i>Production Rate 4 Months after Treatment (Stb/day)</i>
1. Increase fracture permeability in affected layers from 2.2 to 22 mD	39	25
2. Increase extent of fracturing in the affected layers from 495 to 660 feet	29	22
3. Combine strategies 1 and 2	35	23
4. Increase fracture frequency to one every 5 feet	41	24
5. Add a new layer 12 feet thick, with 0.1 porosity, and oil saturation of 0.7	39	31

CONCLUSIONS

Dual-porosity, dual-permeability, single-well numerical modeling increased our knowledge of the importance of numerous reservoir properties. Fractures, specifically fracture permeability are essential to good reservoir performance.

Communication above and below the test intervals was a major problem in the Malnar Pike 17-1 well. The Malnar Pike 17-1 well has numerous perforations that have been acidized several times, increasing the potential for communication behind the casing. It is likely that conventional acid treatments (typically a 500- to 1,500-foot [150-460 m] interval) of older wells in the Bluebell field experience a similar problem. Much of the acid may be moving vertically through the cement and into beds other than the targeted (perforated) ones.

Test results from the Malnar Pike 17-1 well generally confirmed the interpretation of the anisotropy and TDT logs. Beds with fractures indicated by the anisotropy log generally took most of the acid while beds without fractures took little to no acid. The low treating pressure of about 7,000 psi [48,000 kPa], versus the normal treating pressure of 10,000 psi [69,000 kPa], was not high enough to hydraulically induce new fractures.

RECOMMENDATIONS

The use of the TDT and anisotropy logs are effective in identifying pay in new and older wells. The data from these logs can reduce the number of beds perforated, reduce potential water production problems, and when combined with isotope tracers, increase the understanding of the effectiveness of an acid treatment.

The bed-scale completion technique used in the Malnar Pike 17-1 well could be effective in older wells nearing depletion where the larger staged completion is no longer economical. Based on the experience of the Malnar Pike 17-1 demonstration, we recommend the following:

1. Use a dual packer tool instead of a retrievable packer and bridge plug to allow several beds to be treated in one day, greatly reducing the cost;
2. set the packers between perforated intervals so that there is at least 50 feet (15 m) between the perforated bed above and below each packer to reduce the risk of communication;
3. use the anisotropy and TDT logs to select beds that are fractured and have relatively low water saturation; and
4. use a treating pressure high enough to fracture the formation, especially if the anisotropy log indicates that some of the beds being treated do not have open fractures.

ACKNOWLEDGMENTS

The field demonstrations were conducted by Quinex Energy Corporation, Bountiful Utah, under the direction of DeForrest Smouse Ph.D., Lewis Wells, and Smokey Payne. The study was funded in part by the U.S. Department of Energy National Petroleum Technology Office in Tulsa Oklahoma. Contract management was the responsibility of Edith Allison, Jerry Castle, Gary Walker, and Dan Ferguson of NPTO over the many years of the project. Funding was also provided by the Utah Office of Energy and Resource Management under the direction of Jeff Burks.

The demonstration was the result of an extensive reservoir characterization study. The following people were active participants or provided valuable advice during the study: M. Lee Allison Ph.D., Roger L. Bon, and J. Wallace Gwynn, Ph.D., Utah Geological Survey, Salt Lake City, Utah; Richard Curtice, Halliburton Energy Services, Vernal Utah; Doug Howard, formerly consulting engineer, now with Flying J Oil and Gas, North Salt Lake, Utah; Richard Jarrard, Ph.D., University of Utah, Department of Geology and Geophysics, Salt Lake City, Utah; Bart J. Kowallis, Ph.D., Thomas H. Morris, Ph.D., and students Ann Garner and MaryBeth Wegner, Brigham Young University, Department of Geology, Provo, Utah; Rajesh J. Pawar Ph.D., graduate student under the Direction of Milind D. Deo, University of Utah, Department of Chemical and Fuels Engineering, Salt Lake City, Utah; David Ponto, Dowell Schlumberger's in-house engineer for Coastal Oil and Gas, Denver, Colorado; Carol N. Tripp, consulting geologist, Salt lake City, Utah.

REFERENCES

- Anders, D.E., Palacas, J.G., and Johnson, R.C., 1992, Thermal maturity of rocks and hydrocarbon deposits, Uinta Basin, Utah, *in* Fouch, T.D., Nuccio, V.F., and Chidsey, Jr., T.C., editors, Hydrocarbon and mineral resources of the Uinta Basin: Utah Geological Association Guidebook 20, p. 53-76.
- Bredehoeft, J.D., Wesley, J.B., and Fouch, T.D., 1994, Simulations of the origin of fluid pressure, fracture generation and the movement of fluids in the Uinta Basin, Utah: American Association of Petroleum Geologists Bulletin, v. 78, no. 11, p. 1,729-1,747.
- Hintze, L.F., 1988, Geologic history of Utah: Brigham Young University Geology Studies Special Publications 7, 202 p.
- Lucas, P.T., and Drexler, J.M., 1976, Altamont-Bluebell - a major naturally fractured stratigraphic trap, *in* Braunstein, J., editor, North American oil and gas fields: American Association of Petroleum Geologists Memoir 24, p. 121-135.
- Narr, W., and Currie, J.B., 1982, Origin of fracture porosity - example from Altamont field, Utah: American Association of Petroleum Geologists Bulletin, v. 66, no. 9, p. 1,231-1,247.
- Osmond, J.C., 1964, Tectonic history of the Uinta Basin, Utah, *in*, E.F., editor, Guidebook to the geology and mineral resources of the Uinta Basin: Intermountain Association of Petroleum Geologists Thirteenth Annual Field Conference, p. 46-58.
- Stearns, D.W., and Friedman, Melvin, 1972, Reservoirs in fractured rock, *in* King, R.E., editor, Stratigraphic oil and gas fields - classification, exploration methods, and case histories: American Association of Petroleum Geologists Memoir 16, p. 82-106.
- Wagner, MaryBeth, 1996, Core analysis and description as an aid to hydrocarbon production enhancement - lower Green River and Wasatch Formation, Bluebell field, Uinta Basin, Utah: Provo, Brigham Young University, M.S. thesis, 233 p.

Greater Green River Basin Production Improvement Project, Rock Island 4-H, Table Rock Field, Frontier Formation

Frank H. Lim (FrankLim@upr.com; 817-321-7889)
Union Pacific Resources Company
P. O. Box 7
Fort Worth, Texas 76101

Abstract

The objective of this effort is to reduce the technical risks and the economic uncertainty standing in the way of increased efficient industry development of the low-permeability (tight) gas resources of the Greater Green River Basin (GGRB) of Wyoming. The overall goal is to encourage development and utilization of the GGRB tight gas resources by industry. Two of the most prolific tight gas reservoirs in the Green River Basin, the Frontier and the Mesaverde, have been extensively developed in the Moxa Arch and Wamsutter Arch areas, respectively, using vertical wells and hydraulic fracture treatments. The deeper, overpressured areas of the basin have been much less developed due to uneconomic production rates. Yet, the Scotia Group 1993 study identified as much as 200 Tcf of deep Frontier and 50 Tcf of deep Mesaverde gas resource potential. Lower than normal reservoir permeabilities/porosities and the lack of extensive natural fractures are attributed for the low productivities in previous drilled deep wells. The subject project is intended to reduce these technical risks by testing more effective hydraulic fracturing techniques in a vertical wellbore or to intersect significantly more natural fractures in a horizontal or deviated wellbore. The approach to the project consisted of three phases: Phase I Site Characterization, Phase II Vertical Characterization Well, and Phase III Horizontal Well. Phases I and II resulted in the drilling of the Stratos #1 well (S24-T22N-R107W) through the Second Frontier to a total depth of 16,250 ft. Reservoir characterization and production testing of the Frontier formation determined this location was not favorable for attempting an advanced hydraulic fracture treatment nor for attempting a horizontal lateral. Further site characterization work identified the preferred location and wellbore azimuth for attempting a horizontal lateral to intersect substantial natural fractures in the overpressured Frontier formation on the eastern flank of the Rock Springs Uplift. The blanket marine and lenticular fluvial reservoirs characteristic of the Second Frontier represent prime candidates for a demonstration project that would compare production improvements by drilling, completing and testing of vertical and horizontal, directionally-drilled, wells. Developing techniques to more effectively and economically improve exploitation efficiencies in the Second Frontier has potentially high rewards because this previously unattainable gas resource in the deep Frontier is so large.

The horizontal well is located on the north plunge of Table Rock Field (S4-T19N-R97W) in Sweetwater County, southwestern Wyoming. The UPR Rock Island 4-H well (RI-4H) is offset to a vertical well completion, the Government Union #4 (GU #4) located in S8-T19N-R97W,

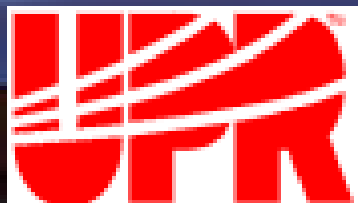
about 1.5 miles southwest of the RI-4H location. GU #4 is currently producing at 5 mmcf/d gas rate from the marine sand (Second Bench) of the Second Frontier formation. Core and log information and production tests from the Government Union #4 well, combined with structural data derived from approximately 1000 square miles of 3-D seismic data were major factors used in the site selection for the RI-4H horizontal well. The path of the horizontal lateral was chosen to be in a direction north 35° east to intersect two sets of natural fractures orientations: a major east-west set and a minor north-south set.

The RI-4H well was spudded on October 14, 1998 and a 14-3/4" vertical borehole was drilled to a depth of 9,517' and set with 11-3/4" casing. Further drilling of a 10-5/8" vertical borehole was done to a depth of 14,440', the kick-off-point (KOP) for directional drilling. From KOP, a 10-5/8" medium radius borehole was drilled at an initial build-up-rate (BUR) of 14° per 100 ft decreasing to a BUR of 4°/100' in the lower curve. At a depth of 15,025' the borehole deviation was 88° and a 7-5/8" liner was cemented into the curve. Using UPR geosteering patented technology, the 6-1/2" horizontal lateral was directionally drilled to stay inside a 20' vertical window within the marine sand of the Second Frontier formation. Since no vertical pilot hole was drilled, offset well logs from the Table Rock #44 well, over 2 miles from the RI-4H, was used for correlation. Once the lateral penetrated the fluvial zone and into the marine zone, the well remained in the marine target zone until it faulted back to the fluvial near the end of the lateral. Total length of the lateral was 1,750' to a final well TD of 16,784' MD (14,953' TVD). This is perhaps a world record depth for a tight gas sandstone horizontal well. Three horizontal cores totaling 77 ft were taken between 15,424'-15,951' MD (14,889'-14,928' TVD), considered to be the deepest horizontal sandstone cores ever taken. The well was completed open-hole using 4" slotted liner and equipped with 2-7/8" tubing and packer. The well was flow tested up to a 12 mmcf/d rate, one of the highest gas flow capacities ever encountered in the tight-gas province of the Cretaceous Frontier formation in Wyoming.

The RI-4H encountered reservoir sand that is dominantly massive to hummocky cross-stratified, very-fine grained, nearshore marine (lower shoreface) sandstone, with about 10% porosity, 25 microdarcies permeability, and is highly fractured. Fractures in the vertical GU #4 core and the horizontal RI-4H core indicate a shear displacement with a dominant strike orientation ranging from 80 to 110 degrees. The fractures are open to partially filled with calcite, quartz, kaolinite and bitumen. Open fractures which strike east-west occur along the entire length of the well, as observed in the core and microresistivity image log data.

Since May 13, 1999 the RI-4H has been flowed to a gas sales pipeline at an average rate of 14 mmcf/d for its first full month of production. The success of the UPR Rock Island 4-H well is anticipated to spark a renewed drilling effort by industry in the deep Frontier Greater Green River Basin. Horizontal drilling is attractive because it allows large well spacings, making per well recoveries larger and greatly reducing environmental impact. Union Pacific Resources is initiating plans to organize operators and leaseholders to form a Federal Unit to efficiently develop this play. Further testing of advanced drilling and stimulation techniques will occur as industry works to optimize technological and economic solutions. This project underscores the value of government and industry research partnerships aimed at solving challenging problems.

Contract No.DE-AC21-95MC31063
Greater Green River Basin
Production Improvement Project



- Lee Krystinik, UPR Geologist and Principal Investigator
- Frank Lim, UPR Engineer and Contract Administrator

- Gary Covatch, FETC Engineer
- Tom Mroz, FETC Geologist



Rock Island 4-H
Table Rock Field, Frontier Formation

PROJECT OBJECTIVE (TARGET)

*** REDUCE TECHNICAL RISKS and
ECONOMIC UNCERTAINTY to
ENCOURAGE DEVELOPMENT of the
200 TCF GAS RESOURCE POTENTIAL**

*** LOCATED in the DEEP OVERPRESSURED,
FRONTIER FORMATION in the GREEN
RIVER BASIN of SOUTHWEST WYOMING**

METHOD (APPROACH) TO PROJECT

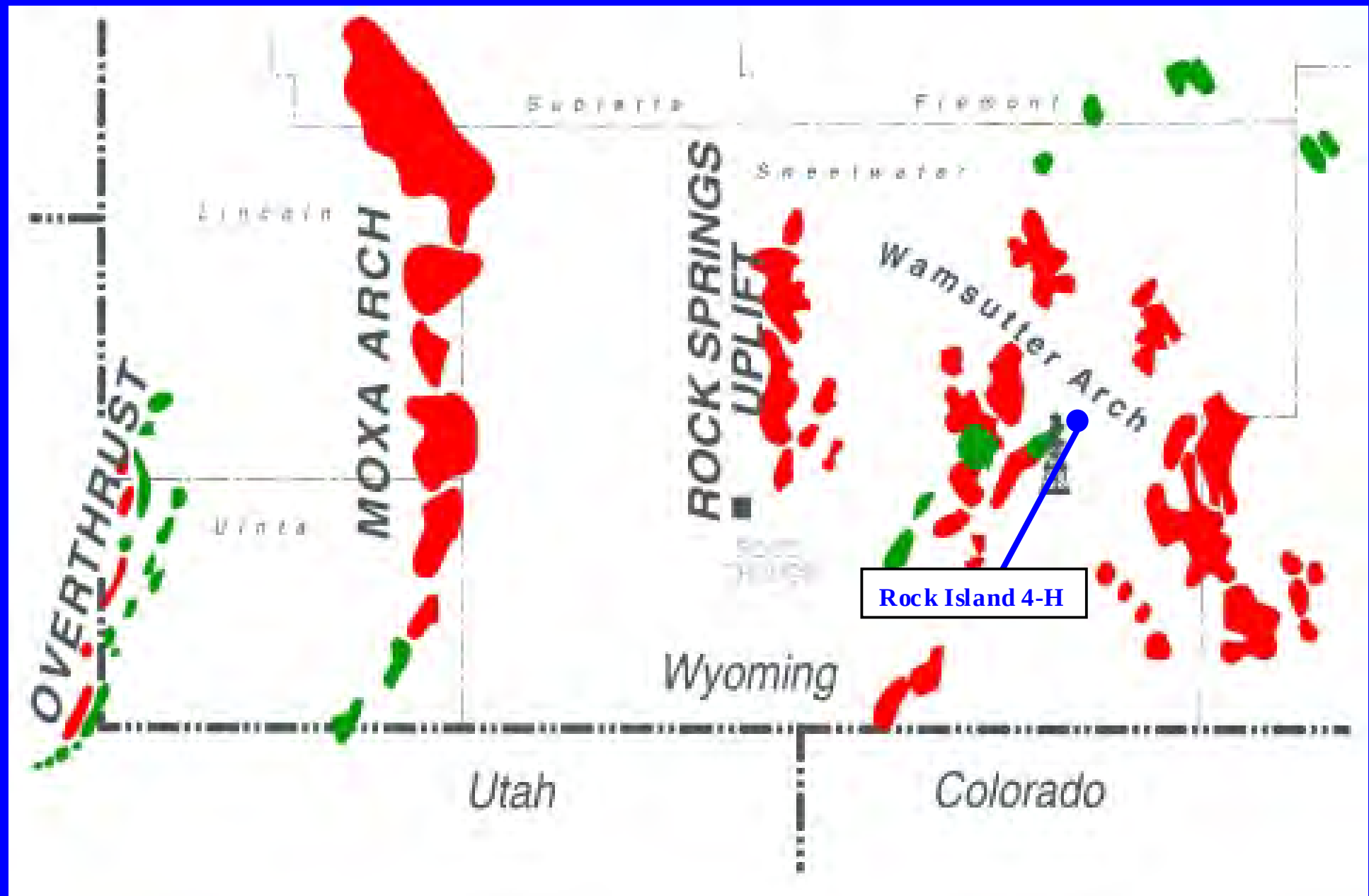
*** LOCATE and CHARACTERIZE “SWEET SPOTS” with
GOOD NATURAL FRACTURES and MATRIX PROPERTIES**

*** USE a VARIETY of METHODS including VERTICAL and
HORIZONTAL WELLS with HYDRAULIC FRACTURE
STIMULATION (as needed) while REDUCING COSTS**

*** USE CORING, LOGGING, and PRODUCTION TESTING
to DEMONSTRATE RESULTS of FIELD TESTING**

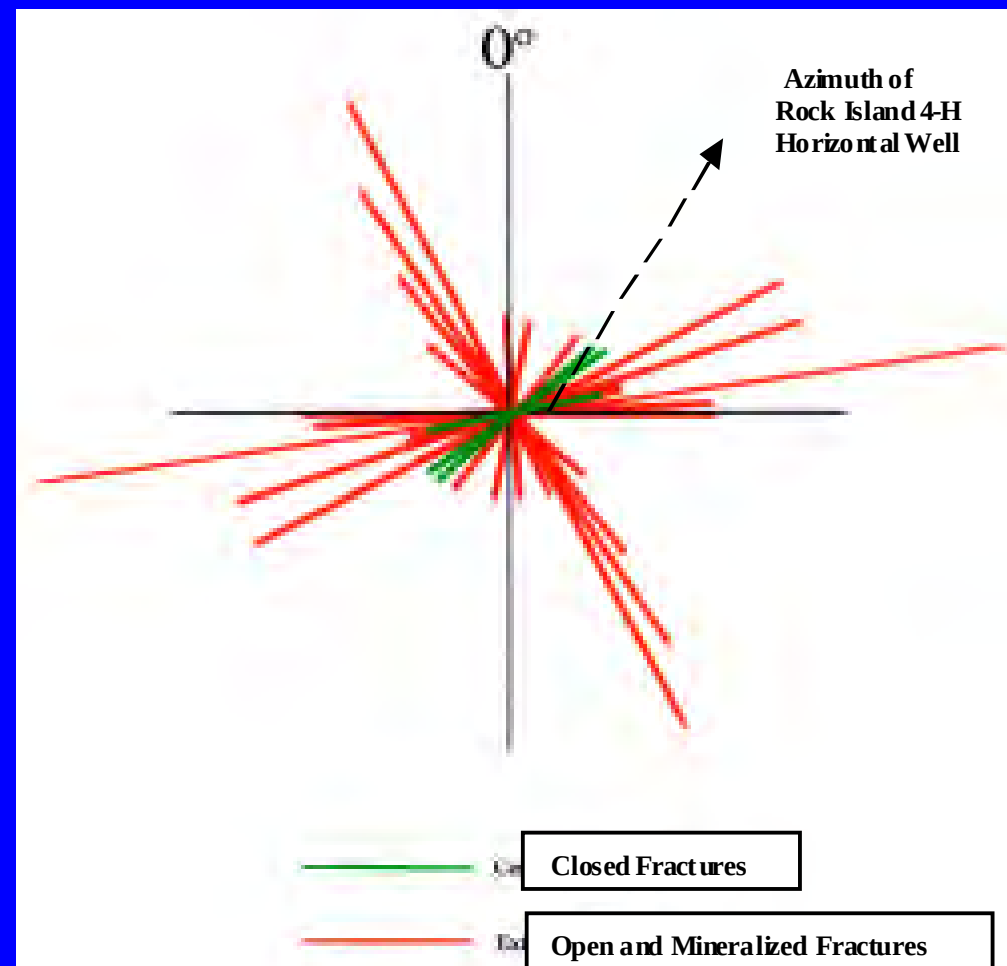
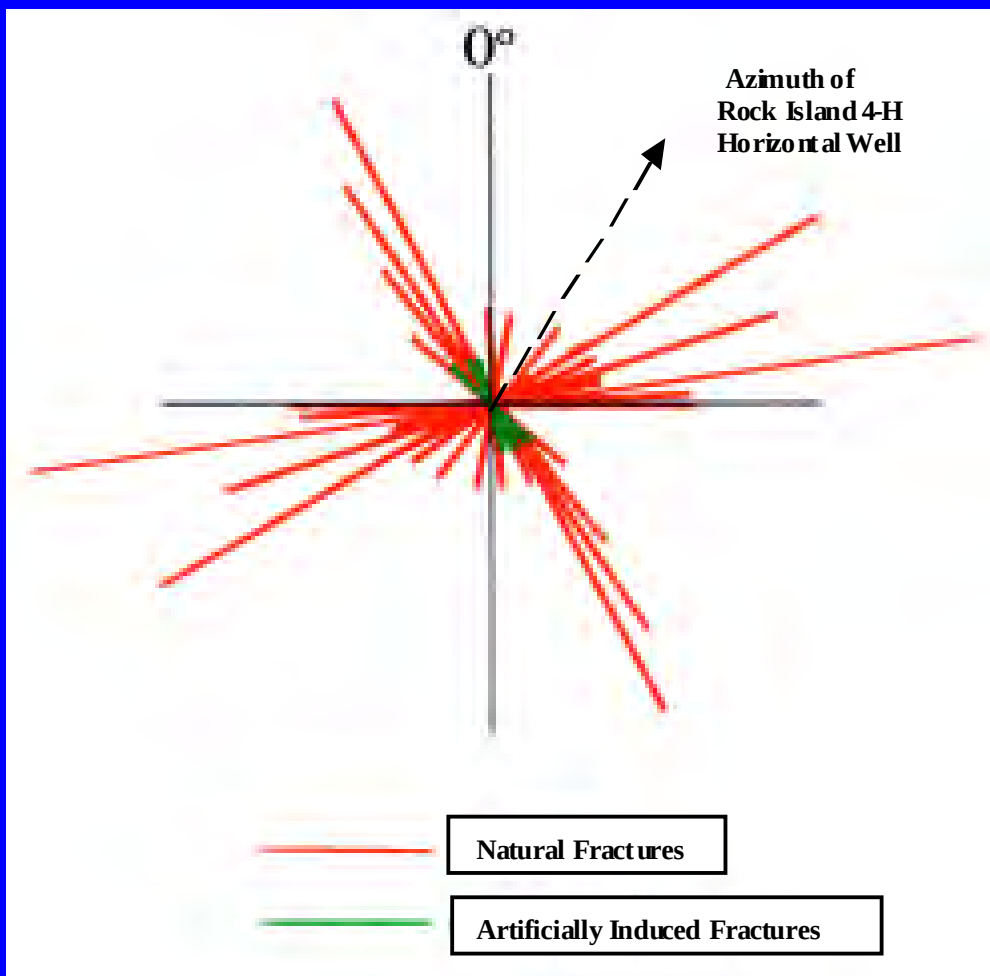
ROCK ISLAND 4-H WELL LOCATION (SW S4-T19N-R97W)

Major Oil and Gas Fields of SW Wyoming



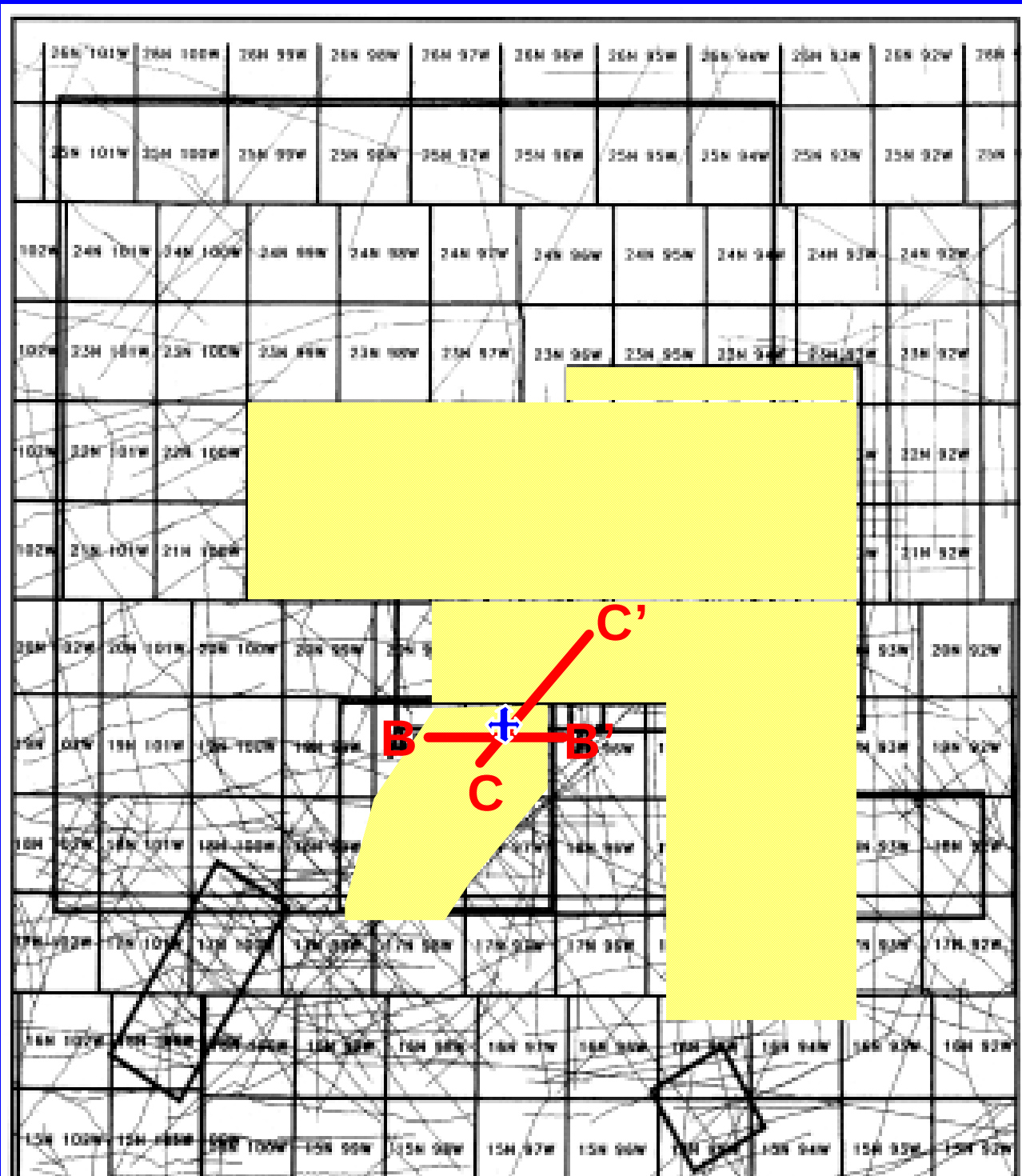
HORIZONTAL WELL PATH AZIMUTH NEEDED TO INTERSECT NATURAL FRACTURES

Fracture Orientations Govt. Union #4, Vertical Core

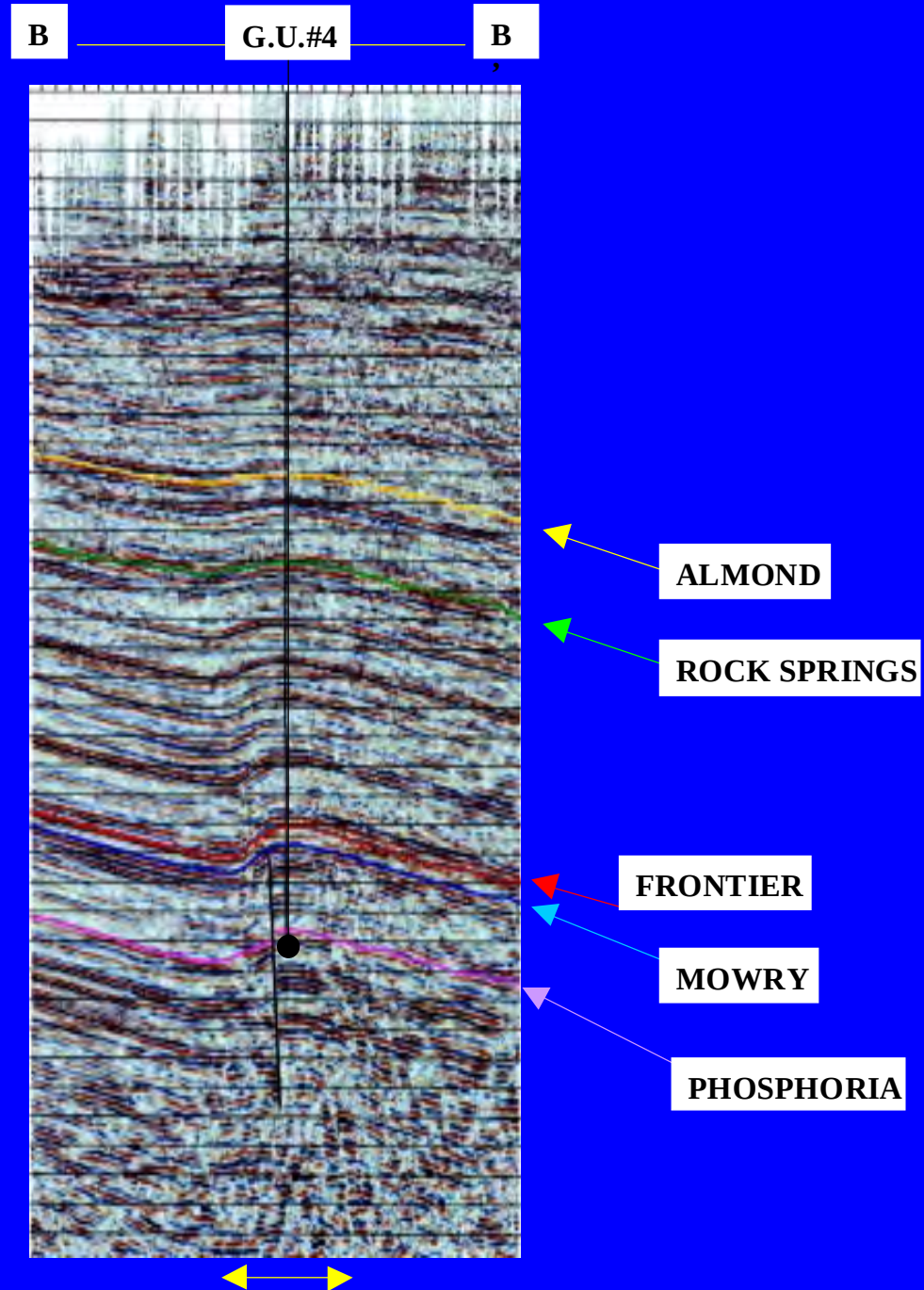


Seismic Site Selection of Rock Island 4-H Well Location

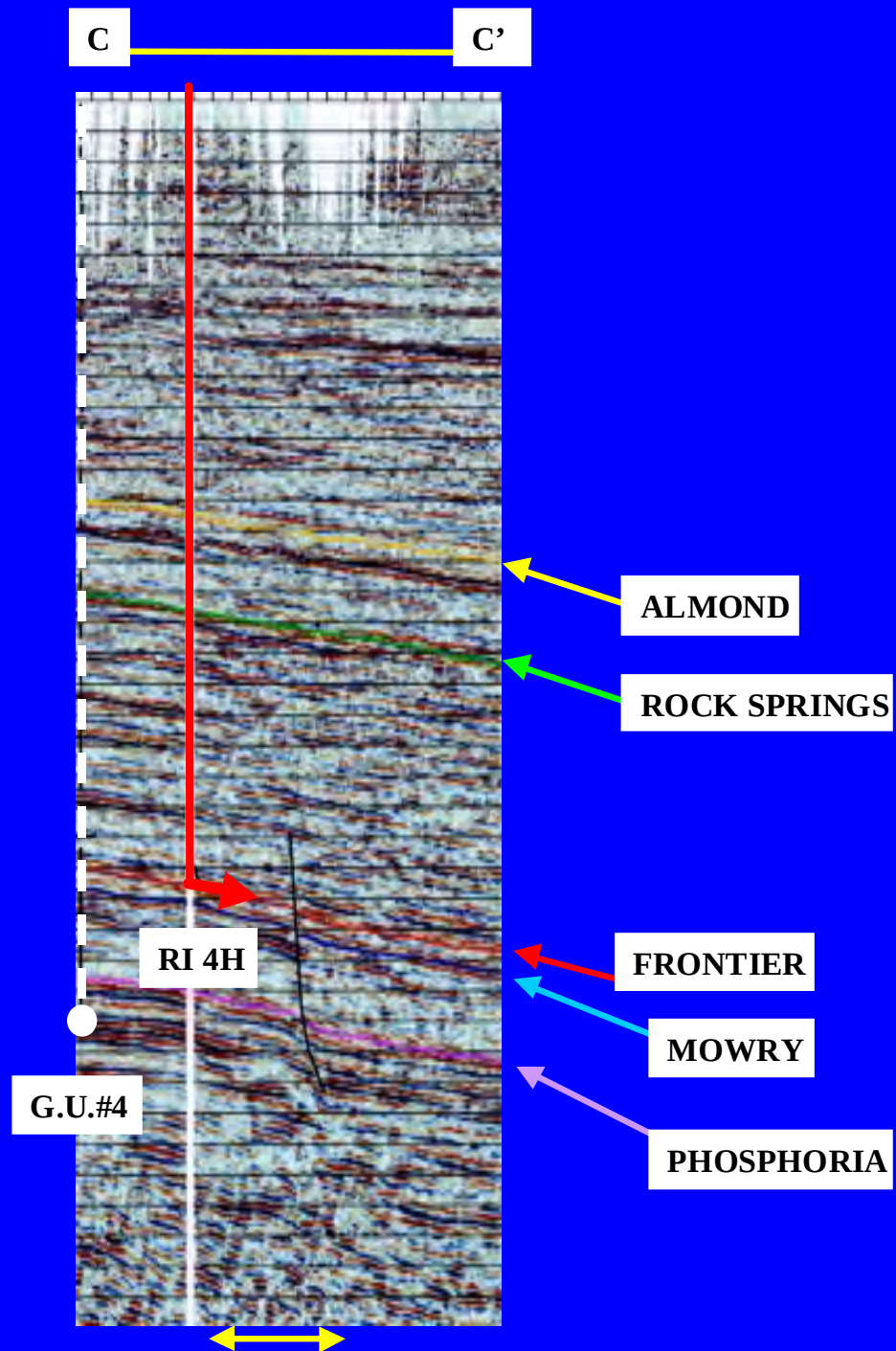
3-D Seismic Coverage of the Rock Island 4-H Project Area



Structural Dip Seismic Section Through the Govt. Union #4 Well



Well Path Seismic for the Rock Island 4-H Well



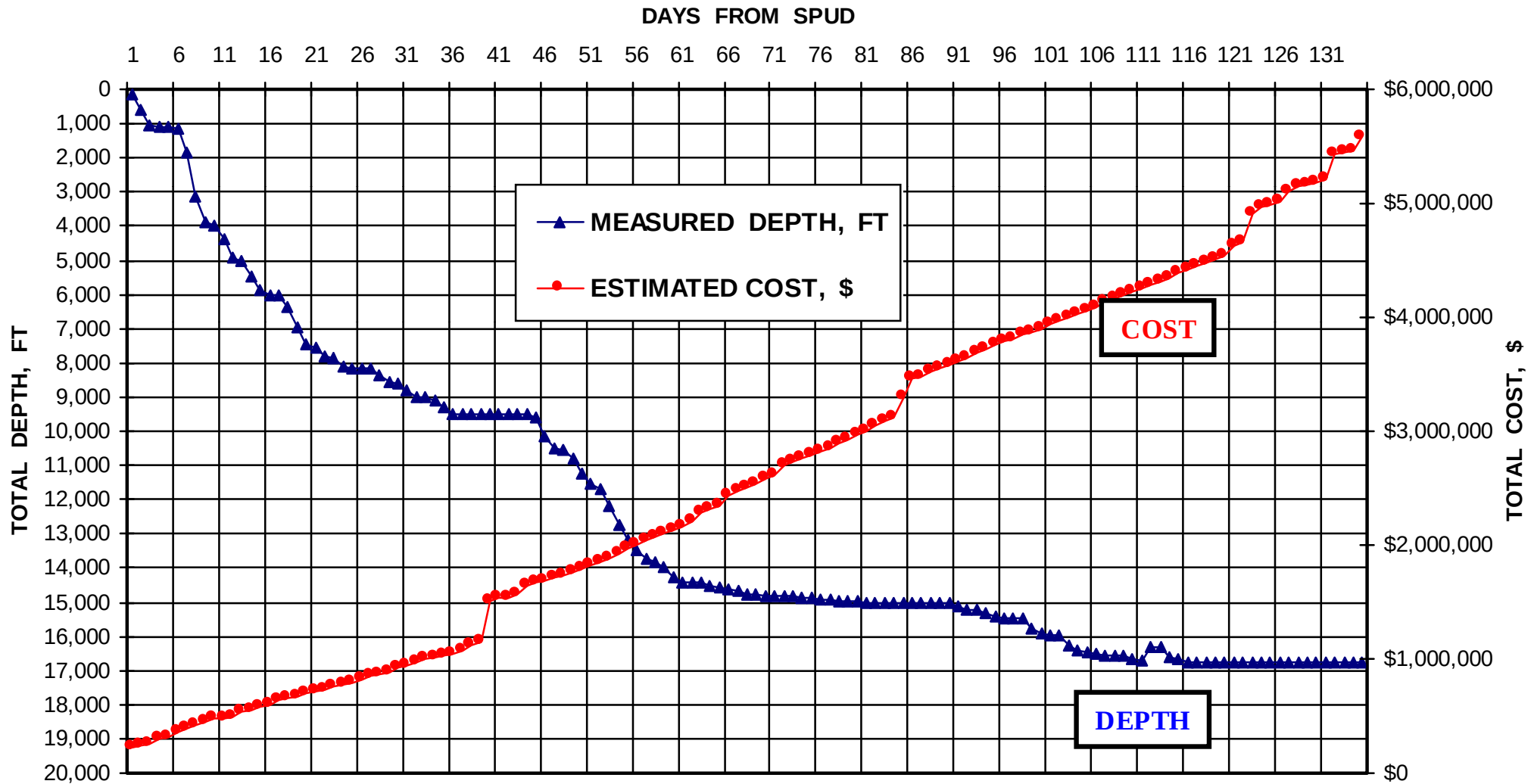
Rock Island 4-H, Parker #235 Drilling Rig



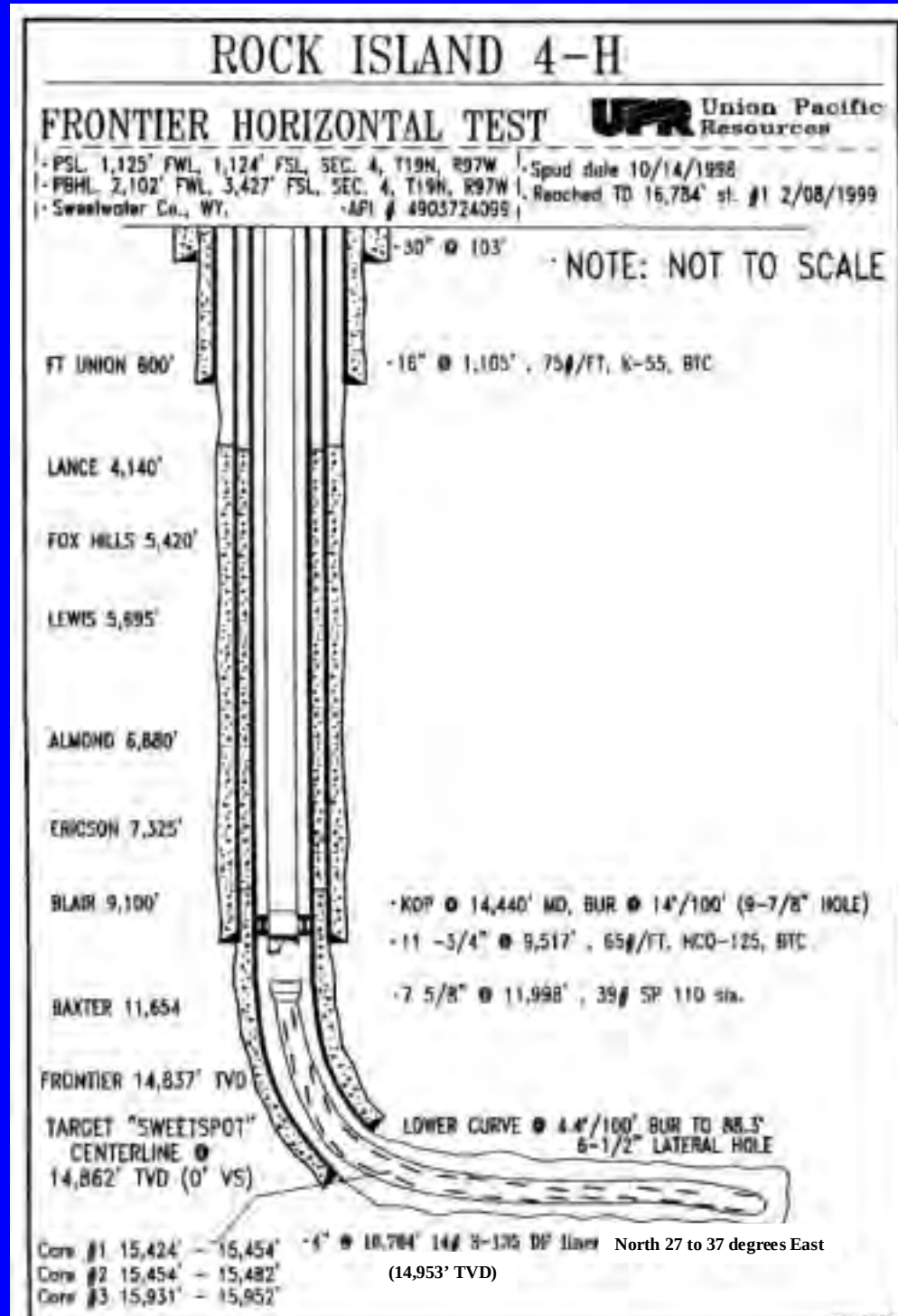
DRILLING DEPTH and COSTS vs. TIME

ROCK ISLAND 4-H - TOTALS to 2/25/99 REPORT (135 Days @ 16,784' & \$5,586,000)

Estimated
Cost



Wellbore Diagram



Chronological History of RI 4-H

Below is a Detailed Time Line of the Complete Well History:

10/14/98 to 11/22/98 Spud, Drill 14-3/4" Vertical to 9,517', Run 11-3/4" Casing

11/23/98 to 12/15/98 Drill 10-5/8" Vertical to 14,440' KOP (Kick Off Point)

12/16/98 to 01/08/99 Build 10-5/8" Curve to 15,025', Run 7-5/8" Liner

01/09/99 to 02/11/99 Drill 6-1/2" Horizontal Lateral to 16,784' (Core and Log)

02/12/99 to 02/24/99 Run 7-5/8" Tie-back Liner from 8,217' to Surface

Run 4" Perforated Liner in Lateral from 14,510' to 16,784'

Run 2-7/8" Tubing to 14,490' with packer set at 14,446'

**02/25/99 Flow Well to Pit 6 hours for Initial Wellbore Cleanup,
(100' Flare at 11/64 choke and 5600psi FTP)**

**03/02/99 to 03/09/99 Flow Well through Separator Test Metering Equipment,
(Rates Measured up to 12 MMCFD)**

**03/13/99 to 03/14/99 Run 4-Point Conventional Flow Test 6, 8, 10, & 12 MMCFD
(26 MMCF Cumulative Gas Produced 3/6/99 to 3/14/99)**

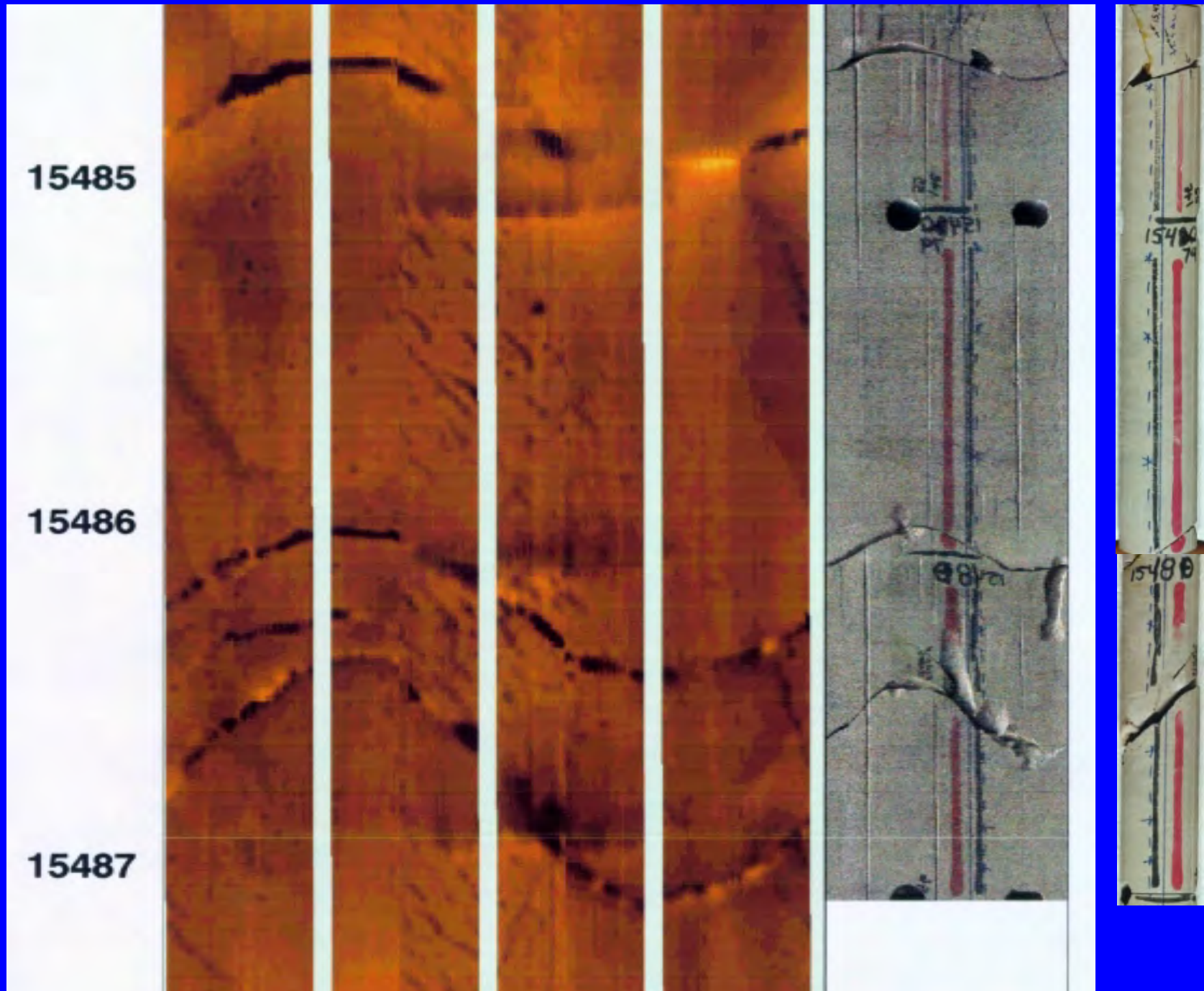
03/14/99 to 03/25/99 Run Shut-in, Bottomhole Pressure Build-up (9,650psi BHP)

03/26/99 to 05/12/99 Well Shut-in Waiting on Pipeline Connection

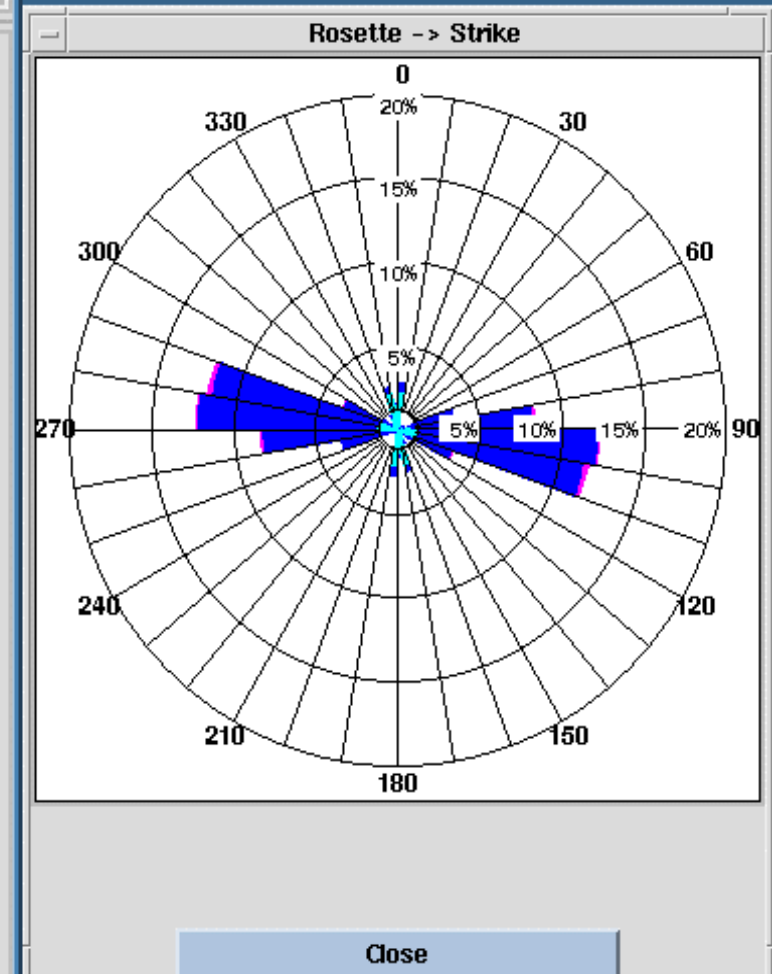
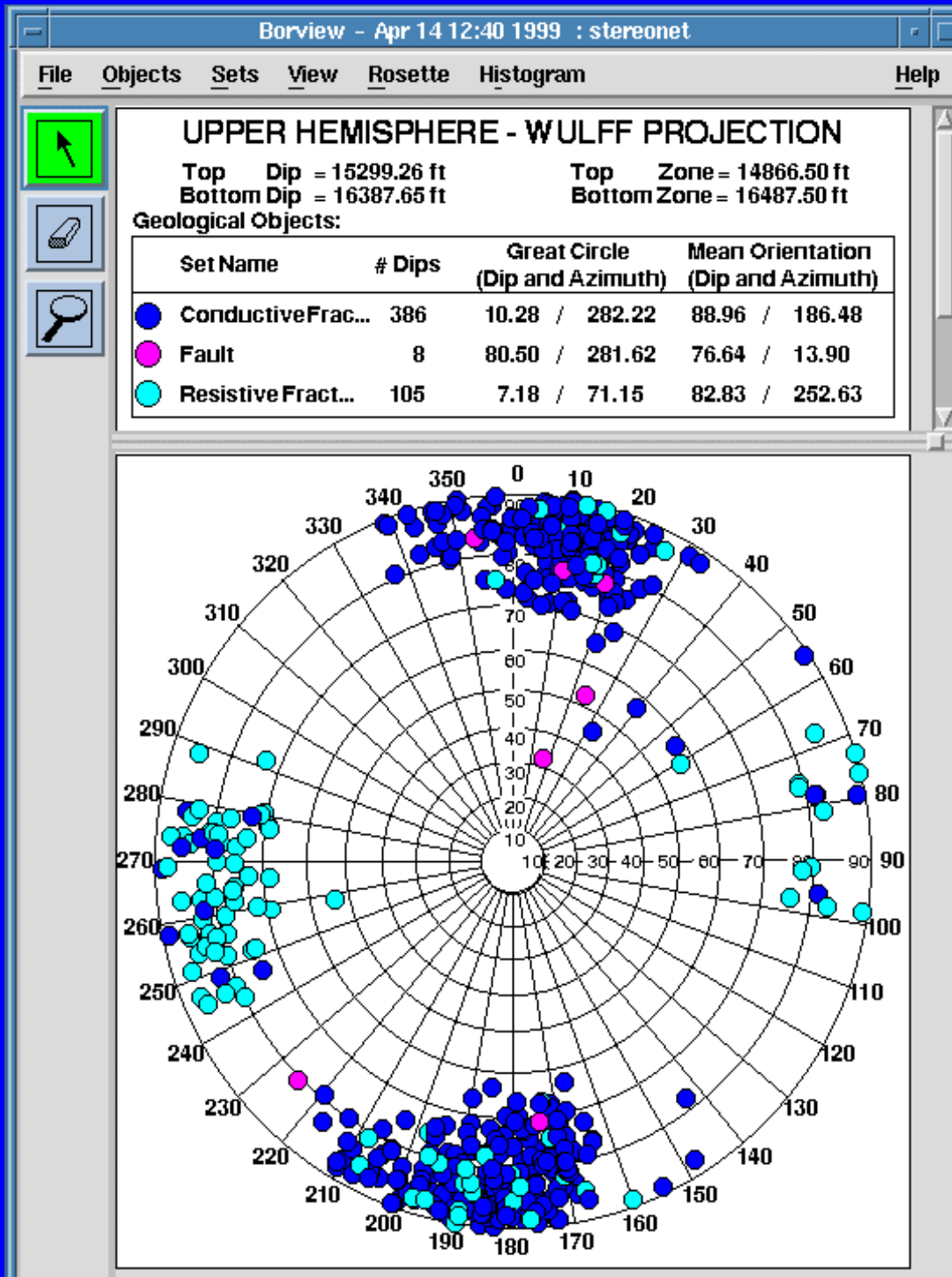
05/13/99 Well Open to Gas Sales at 12 MMCFD Initial Rate

FMI (Formation Micro-Imaging)
LOG USED TO
CHARACTERIZE FAULT AND
NATURAL FRACTURE DATA

Horizontal FMI and Core Comparisons Show Good Correlation of Natural Fractures



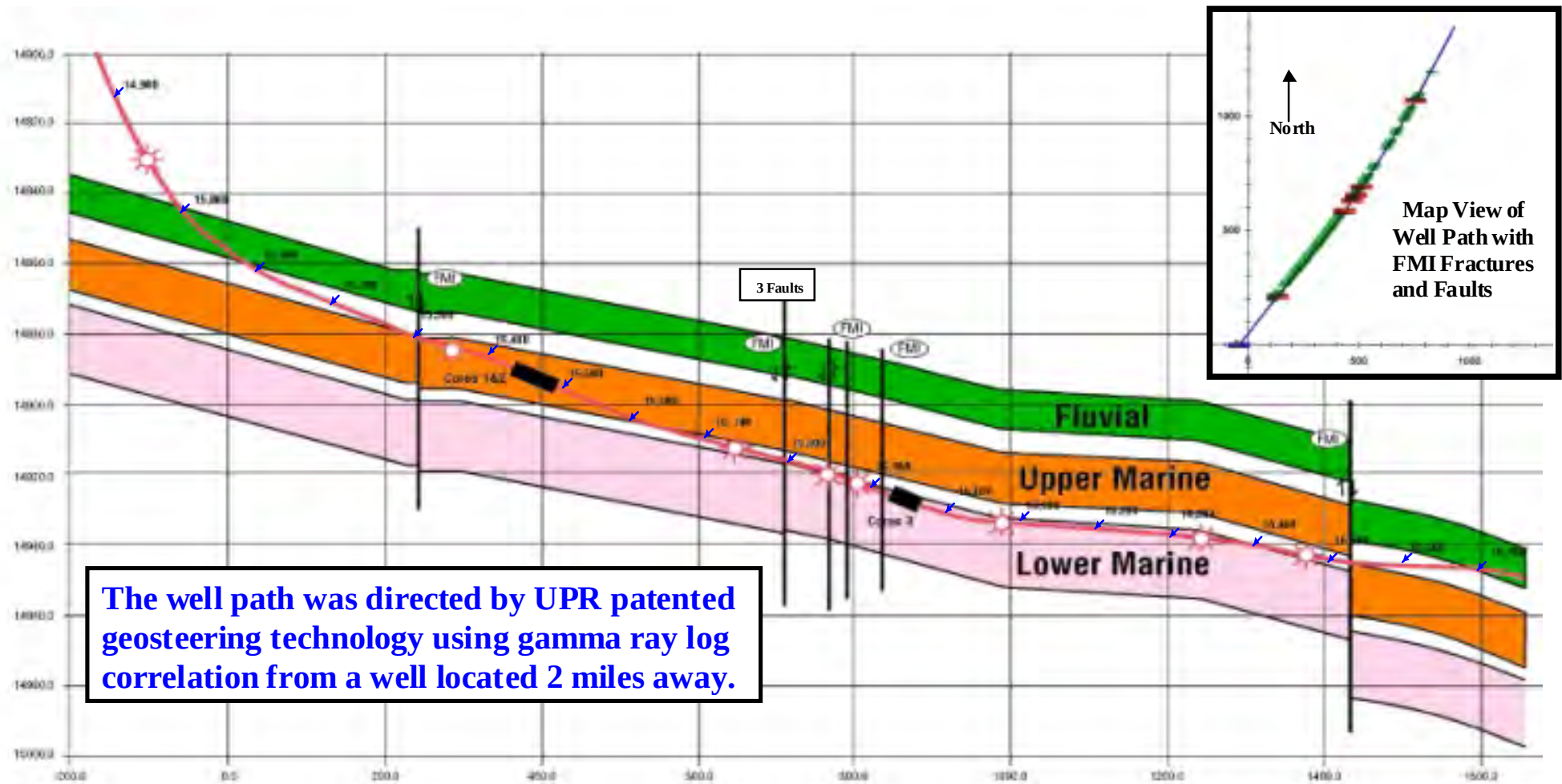
FMI Stereonet and Rose Diagrams



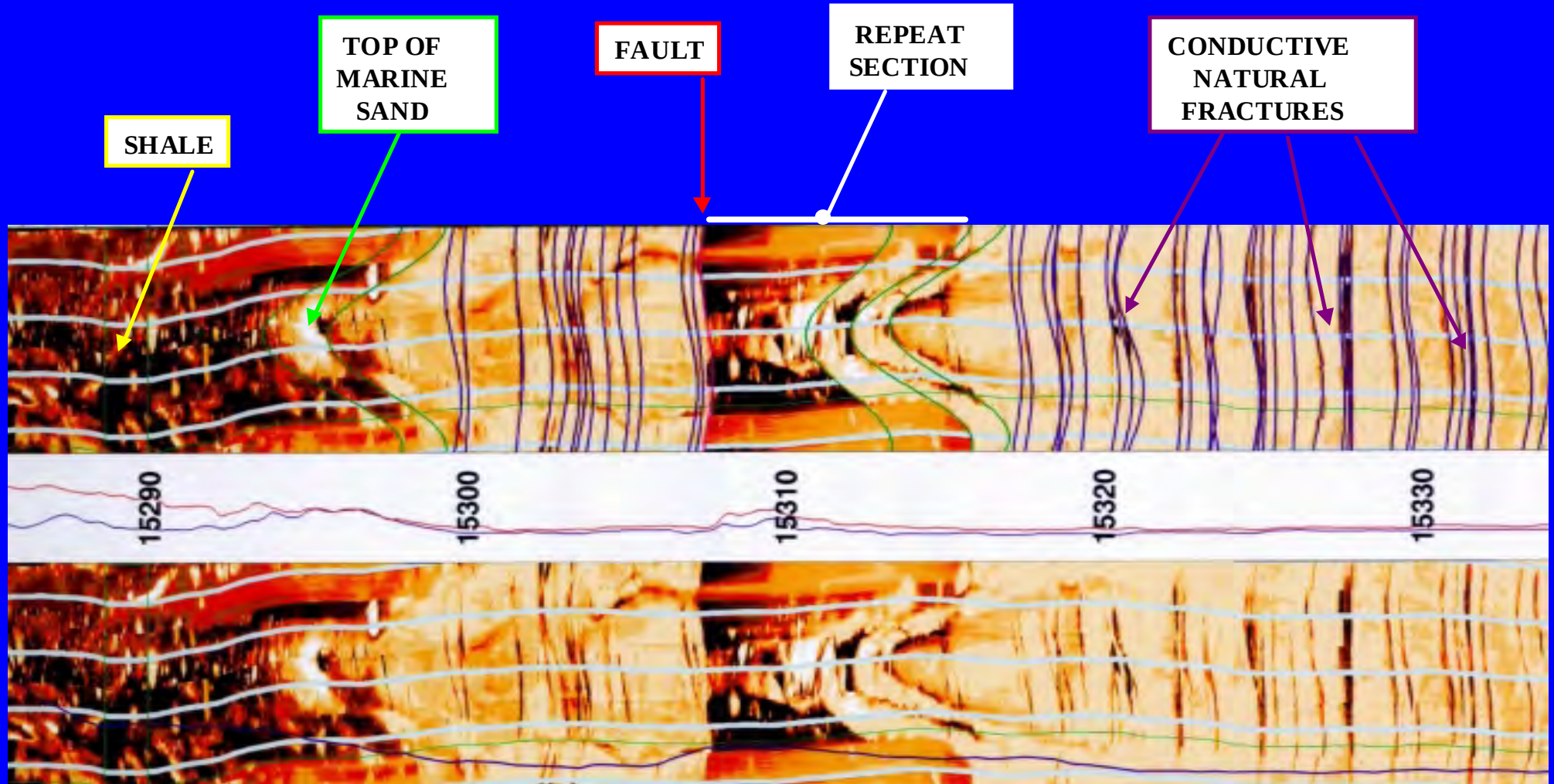
RI 4-H Geosteering Results of Horizontal Lateral

(Post-Drilling, Integrated Geologic Interpretations using FMI and Drilling Data with UPR Geosteering Process)

(Used in April 26, 1999 GRI Presentation in Denver with Updates 5/4/99 for Corrections)

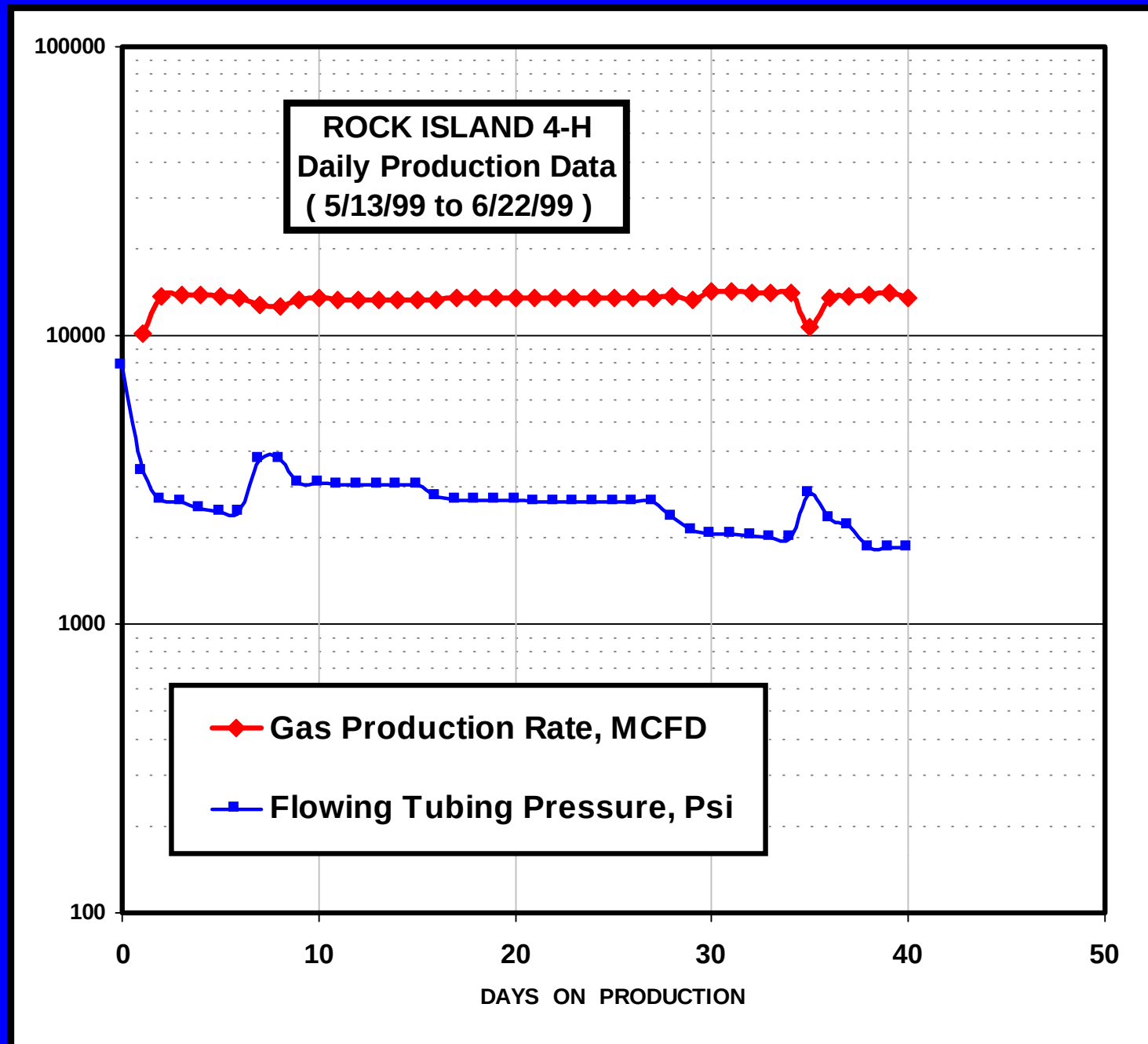


FMI Log of 15,290'-15,330' Horizontal Section



SUMMARY OF PROJECT RESULTS
TO DATE

ROCK ISLAND 4-H PRODUCTION DATA



SUCCESSFULLY DRILLED 1,750' HORIZONTAL LATERAL

(14,973' TVD in FRONTIER MARINE TARGET SAND)

FMI LOG IDENTIFIED GOOD FRACTURE SYSTEM

(386 CONDUCTIVE FRACTURES and 8 FAULTS)

GOOD MATRIX PROPERTIES from LOGS and CORES

(10% POROSITY and 0.025 MD PERMEABILITY)

GOOD PRODUCTION RESULTS from NATURAL COMPLETION

(AVG 14 MMCFD RATE after 40 DAYS PRODUCTION)

*** ADDITIONAL HORIZONTAL WELLS PLANNED by
NUMEROUS PARTICIPANTS to DEVELOP and EXTEND
the PLAY THROUGHOUT the GREEN RIVER BASIN**

Low Cost Methods for Finding Tight Gas, Gas Shales and Coalbed Methane

by

Vello A. Kuuskraa (vkuuskraa@adv-res.com; (703) 528-8420)
Dr. David J. Campagna (dcampagna@adv-res.com; (703) 528-8420)
Advanced Resources International, Inc.
1110 North Glebe Road, Suite 600
Arlington, VA 22201

Abstract

Finding highly productive “sweet spots” in otherwise low permeability sand, shale and coal reservoirs involves delineating areas where natural fractures and gas charged, quality pay coexist. While there is general agreement that finding intense, open sets of natural fractures is essential, accomplishing this ahead of drilling has proven to be a major technical challenge. This paper discusses one approach undertaken by Advanced Resources to address this challenge.

Basic Technology. To advance the state of the art in natural fracture detection and prediction technology, a field-based R&D project was undertaken by Advanced Resources International (ARI) and Barrett Resources for DOE/FETC’s Low-Permeability Natural Gas Program.

The project originated at Rulison Field, Piceance Basin, Colorado and was subsequently applied to neighboring Mamm Creek Field. An integrated geological and geophysical approach proved to be successful in delineating areas with intense, open natural fractures in the tight, massively stacked Mesaverde (Williams Fork) lenticular sands:

- ! The starting point was a thorough examination of the structure and geology of the basin and the prospect area.
- ! Second, regional reconnaissance using Landsat Thematic Mapper (TM) and side-looking airborne radar (SLAR) data was used to identify fault-related geomorphic linears.
- ! Next, the basin was high-graded using data from a high-resolution aeromagnetic survey to identify regional prospects and trends related to basement faults.

Following the regional analysis, a 3-D, P-wave, multi-azimuth seismic survey was shot in the Rulison Field. The results of the 3-D survey were integrated with available 2-D seismic lines to map the nature, orientation and displacement of the thrust-related faults in the Williams Fork Formation. This data served as input to ARI’s Geomechanical Model, FSD (Fault Stressed Domains), that was used to delineate areas (“envelopes”) with fault related natural fracture clusters that provide enhanced permeability, essential for highly productive gas wells.

Field Tests. Two areas of the Rulison Field were selected for calibrating and testing the natural fracture mapping methodology and geomechanical model, North Rulison (the site of the 3-D survey) and South Rulison (a lightly drilled step-out area).

After calibrating the natural fracture detection technology in the North Rulison Test Area, the “before-drilling” field test of the technology was performed at South Rulison. At the time of the test, only a small number of mostly older wells had been drilled in the 20 section South Rulison field area.

Results. The well performance at South Rulison, for the wells drilled inside and outside the geomechanical model projected naturally fractured envelope, is tabulated and discussed below:

- ! The 12 wells drilled inside the naturally fractured envelope have EURs of 3.4 Bcf/well, three times better than the 1 Bcf/well average for the 23 wells drilled outside the envelope.
- ! The average net pay for the inside and outside the envelope wells is essentially the same, confirming that natural fractures provide the control on well performance.

Results of South Rulison Natural Fracture Detection Technology Test

	Wells Inside Naturally Fractured Envelope	Wells Outside Naturally Fractured Envelope
No. Wells	12	23
Average EUR/Well	3.4 Bcf	1.0 Bcf
Average Permeability (md)	17	6
Average Net Pay (ft)	266	224

Similarly, positive results were achieved at the Mamm Creek Field test site in the Piceance Basin.

Recently, the methodology was applied to Table Rock Field prior to the drilling of UPR’s Rock Island Unit #4-H horizontal Frontier Formation well in the Greater Green River Basin. The purpose of testing the geomechanical-based natural fractured technology was to confirm that a favorable natural fracture setting existed in the area and at the specific well site. Initial tests indicate that the Rock Island Unit #4-H well is capable of producing 12 to 20 MMcfd.

“Low Cost Methods for Finding Tight Gas, Gas Shales and Coalbed Methane”

By

Vello A. Kuuskraa

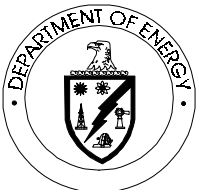
David J. Campagna

Advanced Resources International, Inc.

DOE-FETC Oil & Gas Conference, Dallas, Texas

Session 3A

June 30, 1999



Discussion Outline

- 1. Importance of Tight Gas, Gas Shales and Coalbed Methane**
- 2. The Exploration Challenge: Favorable Natural Fracture Settings**
- 3. Successful Case Studies**
 - *Southern Piceance Basin (Rulison)***
 - *Eastern Green River Basin (Table Rock)***



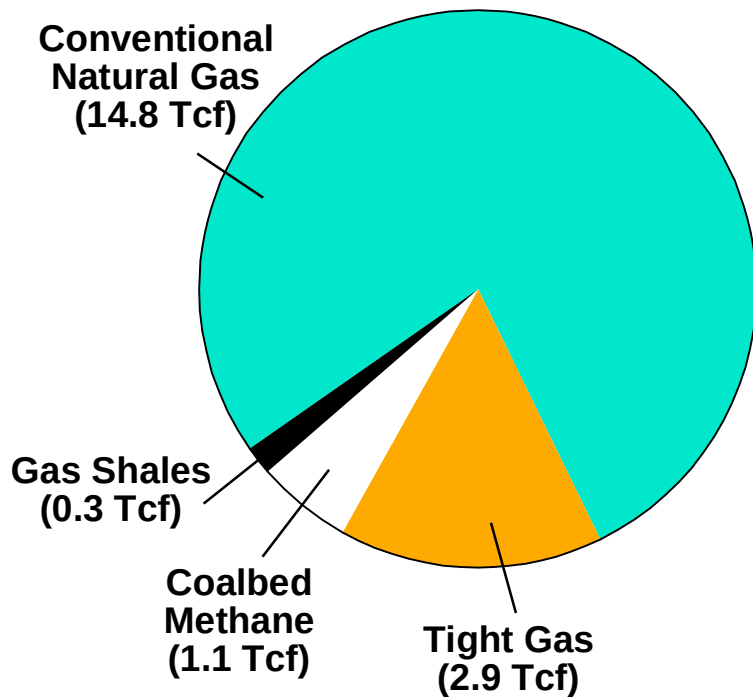
Importance of Tight Gas, Gas Shales and Coalbed Methane

- **Tight Gas, Gas Shales and Coalbed Methane are fastest growing part of gas supply:**
 - *23% of gas production*
 - *31% of gas reserves*
- **Seven of top eleven natural gas fields produce “unconventional gas”.**
- **Largest undeveloped portion of natural gas resource base.**



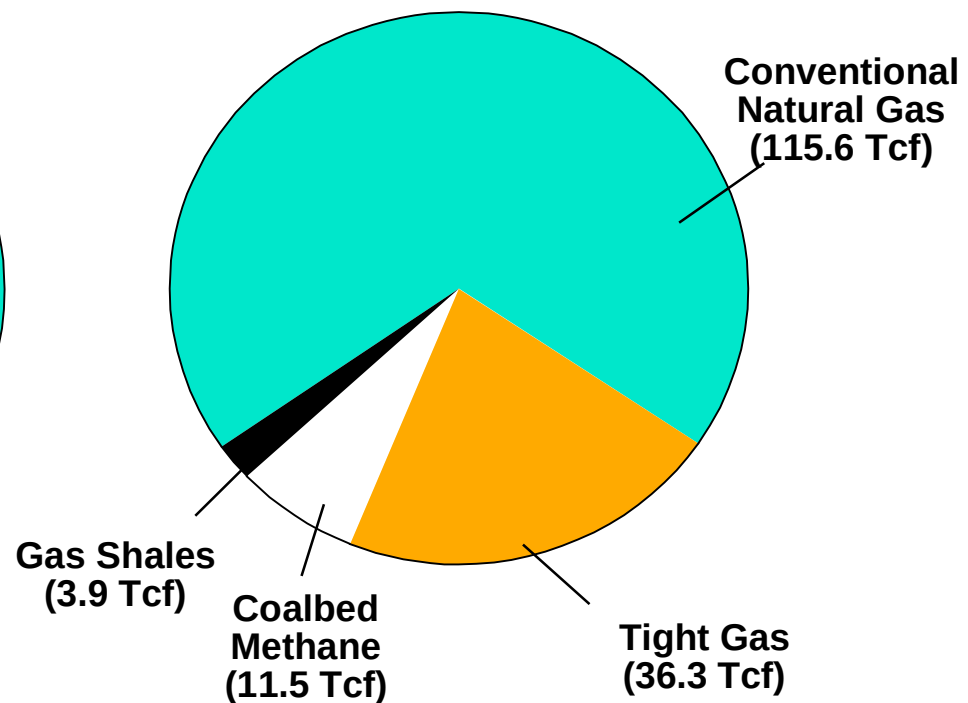
Tight Gas, Gas Shales and Coalbed Methane Are Already Essential Components of U.S. Natural Gas Supply

**23% of Total
Gas Production**



Total Production = 19.2 Tcf

**31% of Total
Gas Reserves**



Total Reserves = 167.2 Tcf



U.S. Natural Gas Fields Producing Tight Gas, Gas Shales and Coalbed Methane

Rank	Field	Basin	State	1997 Gas Production (Bcf)
1.	Basin	San Juan	NM	787
2.	Blanco	San Juan	NM/CO	606
4.	Giddings	Austin Chalk	TX	383
5.	Carthage	East Texas	TX	212
7.	Antrim	Michigan	MI	123
9.	Bob West	Gulf Coast	TX	106
11.	Wattenberg	Denver	CO	95

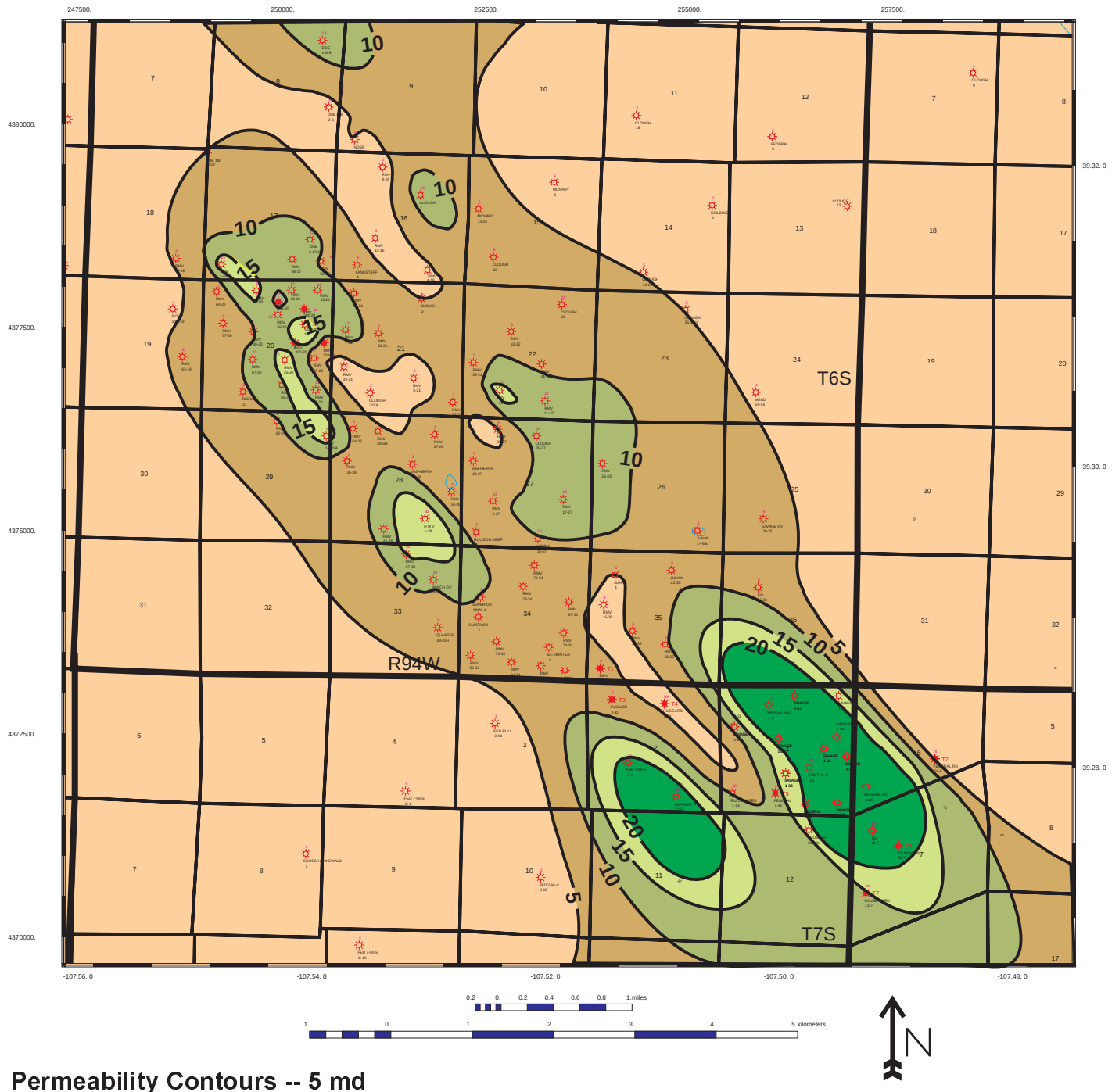


The Exploration Challenge

- Increase success by locating naturally fractured “sweet spots”, *prior to drilling.*
- Highly productive “sweet spots” occur where:
 - *Local natural fracture clusters overprint the regional natural fracture system.*
 - *Local natural fracture system coincides with thick, gas-charged pay.*



Map View of Williams Fork Reservoir Permeability, Rulison Field

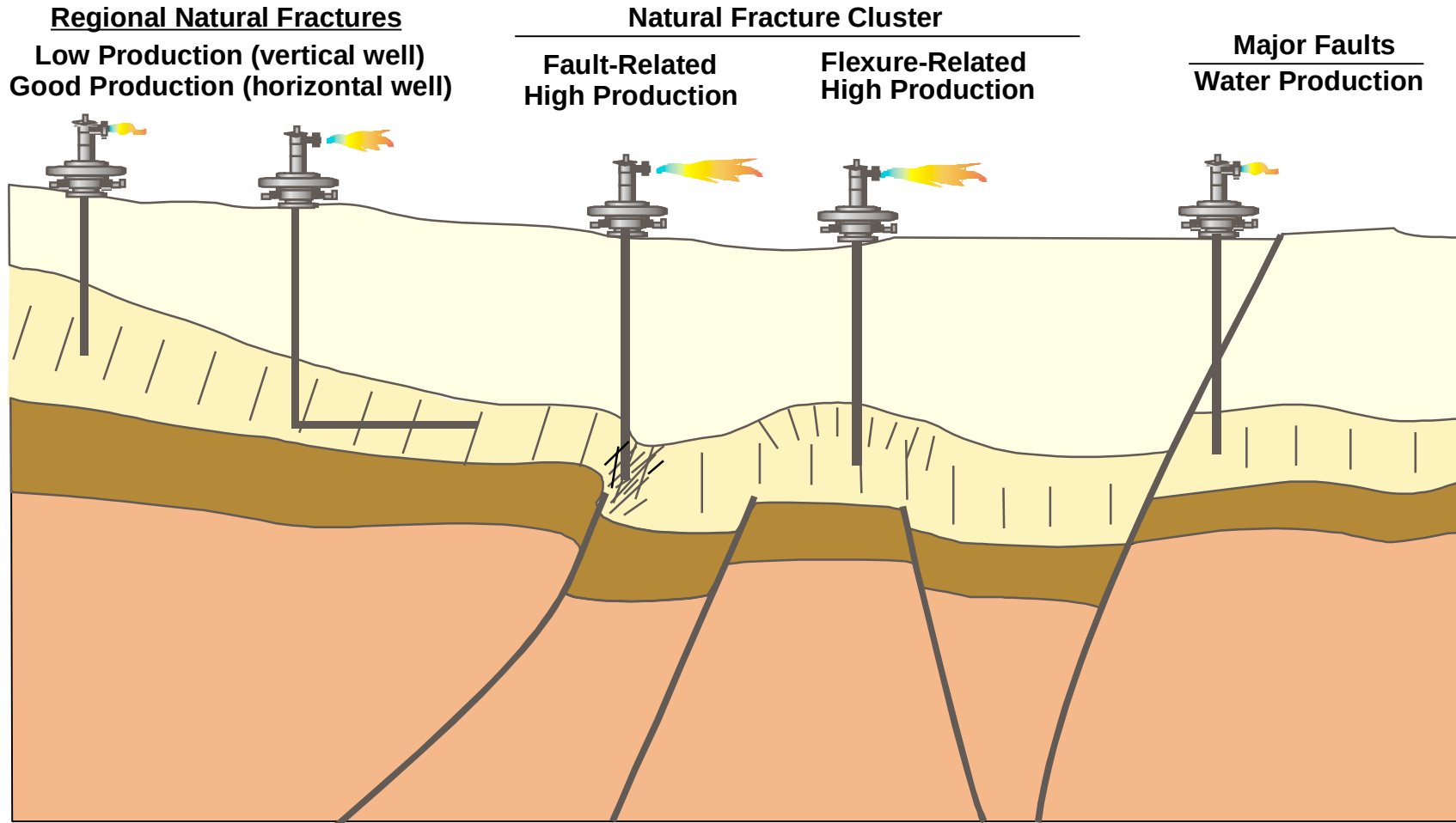


Distribution of Natural Fractures and “Sweet Spots”

- Local, one to ten sections in size, areas of fracture enhanced permeability exist in low-permeability reservoirs.
- These fault-related fractured areas can be located with seismic and geomechanical methods.
- The randomness of well behavior in fractured reservoirs is due to sampling not fundamental geology.



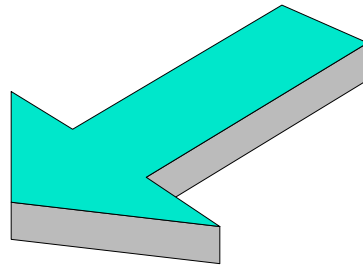
The Exploration Challenge: Finding Favorable Natural Fracture Settings



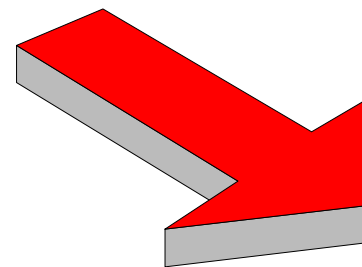
Fractured Reservoir Development Strategy

Basin and Regional High-Grading

*Remote Sensing for Surface Features
Gravity and High Resolution Aeromagnetics
Calibration with Subsurface Data*



Statistical/Step Out
Approach

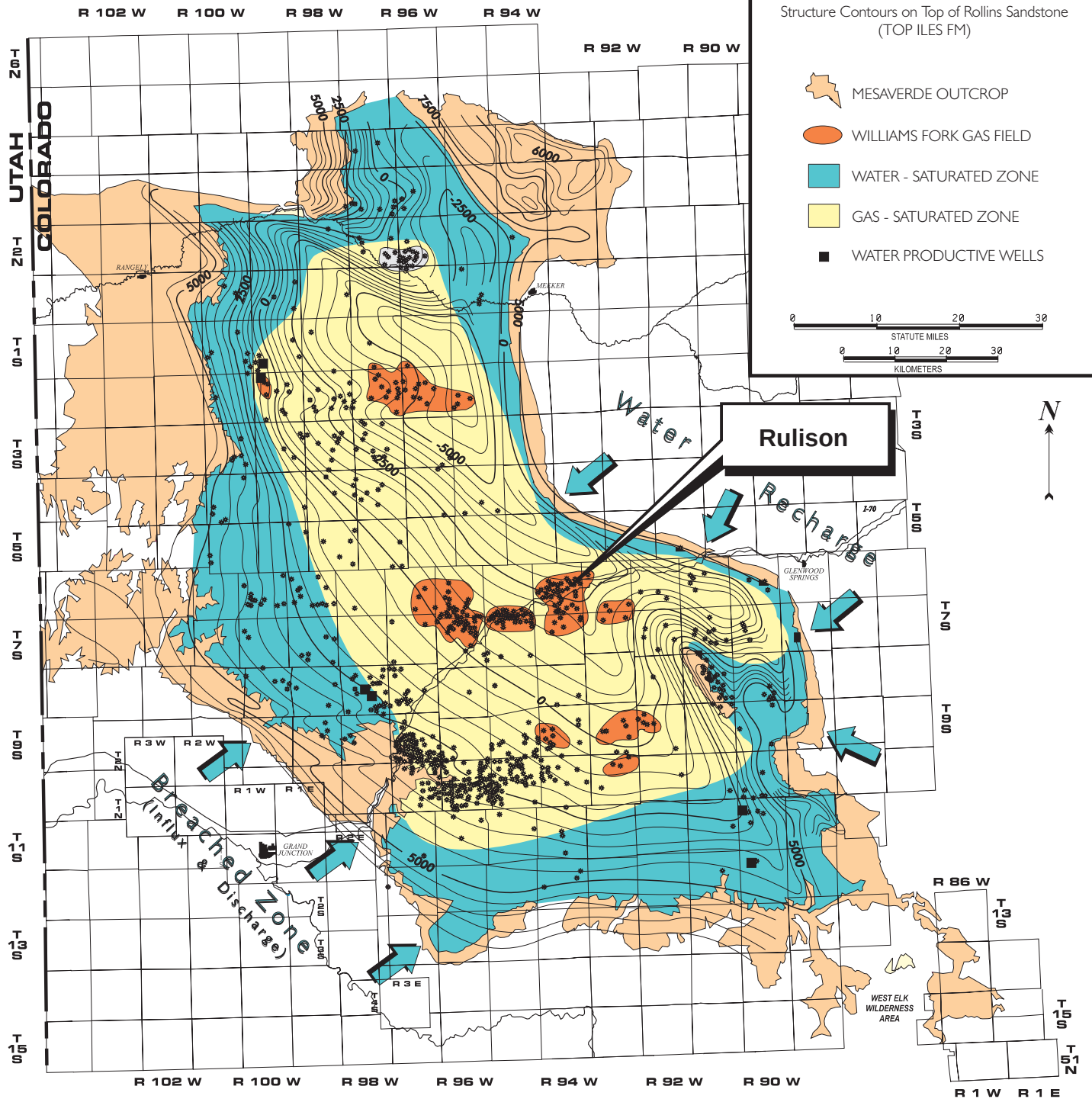


Prospect
Definition



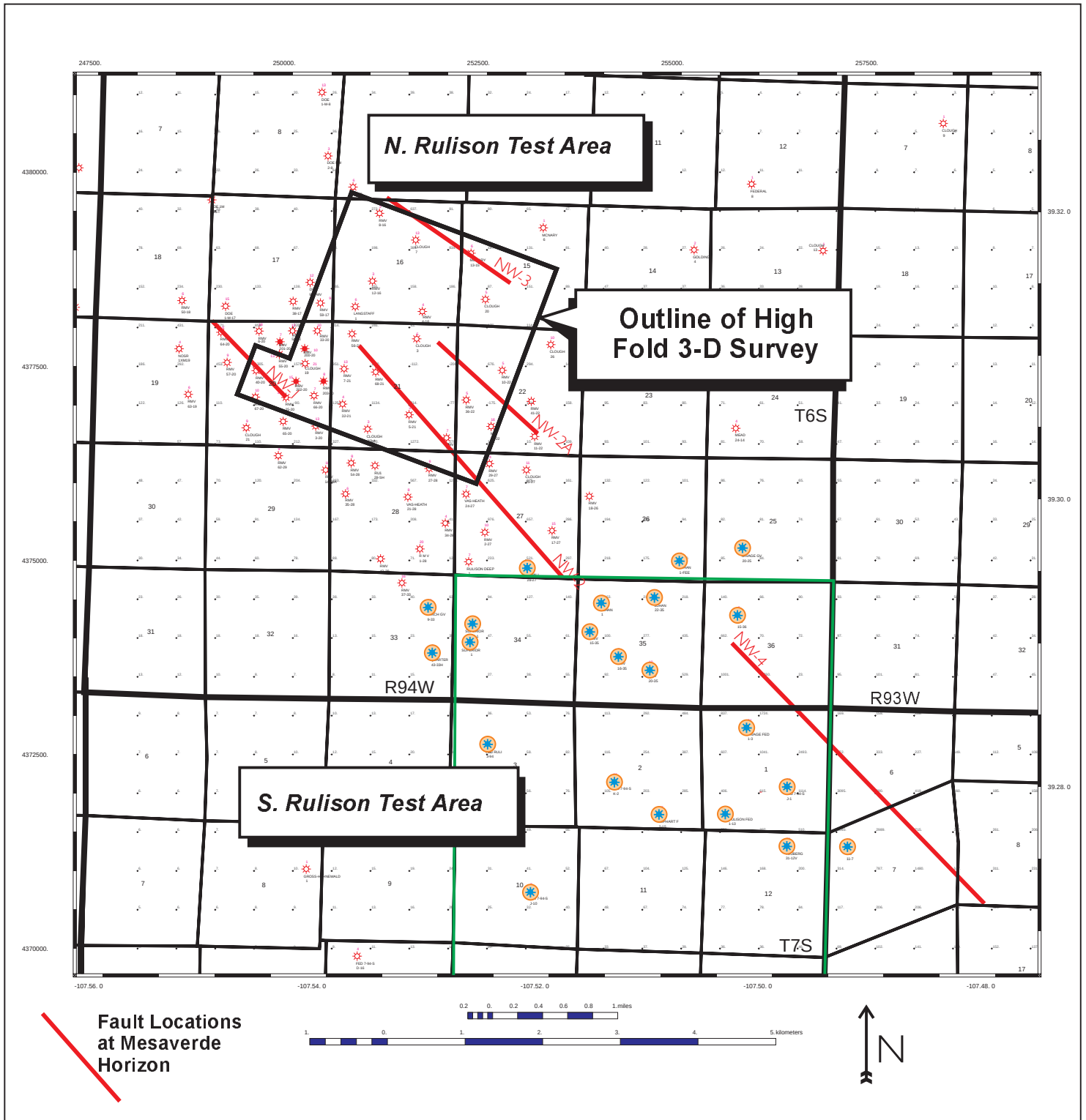
Rulison Field Case Study

Williams Fork Fm, Piceance Basin



North and South Rulison Test Areas and 3-D Seismic Survey

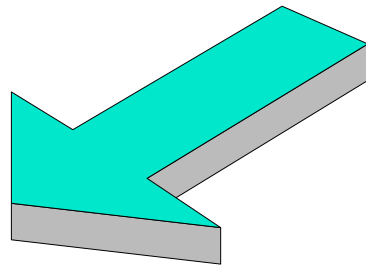
Development Objective (in mid-'96) was to Extend
the Rulison Field to the South-East



Fractured Reservoir Development Strategy

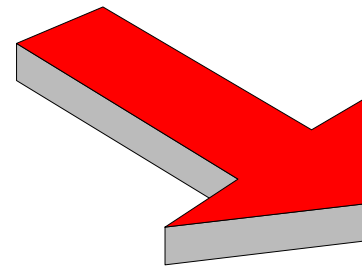
Basin and Regional High-Grading

*Remote Sensing for Surface Features
Gravity and High Resolution Aeromagnetics
Calibration with Subsurface Data*



Statistical/Step Out Approach

- Multiple Well Drilling Program

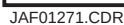


Prospect Definition

- Seismic
- Geomechanical Modeling



Dramatic Changes In Well Performance Are A Characteristic of the Williams Fork Fm



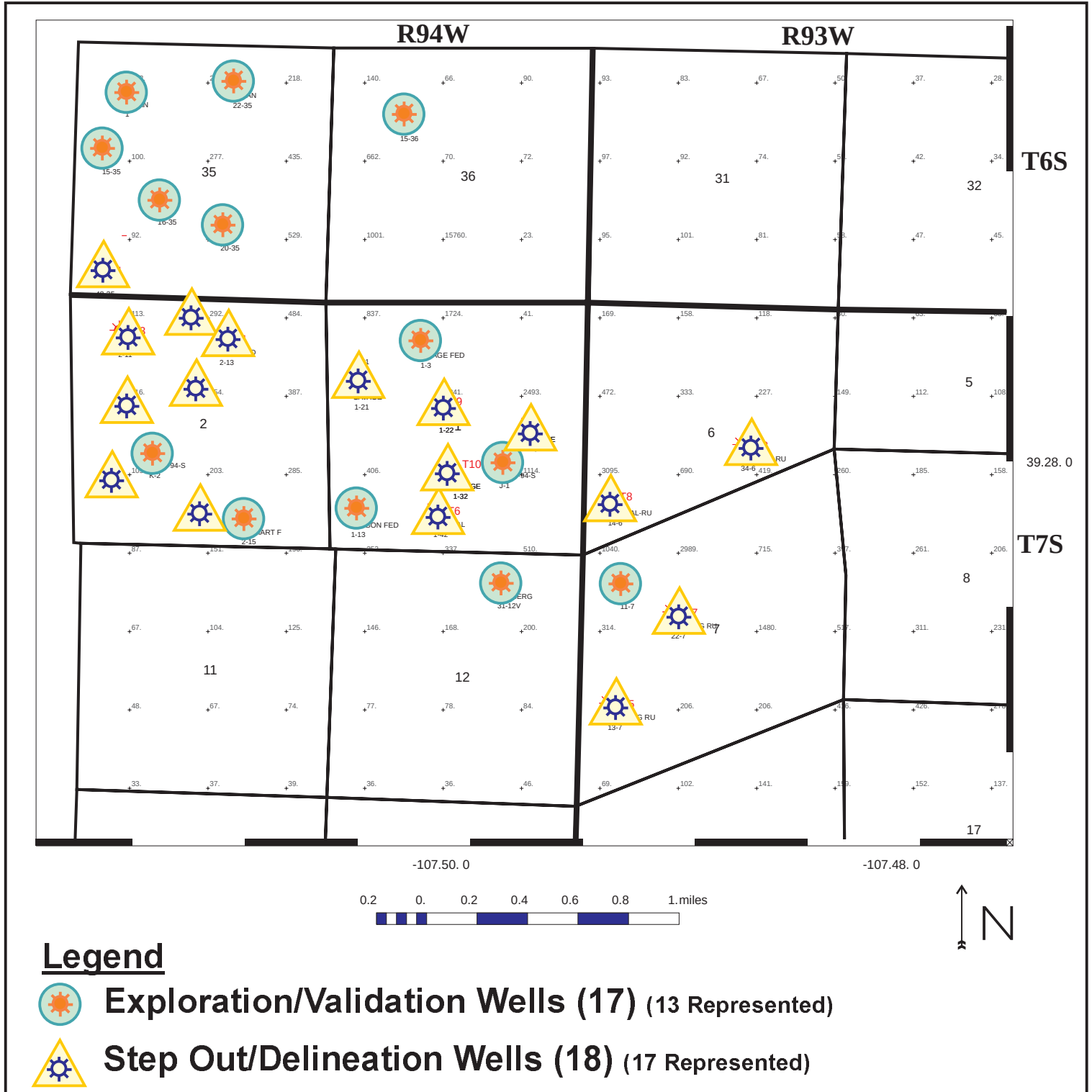
Performance of Three Closely Spaced Wells, S. Rulison Field

	Well #1 Fusilier 2-11 (Sec. 2, T7S, R94W) (Compl. 7/97)	Well #2 Savage Fed 1-3 (Sec. 1, T7S, R94W) (Compl. 2/95, Rec. 10/96)	Well #3 Federal RU 34-6 (Sec. 6, T7S, R93W) (Compl. 12/96)
EUR	0.9 Bcf	4.5 Bcf	0.3 Bcf
NET PAY	300 ft	322 ft	285 ft
Porosity	9.8%	10.60%	12.2%
Permeability	4 md	14 md	2 md



South Rulison Field, Piceance Basin

By Early '98, 35 Wells Completed Using
Statistical/Step Out Drilling



S. Rulison: Step Out Approach

1. Exploration and Validation

- ***17 wells (1990-96)***
- ***\$15.3 million****

2. Step Out and Delineation

- ***18 wells (1996-Present)***
- ***\$16.2 million***

3. Results:

- ***Reserves 63 Bcf***
- ***Total Costs - \$31.5 million***

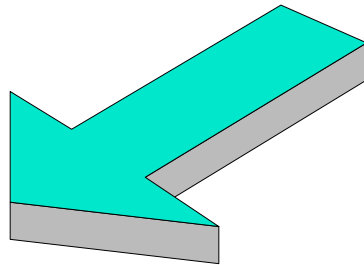
**Assuming \$0.9 million per well.*



Fractured Reservoir Development Strategy

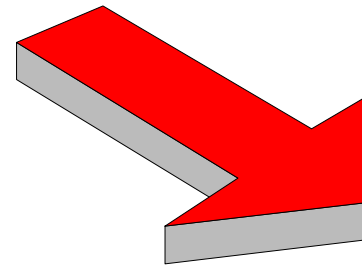
Basin and Regional High-Grading

*Remote Sensing for Surface Features
Gravity and High Resolution Aeromagnetics
Calibration with Subsurface Data*



Statistical/Step Out Approach

- Multiple Well Drilling Program



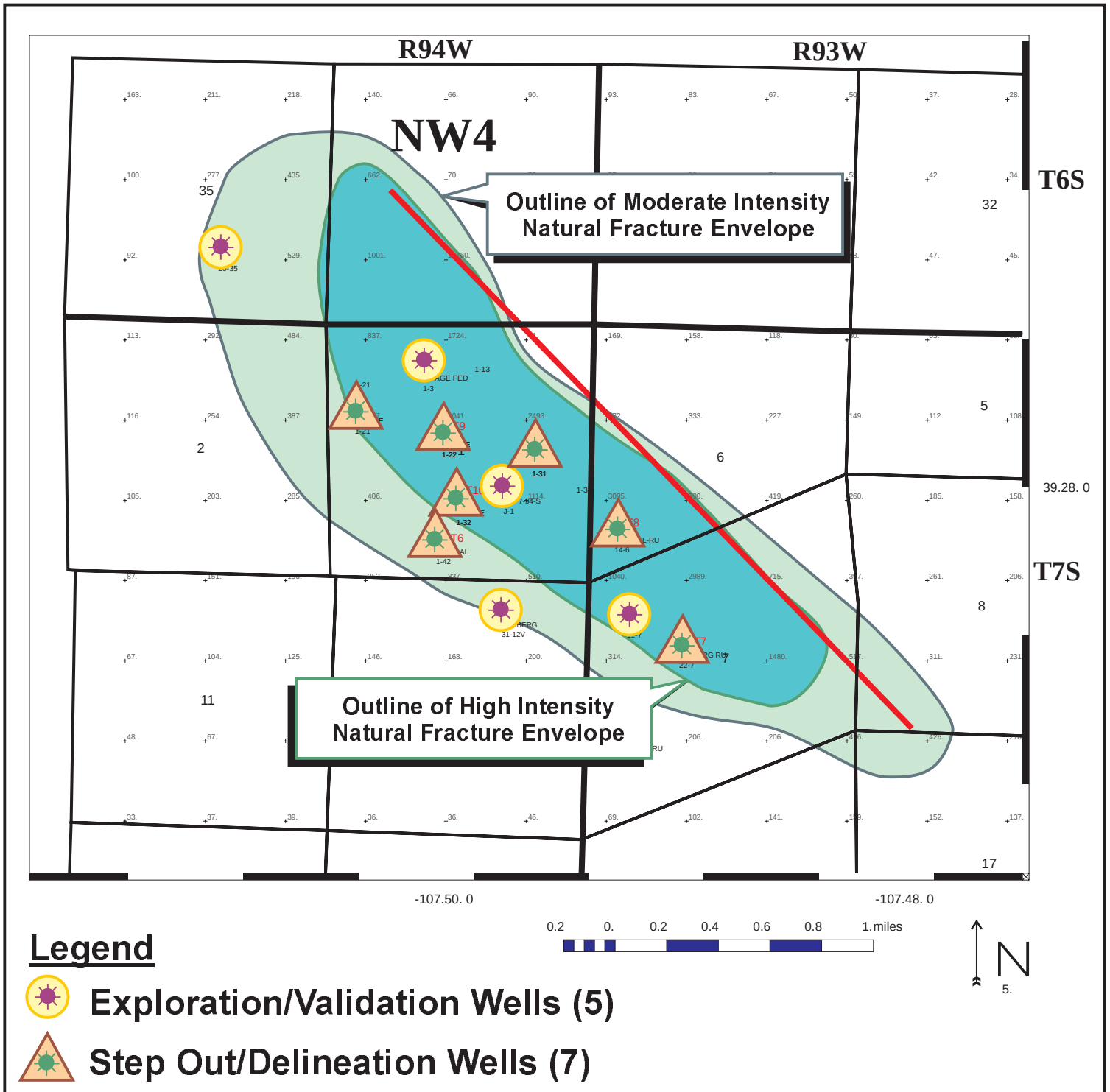
Prospect Definition

- Seismic
- Geomechanical Modeling



South Rulison Field, Piceance Basin

Alternative is Using Prospect Definition (Seismic and Geomechanics) to Locate Wells in Naturally Fractured "Sweet Spots"



S. Rulison: Prospect Definition Approach

1. Exploration and Validation

- *72 square miles 3-D seismic, plus geomechanical analysis*
- *5 wells*
- *\$6.6 million**

2. Step Out and Delineation

- *7 wells*
- *\$6.3 million*

3. Results:

- *Reserves 40 Bcf*
- *Total Costs - \$12.9 million*

**Assuming \$1.8 million for seismic survey, \$0.3 million for analysis, \$0.9 million per well.*



Comparison of Step Out Approach vs. Prospect Definition

	Step Out Approach	Prospect Definition
• Costs*	\$31.5 MM	\$12.9 MM
• Reserves	63 Bcf	40 Bcf
• Wells	35	12
• Reserves/Well	1.8 Bcf	3.4 Bcf
• Finding Costs @85% NRI	\$0.59/Mcf	\$0.38/Mcf

**Includes \$0.9 million per well and \$2.1 million for seismic and geomechanical analysis.*



Cost Savings From Using Prospect Definition (Seismic and Geomechanics) for Efficient Field Development (S. Rulison Example)

	Statistical/ Step Out Approach	Prospect Definition
Target Reserves	1,000 Bcf	1,000 Bcf
Average EUR/Well	1.8 Bcf*	3.4 Bcf**
No. of Wells	556	294
Capital Costs*** (@\$900,000/well)	\$500 million	\$267 million
Cost Savings		\$233 million

*Average EUR for 35 wells statistically drilled in S. Rulison area.

**Average EUR for 12 wells located and drilled in naturally fractured envelope

***Capital costs of Prospect Definition include \$2.1 million for seismic and geomechanical analysis.



Table Rock Field Case Study

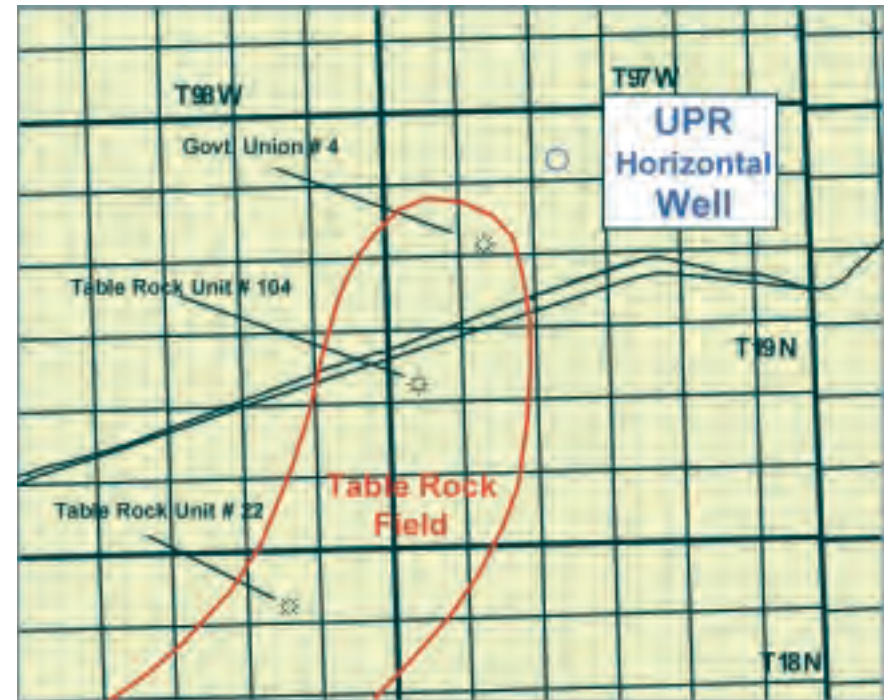
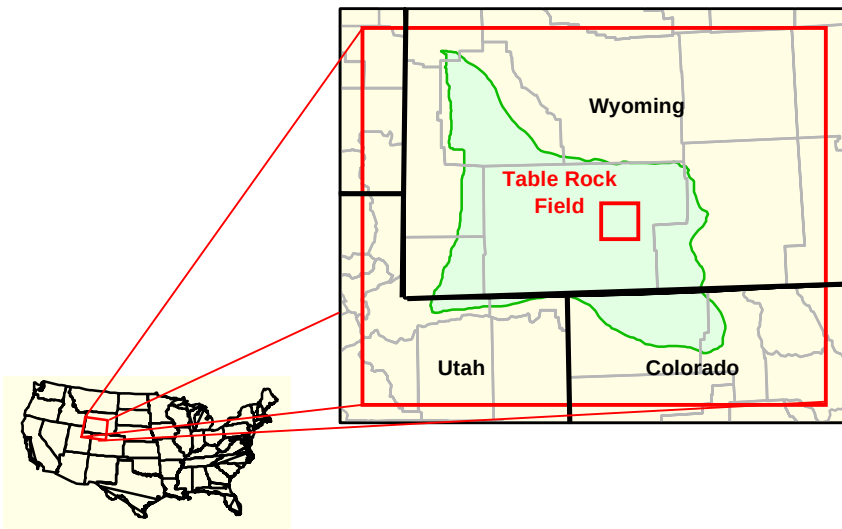
Frontier Fm., Green River Basin

Table Rock Field

Deep, High Risk Frontier Fm. Reservoir

- *15,000'; 270° F; 10,000 psi*
- *Unsuccessful exploration well at Frewen*
- *World record tight gas horizontal well*

Greater Green River Basin



Prospect Corroboration

Given expense and risk of horizontal drilling, statistical approach to locating exploration wells in deep, high-risk Frontier Fm is not viable.

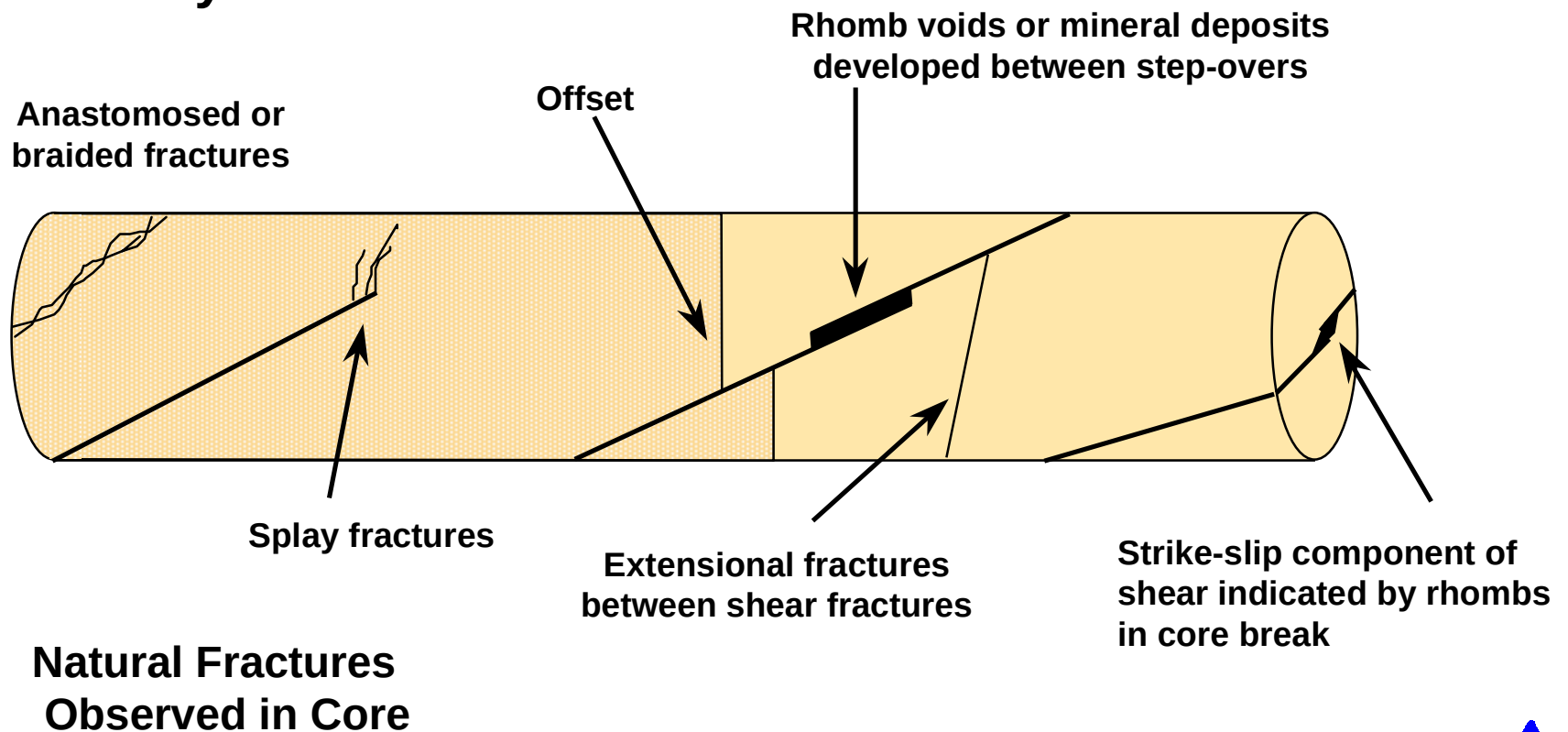
ARI's role was to corroborate the horizontal well location using the Prospect Definition approach:

- ✓ *Natural Fracture Characterization***
- ✓ *Fault Mapping Using 3-D Seismic***
- ✓ *Geomechanical Modeling***



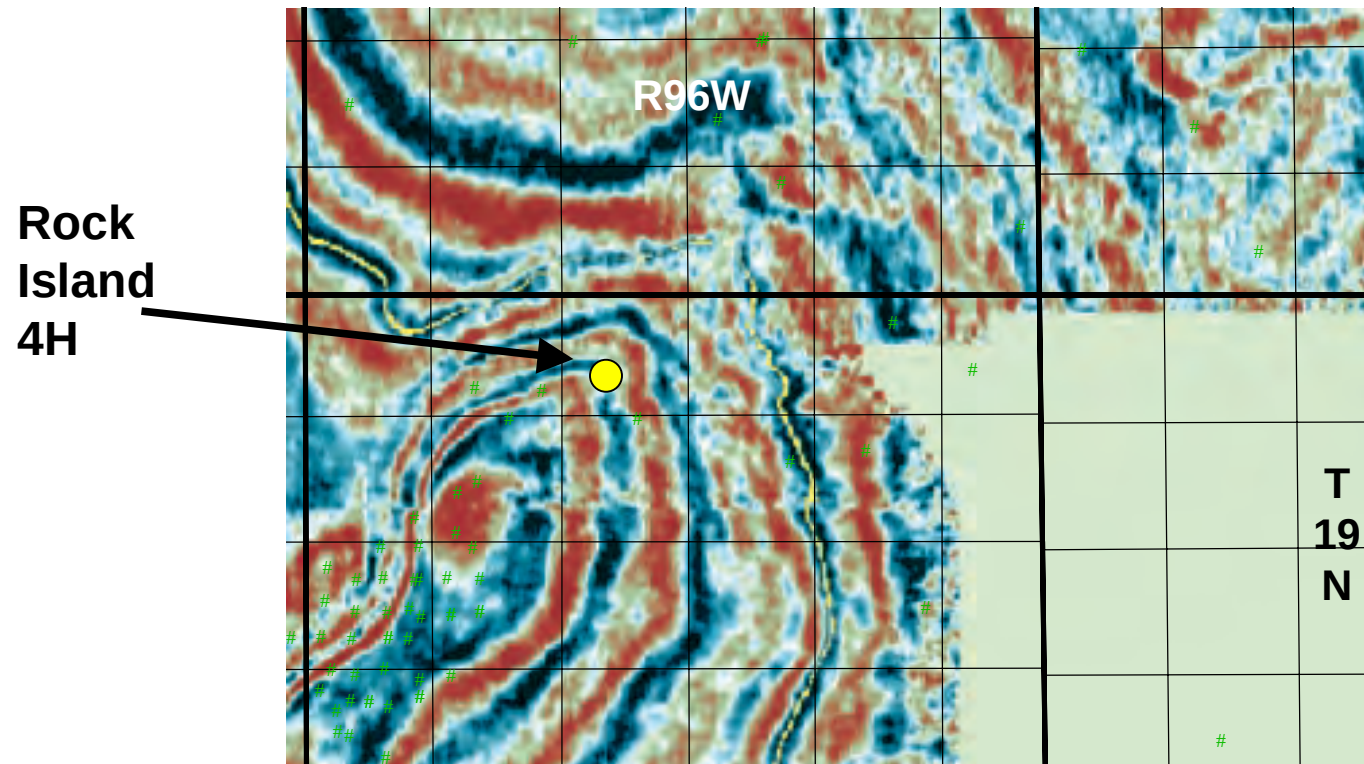
Natural Fracture Characterization: Table Rock, Green River Basin

- Natural fractures in Frontier Fm are dominantly oblique-reverse shears with extensional component.
- Open voids provide storage; shear fractures provide permeability.



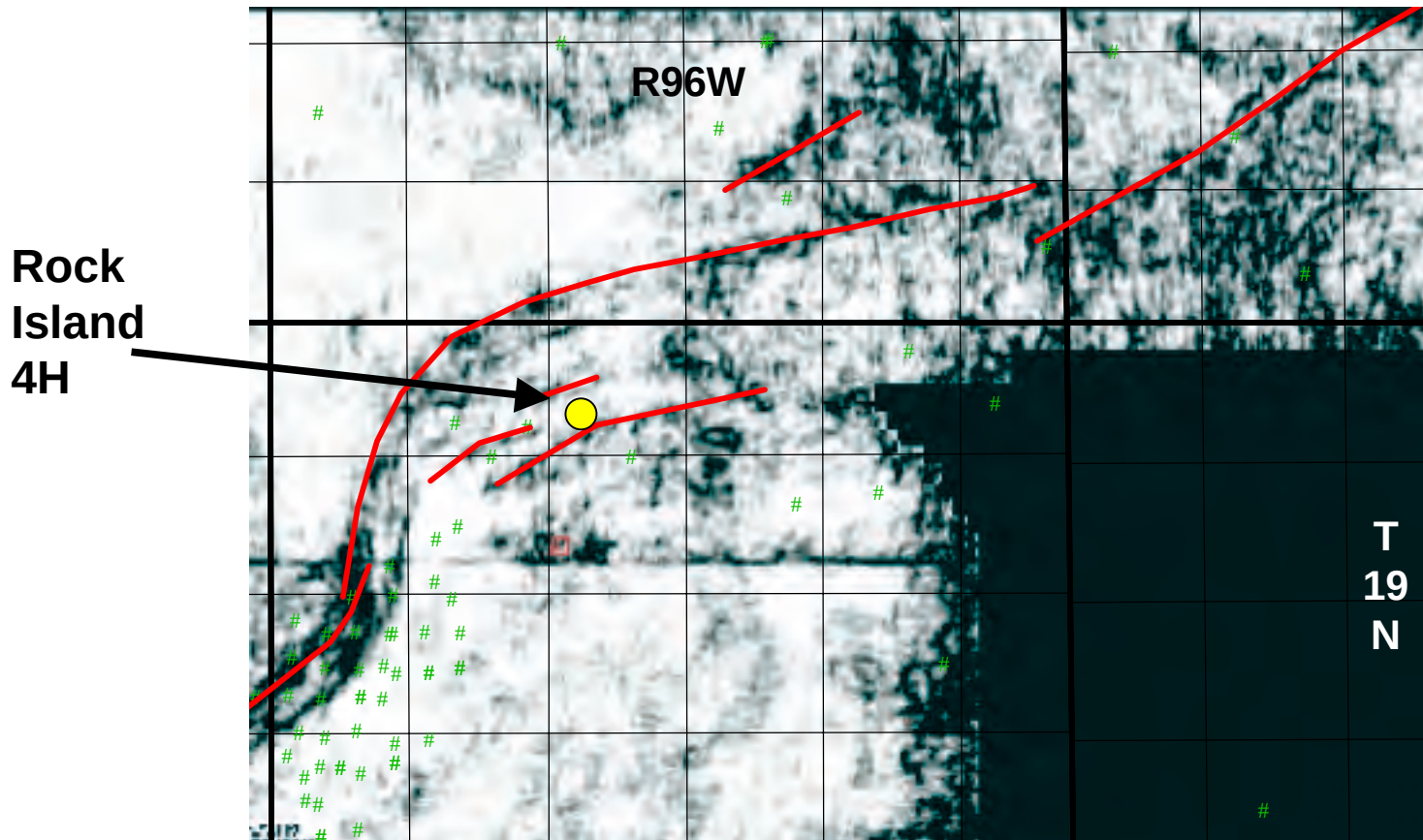
3D Seismic: Depth Slice 16,000'

Location of Rock Island 4H is on the northern nose of the Table Rock fold (off-structure).



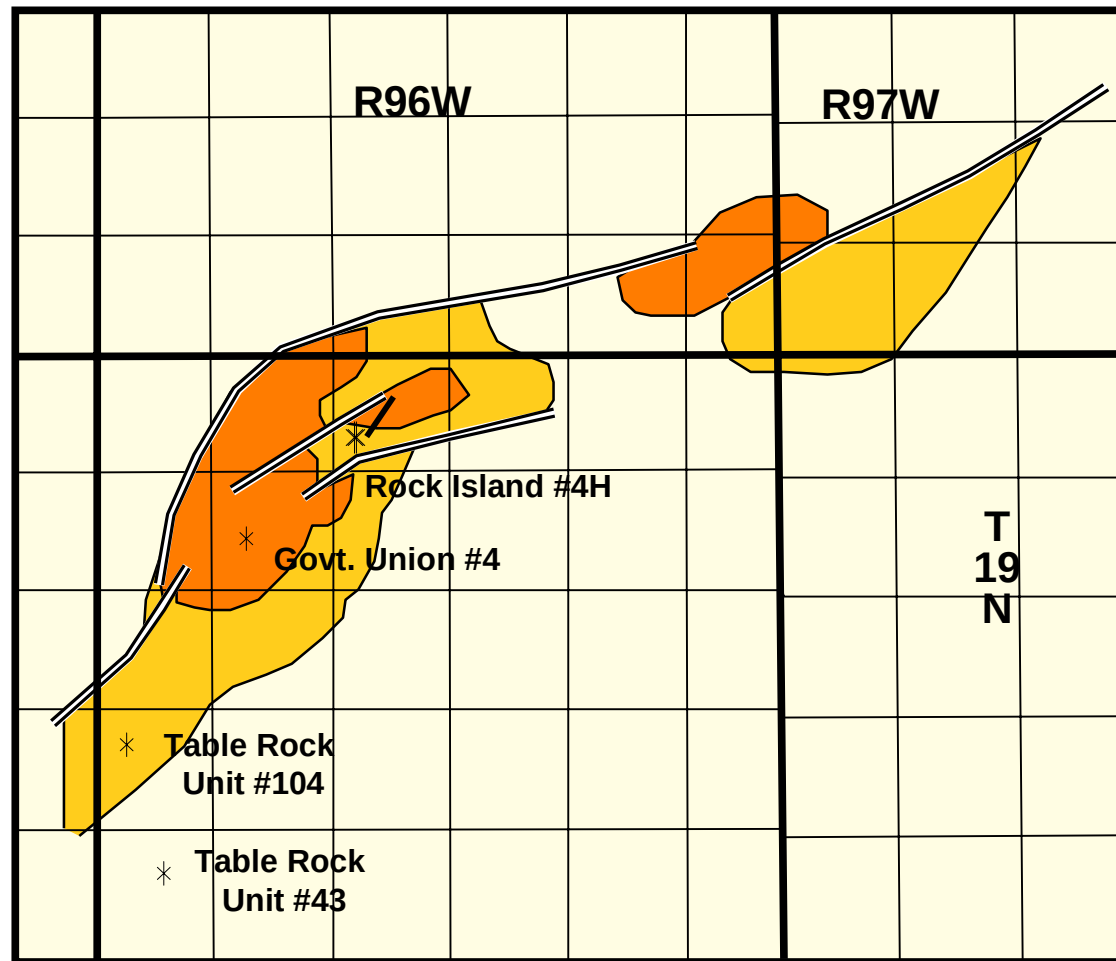
3D Seismic: Fault Mapping

Subtle faults and complex geometry of the main thrust and strike-slip fault system are revealed after coherency filtering.



Natural Fracture Prediction: Geomechanical Model Results

The Rock Island 4H occupies an area between two small faults and may have hit a zone of enhanced stress concentration.



Prospect Definition Results

Monday April 26, 10:55 am Eastern Time

***UPR'S HORIZONTAL WELL TESTED
AT OVER 12 MMCFD***

**Union Pacific Resources Group, Inc., Working with
Federal Energy Tech Center, Completes
Experimental Horizontal Frontier Formation Gas Well**



Value of Using Seismic and Geomechanics for Prospect Definition

1. Play Assessment. Provides viable leads for an economic tight gas exploration program.
2. Exploration Success. Helps avoid “program killers”, early dry holes.
3. Efficient Development. Provides a low cost approach for developing low-permeability gas fields.



Summary

- 1. Tight Gas, Gas Shales and Coalbed Methane Can Provide Large, Economic Resource Targets.***
- 2. Prospect Definition, Using the Geomechanical Approach to Natural Fracture Prediction, Is a Cost-Effective Alternative to Step Out and Statistical Drilling.***



Summary

3. The Geomechanical Approach Provides a Low Cost, Advanced Exploration Tool for Naturally Fractured Reservoirs:

- 2D and 3D seismic data***
- Standard seismic processing***
- Available numerical simulator***

4. Successful Results Have Been Achieved at Rulison (and Mamm Creek), Piceance Basin and Table Rock, Green River Basin.



3A.2 Optimization of Infill Drilling in Naturally-Fractured Tight-Gas Reservoirs in the San Juan Basin*

Lawrence W. Teufel (lteufel@nmt.edu; 505-835-5483)
Petroleum and Chemical Engineering Department
New Mexico Institute of Mining and Technology
Socorro, NM 87801

Abstract

A major goal of industry and the DOE fossil energy program is to increase U.S. gas reserves in tight-gas reservoirs. Production from tight-gas sandstone reservoirs of the Mesaverde and Dakota formations in the San Juan Basin is highly dependent on natural fractures. Fractures not only enhance the overall permeability of these reservoirs, they also create significant permeability anisotropy. Permeability anisotropy causes the drainage area around the wells to be elliptical. Elongated drainage creates more production interference and drainage overlap between adjacent wells and increases the potential for leaving large sections of the reservoir undrained. Reservoir characterization and simulation studies are being conducted in the San Juan basin to (1) define the elliptical drainage area and recoverable gas for existing wells, (2) determine the optimal location and number of new infill wells to maximize economic recovery, and (3) forecast the increase in total cumulative gas production from infill drilling at different locations in the basin. This study provides producers the necessary information required to develop optimal infill drilling strategies for recovery of significant additional gas from tight-gas reservoirs. A preliminary estimate of additional recoverable gas from optimal infill drilling of Mesaverde Formation in the San Juan Basin is 7.8 TCF.

Identification and Evaluation of Fluvial-Dominated Deltaic (Class-I Oil) Reservoirs in Oklahoma

**Jock A. Campbell (jacampbell@ou.edu; 405-325-3031)
Richard D. Andrews (rdandrews@ou.edu;mn 405-325-3031)
Oklahoma Geological Survey
100 E. Boyd Street, Sarkeys Energy Center, Suite N-131
Norman, Oklahoma 73019-0628**

**Robert A. Northcutt (405-755-4783)
Independent Geologist
11422 Red Rock Road
Oklahoma City, Oklahoma 73120-5345**

**Roy M. Knapp (knapp@ou.edu; 405-325-2921)
School of Petroleum and Geological Engineering
The University of Oklahoma, Sarkeys Energy Center, Suite T-301
Norman, Oklahoma 73019-0628**

**Mary K. Banken (mkbanken@ou.edu; 405-325-3131; x223)
Geo Information Systems
The University of Oklahoma
1818 W. Lindsey Street, Suite A-105
Norman, Oklahoma 73069-4160**

INTRODUCTION:

The Oklahoma Geological Survey (OGS), the Geo Information Systems department, and the School of Petroleum and Geological Engineering at the University of Oklahoma engaged in a five-year program to identify and address Oklahoma's oil recovery opportunities in fluvial-dominated deltaic (FDD) reservoirs. This was accomplished under Cooperative Agreement No. DE-FC22-93BC14956. The program included a systematic and comprehensive collection and evaluation of information on all FDD oil reservoirs in Oklahoma and the recovery technologies that have been (or could be) applied to those reservoirs successfully. This data collection and evaluation effort was the foundation for an aggressive, multifaceted technology transfer program that was designed to support all of Oklahoma's oil industry. However, particular emphasis of this program was directed toward smaller companies and independent operators in order to help them maximize oil production from FDD reservoirs.

Specifically, this project identified all FDD oil reservoirs in the State; grouped those reservoirs into plays that have similar depositional and geologic histories; collected, organized and analyzed all available data; performed characterization and simulation studies on selected reservoirs in each play; and implemented a technology transfer program that targeted operators of FDD reservoirs. These elements of the FDD program provided the kind of assistance that could allow operators to extend the life of existing wells with the ultimate objective of recovering more oil.

The execution of this project was approached in phases. The first phase began in January, 1993 and consisted of planning, play identification and analysis, data acquisition, database development, and computer systems design. By the middle of 1994, many of these tasks were completed or nearly finished including the identification of all FDD reservoirs in Oklahoma, data collection, and defining play boundaries. Later in 1994, a preliminary workshop schedule was developed for project implementation and technology transfer activities. In early 1995, a specific workshop agenda was formatted and play publication requirements were identified. Later in 1995, the play workshop and publication series were initiated with the Morrow play in June and the Booch play in September. The remaining six play workshops were completed through 1996 and 1997, with the project ending on December 31, 1997.

OBJECTIVES AND APPROACH:

Task 1: Database and Applications Development: Computer support activities included ongoing database development and maintenance, applications development, and user lab development and operation. An operator database was designed to track operators (and other interested parties) who were working with FDD reservoirs in Oklahoma. Some of these operators were identified to participate in the data-collection process as well as the technology transfer program. A variety of computer applications programs were developed for data analysis, for publication and workshop preparation, and to support users. Computerized mapping and

report programs were necessary for reservoir analysis and regional play interpretations. Database development also involved reformatting *NRIS* well, lease and field mainframe databases for p.c.-level access through a computer user lab, which was one of the primary technology transfer tools implemented during this project. The lab was opened on June 1, 1995, in conjunction with the Morrow play presentation. Industry response to the facility initially was slow, but after the first year, lab usage began to increase and is sustaining.

Task 2: Play Analyses, Publications, and Workshops: During the project, eight FDD workshops involving 11 plays with accompanying folio publications were completed.

The Morrow Play was the first in the series, presented on June 1 and repeated on June 2, 1995 at the Sarkeys Energy Center in Norman, Oklahoma. A total of 215 persons attended. Morrow fluvial systems are found principally in three regions within Oklahoma: the Dewey–Blaine Counties embayment, the Woodward “trench,” and the Panhandle region comprising of Texas, western Beaver, and eastern Cimarron Counties. Detailed information was provided for three Morrow field studies: the Canton field area in Dewey County, the South Balko field in Beaver County, and the Northeast Rice field in Texas County. A reservoir characterization and waterflood simulation study was completed and presented for the Northeast Rice field.

The Booch Play was presented on September 11, 1995 at the Indian Capital Vo-Tech School in Muskogee, Oklahoma. A total of 128 persons attended that workshop. The Pennsylvanian sandstones in the Booch were significant oil reservoirs during the early history of the oil industry in Oklahoma; Booch reservoirs are still important today for potential recovery of additional oil by water-flooding or other enhanced recovery methods. The Booch play is located on the Cherokee Platform in northeastern Oklahoma and extends southward beyond the hinge line of the McAlester Formation into the Arkoma basin. Detailed information was provided for two Booch field studies: the Northwest Wewoka field area in Seminole County, and the Greasy Creek field in Hughes County. Additionally, a reservoir characterization and waterflood simulation study were completed and presented for the Greasy Creek field.

The Layton and Osage-Layton Play was presented on April 17, 1996 at the Francis Tuttle Vo-Tech Center in Oklahoma. It was well attended by 103 persons. The Layton and Osage Layton sands constitute two different zones or formations (the Layton lies 100 ft or more below the Osage-Layton). The names have been so misused by industry, that it is commonly impossible to differentiate between the two reservoirs from production records or from formation tops recorded on completion reports. This problem was addressed in the workshop, but because it is so widespread, both formations were treated as one play in the regional discussion. Detailed geologic field studies within this workshop and play publication include the East Lake Blackwell and South Coyle fields. East Lake Blackwell field is an Osage-Layton sand (Cottage Grove Sandstone) reservoir that also was used in the waterflood simulation study. South Coyle field is a Layton sand reservoir that lies stratigraphically below the Osage-Layton interval.

The Prue and Skinner Plays were presented on June 19 and 20, 1996 in Oklahoma City, and on June 26, 1996 in Bartlesville. Because of the large number of operators and high interest in these plays, three workshops were necessary to accommodate the 201 attendees. Similarities in

depositional origin, stratigraphy, age, and environments of deposition made it convenient to group the Prue and Skinner plays into one workshop. Major topics included in the publication and workshop consisted of the regional analysis of each play along with three Skinner field studies and one Prue field study. The four fields have diverse geologic characteristics that typify many of the clastic reservoirs in the Cherokee Platform of eastern Oklahoma. Two of the reservoirs had been water flooded previously, which provided a good analogy for this technology. Enhanced recovery simulation studies were completed on one Prue and one Skinner reservoir. Computer modeling utilized software demonstrated in previous workshops (Eclipse) in addition to Boast III which is more widely available to the public.

The Cleveland and Peru workshop was completed October 17, 1996 in Bartlesville, Oklahoma with 85 attendees. Each play was presented individually using the adopted protocol of stratigraphic interpretations, a regional overview, and detailed field studies. Two field studies were completed including the Pleasant Mound Cleveland oil pool and the Hogshooter Peru oil pool. A waterflood simulation was completed for the Pleasant Mound Cleveland oil pool. The Peru field study was not considered suitable for waterflood simulation because of the lack of production data. Instead, a guest lecturer presented a talk on formation evaluation of the Peru sand in the Hogshooter oil field.

The Red Fork Play was the subject of a workshop that was presented twice: on March 5, 1997 in Norman, and again on March 12 in Bartlesville, to a total of 195 attendees. The Red Fork sandstone has been, and continues to be, one of the main producers of oil and gas in Oklahoma, as well as the most widespread Cherokee play in Oklahoma. The Red Fork interval extends from the Cherokee platform, across the Nemaha uplift and the central Oklahoma fault zone to the Anadarko basin. Field studies were completed on the North Carmen field in Alfalfa County and the Long Branch field, located in east-central Payne County. This is the same field area in which a reservoir had been the subject of a previous study in the Prue workshop.

The Tonkawa Play had been of continued interest for many operators and geologists for a long time, and recently has become very active in western Oklahoma. The renewed interest in the Tonkawa centers in the Anadarko Shelf and Basin areas where production is prone to gas from marine sands. Because of this high interest, the Tonkawa FDD workshop was partnered with a presentation on the Tonkawa gas play. The workshop was presented on July 9, 1997 in Norman with 101 attendees. Part of north-central Oklahoma has significant areas containing FDD deposits, but only scattered areas within the FDD portion of the play produce oil. The Virgilian-age sandstones of the Tonkawa play are the youngest of the fluvial-deltaic reservoirs to be investigated in the FDD workshops, with drilling depths of about 2,200–4,400 ft. A reservoir study was completed on the Blackwell field in Kay County.

A finale of the FDD program was the Bartlesville Play. Oil reservoirs in the Bartlesville sandstone were the foundation for the dominance of Oklahoma as an oil-producing state, beginning with the No. 1 Nellie Johnstone in 1897. This workshop was presented three times at different locations: on October 29, 1997 in Tulsa, on October 30 in Bartlesville, and on November 12, 1997 in Norman. Attendance at the three sessions totaled 183. The Bartlesville play is situated on the Cherokee platform of northeastern Oklahoma. Bartlesville reservoir

studies included the Paradise field in Payne County and the Northwest Russell field in Logan County.

Since the inception of the workshop program in 1995, industry responses to the program have been very positive. In short, this program has been described by numerous industry representatives as the most valuable program that the Oklahoma Geological Survey has ever implemented. The operator registration statistics for the various workshops support this assertion. There were 1,211 total workshop registrations in the program, reflecting 584 individuals, many with multiple registrations. Of the 584 individuals, 355 (61%) are from active operating companies, based on a comparison of company names to gross production tax records, and 145 (25%) are from other industry interests such as service companies, or are “consultants” (31) or “independents” (30), that could not be linked to the gross production tax records.

Task 3: Professional Outreach: Three levels of professional outreach have been identified as part of this overall project effort. The first, technical advising, refers to those industry contacts that take place as follow-ups to the workshop presentations. Second, the ongoing reservoir characterization and simulation studies provide opportunities for individualized efforts with operators. Third, professional activities such as conferences provide a forum for promoting the FDD program activities.

CONCLUSIONS:

THE FDD PROGRAM:

There is no direct way to measure the impact that this program has had on the volumes of FDD oil production in Oklahoma. Throughout Oklahoma, as in the rest of the domestic petroleum industry, oil well abandonments have continued to increase and production has continued to decline throughout the five years of the program. There is no way of knowing what that decline would have been if this program had not been implemented. Furthermore, most of the volumetric impacts of this program will in fact be realized in future years. If this program has served its function, it will be demonstrated through the ongoing viability of FDD reservoirs five to ten years in the future. We believe that economics (primarily the international price of oil) will be the most significant factor in future production from FDD reservoirs.

Since volumetric measures cannot be provided, the success of the program must be measured in terms of the accomplishments and the industry evaluations of those accomplishments. Eight highly successful workshops and accompanying publications were completed on eleven FDD stratigraphic intervals. A computer user laboratory has been established and continued to be a resource to the industry. Industry relationships with the project participants have shown vast improvements. Industry feedback to the program has been overwhelmingly positive.

REGIONAL OVERVIEW OF DEPOSITIONAL SYSTEMS:

The approach of a regional overview coupled with site-specific reservoir studies was effective, and appropriate to the needs of the industry. Whereas the regional geology of some of the FDD stratigraphic intervals has been discussed in the published literature to varying degrees, none of the FDD intervals had previously been mapped at a useful scale. The regional mapping has also been useful in terms of the informal subsurface stratigraphic nomenclature of the region. The informal names (Table 1) are largely inherited from names applied at a specific lease by drillers and “wildcatters” in the early decades of the 20th Century. Although the names are applied to geologic entities, they commonly are not meaningful *geologically*. Over the intervening years, the names have been carried well beyond their original locale, and have commonly been mis-correlated locally to unrelated sandstone bodies. Sandstone known by an informal name, but occurring *beyond* the limits defined by the regional mapping, is therefore of a separate genesis, and is not contiguous with the mapped sandstone intervals. Similarly, some of the sandstone intervals have *duplicate* informal names; the geologists have identified those duplicate names (Table 1) in an attempt to improve general understanding of the reservoir systems.

GEOLOGIC CHARACTERIZATION OF RESERVOIRS:

The 21 reservoir studies (Table 2) provide detailed mapping and description of the subject interval in that reservoir. The main emphasis was to demonstrate the difference between fluvial and marine depositional environments, as interpreted from gamma-ray and porosity logs. This is because they have different internal structures, and are highly likely to behave differently as petroleum reservoirs. In many cases, the study of depositional environments can identify major compartments within what might otherwise be assumed to be a continuous reservoir. Even elementary knowledge of depositional environments and their identification can improve development strategy at all levels, from initial development drilling to enhanced oil recovery. Drilled rock cores are highly desirable, as they provide confirmation to the interpretations made on the basis of wireline logs. Such cores were rarely available for the reservoirs studied; however, selected cores were studied and interpreted with respect to log response of the subject interval in each play (except for the Peru sand), and presented at the workshops.

RESERVOIR SIMULATION STUDIES:

Using the geologic descriptions, petroleum engineers have conducted simulation studies for 9 of the reservoirs in the 11 plays (Table 2), using Eclipse and/or BOAST III software. In these, they designed one or more reservoir-management strategies for each of the reservoirs studied. The management strategies ranged from simple to complex. For example, a simple management strategy might be the recommendation to complete an interval in a well, or to convert a production well to inject produced water into the reservoir to help maintain reservoir pressure. A complex management strategy might consist of a recommended waterflood, including the placement and purpose of all wells. All recommended management strategies included estimates

of the amount of oil that would be recovered as compared to continuing the existing field procedures.

SIGNIFICANCE OF RESERVOIR STUDIES:

The very nature of fluvial deposits is that they commonly have a high degree of physical variation. This results largely from the variation in the energy level of depositing currents, and the tendency of stream channels to change position. It is this common high variability that has resulted in fluvial reservoirs having the highest percentage of movable oil and their subsequent identification as DOE Class I Reservoirs. The quality of variation tends to provide for a certain uniqueness of any specific reservoir of fluvial origin. That uniqueness is certainly true of each of the Pennsylvanian FDD reservoirs studied in Oklahoma. At the same time, there are no identifiable, specific, *distinguishing* internal characteristics of any of the studied reservoirs that would set it apart from any other. However, given the similarity of sediment source areas and general stream gradients, as well as other factors, there are also remarkable similarities among the 21 reservoirs studied. In other words, the study of any of the reservoirs provides insight to the nature of the entire family of Pennsylvanian FDD reservoirs in Oklahoma.

All of the reservoirs studied were small, commonly consisting of about 25 producing wells; the size typically operated by independent producers. The studied reservoirs were selected on the basis of the availability of a production history for the subject reservoir and the existence of a suite of modern wireline logs. The studies typically incorporated areas much larger than the actual production, in order to understand the interrelationships of depositional environments. Reservoir discovery dates of the 21 studied reservoirs range from the early 1920s to the late 1980s, and all but one of the reservoirs were in operation at the time of this study.

Recoverable oil was present in every reservoir; the recommended reservoir management ranged from completing unexploited oil zones behind pipe to secondary recovery. In the course of the studies, it became evident that reservoir management was commonly not optimized, and often was essentially non-existent in the development history of the 21 small reservoirs. In most cases, oil recovery would have been improved significantly had depositional environments (geologic description) been considered at any stage of reservoir development. Furthermore, the most elementary pressure maintenance, such as injecting produced water into the structurally lowest well at such time as it ceased to produce oil effectively, would have improved oil recovery significantly.

FUTURE ACTIVITIES

Recognizing the success of the FDD workshops, the OGS is proceeding with subsurface geology workshops. The first of the continuing series was the Hartshorne Play in southeastern Oklahoma (an Arkoma Basin gas play), which was presented in Oklahoma City on September 30, 1998. A two-day field trip was offered in conjunction with that play, because the Hartshorne Formation (lower Desmoinesian) exhibits the same depositional environments and facies relationships in

outcrop as in the subsurface. Continuing interest resulted in the field trip being conducted again in the spring. The field trip took advantage of, and built upon the Survey's recent field studies in the region.

OGS has made formal application for continued DOE support of subsurface geology workshops. As of this writing (August, 1999), the Morrow Basin-Sands Play (deep Anadarko Basin gas) is about to go to press, and is to be presented at the Moore-Norman Technical Center on November 10, 1999. Other workshops are in the planning stages.

At the request of the Oklahoma City Geological Society (OCGS), the FDD workshops are being presented quarterly in abbreviated (half-day) format. This activity began with the Tonkawa Play Workshop in March, 1998, and will continue through the end of 1999. They are being presented through the combined effort of OGS, OCGS, and the Petroleum Technology Transfer Council (PTTC). The Tulsa Geological Society (TGS) also has expressed interest in the half-day workshops. They are to be presented in Tulsa quarterly, beginning with the Prue and Skinner Play Workshop, on December 8, 1999. The workshops will be presented under the auspices of OGS, TGS, and the PTTC.

ACKNOWLEDGMENTS

Completion of this study would not have been possible without funding from the U.S. Department of Energy and the combined efforts of many people from the Oklahoma Geological Survey (OGS), Geo Information Systems (GeoSystems), and the OU School of Petroleum and Geological Engineering. The continuing effort of Rhoda Lindsey, Project Manager, Bartlesville Project Office of the U.S. Department of Energy, is greatly appreciated. Special recognition is given to Charles J. Mankin, director of the OGS, and to Mary K. Banken, director of GeoSystems, who originated concepts for this program and provided overall leadership. Both the OGS and GeoSystems also provided funding for this cooperative project.

Space is insufficient here to acknowledge the most fortunate cooperation of several operators, who provided information relevant to reservoir studies that would otherwise not have been available to us. In addition, the investigators wish to acknowledge the assistance of several independent geologists for technical review, and for helpful conversations on some aspects of several of the plays.

Finally, we are most appreciative of many OGS personnel and contract employees for cartography, visual aids, manuscript preparation, editing, publication, printing, core preparation, and by no means least, workshop organization and registration.

Table 1.- Stratigraphic column of fluvial-dominated deltaic reservoirs in Oklahoma

SYSTEM	SERIES	GROUP	FORMATION OR MEMBER ^a	
			FORMAL (SURFACE)	INFORMAL (SUBSURFACE)
		Wabaunsee		
		SHAWNEE	Elgin Sandstone	Hoover sand (Carmichael sand)
			Wynona Sandstone	Endicott sand
		DOUGLAS	Cheshewalla Sandstone Tonganoxie Ss. (Kansas)	Tonkawa sand Stalnaker sand (Kansas)
		OCHELATA	Cottage Grove Sandstone _____	Osage - Layton sand (Layton & Musselem sands) Wade sand ^b
		SKIATOOK	_____	Medrano sand ^b
			Dodds Creek Sandstone _____	Layton sand Marchand sand ^b
			Seminole Fm.	(Seminole & Cleveland sands)
		MARMATON	Tulsa Sandstone Jenks Sandstone Walter Johnson Ss. Englevale Sandstone	u. Cleveland sand (Jones) l. Cleveland sand (Dillard) Wayside sand Peru sand
		CABANISS	Lagonda Sandstone	Prue sand (Squirrel & Perryman sands) Calvin sandstone u: Senora, Allen, etc. m: Allen, Olympic, etc. l: Hart, Senora, etc.
			Calvin Sandstone Oowala Sandstone Chelsea Sandstone	
		KREBS	Taft Sandstone Bluejacket Sandstone Warner Sandstone Hartshorne Fm.	Red Fork sand (Burbank, Earlsboro, Osborn, Dora & Chicken Farm sands) Bartlesville sand (Glenn & Salt sands) Booch sand Hartshorne sandstone
			_____ _____ _____	Gilcrease sand Dutcher sand Spiro sand
			Kearny Fm. (Kansas)	Purdy, Sturgis, u: Bowles, Kelly and Lips sands Mocane-Laverne l: and Keyes sands

^a Bold print indicates fluvial systems investigated in FDD light-oil studies. Names in parentheses are names applied locally in the subsurface.

^b Reservoirs systems occur only in southern and western Oklahoma.

PENNSYLVANIAN

MORROW

ATOKA

DESMOINES

MISSOURI

VIRGIL

**Morrow
Formation^b**

**Morrow
formation**

**Skinner
sand**

**Skinner
sand**

Cherokee group

Cherokee group

(former) Cherokee group

Cherokee group (former)

Table 2.—Fluvial-dominated deltaic (FDD) plays and accompanying reservoir studies. All publications are of the Oklahoma Geological Survey.

Publication	Play	Field	County	Reservoir	Township & Range
OGS SP 97-3	Tonkawa	Blackwell*	Kay	Tonkawa	27 & 28 N – 1 W
OGS SP 96-1	Layton and Osage-Layton	Lake Blackwell E*	Payne	Osage-Layton	19 N – 1 E
		Coyle S	Payne	Layton	17 N – 1E
OGS SP 97-5	Cleveland and Peru	Pleasant Mound*	Lincoln	Cleveland	16 – 6 E
		Hogshooter	Washington	Peru	26 N – 13 E
OGS SP 96-2	Skinner and Prue	Perry SE	Noble	Skinner	21 N – 1 E & 1 W
		Salt Fork N*	Grant	Skinner	25 N – 3 & 4 W
		Guthrie SW	Logan	L. Skinner	16 N – 2 & 3 W
		Long Branch*	Payne	Prue	18 N – 4 E
OGS SP 97-1	Red Fork	Carmen N*	Alfalfa	Red Fork	24 & 25 N – 12 W
		Otoe City S	Noble	Red Fork	22 N – 1 E
		Long Branch	Payne	Red Fork	18 N – 4 E
OGS SP 97-6	Bartlesville	Paradise*	Payne	Bartlesville	17 & 18 N – 12 W
		Russell NW	Logan	Bartlesville	18 N – 2 & 3 W
		Ohio-Osage	Osage	Bartlesville	21 N – 9 E
OGS SP 95-3	Booch	Holdenville	Hughes	Booch	6 N – 8 E
		Seminole	Seminole	Booch	9 & 10 N – 7 E
		Greasy Creek*	Hughes	Booch	8 & 9 N – 11 E
OGS SP 95-1	Morrow	Canton SW	Dewey	L. Morrow	18 N – 14 W
		Balko S	Beaver	U. Morrow	2 N – 23 ECM
		Rice NE*	Texas	U. Morrow	3 N – 10 ECM

Number of Special Publications — 8; Number of Play Studies — 11; Number of Reservoir Studies — 21
Number of Reservoir Simulation Studies — 9 (indicated by *)

Table 1.—Stratigraphic Column of Fluvial-Dominated Deltaic Reservoirs in Oklahoma

SYSTEM	SERIES	GROUP	FORMATION OR MEMBER ^a	
			FORMAL (SURFACE)	INFORMAL (SUBSURFACE)
PENNSYLVANIAN	VIRGIL	Wabaunsee		
		SHAWNEE	Elgin Sandstone	Hoover sand (Carmichael sand)
			Wynona Sandstone	Endicott sand
	MISSOURI	DOUGLAS	Cheshewalla Sandstone Tonganoxie Ss. (Kansas)	Tonkawa sand Stalnaker sand (Kansas)
		OCHELATA	Cottage Grove Sandstone	Osage-Layton sand (Layton & Musselem sands) Wade sand ^b
				Medrano sand ^b
		SKIATOOK	Dodds Creek Sandstone	Layton sand
				Marchand sand ^b
			Seminole Fm.	(Seminole & Cleveland sands)
	DESMOINES	MARMATON	Tulsa Sandstone Jenks Sandstone Walter Johnson Ss. Englevale Sandstone	u. Cleveland sand (Jones) l. Cleveland sand (Dillard) Wayside sand Peru sand
		CABANISS	Lagonda Sandstone	Prue sand (Squirrel & Perryman sands) Calvin sandstone
			Calvin Sandstone Oowala Sandstone Chelsea Sandstone	u: Senora, Allen, etc. m: Allen, Olympic, etc. l: Hart, Senora, etc.
		KREBS	Taft Sandstone	Red Fork sand (Burbank, Earlsboro, Osborn, Dora & Chicken Farm sands)
			Bluejacket Sandstone Warner Sandstone Hartshorne Fm.	Bartlesville sand (Glenn & Salt sands) Booch sand Hartshorne sandstone
	ATOKA			Gilcrease sand Dutcher sand Spiro sand
	MORROW		Kearny Fm. (Kansas)	Morrow Formation^b Purdy, Sturgis, u: Bowles, Kelly and Lips Mocane-Laverne l: and Keyes sands

^a Bold print indicates fluvial systems investigated in FDD light-oil studies. Names in parentheses are names applied locally in the subsurface.

^b Reservoirs systems occur only in southern and western Oklahoma.

Incorporating Seismic Attribute Modeling into a Flow Model of the Grayburg Reservoir in the Foster-South Cowden Field, An Update.

Robert C. Trentham (muskoka@texasonline.net; 1-915-686-9692)

Richard M. Weinbrandt (weinbrandt@jhinet.com; 1-307-733-8216)

William C. Robinson (seisdec@aol.com; 1-915-686-7865)

Laguna Petroleum Corp.
1003 N. Big Spring Street
Midland Texas, 79701

ABSTRACT

The Grayburg and San Andres reservoirs in the Foster – South Cowden Field have been producing since 1939, and under waterflood since 1962. Production had declined to near abandonment level at the start of this project. The objective of the project was to utilize low cost, state-of-the-art technologies available to small independent operators to preserve access to well bores and extend the economic life of mature fields. The use of an integrated team of a geologist, geophysicist, and engineer is not new to major oil producers. However, utilizing a team of experienced consultants along with in-house personnel is new at the smaller independent level.

The initial approach of this study was to construct a flow model with conventional data. Logs and cores provided the basis for the geological model. Production data was assembled and validated along with the few measured pressures taken early in the field's history. Production testing of all wells was initiated to provide accurate current production data. Pressure transient testing of all wells was initiated to provide accurate current bottom hole pressures. History matching of pressure and water-cut data validated the flow model, and the flow model has since guided field operations, subject to the limits imposed by the spacing of the well data (one reliable well log per 18 acres of reservoir). At this scale, compartmentalization and heterogeneity of the reservoir is obvious. The engineering history match and reservoir simulation, however, is conducted at one-acre (220 x 220 feet) spacing or less. 3-D seismic is required to define porosity in the areas between the wells and reduce the uncertainty inherent in data sets from old fields.

The 3-D seismic data set was processed to retain high frequencies, thereby improving vertical resolution to the range of 50 feet. Seismic bin size is 110 x 110 feet, equal to the scale utilized in the history match and reservoir simulation. Traces from the seismic inversion model exhibit a high degree of correlation with the well log data. A correlation was developed between seismic velocities and porosity for each geologic zone. The correlation was used to develop porosity maps for each zone in the flow model. The seismic derived/geologically guided maps delineated small-scale reservoir heterogeneities with a degree of confidence here-to-fore unavailable. The history match and reservoir simulation grids were reoriented to make use of a porosity barrier identified on the porosity maps. The resulting flow model was validated through the history match process, and used to guide the realignment of the waterflood.

The recommendations made during the project to date have resulted in the production of an additional 114,000 Barrels of Oil to date, an increase in the injection water quality, and a paradigm shift in the approach to data collection for day to day decision making. The initiation of the waterflood realignment program is aimed at extending the life of the field and the recovery of significant incremental oil. Five wells have been restimulated and the production from these wells has increased from 16 BOPD to 134 BOPD.

INTRODUCTION

Grayburg and San Andres restricted, shallow-water carbonate platform reservoirs on the Central Basin Platform have been prolific producers for over 75 years. Beginning in the 1950's, waterfloods were implemented in most of the major fields. Reservoir heterogeneities have resulted in low recovery efficiencies during both the primary and secondary phases of production in most fields. The conventional wisdom states that old fields, such as the Foster-South Cowden Field, are entering the final stage of their decline, that there exists little if any additional incremental reserves that can be produced economically, that well bores and equipment are beginning to fail, and once lost will not be replaced. That watercuts, already in the 90+ percent range will only increase, and that little could be done to reverse declining oil recoveries. It has been estimated that the eventual abandonment of these fields, in as few as 15 years, would occur as wells fall below their economic limits.

There is a need for a methodology, that can be made available to the small independent, which can reverse this decline. Methods pioneered by major oil companies, and presently being employed on large properties, have applications in smaller properties if they can be demonstrated to be both cost effective and within the technical capabilities of employees of, and consultants for, the smaller independents. Many small properties have been sold by large oil companies because it is uneconomic for large companies to apply the state-of-the-art technologies to the smaller properties. This study proves that state-of-the-art technologies, including 3D inversion modeling, produced and injection water chemistry analyses, modern field engineering testing methods, and the development of an integrated reservoir characterization can identify economically attainable incremental reserves in the leases of smaller producers.

OBJECTIVE

The objective of the project was to utilize low cost, state-of-the-art technologies, available to small independent operators, to preserve access to well bores and extend the economic life of fields by identifying incremental and bypassed reserves. The use of an integrated team of a geologist, geophysicist, and engineer is not new to major oil producers. However, utilizing a team of experienced consultants along with in-house personnel is new at the smaller independent level.

Paradigms describing the status of older fields need to be addressed and overcome. Some of the more established paradigms are: that the majors have done the right things to develop their reservoirs, that periodic long duration shut in build up tests and field wide

water chemistry are not necessary, that a company of Laguna's size (9 full time employees) are too small to apply the technologies pioneered by the majors, that 3D seismic and inversion modeling do not have the "bang for the buck" in a smaller property (less than 640 acres), and that integrated reservoir characterization is too costly or has little return on investment.

The developed methodology had to be demonstrated to be cost effective, accessible to smaller independents, and capable of resulting in the development of incremental reserves at a low dollar-per-barrel cost.

Although this study is of a shallow shelf carbonate reservoir in the Permian Basin, the solution presented applies to fields in other basins and other reservoir classes as well.

APPROACH

With the aid of the DOE, Laguna Petroleum and Phillips Petroleum developed a two phase program for simulating the Grayburg/ San Andres reservoirs and determining the potential for incremental recovery of reserves through an integrated reservoir characterization, 3D seismic acquisition, interpretation, and inversion modeling, waterflood realignment, and an infill drilling and workover program. Although many of the Grayburg/San Andres reservoirs can be coaxed to give up accelerated reserves utilizing standard field management practices, it is believed that only by an integrated approach to field management, which includes a sequence stratigraphic based reservoir characterization, can significant incremental reserves be recovered.

The 3D survey was shot in August of 1994, but because of processing and interpretation problems, it was not available for integration into the simulation until Phase II in 1996. A geology based history match and engineering reservoir simulation was completed during Phase I. Cores existed for only one of the 5 wells cored in Section 36 although standard core analyses did exist for the remaining cored wells. A sequence stratigraphic model was built utilizing available core and log information. With 53 wells drilled in, or peripheral to, the section, it would be logical to assume that excellent control would be available. The reverse was true as the 40 acre 1940's vintage wells were not logged, and the deep (Canyon and Ellenburger) wells had, at best, cased hole neutron logs through the Grayburg/ San Andres. Only 34 wells have porosity logs usable in the construction of a porosity map for the identified flow units. The porosity maps generated for input into the history match and simulation had only one data point per 18 acres. The geology-only based history match was adequate to demonstrate sufficient additional potential to drill, recomplete and re-enter a number of wells, and identify that the upper Grayburg contained significant bypassed and unswept reserves. A waterflood realignment was needed to recover these reserves. The history match also determined that the lower Grayburg had significant remaining potential and that the San Andres reservoir had been compartmentalized as a result of karstification and despite the largest OOIP was an uneconomic target. Phillips Petroleum sold their property in the project area at the end of Phase I. Laguna chose to continue into Phase II with their property (Section 36).

GEOLOGIC SETTING

The Foster-South Cowden Field is located on the eastern margin of the Central Basin Platform in central Ector County, Figure 1, immediately west of Odessa, Texas. Like most San Andres and Grayburg reservoirs, Foster-South Cowden is situated on the shallow shelf at Grayburg time, which trend north to south and oblique to the paleo-wind direction. Major deep seated uplifts to the west form the spine of the Platform and restrict the shelf to a width of six to 10 miles from shelf edge to sabkha. The field is part of the trend of San Andres – Grayburg production that extends from Yates Field at the southeast, to Seminole Field at the north end of the platform

FIELD HISTORY

The Foster-South Cowden Field has a history typical of many fields in the United States. Oil was first discovered in the Foster-South Cowden Field in 1934. Production was established in the study area in 1939. The property, originally owned by ARCO and Sun, Figure 1B, was developed beginning in 1940, complete open hole, shot with nitroglycerine, and developed on 40 acre spacing. The field produced from 550 feet of gross pay and as much as 200' of net pay in the upper and lower Grayburg and San Andres. The wells were hydro-fracture stimulated in 1955 which resulted in a three fold increase in production. In 1962, the poorest producer on each 160 acre tract was converted to injection, initially injecting on vacuum as the field pressure had been severely reduced since 1939. In the 1970's an infill drilling program reduced spacing to 20 acres. No structured waterflood with an identifiable pattern has ever been attempted. The "waterflood" as it exists today, is a partial line drive.

Production from the Canyon and Ellenburger was also established during the 1970's bringing the total well count in the section to 53 (including 4 lease line injectors). Injection profiles indicate that over 80% of the water was being injected into the upper Grayburg, 5% into the lower Grayburg, less than 5% of into the San Andres, and the remaining injection going "out of zone".

Laguna purchased the NE/4 of Section 36 in 1990 and the remaining ¾ of the section in 1992, anticipating that with prudent, well established field management, the property would have an economic life of +/- 15 years.

METHODOLOGY

Geophysics

The 3D seismic survey acquired is 3.3 square miles, intended to image the Grayburg reservoir at 4,000 feet. One requirement for the DOE is to develop a methodology for other workers to use multiple scientific disciplines, and this report details the geophysical work done in a "cookbook form". Another DOE objective is to give independent operators the ability to apply these methods using inexpensive computers and software. The Inversion Modeling process was accomplished within these criteria at the offices of Laguna Petroleum.

Maps have been made using analyses of seismic Inversion Model data (calibrated to well data) to show the distribution of gross average rock porosity of several oil productive zones of the upper Grayburg formation beneath the 3D shoot. These data were factored into an engineering model to define reservoir capacity and preferred fluid flow, explaining the historical production of oil and water and the injection of fluids. This overall model has guided decisions for future expenditures for workovers, recompletions, and new wells. Figure 1a & 1b compares a map of the seismic-derived porosity distribution with a map made using only log-derived porosity data, and demonstrates that increased data density offers a more complete image of porosity distribution.

The overall task defined for the geologist and geophysicist is to define geologic parameters significant to the production and determine ways to map those parameters. When the engineer is initially involved with those decisions, his needs and concerns can be addressed as part of that task. Primary among his needs are production zone-dependent reservoir characteristics at the scale of the reservoir, specifically, the flow unit scale. Quantitative, not relative values are required to be useful for production history comparison. Reservoir porosity is the factor with the most influence on production and waterflood injection; permeability is proportionally related to productive porosity in this project area.

A seismic interpretation of the Grayburg is simplified since that sequence contains no seismically discrete siliciclastic layers within the reservoir in this project area that would affect the seismic data. Changes in porosity will cause a seismic reflection response because porosity affects sonic velocity, thus, acoustic impedance. Thickness of producing zones is measured using log correlations of thin siliciclastic markers. The thickness maps are essential to calculate the same zones for the seismic data analysis. Porosity values are determined from log calculations. Structure is not a primary factor controlling production at the project scale, but may have profoundly affected facies distributions. The geophysical task is to isolate production zones in seismic time, convert the seismic data to a reservoir-quantitative form, and to produce maps of value to the engineer for detailing the distribution of oil in place.

The first consideration for the seismic analysis of any project is where to begin, since different projects have different geologic considerations. Tracking seismic reflectors and making time and reflection amplitude maps are a start, but do not define the critical factors of rock properties. Seismic waveform attributes are a button-click away, but analyses of results are vague and probably useless on the required scale, even when applied critically. The foundation of the project is to relate seismic data to well data through theory, as preferable to empirical or statistical methods. Results are then understandable and errors are noticeable. Inversion model results can be evaluated in context with rock properties, whereas waveforms (wiggles) are essentially in a foreign script, a convenience of data recording. Reflections are only a response to *relative* rock property changes. Why would a geophysicist be negative about reflections? Because reflections don't contain the quantitative answers, as will be shown.

Inversion Modeling

Seismic reflection data have no stratigraphic significance ... until geologic data are incorporated using well control and interpreter experience. Actually, a number of technical points (phase, for one) must be met to even qualify any seismic display.

Inversion Modeling is a process that removes the ambiguities of the seismic wavelet to establish some uniqueness to the data model. The model then has some characteristics of the stratigraphy to which the seismic data are the response. In a nutshell (which will be cracked later) **Inversion Modeling removes the wiggle and infuses geologic constraints into the seismic data set.** A discussion of Inversion Modeling procedure follows in the methodology. Figure 2 shows profile L-L', an example of the seismic data in the project. The zone of most interest is only about 24 milliseconds of the upper Grayburg. Figure 3 is an enlargement of a part of the data in figure 2, showing the Inversion Model traces.

Expectations from the seismic data will be considered from acquisition and processing parameters. The survey data quality embodies actual fold, noise, wavelet bandwidth and phase. The scale of the geology to be imaged is compared to the resolution of the seismic analysis. Inversion Modeling reveals the sensitivity of seismic traces to the qualities of wavelet and noise, and model traces may represent the true seismic resolution.

A number of expected intrinsic problems of defining rock properties are considered. Porosity values are measured from logs, but calibration varies with log type. The difficulty of normalizing porosity values causes inherent scatter in the porosity calibration data set. Reservoir anhydrite also complicates porosity measurements. Sonic velocity (both seismic and log-derived) responds to changes in primary porosity but is not very responsive to vuggy porosity. By comparison, the neutron-sourced log device measures total porosity. Lithology contrasts can potentially appear seismically the same as rock property changes. Synthetic seismogram models show that geologic correlations are not represented by reflections, so that placement of analysis zone boundaries in x, y, t space contains some error. Waveform attributes will not define rock properties in thick carbonate reservoir situations; reflections do not quantify reservoir properties but only show relative changes.

Inversion Model building is an important tool of geophysics for quantifying rock properties. A brief description of the method is intended to reveal the requirements for model building and the "do-it-yourself" nature of modeling using the PC. The interpreter familiar with the geology will be best qualified to assess the model results. The software used for this project is Vest Exploration Services 3DINV program. It creates a model controlled by user constraints. The modeling is performed using a Generalized Linear Inversion (GLI) method that, by iteration, converges on a best result. This program internally creates a pseudo-sonic log trace from each seismic trace. Constraining the model refers to infusing into the model traces values of sonic velocity and horizon location; other constraints of known waveform characteristics of amplitude and frequency bandwidth are absent from the model traces. Phase of the input seismic data must be zero. The results of a model are greatly influenced by data quality. Seismic noise is the worst contaminator since it decreases the accuracy of seismic reflection placement and amplitude. Data processing methods involving wavelet shaping, specifically of frequency and phase, affect model trace accuracy and vertical resolution.

Model Analysis is the ultimate goal and produces the maps needed. Techniques used for the Grayburg are described in the step-by-step discussion that follows. The qualification of the model accuracy and resolution rely on the model analysis of geologic zones and relationships to subsurface knowledge.

The upper Grayburg zones appear to be well described in the final analysis. However, seismic relationships for lower Grayburg zones (source of some oil production) with subsurface data have not been strong enough to be of value. Similarly, work with the San Andres has been unfulfilling. The reservoir internal structure of these problem zones is more complicated and analysis zones are thinner. Lateral relationships in the karsted San Andres are complex compared to the upper Grayburg.

Production History

1. Past production was estimated and allocated to correlated zones of the upper Grayburg.

Geological Preparation

(for a more complete review of the geological portion of the study, the reader is referred to the 1996-1997 and 1997-1998 annual reports and the tech transfer presentations listed at the end of this paper.)

1. Geologic data were prepared in a data base format. Available logs were correlated, production zones were defined, and log correlation's were made for important zone boundaries (Figure 4).
2. Depth (Figure 5) and thickness (Figure 6) maps were made of the major production zones (typically 100'-200' thick). Zones were subdivided into zones as thin as about 50' for further study.
3. Digitized neutron, density, and sonic log curves were used to calculate porosity and its relation to zone thickness. Average porosity, and other porosity parameters were calculated for the upper Grayburg zones. Gross average porosity is the parameter most likely sensed by the seismic tool.
4. Relationships of log properties were studied in core and logs. A very important revelation observed from core study is that lithology throughout the Grayburg is consistently dolomite and anhydrite, so that non-carbonate lithologies are unlikely to complicate the seismic analysis.

Geophysical Procedure

1. Basic, conventional seismic time maps were made for the Queen, lower Queen, Grayburg, San Andres, and Holt reflections. Waveform attributes associated with some of these reflections were observed.
2. Synthetic seismogram models (Figure 7 & 8) were made to examine seismic relationships to geologic data. The top of the Grayburg A zone geologic correlation is represented as a reflection in the west part of the 3D survey but not in the east part because of dolomite within the lower Queen. The other Grayburg zones do not have associated reflections at all since they are not bounded by significant non-carbonate clastic beds.
3. Sonic logs integrated in time were measured for interval time and thickness to determine average velocity of each zone. Figure 4 shows the sonic log with the velocity calculations, the synthetic seismogram and the Inversion Model traces at the well tie. The figure provides a comparison of the three data types, and a sense of the resolution of each. This velocity field from all sonic logged wells was mapped (contoured) and digitized for the area of the 3D survey. These contour

- maps were revised for final use by considering the distribution of velocity from inversion-derived maps. The final isochron maps were calculated using these velocity maps.
3. Isochron maps were calculated from subsurface-mapped isopach and the interval velocity maps. In fact, a depth to time conversion was done. Time thicknesses were mapped for the Grayburg A, B, and C zones.
 4. An inversion model was calculated for the 3D volume. The input parameters for the model include reflection horizons, sonic velocities determined from logs, and frequency and amplitude characteristics of the seismic data. In common with the 3D survey, the model traces replace seismic wiggle traces. The model trace lengths (in time) are shorter than the seismic traces, since they are windowed from 500-1100 milliseconds around the zones of study.
 6. Profile comparisons were made of the model traces with the sonic logs in time for qualification purposes. The inversion model traces have a minimum resolution of about 50 feet, compared to the sonic log with one foot resolution, or a wiggle trace of undefined resolution. Refer to Figure 3.
 7. The lower Queen reflection horizon picks were edited on the Inversion Model traces to map the lithologic boundary of the top of the lower Queen clastics. This horizon is the **reference** for horizon building the Grayburg horizons. The lower Queen is a reasonable lithologic boundary near the top of the Grayburg.
 8. Isochron maps were successively added, beginning with the lower Queen reference, to build horizons for the A, B, and C. Deeper horizon levels were also calculated for the Grayburg, as well as the San Andres. For example, the isochron of the lower Queen to Grayburg A interval, added to the lower Queen time horizon, yields a time horizon for the Grayburg A.
 9. Average Interval Velocity was calculated from the Inversion Model for the Grayburg A and B zones, using the zone boundary horizons and the interval averaging routine in the Vest seismic software. These maps represent the seismic response to dolomite velocity at specific places in the rock sequence.
 10. The values of Average Interval Velocity were graphically compared to well log-derived values of Gross Average Porosity at well locations. The zones analyzed in the Inversion Model lie between the calculated time horizons. Figure 9 shows the cross-plot relationship of gross average porosity with seismic-derived velocity for the Grayburg A zone (thick line). A Schlumberger chart (curved dashed lines) shows the commonly used relationship of sonic log velocity and measured porosity. That chart has been used as a guide to judge the normalized values of velocity from the Inversion Model and to interpret the slope of the line used to convert the velocity data to porosity data.
 11. A linear function was determined from the cross-plotted points, and was used to convert the Inversion Model velocity values to Gross Average Porosity values using the Vest software. The map of calibrated Gross Average Porosity of each Grayburg zone was used in the production history model.
 12. Quality of the seismic-derived porosity map was partly assessed by the scatter within the alignment of cross-plot points. By comparison, that scatter is comparable to the scatter of laboratory-derived relationships of velocity and porosity.

Seismic Derived Porosity Maps

Seismic-derived porosity maps for the Grayburg A and B zones are shown in figures 10 and 11. These zones comprise the upper part of the Grayburg and are reservoirs for the significant historic production. The complex areas of high porosity within the A zone are adjacent to areas of much lower porosity. Water injection wells placed in the low porosity areas might not be effective for moving fluids toward producing wells. A significant trend in the A zone is the southwest oriented low porosity area that coincides with the structural break in the southeast part of Section 36 (see Figure 5). As a barrier to fluid flow, the engineering simulation was reoriented to parallel the anomaly. The B zone is, on average, less porous than the A zone, but was included in the fluid simulation. A brief supplemental study of the gas-to-oil ratios measured for the Grayburg production was made from early records. GOR values in Section 36, west of the A zone porosity barrier are about one-fourth of the values on the down-dip side of the barrier in Section 31. A discontinuity of the A zone reservoir is strongly suggested by that relationship. The barrier may be a stratigraphic trap to fluid movement, demonstrated by high GOR values at the updip limit. Waterflood attempts across such a barrier would be pointless. The seismic-derived porosity data were exported as spreadsheet values of x, y, and porosity to engineering software that contains data from historic production of oil, gas, and water, zone thicknesses, and other relevant parameters. The more densely defined porosity distribution contributed to building an optimum reservoir model. The objectives of that model are to determine remaining oil in place and optimum ways of extracting it. The reservoir model is qualified by the match with production history. This model is the basis of understanding waterflood effectiveness and of planning recompletions, new wells, and abandonments.

The surface seismic tool holds great potential for characterizing carbonate reservoirs in the Permian Basin. Although specific local problems must be addressed in the approach to analyzing the data, Inversion Modeling is an important step in converting seismic data into an intuitively useful form. Ultimately, the multi-disciplinary approach is necessary to produce hundreds of millions of barrels of oil already discovered.

ENGINEERING

Simulation Results

Flow models were built specifically to test the seismic-derived porosity maps (see Geophysics). After reviewing the seismic derived porosity map, it became apparent that the simulation grid needed to be rotated approximately 45 degrees to match a no-flow boundary (a very low porosity trend parallel to a break in slope in the Foster-Pegues lease). The original simulation grid was oriented parallel to the section lines as the “geology only” porosity map was not of sufficient detail to define the no flow boundary. The flow models considered only Section 36. Separate models were built for each upper Grayburg layer (A, B, and C). The purpose was to directly compare the oil in place (OOIP) for a model built from the seismic-derived porosity map to the OOIP for a model built from well values and then history matched. Initial comparison indicated that the

OOIP from the seismic-derived porosity maps was about 50% greater than the OIP from the history matched model. The velocity to porosity transform to create the seismic maps was adjusted until the values of OOIP were within 20%. At that point the conventional history matching process started.

Although similar to the original simulation, the reoriented simulation exhibited significant differences in the distribution of present day water saturations. A suite of bottom hole pressure tests was begun on all wells that have not already been refractured. The new simulation will be run again in the future when the pressure buildup tests, produced water analyses, additional production and data from additional refracs are completed and analyzed.

The upper Grayburg is now the primary target in the study area. Completions in the San Andres have demonstrated the limited nature of the reservoir. As previously discussed (see 1996 – 1997 Annual Report), the karst event at the end of the San Andres has compartmentalized the reservoir in this portion of the platform. The lower Grayburg has also been isolated and tested in a number of wells and appears to be a candidate for waterflood at a later date. CIBP's are being set above the San Andres and lower Grayburg zones so that, in the future, the zones can be re-entered. In most of the wells, the lower Grayburg and San Andres were completed through a single set of perforations and a single frac. Therefore, we will refer to the lower Grayburg and San Andres as a single unit, the lower Grayburg/San Andres. The upper Grayburg waterflood (A, B, and C zones) has become the focus of the project. The high confidence level in the upper Grayburg seismic derived porosity maps re-enforces the decision to enhance the existing waterflood.

Field Engineering Objectives

Together with the continuous testing and monitoring of bottom hole pressures, individual well production, injection volumes, injection pressures, injection profiles and day to day operations, the engineering objectives of the year were to:

- Redirect the focus of the project on the re-alignment of the upper Grayburg waterflood
- Isolate the upper Grayburg in wells producing from multiple intervals
- Initiate a new bottom hole pressure testing procedure and program
- Implement recommendations derived from bottom hole pressure data.

Re-Alignment of Upper Grayburg Waterflood

The re-alignment of the upper Grayburg waterflood became the focus of the study area throughout 1998. Completion attempts in the San Andres had little success due to the limited nature of the reservoir. Tests in the lower Grayburg have indicated the interval to be productive. However, efforts to produce and waterflood both the upper and lower Grayburg in tandem have proven to be unsuccessful and inefficient due to the difference in reservoir characteristics.

Thus, it was decided to plug back and isolate the upper Grayburg in all wells producing from multiple intervals and focus the project on re-alignment of the waterflood for the upper Grayburg. Figure 12 identifies the wells currently producing from the upper Grayburg that have been restimulated. These wells highlight the inefficiency of the so called "flood pattern". Although wells were originally drilled in a pattern adequate to

flood the upper Grayburg, the present distribution of upper Grayburg emphasizes the need for the flood to be re-oriented, and available P & A'd and T & A'd to be utilized. Prior to running the final re-oriented simulation (see simulation) it was necessary to gather as much additional information on the upper Grayburg as possible. Production tests, water analysis and a new suite of bottom hole pressure test were taken on all wells before and after isolating the upper Grayburg.

Bottom Hole Pressure Testing

Initial bottom hole pressure information obtained during the project was considered insufficient to aid in the re-alignment of the upper Grayburg waterflood. Previous bottom hole pressure tests were very short in nature. Generally, the tests lasted for a duration of three to four days and required a significant amount of extrapolation of the data. Due to the short shut-in periods, the results were uncertain and were considered unusable. Thus, a revised testing procedure and program was initiated for the project.

The new testing procedure consisted of continuously analyzing the data during the shut-in period. The tests were continued until a reasonable data set was collected for interpretation. On average, a good data set was collected after approximately 900 hours of shut-in time. Additionally, great attention and detail was given in the actual data gathering in the field.

Recommendations

As a result of the plug backs, production tests, and new suite of bottom hole pressure tests, it became apparent that although many of the wells have been a part of a waterflood for 30 years, their capability of producing fluids was poor. This is a result of the very short frac wing lengths achieved during a fracture program performed on the leases in the late 1970's and early 1980's. The fracture treatments pumped at that time consisted of 40,000 gallons of fluid and 20,000 lbs of sand. Although the treatments achieved initial producing rates considered as successful, the relatively small treatments created short frac wing lengths resulting in rapid production declines.

Based upon high bottom hole pressures, short frac wing lengths and low total fluid production, it was recommended to initiate a re-stimulation program for the upper Grayburg. Seven wells were identified and recommended as re-frac candidates. Three wells, the Brock #6, Brock #5 and Foster-Pegues #8 were re-stimulated in 1998. It was determined much larger treatments needed to be utilized to achieve greater frac lengths. The treatments, designed to obtain frac lengths of up to 180', averaged 28,000 gallons of fluid and 104,000 lbs. of sand. Producing rates in the wells prior to the treatment averaged less than twenty barrels per day. After initial declines following the treatments, the rates stabilized at over 150 barrels of fluid per day resulting in a seven fold increase in sustained production (see figure 13).

A standard water analysis costs \$75.00. A bottom hole pressure test is included as part of daily operations and is a no-cost item. The cost to analyze a bottom hole pressure is \$425.00. The production "lost" during a 30 day build up test is quickly recouped as flush production after the well is returned to production. A fracture stimulation, without new well equipment is \$25,000.00. All costs are approximate and fluctuate with the price of oil.

ACCOMPLISHMENTS

The major accomplishment of the project has been demonstrating that state-of-the-art technology can be economically applied to smaller properties (+/-640 acres) operated by independent operators. The project has proven that reservoir characterization, including periodic water chemistry analyses and production tests, long duration shut in build up tests (data collection), integrated core and log data, and 3D seismic and inversion modeling can be performed on smaller leases in a timely and cost effective manner.

The recommendations made during the project have resulted in the production of 114,000 Barrels of incremental oil to date. Coincident with the 7 fold increase in oil production in the five refraced wells (from 16 BOPD to 134 BOPD) was a 13 fold increase in water production. The water production from the 5 wells rose from 74 BWPD to 959 BWPD. This water was needed for injection as the results of the simulation indicated that an increase in injection in the reservoir was a necessary part of the waterflood realignment program. In addition, the injection water quality has been improved through changes in the water system.

For the first time, the reservoir has also been divided into its component parts. The upper Grayburg is a 68 year old field with a 37 year old waterflood in need of realignment. The main waterflood target remains the upper Grayburg where significant bypassed and incremental reserves remain to be exploited. The lower Grayburg is at near virgin reservoir conditions in part of the field and is a future candidate for waterflood. In order for the waterflood to be viable, access to as many well bores as possible need to be maintained. The San Andres is a compartmentalized reservoir with a large OOIP but very low recoveries. Completions in the San Andres have resulted in good initial potentials but very low ultimate recoveries. Presently, technologies are not available to make San Andres completions economic.

APPLICATIONS

The results of this project demonstrate that low cost state-of-the-art technology and integrated reservoir characterization can be utilized to preserve access to existing well bores, prolong field and reservoir lives, and enhance ultimate recoveries. This methodology is applicable to not only shallow shelf carbonate reservoirs in the Permian Basin, but is also applicable to carbonate fields in other basins and fields in and other reservoir classes.

The use of long duration shut in buildup tests, water chemistry analyses, and 3D seismic inversion modeling has been demonstrated to be both cost effective and available to the small independent. The use of inexpensive, off the shelf geological, geophysical and engineering software packages which all run on a PC platform, and the integration of familiar engineering, geological, and geophysical practices in the integrated reservoir characterization provides a “comfort factor” for independents.

FUTURE ACTIVITIES

Laguna has developed a management plan for each well in the project area and identified action items for each well. Laguna has initiated extended shut in build up tests and periodic production tests and produced water analyses on their offset leases to the east and west. They have also completed a series of tests in a deep water clastic unit in the Delaware Basin, and will soon initiate testing programs on other leases. Offset operators and a number of operators with leases on trend have requested more information, reviews of the project, or have expressed interest in having a review of their properties to determine if the methodology developed here was applicable to their leases.

In the next six months, Laguna plans to drill one producer, one lease line injector, acidize two wells, re-enter two wells to convert to injectors, re-enter one well to place back on production, and re-frac two wells as part of the upper Grayburg waterflood realignment. In addition, one well will be deepened to the lower Grayburg. The results of this activity will be monitored and based on results additional well work planned. This program is aimed at extending the field life beyond 10 to 15 years and recovering significant incremental oil. The upside potential for the project area is estimated to be 3,000,000 barrels of incremental oil bringing the recovery factor from 12.5% to almost 19%.

We are committed to presenting as many tech transfer events as possible, targeting operator, engineering, geologic, and geophysical audiences. We will continue to update our website (www.lagunapetrol.com) as often as necessary.

RECENT TECH TRANSFER EVENTS

(In Reverse Chronological Order)

Trentham, R. C., and K. Widner, 1999, Using Produced Water Analyses to Evaluate Production Problems and Recompletions in an "Old Waterflood", an Update: Foster-South Cowden Fields, Ector County, Texas, *in* Luftholm, P. and G. Hinterlong, eds., Permian Basin: Providing Energy for America: West Texas Geological Society Symposium, *in Press*.

Trentham, R. C., and K. Widner, 1999, Using Produced Water Analyses to Evaluate Production Problems and Recompletions in an "Old Waterflood": Foster-South Cowden Fields, Ector County, Texas, *in* J. Campell, ed., Mapping the Future: Fundamental Geology/New Technology, Transactions and abstracts of the AAPG SW Section Convention, Abilene Geology Society, Publication 99-1, p. 85, and extended abstract.

Robinson, William C., 1998, The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics: A Case Study, *in* Bulletin of the West Texas Geological Society, Part I in Dec. 1998, vol.38, no.4., p.4-11 and Part II in Jan.1999, vol.38, no.5 p. 4-8.

Robinson, William C., 1998, The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics: A Case Study presented at Society of Professional Earth

Scientists III Seismic Symposium, November 11, 1998, in Midland, Texas. The abstract appears in the Symposium publication.

Weinbrandt, Richard M., R.C. Trentham, W.C. Robinson, 1998, Incorporating Seismic Attribute Porosity Into a Flow Model of the Grayburg Reservoir in the Foster – South Cowden Field SPE#39666. *In* ed. W.D. DeMis and M.K. Nelis, “The Search Continues into the 21st Century”: West Texas Geology Society Pub. 98-105, p.231-238. Presented orally at the Symposium, October 31, 1998.

Weinbrandt, R. M., R. C. Trentham, W. C. Robinson, 1998, Incorporating Seismic Attribute Porosity Into a Flow Model of the Grayburg Reservoir in the Foster – South Cowden Field SPE#39666. SPE/DOE Eleventh Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 19-22, 1998. Proceedings, vol. 2, p. 115-128.

Trentham, R. C., W. C. Robinson, R. M. Weinbrandt, 1998, The Use of Core in an Integrated 3D Seismic, Geological, and Engineering Study of the Grayburg/San Andres of Foster and South Cowden Fields, Ector County, Texas, *in*. E. L. Stoudt, D. W. Dull, and M. R. Raines, eds., Permian Basin Core Workshop – DOE Funded Reservoir Characterization Projects: Permian Basin Section SEPM Core Workshop, Publication 98-40, 22 pages.

Robinson, W. C., R. C. Trentham, 1997, Practical Mapping of Lithology and Rock Properties Using Analyses of Seismic Inversion Models, *in* W. D. DeMis, ed., Permian Basin Oil and Gas Fields: Turning Ideas into Production: West Texas Geological Society Symposium, Publication 97-102, p.105.

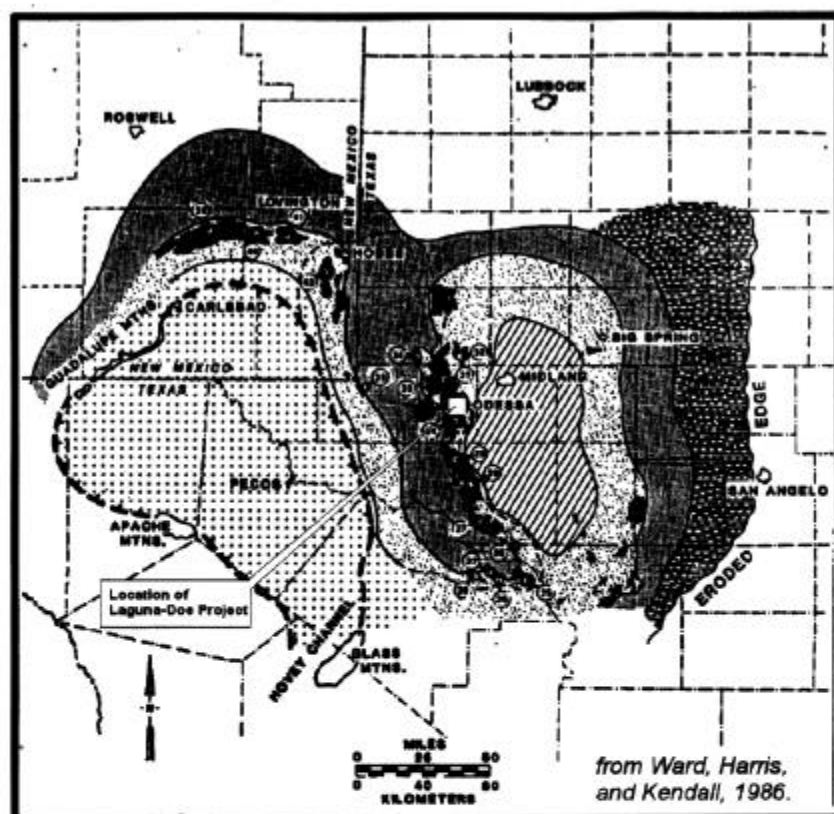
Trentham, R. C., W. C. Robinson, R. M. Weinbrandt, 1997, How an Independent Operator Can Integrate Engineering, Geophysics and Geology in a Reservoir Study: Grayburg/San Andres of Foster and South Cowden Fields, Ector County, Texas, *in*. W. D. DeMis, ed., Permian Basin Oil and Gas Fields: Turning Ideas into Production: West Texas Geological Society Symposium, Publication 97-102, p. 109.

A presentation titled, “*How An Independent Can Integrate Geology, Geophysics, And Engineering To Enhance Reserves In An Old Field*”, was made by R. C. Trentham to the Kansas Geological Society on November 5, 1997 in Wichita, Kansas.

ACKNOWLEDGEMENTS

The work on this project was performed under contract # DE-FC22-94BC14982. Robert C. Trentham is the Laguna Petroleum contact for this project. Dan Ferguson at the National Petroleum Technology Office (1-918-699-2047) is the Contracting officer’s Representative (COR). The project began Aug 2, 1994 and will be complete Aug, 2,1999. We would like to acknowledge James J. Reeves and Hoxie W. Smith for conceiving and managing the DOE study and for being responsible for the geophysical study. Since April 1996, William C. Robinson has been responsible for reprocessing and reinterpreting the

seismic data and for the geophysical study. Also since that date, Robert C. Trentham has been responsible for project management.



**PERMIAN
MIDDLE GUADALUPE SERIES
GRAYBURG FORMATION**

--- CAPITAN "REEF" FRONT (SUBSURFACE) DELAWARE BASIN-CHERRY CANYON FORMATION BASINAL SANDSTONE, SILT, SHALE AND LIMESTONE DOLOMITE --- OUTLINE CENTRAL BASIN PLATFORM ⊙ OILFIELDS LISTED IN TABLES	EVAPORITIC FACIES-DOLOMITE, POROSITY PLUGGED BY EVAPORITES. LIMESTONE ANHYDRITE AND HALITE RED SANDSTONE, RED SILTS, RED SHALES AND BEDDED ANHYDRITE OIL OR GAS FIELD

SIMPLIFIED GEOLOGIC MAP OF THE GRAYBURG FORMATION, PERMIAN BASIN, SHOWING THE LOCATIONS OF PRODUCING FIELDS. SEE TABLE 2 IN APPENDIX FOR DETAILED DESCRIPTIONS OF THE NUMBERED FIELDS.

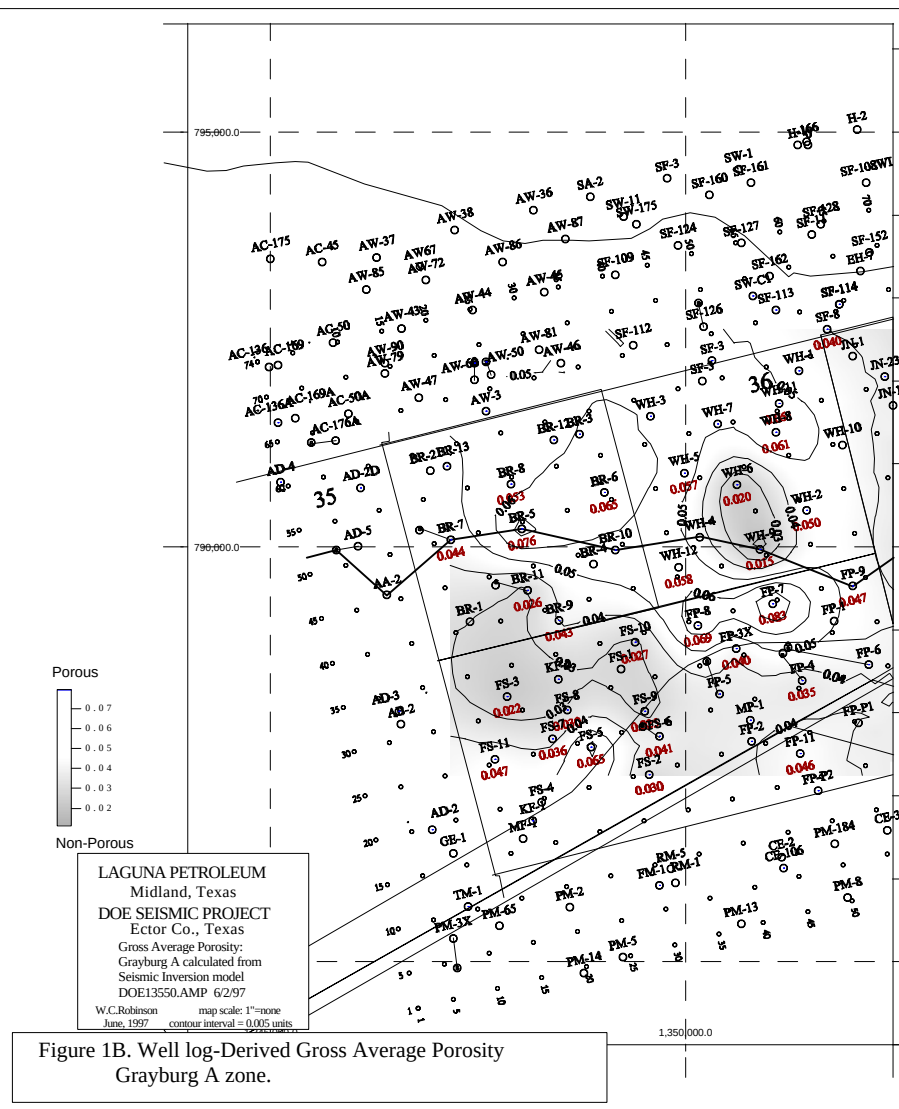
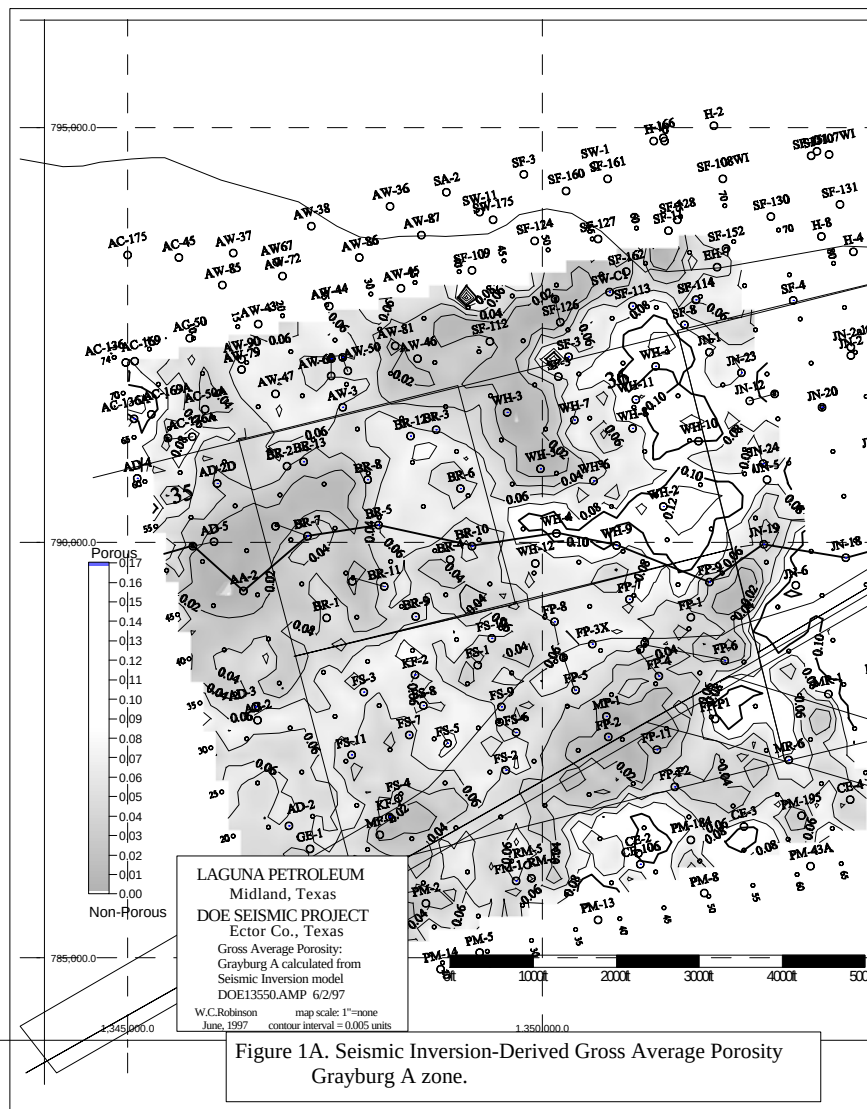
SYSTEM	SERIES	STRATIGRAPHIC UNIT
PERMIAN	Ochoan	Dewey Lake
		Rustler
		Salado
	Guadalupian	Castile
		Tansill
		Capitan
		Yates
		Seven Rivers
		Goat Seep
		Queen
PENNSYLVANIAN	Leonardian	Grayburg
		San Andres
	Wolfcampian	Clear Fork
		Spraberry
	Wolfcampian	Dean
		Wolfcamp
		Cisco
		Canyon
		Horseshoe Atoll
		Strawn
MISSISSIPPIAN		Bend
		Mississippian
DEVONIAN		Thirtynine
		Wristen
SILURIAN		Fusselman
ORDOVICIAN	upper	Mentoya
	middle	Simpson
	lower	Ellenburger
CAMBRIAN		

Relative production ● ————— ●

QA144216

Paleozoic section in West Texas showing relative importance of oil producing unit (from Galloway and others, 1983).

Figure 1. Location Map for the Laguna-DOE Project and Stratigraphic Column.



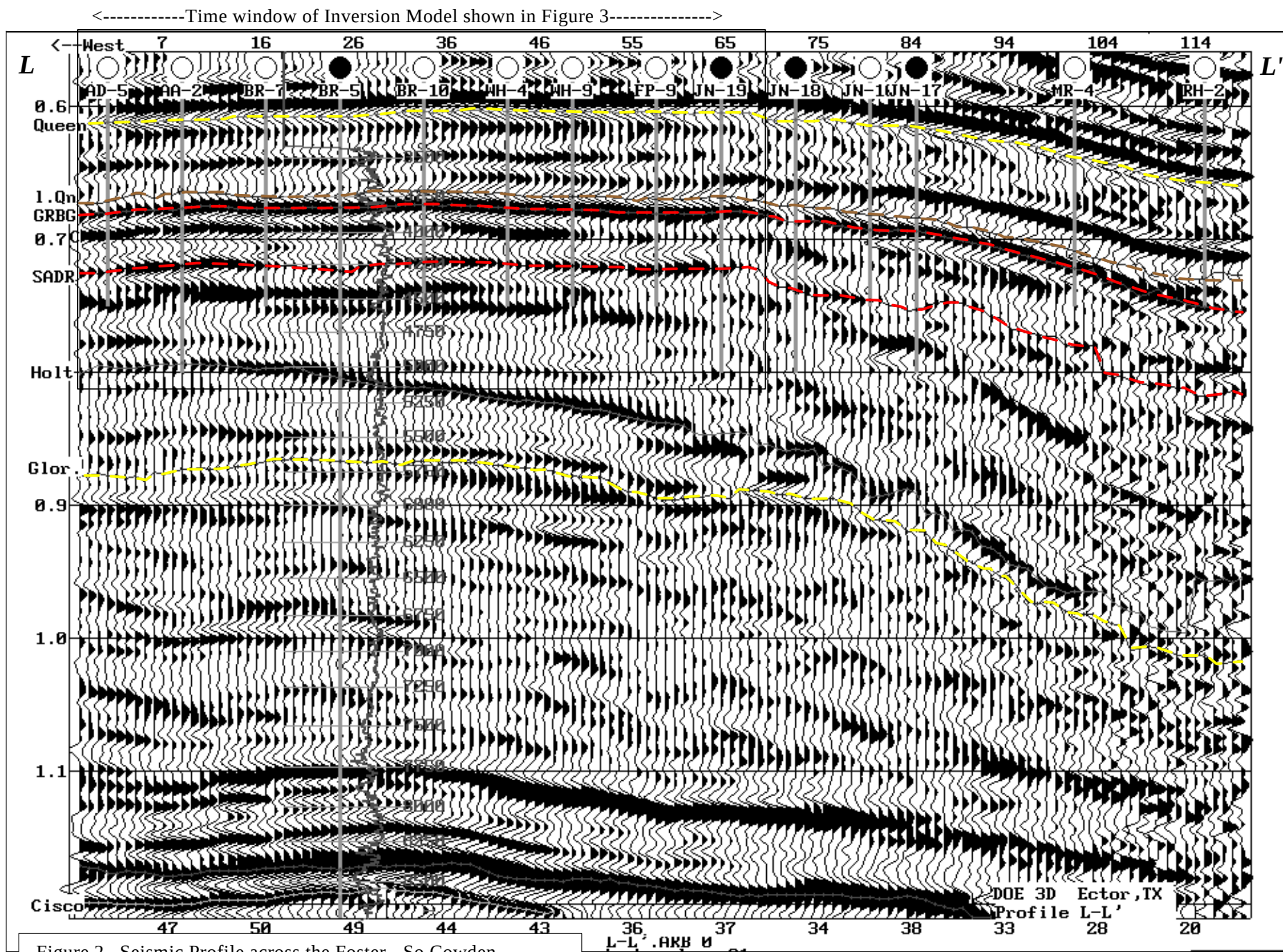


Figure 2. Seismic Profile across the Foster - So.Cowden 3D seismic survey, showing some structural and stratigraphic features of the project.

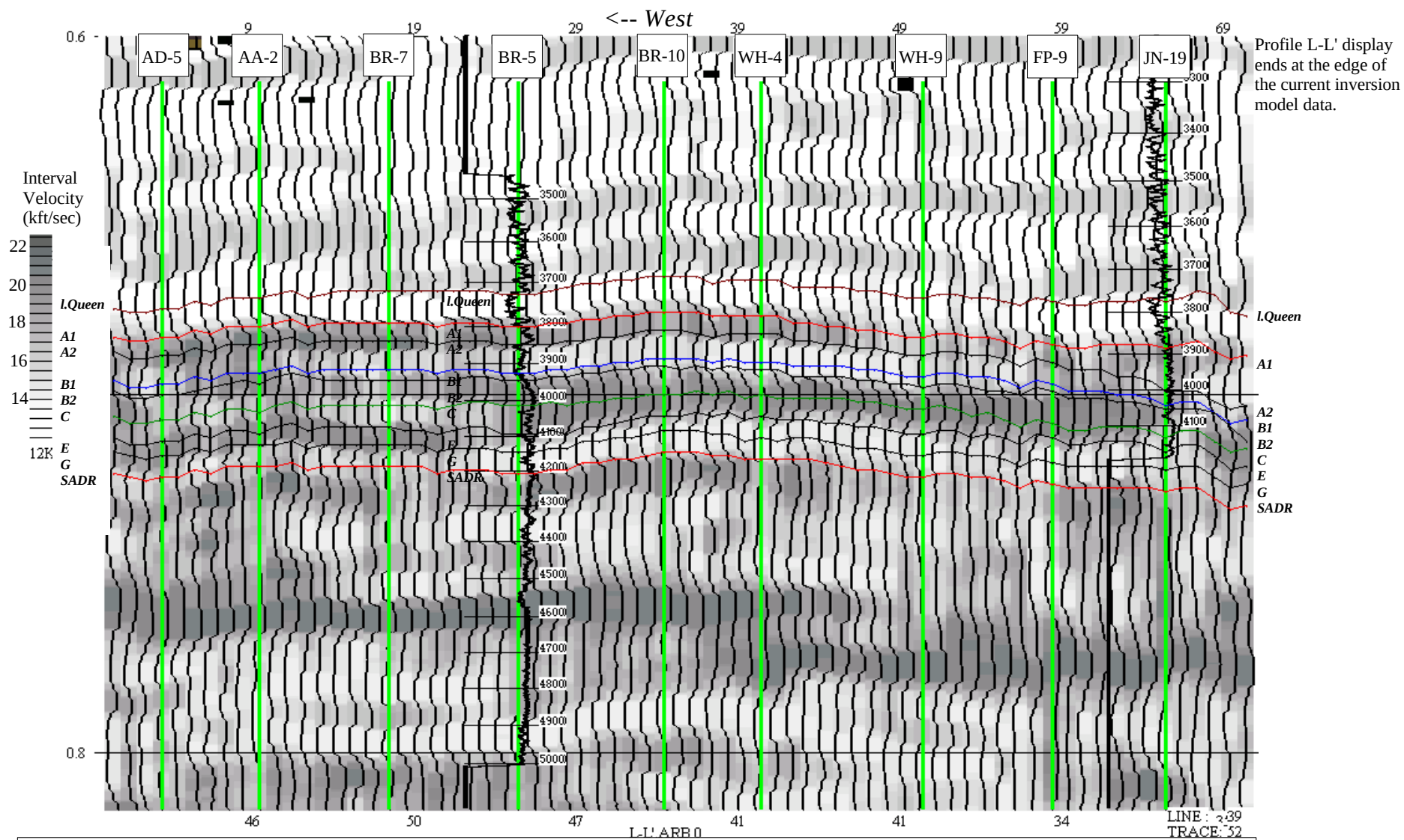


Figure 3. Profile L-L' (partial) from the inversion model data volume showing ties with wells and sonic logs.

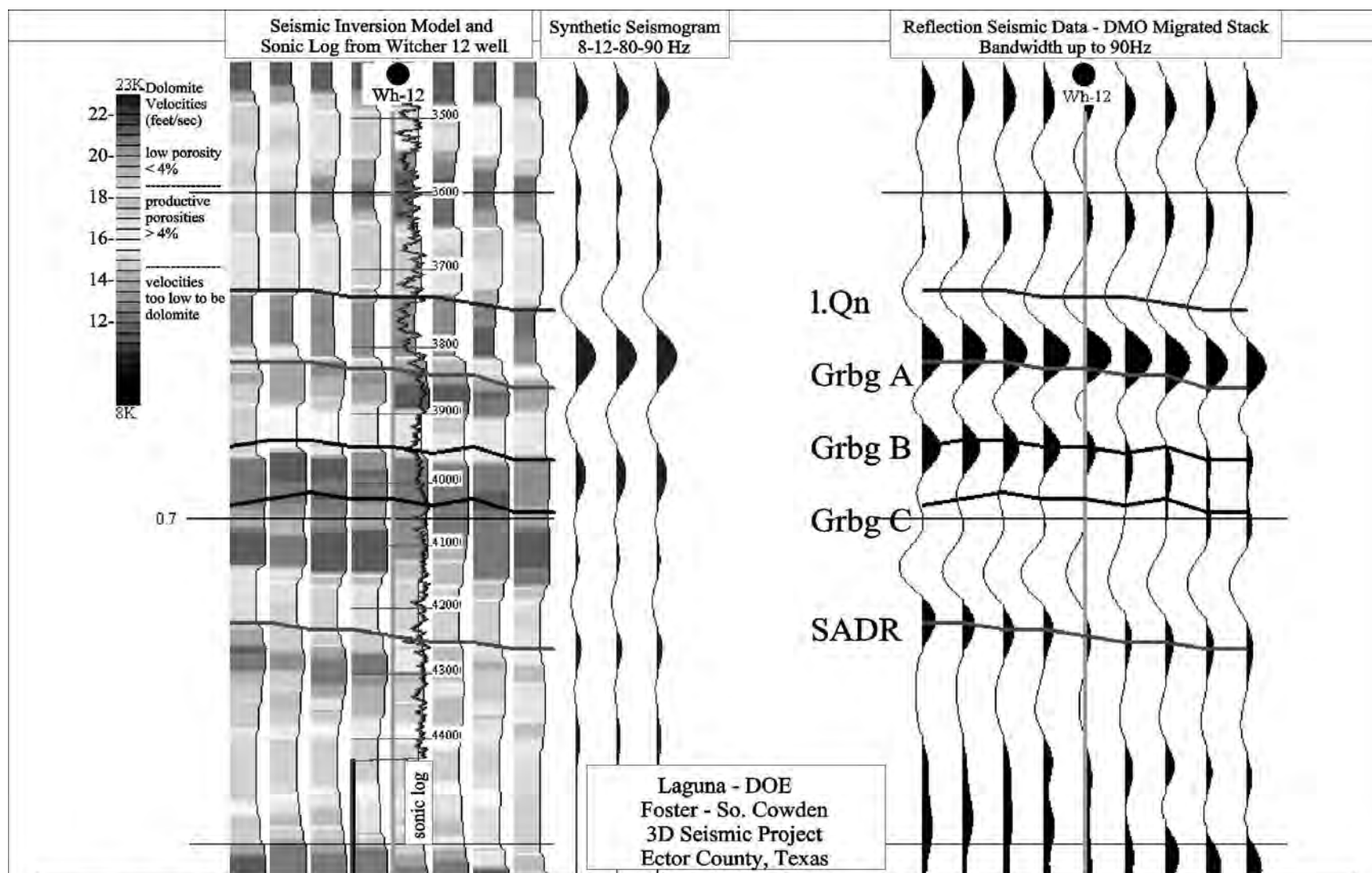
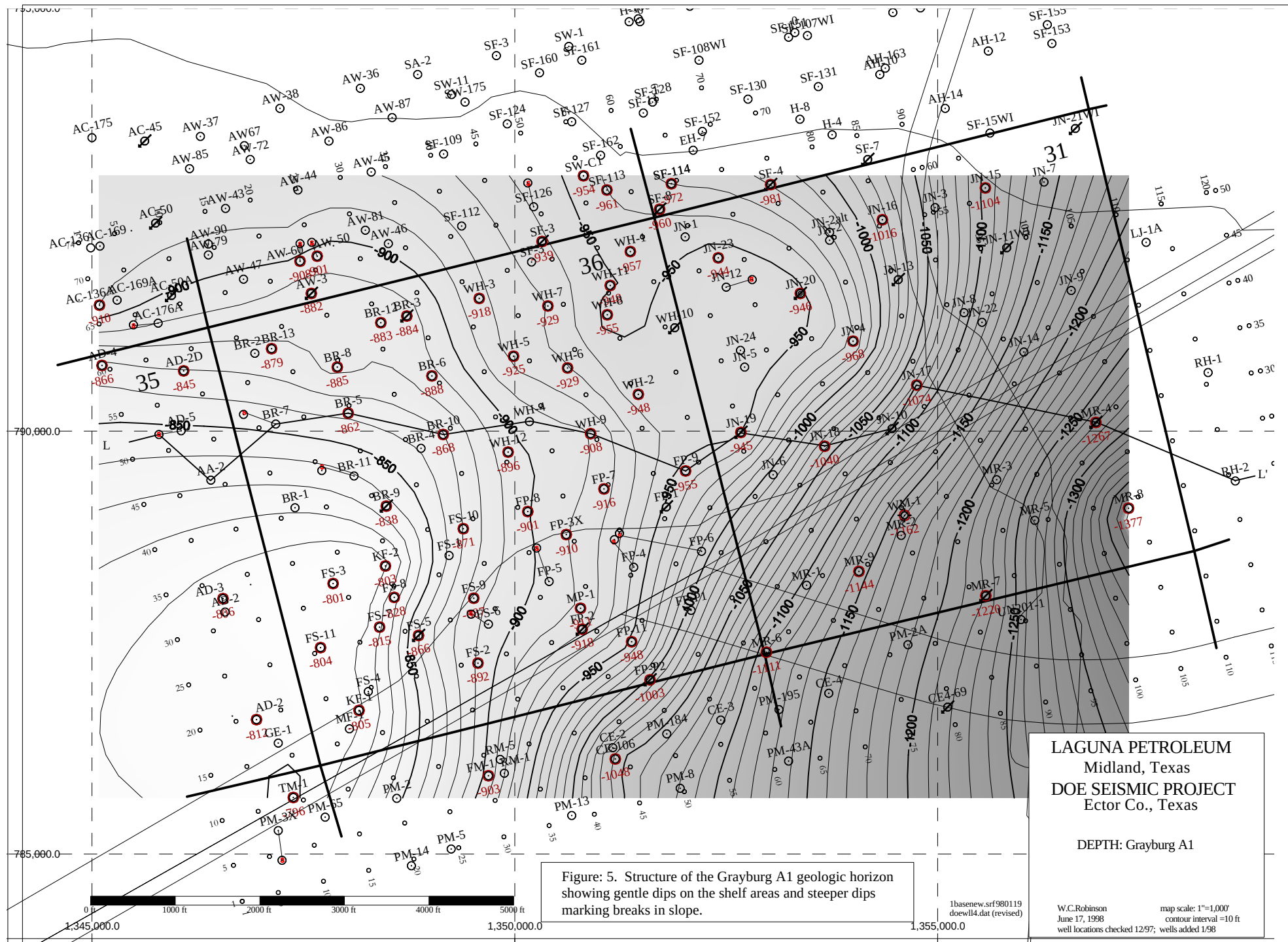
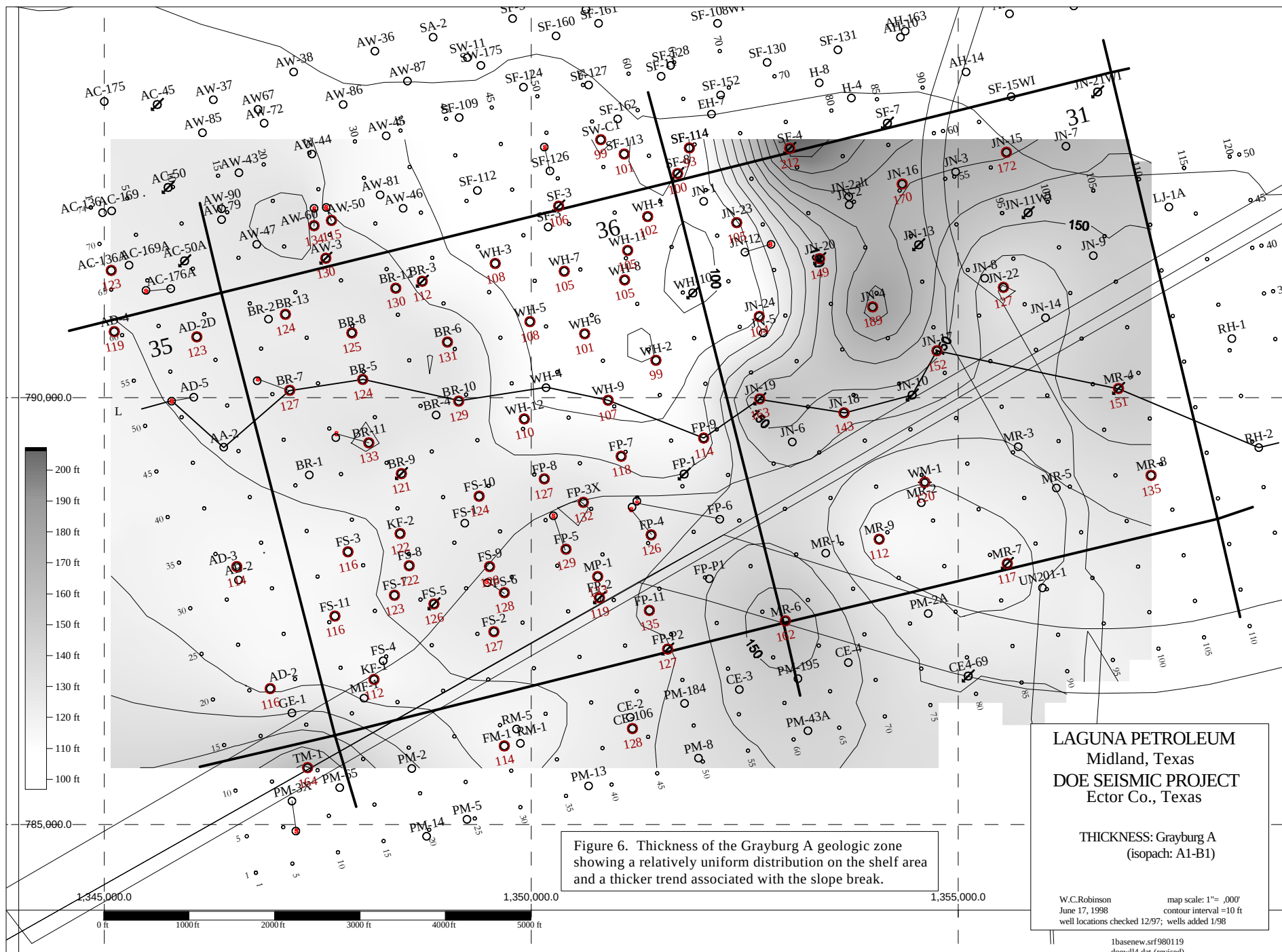


Figure 4. A comparison of Seismic Inversion Model traces to the Reflection Seismic data input traces. Inverted traces compare to the sonic log curve in velocity values and shape. Resolution of about 50 feet is achieved from the Inversion Model traces, compared to the one foot resolution of the sonic log. The synthetic seismogram trace, a product of the sonic log, compares well to the reflection seismic traces for major reflectors. Amplitudes are strong in the lower Grayburg and San Andres; the Inversion Model shows more velocity contrast there than the sonic log.





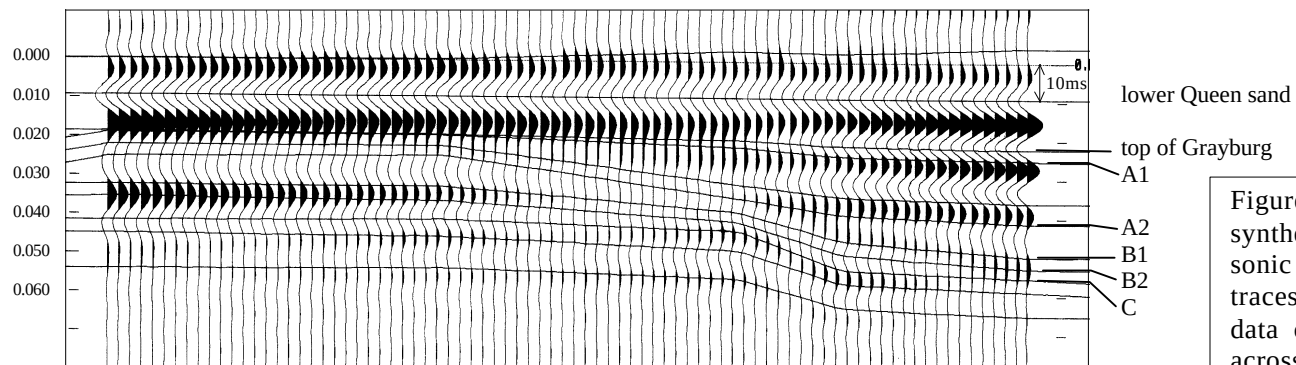


Figure 7 . A seismic forward model made of synthetic seismograms generated from well sonic logs and interpolated logs. These traces represent the expected changes of seismic data character due to geologic variations across the survey discussed in this report.

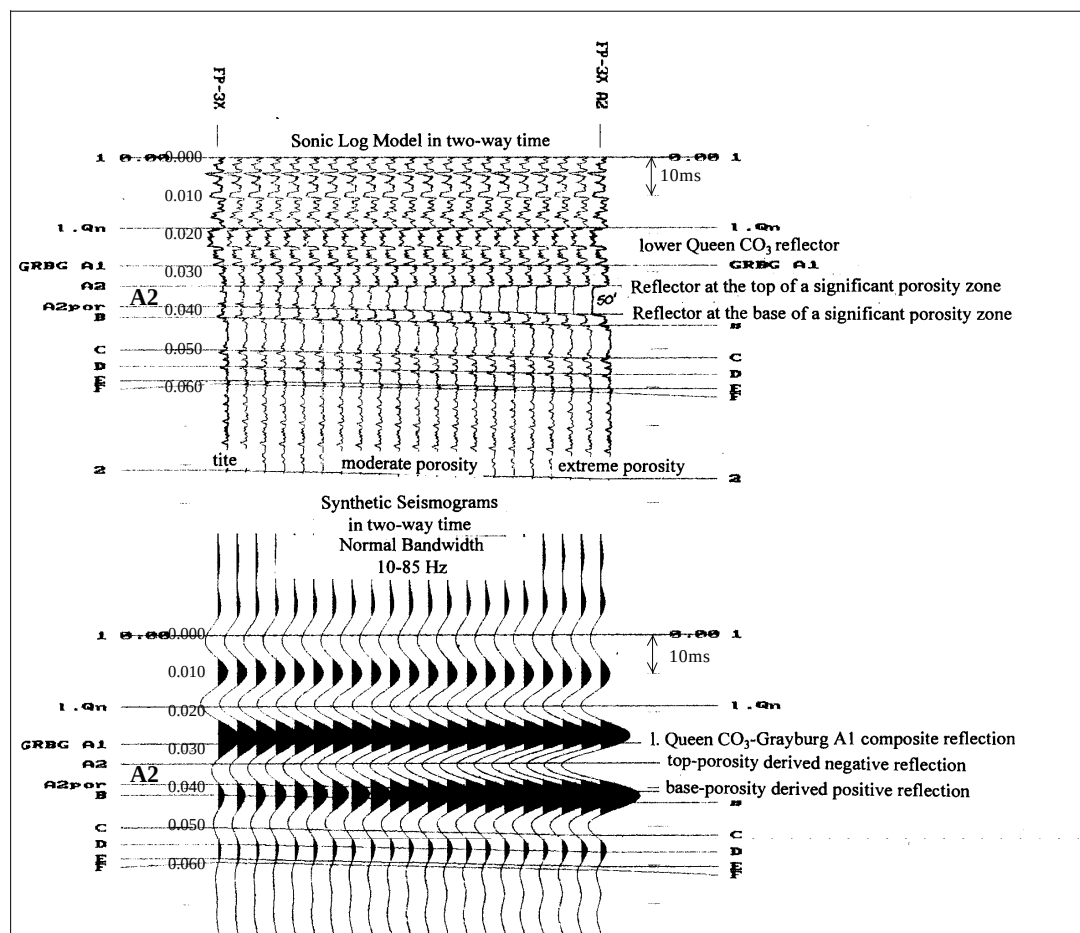
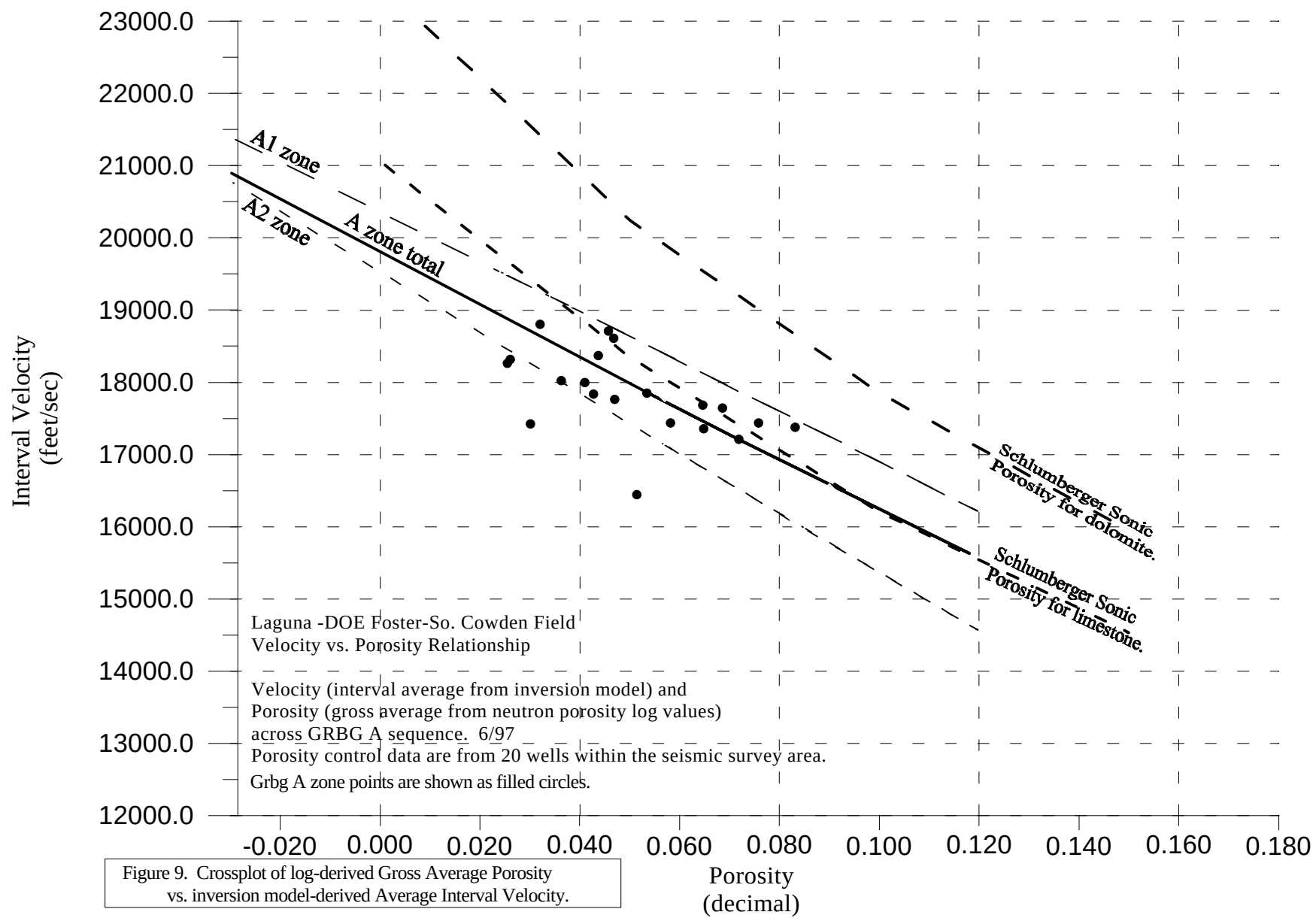
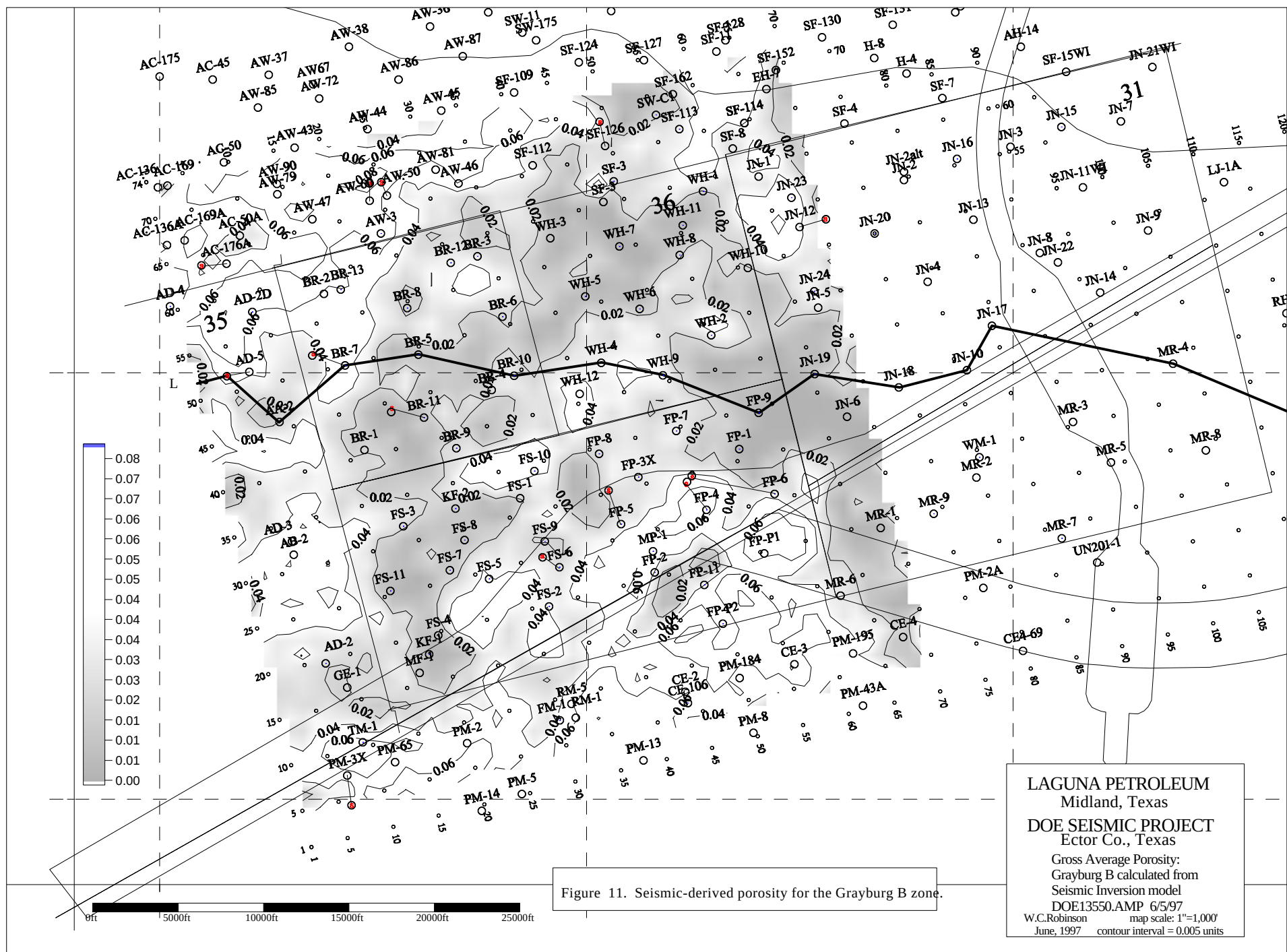


Figure 8 . A seismic forward model similar to Fig. 7, but changes are made to only a single sonic log. The amount of porosity in the A2 zone is varied from very low (left) to very high (right). The purpose is to create a significant pair of impedance contrasts, at the top and the base of the modeled porous unit. The seismic response is a trough, then peak reflection having increased strength with increased porosity.





Well Name	Production Prior to Frac			Initial Production After Frac			Stabilized Production After Frac		
	BOPD	MCFD	BWPD	BOPD	MCFD	BWPD	BOPD	MCFPD	BWPD
Brock #13	0	0	0	80	20	313	30	3	125
Brock #5	6	1	6	72	10	200	43	10	110
Brock #6	3	1	9	38	10	220	22	4	110
Foster Pegues #8	2	0	13	25	2	455	22	2	455
H. C. Foster #8	5	1	45	17	2	150	17	2	150
Witcher #1	11	60	2						
Total									

Figure 12. Results of Refracture Stimulation Program

SECTION 36
ECTOR COUNTY, TX
FOSTER FIELD

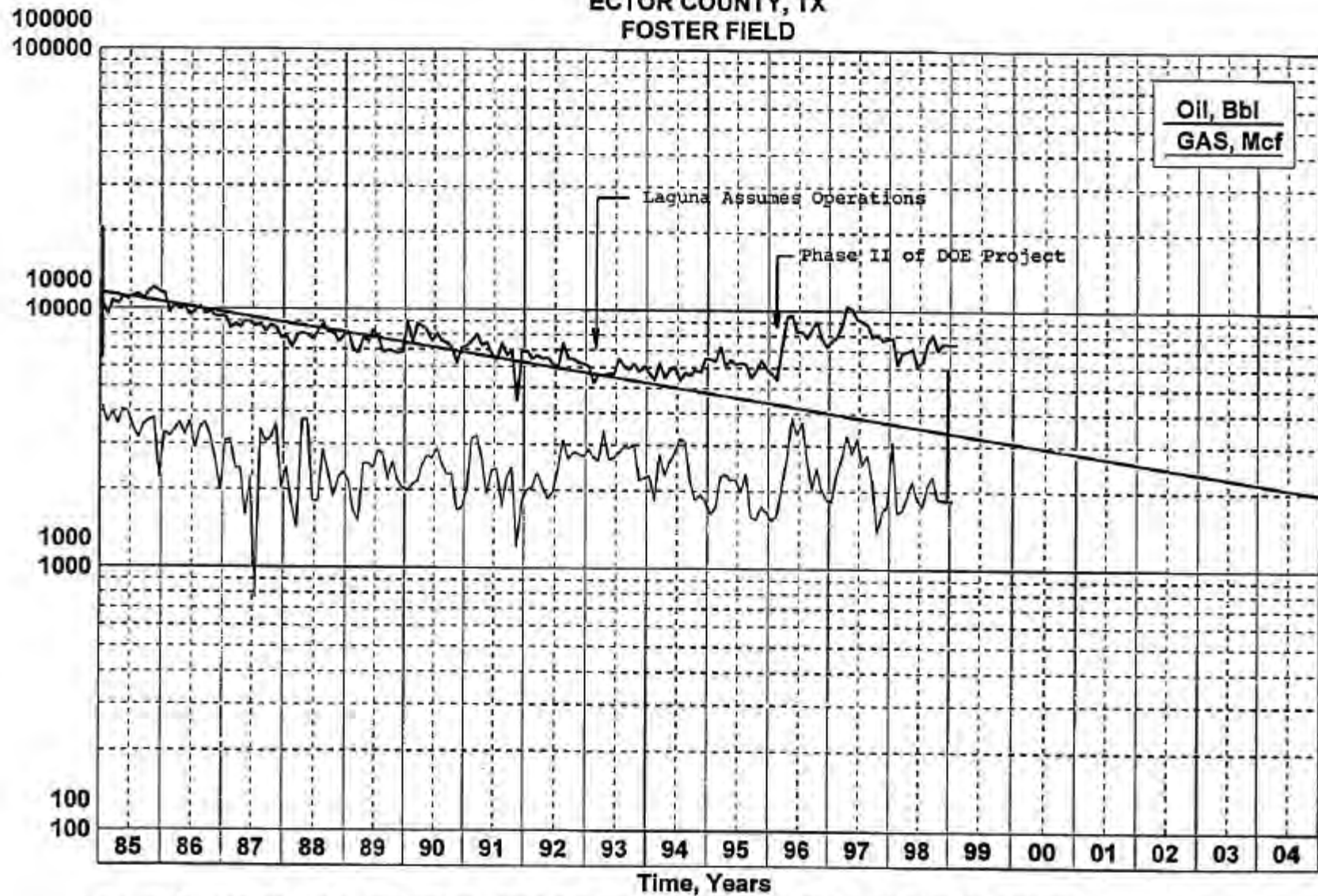


Figure 13. Foster Field Production. Note production increase since inception of project.

Multi-Disciplinary and High-Resolution Seismic Survey on Native American Lands in Osage County, Oklahoma

T. K. Reeves
Bijon Sharma
Sanjay Banerjee
Genliang Guo
Len Volk
David Djikine
Steve George

Formerly of TRW Petroleum Technologies
Current contact: T. K. Reeves
treeves@ionet.net
(918) 331-0012
PO Box 2008
Bartlesville, OK 74005-2008

Introduction

This work was performed by BDM Oklahoma, BDM Petroleum Technologies, and TRW Petroleum Technologies personnel for the US Department of Energy (DOE). The work was funded through Contract No. DE-AC22-94PC91008 under Contracting Officer Rhonda Lindsey of the National Institute for Petroleum and Energy Research (NIPER) in Bartlesville, OK, and the National Petroleum Technologies Office (NPTO) in Tulsa, OK.

The Multi-Disciplinary survey was designed to identify the capabilities, costs and effectiveness of conducting 3-D seismic surveys in a small operator setting through a field demonstration test. The seismic aspects of the plan were coordinated with plans for surface geochemical work and a microbial survey. As the seismic interpretation phase progressed, several innovative techniques were advanced.

Osage County was selected in part to further the goals of the President's initiatives for promoting economic progress on Native American Lands, and in part because of the high concentration of small independent operators in this county. Osage County is comprised of predominantly Osage Nation tribal land. The county was the site of an oil boom during the early part of the Twentieth Century and still has many stripper wells and small operators that have been in the business for multiple generations.

Study of old well records suggested that there were many areas in the county that still held the potential for significant new production from thinner units, subtle stratigraphic traps, and reservoirs with secondary porosity.

Geo-Microbial Technologies (GMT) of Ochelata, OK, was sub-contracted by BDM Oklahoma to conduct a microbial survey in the study area.

Objectives

This program was designed to demonstrate the capabilities of state-of-the-art 3-D seismic technology for the imaging of shallow, thin target beds in subtle traps and to determine the cost-effectiveness of current survey techniques and procedures as a prospecting tool for the smaller independent geological/geophysical exploration company.

The 3-D field test included the following tasks:

- The development of technologies for use in the identification of shallow exploration targets,
- The design of a field test on a scale appropriate for small operators or other independents, such as a native American Tribe,
- A field test of the design,
- A test and evaluation of state-of-the-art 3-D technologies to image subtle hydrocarbon traps,
- An assessment of the effectiveness and economics of the process from the point of view of the typical small operator,
- Transfer of the technology to independent operators and native tribes.

The ultimate goal of the program was to design, develop, and promote new and innovative petroleum exploration techniques, to encourage drilling activity by independents within the U.S., and ultimately to increase domestic production. In addition, a location in Osage County was chosen to further the objectives of the President's Native Tribes Initiative, which has a goal of encouraging entrepreneurial activities on Native American lands.

Approach

The study area chosen was a mature oil-producing region, with many shallow wells dating back to the early years of the century. At the same time, many thinner reservoirs were ignored and bypassed in the early days, remaining in place today behind pipe, and undrilled parcels can still be found in the region.

Initially, a multi-disciplinary geoscience survey was conducted of the county. Multiple potential study locations were selected, by:

- The study of surface lineaments, fractures, and circular and arcuate anomalies identified from satellite images and aerial photographs.

- The study of subsurface structure contour maps and oil and gas pool distribution maps.
- Analysis and graphical representation of fracture orientations, lengths, and density. The fundamental fracture characteristics used for structural interpretation were characterized with computer software developed specifically for this DOE program.
- Analysis of production trends by recording and studying the producing formations, cumulative production data, and other production information, such as which formations and locations had water problems, etc.
- Investigation of regional stratigraphic trends through an examination of drillers' and electric logs and the construction of cross-sections to identify regional and local stratigraphy.
- Mapping and analysis for areas with:
 - ✓ multiple structures that might contain commercial-sized quantities of hydrocarbons in older Paleozoic sediments,
 - ✓ older structures that could be identified and mapped by a 3-D seismic survey, and
 - ✓ topography allowing easy vehicle access in relatively unwooded areas.

When the original series of prospects were presented to the Osage Tribal Council for approval, it turned out that the publicity generated for the program had attracted the attention of Chevron, as well as several independents. It was determined that all of the initial prospects were already in the process of being leased by large and small operators. Well over half the county was eventually leased by outside operators during the peak period of this activity. A second major began a program in nearby counties in Kansas, significantly reviving survey and drilling activity in that region, as well.

Since one of the goals of the DOE program had been the stimulation of exploration and drilling, these activities had to be classified as a major success, although they certainly complicated the site selection process for the work plan.

A succession of six proposed locations turned out to be previously leased. Ultimately, a decision was made to combine the DOE survey with work being done by DLB, one of the independent operators who had moved into Osage County.

The plan was for this operator to shoot a large survey area using a "conventional" configuration with 110' bin size. In one nine-sq mi block, at the NW corner of this survey, DLB gathered data using a high-resolution 55' bin size. The results for the entire survey area were processed as 110' data. In addition, the information from the NW corner area was processed as 55' bin size data.

This allowed the results of the 55' data to be compared directly to the 110' data over exactly the same structures, beds, and geologic features, allowing direct comparison of data quality at the two spacings. Knowing the costs per mile for the conventional portion of the survey and the costs for the 55' work made it easy to determine a cost/benefit ratio for the two types of surveys.

Technology

The nine sq-mi area selected for the 55'-bin size acquisition was chosen based on the same selection criteria described above.

An important element in the area selection process was the development of a new technique for remote-sensing analysis of air or satellite photos. The software, FRAC-EXPLORE, is designed to identify areas with concentrated or unusual fracture patterns or lineaments, which can be clues to basement faulting, buried structures or fracture reservoirs. The software is available on the DOE NPTO website at www.npto.doe.gov/.

The survey specifications and parameters are described below:

- The x, y, and z coordinates for shot point (SP) and geophone placement were identified using a highly sophisticated GPS system accurate to within 15 cm.
- The seismic energy for the Bigheart 3-D seismic survey was provided by four relatively light vibroseis trucks synchronized in unison that transmitted energy into the ground. The truck size and model were selected on the basis of depth of target formations; depth to regional basement; terrain; soil type, stability, and hardness; and environmental considerations.
- Eight successive vibration sets were transmitted from each SP, and each vibration suite produced a record that was summed automatically with the sum of the previous sweep, until eight sweeps per SP had been completed. Each vibrator sweep was 8 sec long, with a listening time of 3 sec. The frequency bandwidth of the transmitted signals ranged from 30 to 120 Hz.
- Field recording was done with the input/output (I/O) Data Recording System II, with a dynamic range (DR), of 120 dB, which enabled the recording of a maximum to minimum amplitude ratio of about 1 million. This was suitable for recording even very faint signals from subtle geological features.
- DLB used 10-Hz, high-fidelity transducers. There was a string of six geophones, potted, buried, and covered at each receiver location for noise reduction. The summed signal received by these geophones produced the output of one data channel. The I/O System II was capable of simultaneously recording data from 1,008 channels for each source point. Three hundred cables and 1,650 strings of geophones were available for this survey.
- Receiver lines run east to west and are marked R1 to R133. The SP vibrator lines run north to south and are marked SP 100 to SP 257. Both shot point and receiver intervals were 220 ft and 110 ft (for 110-ft and 55-ft bin sizes, respectively), giving approximately 300 SP/mi² for the 110-ft bins and approximately 600 SP/mi² for the 55-ft bins.
- Nine hundred channels/SP (15 lines 60 channels pattern layout) were recorded for the 110-ft bin size; 450 channels/SP (15 lines 30 channels pattern layout) were recorded for the 55-ft bin size. Pattern dimensions were 6,160 ft north-south and 6,380 ft or 6,490 ft east-west. Recording offsets were 3,190 ft or 3,245 ft inline and 3,080 ft crossline. There was roll/on/off.
- A 2-msec sample interval and a total record length of 3 sec was used.

In the portion of the survey with the 55-ft bin size, the data were 14 fold at 1,000 ft, 24 fold at 2,000 ft, and 50 fold at 3,000 ft.

A total of 5,778 points were vibrated. All field tapes were shipped to Geo Trace Technologies for processing.

Important points about the processed 3-D data follow:

- The data from the field tapes were processed in the seismic data processing center to enhance the signal-to-noise ratio of the seismic data by the application of different data processing routines. The seismic reflections were always assumed to be from the point midway between the shot and the receiver. All seismic reflections from within a certain area (called the “bin”) were averaged to represent the seismic data from the center of the bin. The final processed data were, therefore, represented by the averaged seismic traces from the various bins located throughout the seismic survey area. So the 110-ft bin data involved averaging over a larger area than the 55-ft bin data.
- At each bin location, a seismic trace was sampled at discrete intervals, say 2 m-sec and extending from 0 seconds up to the total length of the record which, for example, may be 5 secs. The length of the record was determined by the depth of investigation.

For the interpretation phase of the project, hardware and software requirements for loading and interpreting the data were considered with the needs of small independent operators in mind. A desktop computer program, 3Dpak, was used for the interpretation work. The data installation into the personal computers was straightforward, but precautions were taken to ensure that the computer had adequate disk storage space. About 600 Mb of storage space were required for data storage alone. At least 16 Mb of RAM and a math processor were also needed to run the software smoothly.

The interpretation of 3-D data was initiated by investigating certain important features of the data and then evaluating the imaging capabilities of data collected with 55-ft and 110-ft bin sizes.

The first step in the interpretation of the seismic data was the identification of the various reflections on the seismic section. This correlation of seismic reflection with geology was best done with the help of synthetic seismograms generated from the sonic and the density logs. Well logs were collected for the study area.

Key horizons of interest, representing producing formations or distinctive seismic marker beds were identified on the seismic sections that passed through wells with synthetic seismograms. These seismic reflectors were mapped along inlines and crosslines forming a closed loop to ensure that the starting and the ending reflectors were the same.

Key reflectors included the:

- Seismic Basement,
- Bartlesville Sandstone, and the
- Layton Sandstone.

Detailed mapping of the basement reflector can permit identification of basal Paleozoic sandstones and conglomerates and of Cambrian-aged Reagan sandstone reservoirs. Mapping of the study area showed that the southern portion was cut by a large number of faults, with several small popup blocks and local lows with a good potential for the accumulation of basal sands.

As expected, the 110-ft bin data were much smoother than the 55-ft bin data and lacked detail. The reflector definition was much sharper on the high-resolution data, permitting small structures, including probable fault traps and “bright spots,” to be identified.

The Final Report for the project, “An Exploration 3-D Seismic Field Test Program in Osage County, Oklahoma,” Reeves et al, DOE publication DOE/PC/91008-0376, includes a detailed discussion of several methodologies that were used, refined, or specifically developed for this project. These included techniques to:

- Detect and map small faults
- Image subtle geological features in platform deposits with rapid changes in lithology and facies,
- Map subtle stratigraphic features
- Track a thin gas sand on a high-resolution section
- Perform statistical time-series analysis of amplitude data
- Combine Fourier analysis and statistical analysis of the 3-D data for a spectral study of a time series
- Utilize color on a workstation display to assist in the identification of subtle features on high-resolution sections

In addition, an analysis was made to determine if basement structures were exercising influence on the location of the shallow oil fields. These showed a slight positive correlation in the southern area, where the basement was most disturbed, but little correlation was seen to the north where there was little basement relief.

A surface geochemical survey was designed to complement the high-resolution seismic work in Osage County. The aim was to examine several surface geochemical techniques that could be used for locating oil or gas seeps by independents with limited budgets and personnel. To this end, both the sample collection and analytical techniques had to be inexpensive. This translated to collecting samples within 1 ft of the surface. It also eliminated integrated soil-gas methods in which a gas absorber is placed in the ground for a period of time and collected at a later date.

The surveys used in Osage County were essentially noninvasive. To further reduce costs, the techniques did not require extensive expertise in soil science for sample collection, because many independents do not have formal training in this area.

The area of the seismic survey was the target for the surface geochemical survey. The seismic survey was designed on a grid with a 440-ft spacing with survey points every 110-ft along these grid lines. Each of these points was located using a GPS survey. Using multiple benchmarks and satellites, survey points were pinpointed to within 15 cm. Geochemical samples were taken at the intersection of the grid points, corresponding to 12 sample points per mile.

Three types of samples were collected at each grid point:

1. Approximately one-half of a 1-quart polyethylene storage bag of soil was collected from within the top 1–1.5 inches of the surface using a small (Army-style) trenching shovel. This sample was collected for iodine analysis.
2. A 6-inch long X 0.75-inch diameter soil plug was taken with a standard soil sampler. These samples were collected for pH, and possibly metals or magnetic susceptibility analysis.
3. After the first 6 inches of sample were removed with the soil sampler, each hole was reentered and a second 6-inch sample was retrieved (6–12 inches below the ground surface). This sample was used for soil gas analysis.

The results from the iodine survey showed two strong anomalies, and possibly a third. These anomalies appeared as normal levels of iodine at the center and a ring, or arc, of unusually high values surrounding this center. The iodine values in these rings were more than 1.5 standard deviations above the background. In addition, there were conspicuous “holes” in the iodine map where the anomalies exist.

The raw pH data did not readily reveal anomalous areas. Upon using a mild smoothing routine, anomalies were easily seen as areas of low pH surrounded by high pH. These high pH values were in turn surrounded by low pH values. The pH anomalies were centered on the same area as the iodine anomalies, except that the ring of high pH values encompassed the highest iodine values. The third pH anomaly is the most evident feature in this survey.

Cultivated fields of winter wheat, maize, and Bermuda grass did not appear to correlate with any anomalous iodine or pH values. There was also no correlation with stream beds. There was an identifiable correlation between the pH values and the location of a gravel road along row R-85. pH values along the road were unusually high, possibly because of lime applied to the road. A few abandoned oil wells exist within one anomaly. Although several dry holes exist within the survey area, none are within any of the anomalies identified here.

The same gridwork used for the seismic and geochemical surveys was used by GMT, of Ochelata, Oklahoma, to collect samples for a microbial survey. GMT’s objective was to look for biomarkers in the shallow subsurface. The GMT work was performed under a separate subcontract.

The GMT field collection procedure was highly efficient and quickly completed. The GMT samples were analyzed at the GMT laboratories. The results of the GMT survey were extremely interesting.

Sample collection across an old oil field showed little of interest. This is what would be expected in a depleted area.

There was one highly distinctive anomaly of particular note. It was located in the northern portion of the study area, and generally coincided with a distinctively-shaped apparent channel sand identified on the 55-ft high-resolution seismic data. The anomaly was large in amplitude and had the same distinctive shape as the seismic feature.

Results

The DOE Osage County program was designed to be a comprehensive demonstration program, testing a wide variety of processes and procedures.

The initial publicity surrounding the project stimulated a multi-county/multi-state flurry of exploration and drilling, benefiting a Native American tribe and their neighbors, and increasing the domestic oil supply.

The well-location phase of the program involved the development and first field test of a new remote-sensing exploration and regional evaluation software program, FRAC-EXPLORE. This software program worked well, has been refined and upgraded, and is now available for free on the NPTO website, www.npto.doe.gov/.

The overlapping technique of shooting the precise same area in both 55-ft bin and 110-ft bin size graphically demonstrated the significant advantages of the higher-resolution approach. Repeatedly, the 110-ft survey showed gross structures, and little more, while the 55-ft survey could be manipulated to identify very small faults and other structures.

The high-resolution data also made it possible to use waveform characteristics, including amplitude studies, to detect lithologic properties, including porous zones and fluid-filled reservoirs within formations with variable porosity.

Several innovative statistical approaches were developed and applied to the 55-ft data for a variety of time-series and spectral analysis.

Three surface geochemical survey techniques were designed and tested in the study area, using the same survey points from the seismic study. Two of these techniques identified prominent anomalies. The third data set required some data manipulation before a similar pattern emerged from the data. There was relatively good correspondence between the results of the three approaches.

Geo-Microbial Technologies (GMT) conducted a microbial survey of the study area, using the same survey points as the seismic and surface geochemical surveys. This survey had been totally isolated from the work by BDM/TRW until after the analyses of all the surveys had been completed.

The final results from the GMT survey displayed an extremely close correspondence to the seismic maps, although neither team knew anything about the work of the other. The largest microbial anomaly matched a key feature on the seismic interpretation, both in size, position, and overall configuration.

Benefits

The DOE survey brought immediate economic benefits to Osage County and surrounding regions, including nearby parts of southern Kansas. Early press releases and publicity efforts from NIPER and the Osage tribe led to significant interest in the county by Chevron and several independents. A mini boom of exploratory activity resulted, followed by a wave of drilling and increased production. This activity helped meet the goals of the President's Native American Initiative.

The remote-sensing analysis software, FRAC-EXPLORE, that was first used in Osage County has been available to industry for several years now and has received praise from majors and independents, alike. The package is described in the final report, DOE Report No. DOE/PC/91008-0376. It is available, free, for use by small or large operators on the DOE NPTO website, www.npto.doe.gov/.

The comparison of the 55-ft bins to the 110-ft bin-size in the seismic surveys clearly demonstrated a massive superiority for the high-resolution techniques. Although costs for the entire survey were impacted negatively by a succession of storms that may have been related to the onset of El Niño conditions, several suggestions were offered listing ways to contain costs for seismic field work, even in the face of adverse weather conditions.

The Final Report described several innovative ways to use this type of high-resolution data for facies interpretation, for the identification of micro-structures and fluid-filled reservoirs, for statistical analysis and other unconventional methods for interpretation, including taking maximum advantage of the new types of computer displays.

A key goal of the surface geochemical survey was to design a field technique that could be quickly utilized by a new, non-specialized crew, hired by an independent, with minimal training or learning-curve time. The results were highly successful.

The survey analyses produced varying results, with the iodine and magnetic susceptibility maps both revealing intriguing anomalies. The pH survey required some smoothing of the data before similar features became evident. The field technique and sampling procedures proved to work very efficiently.

The Geo-Microbial Technologies (GMT) survey produced a map showing several anomalies, with one particularly interesting one. This anomaly was quite strong and matched a channel and overbank splay deposit seen on the seismic map in both location and general configuration. The description of this work is contained in the Appendix to the Final Report.

The GMT survey used proprietary techniques. The work was conducted in a rapid, highly-professional manner, with a very fast analytical turn around. The extremely close correspondence between the seismic and GMT results were extremely interesting.

Reference

Reeves, T. K., et al. 1999. An Exploration 3-D Seismic Program in Osage County, Oklahoma. DOE Report No. DOE/PC/91008-0376, OSTI_ID: 3181 January. With one Appendix.

Integrated Approach Towards the Application of Horizontal Wells to Improve Waterflooding Performance

Mohan Kelkar

(E-mail: mohan@utulsa.edu; Phone: (918) 631-3036)

Department of Petroleum Engineering

The University of Tulsa

Tulsa, OK 74104

ABSTRACT

This paper discusses the various approaches used in attempting to improve the performance of mature oil field. The results of the implementation and the lessons learned from the implementation are also included in the paper. The field selected for the implementation is Glenn Pool oil field, a field, which has been producing for more than 90 years. Overall, the technologies that proved to be effective include: integrated approach to describe reservoirs, geological description using Discrete Genetic Intervals (DGI's), use of productivity index to rank various parts of the reservoir, geostatistics and flow simulation. The technologies which proved to be only marginal effective or ineffective include: use of micro-resistivity logs for detailed geological description, cross bore hole tomography and drilling of deviated hole using surface steered drilling assembly.

The overall project was divided into two phases. In the first budget period, we collected modern data sets to evaluate the cost effectiveness of new data in improving the reservoir description. In contrast, in the second budget period, we used conventional data to describe the reservoir. In both the budget periods, based on our detailed evaluation of the data, we developed reservoir description, and based on various reservoir management strategies, recommended the optimal reservoir management plan to improve the performance of the reservoir. In the first budget period, the recommended plan was to re-complete the existing wells. Implementation of the plan resulted in significant additional oil recovery in part of the field. Further, the predicted performance matched with the observed performance. In the second budget period, the recommended plan was to drill a

deviated well to selectively complete certain intervals of the field. Unfortunately, due to various drilling problems, the well could not be completed and had to be abandoned. As a result, the observed performance could not be compared with the predicted performance during the second budget period. Based on our experience in the first budget period, we are confident that if the recommended plan as indicated in the second budget period is implemented, it will result in significant additional oil recovery. In addition, several other potential locations within the Glenn Pool field exist where similar approach can be used to recover additional oil.

BACKGROUND

The DOE Class I Program is targeted towards improvement of production performance of existing mature oil fields located in fluvial-dominated deltaic sandstone reservoirs. This project is selected under the near-term program which requires that existing new technologies be applied in these fields to prevent any premature abandonment of these mature fields. The Glenn Pool field selected for this project fits the desired characteristics under this program.

The Glenn Pool field is located in portions of Tulsa and Creek Counties of Oklahoma. The field was discovered in 1905, and it is estimated as having produced 330 MM barrels of oil from the Middle Pennsylvanian (Desmoinesian) age Bartlesville sandstone. Glenn Pool field, like other fields developed in the Bartlesville sandstone, is located on the Northeastern Oklahoma Platform, a paleotopographic and structural depression of mid-Mississippian-Pennsylvanian age lying between the Ozark Uplift to the east and the Nemaha Ridge on the west (**Figure 1**). The figure also shows the area of study for this project. The Self-unit indicated in the figure was the subject of first budget period investigation, whereas the gray area surrounding the Self-unit was the subject of the second budget period.

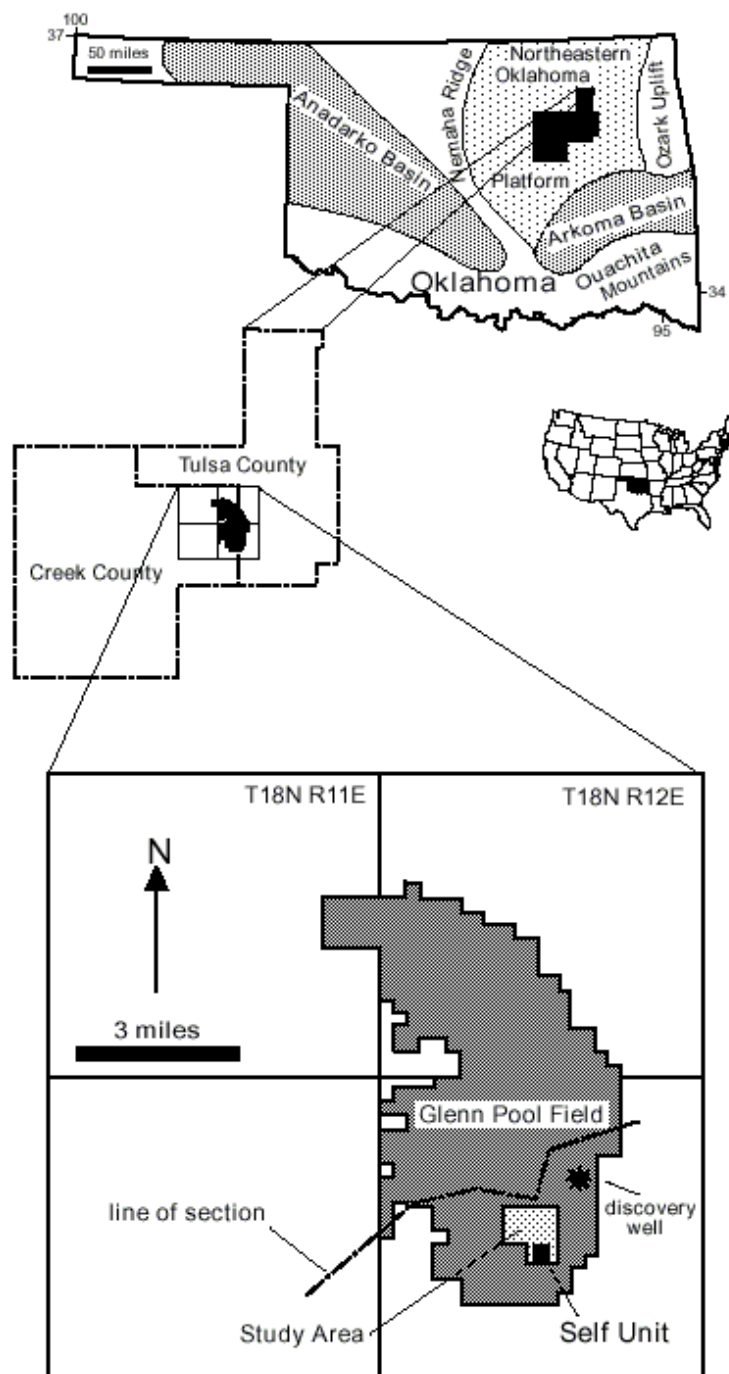


Figure 1 – Location of Glenn Pool field

The field encompasses 27,440 acres. Initial production from the wells ranged from 75-500 BOPD to 4,000 BOPD. After discovery in 1905, the field reached peak production in 1907. The first well in the field was drilled in fall of 1905. The well was located on the Ida Glenn farm near the center of the SE/4 of section 10, T17N, R12E, in Tulsa County (see Figure 1). The well was 1,458 ft. deep and produced at a flowing rate of 75 BOPD. The producing interval was called "Glenn sandstone" and in the subsequent years became the target pay zone. The average producing span was estimated to be close to 240 ft. and was the most productive compared to the other nearby fields.

With depletion of production, gas injection was introduced in 1940, and gas collected at producing wells was recycled to injection wells. Water flooding operations began in 1944. Cumulative oil production records prior to field-wide water flooding are incomplete. By 1943, it was estimated that the production throughout the field was between 222 and 236 MMBO. Over 100 MMBO had been produced up to 1990 by secondary gas repressuring, water flooding, and tertiary recovery methods bringing total production to 330 MMBO. The field is being depleted at present. Several large production units are under water flood, and a few units have undergone testing and implementation of micellar-polymer enhanced recovery methods. Results have shown the possibility for significant additional volumes of recoverable oil.

The Glenn sand has been conventionally divided into 3 units: upper, middle and lower Glenn.¹ Each is separated by apparent permeability barriers consisting of interbedded siltstones and shales. In the central portion of the Glenn Pool field the Glenn sand is present at a depth of approximately 1,500-ft, and the thickness varies from 100 to 185-ft. The upper and middle Glenn are the producing intervals in the central portion of the field and the lower Glenn is below the oil-water contact.

Oil from the Glenn sand has a gravity of 35.8° to 41.3°. It contains 3.12 to 11.46% paraffin and a sulfur content of 0.3%. Initial reservoir pressure has been estimated in the range of 600 to 700 psi. Current water flooding injection pressure ranges from 100 to 1,100 psi.¹

BUDGET PERIOD I

Introduction

In the first budget period, our effort concentrated on Self-unit located in the southeast portion of the Glenn Pool field (see Figure 1). During this period, we applied several new technologies to improve the reservoir description. These technologies include integrated reservoir description, geological description using DGI's (discrete genetic intervals), modern logs, cross borehole tomography, geostatistics and reservoir flow simulation. The description and success of each of these technologies is discussed in this section.

Self Unit

The Self-unit, area of investigation of project during budget period one is a 160-acre tract located in southeast portion of Glenn Pool oil field in section 21-17N-12E (**Figure 1**). Currently the unit is operated by Uplands Resources, Inc. The first well on the lease was put on production November 6, 1906. In all, 5 wells were put on production in 1906. Out of the three Glenn Sand intervals, the upper and middle are present while lower Glenn is absent in the Self-unit.

The original oil in place (OOIP) for the unit has been estimated to be 13.009 MMBO. Primary production during 1906-1945 resulted in the production of 1.809 MMBO representing 13.91% of OOIP. In 1945, gas repressuring began in the unit. This resulted in a recovery of 0.231 MMBO representing 1.8% of OOIP. During 1954-1966 the unit was put on a pilot water flood resulting in production of 0.169 MMBO (1.3% of OOIP). The recoveries were higher in the areas surrounding the pilot and the gas injectors. In 1966, water flooding was extended to the majority of the field. In the initial period of water flooding, the production increased across the entire Self-unit. The total production during 1966-1978 resulted in production of 0.235 MMBO representing 1.8% of OOIP. The unit was redrilled in 1978 on a ten-acre 5-spot pattern. During 1978-1983, 0.146 MMBO production representing 1.12% of OOIP was obtained. From 1984-1992, production was 0.157 MMBO representing 1.2% of OOIP. Total production obtained to date from the unit is around 20% of the OOIP.

The Self-unit experienced good primary recovery, but response to the subsequent secondary recovery efforts has not been encouraging. Study of the available well logs and core reports indicate that lithologic heterogeneities and permeability vary throughout the lease. Well logs taken in

the 1980's indicate higher water saturations in middle Glenn portions rather than in the upper Glenn. Upper Glenn portions could not be swept by water flooding because of, perhaps, lower permeabilities in these portions and inadequate perforation coverage.

Despite subsequent water flooding, water injection could not be contained on the lease and water possibly migrated to other parts of the field. Large permeability variations in upper and middle Glenn also contributed to this inefficient use of water injection. Injection pressures and rates vary throughout the lease; pressures range from 50 to 700 psi, and the rates range from 40 to 2,000 barrels of water per day. At the start of budget period one, oil production from the lease was less than 18 bbls/d with water cut of 99%.

In total, 81 wells have been drilled on the Self-lease. The study required the availability of all well records. Though starting production and abandonment data for most of the wells are available, information with regards to the production history for individual wells could not be traced. The well map depicting all the wells drilled in the Self-unit is shown in **Figure 2**. Initial development occurred along the periphery of the unit; subsequently, development occurred in the interior.

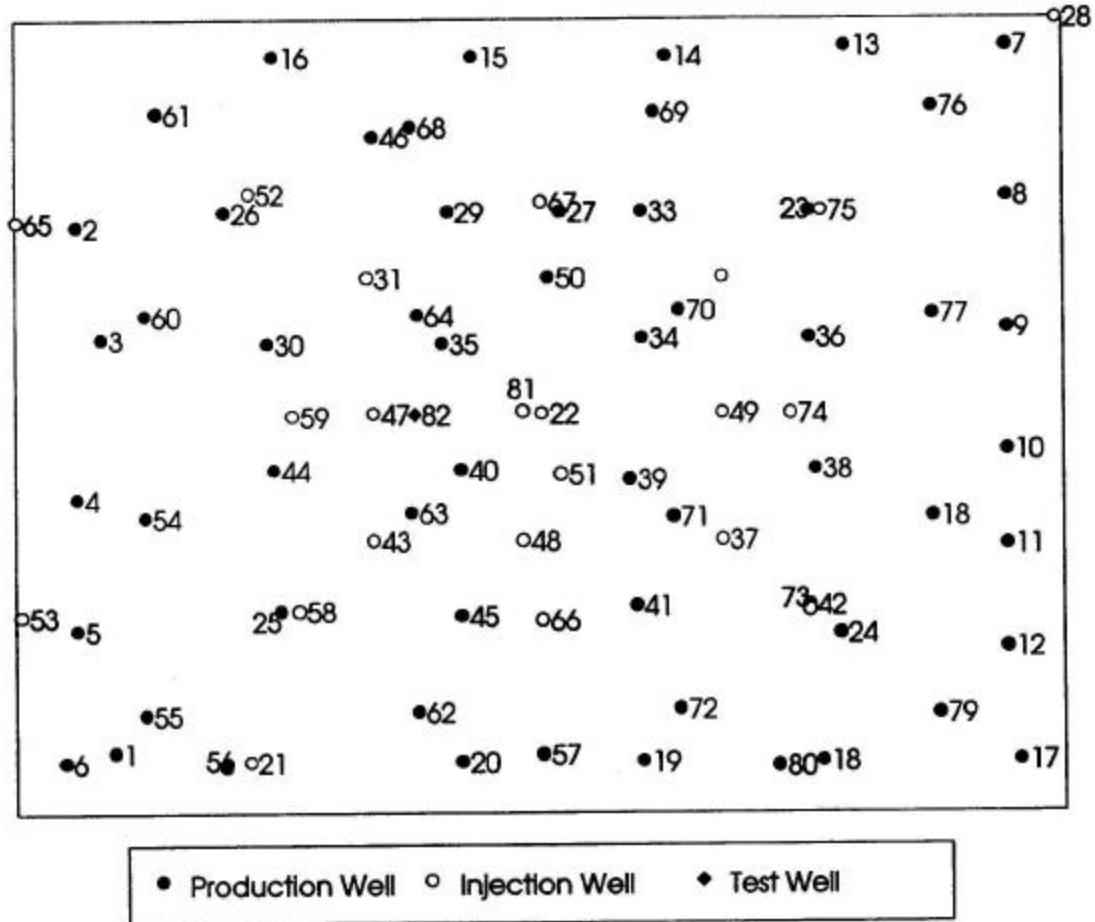


Figure 2 – Well locations

The overall production history based on the above information is summarized in Figure 3. As evident from this figure, every time new technology was implemented in Self-unit the field responded with substantial increase in production. This is evident in 1946, 1965 and 1978. This also gives an indication that if new technology is properly used and a good reservoir management plan is implemented, the Self-unit will respond with an increase in oil production.

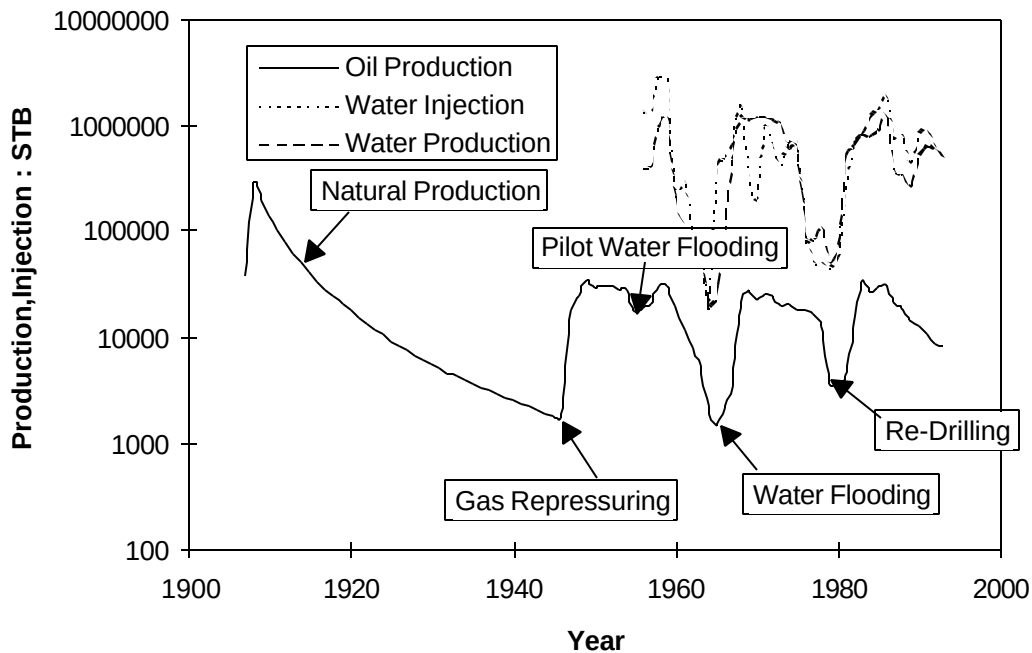


Figure 3 – Production history of Self-unit

For information related to the petrophysical properties, well logs for the drilled wells after 1978 are available. Permeability data availability for the Self-unit are not that abundant. Though eight core reports are available from the wells operating during 1940's and 1950's, the logs for those wells could not be traced and as a result no relation between the core and well log of the same well could be established. Furthermore, the existing wells have only been logged and there is no core report relevant to these wells.

Although significant production data were available, the project team believed that an additional well needs to be drilled for the following reasons.

- We did not have a single core from the Self-unit. The only core available to us was from northern part of the Glenn Pool field. We did not believe that it would be representative of Self-unit.

- We intended to run micro-imaging log to obtain detailed geological architecture. To run the micro-imaging log, we needed an open hole. With the existing wells, no open hole was available.
- We wanted to use cross borehole tomography to generate cross section information between two wells. To properly obtain the image of the reservoir, the well needs to be drilled deeper than the formation. All the existing wells were drilled to the total depth of Glenn Sand. To properly obtain the cross borehole imaging information, we needed to have at least one well 400-ft deeper than the bottom of the Glenn sand.

In view of the above considerations, a vertical well was drilled in the Self-unit at the end of 1993. The location of the well, Self-82 is shown in Figure 2. The location was decided based on preliminary geological mapping, as well as distance considerations from the surrounding wells. The well was drilled 400-ft deeper than the Glenn sand. It was cored, a suite of modern logs, including micro-imaging log, was run successfully. The well was completed in January 1994.

Using this well as a source well, three cross bore hole tomography surveys were conducted between Self-82 and the surrounding three wells. With the help of a modified geological description as well as geophysical and engineering data, a detailed reservoir description was constructed using geostatistical methodology. After validating the description by comparing the simulated flow performance with the historical data, several operating scenarios were simulated to optimize the flow performance under modified conditions. A combination of recompletion and stimulation of most wells followed by increasing the water injection rate in the field was observed to be the most optimal change to improve the flow performance of the Self-unit.

The proposed reservoir management plan was implemented, and the unit performance was monitored for over three years. At the base level, the Self-unit was producing between 15 to 17 bbls/day. The initial increase in the incremental oil production was predicted to be in the range of 15 to 32 bbls/day (see **Figure 4**). The cases in Figure 4 represent the use of different relative permeability curves. The actual increase was 24 bbls/day (see **Figure 5**). After 3 years, the incremental increase was predicted to be about 10 to 12 bbls/day. Currently, the field is producing

10 incremental bbls of oil per day over its base rate. In short, we were able to correctly predict the performance of the reservoir. Although in terms of actual production, this increase is not much, note that it still represents about 150% increase in the production. Further, the field is more than 90 years old, and has been subjected to many technologies in the past. If we can cost effectively increase production from such a mature field, we would be able to do better in other, relatively younger, fields. The economic evaluation indicated finding cost of oil is in the range of \$4.80 to \$6.00 per barrel. This cost can be reduced substantially (to about \$2 to \$3 per barrel) if we only use the cost-effective technologies and eliminate the use of other technologies.

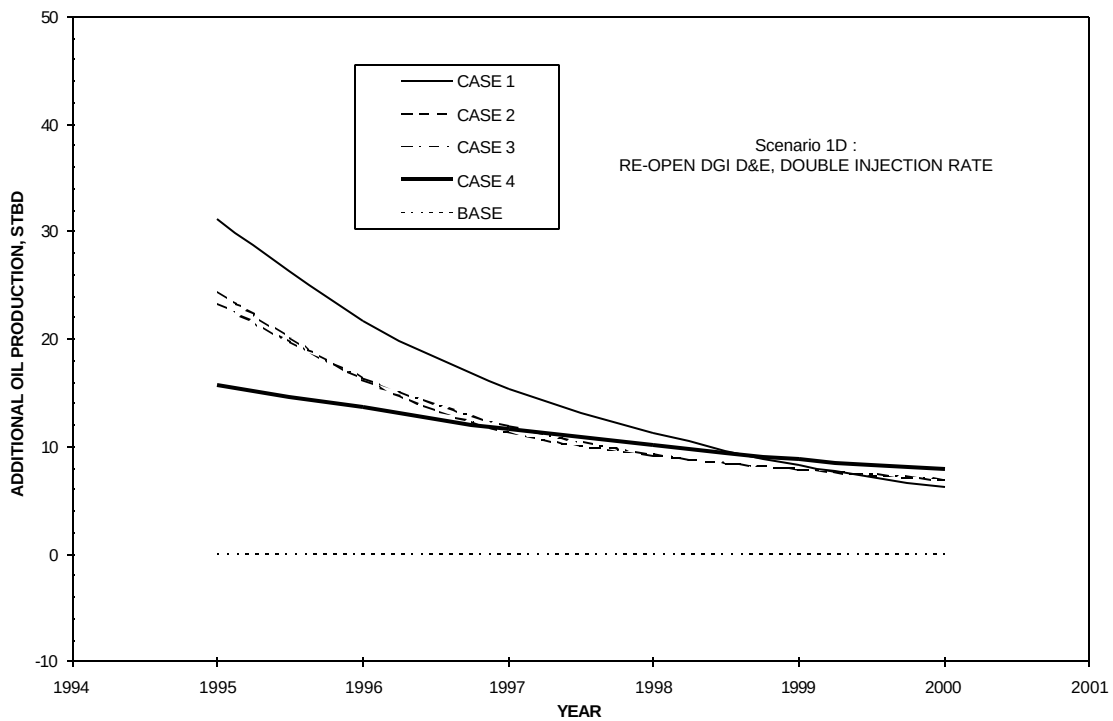


Figure 4 – Incremental production rate for the Self-unit for various cases

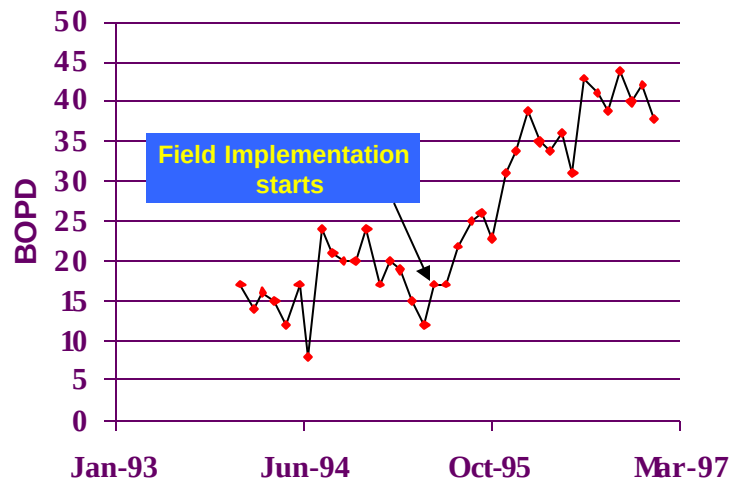


Figure 5 – Results of field implementation

In the following sections we will describe various technologies used in improving the reservoir description. Here, we only provide the summary of the technologies. The details can be found somewhere else.²

Evaluation of Various Technologies

In this budget period, we used several modern technologies. In this section, we briefly describe the technologies and their value to the project.

Integrated Approach

We made a concerted effort to integrate information from various sources to better understand the reservoir. Geophysical, geological, and engineering data were used to better describe the reservoir properties. In addition to interdisciplinary nature of the project, this project also involved active participation from government, the university, a small oil company and a major oil company. The biggest benefit of working together among such a diverse group of people is understanding and appreciating each other's language and perspective on the issues at hand. Communication between different disciplines helped us better understand what each discipline considers to be an important part of the reservoir description. We tried to create a good balance between the form of the reservoir (architecture) and the function of the reservoir (production performance). Interaction

among various entities during the project made us aware of each other's priorities and each other's objectives. Although the objectives of each organization did not always coincide, we learned to appreciate and respect each other's objectives. This helped us in proceeding in the project in an optimal way.

Cross Borehole Tomography

Cross borehole tomography is a method by which an inter well image of reservoir characteristics is constructed by using an acoustic source in one well and receivers in another well. We conducted three such surveys with the help of Amoco Production Company and Conoco. The surveys were conducted between well pairs 82-63, 82-64 and 82-81. The collected data were processed by Amoco, using a public domain software and by Memorial University in Newfoundland, Canada. In addition, data were also provided to a group of scientists from Imperial College. Depending on the assumptions involved in the software, the results obtained from the three methods were significantly different. The results are in the form of sonic velocity distribution across the well pair. We used this information by relating the velocity to the porosity and the facies at the well location. The use of these data slightly improved our reservoir description. Because of the high cost of acquisition and significant uncertainty in the interpretation, the use of cross borehole data were limited.

Formation Micro-Resistivity Borehole Imaging

We used this tool in the newly drilled well 82. Along with the resistivity imaging, we also cored the desired interval. Formation Micro-resistivity imaging tool produces a high-resolution resistivity of the wellbore. Analysis of the image provides spatial orientation of architectural elements in the vicinity of the wellbore. By combining the information from the core data and the imaging tool, we were able to describe the geological heterogeneities at higher resolution level than otherwise possible with conventional well logs. Unfortunately, we were not able to use this detailed information in an effective way in flow simulations due to computer memory limitations. For a mature, shallow, oil field with marginal oil production, the detailed knowledge of geological structure may not be important in predicting unswept reservoir and preferential flow paths. The cost benefit analysis of using micro resistivity log versus taking an oriented core needs to be evaluated further before

reaching the final conclusion on the utility of these type of logs. The preliminary analysis indicates that micro-imaging log may not be very valuable in terms of adding incremental value compared to taking a core sample.

Discrete Genetic Interval (DGI) Evaluation

Using the data collected from all the wells, we were able to construct a detailed description of geologically distinct units deposited during a limited time interval. This information was extremely valuable in understanding the vertical as well as areal heterogeneities. Previously, Glenn sand was divided into three basic units - upper, middle, and lower. With the help of DGI approach, we were able to divide the sand in six geological units. This detailed geological description helped us in flow simulation as well as in our overall reservoir management planning.

Geostatistics

Geostatistics is a procedure by which inter well properties are described using all the available information. Geostatistics assumes that the reservoir properties are spatially correlated, and this correlation can be quantified by a method called variogram analysis. Geostatistics further allows us to quantify uncertainties in describing these properties. Using geostatistics as a tool, we were able to describe the spatial relationships for geological facies as well as the petrophysical properties. By using the relationship between the seismic velocity and the porosity, we were able to use the cross borehole data to improve the spatial relationship for porosity at inter well distances. Using a geostatistical technique called conditional simulation; we generated geological facies image. The comparison between the simulated image and the geologist's view of the reservoir indicated good results. This provided us the confidence that the architecture of the reservoir is preserved. Using the geological description as a starting point, alternate images of the petrophysical properties (permeability and porosity) are constructed by further integrating engineering and geophysical information. Overall, geostatistics was a valuable tool in constructing realistic reservoir descriptions.

Flow Simulation

Once the reservoir description was constructed, we used the ECLIPSE commercial simulator to simulate the reservoir performance. We used both the deterministic (conventional, “layer-cake”) as well as geostatistical reservoir descriptions for simulation purposes. Typically, the number of grid blocks in the simulator is less than the number of grid blocks in geostatistical simulation. As a result, appropriate up scaling procedure is used to scale the petrophysical properties suitable for simulation purposes. Since the performance data from individual wells were not available, we could only match overall unit performance. After matching the historical oil production performance, we projected the future oil production performance under various scenarios to understand the benefits and the drawbacks of various alternatives.

With increasing speed of computers, flow simulation technology is becoming increasingly viable for small operators. Field simulations can be conducted on personal computers without much difficulty. We believe that flow simulation will be an integral part of future reservoir evaluation procedures.

BUDGET PERIOD II

Introduction

In the second budget period, we extended our efforts to other parts of the Glenn Pool field (see Figure 1). This part of the Glenn Pool was also operated by Uplands Resources, Inc. The main idea behind the second budget period is to apply conventional technology to develop reservoir management plan. Unlike the first budget period, where modern technologies such as micro-resistivity logs and cross bore hole tomography data were collected, in the second budget period, the analysis relied on more conventional data. Any use of modern technology was restricted to the analysis and interpretation of the data.

Data Collection

During the second budget period of the project, we intended to concentrate on tract 7 and surrounding areas. tract 7, another 160-acre unit in southern Glenn Pool field, is located about 1 mile north of the Self-unit. The emphasis of the second budget period is to use conventional

technology and knowledge gained from advanced technology of the first budget period (FMI, cross-well tomography etc.) in developing an effective reservoir management plan.

Study of tract 7 and adjacent area involved data compilation, well log correlation of DGI's, and facies architecture reconstruction. For a better and more complete description of tract 7, its adjacent areas including tract 6, tract 10, tract 12, tract 13, tract 11, part of tract 3, tract 4, tract 33, and Corbray unit are included into the mapping area, with total area about 1.6 square miles. Subsequently, the area of coverage was expanded to include additional areas in the southern part of the Glenn Pool field including tract 9 and Chevron miceller-polymer unit which is directly north of tract 9, and is directly west of tract 6 (see **Figure 6**). Figure 6 shows the area of concentration. In addition to the existing logs, six new Gamma Ray logs were acquired to compliment the existing data. Five of them are in the tract 7 unit (well numbers: 7-97, 7-99, 7-100, 7-103, and 7-107), and the other one (11-82) is in the tract 11 unit. There is a suspicion that upper part of the Bartlesville Sandstone in tract 7 area may contain a gas cap. Thus cased-hole neutron logging (TDT) was also performed for three wells (well numbers: 7-97, 7-103, 7-107). These TDT logs do not show any evidence of gas.

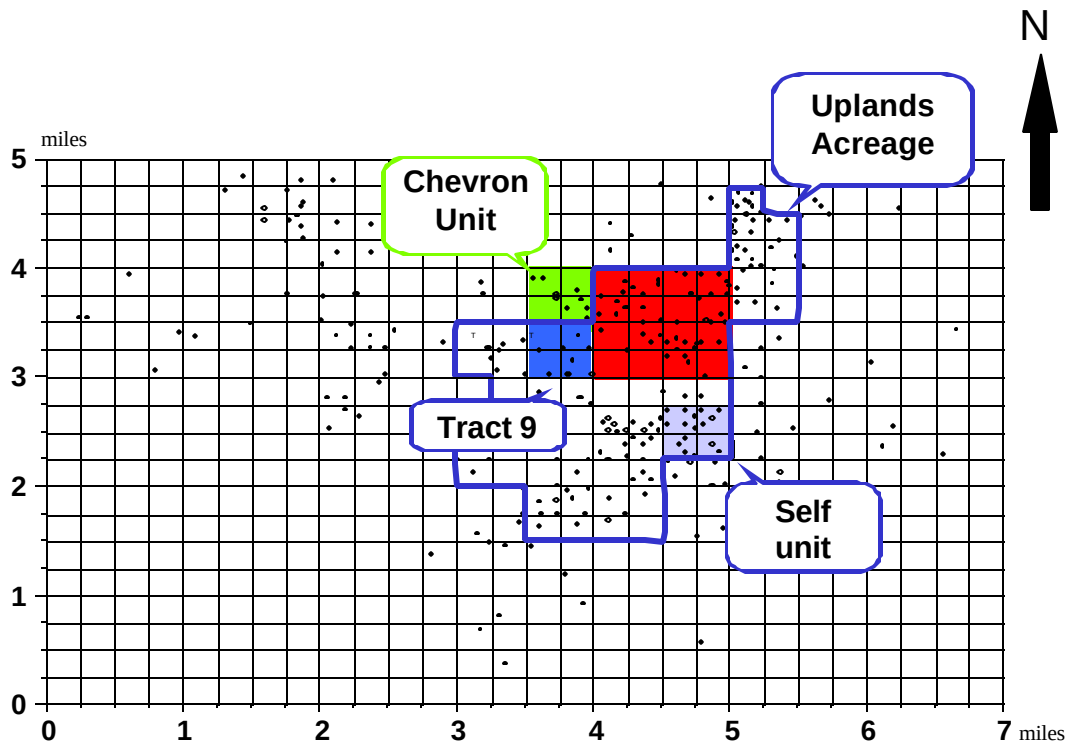


Figure 6 - Area of concentration

Reservoir Evaluation

We evaluated the entire area operated by Uplands Resources for the second budget period. In addition, we also evaluated an adjacent unit, which used to be operated by Chevron. The Chevron miceller-polymer unit was successfully flooded in early 80's using miceller-polymer flood. We wanted to understand the reasons for the success.

Since it was difficult to study all parts of the reservoir in great details, we graded the reservoir based on a method of potential index mapping. This mapping involves evaluating various areas in the reservoir based on the permeability, thickness, porosity, saturation as well as prior access to that area by already existing wells. A reservoir with high conductivity and high storativity is given higher productivity index. Depending on whether the area of interest is drained by already existing wells, potential index is calculated. A region with higher potential index is investigated further, whereas, the region with low potential index was eliminated from further consideration. In addition to potential index mapping, we also examined the primary and secondary recovery production from

various units. Based on the grading of various parts of the reservoir, we decided to concentrate on tracts 7 and 9.

We began our evaluation by studying Chevron unit. Our evaluation indicated that the success of the Chevron unit could be partly attributed to re-completion of the upper intervals in Glenn sand. Unlike other operators, Chevron concentrated on the upper and middle Glenn sand, and implemented the miceller-polymer flood in those sands. The increase in oil production as well as reduction in water cut was substantial. We re-simulated Chevron unit assuming that it is water flooded with same completion as Chevron had used. The response indicated that Chevron would have achieved substantial increase in the oil production with reduction with water cut just by using water flood. Although not as impressive as miceller-polymer flood, the simulation indicated to us that we can use similar approach in other parts of the field.

We studied both tracts 7 and 9, and investigated various scenarios for improving the performance of those units. For tract 9, we observed that drilling of a deviated producing well will result in the most improvement in the production. For tract 7, we observed that re-completion and stimulation of upper intervals will result in the most improvement in the production.

Based on our evaluation, we decided to drill a deviated well in tract 9, which would be completed in the upper and middle part of the Glenn sand. The location is shown in **Figure 7**. The deviated producing well will be supported by three injectors; one in the north and two in the south. To achieve the drilling in a cost-effective manner, we employed a relative new technology of surface steered drilling which is much cheaper than conventional deviated hole drilling. Unfortunately, drilling of deviated hole proved to be much more challenging than anticipated. We lost the drilling assembly twice. During the second time, we could not fish it, and the hole had to be abandoned. As a result, our reservoir management plan during the second budget period could not be validated. Because of budget constraints, another attempt at drilling the deviated hole could not be made. Hopefully, private owners would take an initiative, and with favorable oil price, drill deviated wells in the same field to validate the concept.

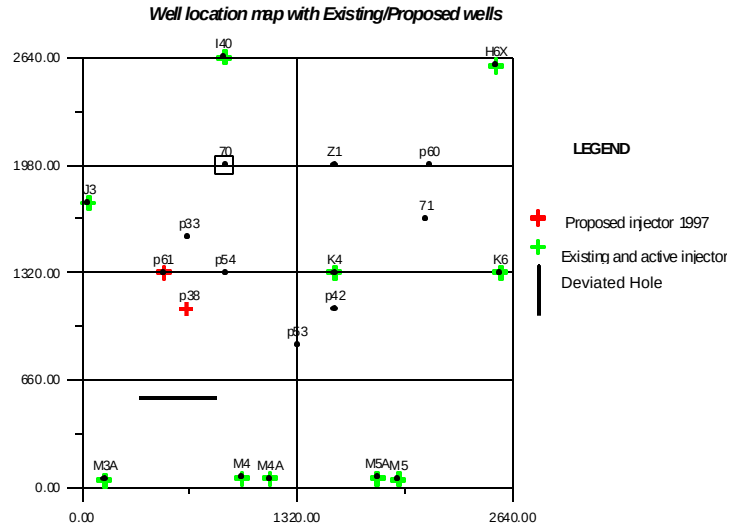


Figure 7 - Proposed management plan for tract 9

Evaluation of Technologies

The two new technologies we pursued in this budget period were the use of production index technique to grade the reservoirs, and the use of surface steered deviated hole drilling. The use of production index technique was proved to be extremely valuable in describing the reservoir in terms of quality. The reservoir was effectively divided into two regions. One with high quality with a potential to recover more oil, and one with low quality because of either poor petro-physical properties or by the fact that the area is already been drained by existing wells. This tool has lot of practical applications since the type of data required to apply the method is limited and is easily available.

In contrast, the use of surface steered tool to drill the deviated hole proved to much more difficult than anticipated. Although the technology has been used in the past in some reservoirs, this was the first time it was used in a mature reservoir such as Glenn Pool. For the technology to be cost-effective, the well had to be drilled with a reasonable cost. Our expected cost was less than \$150,000, which would have three times more than a typical vertical well. In reality, the actual cost was more than \$300,000, and the well was never completed. There is no question that the technology needs to be perfected to make it more reliable and cost effective.

TECHNOLOGY TRANSFER ACTIVITIES

To compliment our technical effort, we vigorously pursued various technology transfer activities. These activities resulted in 26 publications and 10 presentations. In addition, four technology transfer workshops were conducted for the benefit of small operators and independents. These workshop locations included Tulsa, Houston, Denver and Ft. Worth. We also published two news-letters and sent them to over 300 interested parties.

SUMMARY

Looking back at the project, we can conclude that, although the project ended on a sour note, we were able to demonstrate that cost-effective technologies can be used to improve the performance of marginal oil fields. We evaluated various technologies, and determined their cost effectiveness for future use. We also demonstrated the usefulness in describing the reservoir using integrated information so that we will be able to better predict the future performance of the reservoir. The success is further satisfying by the fact that Glenn Pool field is 90 years old. If we can demonstrate that the field can be rejuvenated with cost effective technologies, there are many other younger fields, where the technologies would be much more useful.

REFERENCES

1. Kuykendall, M. D., and Matson, T. E.: "Glenn Pool Oil Field, Northeast Oklahoma Platform," American Association of Petroleum Geology - Treatise of Petroleum Geology Atlas of Oil and Gas Fields: Stratigraphic Traps III, pp 155-188 (1992).
2. Kelkar, M., Kerr, D. and Liner, C.: "Integrated Approach Towards the Application of Horizontal Wells to Improve Waterflooding Performance", Final DOE Report (Contract No. DE-FC22-93BC14951), September 1999.

Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic Reservoirs

Bill Weiss
Petroleum Recovery Research Center
New Mexico Tech
Socorro, NM 87801

Abstract

Advanced oil recovery technologies applied to the Nash Draw Brushy Canyon Pool revealed that the initial reservoir characterization was too simplistic. The field discovered in 1992, currently produces 458 BOE/day from a deep-water marine turbidite sandstone reservoir in the Delaware Mountain Group at 6800 ft.

A new log interpretation method tuned with core analyses demonstrated that the initial OOIP estimate was too large. This log interpretation method found oil behind-pipe and reduced completion costs.

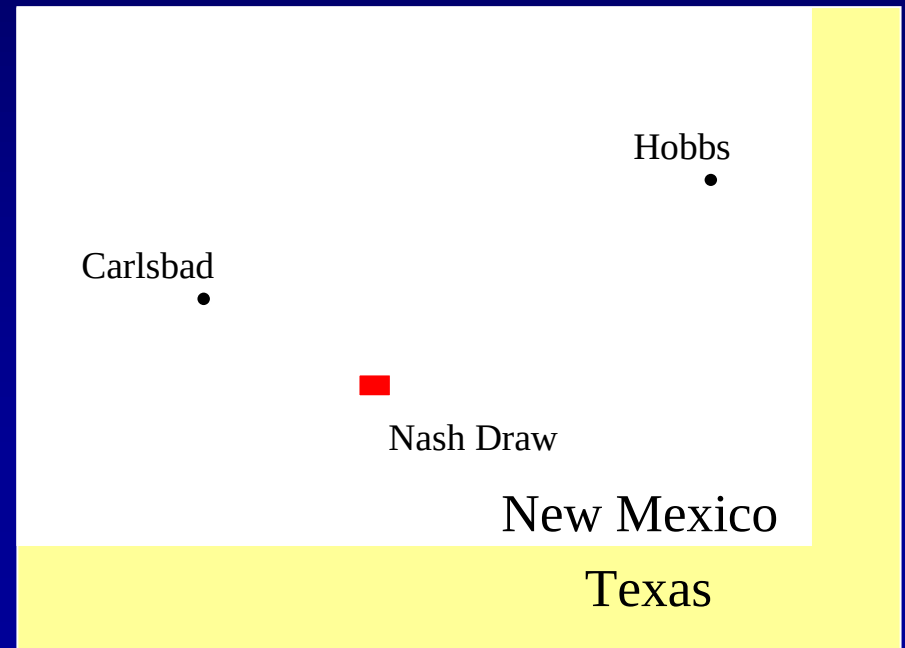
Geostatistical maps based on well parameters targeted zones of high oil saturation between wells, but were of little value when extrapolating outside the area of well control. A high resolution, 3D seismic survey designed for the thin-bedded turbidite sands provided the information to extrapolate beyond the area of well control. Computational intelligence applied to seismic attributes targeted sweet spots, mapped as hydrocarbon pore volume.

Reservoir simulation mapped the pressure distribution in a potential pilot waterflood area. Seismic results and simulation indicated that the reservoir flow units were limited in size and reservoir pressure was low in the pilot area. Therefore, positive flood response could be anticipated only if gas injection commenced early in the field development.

Strata Production Company

**Advanced Oil Recovery Technologies for
Improved Recovery from Slope Basin Clastic
Reservoirs,**

**Nash Draw Brushy Canyon Pool,
Eddy County, New Mexico**



Outline

- Initial Beliefs & Misconceptions
- Findings of the Study & Reality
- Using Results of the Class III Study

Misconception

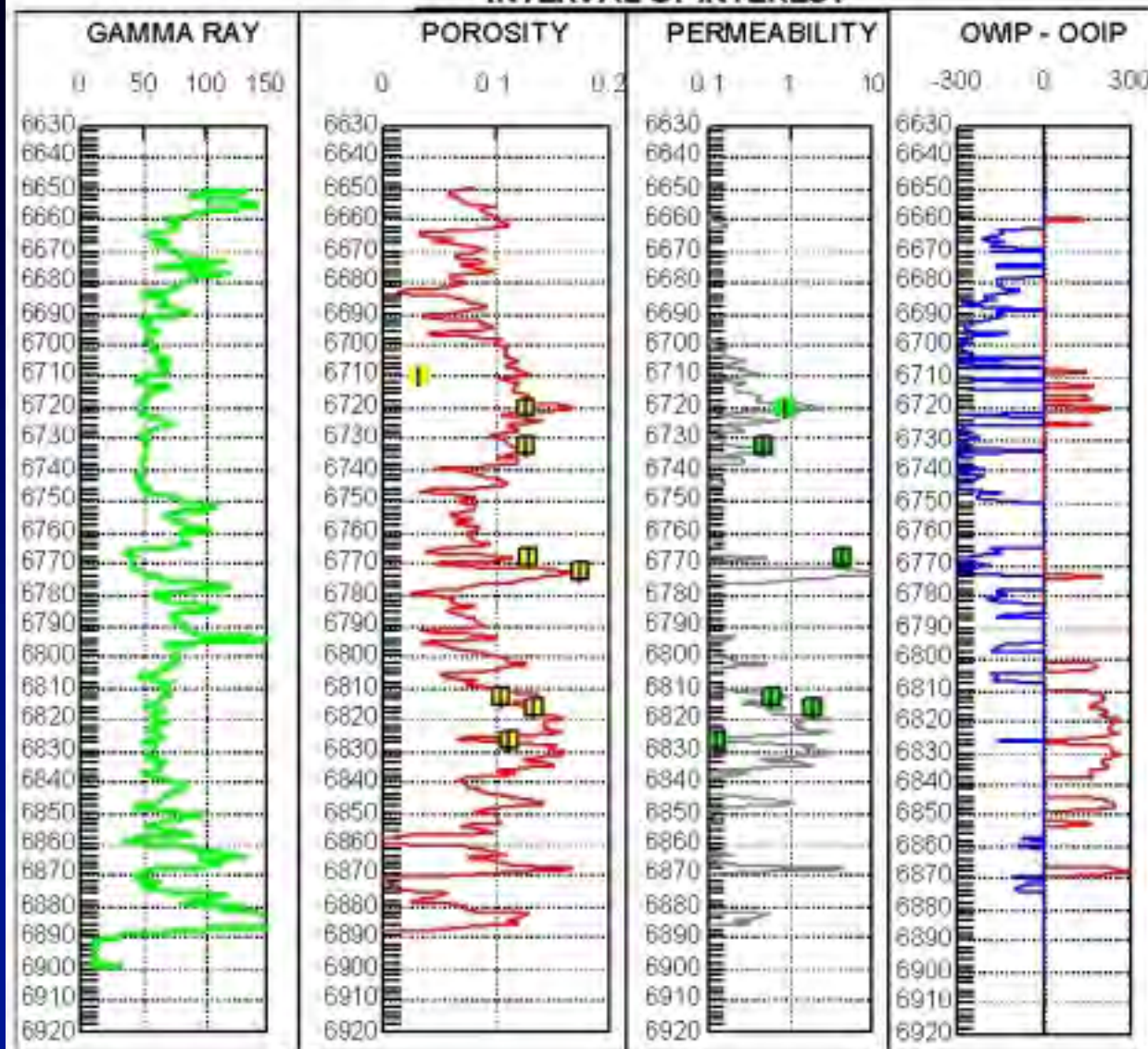
- Initial Calculations Suggest Oil Recovery from the Brushy Canyon Reservoir to be about 10% OOIP

Results of the Study

- An **Advanced Log Analysis** Procedure was developed that improved the ability to distinguish productive pay from non-pay
- Oil Recovery from the Brushy Canyon Sandstones is now calculated to be 16.6%
- The Log Analysis Procedure was used to optimize completion/stimulation as well as to identify new productive intervals

TYPICAL BRUSHY CANYON "K" AND "L" ANALYSIS

INTERVAL OF INTEREST



"K"

"L"

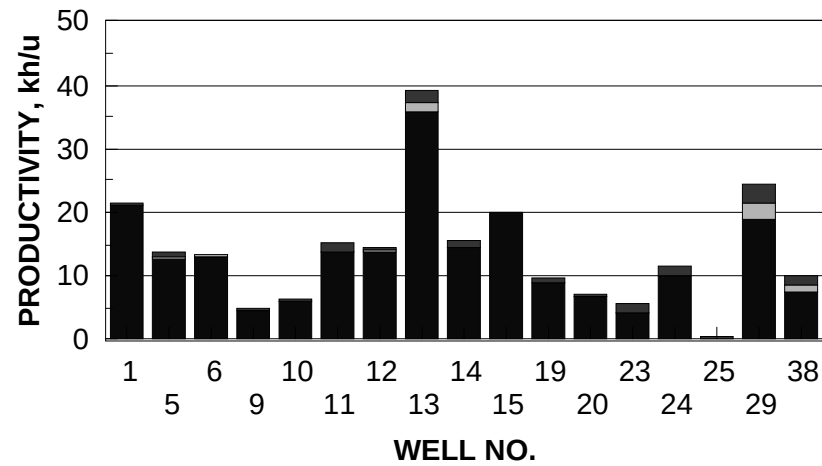
Misconception

- Both the “K” and “L” Sandstones of the Brushy Canyon Interval Were Major Oil Producing Zones

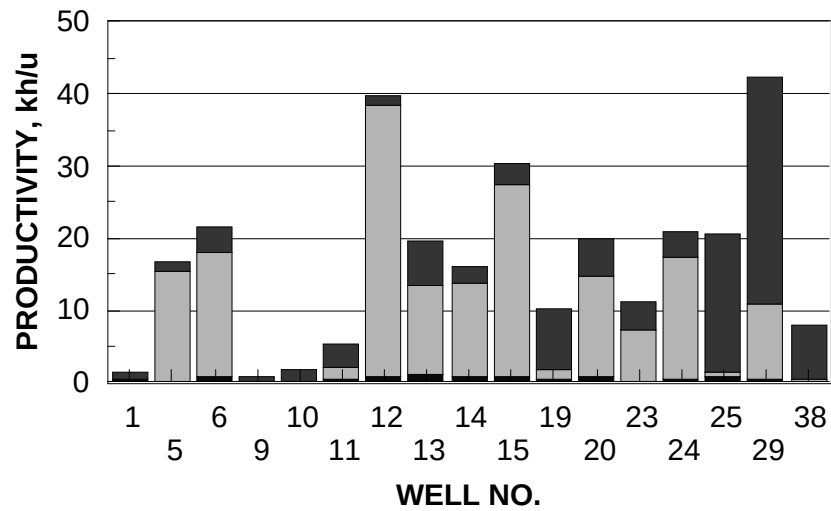
Results of the Study

- Approximately 90% of the Oil Produced at the Nash Draw Pool is from the “L” Zone
- However, Most of the Water is Produced from the “K” and “K-2” Sandstones, if the latter zone is present
- Based on These Results, Well Completions Were Altered

OIL PRODUCTIVITY

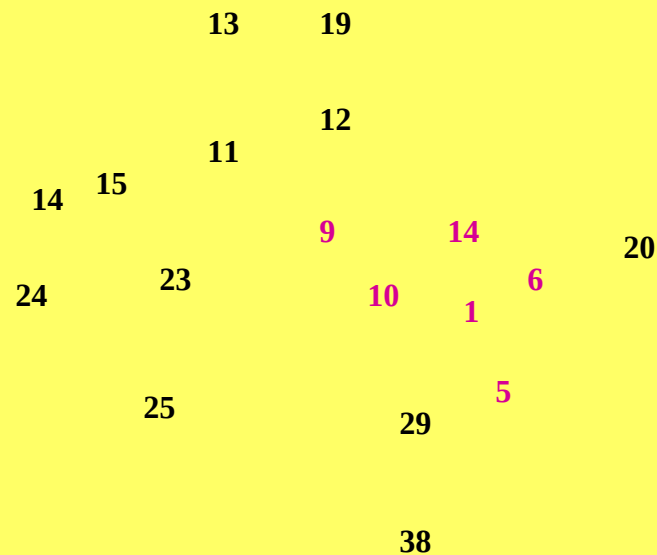


WATER PRODUCTIVITY



Misconception

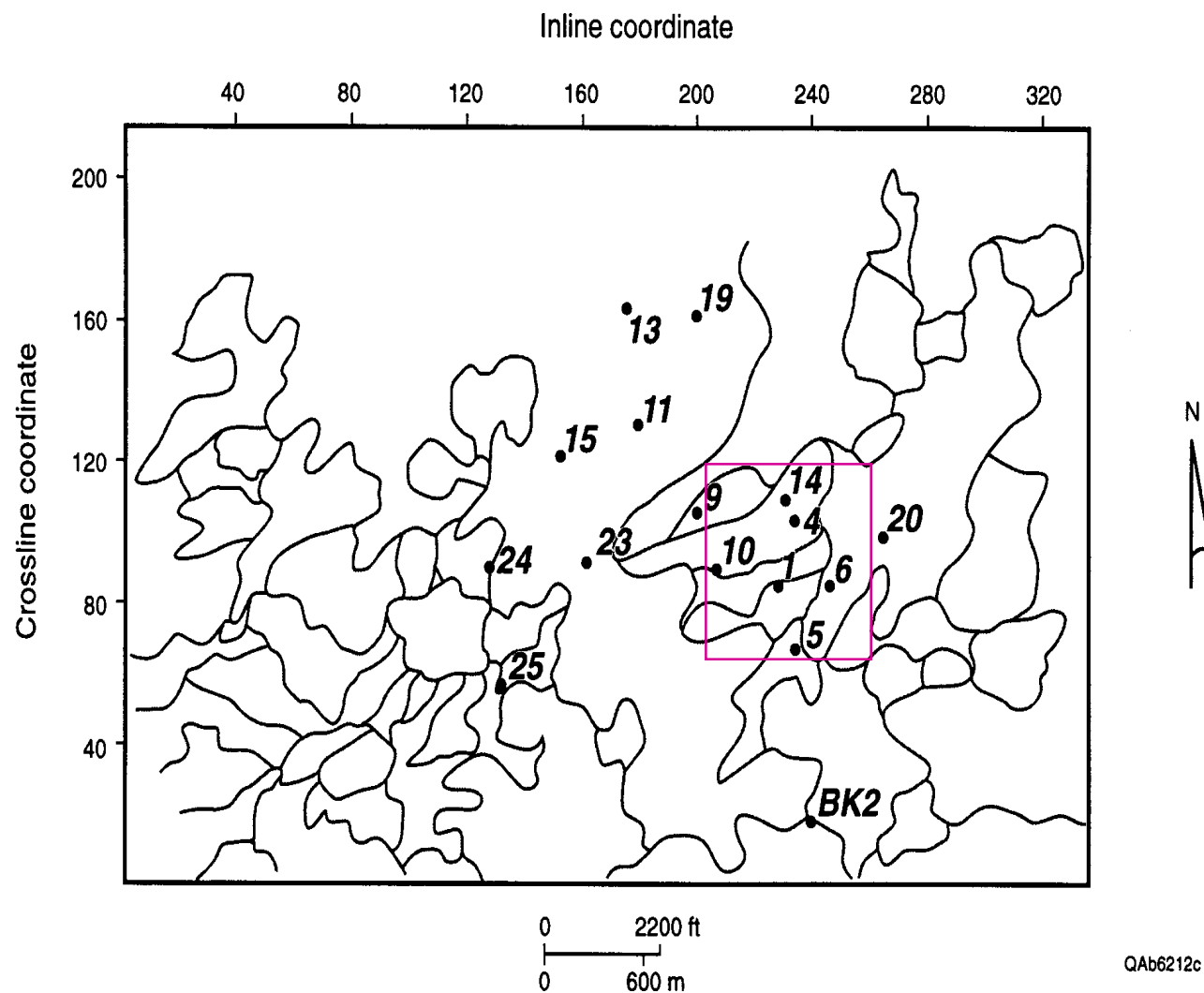
- A Pilot Waterflood Could Be Evaluated in a Developed Portion of the Nash Draw Pool and, If Successful, Could Be Expanded Fieldwide



Results of the Study

- Reservoir Simulation results suggest that low permeabilities would dictate gas injection, but the pilot area was pressure depleted & oil recoveries would be low
- Interpretation of the 3D Seismic & other data indicates that the pilot area was very compartmentalized & some sands were not continuous from Well to Well

RESERVOIR COMPARTMENTS: L SEQUENCE (BONE SPRING - 14ms)



Using Results of the Study

- Improved Completions Strategies
- Targeted Infill Drilling & Extended Reach Drilling
- Plans for Early Implementation of Pressure Maintenance/Gas Injection

Log Analysis Input Page Well #19

IIIIE CORE CALIBRATED LOG ANALYSIS FOR SANDSTONE RESERVOIRS V

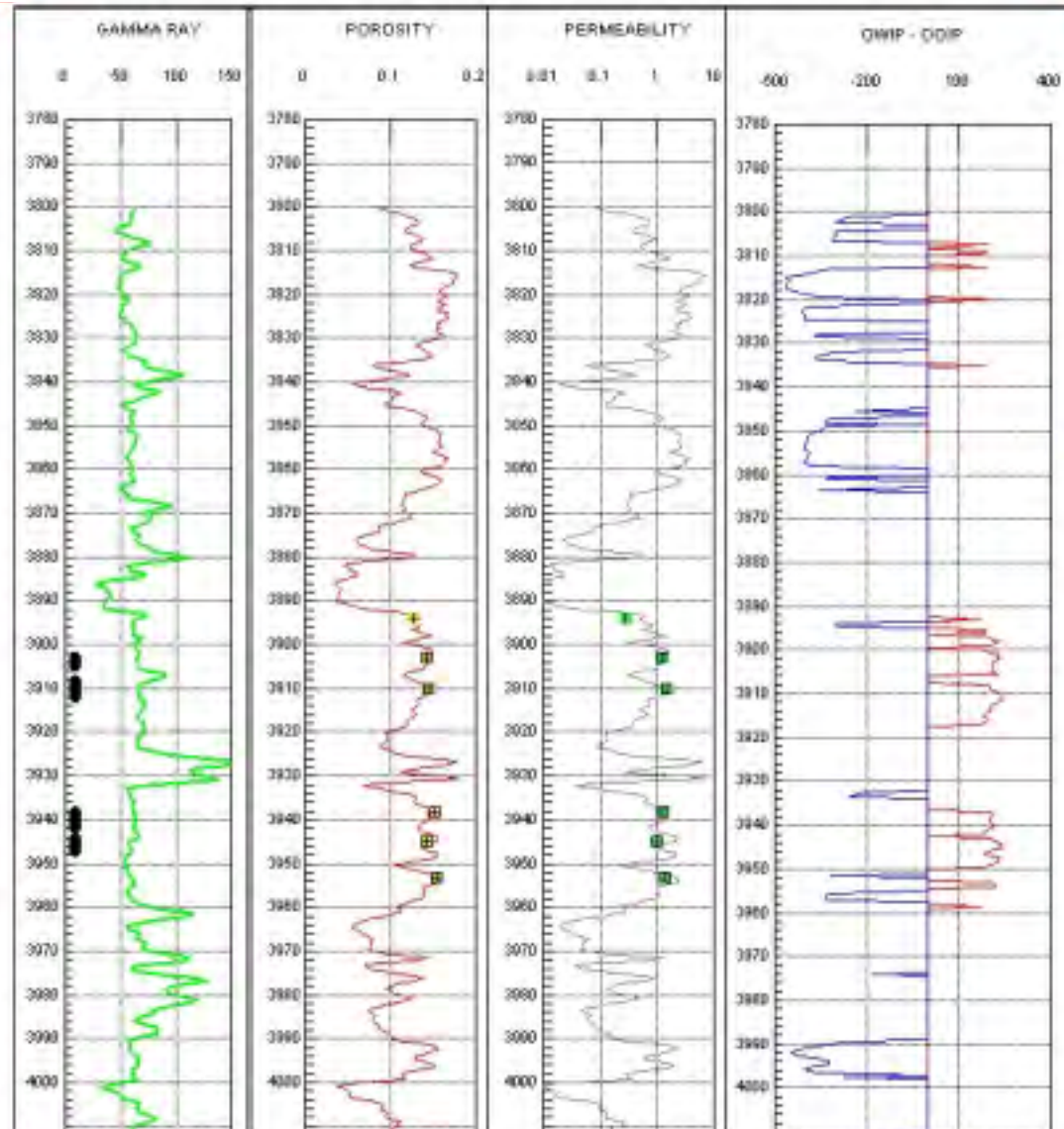
WITH MODIFIED X-PLOR POROSITY CALCULATION 6-4-97

WELL INFORMATION		INPUT		MEASURED BHT=		7200		F	
OPERATOR:	Strata Production Company			BHT DEPTH=		7200		FT.	
WELL NO.:	Nash Unit #19			AMBIENT TEMPERATURE=		60		F	
FORMATION:	Nash Draw Delaware			INTERVAL TO BE CALCULATED=		3800		TO 4200	
LOCATION:	SECTION 12-T23S-R29E			TEMPERATURE GRADIENT=		0.9722		F/100 FEET	
COUNTY:	Eddy			VISCOSITY OF RESERVOIR FLUIDS OIL, cp=		0.8		WATER, cp= 0.8	
STATE:	New Mexico			ESTIMATED RILs=		0.0449			
DATE:	16-MARCH-1999			DELAWARE R _w =		0.047		@ 70 F	
				DELAWARE R _w =		0.05		@ 75 F	
				PERMEABILITY TYPE=		1		TITLE=1, HIGH=2, MED=3, MANUAL=4	
				CORE CALIBRATED PERMEABILITY FACTOR=		1.00			
				MEASURED R _{mf} =		0.103		@ 75 F	
				CALCULATED @ 75 F		0.063		@ 75 F	
				CORE CALIBRATED POROSITY FACTOR=		0.85			
				Bg, OIL FORMATION VOLUME FACTOR=		1.30		RES BBL/STB	
				DRAINAGE AREA=		40		ACRES	
				Rt-corr CORRECTION FACTOR=		1.10			
				CUTOFF RESIDUAL OIL SATURATION=		20.00%			
				ESTIMATED RECOVERY FACTOR=		15.70%			
				ORIGINAL GOR=		800		SC FG/BO	
				CUTOFF VALUES					
				MAXIMUM S _w VALUE=		55.00%			
				MINIMUM POROSITY - OIL ZONES=		12.00%			
				MINIMUM POROSITY - WATER ZONES=		8.00%			
				MAXIMUM GAMMA RAY VALUE=		75		API UNITS	

CALIBRATIC	INPUT	OUTPUT
Rt-corr=	1.10	POROSITY= 14.35%
DEPTH=	3800	Sw= 51.00%

ENTER DEPTH OF A KNOWN PRODUCING ZONE, THEN ADJUST Rt CORRECTION FACTOR TO ACHIEVE CORRECT Sw VALUE

Output for Well #19



PERMEABILITY MATCH
INDICATES ROCK
TYPE #1 - VERY FINE
GRAINED

Wet Zone

Oil Zone

Log Analysis Input Page For Well #24

THE CORE CALIBRATED LOG ANALYSIS FOR SANDSTONE RESERVOIRS V

WITH MODIFIED X-PLAT POROSITY CALCULATION 6-4-97

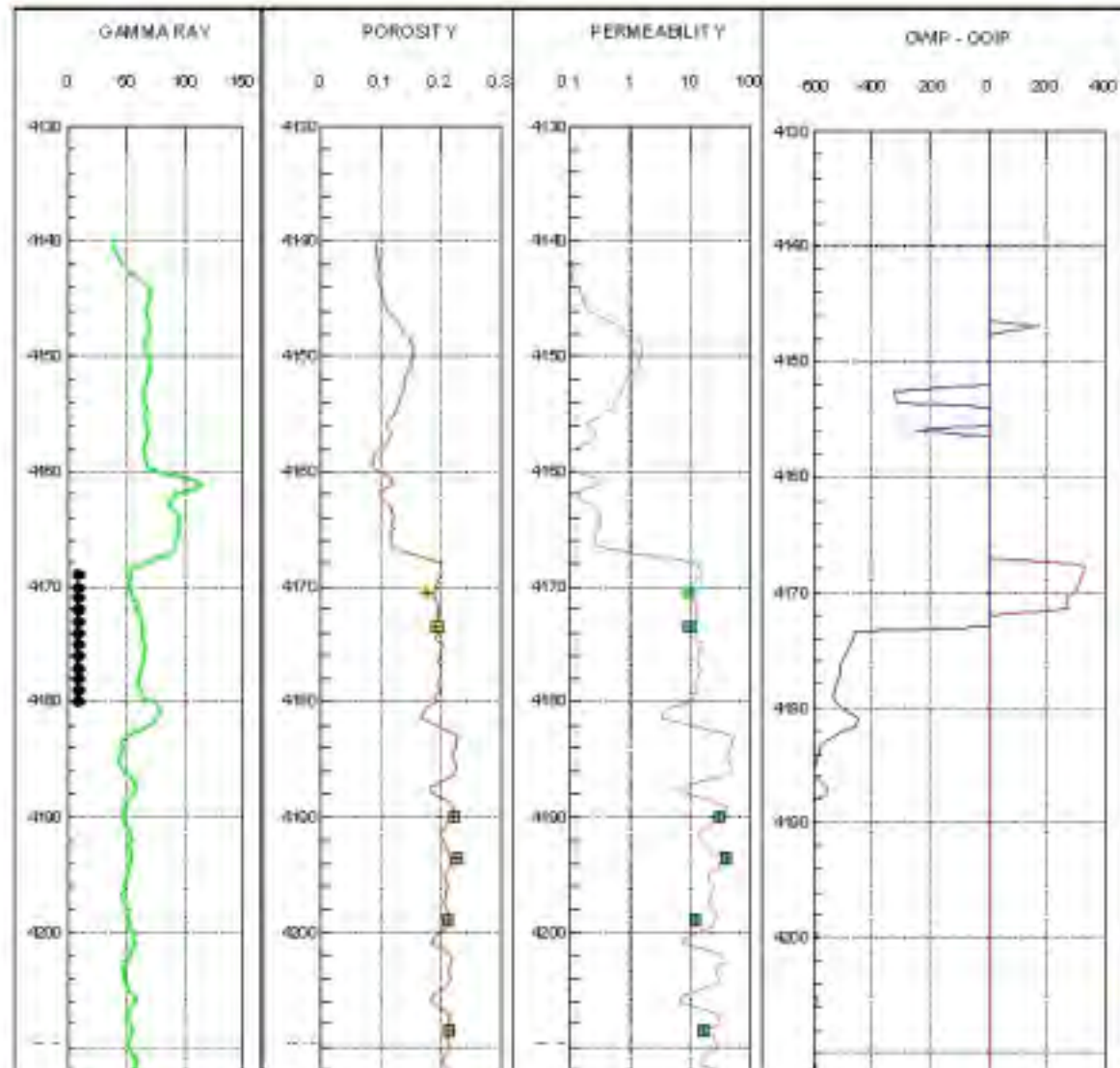
WELL INFORMATION		INPUT		MEASURED BHT=	
OPERATOR:	Strata Production Company	BHT DEPTH =	7200	FT	
WELL NO.:	Nash Unit #24	AMBIENT TEMPERATURE =	60	F	
FORMATION	Nash Draw Delaware	INTERVAL TO BE CALCULATED =	4140	TO	4200
LOCATION	SECTION 14-T23S-R29E	TEMPERATURE GRADIENT =	0.9722	F/100 FEET	
	SE/NE	VISCOSITY OF RESERVOIR FLUIDS OIL, cp =	0.8	WATER, cp =	0.8
COUNTY:	Eddy	ESTIMATED RIIS =	0.0411		
STATE:	New Mexico	DELAWARE RW =	0.047	@ 70 F	
DATE:	16-MARCH-1999	DELAWARE RW =	0.05	@ 75 F	
		PERMEABILITY TYPE =	1	TYPE=1, HIGH=2, MED=3, MANUAL=4	
		CORE CALIBRATED PERMEABILITY FACTOR =	0.80		
		MEASURED Rmft =	0.103	@ 75 F	
		CALCULATED @ 75 F	0.05	@ 75 F	
		CORE CALIBRATED POROSITY FACTOR =	0.95		
		Bg, OIL FORMATION VOLUME FACTOR =	1.30	RES. BBL/STB	
		DRAINAGE AREA =	40	ACRES	
		Rt-corr CORRECTION FACTOR =	1.10		
		CUTOFF RESIDUAL OIL SATURATION =	20.00%		
		ESTIMATED RECOVERY FACTOR =	16.70%		
		ORIGINAL GOR =	800	SCFG/BO	
		CUTOFF VALUES			
		MAXIMUM SW VALUE =	65.00%		
		MINIMUM POROSITY - OIL ZONES =	12.00%		
		MINIMUM POROSITY - WATER ZONES =	8.00%		
		MAXIMUM GAMMA RAY VALUE =	75	API UNITS	

OUTPUT	
ORIGINAL-OIL-IN-PLACE=	113,544 BBLs.
RECOVERABLE OIL =	18,962 BBLs.
	5 FEET
ORIGINAL-GAS-IN-PLACE=	90,835 MCFG
ORIGINAL-WATER-IN-PLACE=	6,415,637 BBLs.
RECOVERABLE WATER =	1,071,411 BBLs.

CALIBRATIC	INPUT	OUTPUT
Rt-corr=	1.10	POROSITY= 19.91%
DEPTH =	4178	Sw= 67.15%

ENTER DEPTH OF A KNOWN PRODUCING ZONE, THEN ADJUST RI CORRECTION FACTOR TO ACHIEVE CORRECT SW VALUE

Output for Well #24



TYPE I SAND -VERY
FINE GRAIN

OIL ZONE

INCREASING WATER
SATURATIONS WITH
DEPTH

PREDICTED
20 BOPD & 150 BWPD

ACTUAL
20 BOPD & 120 BWPD

WET ZONE

Increased Reserves

Well #	Zones	Reserves, BOE	A.F.E. Estimated Cost	Development Cost, \$/BOE
13	“H”, “E” & “C-2”	80,325	\$84,593	\$1.05
15	“H-4”, “G-3” & “F-3”	47,514	\$75,114	\$1.58
19	“J” & Bell Canyon-Lower	95,163	\$91,942	\$0.97
24	“F-3”, “F-2”, “D” & “CC-2”	66,944	\$96,676	\$1.44
	Total	289,946	\$348,325	\$1.20

Initial Incremental Production

Well #	Incremental Oil BOPD	Incremental Gas MCFGD	Incremental Water BWPD
13	29	24	146
15	12	10	88
19	12	22	173
24	28	165	120
Total	81	221	527

Targeted Drilling

- Geostatistical Analysis for Spatial Distribution of Reservoir Properties
- Reservoir Simulation to Assess Reservoir Pressure Throughout the NDP
- Multivariable Seismic Attribute Analysis
 - Interwell Reservoir Properties
 - Extrapolate to Regions Beyond Well Control

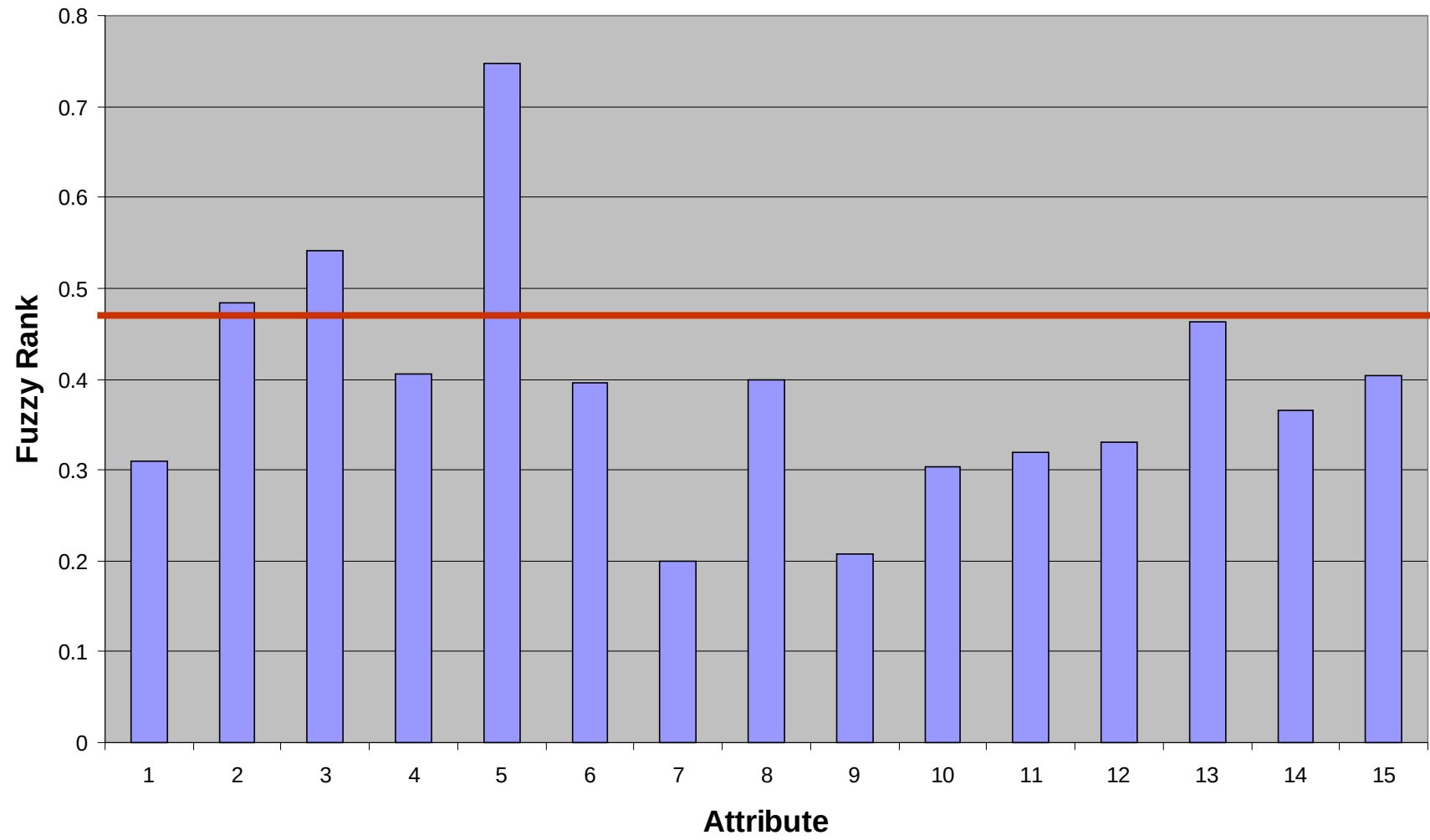
Geostatistical Analysis

- Log data used to map HCPV
- Results were similar with 3 techniques (nearest-neighbor, kriging algorithm, and a fractal model) and confirmed drilling targets
- Geostatistics interpolates--extrapolation of properties was needed

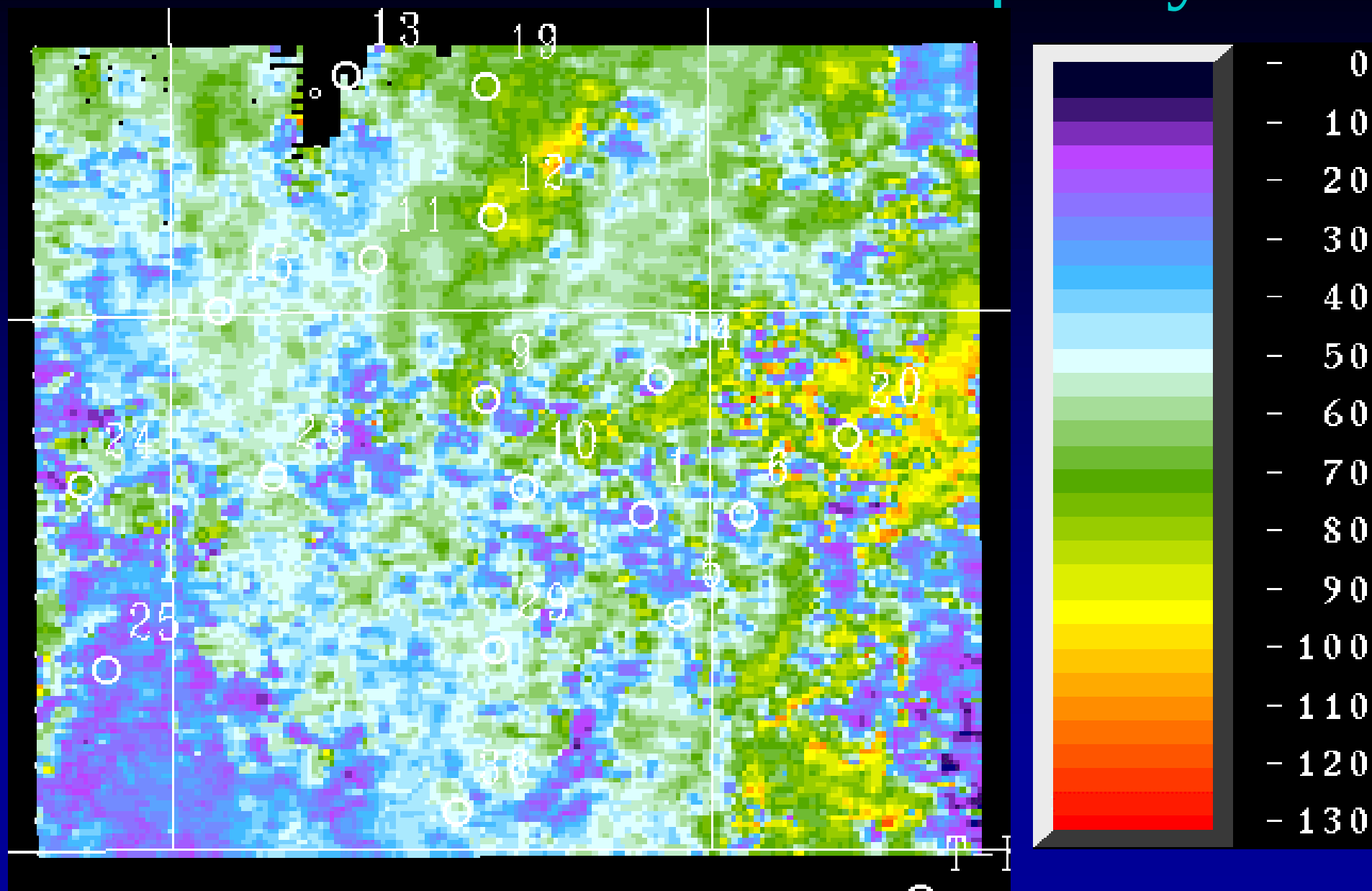
Pattern Recognition

- Fuzzy Logic or Fuzzy Ranking used statistics to decide which seismic attributes provide the best correlation with reservoir properties (porosity, net pay, and water saturation)
- Neural Networks trained to fit non-linear multi-variable relationships between input data and desired parameters

Fuzzy Ranking of Attributes for Correlating to Average L Interval Porosity



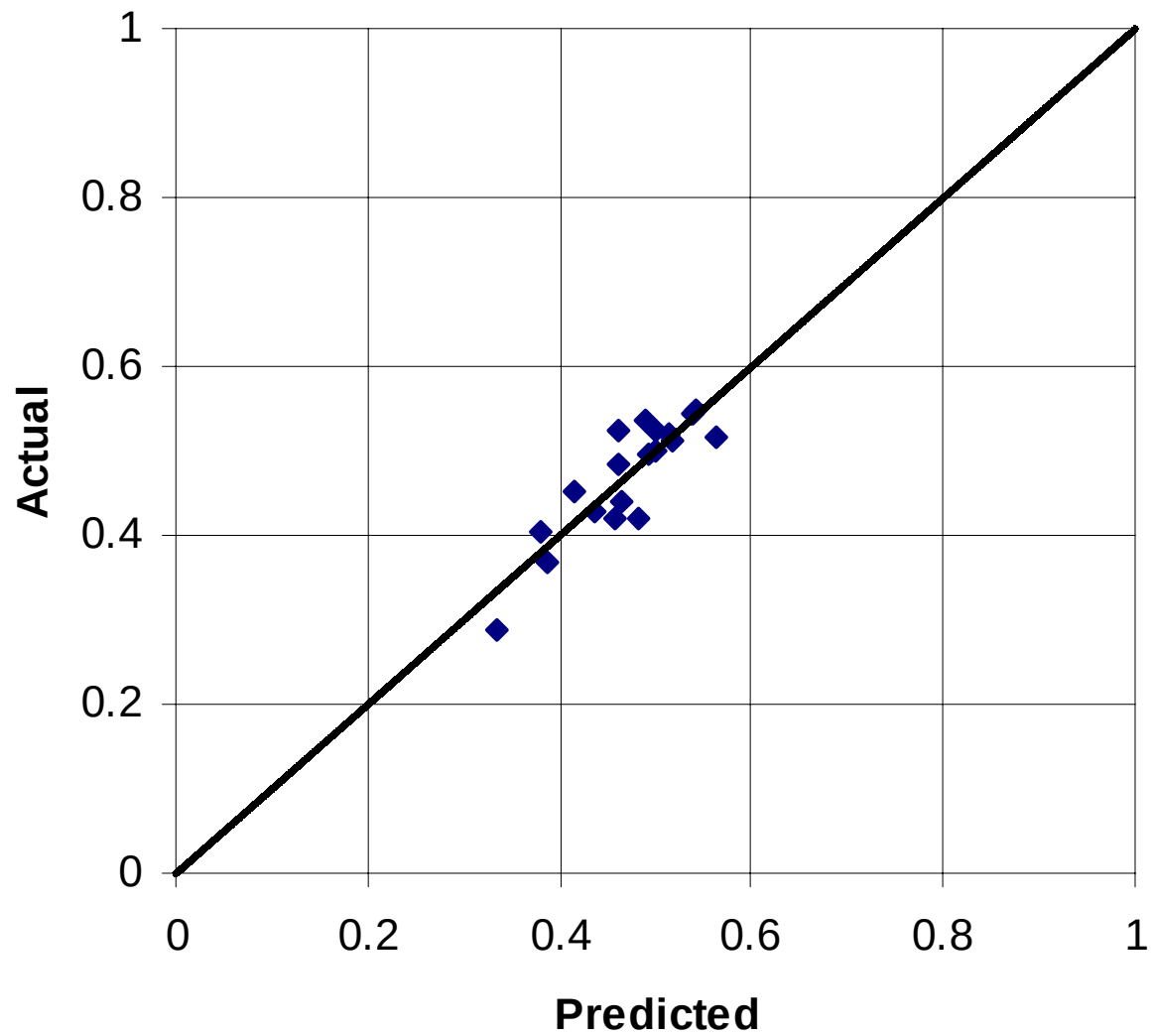
L Ave Instantaneous Frequency



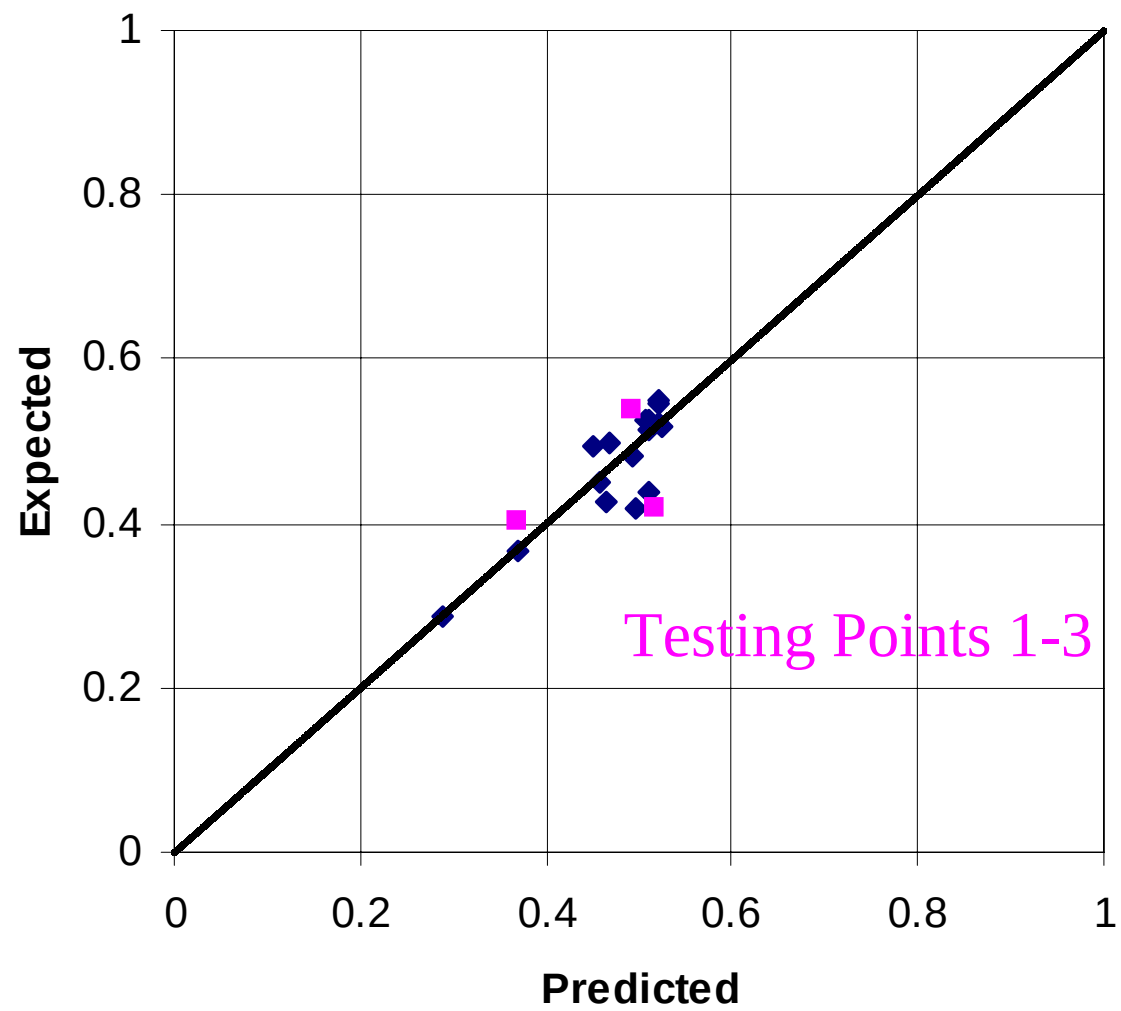
Predicting Interwell Data

- Neural Networks were trained to evaluate ϕ , Sw , and net pay using seismic attributes extracted from the “L” zone
- Well data averaged across that interval to guide the training algorithms
- Several data were removed and the Networks were retrained to test how well the Network can predict interwell data

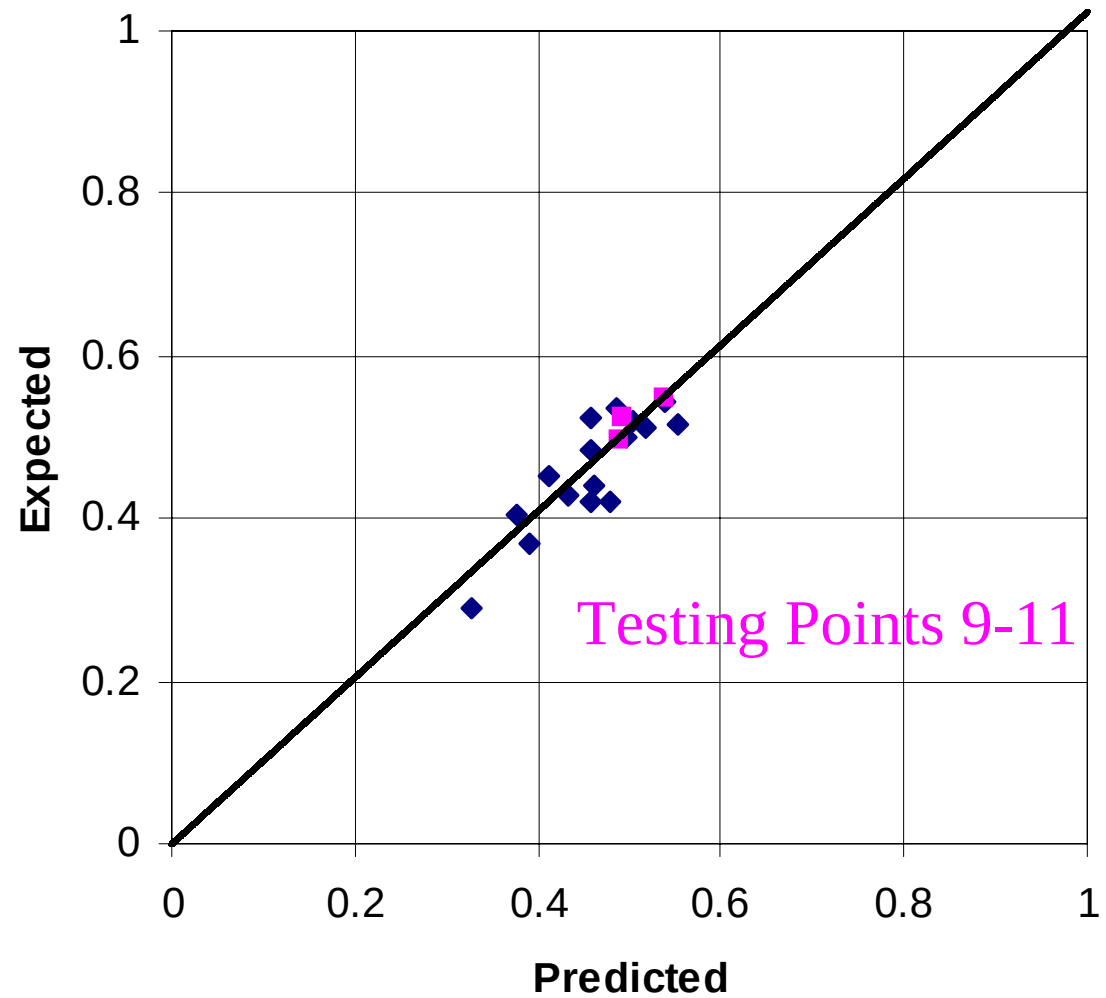
Porosity training - All 19 points



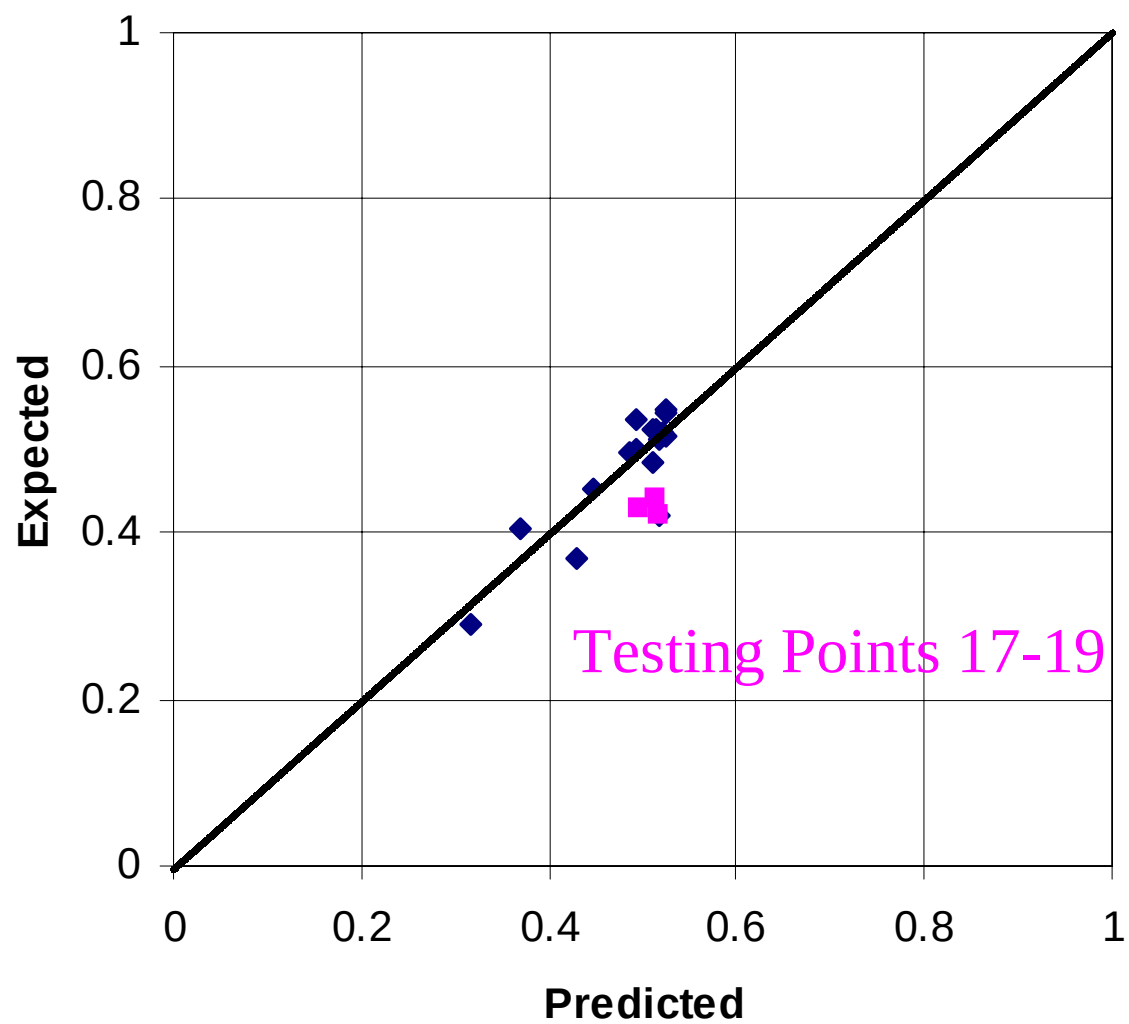
Porosity training - Points 4-19



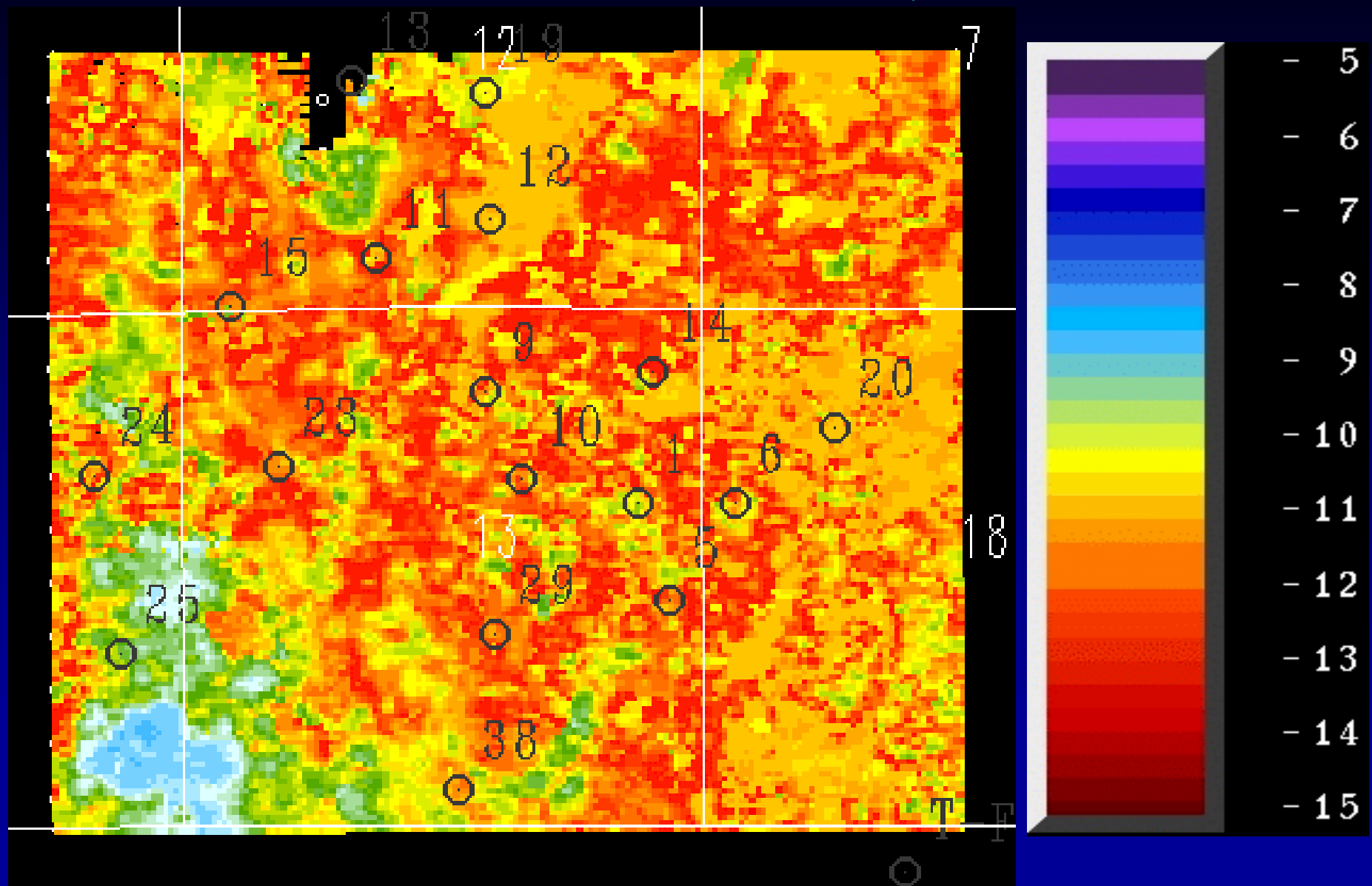
Porosity training - Points 1-8 & 12-19



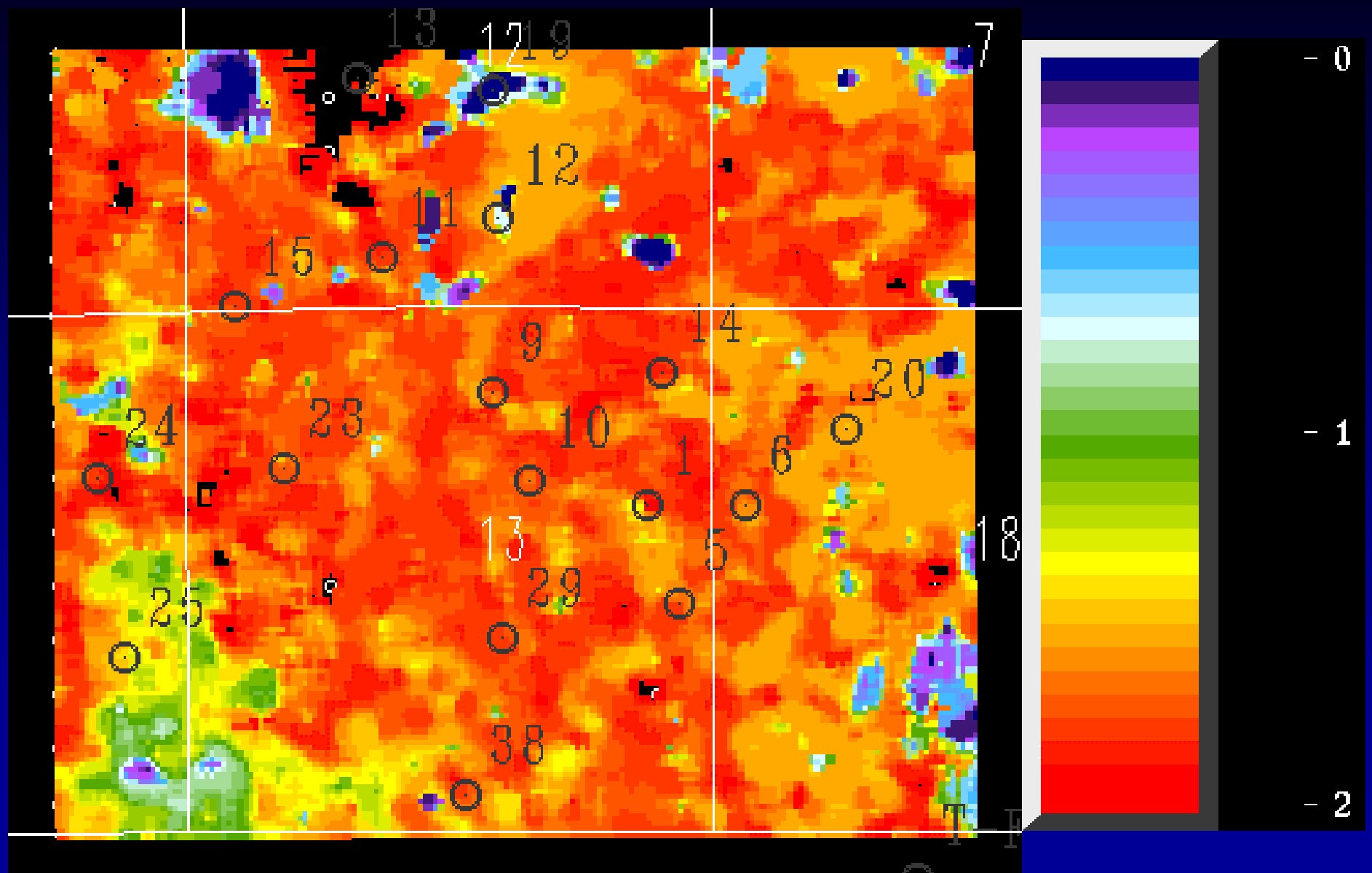
Porosity training - Points 1-16



Predicted $L \phi$



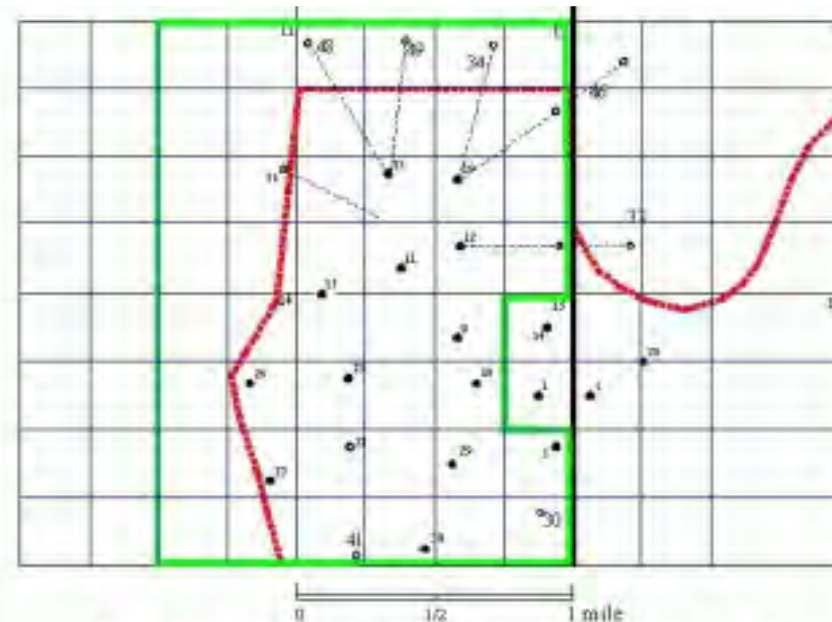
Predicted L h ϕ So



Seismic Attribute Findings

- Fuzzy Ranking can help decide which seismic attributes are most useful for evaluating reservoir properties
- Multivariable non-linear regression (Neural Networks) can be used to correlate well and seismic data
- Predictions of interwell reservoir properties are feasible--extrapolation is possible

Directional/Horizontal Wells to develop areas
under the potash area and playa lakes



NASH DRAW UNIT

EDDY COUNTY, NM

T23S-R29E & T23S-R30E

----- Potash Boundary

— Farmout Area

Project Status

- A proposed pressure maintenance injection in Phase I was not conducted because the pilot area was pressure depleted, and seismic results suggest compartmentalization
- In Phase II, a pilot injection test will be reconsidered in a more continuous part of the NDP if such areas have sufficient reservoir pressure

Project Status

- To develop better areas of the field located under playa lakes and potash mining, deviated/horizontal wells will be drilled in Phase II-- Initially 3 wells to evaluate:
 - Drilling & completion techniques
 - Ability of the seismic attribute analysis to identify high quality targets
- Additional development wells

Advanced Fracturing Technologies for Marginal Oil and Gas Wells

Scott R. Reeves, (sreeves@adv-res.com, Phone: 713-780-0815)

Advanced Resources International
9801 Westheimer, Suite 805
Houston, TX 77042

DOE Contract: DE-AC21-94MC31112
Period of Performance: Oct. 1994 – Sept. 1999
FETC COR: Jim Ammer

Introduction

In 1994, the DOE/FETC began a field-based R&D project to investigate the application of “new and novel” fracture stimulation technologies for gas storage wells. The project was initiated in response to the persistent decline in deliverability that occurs in gas storage fields, reported to be on the order of 5% per year. To counteract that decline, industry currently spends about \$100 million annually; two-thirds of which is used to drill infill replacement wells. However, in the highly competitive post-FERC 636 market environment, a more cost-effective approach to maintaining deliverability is required. A study published by the GRI in 1993 suggested that fracturing holds considerable promise in this regard, and DOE/FETC responded with this project.

Similar to the needs and economic pressures of gas storage wells, marginal oil and gas wells may also benefit from the fracturing technologies investigated in this project. Such wells, typically characterized by low reservoir energy and/or tight formations, can be highly susceptible to damage by stimulation fluids, similar to gas storage wells. In addition, due to marginal economics particular attention must be paid to the stimulation costs, and the production (or deliverability) results obtained therefrom. This paper discusses the technologies and results of the DOE/FETC gas storage project, and how they might be applicable to marginal oil and gas wells.

Objectives

The fundamental objective of the project is to demonstrate the application and economic feasibility of “new and novel” fracturing technologies for restoring the deliverability of existing underground gas storage wells. Within this primary objective, several tactical objectives are as follows:

- Identify “new and novel” fracture stimulation methods that hold potential for gas storage wells.
- Demonstrate their application, including treatment design, implementation and results.

- Evaluate their economic performance as compared to “typical” (non-fracturing) stimulation practices of gas storage operators, such as blowing/washing or mechanical cleaning of the wellbore, reperforating, water/solvent washes, and acidizing.

Approach

The approach utilized for the project was to test the “new and novel” fracture stimulation technologies in various geologic and reservoir settings across the U.S. Four different technologies were tested at nine field sites. At each site, three “new and novel” treatments were performed, and compared to the results of one “control” well where the operator’s typical stimulation technique was applied. To understand treatment mechanics, state-of-the-art design procedures were utilized together with on-site diagnostics and post-treatment analysis. Treatment effectiveness was determined using multi-point deliverability and pressure transient testing with downhole instrumentation; tests were run before a treatment, afterwards and again one year later to determine long-term impact. Cost/benefit analyses were performed to estimate the economic benefit of the “new and novel” methods as compared to non-fracturing stimulation techniques.

Technology Description

Gas storage wells have a number of unique characteristics that require special attention when considering fracture stimulation. First, due the high-permeability nature of most gas storage formations, the desired fracture geometry is short in length with high conductivity. This is to bypass near-well damage and create a highly conductive flowpath to the wellbore. Second, fracture height growth is of concern due to the potential for gas loss. Therefore, treatments that minimize the potential for upward or downward growth are required. Finally, due the cycling of dry, pipeline quality gas into and out of gas storage wells, water saturations can be at sub-residual levels. Therefore, the introduction of aqueous fluids tends to be “damaging” to gas permeability. Treatments must therefore minimize this effect. With these criteria, four technologies were selected for testing.

- Tip-screenout fracturing. This hydraulic fracturing technique is ideal for creating short, highly conductive fractures in high permeability formations. However, relatively large volumes of aqueous-based fluids are required and the potential for height growth exists.
- Hydraulic fracturing with liquid CO₂ and proppant. This technique utilizes a non-aqueous carrier fluid to completely avoid the fluid-damage issue, hence providing immediate stimulation benefits. However, high proppant volumes and concentrations cannot be pumped, limiting fracture conductivity.
- Extreme overbalance fracturing. This method involves exposing the target formation to a high-pressure pulse of nitrogen, thus creating fractures. The technique utilizes small fluid volumes and the potential for height growth is minimized.
- High energy gas (propellant) fracturing. This method utilizes propellants which are ignited and burned to form a small volume of high-energy gas that fractures the formation. Multiple, radiating fractures are created and, similar to the above method, the potential for height growth is minimized.

Results

Significant findings that are relevant to the application of these technologies to oil and gas wells are:

- Tip-screenout treatments are extremely effective at enhancing deliverability in high-permeability, high-pressure wells.
- Liquid CO₂ with proppant treatments provide immediate stimulation benefits and avoid a prolonged fluid cleanup time. However, fluid leakoff appears to be a problem, and hence their application is probably limited to where pump rate can overcome fluid loss. While treatment costs are higher than aqueous-based treatments of comparable volume, this is offset by the greater immediate well response. These treatments also appear to be effective in cleaning up hydrocarbon residue damage due to the solvent characteristics of CO₂.
- Extreme overbalance treatments suffer from operational complexity, high cost and poor understanding.
- High energy gas fracturing is operationally simple and low in cost, but the fractures created, being unproped, provide stimulation of uncertain durability.

Application

Of the techniques investigated, several are likely to be of benefit to marginal oil and gas wells. Tip-screenout treatments are best suited for higher permeability formations with sufficient remaining pressure for effective cleanup; hence, their application to marginal oil and gas wells may be limited. Liquid CO₂ with proppant treatments seem well suited to water-sensitive tight gas wells, provided sufficient fracture length can be achieved. Lack of fluid damage, which maximizes flush production, should be sufficient to offset the higher cost. In addition, the solvent characteristics of CO₂ make it attractive for oil wells. Extreme overbalance treatments are probably not well suited for marginal oil and gas well applications, but for cost reasons, high-energy gas fracturing may be for the same reason (cost).

Acknowledgement

This work was performed under DOE/FETC contract number DE-AC21-94MC31112, "Field Verification of New and Novel Fracture Stimulation for the Revitalization of Existing Underground Gas Storage Wells", with a period of performance from October 1, 1994 through September 30, 1999. The Contracting Office Representative is James R. Ammer, (jammer@fetc.doe.gov, Phone 304-285-4383). Industry partners were Columbia Gas Transmission, Consumers Energy, CNG Transmission, East Ohio Gas, KN Energy, MichCon Gas, National Fuel Gas Supply, and Natural Gas Pipeline. Significant subcontractors included NSI Technologies and John F. Schatz Research and Consulting

ADVANCED FRACTURING TECHNOLOGIES FOR MARGINAL OIL AND GAS WELLS

by

Scott Reeves

Advanced Resources International, Inc.

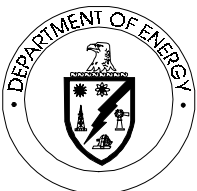
DOE Contract: DE-AC21-94MC31112

FETC COR: James R. Ammer

DOE Oil & Gas Conference

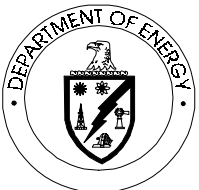
June 28 - 30, 1999

Dallas, Texas



PRESENTATION OUTLINE

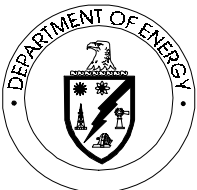
- ◆ **Introduction**
- ◆ **Objectives**
- ◆ **Approach**
- ◆ **Technology Description**
- ◆ **Results**
- ◆ **Application**



BACKGROUND

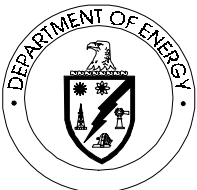
- ◆ **Project initiated in 1994:**
 - “Application of New and Novel Fracture Stimulation Techniques to Enhance the Deliverability of Gas Storage Wells.”

- ◆ **DOE responds to an industry need:**
 - Persistent deliverability decline ($>5\%$ /year).
 - High cost of deliverability maintenance (\$100 million/year, two-thirds for infill replacement wells).
 - Fracturing identified as a potentially more efficient path to maintaining deliverability.



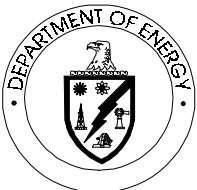
CONCERNS AND SPECIAL ISSUES WITH FRACTURING IN GAS STORAGE WELLS

- ◆ **Fracture Height Growth**
 - Gas Loss
 - Water Production
- ◆ **High Permeability Formations**
 - High Fracture Conductivity
 - Short Fractures to Bypass Damage
- ◆ **Fluid Sensitivity**
 - Gas Permeability Reduction, Long Cleanup Times
 - Particulate Damage
 - Chemical Reactions
- ◆ **Tight Economics**
 - No tangible gas “reserve” to offset costs
 - How to value improved deliverability?



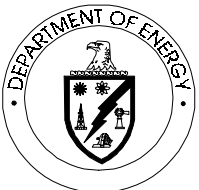
COMPARISON OF GAS STORAGE AND MARGINAL OIL/GAS RESERVOIRS

	<u>Gas Storage</u>	<u>Marginal Oil/Gas</u>
Depth	Similar	Similar
Permeability	higher	lower
Pressure	can be higher	probably lower
Fluid Sensitivity	high	high
Economics	marginal	marginal



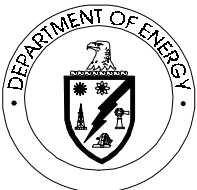
PRESENTATION OUTLINE

- ◆ Introduction
- ◆ Objectives
- ◆ Approach
- ◆ Technology Description
- ◆ Results
- ◆ Application



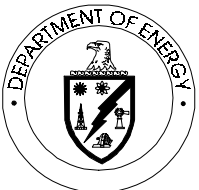
PROJECT OBJECTIVE

- ♦ **To demonstrate, through a series of field tests, the application and benefits of “new and novel” fracturing technologies that directly address these challenges and obstacles and that can enhance the long-term deliverability of gas storage wells.**
 - **Identify potential fracturing methods.**
 - **Demonstrate their practical application (design, implementation).**
 - **Compare them, commercially, with traditional methods.**



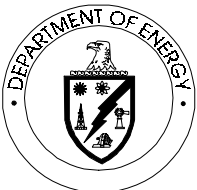
PRESENTATION OUTLINE

- ◆ Introduction
- ◆ Objectives
- ◆ Approach
- ◆ Technology Description
- ◆ Results
- ◆ Application

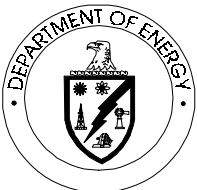
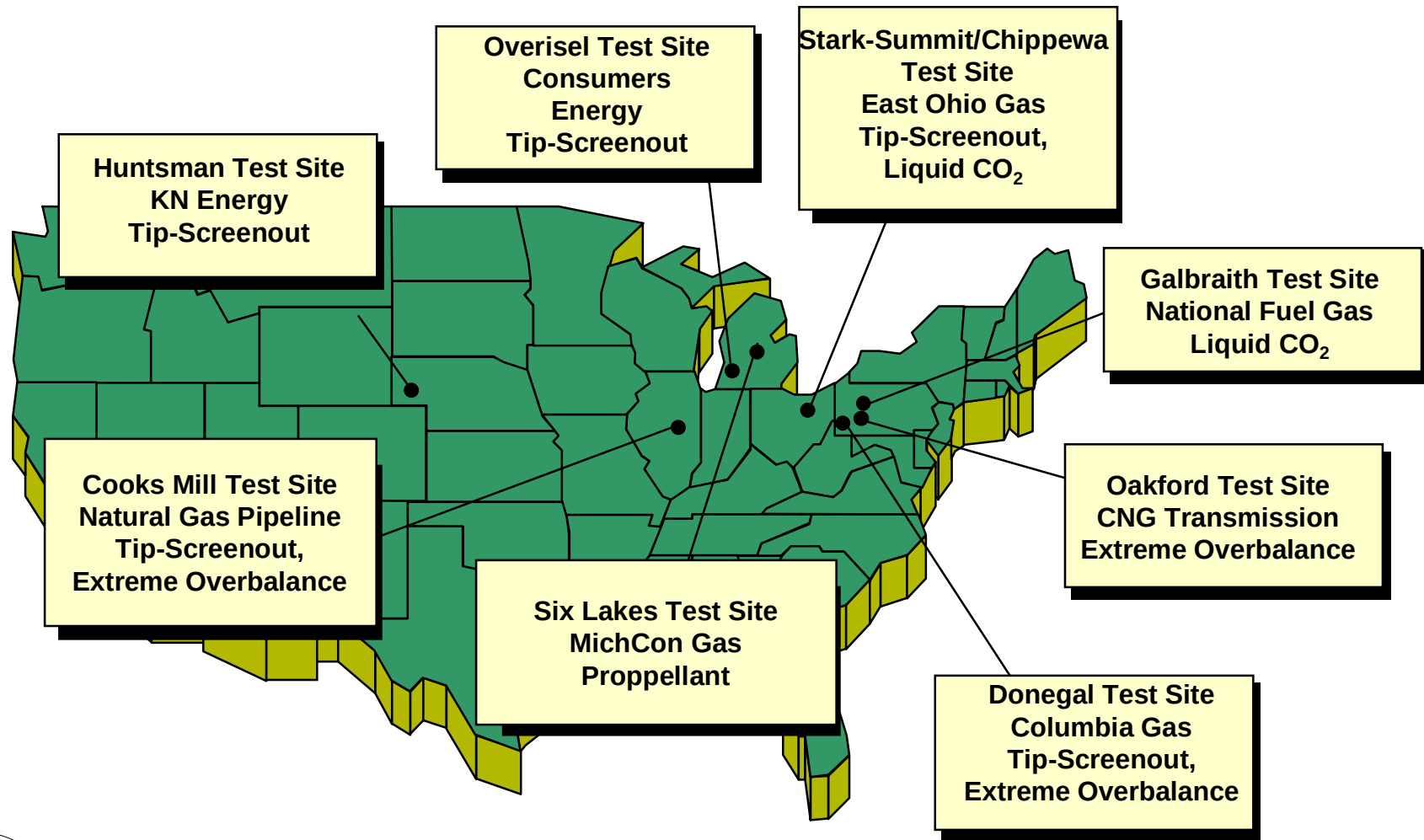


PROJECT OVERVIEW

- ◆ **Nine field projects**
- ◆ **Each project consists of multiple wells:**
 - Target of 3 “new and novel” fracture test wells
 - At least one “conventional” stimulation control well
- ◆ **Detailed design and diagnostics:**
 - pre-, post- and annual multipoint deliverability and pressure transient tests with downhole instrumentation
 - rock mechanics studies, fracture height surveys
 - treatment design and post-analysis modelling
- ◆ **Economic and benchmarking analysis**



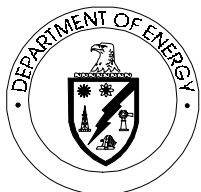
LOCATION OF TEST SITES



SUMMARY OF FIELD ACTIVITIES PERFORMED TO DATE*

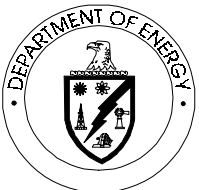
	Tip-Screenout				Liquid CO ₂		Extreme Overbalance		Propellant	
Activity	Huntsman	Stark-Summit/ Chippewa	Overisel	Cooks Mills	Galbraith	Stark-Summit/ Chippewa	Donegal	Oakford	Six Lakes	Total
New and Novel Fracture Treatments Performed	2	3	3	1	3	3	7	2	3	27
Pre-Fracture Deliverability and Pressure Transient Tests Performed/Analyzed	7	18	4	4	4	13	16	4	4	74
Acoustic Logs Run/Analyzed	-	-	-	-	-	-	1	-	-	1
Core Plugs Taken/Tested	-	-	-	-	-	-	6	-	-	6
Step-Rate Tests Performed/Analyzed	2	1	3	-	-	-	2	-	-	8
Mini-Frac Performed/Analyzed	4	1	3	-	-	-	1	-	-	9
Main Frac Bottomhole Treating Pressure Records	2	-	3	-	-	1	-	2	3	11
Radioactive Tracer Surveys	3	1	1	-	-	-	5	-	-	10
Temperature Surveys	3	2	-	-	-	-	-	-	-	5
Downhole Camera Surveys	-	-	-	-	-	-	-	1	7	8
Post-Fracture Deliverability and Pressure Transient Tests Performed/Analyzed	3	4	2	3	3	2	13	2	3	35
Annual Deliverability and Pressure Transient Tests Performed/Analyzed	2	3	2	-	3	1	13	3	-	27

* As of June 1999

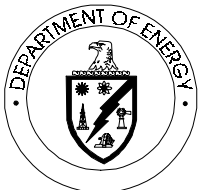
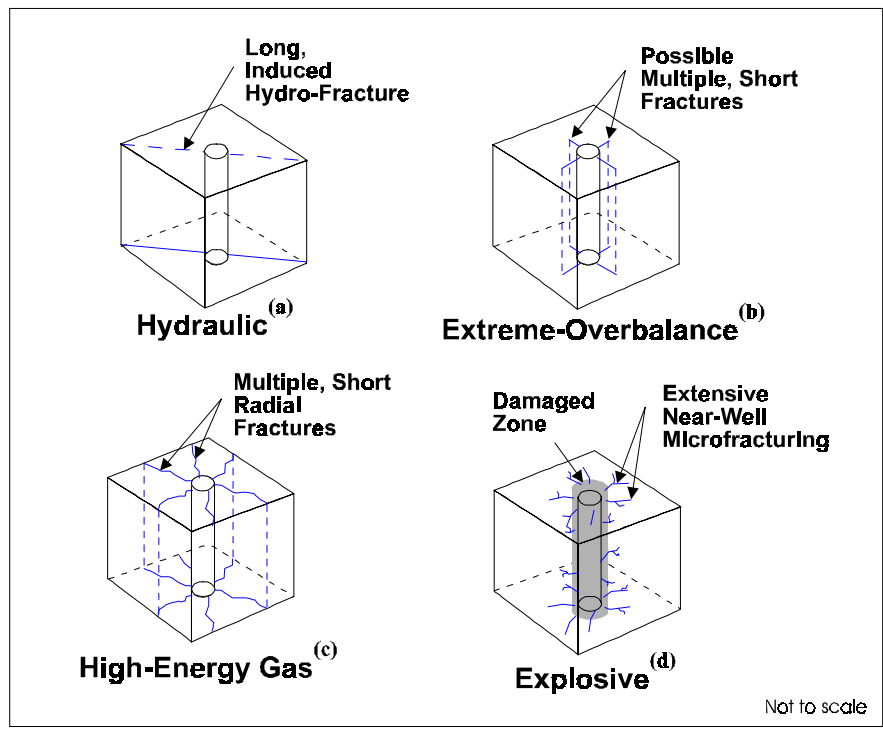
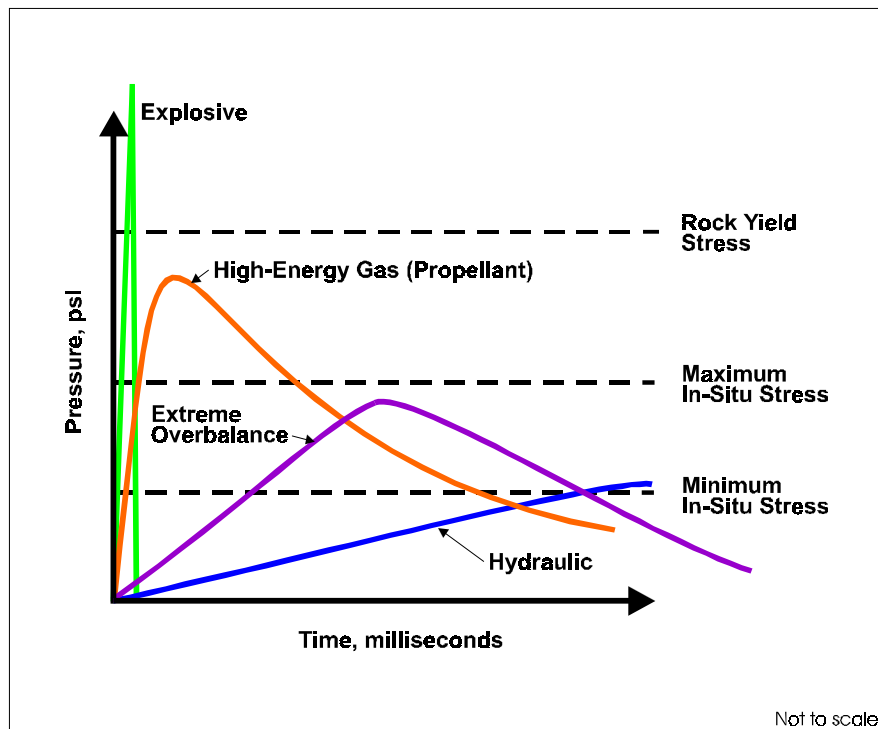


PRESENTATION OUTLINE

- ◆ Introduction
- ◆ Objectives
- ◆ Approach
- ◆ Technology Description
- ◆ Results
- ◆ Application



ENERGY APPLICATION RATES AND RESULTING FRACTURE PATTERNS FOR VARIOUS FRACTURE-STIMULATION TECHNOLOGIES



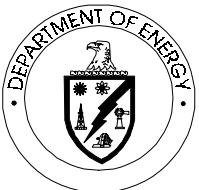
“NEW AND NOVEL” FRACTURE STIMULATION TECHNOLOGIES

Hydraulic Fracturing

- ◆ **Tip-Screenout**
- ◆ **Liquid CO₂
w/Proppant**

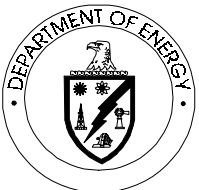
Pulse Fracturing

- ◆ **Extreme Overbalance**
- ◆ **Propellant**

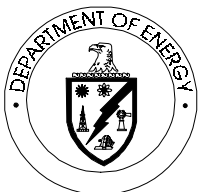
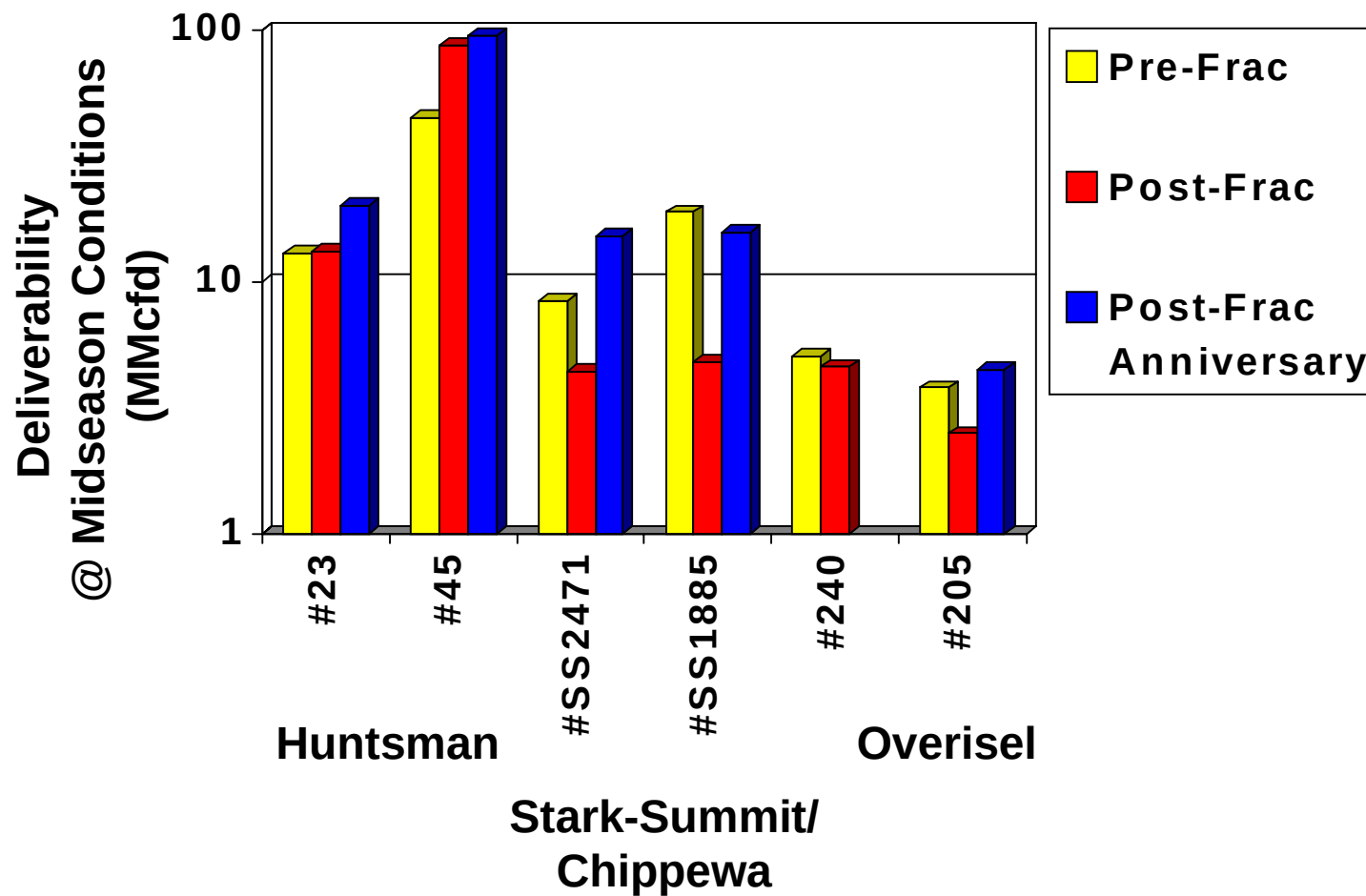


PRESENTATION OUTLINE

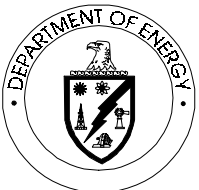
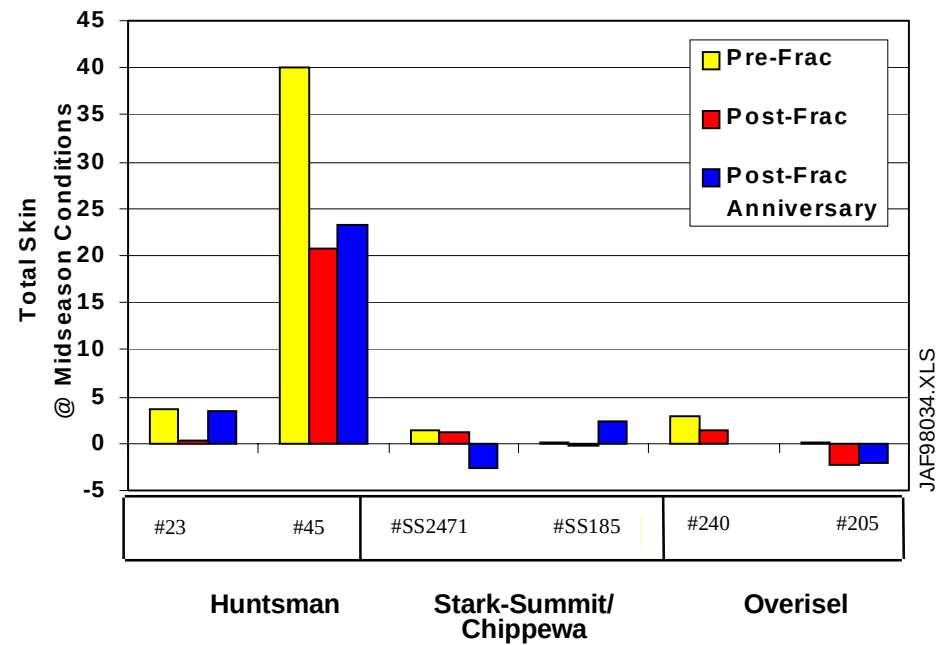
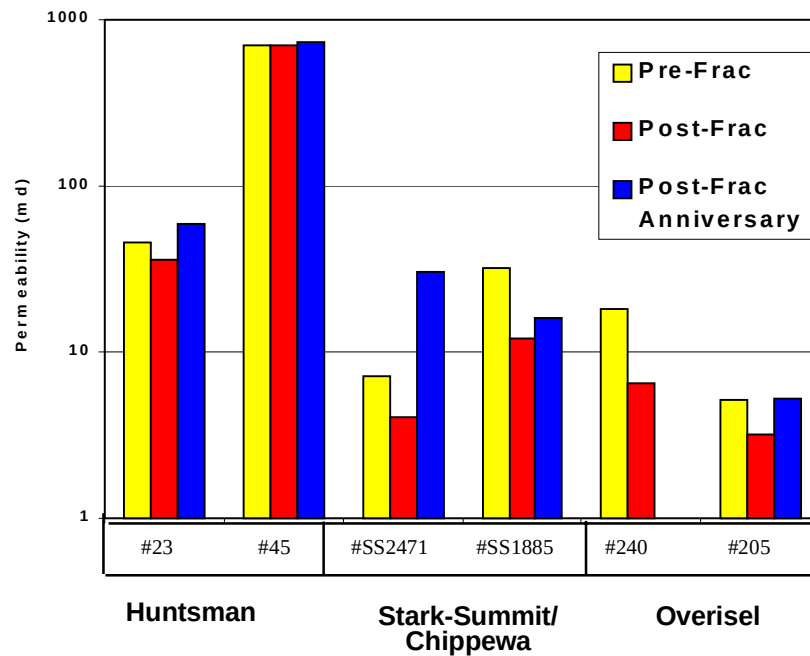
- ◆ Introduction
- ◆ Objectives
- ◆ Approach
- ◆ Technology Description
- ◆ Results
- ◆ Application



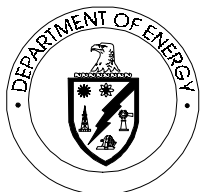
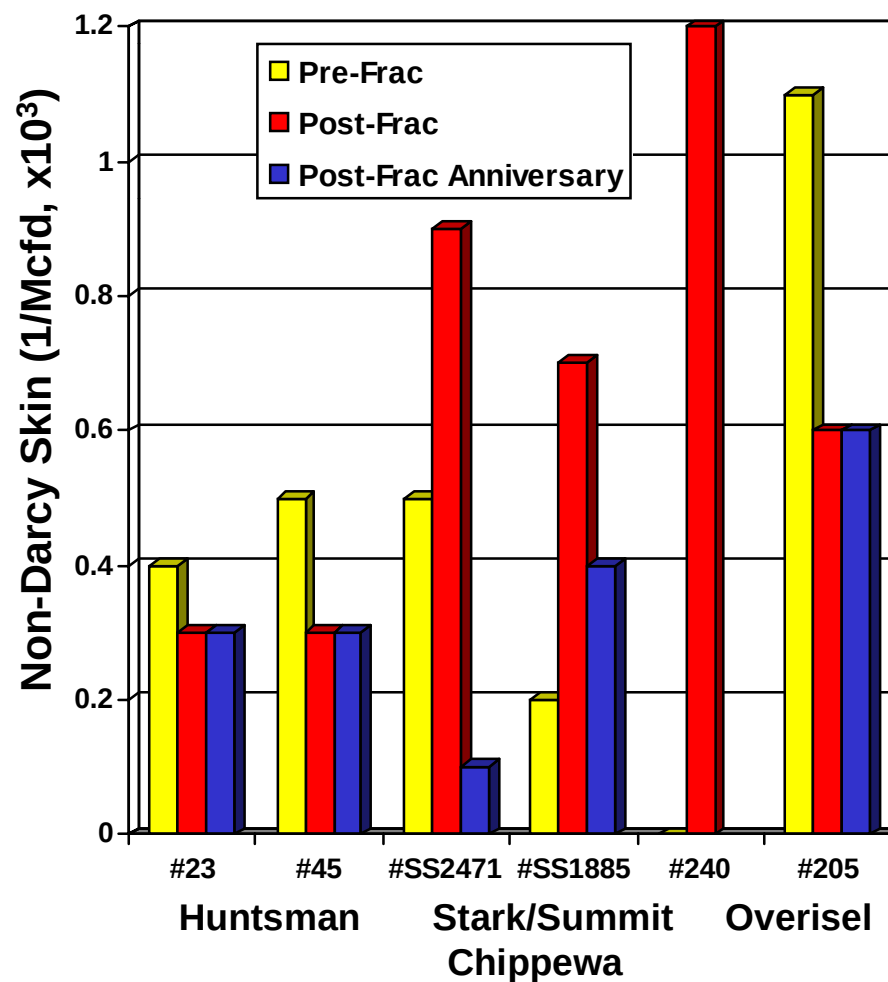
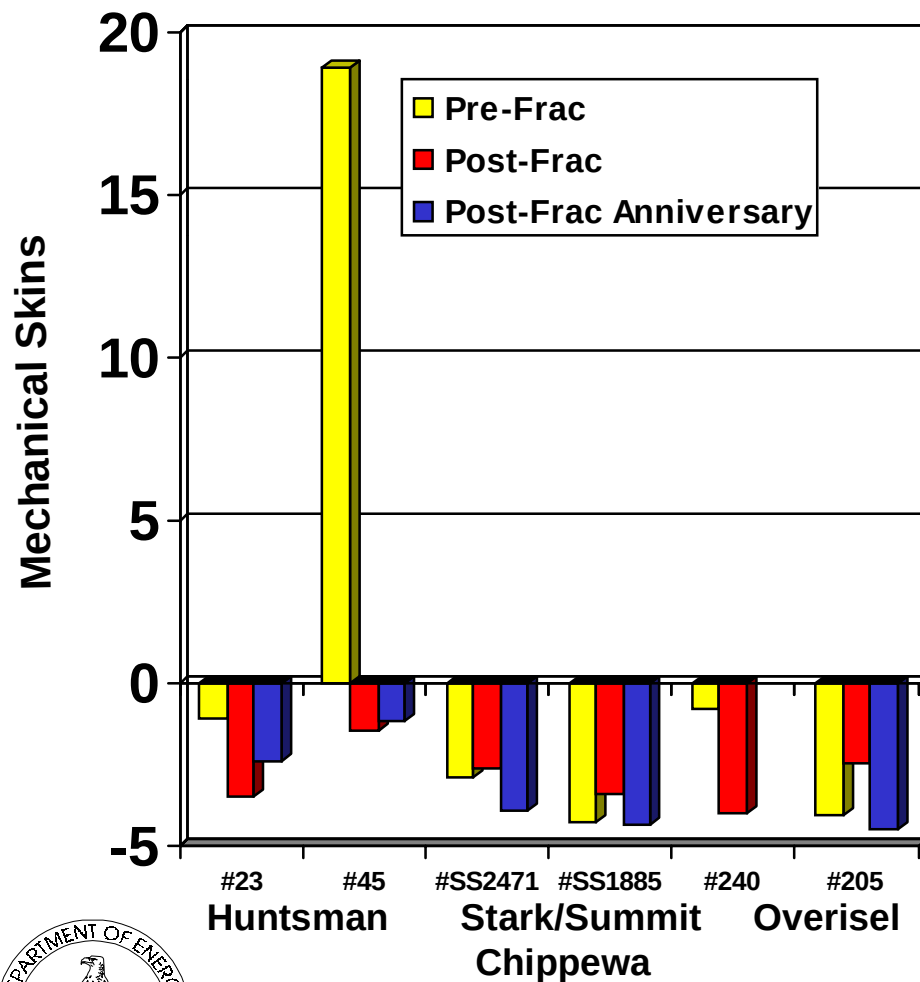
DELIVERABILITY RESULTS, TIP-SCREENOUT TREATMENTS



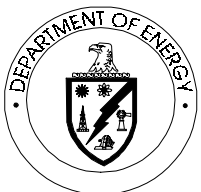
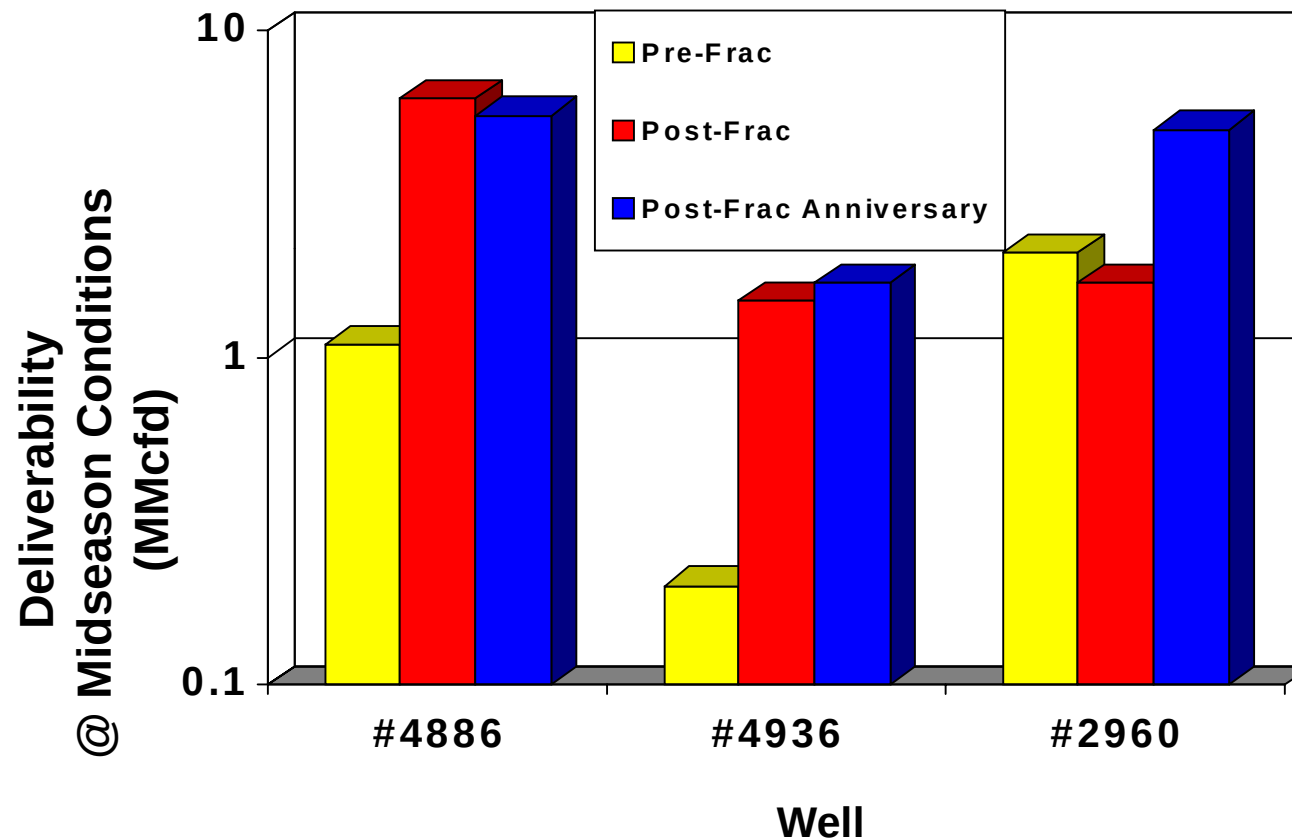
TRANSIENT ANALYSIS RESULTS, TIP-SCREENOUT TREATMENTS



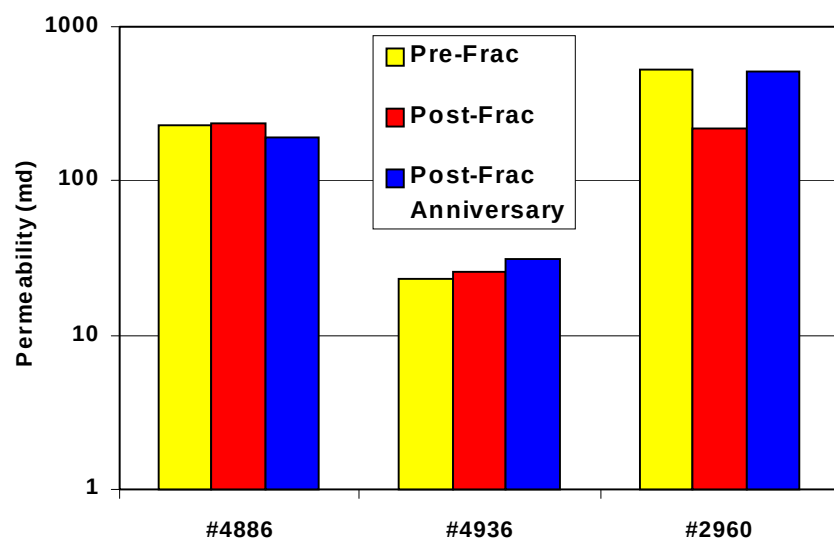
SKIN EFFECT COMPONENTS, TIP-SCREENOUT TREATMENTS



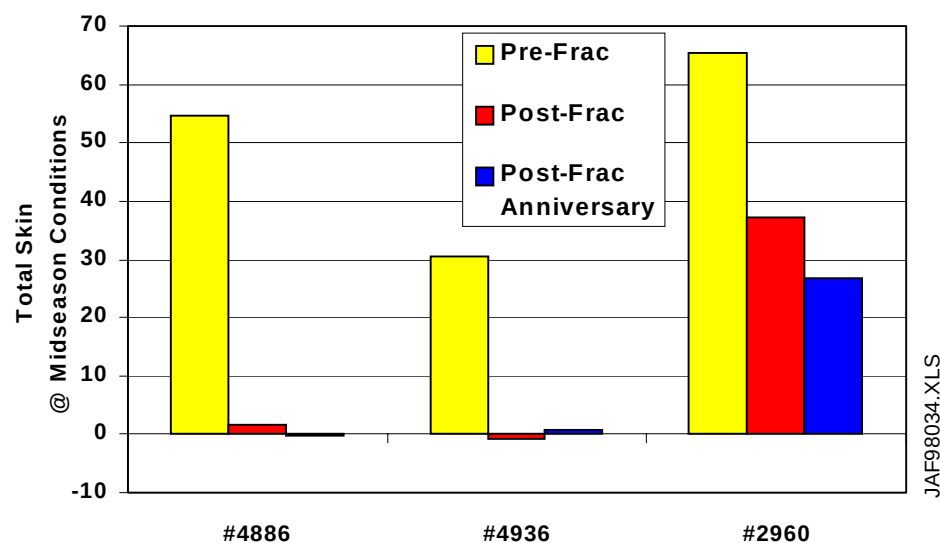
DELIVERABILITY RESULTS, LIQUID CO₂ W/ PROPPANT TREATMENTS



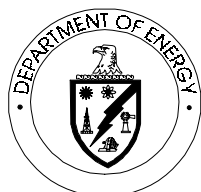
TRANSIENT ANALYSIS RESULTS, LIQUID CO₂ W/PROPPANT TREATMENTS



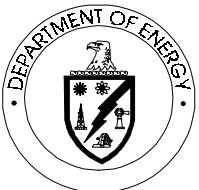
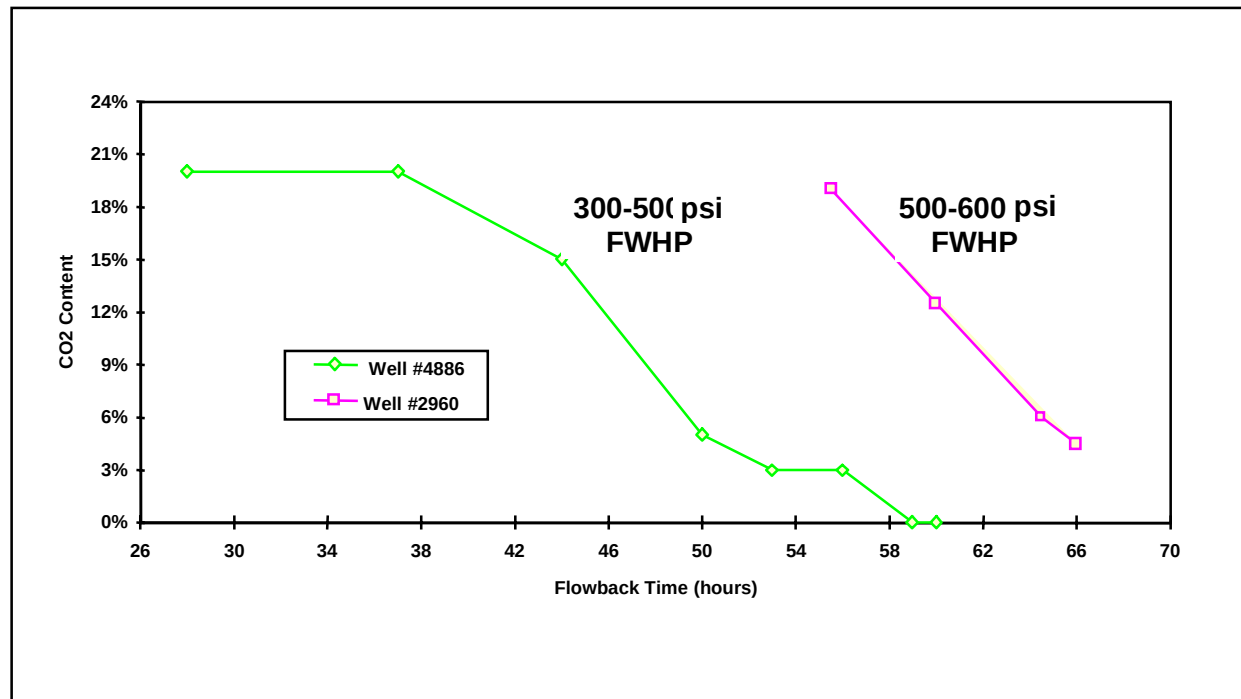
Well



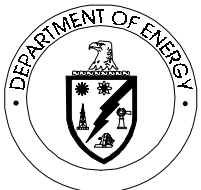
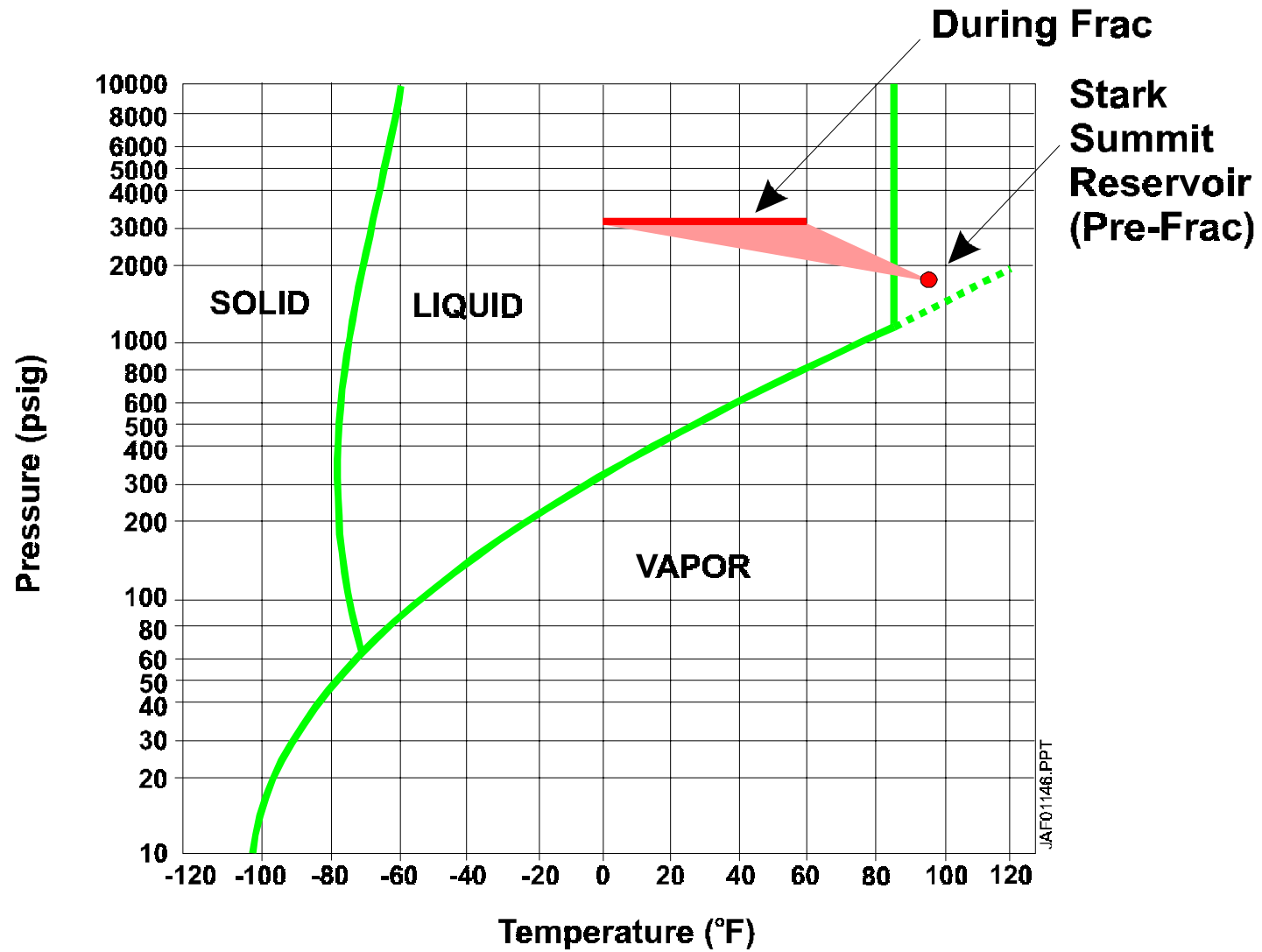
Well



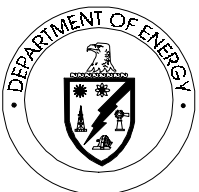
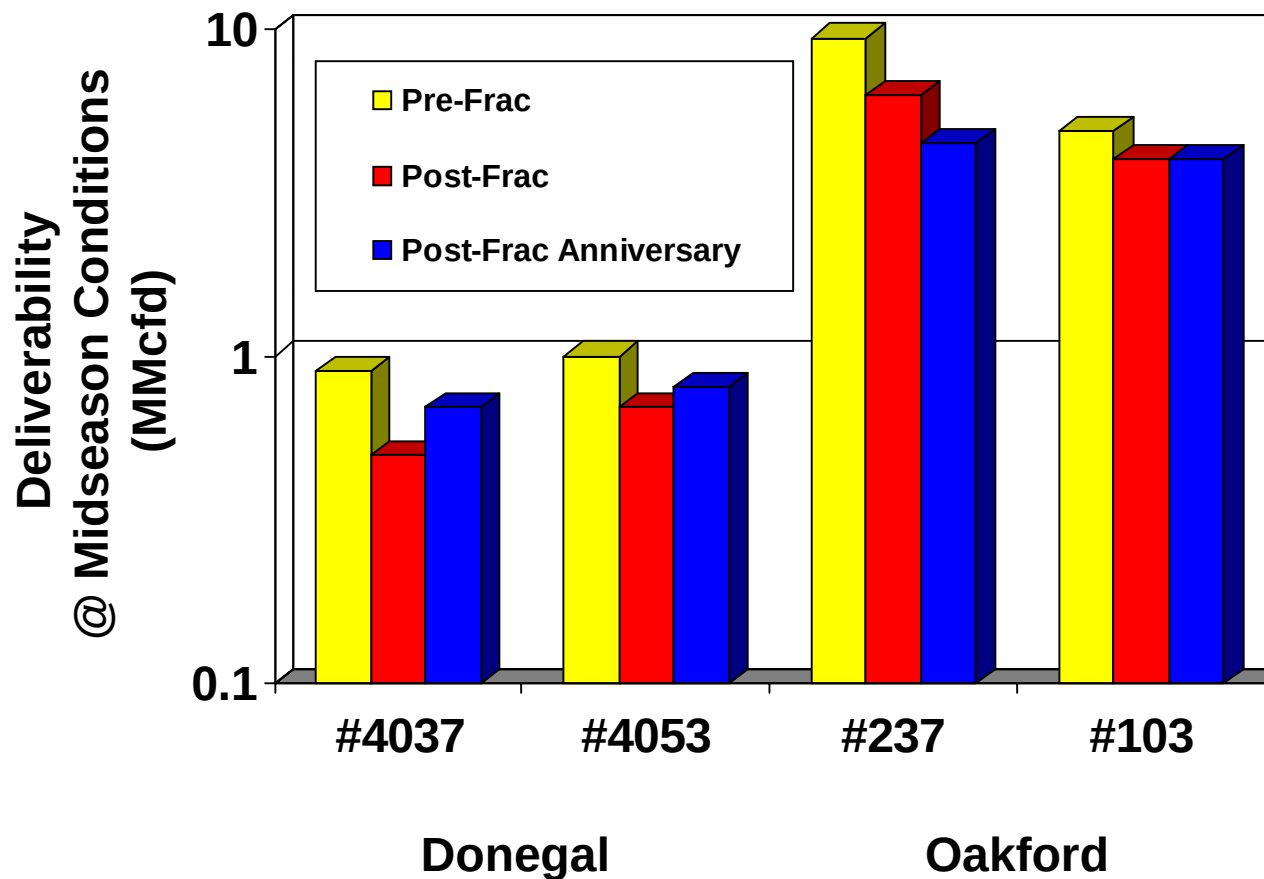
CO₂ CONTENT OF FLOWBACK GAS, GALBRAITH TEST SITE



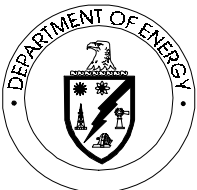
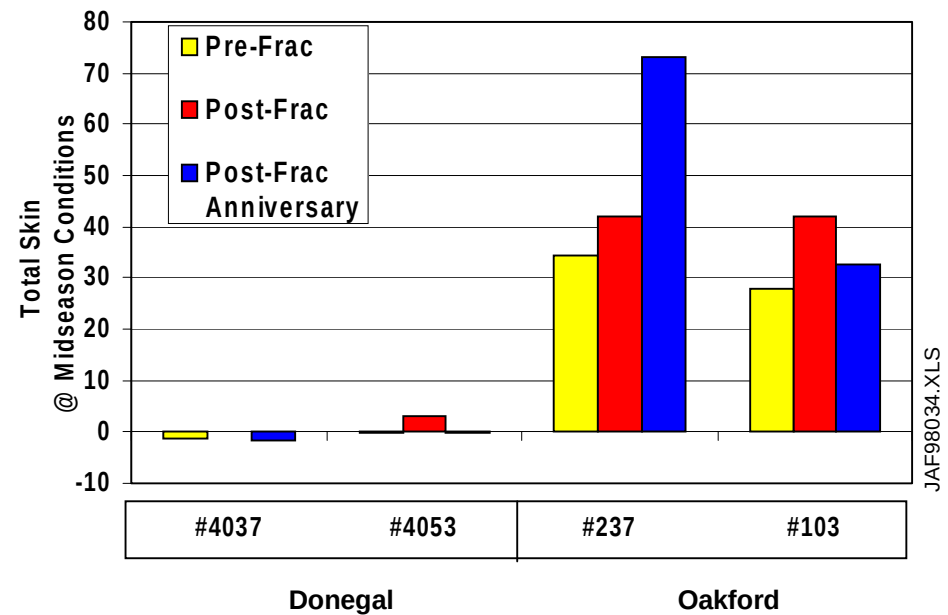
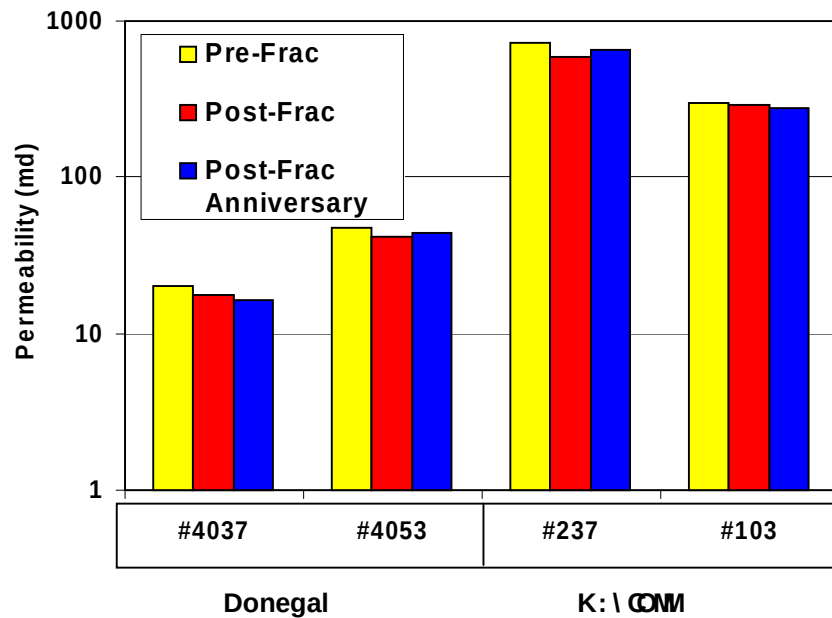
CO₂ PHASE DIAGRAM



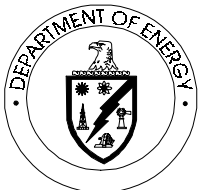
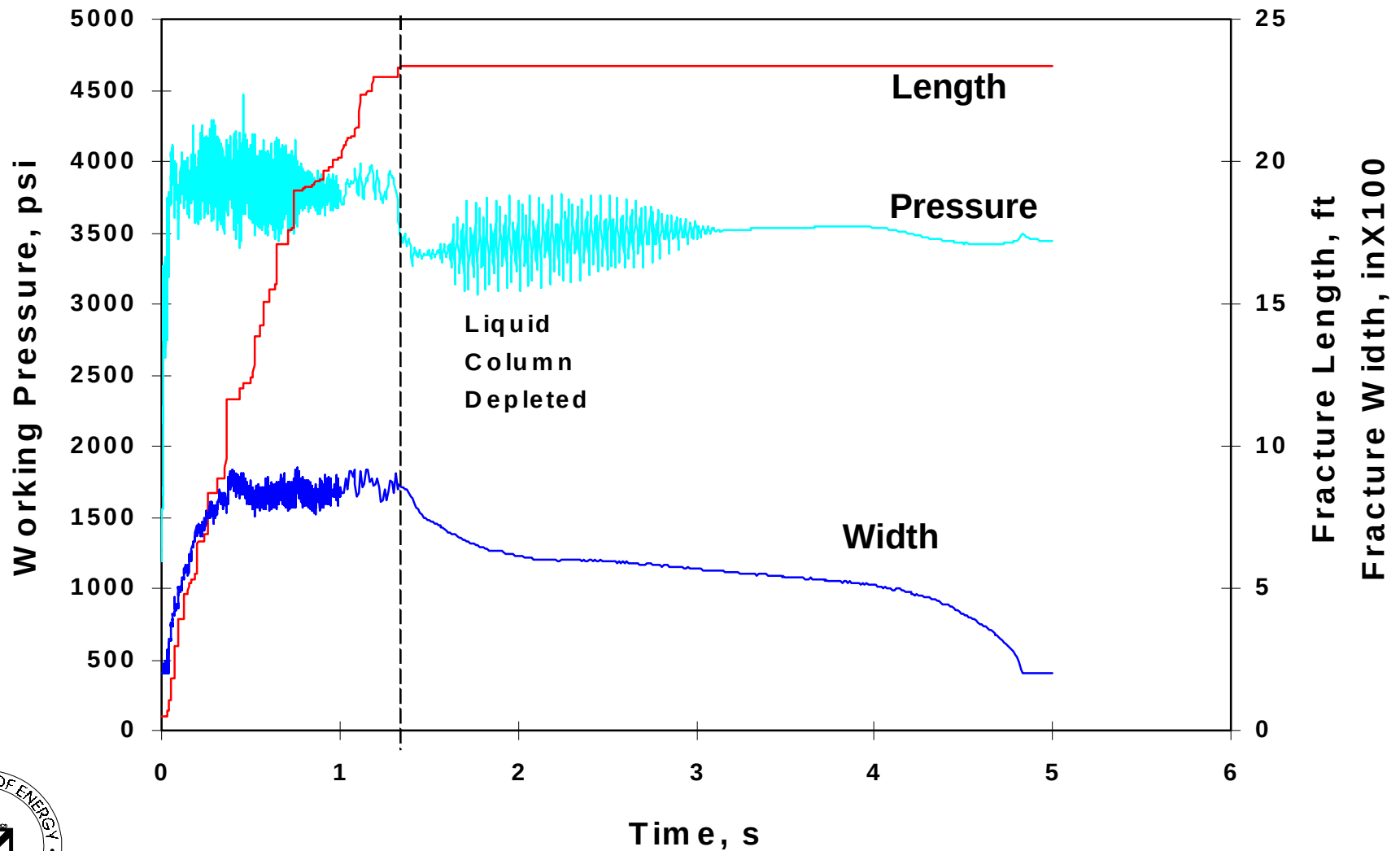
DELIVERABILITY RESULTS, EXTREME OVERBALANCE TREATMENTS



TRANSIENT ANALYSIS RESULTS, EXTREME OVERBALANCE TREATMENTS



EXTREME OVERBALANCE DESIGN, DONEGAL 12155

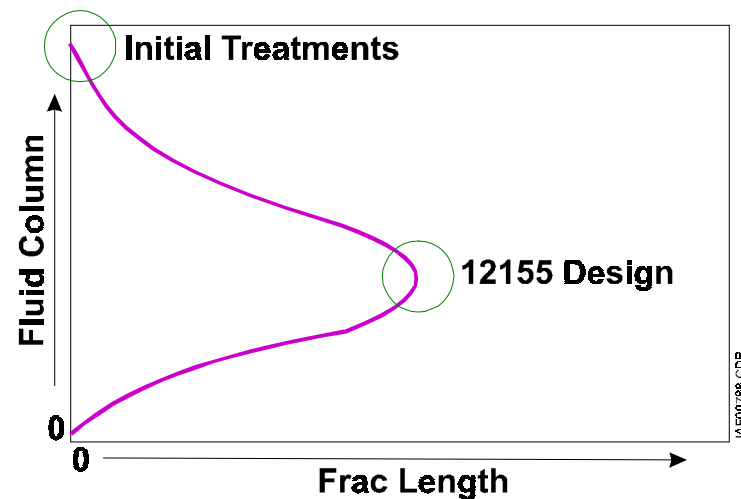


Bmk99310.ppt

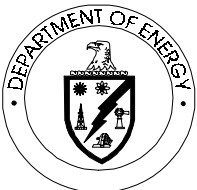


IMPORTANT EOB DESIGN VARIABLES

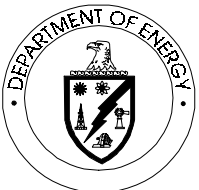
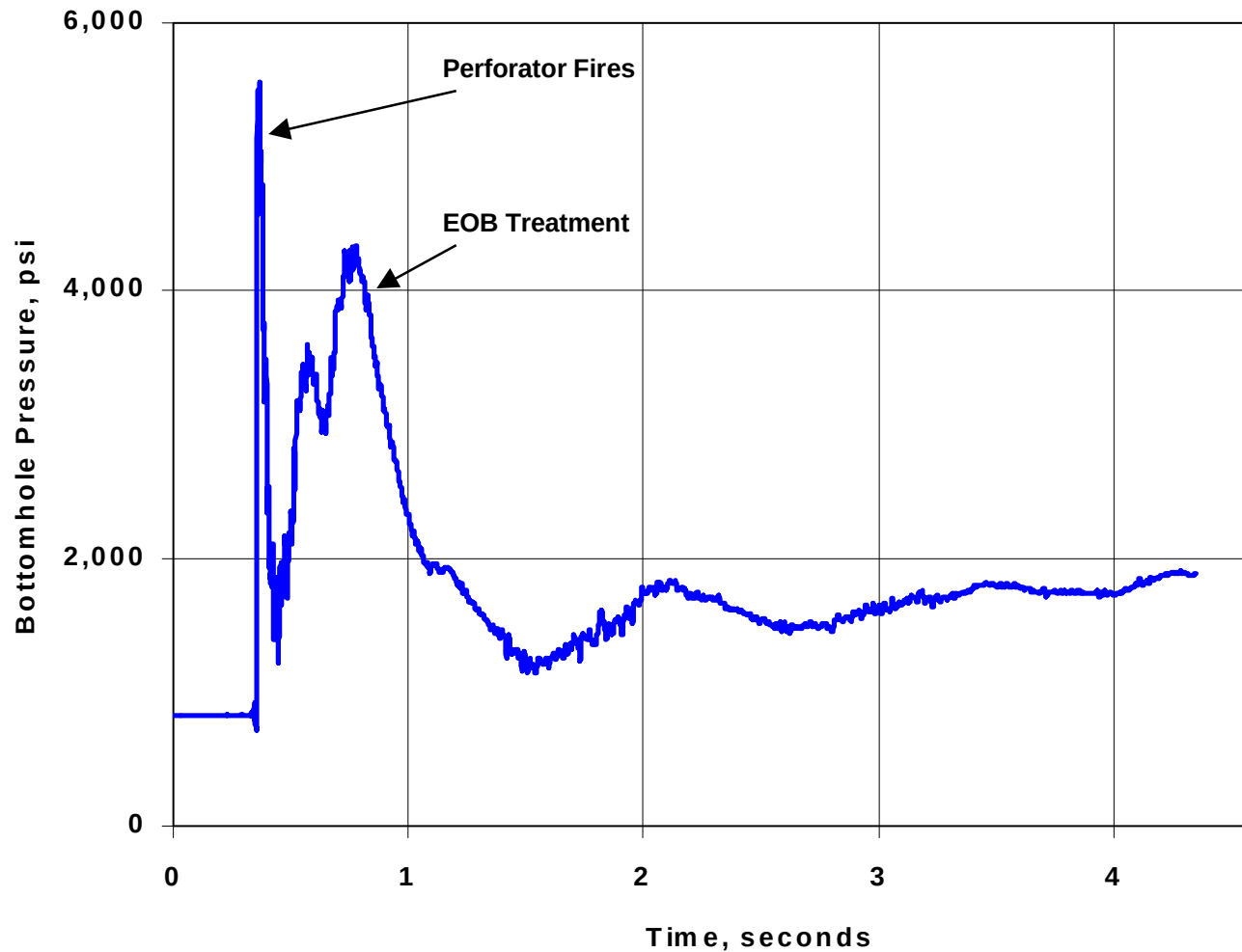
- ◆ Relationship between maximum pressure, fluid volume, fluid column height:



- ◆ Continued nitrogen pumping after initial surge provides no benefit.

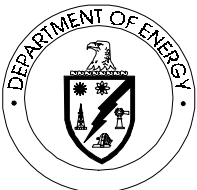


DOWNHOLE PRESSURE RECORD OF EOB TREATMENT, OAKFORD #103



COST BENEFIT ANALYSIS RESULTS FROM EACH TEST SITE

Test Site	New and Novel Technology	Benchmark Method	Cost of Deliverability Maintenance (\$/Mcf/Yr)	
			New & Novel	Benchmark
Huntsman	TSO	Coiled tubing cleanout	\$0.08	\$0.77
Stark-Summit/ Chippewa	TSO	Conventional hydraulic fracturing	\$0.05	\$0.08
Overisel	TSO	Acidizing	\$0.21	\$0.47
Donegal	TSO	Reperforating	\$0.79	\$37.71
Galbraith	Liquid CO ₂	Conventional hydraulic fracturing	\$0.98 (actual) \$0.36 (successful efforts)	\$0.50
Donegal	EOB	Reperforating	\$4.28	\$37.71
Oakford	EOB	Coiled tubing cleanout	Not operationally successful	\$0.12



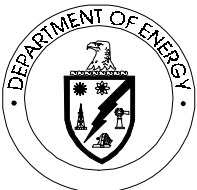
SUMMARY OF FINDINGS

♦ TSO Treatments

- Highly effective at improving deliverability in high-permeability, high-rate wells; reduction in non-Darcy flow is an important contributor to this.
- Fluid cleanup appears more problematic in low-volume wells.

♦ Liquid CO₂ Treatments

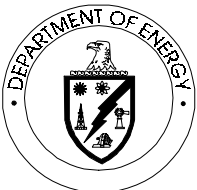
- As anticipated, immediate deliverability improvements with no cleanup effects observed.
- Some difficulty in pumping proppant (leakoff, fracture width, proppant transport) suggests specific window of application.
- Higher cost can be offset by better short-term results.



SUMMARY OF FINDINGS (cont'd)

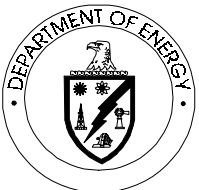
◆ EOB Treatment

- Lack of engineering design tools can inhibit treatment success.
- Can be operationally complex and costly.
- Convergence with propellant technology may prove key to success.



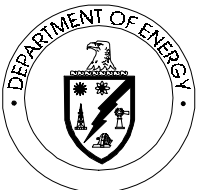
PRESENTATION OUTLINE

- ◆ Introduction
- ◆ Objectives
- ◆ Approach
- ◆ Technology Description
- ◆ Results
- ◆ Application



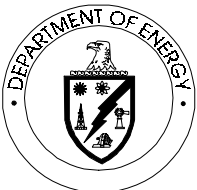
POTENTIAL APPLICATION TO MARGINAL OIL/GAS WELLS

- ◆ **TSO treatments may not be well suited for this application:**
 - best suited for high-rate wells
 - damage potential
 - fluid cleanup (low permeability, pressure)
- ◆ **Liquid CO₂ treatments may be very favorable:**
 - non-damaging
 - solvent properties of CO₂
 - proppantless fracturing (or non-fracturing) approaches can reduce costs



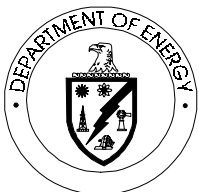
POTENTIAL APPLICATION TO MARGINAL OIL/GAS WELLS (cont'd)

- ◆ **EOB treatments may not be applicable at the current state of technology:**
 - uncertain reliability, results
 - operational complexity and cost
- ◆ **Proppant methods, while results from this project are not yet available, may be favorable:**
 - same principle, superior dynamics as EOB
 - operationally simple and low in cost



ALTERNATIVE “NEW & NOVEL” LOW-COST STIMULATION METHODS FOR MARGINAL OIL & GAS WELLS

- ♦ Jetting
- ♦ Extended perforating
- ♦ Short-radius laterals
- ♦ Propellants
- ♦ Chemical methods
- ♦ etc.



Class III Mid-Term Project - Cooperative Agreement No. DE-FC22-95BC14939

"Increasing Heavy Oil Reserves In The Wilmington Field Through Advanced Reservoir Characterization And Thermal Production Technologies"

U. S. Department of Energy Oil and Gas Conference - Dallas, TX, June 28-30,1999:

Title: "A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam"

**Authors: Philip Scott Hara, Tidelands Oil Production Company
Julius J. Mondragon III, University of Southern California
David K. Davies, David K. Davies and Associates, Inc.**

Abstract

This paper will discuss a competitively-priced and superior well completion technique for controlling unconsolidated sand formations by injecting high temperature and pressure steam to geochemically bond the sand grains in the perforation tunnels. Wells applying this method are cased and cemented through the desired producing interval and completed with only a few small diameter perforations. This well completion technique has been applied in 12 horizontal wells and 22 vertical wells with over 90% of the wells capable of production or injection after two years.

The use of the hot alkaline / steam sand consolidation technique to complete wells is based on the geochemical bonding of unconsolidated formation sand grains with a lattice of primarily high temperature complex synthetic silicate cements and possibly other lower temperature precipitates such as silica cements and carbonate scales. The complex silicate cements and other mineral precipitates are created by the high temperature and high alkaline pH steam condensate which preferentially dissolves sand grains with high specific surface area. The injected fluids rapidly lose heat to the formation and various cements precipitate with changes in temperature, alkalinity, and contact time. The lattice of cement bonds are created by the relatively high volume and high velocity steam vapor phase which dissipates through the near-wellbore region quickly and carries away excess cements and other precipitates where they do not adversely affect formation porosity and permeability.

The wells completed with this technique have equivalent or higher productivity and injectivity than wells completed with opened-hole, gravel-packed slotted-liner completions. In addition, this technology can significantly lower drilling and completion costs, improves fluid entry or injection profile control, provides a low cost means to eliminate unwanted completion intervals, and provides flexibility to use the wells interchangeably as producers or injectors.

This study is part of the U.S. Department of Energy Class III Reservoir Program to improve oil recovery in Slope and Basin Clastic (SBC) reservoirs.

Introduction

Thermal recovery operations in the Wilmington Field have met with operational difficulties peculiar to its geology. Thermal operations have been subject to premature well and downhole equipment failure as a result of early steam breakthrough and sanding. These problems are commonplace in other Slope and Basin Clastic reservoirs with heterogeneous and unconsolidated sands. Additionally, the high reservoir pressures and associated high steam temperatures in the Wilmington

Field aggravate the wellbore completion and equipment problems associated with early steam breakthrough.

The unconsolidated nature of the turbidite sands in the Wilmington Field result in well producibility problems. Thus, a means of limiting sand production has been of paramount importance with regard to operations in the field. The conventional well completion method applied in the field involves using an opened-hole, gravel-packed and slotted liner completion. To reduce capital costs and to improve vertical injection profile control, two new vertical steam injection wells in the Fault Block II-A, Tar Zone (Tar II-A) were selected in 1990 to test a new well completion technique applying limited-entry perforating¹ with the wells cased and cemented to total depth. Three subsequent new vertical steam injection wells were given conventional perforated completions in wells cased and cemented to total depth. Engineering observed that the five steam injection wells had only minor to no sand inflow problems and suspected that a form of sand consolidation was occurring in the perforation tunnels, most likely bonding with silica cements. The alkaline hot water/steam sand consolidation technique for completing wells (henceforth called "the Sand Consolidation Technique or Treatment") was first intentionally tested in producer well UP-779. Well UP-779 was an existing producer which was recompleted into the Tar II-A, placed on steam injection in December 1991, and performed equivalent to offset steam drive producers. The new sand consolidation technique was further tested in eight new vertical wells and two vertical well recompletions in the Tar II-A and two new horizontal wells in the Tar I using various numbers of perforations, perforation sizes, steam volumes and steam rates from 1992 – 1994. An empirical well completion process was developing, but an understanding of the actual detailed geochemistry of the sand consolidation process occurred with its application in the four DOE project horizontal wells (UP-955, UP-956, 2AT-61 and 2AT-63) in the Tar II-A in 1996. Consolidated sand samples were found encrusted to the steam injection tubing tail following a cyclic steam stimulation job in well UP-955 in October 1996. The samples showed bonding of the sand grains with high temperature cements not found in the native formation rocks, but geochemically created through the dissolution of formation minerals from the hot alkaline in the condensate phase of the steam. The success of the sand consolidation technique led to its subsequent application in six new horizontal wells and four vertical well recompletions.

The Sand Consolidation Technique has been applied for purposes other than new well completions and has proven to have other beneficial qualities. In October 1994, well UP-932 successfully underwent the technique to repair enlarged slots in its slotted liner. Well UP-932 production was restored to its previous production rates without sand production. A second well, UP-924, was successfully given a sand consolidation treatment to repair a damaged slotted liner in November 1997. Several wells with sand consolidation completions have been given hydrochloric acid jobs to successfully remove scale damage without affecting the consolidated sands. Gross fluid production rates following the HCl acid jobs typically are restored to pre-scale damaged rates.

Wells with sand consolidation completions have very high productivity for the relatively small number and size of perforations used and production and injection well rates have been equivalent to greater than wells with opened-hole gravel-packed slotted-liner completions. The sand consolidation completions can fail if produced under high differential pressures. However, these types of well failures have generally been repaired successfully by applying another alkaline hot water/steam sand consolidation treatment.

Tables 1-3 list the wells that have been given Sand Consolidation Treatments and pertinent well data including the number and size of perforations, the volume of steam used, the length of the completion interval, and the maximum stabilized injection and production rates. Table 1 lists the new vertical wells, Table 2 lists the new horizontal wells, and Table 3 lists the wells that were recompleted or had liner repairs.

Production History and Geology

The Wilmington Oil Field is the third largest oil field in the United States, based on the total oil recovered. Over 2.5 billion barrels of oil have been produced to date, from an original oil in place of 8.8 billion

barrels. The field is located in and around the City of Long Beach, in Southern California. Location maps of the field are shown in Figures 1 and 2. The field is divided into ten fault blocks and seven major producing zones as illustrated in Figures 3 and 4. The Sand Consolidation Technique has been applied in wells completed into the heavy oil sands of the Tar, Ranger and Upper Terminal zones in Fault Blocks I – V, with the primary testing performed in the Tar II-A.. As such, most of the discussion will center on this area.

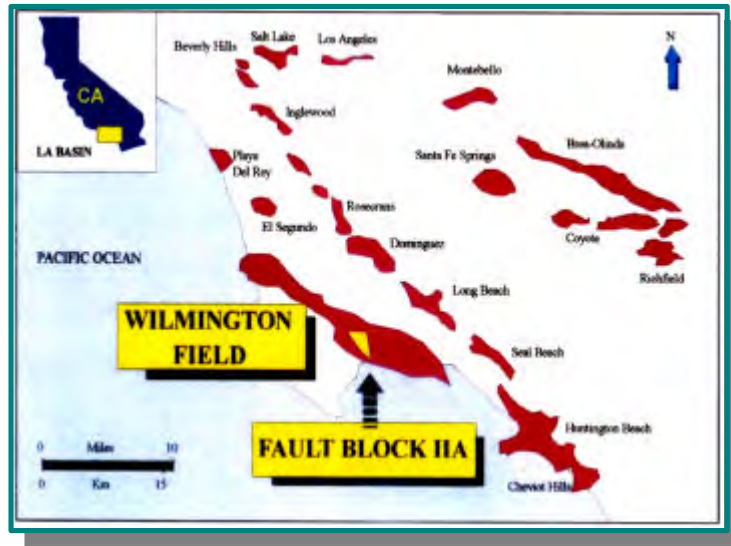


Figure 1 Map showing the geographical location of the Wilmington Field in Southern California.

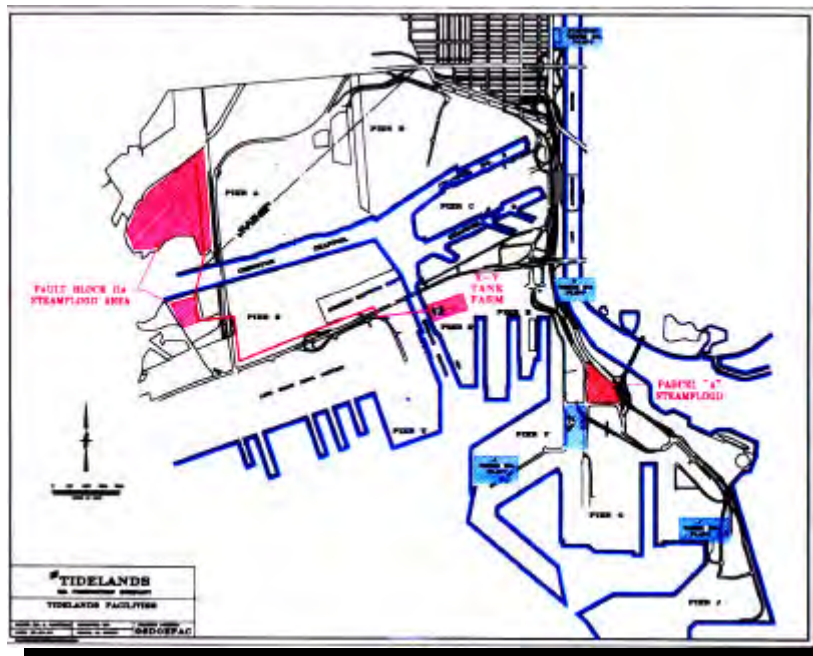


Figure 2 Plan view of Tideland's facilities showing the steamflood areas in Fault Blocks II-A and V, Wilmington Field.

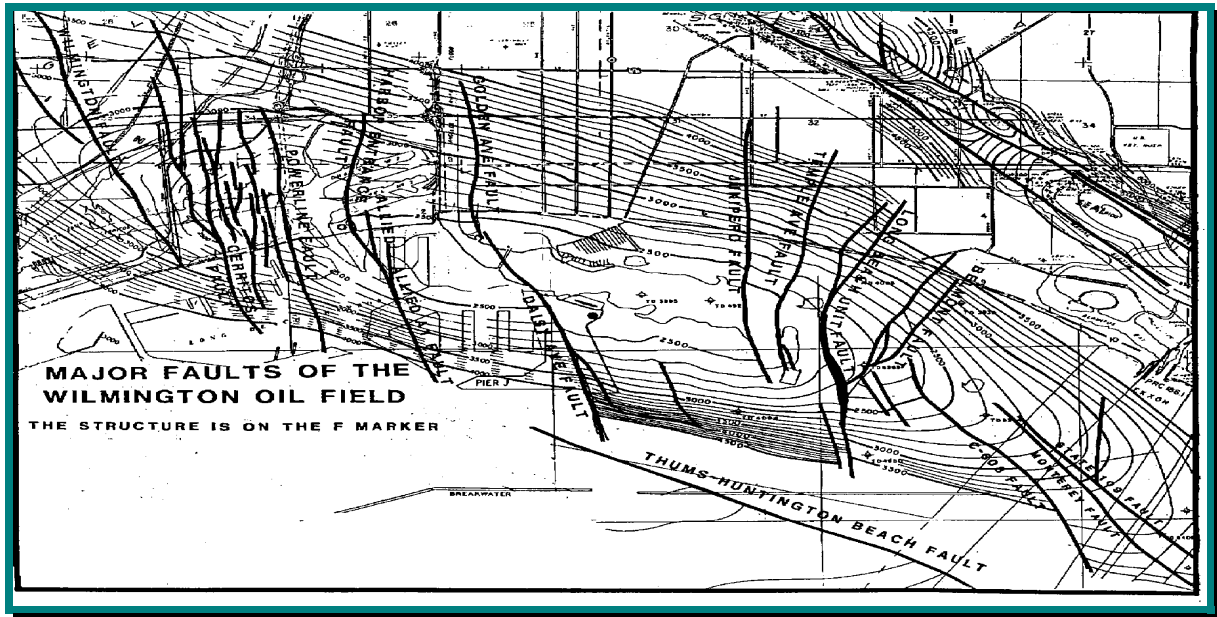


Figure 3 Geologic representation of the Wilmington Oil Field detailing fault line layout.

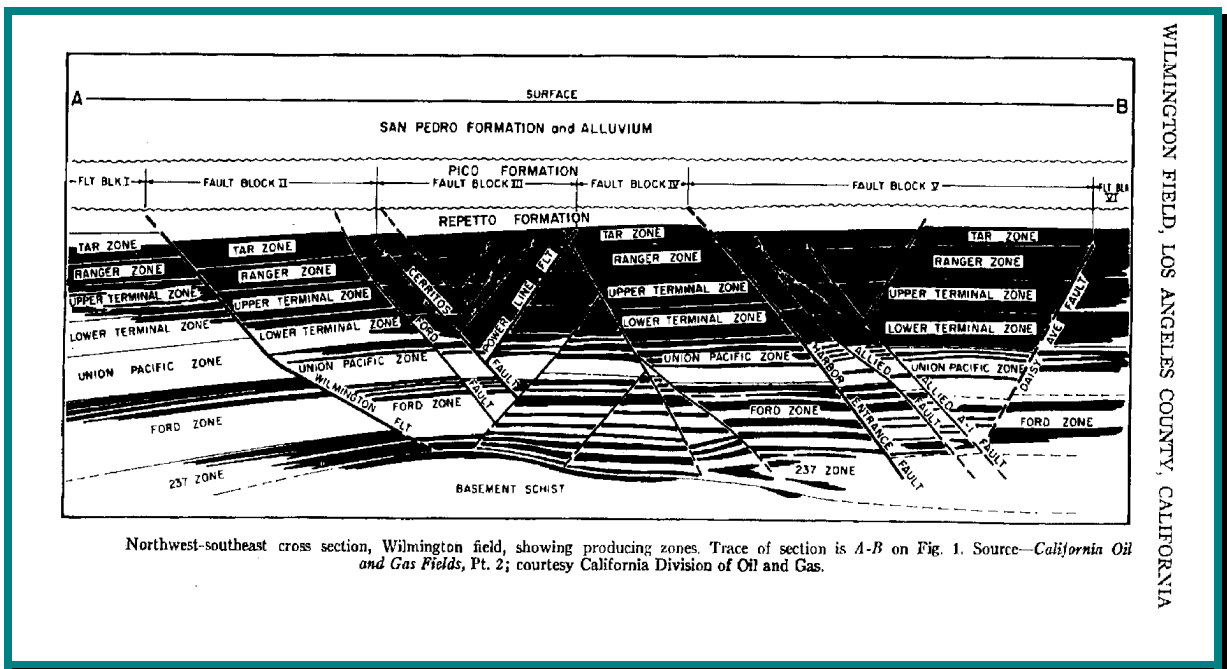


Figure 4 Cross section of a representative sector of the Wilmington field detailing producing zones.

Primary production from the field began in 1936. Waterflood operations were introduced on a large scale during the 1950-60s to increase oil recovery and control surface subsidence. Various tertiary recovery projects have been tried since 1960, but with limited success. A successful steam injection pilot test, comprised of four inverted 5-acre five-spot patterns, was carried out in the Tar II-A from 1982-1989. The pilot recovered 1.1 million barrels of oil, for a recovery factor of 75% of the oil-in-place in a previously waterflooded area. The pilot was expanded to 150 acres using an inverted 7-spot pattern throughout the

northern half of the fault block in 1989. The steamflood was further expanded in 1990, 1991, 1993, 1994, and 1995 to develop the remainder of the Tar II-A and to make more efficient use of the steam as the existing patterns matured.

The Wilmington Oil Field is an asymmetrical, highly faulted, doubly plunging anticline, eleven miles long and three miles wide. The productive area consists of approximately 13,500 acres. Oil from the Wilmington Field and from throughout the Los Angeles Basin is produced mainly from Lower Pliocene and Upper Miocene age deposits. The seven zones within each fault block listed in order of increasing depth are the Tar, Ranger, Upper Terminal, Lower Terminal, Union Pacific, Ford and "237" sands. Fault Block II-A is located near the western edge of the field. It is bounded on the east by the Cerritos Fault and on the west by the Wilmington Fault. The north and south limits of the fault block are governed by water-oil contacts within the individual sand members of the various zones.

The Tar zone is the shallowest oil producing formation and consists of lower Pliocene, middle Repetto formation lobe deposits. The upper Miocene Puente and lower Pliocene Repetto formations within Fault Block II-A consist of interbedded sand/shale sequences belonging to submarine fan facies. These are considered to be bathyal, slope and base-of-slope deposits. The upper Miocene sands are intercalated with shales and siltstones in the form of widespread thin turbidites. Large lobate fans dominate the Pliocene section.

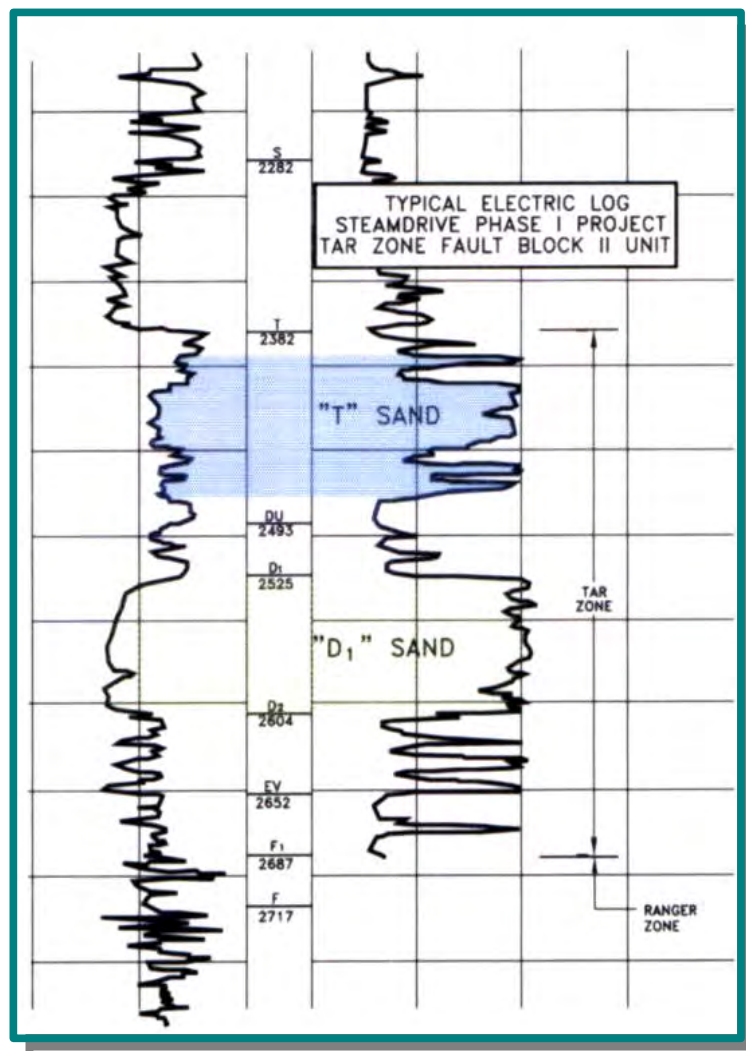


Figure 5 Type Log 1, Tar Zone, Fault Block II-A illustrating "T" and "D1" sands.

The Tar II-A consists of four major producing intervals exhibiting typical California-type alternation of sand and shale layers as illustrated by the type log in Figure 5. The Tar Zone reservoir sands are unconsolidated, friable, fine to medium-grained with varying amounts of silt, and comprised dominantly of subangular grains of quartz and plagioclase feldspar as shown in Figure 6. No cemented sands have been found in any of the cores taken from pre- and post-steamflood wells in the field.

The thickness of the sand layers varies from a few inches to several tens of feet. Shales and siltstones are generally massive, with abundant foraminifera, mica, and some carbonaceous material. The shales are generally soft and poorly indurated, although there are thin beds of fairly firm to hard shale. The oil is of low gravity, ranging from 12-15° API with a viscosity of 360 cp and an initial formation volume factor of 1.057 RB/STB. Based on available information, the Tar zone sands have an average porosity ranging from 28-33% and permeabilities ranging from 500-8,000 millidarcies with a weighted average of 1,000 millidarcies. Approximate zone thickness ranges from 250-300 ft. The top of the structure appears at a depth of 2,330 ft below sea level in Fault Block II.

Mineral Composition of Sandstones	
♦ Quartz - SiO_2 }	48-50%
Calcedony - SiO_2 }	
♦ <u>Feldspars</u>	
Orthoclase - KAlSi_3O_8	11-12%
Anorthite - $\text{CaAl}_2\text{Si}_2\text{O}_8$ }	
Albite - $\text{NaAlSi}_3\text{O}_8$ }	32-35%
Igneous Rock Fragments}	
♦ Mica (Biotite) - $\text{K}_2(\text{Mg, Fe})_2(\text{OH})_2(\text{AlSi}_3\text{O}_{10})$	4-6%
♦ Clays - Smectites, Illites, Chlorites	1-2%

Figure 6 Typical Mineralogy of Tar Zone Sands

Alkaline Hot Water/Steam Sand Consolidation Procedure - A Brief Description

A well with cemented casing is first selectively perforated with $\frac{1}{4}$ in. to $\frac{1}{2}$ in. perforations, preferably $\frac{1}{4}$ in., with the number of perforations needed based on attaining limited-entry conditions¹ for the steam rates and pressures available. To minimize heat loss, thermally insulated tubing, an expansion joint and a thermal packer are run into the well. Steam quality should range from 60-80%, which provides a highly alkaline (pH = 10-12) liquid phase and the steam temperatures should be high enough (> 300°C) to geochemically create the cements for bonding the sand grains. The steam rate should be high enough to achieve the critical velocities required by the limited-entry perforating theory to ensure distribution of the steam into all of the perforations. The empirically based minimum steam volume necessary to achieve sand consolidation is 750 barrels of cold water equivalent steam per $\frac{1}{4}$ in. perforation.

The hot alkaline liquid phase in the 80% quality steam causes sandstone dissolution^{2,3,4,5}, preferentially acting on the sand grains with high specific surface area such as clays, rock fragments, and micas. As the injected fluids exit the perforations and cool, various precipitates drop out at different temperatures. The high temperature precipitates or cements bond the sand grains around the perforation tunnels and control sand movement into the wellbore. The lower temperature precipitates are driven away from the wellbore by the injected fluids, especially the steam vapor phase, where they are dispersed

over enough rock volume to not cause any appreciable negative effect on formation porosity and permeability. Limited-entry perforating¹ assures that each perforation is treated with steam, that the steam is moving at maximum fluid velocities to drive off unwanted precipitates, and that the operator will have future steam injection profile control. Gross fluid rates from production wells completed with sand consolidated perforations appear to be equal to or better than wells completed with a gravel-packed liners over a similar interval. This indicates that the sand consolidation treatment is creating secondary porosity, or wormholes, through the selective dissolution of formation fines and thus increasing permeability. Many wells given a Sand Consolidation Treatment also experience higher oil cuts than offset wells. This could be attributable to the wormholes having less formation fines and therefore higher oil relative permeability. A schematic of the sand consolidation process is shown in Figure 7.

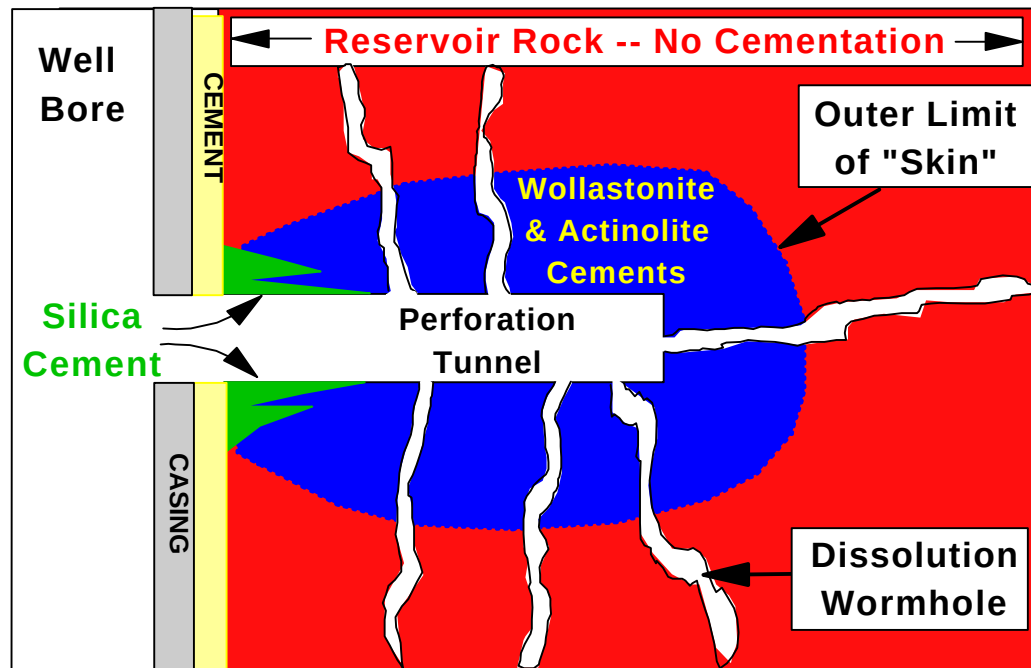


Figure 7 Schematic representation of an ideal perforation showing distribution of synthetic cements and dissolution wormholes

Application of Sand Consolidation Technique on UP-955

UP-955 is a horizontal steamflood well that was completed and cyclically steamed from June – October 1996. The horizontal section of the well was drilled into the “D1” Sand, within the Tar II-A, and completed using the sand consolidation technique.

The well was completed with a total of 48 perforations from 3915’ to 4430’, which were 0.3” in diameter. A casing scraper was then run and the casing was circulated clean with clean water. Sand consolidation began in June 1996, with the injection of 80% quality steam through insulated tubing, an expansion joint and a thermal packer set at 2398’ with a tubing tail to 3907’. See Figure 8 for a wellbore diagram schematic.

The Sand Consolidation Treatment required 36,000 CWE Barrels of steam and an additional 78,000 CWE Barrels of steam were injected for the Huff “N” Puff cycle. The well was then shut-in for a 5 week steam soak. In October 1996, the insulated tubing was pulled and a coating of formation sand was found cemented to the tubing tail from 2963’ to 3401’. Samples of the sand were analyzed using thin sections, x-ray diffraction and a scanning electron microscope (SEM).

The sand cemented onto the tubing tail is believed to be the result of unconsolidated sands entering the wellbore early in the cyclic steam job when the steam source underwent a shutdown on July 13 and 14. This occurred after cumulative injection was 11,500 CWE bbls of steam, approximately 30% of the volume needed to perform a successful sand consolidation on the 48 perforations. The remainder of the cyclic steam injection job proceeded without problems.

The well was placed on production in November 1996 at an initial rate of 29 BOPD and 1037 BWPD, and by March 1997, had peaked at 80 BOPD and 1450 BPD gross, with a 1700-ft fluid level over the pump. A vertical well completed over a 280-ft interval with an opened-hole, gravel-packed and slotted liner completion typically produces 1000 BPD gross. In effect, 48 – 0.3" holes were too many by a factor of two and the high fluid level hurt net oil production.

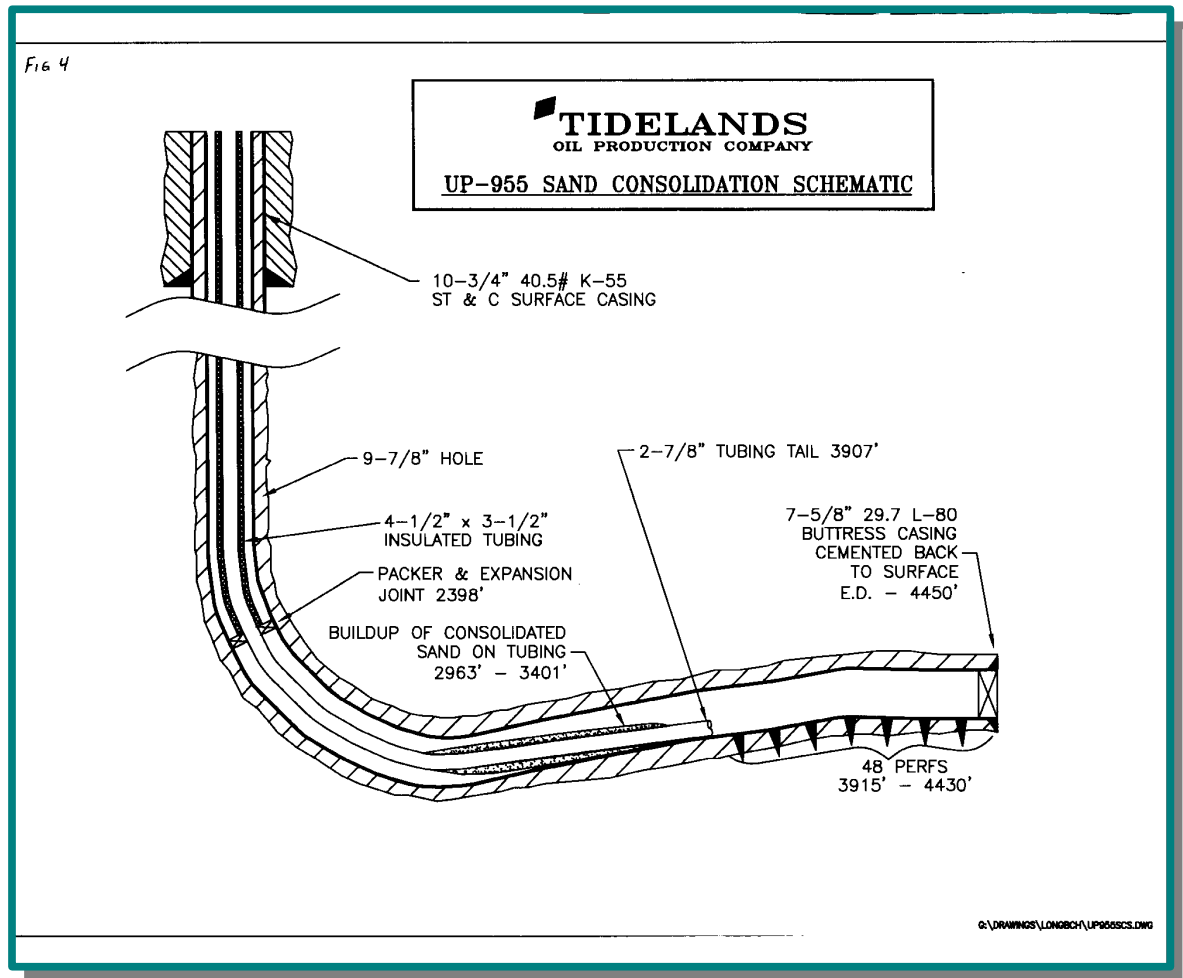


Figure 8 Wellbore Schematic for UP-955 showing sand inflow encrusted onto tubing tail.

Analyses of Sand Consolidation on UP-955 Tubing Tail

The thin section, x-ray diffraction and SEM work revealed that the grain composition and grain size of the artificially cemented sands were the same as the formation sands and entered into the wellbore by means of the open perforations⁷. The sand grains flowed down the casing annulus between the casing and tubing tail, completely surrounding the tubing tail, as shown in Figure 8. The cemented sand samples indicated the presence of three concentrically arranged layers as described below and shown in Figure 9:

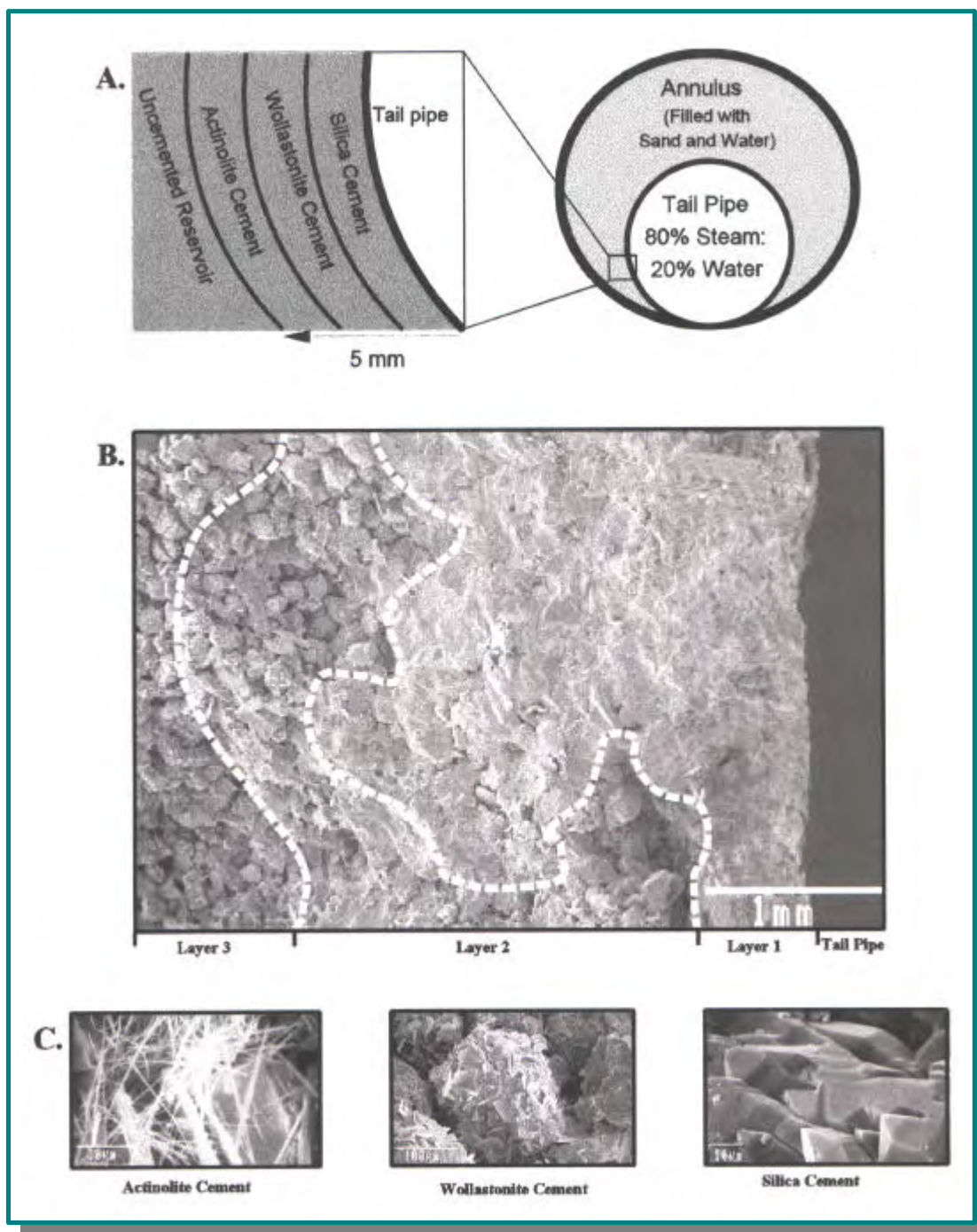


Figure 9 UP-955 tubing tail sample showing the three cement layers and the pictures of the three cement types bonding the sand grains.

Layer 1 was the closest to the tubing wall and consisted of sand grains bonded with silica cement (SiO_2). The 1 to 3 mm thick layer had a low porosity of $< 1\%$, as determined from thin section analysis, and was considered to be essentially impermeable. Silica cement is a low temperature cement which precipitates at about 150°C . Layer 1 is believed to have been initially bonded with high temperature Layer 2 cements and subsequently covered with Layer 1 cements when cyclic

steam injection ceased and the tubing filled with cool kill fluids. The silica cement occurs as grain coating chalcedony and as quartz overgrowths.

Layer 2 formed within and above Layer 1 and is 1 to 3 mm thick. This layer consisted of artificially cemented sand grains, primarily by a complex calcium silicate (CaSiO_3) mineral. The crystals formed a plate structure, which extended from one grain to the next. This layer had high porosity > 25% as determined by thin section analysis, however, a reduced permeability resulted from cemented pore throats. This layer is loosely referred to as the Wollastonite layer, as Wollastonite is the closest known mineral to this artificially-made cement. Wollastonite is a high temperature cement which precipitates at about 300°C.

Layer 3 was the outermost layer and was 1 to 3 mm thick. Synthetic accicular (needle-like) crystals of another complex calcium silicate loosely cemented the sand grains. This layer has a high porosity > 25% as determined by thin section analysis. Permeability is higher than Layer 2 (by visual analysis), but like Layer 2, cannot be accurately determined reliably as the layers are too thin. This layer is loosely referred to as the Actinolite layer, as Actinolite is the closest known mineral phase of this artificially-made cement. Actinolite is also a high temperature cement which precipitates at about 250°C.

Geochemistry of the Process

The use of the hot alkaline / steam sand consolidation technique to complete wells is based on the geochemical bonding of unconsolidated formation sand grains with a lattice of primarily high temperature complex synthetic silicate cements. In the case of well UP-955, the high temperature (> 250°C) synthetic silicates created contained calcium, magnesium, and iron⁷. Many relatively lower temperature precipitates are also created including other calcium and magnesium-based silicates, silica cements and sulfate, carbonate, and oxide scales⁸. The complex silicate cements and other mineral precipitates are created by the high temperature and high alkaline pH steam condensate which preferentially dissolves sand grains with high specific surface area^{2,3,4,5} and that the framework sand grains, such as quartz, are less affected. The injected fluids rapidly lose heat to the formation and various cements precipitate with changes in temperature, alkalinity, and contact time. The lattice of cement bonds are created by the relatively high volume and high velocity steam vapor phase which dissipates through the near-wellbore region quickly and carries away excess cements and other precipitates where they do not adversely affect formation porosity and permeability.

Research by Reed² of Chevron USA and Watkins, et al³ of Union Oil of California describe how high temperature and high pH fluids above 9.5 can cause significant silica dissolution of the gravel pack and formation sands. They discussed how typical oil field steam generators created 80% quality steam, of which the 80% vapor phase was slightly acidic (pH of 5-7) and the 20% liquid condensate phase was highly alkaline (pH of 10-12) based on the bicarbonate (HCO_3) content of the steam feedwater. The bicarbonate ions decompose into CO_2 and H^+ ions which partition to the vapor phase and make it acidic and OH^- ions which partition to the liquid phase and make it alkaline.

Research by McCorriston, et al of Gulf Canada, Sydansk of Marathon Oil, and Caballero of Advanced Technology Laboratories^{4,5,6} touch on the geochemical reactants created by injecting steam into the formation and the resultant precipitates which can fill the pore spaces between the formation sand grains and gravel pack. The geochemical reactants include the sand grain minerals dissolved by the high temperature highly alkaline steam condensate and the minerals and salts in the steam feedwater and the formation oil, gas, and water. Figure 10 shows the typical water analyses for the steam feedwater and the pre- and post-steamflood formation waters for the Tar II-A project.

In summary, the complexity of analyzing the dissolved geochemical reactants created from sandstone dissolution was recognized in previous research, but generally for adverse effects. That research was concerned about silica dissolution of gravel packs, the related well failures, and formation damage from plugging the pore spaces with precipitates, primarily silica cements and acid insoluble

silicates and scales. All of the tests were performed in the laboratory, usually at temperatures and pressures below 250°C and 700 psia. Some researchers mentioned the possible benefits of sandstone dissolution, such as increased porosity and permeability from dissolving sand grains and creating water-soluble silicates for enhanced oil recovery, but did not elaborate in their papers.

Analyses of Produced Water and Steam Feedwater			
<u>Selected Radicals</u>	<u>Steam</u>	<u>Pre-Steam Wells</u>	<u>Post-Steam Wells</u>
Calcium	0.2	500	0 - 200
Magnesium	0.1	500	5 - 50
Iron	0	0.7 - 3.0	0.3
Silica	0	50 -100	100 - 200
Sodium	200	9500	1000 - 3000
Chloride	260	17,000	2000 - 4000
TDS	600	29,500	4000 - 9000

Figure 10 Typical Water Analyses of Steam Feedwater and Formation Waters

Influence on Permeability

The precipitation of synthetic cements reduces the permeability of the formation sands because the cements occur in the pore throats. However, the effective formation permeability in the near-wellbore region is probably greater following a sand consolidation treatment because of sandstone dissolution that creates secondary porosity and permeability. As mentioned previously, the dissolution reactions show selectivity towards grains with inherent planes of weakness and high specific surface areas. In this case, feldspathic grains appear to be extensively leached as shown in Figure 11. Due to the high abundance of feldspathic grains in the Tar II-A, extensive dissolution is apparent in the cemented sand samples, especially where several feldspathic grains occur in series. This group dissolution forms wormholes that have significantly larger pore throat channels than the natural intergranular pores. This phenomenon increases absolute permeability and explains the high productivity and injectivity indexes for the sand consolidated wells. This phenomenon could also be increasing relative oil permeability as evidenced in the production performance of certain wells. These dissolution wormholes appear to form only in areas of high heat transfer - immediately adjacent to the wellbore in steam injection wells. No evidence of wormholes or precipitates from the dissolution process has been observed in post-steamflood cores.

A closer analysis of the Wollastonite and Actinolite crystals reveals the presence of loose cement bonds between the sand layers. This is due to the habit (shape) of the said crystal layers. The loosely bonded nature of the Wollastonite and Actinolite layers implies that the rock framework is stabilized but not rigid. Thus, the skin around the perforation is correspondingly loosely cemented and can fail in the presence of high differential pressures across the formation face that has occurred in several wells. These types of well failures have generally been repaired successfully by applying another alkaline hot water/steam sand consolidation treatment.

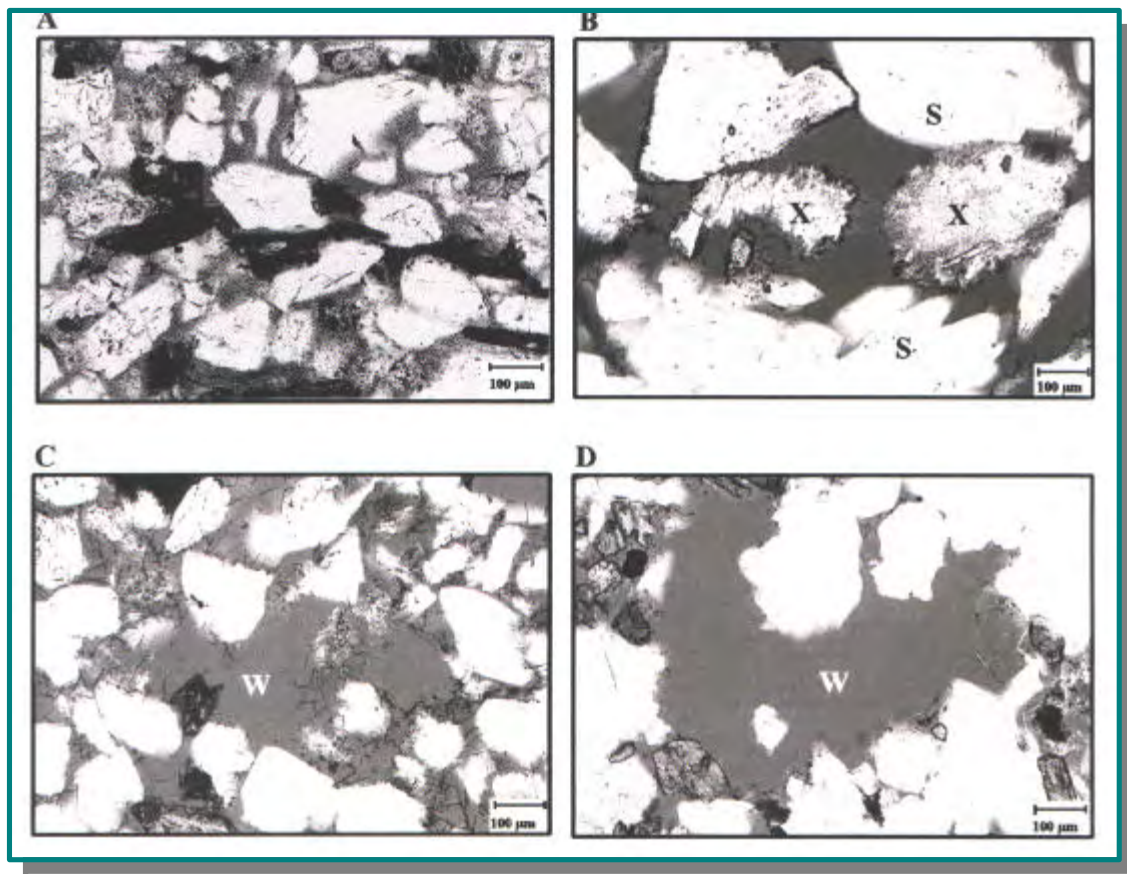


Figure 11 Thin section photomicrographs of pore structure. Sand grains are white and black; pores are gray areas between sand grains.
A. Actual pore structure of Tar Zone Sands (pre-steam core).
B. Partial dissolution of unstable grains (X).
Note: irregular grain outlines. Surrounding sand grains are relatively large due to precipitation of silica cement (S).
C&D. Dissolution wormholes (W) produced through leaching of pre-existing silicate grains.

Results and Conclusions

- 1) The Sand Consolidation Technique has seen successful applications on 13 vertical wells, 12 horizontal wells, 7 recompletes, and two repaired liners in three heavy oil zones in Fault Blocks I, II-A and V in the Wilmington Field. After 2 years of production and injection well service, over 90% of the wells experienced minor or no sand inflow problems. The application in horizontal wells has significantly reduced the risk of wellbore completion failures.
- 2) The Sand Consolidation Technique can provide substantial cost savings in well drilling and completion operations by eliminating the need for "conventional" opened-hole gravel-packed slotted-liner completions and replacing it with a simple cased-through and cemented completion with a limited number of selected small perforations. The wells completed with this technique have equivalent to higher production or injection rates than wells with the "conventional" completions due to increased permeability from sandstone dissolution.

- 3) The limited-entry perforating used in the Sand Consolidation Technique provides superior production and injection profile control in the treated wells. The treated wells can easily be reworked to eliminate unwanted perforations and to recomplete and treat new perforations.
- 4) The synthetic cements bonds tend to resist hydrochloric acid and therefore the wells with Sand Consolidation Treatments can be acidized to remove scales and other formation damage.
- 5) The Sand Consolidation Technique allows both production and injection wells to be completed the same way, thereby making it possible to convert wells easily to either service.
- 6) The Sand Consolidation Technique appears to work best in "dirty" sandstone reservoirs, those with chemically complex and unstable sand grains that are typically sensitive to foreign fluids or easily move in the reservoir, both causing formation damage. The sand consolidation process preferentially dissolves the sand grains with high specific surface area and, where several affected grains are connected, leaves "wormholes" in the near-wellbore region that enhance well performance.

References:

1. Small, G.P.: "Steam-Injection Profile Control Using Limited-Entry Perforations", SPE Paper #13607 presented at 1985 SPE California Regional Meeting, Bakersfield, CA, March 27-29, 1985.
2. Reed, M.G.: "Gravel Pack and Formation Sandstone Dissolution During Steam Injection", Journal of Petroleum Technology, June 1980, pages 941-949.
3. Watkins, D.R., Kalfayan, L.J., Watanabe, D.J., Holm, J.A.: "Preventing Gravel Pack and Formation Dissolution During Steam Injection", SPE Paper #13660 presented at 1985 SPE California Regional Meeting, Bakersfield, CA, March 27-29, 1985.
4. McCorriston, L.L., Demby, R.A., Pease, E.C.: "Study of Reservoir Damage Produced in Heavy Oil Formations Due to Steam Injection", SPE Paper #10077 presented at 1981 SPE ATCE, San Antonio, TX, October 5-7, 1981.
5. Sydansk, R.D.: "Elevated-Temperature Caustic/Sandstone Interaction: Implications for Improving Oil Recovery", SPE Journal, August 1982, pages 453-462.
6. Caballero, E.P., Advanced Technology Laboratories, Lab results to Tidelands regarding "Preliminary Study on the Effect of Commingling Steam Condensate and Produced Water" dated October 9, 1994 on steam and produced water from Tidelands' Wilmington Field operations.
7. Davies, D.K., Mondragon, J.J.III., Hara, P.S.: "A Novel, Low Cost, Well Completion Technique using Steam for Formations with Unconsolidated Sands, Wilmington Field, California", Society of Petroleum Engineers (SPE) Paper #38793 presented at 1997 SPE Annual Technical Conference and Exhibition (ATCE), San Antonio, TX, October 5-8, 1997.
8. Davies, D.K., Vessell, R.K., Fu, R.Y., Mondragon, J.J. III, Stepp, D. A., Aguey, O. J., "Nature, Origin, Treatment and Control of Well-bore Scales in an Active 1996 Steamflood, Wilmington Field, California," SPE Paper #35418 presented at the SPE / DOE Tenth Symposium on Improved Oil Recovery, Tulsa, OK, April 21-24, 1996.

TABLE 1
WILMINGTON FIELD
SAND CONSOLIDATION JOBS
NEW VERTICAL WELLS

<u>Well</u>	<u>Flt</u> <u>Blk</u> <u>Zone</u>		<u>Well Length</u> <u>MD/TVD</u>	<u>Well Type</u>	<u>Well Completion Data</u>					<u>Max Stabilized Rates</u>		
					<u>Date</u> <u>(Mo/Yr)</u>	<u>No.</u> <u>Perfs</u>	<u>Perf</u> <u>Dia (in)</u>	<u>Interval</u> <u>Perfd (ft)</u>	<u>Cum Steam</u> <u>Treatment</u> <u>(BCWES)</u>	<u>Inj</u> <u>Rate</u> <u>(BPD)</u>	<u>Prod</u> <u>Rate</u> <u>(BPD)</u>	<u>PUMP</u> <u>FL</u> <u>(FOP)</u>
2AT-049	2A	Tar	2890 / 2688	SF Inj	09/90	7	0.25	2748 - 2823	2,215,000	1000 S	N/A	N/A
2AT-052	2A	Tar	2848 / 2000	SF Inj	11/90	13	0.25	2517 - 2770	3,517,000	1440 S	N/A	N/A
2AT-053	2A	Tar	2800 / 2715	SF Inj	08/91	80	0.25	2694 - 2714	3,090,000	1500 S	N/A	N/A
2AT-055	2A	Tar	2721 / 2658	SF Inj	09/91	42	0.25	2634 - 2695	2,600,000	1500 S	N/A	N/A
2AT-054	2A	Tar	2768 / 2663	SF Inj	10/91	22	0.25	2690 - 2712	3,201,000	1500 S	N/A	N/A
2AT-056	2A	Tar	2896 / 2801	SF Inj+Prod / WF Inj	03/93 09/93	20	0.50	2772 - 2782	21,000	4500 W	1400	N/D
2AT-057	2A	Tar	2883 / 2757	SF Inj+Prod	03/93 10/93	58	0.25	2764 - 2824	24,000	1000 S	1450	900
2AT-058	2A	Tar	2883 / 2763	SF Inj+Prod	04/93 11/93	56	0.25	2751 - 2826	13,000 26,000	1200 S	1600	1200
2AT-059	2A	Tar	2900 / 2745	SF Inj+Prod	05/93 08/93 02/94	20 60	0.25 0.25	2778 - 2860	5,000 55,000 50,000	1150 S	1550	1850
UP-951	2A	Tar	3016 / 2799	SF Prod+Inj / WF Inj	06/94	79	0.31	2866 - 2982	60,000	4500 W	1300	N/D
UP-952	2A	Tar	3058 / 2789	SF Prod+Inj	06/94	64	0.31	2912 - 3008	45,000	1100 S	1100	2100
UP-953	2A	Tar	2952 / 2801	SF Prod+Inj / WF Inj	07/94	79	0.31	2806 - 2916	67,000	4000 W	1350	N/D
UP-954	2A	Tar	3133 / 2815	SF Prod+Inj	07/94	68	0.31	2954 - 3060	55,000	1200 S	1450	N/D

TABLE 2
WILMINGTON FIELD
SAND CONSOLIDATION JOBS
NEW HORIZONTAL WELLS

<u>Well</u>	<u>Flt</u> <u>Blk</u>	<u>Zone</u>	<u>Well Length</u> <u>MD/TVD</u>	<u>Well Type</u>	<u>Well Completion Data</u>					<u>Max Stabilized Rates</u>		
					<u>Date</u> <u>(Mo/Yr)</u>	<u>No.</u> <u>Perfs</u>	<u>Perf</u> <u>Dia (in)</u>	<u>Interval</u> <u>Perfd (ft)</u>	<u>Cum Steam</u> <u>Treatment</u> <u>(BCWES)</u>	<u>Inj</u> <u>Rate</u> <u>(BPD)</u>	<u>Prod</u> <u>Rate</u> <u>(BPD)</u>	<u>Pump</u> <u>FL</u> <u>(FOP)</u>
1T-001	1	Tar	3520 / 2487	Cyclic	07/93	140	0.50	2890 - 3500	72,000	2300 S	2500	750
SF-001	1	Tar	3510 / 2555	Cyclic	02/94	160	0.50	2890 - 3500	160,000	1600 S	3100	N/D
2AT-061	2A	Tar	4357 / 2438	Cyclic / SF Inj	12/95	11	0.25	3972 - 4302	146,000	1770 S	1800	N/D
2AT-063	2A	Tar	4726 / 2418	Cyclic / SF Inj	12/95	11	0.25	4240 - 4705	186,000	1400 S	1450	1300
FJ-202	5	Tar	4475 / 2114	Cyclic / SF Inj	04/96	14	0.29	3730 - 4470	97,000	2100 S	1550	40
FJ-204	5	Tar	4141 / 2126	Cyclic / SF Inj	05/96	14	0.29	3600 - 4050	119,000	1800 S	900	450
UP-955	2A	Tar	4466 / 2432	SF Prod	06/96	48	0.30	3915 - 4430	114,000	1800 S	2450	1250
UP-956	2A	Tar	4805 / 2374	SF Prod	06/96	36	0.22	4230 - 4710	183,000	1800 S	2000	1600
J-205	5	Tar	4145 / 2130	SF Prod	08/96	45	0.29	3388 - 4094	167,000	1900 S	1100	150
J-203	5	Tar	4648 / 2127	SF Prod	11/96	44	0.29	3745 - 4640	122,000	1300 S	1600	1450
J-201	5	Tar	4800 / 2111	SF Prod	01/97	46	0.29	3742 - 4125	169,000	1300 S	1250	400
J-017RD	5B	UT	4110 / 2849	Cyclic	05/97	40	0.29	3285 - 3900	91,000	820 S	900	1200

TABLE 3
WILMINGTON FIELD
SAND CONSOLIDATION JOBS
VERTICAL WELL RECOMPLETES / LINER REPAIRS

<u>Well</u>	<u>Flt Blk Zone</u>		<u>Well Length MD/TVD</u>	<u>Well Type</u>	<u>Well Completion Data</u>				<u>Max Stabilized Rates</u>			
					<u>Date (Mo/Yr)</u>	<u>No. Perfs</u>	<u>Perf Dia (in)</u>	<u>Interval Perfd (ft)</u>	<u>Cum Steam Treatment (BCWES)</u>	<u>Inj Rate (BPD)</u>	<u>Prod Rate (BPD)</u>	<u>Pump FL (FOP)</u>
UP-779	Rec	2A Tar	2750 / 2722	SF Prod	12/91	80	0.25	2675 - 2695	60,000	1000 S	700	N/D
UP-836	Rec	2A Tar	2927 / 2919	SF Prod	08/92	120	0.50	2540 - 2570	20,000	1250 S	600	N/D
2AT-019	Rec	2A Tar	2724 /	SF Waste Gas Inj	05/95 12/92	40	0.25	2530 - 2550	67,000 30,000	GAS	N/A	N/A
UP-932	LR	2A Tar	2830 / 2552	SF Prod	10/94	SLOTTED LINER		2568 - 2828	51,000	1050 S	1400	N/D
J-015	Rec	5 TB	2415 / 2393	Cyclic	05/96	31	0.49	2310 - 2345	93,000	1600 S	980	1200
J-120	Rec	5B UT	3080 / 2927	Cyclic	05/96	21	0.48	2993 - 3009	19,000	325 S	450	2300
J-046	Rec	5 TB	2400 / 2328	Cyclic	12/96	148	0.41	2345 - 2387	144,000	1100 S	1050	700
Z-061	Rec	5 Ranger	2600 / 2463	Cyclic	03/97	18	0.29	2471 - 2509	15,076	750 S	350	200
UP-924	LR	2A Tar	2670 / 2533	SF Prod	11/97	SLOTTED LINER		2404 - 2667	78,000	1500 S	750	600

Coiled-Tubing High-Pressure Jet Drilling System

by

Dr. William C. Maurer (maurer@maureng.com, 713-683-8227, ext. 216)

Curtis E. Leitko (leitko@maureng.com, 713-683-8227)

Mel Hightower (hightower@maureng.com, 713-683-8227)

MAURER ENGINEERING INC.

2916 West TC Jester

Houston, Texas 77018-7098

INTRODUCTION

High drilling costs are a major constraint on the development of marginal oil and gas reserves in the USA. New drilling technology is needed to significantly reduce drilling costs and increase oil and gas recovery.

In a typical well, approximately 50 percent of the expenditures go toward making the hole and 50 percent toward completing the well (i.e., casing, cementing, logging, artificial lift, etc.). Therefore, techniques that will double the drilling rate have the potential to reduce overall well costs by up to 25 percent.

Developing a technique to significantly increase drilling rate therefore is of paramount importance, because no other development, except slimhole drilling, has the potential to make such a significant reduction in drilling cost.

This development is being sponsored by the U.S. Department of Energy's Federal Energy Technology Center under contract DE-FC26-97FT33063 with Maurer Engineering Inc., 2916 West TC Jester, Houston, Texas; fax: 713-683-6418; email: mei@maureng.com.

OBJECTIVE

Coiled-tubing (CT) rigs utilize continuous tubing to rapidly reel bits, motors, and other tools in and out of wells. They significantly reduce drilling, completion and workover costs in many areas and are ideal for underbalanced drilling since they can be reeled in and out of the well under pressure. CT has reduced squeeze cementing and workover costs by as much as 70 percent at Prudhoe Bay and other areas.

A major limitation of CT drilling is the relatively low power output of the slimhole motors due to their small diameters. For example, a 6¾-inch PDM motor delivers 130 to 170 horsepower compared to only 20 to 30 horsepower for a 2⅞-inch motor.

On another recent DOE project, Maurer Engineering developed high-power PDM motors that deliver twice as much power as conventional motors and drill twice as fast. The goal of this CT project is to further increase the drilling rate of these high-power motors to significantly reduce slimhole drilling costs.

APPROACH

In the 1970s and 1980s, Exxon, Shell, Gulf Oil and FlowDril demonstrated that high-pressure jet bits operating at 10,000 to 15,000 psi can drill many formations 2 to 3 times faster than conventional bits (**Figures 1 and 2**). These systems were not commercialized because of difficulties in pumping the high-pressure fluids to the hole bottom through conventional threaded drillpipe.

In the 1980s, Maurer Engineer developed a high-pressure motor on a DOE project that operated reliably at pressures up to 10,000 psi (**Figure 3**). The jets on the high-pressure bits drilled grooves in the rock which were easily removed by the PDC bit cutters (**Figures 4 and 5**).

These high-pressure motors drilled Berea sandstone at rates in excess of 1,000 ft/hr compared to 230 ft/hr for conventional motors and 100 ft/hr for rotary bits (**Figure 6**).

The approach being taken on this project is to develop a high-pressure slimhole motor for use on CT to overcome the drillpipe tooljoint leakage problems encountered with the earlier jet drilling systems.

PROJECT DESCRIPTION

Three types of downhole motors were evaluated for use with this system. PDM motors were selected over turbine and vane motors because they can be readily adopted for high pressure, they are widely used worldwide, and there are PDM motor maintenance facilities available worldwide.

Two basic high-pressure CT systems were evaluated on this project. With the *single-flow* system (**Figure 7**), high-pressure (HP) fluid (10,000 psi) is pumped down a single CT string to power the motor and deliver HP fluid to the bit nozzles. This system is preferred for smaller diameter holes (5" and smaller) due to its simplicity, higher reliability, and compatibility with existing equipment.

With the *dual-flow* system (**Figure 8**), two concentric strings of CT are used to deliver both low-pressure (LP) (2,000 psi) and HP fluid (10,000 psi) to the hole bottom. High-pressure fluid is pumped down the inner tube to the jet nozzles and LP fluid is pumped down the annulus between the concentric tubes to power the downhole motor (**Figure 9**).

Concentric CT, currently used with insulated steam injector CT (**Figure 10**) and other applications, is preferred with larger diameter wells (over 5") where additional flow rate is needed to effectively clean the hole.

With the *single-flow* system, a conventional PDM motor was modified for HP operation by increasing the outer housing wall thickness to increase burst pressure, and increasing the thrust bearing capacity to handle high hydraulic downthrust loads (**Figure 11**).

With the *dual-flow* system, two hollow titanium flexshafts and a hollow motor rotor are required to transfer the HP fluid from the inner CT to the HP bit nozzles (**Figure 12**).

A *modified dual-flow* system bypasses LP fluid to the wellbore annulus above a *single-flow* HP motor to improve hole cleaning.



Figure 1

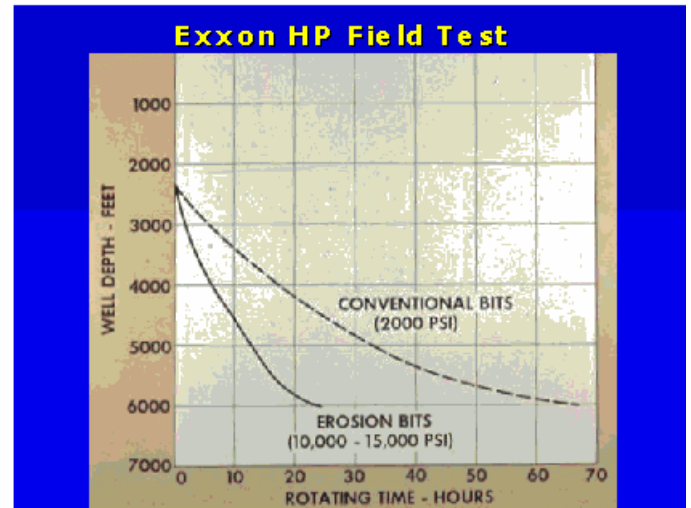


Figure 2

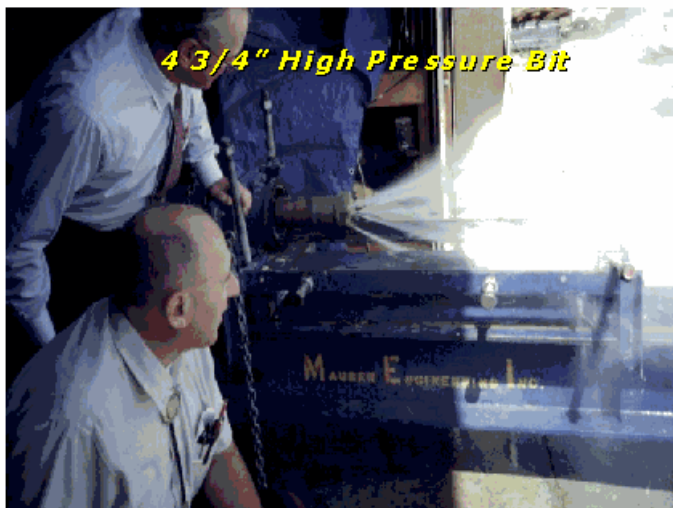


Figure 3



Figure 4



Figure 5

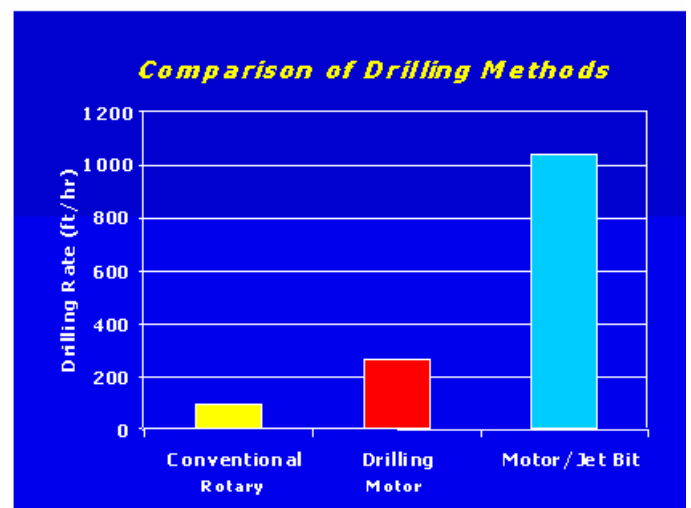


Figure 6

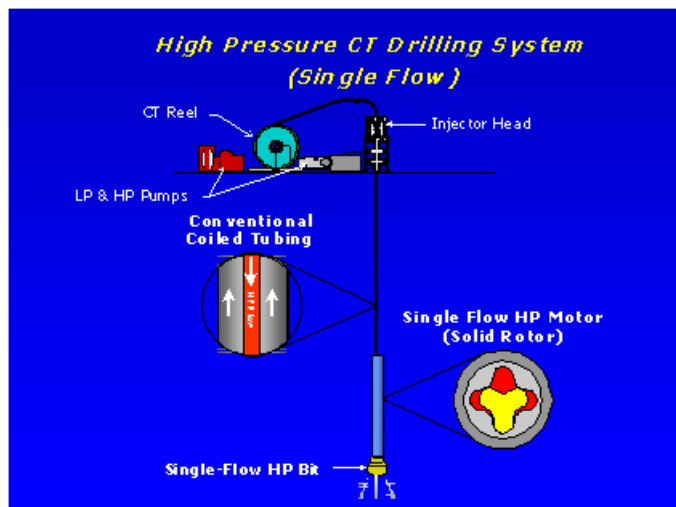


Figure 7

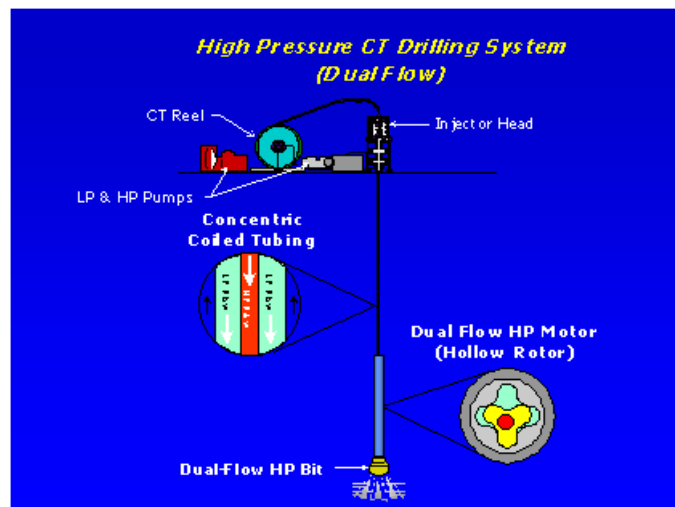


Figure 8

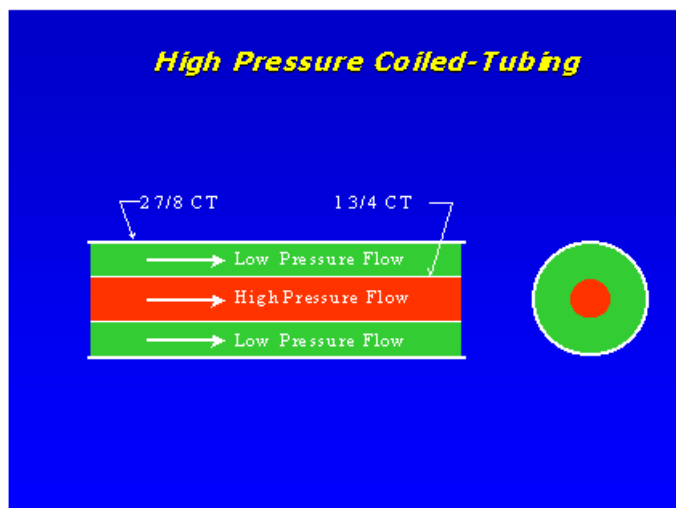


Figure 9

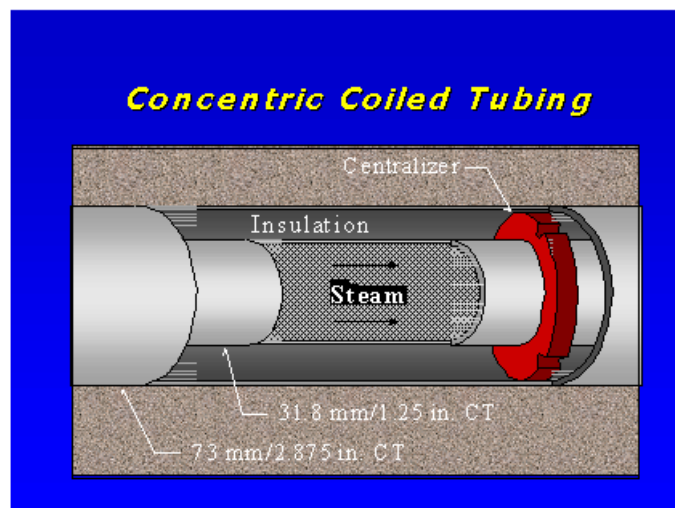


Figure 10

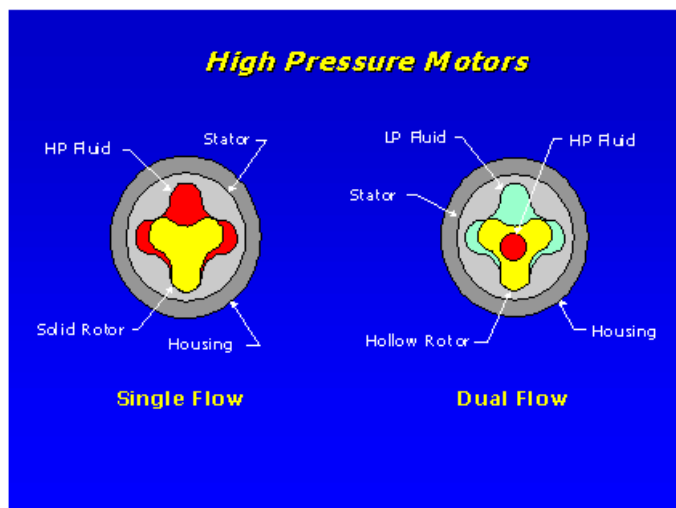


Figure 11

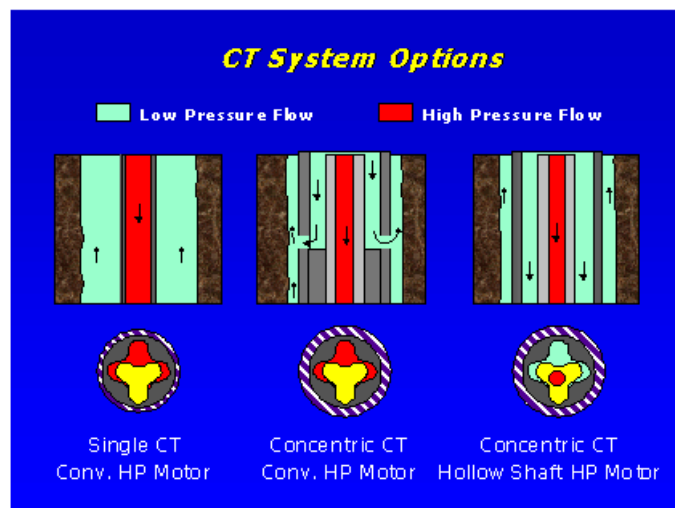


Figure 12

The Phase I Advisory Committee recommended that the *single-flow* system be developed during Phase II for use in smaller diameter holes (5" and smaller) due to its simplicity, lower cost and higher reliability. The more complicated *dual-flow* system shown in **Figure 8** will be developed later, once the *single-flow* system is commercialized.

PROJECT ACCOMPLISHMENTS

The high-pressure (HP) motor and HP CT rig components have been designed and the HP CT motor is now being assembled (**Figure 13**).

The HP motor (10,000 psi) utilizes several advanced features including special PDM rotors and stators that operate at high pressure, high-capacity titanium driveshafts and flexshafts, PDC thrust bearings (**Figures 14** and **15**), and labyrinth seals that control leakage at pressures up to 10,000 psi (**Figures 16** and **17**).

The prototype motor is being tested on HP drilling and dynamometer test stands at the Drilling Research Center (DRC) in Houston. These test stands were previously used to test DOE high-power motors.

Conventional CT is available with burst strengths in excess of 10,000 psi and can be used with this CT drilling system (**Figure 18**). Two-inch diameter CT (0.203" wall), which has a burst strength of 19,800 psi, was selected for use with the *single-flow* system. This size CT is a good compromise because it allows adequate flow rates to power the motor and provide good hole cleaning without producing excessive pressure drop inside the CT (**Figures 19** and **20**).

Fatigue failures are a problem when CT is cycled with high internal pressure (**Figure 21**). For example, with 12,000 psi internal pressure, 2 inch QT-1000 CT will fail after 16 cycles. This is adequate for initial field testing, but longer CT life will be needed when this system is commercialized.

QUALITY TUBING is testing Incoloy-625 CT that increases the fatigue life from 16 to 72 cycles and FIBERSPAR SPOOLABLE PRODUCTS is testing carbon fiber composite tubing with a fatigue life in excess of 2,000 cycles (**Figure 22**). The burst strengths of these new materials are considerably higher than conventional steel CT (**Figure 23**).

High-pressure drill bits were designed for use with these systems. The *single-flow* system utilizes bits with only HP nozzles whereas the *dual-flow* system utilizes bits with both LP and HP nozzles (**Figure 24**).

The HP bits will utilize PDC and roller cutters to mechanically remove the rock weakened by the HP jets. This allows these bits to conventionally drill through hard formations that cannot be eroded by HP jets, and eliminates the need to pull the HP bits when hard streaks are encountered.

Exxon utilized HP bits with diamond, drag and roller cutters so the bits could be optimized for all types of rocks ranging from soft shales to hard dolomites (**Figure 25**).

The HP roller and PDC bits shown in **Figures 26** and **27** were designed during this project. PDC bits have the advantage that they allow the HP jets to be distributed across the entire hole bottom to cut multiple grooves in the rock.

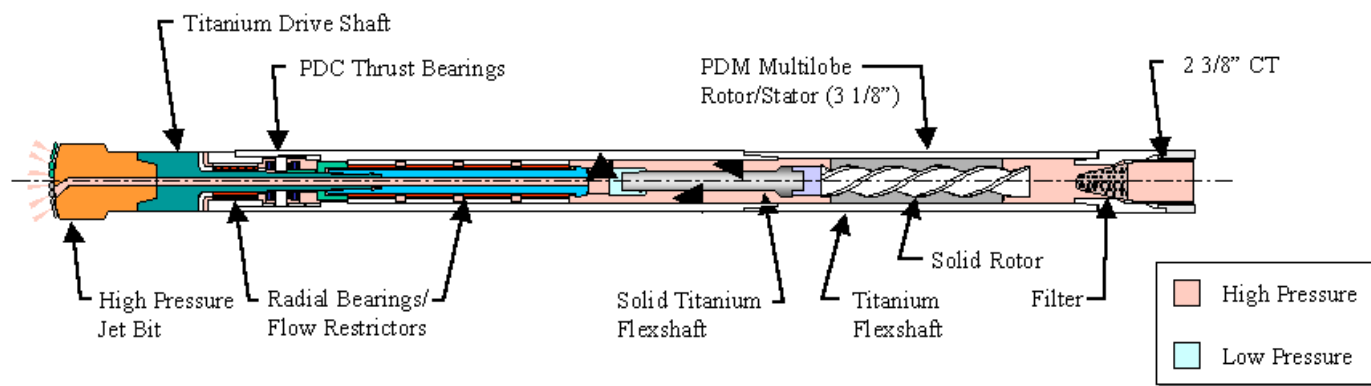


Figure 13. High Pressure CT Motor (Single Flow)

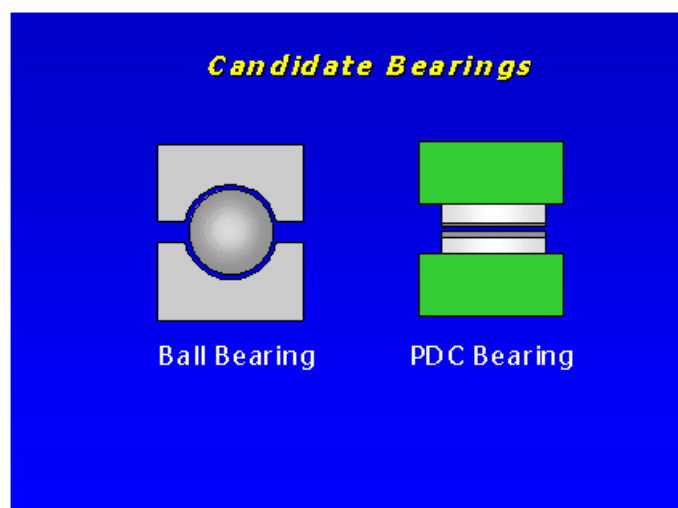


Figure 14

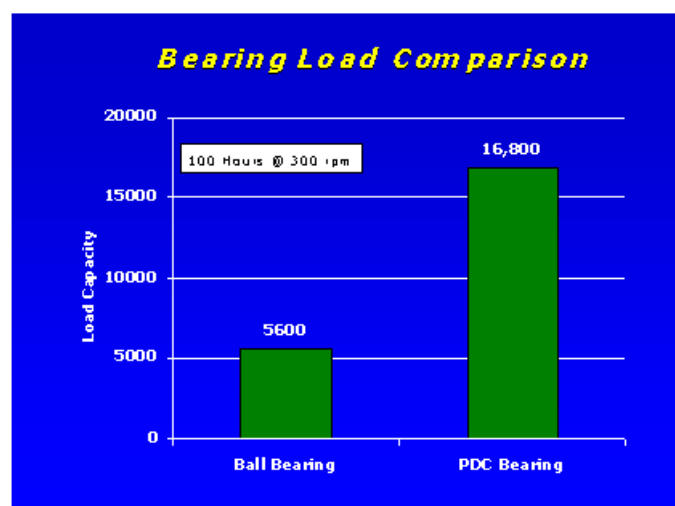


Figure 15

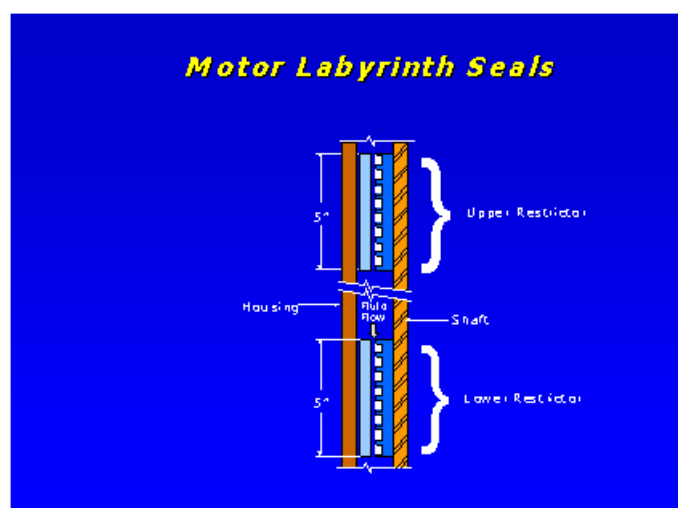


Figure 16

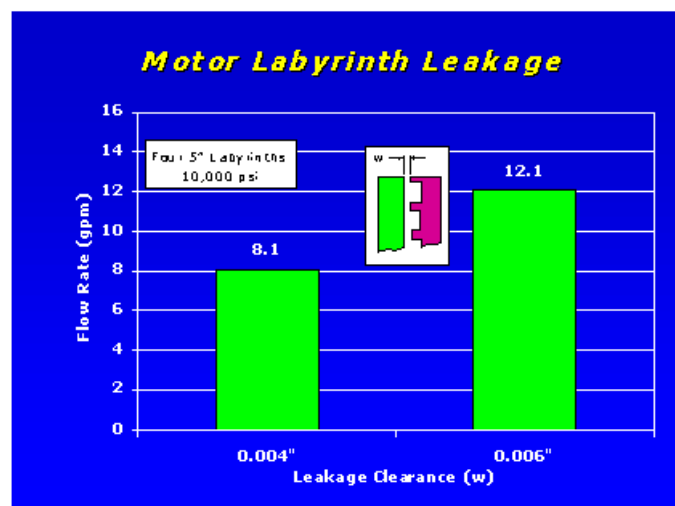


Figure 17

Coiled Tubing Burst Pressure
(100,000 psi yield)

CT Diameter (in.)	Wall Thk. (in.)	Burst Pressure (psi)
1.00	0.109	20,800
1.25	0.156	24,160
1.50	0.175	22,670
1.75	0.188	20,910
2.00	0.203	19,800
2.375	0.203	16,670
2.875	0.203	13,770
3.500	0.203	11,310

Figure 18

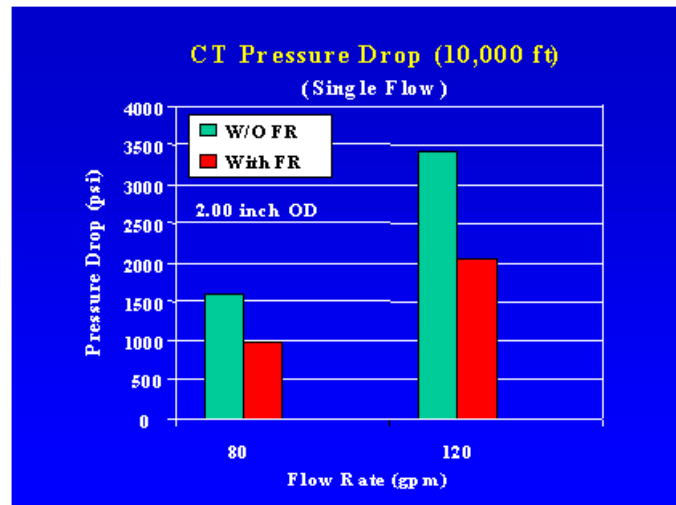


Figure 19

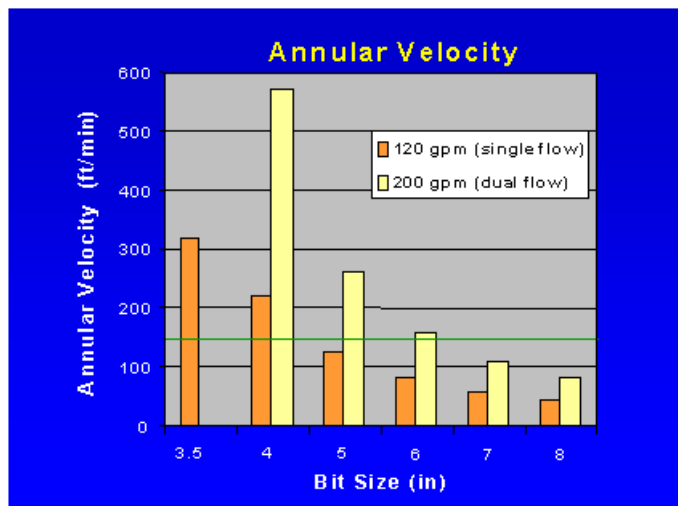


Figure 20

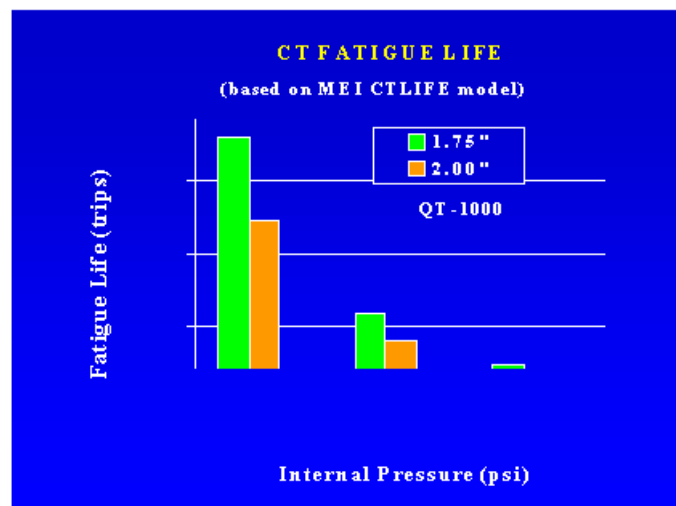


Figure 21

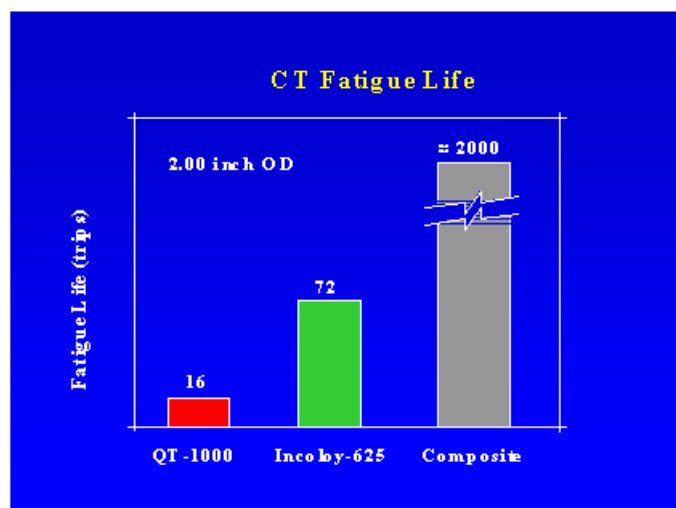


Figure 22

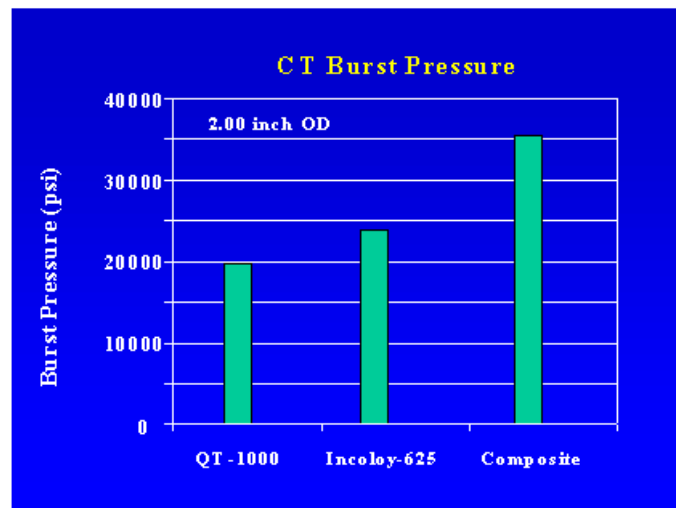


Figure 23



Figure 24

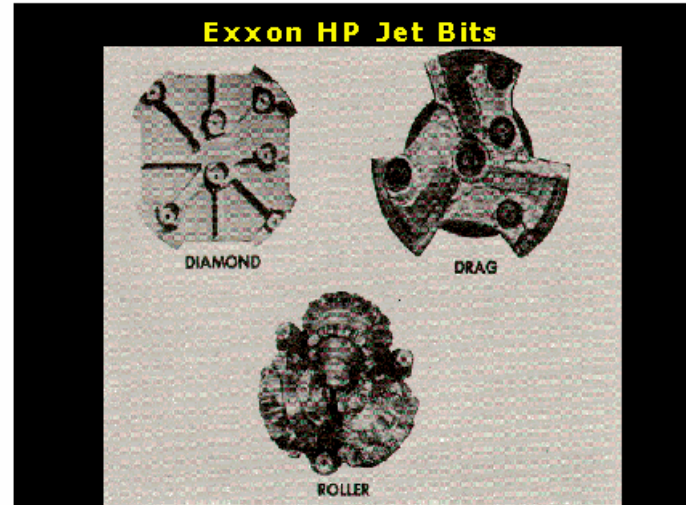


Figure 25

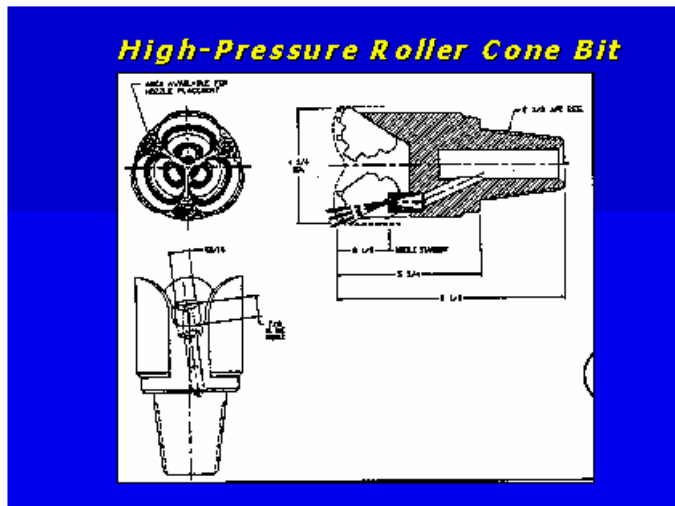


Figure 26

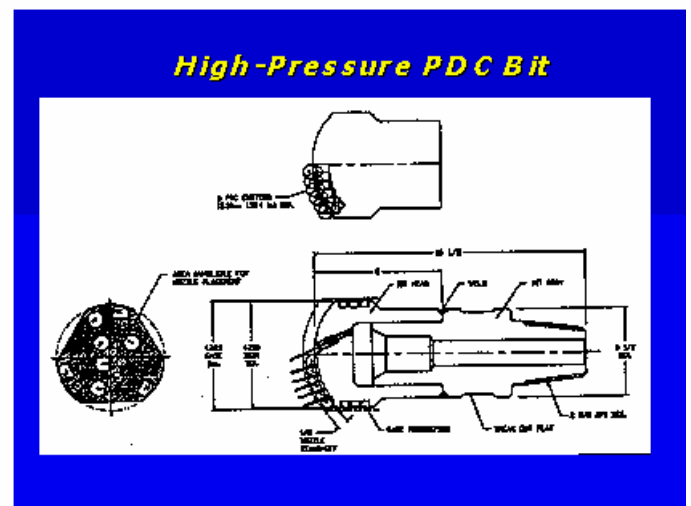


Figure 27

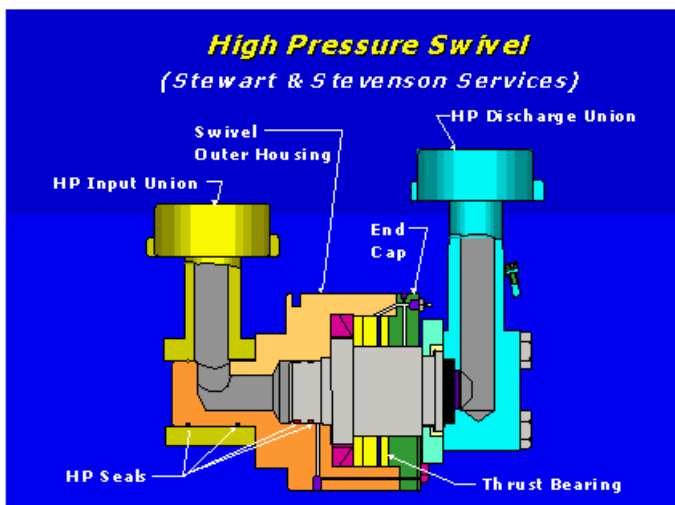


Figure 28

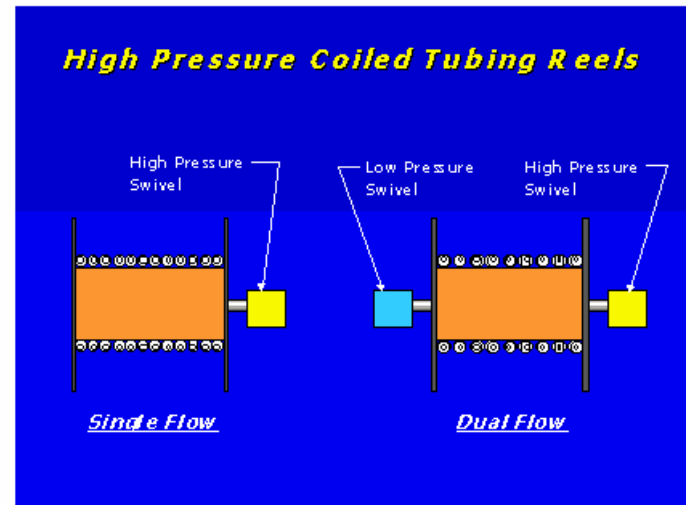


Figure 29

With roller bits, the HP nozzles must be placed on the edge of the bit (due to space constraints) to cut large grooves at the gauge of the hole. Exxon field tests showed that both types of bits are effective, but that PDC bits are preferred in small-diameter holes (3 to 5 inch).

HP bits designed by Exxon, Shell, Gulf and FlowDril performed well in the field and were very reliable, so developing reliable HP bits for use as with this HP CT drilling system will not a major technical problem.

Stewart and Stevenson developed a HP swivel (15,000 psi) for use with the system (**Figure 28**). The *single-flow* system utilizes a HP swivel on one end of the reel shaft to transmit HP fluid to the inside of the CT (**Figure 29**).

With the *dual-flow* system, a conventional low-pressure (LP) swivel will be used on the opposite end of the reel shaft to transmit LP fluid to the annulus between the concentric CT strings. A dual-pressure swivel (LP and HP) could also be used on one end of the reel shaft with the *dual-flow* system.

APPLICATIONS AND BENEFITS

The high-pressure CT drilling system should drill 2 to 4 times faster than conventional drills and reduce hole-making costs by up to 50 percent and overall well costs by 25 percent. This CT drilling system will find application in slim hole and underbalanced drilling and operations.

FUTURE ACTIVITIES

Following Phase II laboratory tests, the HP CT system will be tested including the HP motor, the HP swivel developed by Stewart and Stevenson and the HP CT developed by Quality Tubing. The system will then be commercialized following full-scale field testing.

ACKNOWLEDGMENTS

The authors appreciate the contributions of the FETC Contracting Officer's Representative, Mr. William J. Gwilliam. The period of performance for this development project is September 30, 1997, through September 30, 2002. Stewart and Stevenson (Mike Dearing) and Quality Tubing (John Martin) are both participating in the effort as subcontractors.

We also gratefully acknowledge the significant contributions of the members of the Advisory Committee including Gary Collins of Marathon Oil, Mel Hightower of ARCO, and John Misselbrook of BJ Services.

REFERENCES

- Deily, F.H. et al., 1977: "Five Wells Test High-Pressure Drilling," *Oil & Gas Journal*, July 4. (Exxon)
- Kolle, J.J., Otta, R. and Stang, D.L., 1991: "Laboratory and Field Testing of an Ultra High-Pressure, Jet-Assisted Drilling System," SPE/IADC 22000, presented at the 1991 SPE/IADC Drilling Conference, held in Amsterdam, March 11-14. (FlowDril)

Maurer, W.C. et al., 1986: "Laboratory Testing of High-Pressure, High-Speed PDC Bits," SPE 15615, 61st Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, held in New Orleans, Louisiana, October 5-8. (Maurer Engineering)

Maurer, W.C., Heilhecker, J.K., and Love, W.W., 1973: "High-Pressure Drilling," *Journal of Petroleum Technology*, July 4. (Exxon)

Maurer, W.C. and Leitko, C.E., 1998: "Advanced High-Pressure Coiled-Tubing Drilling Systems, Phase I — Final Report," TR98-22, October. (Maurer Engineering)

Ostrovskii, N.P., 1960: "Deep-Hole Drilling with Explosives, *Gostroptekhiia `dat Moscow*," translated by Consultants Bureau Enterprises, Inc., New York. (Russian)

Pols, A.C., 1977: "Hard-Rock Jetting — Conclusion: Rock-Type Decided Jetting Economics," *Oil & Gas Journal*, February 7. (Shell)

Pols, A.C., 1977: "Hard-Rock Jetting — 1: Tests Show Jet-Drilling Hard-Rock Potential," *Oil & Gas Journal*, January 31. (Shell)

Weber, 1971: "New Gulf Method of Jetted Particle Drilling Promises Speed and Economy," *Oil & Gas Journal*, June 21. (Gulf)

Weber, 1971A: "Gulf's New Abrasive Drill: Is It The Breakthrough?," *Oil & Gas Journal*, July 26. (Gulf)

High-Power Drilling Motor Field Tests

by

John H. Cohen (jhc@maureng.com, 713-683-8227, ext 215)

Curtis E. Leitko (leitko@maureng.com, 713-683-8227)

William C. Maurer (maurer@maureng.com, 713-683-8227)

MAURER ENGINEERING INC.

2916 West TC Jester

Houston, Texas 77018-7098

INTRODUCTION

High drilling costs are a major constraint on the development of marginal oil and gas reserves in the USA. Hole-making drilling costs constitute approximately 50 percent of the total well costs, so increasing drilling rate can have a major impact on drilling costs.

Doubling drilling rates in oil and gas wells could save hundreds of million of dollars in the USA and significantly improve the economics of producing marginal oil and gas reservoirs.

This development is being sponsored by the U.S. Department of Energy's Federal Energy Technology Center under contract DE-AC21-94MC30088 with Maurer Engineering Inc., 2916 West TC Jester, Houston, Texas; fax: 713-683-6418; email: mei@maureng.com.

OBJECTIVE

The objective of this project is to double the power output of downhole positive-displacement motors (PDMs) so that they will drill twice as fast. Doubling the drilling rate will reduce drilling costs by up to 25 percent since approximately 50 percent of well costs are spent in making the hole, which is directly related to drilling rate.

APPROACH

A PDM motor utilizes a steel rotor and a rubber stator to convert hydraulic power to mechanical power to rotate the drill bit. PDM stators contains one more lobe than the rotors, as shown in **Figures 1** and **2**.

For a given rotor/stator design, motor speed is proportional to flow rate and motor torque is proportional to pressure drop across the motor. Multilobe motors have larger volumetric displacement than single-lobe motors and therefore deliver higher torque and run at lower speeds.

The pressure drop, p , across a motor equals:

$$p = np_s \quad (1)$$

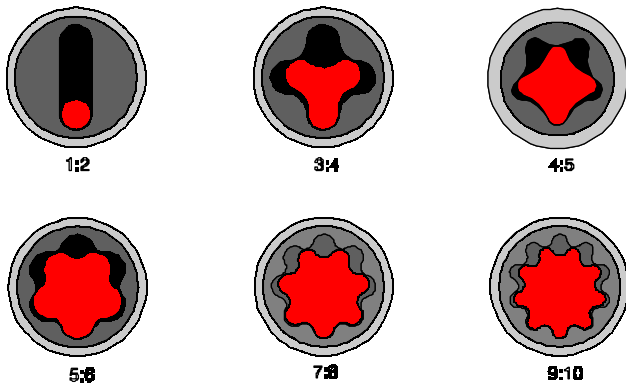


Fig. 1. PDM Multilobe Stator Combinations

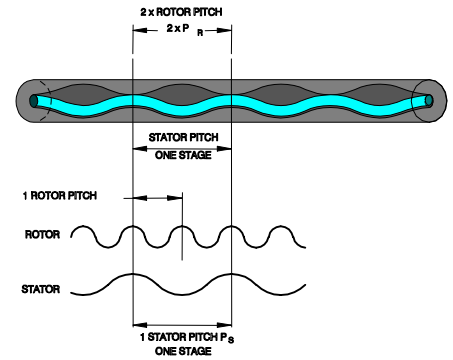


Fig. 2. PDM Rotor/ Stator Pitches

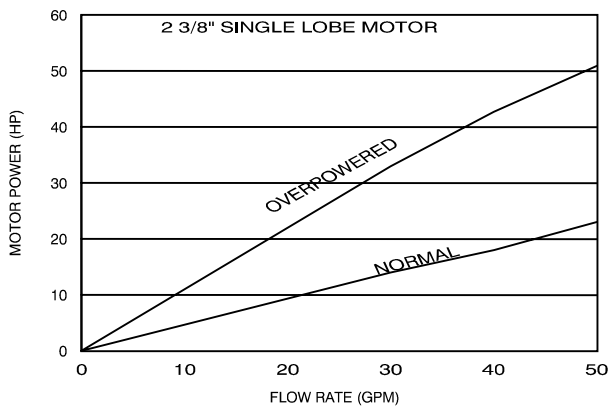


Fig. 3. Motor Power vs. Flow Rate

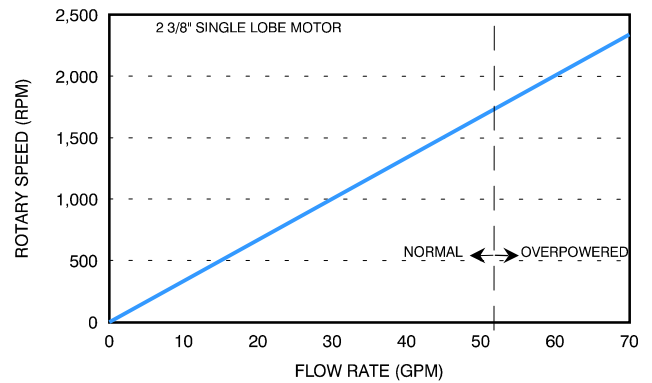


Fig. 4. Rotary Speed vs. Flow Rate

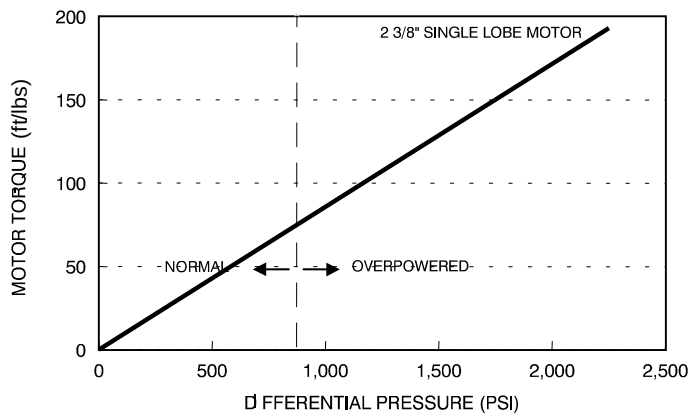


Fig. 5. Motor Torque vs. Pressure

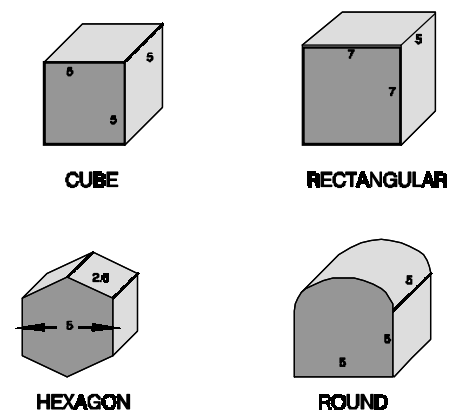


Fig. 6. Large TSP Cutters

where

- p = motor pressure drop
- p_s = pressure drop per stage
- n = number of stages

Eq. 1 shows that the motor pressure drop (i.e., power output) can be increased by increasing the number of stages (i.e., increasing motor length) or by increasing the pressure drop per stage (e.g., tighter interference between the rotor and stator). Increasing pressure increases torque, but does not change rotary speed.

The approach taken on this project is to double the number of stages in the motor (which doubles the power output) and to increase the rotor/stator interference to increase the pressure drop per stage, thus increasing motor output by over 150 percent.

PROJECT DESCRIPTION

A 2³/₈-in. (60-mm) high-power motor was developed that delivers up to 50 HP compared to 23 HP for a conventional motor of the same size (**Figure 3**). The 2³/₈-in. motor, which normally operates at a rotary speed of 1,670 rpm with 50 GPM, was operated at 2,340 rpm with 70 GPM flow (**Figure 4**).

Motor torque is proportional to motor pressure drop as shown in **Figure 5**. The 2³/₈-in. high-power motor delivered a maximum of 195 ft-lbs compared to 73 ft-lbs for a conventional motor.

Special high-power thermally stable diamond (TSP) bits were developed for use with these high-power motors because conventional bits cannot operate reliably at these high power levels. Large TSP cutters of different shapes were tested in these bits (**Figure 6**).

Laboratory drilling tests were conducted at the Drilling Research Center (DRC) in Houston, Texas, with the high-power motor and these TSP drill bits. The overpowered 2³/₈-in. high-power motor (2,060 rpm) drilled Batesville marble at rates up to 540 ft/hr with 3-in. large-cutter TSP bits compared to 190 ft/hr for a conventional motor and 60 ft/hr for rotary drilling (**Figure 7**).

Following these tests, a 3³/₈-in. high-power multi-lobe motor was developed that utilizes a 4:5 rotor/stator design, with the number of stages increased from 5 to 10 and the interference between the rotor/stator increased to allow higher pressure drop per stage (**Figure 8**). A bearing pack with stronger bearings, a stronger shaft, and a stronger flex coupling were used on this motor.

Dynamometer tests were conducted at the DRC (**Figure 9**). The high-power 3³/₈-in. motor delivered up to 75 HP compared to 30 HP for a conventional motor (**Figure 10**). In laboratory tests, the 3³/₈-in. motor drilled a 4³/₄-in. hole in Carthage marble at 50 ft/hr compared to 25 ft/hr with a conventional motor (**Figure 11**).

Following these laboratory drilling tests, the 3³/₈-in. high-power motor was field tested at AMOCO's Catoosa test site near Tulsa, Oklahoma in a dolomite formation at depths of 1,600 to 1,900 feet (**Figure 12**).

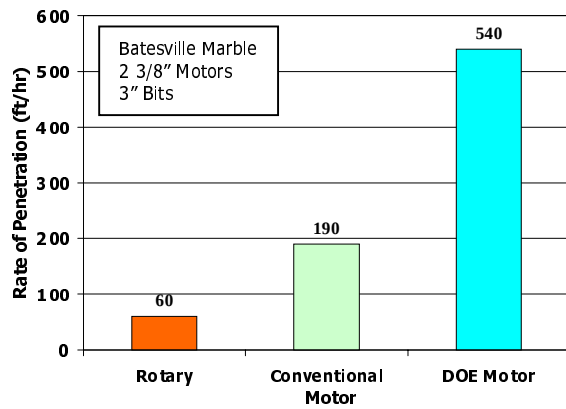


Fig. 7. Drilling Rate Comparison

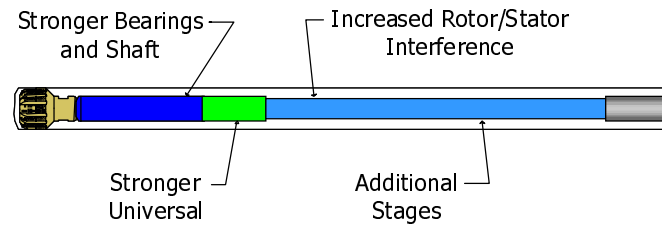


Fig. 8. DOE High-Power Motor Design



Fig. 9. DOE Motor In Dynameter

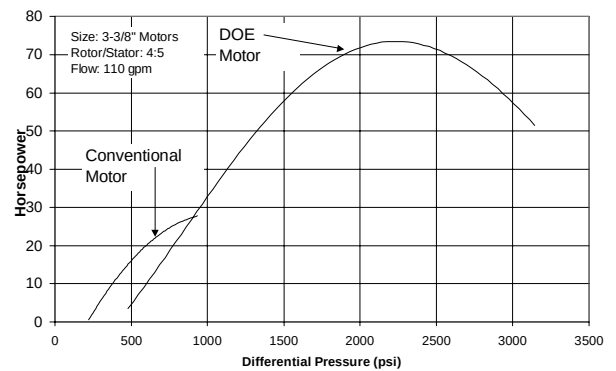


Fig. 10. Motor Performance Comparison

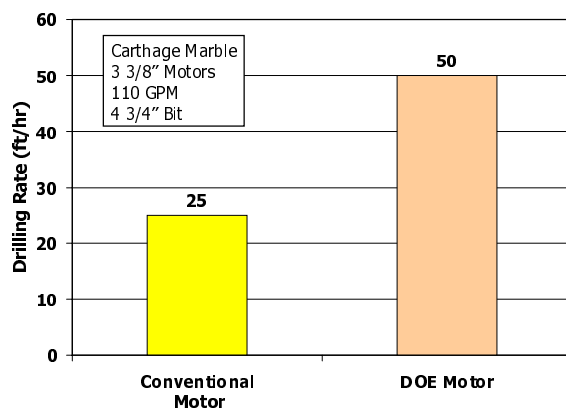


Fig. 11. Laboratory Drilling Rates



Fig. 12. Catoosa Drilling Rig

The lithology at the Catoosa test site is well documented, allowing good comparative test drilling with different motors. The Arbuckle Dolomite, a hard dolomite formation that extends from 1,621 ft to 2,920 ft, was selected for the tests. The motors were run sequentially with the conventional motor being run between the two high-power motors to allow direct comparison between the motors.

Figure 13 shows the two 3 $\frac{3}{8}$ -in. DOE high-power motors and the 3 $\frac{3}{8}$ -in. conventional motor used in these tests. The DOE motors are longer due to the longer rotors and stators used in these high-power motors.

New hybrid bits were developed for use with the DOE high-power motor (**Figure 14**). The PDC cutters on these bits drill at high rates in softer formations, while TSP cutters located behind the PDC cutters protect the PDC cutters in hard streaks. These bits performed well during the field tests. The first bit was damaged when it drilled through a 1-ft thick chert stringer in one hour at the end of the first run. However, the bit was able to successfully drill through the chert stringer, showing the strength of the hybrid bit.

Figure 15 shows the DOE high-power motor in the derrick and **Figure 16** shows the rig crew attaching the hybrid bit to the DOE motor.

Due to large casing (13 $\frac{3}{8}$ -inch) in the upper section of the well, the annular velocities would have been inadequate to clean the hole effectively with the low flow rates used with the 3 $\frac{3}{8}$ -in. motor. A Halliburton pump (**Figure 17**) was used on a parasite string to increase the annular flow rate to effectively clean the cuttings from the well.

The hybrid bit on the first DOE motor run was damaged in a chert stringer so a drilling rate comparison could not be made. The second DOE motor drilled at 48 ft/hr compared to 23 ft/hr for the conventional motor, demonstrating the high drilling rate capabilities of the high-power DOE motor (**Figure 18**).

The high-power output allowed the DOE high-power motors to be run at bit weights of 8,000 to 10,000 lbs compared to maximum bit weights of 3,000 to 7,000 lbs with the conventional motors.

The drillers found the DOE motors much easier to operate than conventional motors because they tended to stall less due to their higher torque capability. The DOE motors could be restarted by reducing the bit weight, whereas the conventional motor had to be raised off bottom to be restarted.

Dynamometer tests conducted at the DRC following the field tests showed that the DOE motors were in excellent condition and could have drilled further during the tests. These field tests were very successful, demonstrating the high potential of the DOE high-power motors.

APPLICATIONS AND BENEFITS

The DOE high-power motor has potential application in directional and horizontal drilling since motors are required in these wells. Directional drilling is usually much more expensive than straighthole drilling because of the added costs of the motors, MWD tools and other directional drilling equipment. Doubling the drilling rate in these wells could save the industry hundreds of millions of dollars per year.



Fig. 13. DOE and Conventional Motors



Fig. 14. DOE Hybrid TSP/PDC Bit



Fig. 15. DOE Motor In Derrick



Fig. 16. Attaching Hybrid Bit to DOE Motor



Fig. 17. Parasite String Pump

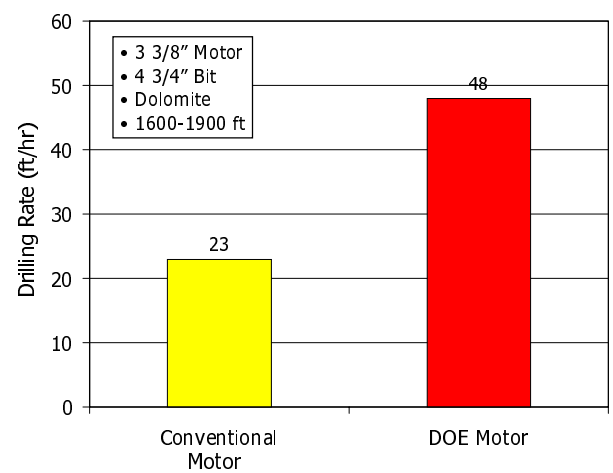


Fig. 18. Field Drilling Rates

These high-power motors also have application with coiled tubing (CT) drilling because drilling motors must be used with CT since the CT cannot be rotated in wells. CT rigs are more expensive than conventional drilling rigs, so increased drilling rates could produce significant cost savings with these rigs.

The high-power motors drill up to 2 to 4 times faster than rotary rigs, so they also have potential application in straighthole drilling.

FUTURE ACTIVITIES

Additional field tests need to be conducted in oil and gas wells to demonstrate the economic benefits and reliability of these motors to service companies and operators and to accelerate implementation and commercialization of these high-power motors.

ACKNOWLEDGMENTS

The authors appreciate the contributions of the FETC Contracting Officer's Representative, Roy C. Long. The period of performance for this development project is September 30, 1994, through July 31, 1999.

REFERENCES

Bourgoyne, Jr., Adam T., Millheim, K.K., Chenevert, M.E., Young, Jr., F.S., 1986: *Applied Drilling Engineering*, Society of Petroleum Engineers, Richardson, Texas.

Cohen, John H., Maurer, W.C., and Westcott, P.A., 1993: "High-Power TSD Bits," presented at the Energy-Sources Technology Conference and Exhibition, held in Houston, Texas, January 31-February 4.

Cohen, John H., Maurer, W.C., and Westcott, P.A., 1994: "Improved High-Power TSD Bits," ASME Book No. G00827, PD-Vol. 56, *Drilling Technology*.

Cohen, John H., Maurer, W.C., and Leitko, Curtis E., 1995: "High-Power Slim-Hole Drilling System," SPE 30485, presented at the 1995 SPE Annual Technical Conference and Exhibition, held in Dallas, Texas, October 22-25.

Cohen, John H., Maurer, W.C., and Evans, C.R., and Westcott, Paul, 1995: "High-Power Downhole Motor," *Drilling Technology*, The American Society of Mechanical Engineers, Book No. H00920, Vol. 65.

Cohen, John H., 1996: "Development and Testing of a High-Power Slim-Hole Drilling System-Phase I, Final Report," (TR96-18) presented to the U.S. Department of Energy, Morgantown Energy Technology Center (Project No: RFP: DE-RP21-93MC30088), August.

Jürgens, R., 1978: "Down-Hole Motors—Technological Status and Development Trends," paper presented at the 7th International Symposium of the firms Baker Oil Tools GmbH, Christensen Diamond Products GmbH, and Vetco Inspection GmbH, Celle, FDR, September 8.

Advanced Mud Hammer Systems

D. Pixton (dpixton@novatekonline.com; 801-374-2755)

D. Hall (dhall@novatekonline.com; 801-374-6222)

Novatek, Inc.

2185 South Larsen Parkway

Provo, UT 84606

Abstract

Novatek and the U.S. Department of Energy's Federal Energy Technology Center have engaged in a cooperative effort to develop an integrated, steerable drilling system, which includes a mud-actuated hammer as a key element. The overall goal of this system is to provide significant cost reduction and technical advantage over current drilling practice, particularly in deep, medium-to-hard rock formations. Following preliminary evaluation of several advanced drilling concepts, a system concept has been developed which offers potential improvements in drilling rate, directional control, formation evaluation, and wellbore stability. This paper describes several key subsystems of the integrated drilling system concept in some detail, including an advanced telemetry system, a steerable drilling head that offers advanced sensing capabilities, and a means of lining the wellbore while drilling. Progress on prototype development is reported, and key technological developments and hurdles are described.

Introduction

In a study completed in 1994, a committee appointed to review the future needs of drilling technology concluded that "the principal thrust of an R&D program should be on the development of the smart drilling system." A "smart" drilling system is defined as a system that is able to sense conditions at and ahead of the drill bit and adapt to these varying conditions while drilling. This drilling system was identified to include, among other things: a) sensors to measure conditions at and ahead of the drill bit; b) improved methods to steer the drill bit; c) improved telemetry methods to transmit real time data to the surface; and d) continuous and instantaneous support of the borehole.¹

Identifying that several of these functions could be supplied by a down-hole mud actuated hammer, Novatek began a joint development effort in 1997 with the US Department of Energy's Federal Energy Technology Center to develop key elements of this "smart drilling system." This effort was first to evaluate several competing methods of accomplishing the above-mentioned functions, and then proceed with development of the most promising technologies. The competitive evaluation just mentioned was accomplished during the first phase of work ending in fall of 1998. A discussion of the concepts evaluated and the conclusions of the initial evaluation have been submitted previously in reports to the U.S. Department of Energy.^{2,3}

Since that time, Novatek has refined the designs of the key components of the smart system and has begun prototype manufacture to enable verification and further refinement of the

various subsystems. The purpose of this writing is to report on these activities which have taken place since the phase I reports.

Objectives

The overall objectives of the present research effort are to decrease the cost of drilling wells and extend the capabilities of current drilling technology to more effectively tap energy reserves. More specifically, the program objectives are to:

- 1) Develop key elements of a smart drilling system including an improved steerable drilling head, advanced formation sensing means, high data rate communication between top and bottom of well, and an *in-situ* wellbore lining means, and
- 2) Provide means for integrating these individual elements into a complete system

The first objective mentioned above focuses on improvements to present drilling technology and is expected to yield tools and subsystems capable of stand-alone use^{*}; the second focuses on compatibility of the subsystems and thereby assures that a complete system may be developed.

Approach

To accomplish the above objectives, the study has sought first to develop and exploit various features of Novatek's mud hammer drilling head. The features most readily exploited are the hammer's ability to improve penetration rate, its interaction with the formation, and the linear oscillation of the hammer piston. The first of these features offers the ability of the system to drill more rapidly, thereby helping to decrease well costs. The second feature offers novel means of diagnosing the formation characteristics at and ahead of the drill bit, thereby allowing adjustment of drilling parameters to meet changing drilling conditions, and facilitating direction of the drill into the desired formations. The third feature enables down-hole generation of high-pressure hydraulic power, which is important in further penetration rate increase and improved steering.

Although it is technically possible to use the oscillation of the hammer piston to also drive rotation of the drill bit, generate electrical power, and even send mud pulse or acoustic signals for communication with the surface, the present study has chosen not to pursue these functions because better approaches are possible. Since the hammer alone cannot accomplish the objectives outlined above, novel downhole mechanisms have been designed to complete the remaining objectives. These mechanisms include a very high data rate communications system and a means of lining the borehole while drilling.

As mentioned previously, the first phase of activity in this project has been a conceptual distillation process, wherein several competing concepts were evaluated, and the most promising were selected for further study. The current phase of work includes:

1. Generating detailed designs of the selected subsystems

^{*} Varying development times and market pull for various of the concepts discussed herein will necessitate introduction of some of the technologies as stand-alone tools, or as enhancements which build upon existing systems. The first of these stand-alone tools will most probably be a down-hole hammer drill.

2. Building prototype models of these designs
3. Testing prototype models under laboratory conditions (and field sites where possible), and
4. Evaluating test results to determine the technical fitness and probable economic impact of the tested mechanisms.

A third phase of work will take promising technologies to field sites for testing and demonstration, and will lead to commercialization of these technologies.

Description of Technology

Overall System

Figure 1 illustrates the basic components of the overall system, which have been selected for consideration in this study. As shown, the system includes a mud-actuated hammer drilling head, real time formation sensors, a high-pressure jet enhanced steering assembly, a borehole lining assembly, and a high-speed data link. It is anticipated that, along with the formation sensors described herein, other current art and novel sensors will be added as needed to provide more complete downhole diagnostic information. Also not specifically shown is a central processing unit and associated hardware that enables adaptation of the hammer and steering assembly to the diagnostic information provided by the sensors and the operator. This unit will likely reside in the steering assembly shown in the figure. A discussion of each of the main subsystems follows.

Mud Hammer Drilling Head/Formation Sensors

As mentioned, a key component of the overall drilling system is a down-hole mud hammer. The primary motivation for employing the hammer in the system is of course its potential to bring improved rate of penetration (ROP). The hammer does this by creating an instantaneously high axial force, which in brittle formations causes high fracturing, and in more ductile formations causes greater indentation of the cutters in the bit. In previous field trials, hammers have also been noted to help remove unwanted deviation, and improve bit footage.^{4,5}

Aside from these benefits, the motion and vibrational output of the hammer may also potentially be used as a type of formation sensor, and also provide a seismic signal while drilling. The ability of the hammer to act as a formation sensor derives from the fact that it is influenced somewhat by the formation it is drilling: formations of differing mechanical properties will cause different rebound in the hammer as it strikes the formation. If the linear motion of the hammer can be evaluated near impact, this information can be used to determine at least a composite index that identifies overall rock characteristics. This information may be used alone or to supplement formation data obtained from other current art sensors and give a more detailed picture of the formation. By so combining data from multiple sources, fewer assumptions than presently required may need to be made, resulting in more accurate data interpretation. Furthermore, the motion of the hammer can be used as an important feedback quantity to verify and quantify the output of the hammer drill as the hole progresses in time and depth.

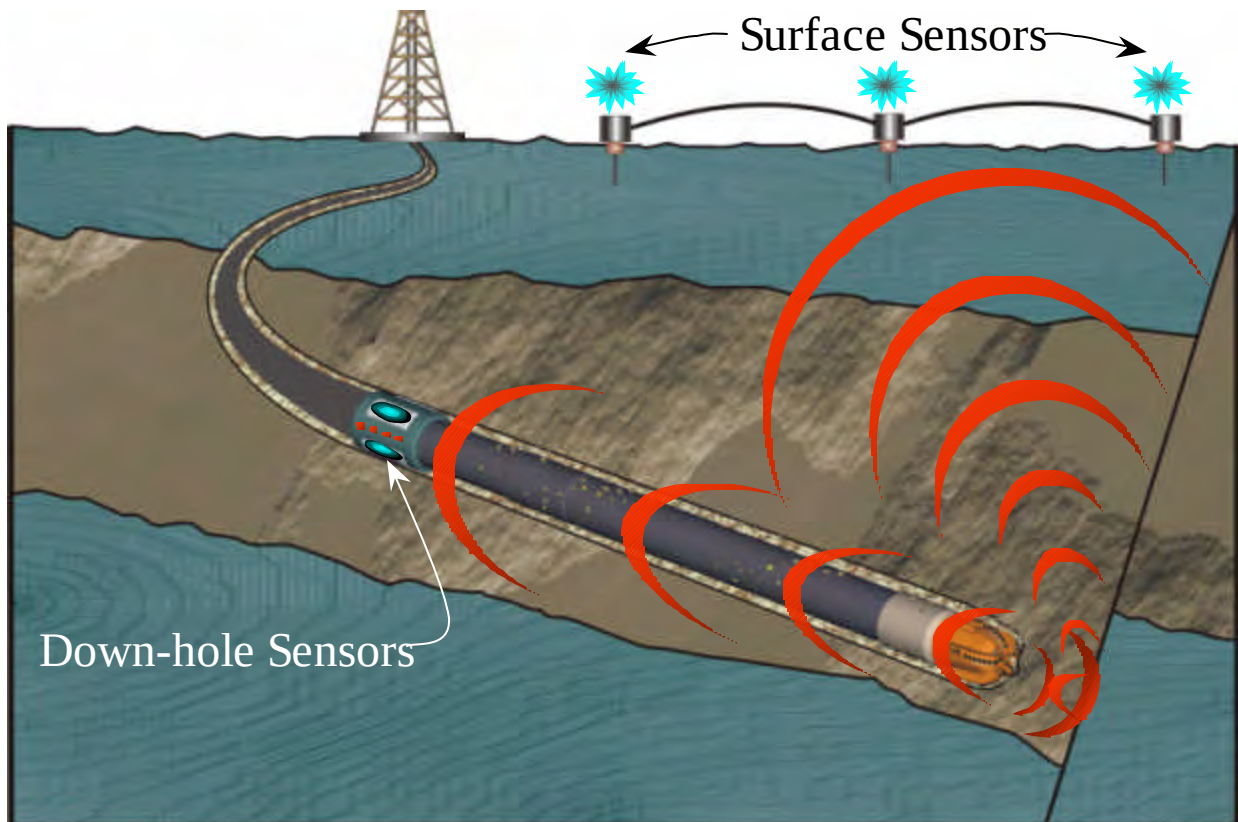
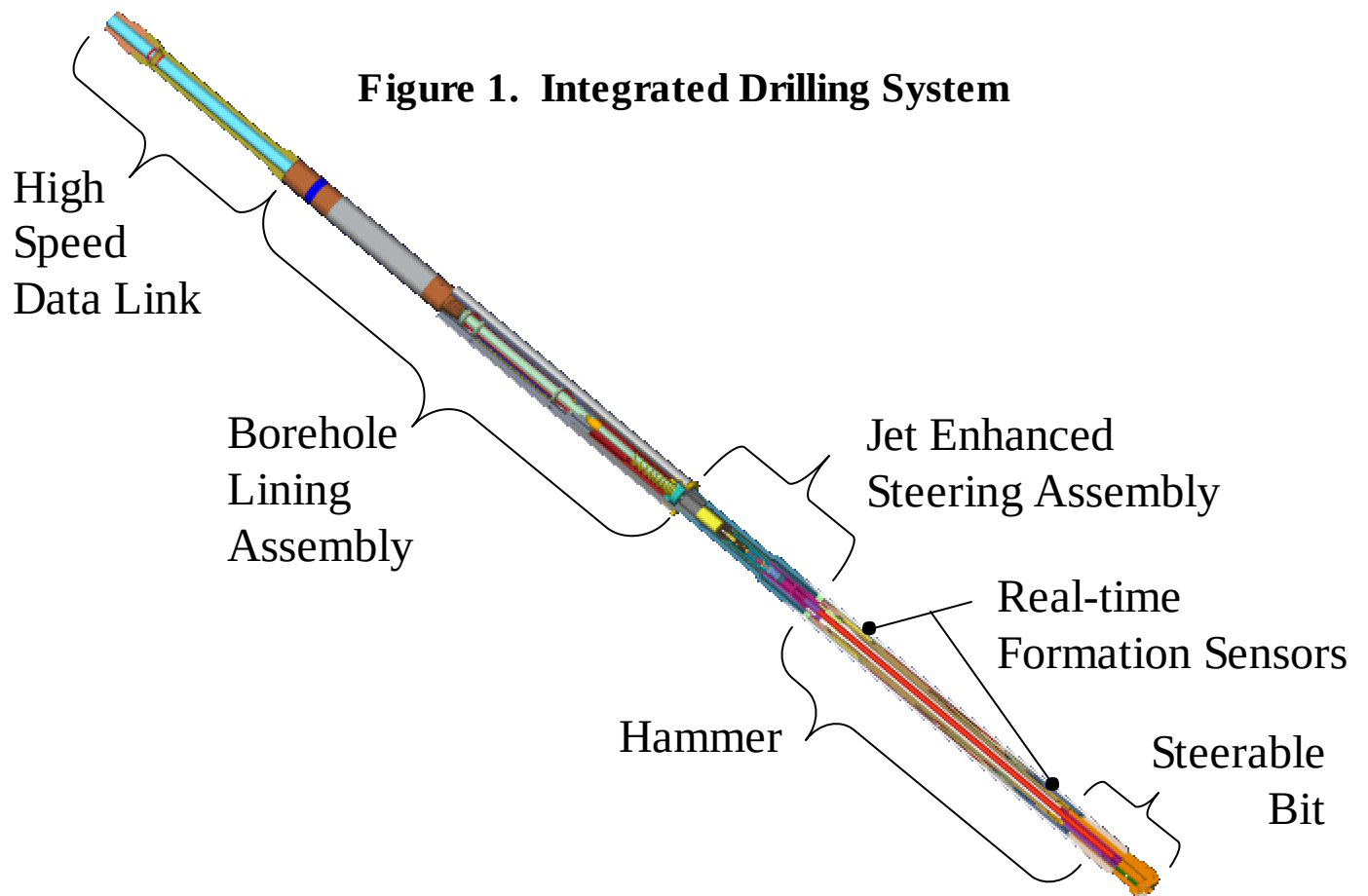


Figure 2. Percussion Bit Seismic

The impact of the hammer upon the formation being drilled also provides a steady seismic signal at the hole bottom, which may be used for reverse vertical seismic profiling and look ahead measurements. This concept is similar to the concept of drill bit seismic, which is already in practice.⁶ This system would ideally require seismic sensors near bit and at the surface, as shown in Figure 2.

High Pressure Jet-enhanced Steering System

The reciprocating motion of the mud hammer may further be used to drive a hydraulic piston and generate high hydraulic pressure down hole. This high-pressure fluid may be used to enhance bottom hole cleaning and rock fragmentation, resulting in faster penetration of the bit.

If this high-pressure fluid is applied only to a certain region of the hole, the drill bit will preferentially drill in that region, resulting in deviation of the bit. In this manner, the bit may be steered to a desired location. This concept is shown in Figure 3. As shown, drilling fluid enters passages in the drill bit and is intensified in pressure by the hammer piston striking intensifier pistons in the bit face. This intensified fluid then exits the bit through nozzles distributed about its face and impinges just adjacent to the region of the rock being drilled by the cutters. Figure 4 depicts the hardware necessary to control application of the high-pressure fluid to one region of the borehole. Key elements of this control system are: a rotary valve, which is capable of segmenting flow for directional drilling, while still allowing flow to all regions of the borehole for straight-ahead drilling; a sensory module comprised of an accelerometer /magnetometer package, which determines rotational position of the drill head; a rotary actuator, which turns the valve relative to the rotational position of the drill; and a computer driver which converts uphole commands and data from the sensory module into a control signal which selects the appropriate positioning of the valve.

Borehole Lining while Drilling System

Beyond the hammer-related drilling and sensing systems, a means of supporting and stabilizing the drilled borehole is required by the overall system. Supporting the rock while drilling prevents a variety of borehole stability problems and enables drilling horizontally in poorly consolidated or fractured formations and shales. Currently, mud cake or other sealing agents are used to stabilize the borehole while drilling. The technology investigated in this study involves casting a more permanent and structurally competent liner into the borehole while drilling. Whereas current (temporary) stabilization means must be followed by cementing steel casing at several points along the length of the well, the liner under investigation would permit the use of a single continuous steel casing string, or none at all in some cases.

Key to the success of such a system are the means of conveying material continuously to the bottom of the borehole, and the means of applying the material to the rock. Figure 5 shows the concept under investigation. As shown, the lining material is fed to the bottom of the well by injection into the drilling fluid. The material is then strained out of the fluid, ground up downhole, and deposited against the borehole wall. The material is shaped and cured inside a form that is friction heated to allow control of cure time. Figure 6 shows other components required for the system. As can be seen, a bit with an offset reamer is used to drill and ream the hole oversize, so that the bit assembly may be retrieved back through the

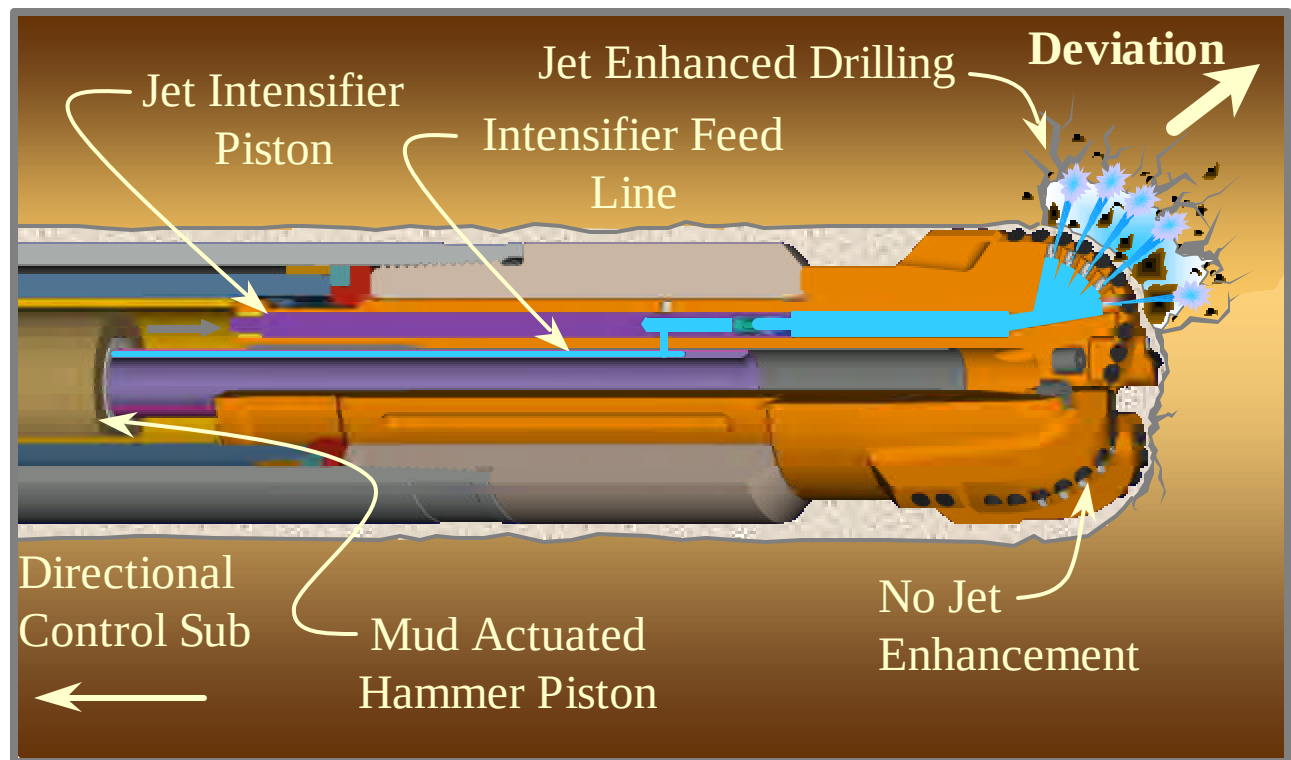


Figure 3. Jet Enhanced Steering Concept

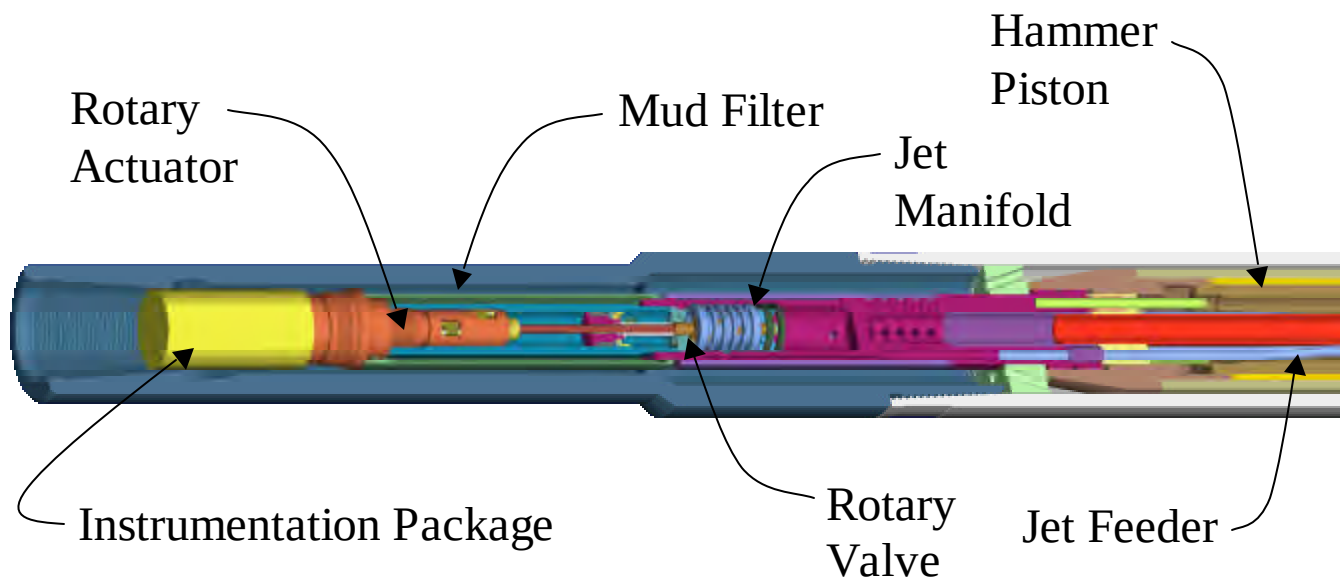


Figure 4. Steering Control Components

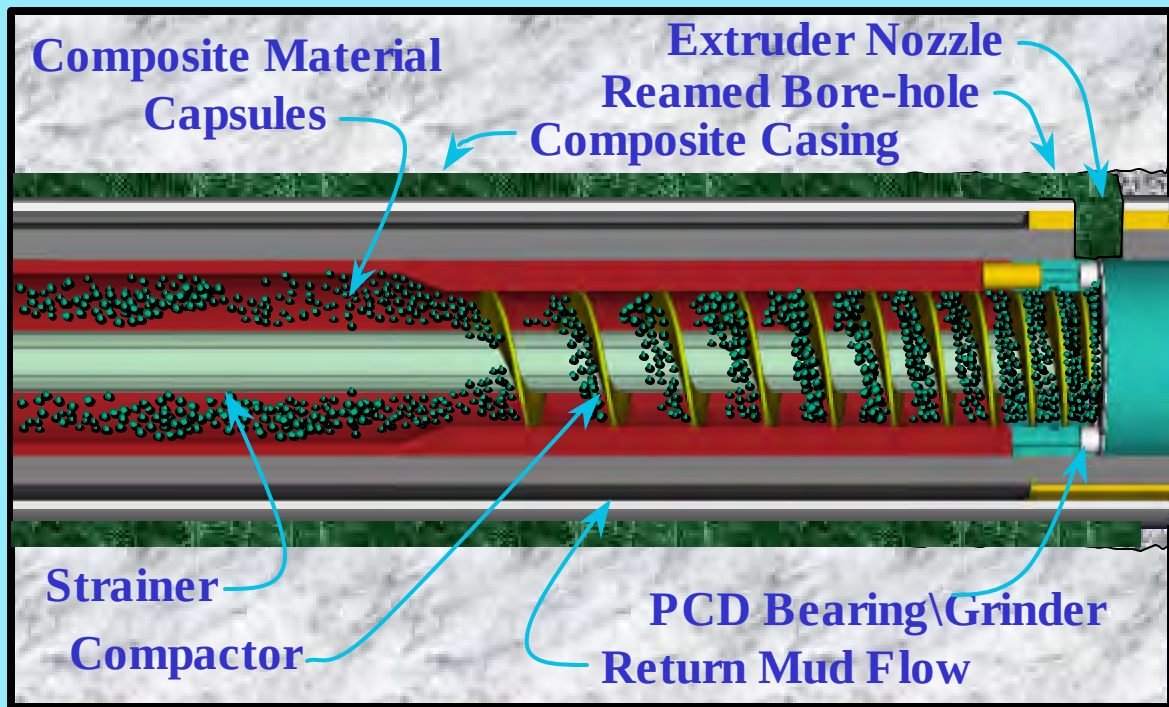


Figure 5. Lining While Drilling Concept

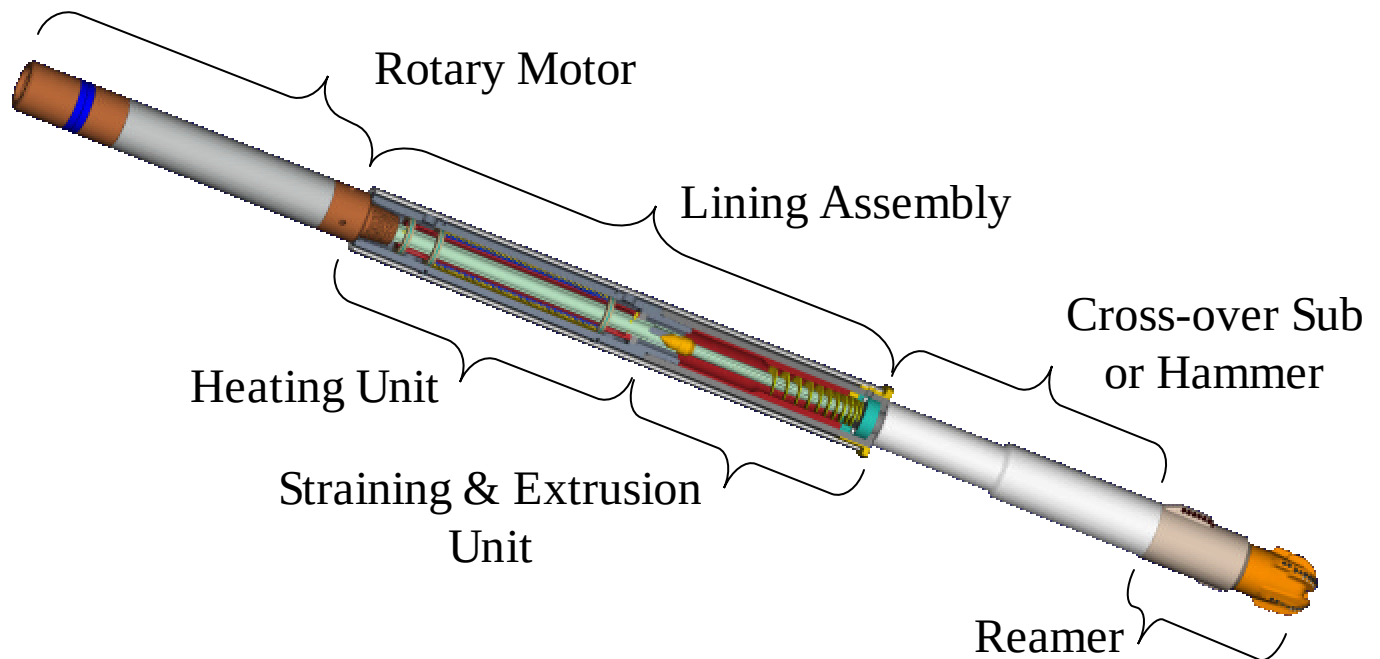


Figure 6. Lining While Drilling System

completed liner. A small high-speed down-hole motor is also required to drive the grinding mechanism and friction heater in the form. Care is taken to route annular return flow around the liner form so that the liner is not damaged during cure.

High Data Rate Communication System

Completing the basic drilling system is a high data rate communication system. Such a system allows for more detailed communications between operator and drilling assembly, and enables greater understanding of the conditions at the drill bit, while minimizing the burden of downhole data processing and storage. Current systems used by the industry communicate between top and bottom of the wellbore by sending low frequency signals the entire distance. While other transmission media have been investigated, e.g., the drill pipe and the earth, the drilling fluid is the present medium of choice. These systems are presently limited to a few bits per second data rate – tens of bits per second, if data compression techniques are used.

The current system under investigation takes a different approach: that of sending very high frequency signals a very short distance, and repeating the signal several times to traverse the length of the drill string. This system fundamentally offers a very high data rate. Several systems are possible using this approach and these are described below.

Accomplishments and Future Activities

Mud Hammer Drilling Head/Formation Sensors

Performance of Drilling Head. The operation and effectiveness of the Novatek mud hammer has been published previously.⁷ In short, this tool has been shown to operate on a variety of drilling fluids, from water to a 10 lb bentonite/barite mud, and has improved drilling rate in Carthage marble by between 15% and 300%, depending on drilling conditions. Recent development efforts have focused on improving hammer performance, particularly in medium to deep well conditions, where benefits were shown to be the least. Optimization of valve timing and reduction of cycle inefficiencies in recent months has resulted in an estimated doubling the output impact energy of the tool. Optimization efforts are expected to continue into early fall, where further quantitative drilling tests will be carried out to verify improvements.

Hammer rebound sensor. A simple prototype transducer has been built using a magnet and coil arrangement that fits inside the hammer piston. This transducer, shown in Figure 7, was designed to not only measure hammer motion near impact, but to measure hammer motion at all points in the hammer cycle. This increased measurement range is important in using the transducer as a diagnostic tool that monitors hammer performance continually.

Testing of the rebound sensor has shown that such a device can determine differences in operation of the hammer. An example of such operational information is shown in Figure 8. As can be seen in Figure 8a, the hammer cycle is very symmetrical on the leading and falling edges, suggesting equivalent biasing of upstroke and drive stroke portions of hammer movement. Note also that the hammer does not appear to impact at the bottom of its stroke. These indications are quantitative evidence of short-stroking of the hammer. Figure 8b shows improved timing of the upstroke and drive stroke motions, showing a clear bias



Figure 7: Prototype Rebound Transducer (MEG)

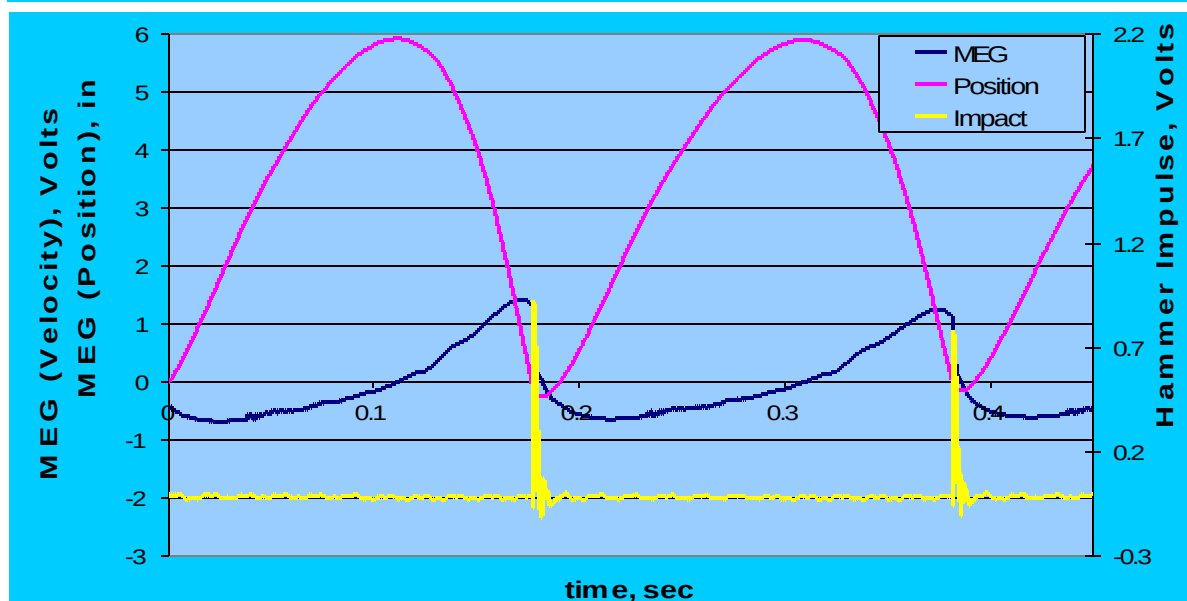
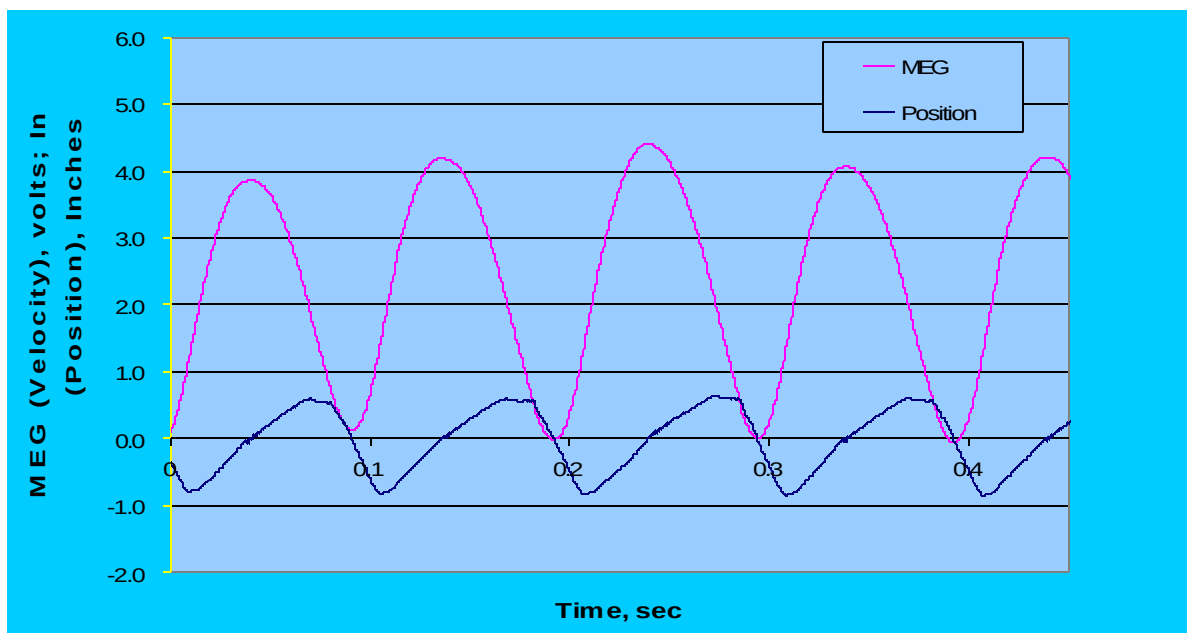


Figure 8: Sample Output from Rebound Transducer

towards the drive stroke. Impact is also evident, as the velocity signal drops quickly to zero; in fact, a quantification of impact velocity is possible. Hence, it may be concluded that the present configuration may provide important system diagnostics.

Further work is needed to verify that the hammer rebound sensor is useful in discriminating rock properties. Fundamental studies have concluded that the percussive rebound may be related to rock type through a drillability constant K , and the governing theoretical model for this relationship has been proposed. However, values of K for different lithologies have yet to be determined. Furthermore, it is suggested that correlation with a second measured quantity, such as sonic velocity, may enhance the usefulness of the rebound measurement. Future work will therefore focus on two areas: gathering and correlation of empirical data relating sensor output to useful rock characteristics and ensuring that the transducer used within the hammer is sensitive enough to measure rebound of the hammer with the required accuracy. Gathering of data will need to be done with full-scale prototype hammers to minimize geometrical concerns. Of particular interest is the influence of drill bit geometry or complexity on the constants obtained.

Hammer seismic qualities. Instrumentation of the hammer drill has yielded a better understanding of the useful vibrational frequencies generated by the hammer. The hammer induces vibrations into the rock formation by means of mechanical impact waves transmitted to the rock through the drill bit, and also by means of hydraulic pressure fluctuations in the borehole. Both of these sources have been instrumented and analyzed, and samples of these signals are shown in Figure 9. As can be seen from the frequency domain plots of Figures 9b and 9c, a wide spectrum is offered by the various physical outputs of the hammer. Particular vibrational energy can be seen in the 10-20 kHz range, which range has been found useful for acoustic wireline and logging while drilling tools. Such tools have been used to estimate porosity, compute elastic moduli of the rock, and create synthetic seismograms for comparison with surface seismic data.⁸

Fundamentally, these higher frequency components must be measured in close proximity to the bit; hence downhole sensors will be key for collecting information from this signal. Lower frequency components may be used to measure grosser formation qualities that are measurable at the surface. Usefulness of the generated frequencies will best be determined by instrumenting field tests of the hammer. Future work in this area will focus first on signals that are measurable using existing surface geophone arrays, and later on the signals to be measured down-hole.

High Pressure Jet-enhanced Steering System

Preliminary studies have shown an average of 34% increase in depth of penetration of a *percussive* cutter in Missouri Red Granite when a 6000-psi fluid jet is added.⁹ This implies that significant bit deviation can be accomplished if that increase is focused towards a particular region of the borehole. What remains to be determined is the actual response of a multi-cutter bit to these differential drilling forces. To this end, focus has been placed on development of a full-scale prototype bit with an in-bit mud jet intensifier* and a deviation control system. Developments regarding the full-scale bit have been reported previously.¹⁰

* Bit development under contract DE-FG03-96ER82242, scheduled for completion fall 1999.

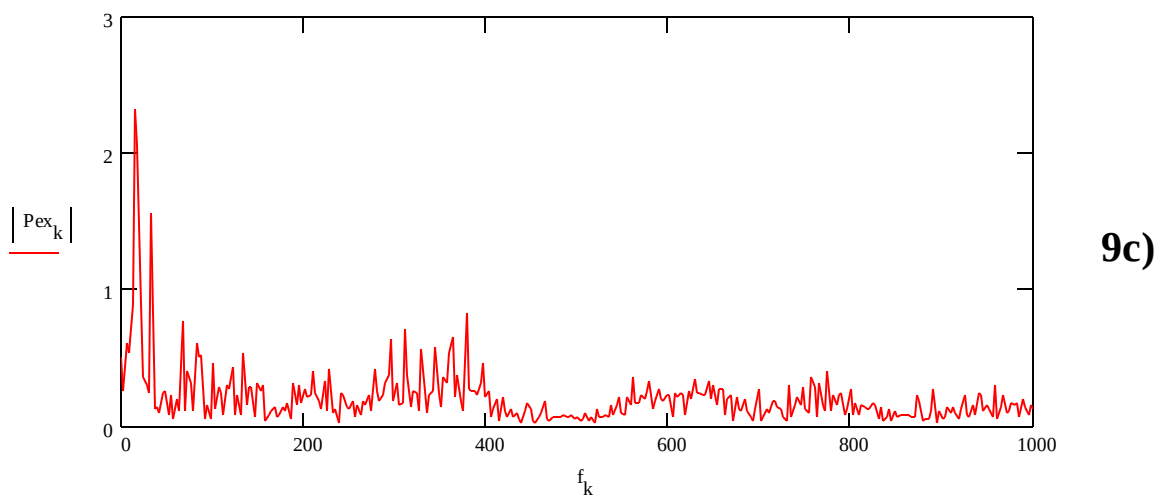
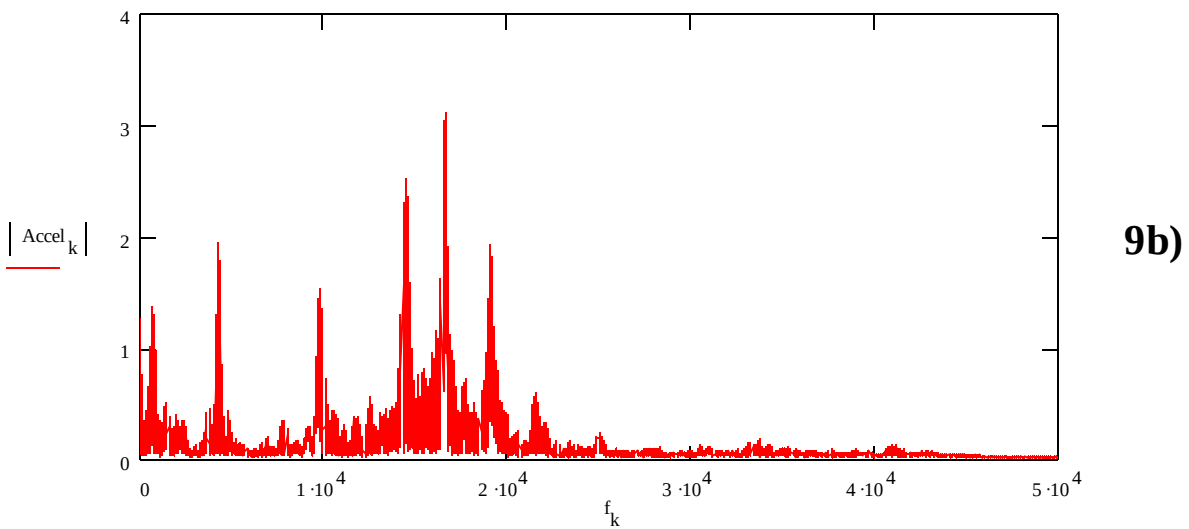
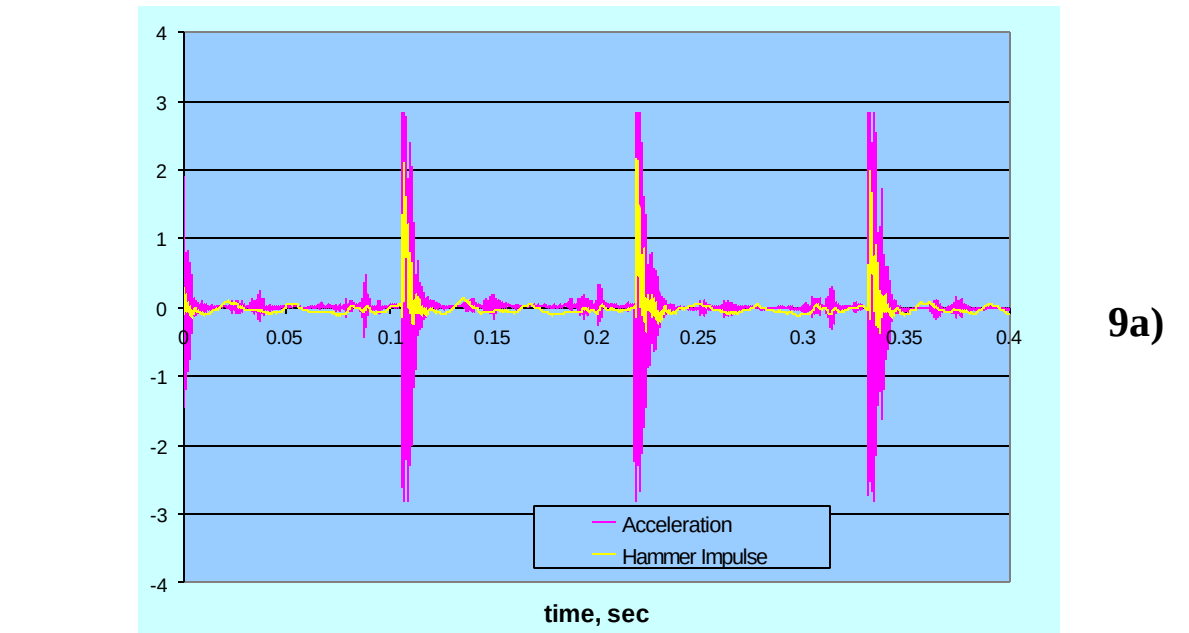


**Figure 9: Vibrations at Hammer Bit: a) Time domain
b) and c) Frequency Domain**

Efforts to direct a bit by biasing *conventional* bit hydraulics (as opposed to the high-pressure jets of the present system) have been exerted previously.¹¹ The resultant system, which seems to have most likely application in softer formations where conventional bit hydraulics are more effective, suffered from valve wear problems. To minimize this concern in the present system, the control system design includes a fully pressure-balanced valve, thereby minimizing torque and thrust on the valve. The valve has also been designed to minimize the potential for erosion and clogging from drilling mud, resulting in high life and reliability, as well as minimal power requirements. Figure 10 shows the prototype valve assembly to be used in fundamental and full-scale operational verification tests. Bench testing of these mechanisms is expected to begin in fall of 1999. Once proper operation is demonstrated, further work will focus on implementing downhole-compatible rotary actuators and, finally, position measurement sensors.

Borehole Lining while Drilling System

Initial studies of the borehole lining system have focused on the type of material to be employed in the lining and the means of applying it to a submerged borehole. Several different materials have been investigated for the lining material, including metals and metal reinforced polymers, aggregate reinforced materials, and fiber reinforced polymers. Difficulties encountered with several of these materials included problems with underwater adhesion, density (which manifests itself in slumping or sloughing of the material), and poor strength. This investigation found fiber-reinforced polymer systems to provide the best combination of cost, strength, and workability.

A key issue when dealing with polymer systems is curing method. Cure time is particularly an issue with a down-hole system, since too slow a cure time impedes drilling progress and too fast a cure time compromises material strength and poses potential problems with clogging mixing and application mechanisms. Furthermore, variable down-hole temperatures may adversely influence cure time. To obtain better control over cure time, polymerization processes other than simple chemical initiation have been considered, including UV, gamma ray, and thermal initiators. While the former two were unacceptable for depth of cure and cost considerations respectively, the study has concluded that a thermal initiation process, where polymerization is initiated at a temperature above down-hole ambient, may give the most repeatable casing quality. Accordingly, a system utilizing a fluid-driven friction heater has been designed (see Figure 6). Further work with the materials system will include verification of cure time and strength and final composition. Some work has previously been done to characterize the improvement to borehole stability offered by another polymer lining system¹²; further such work will be necessary in order to determine suitable applications for the current system.

Studies into the means of application of the material to the borehole have included simple mockup tests, where a bead of material was applied to the bore of a concrete pipe in a coiled rope fashion, then smoothed and trowelled in place. A sample result from these mockup tests is shown in Figure 11. From these tests, it was determined that good adhesion could be achieved with a submerged surface, but that mechanical working of the materials into the rock was important to exclude wellbore fluids and promote this adhesion. Due to difficulties working the material into the rock in an unconfined space, as required by the coiled rope approach, it has been determined that this method is less desirable. An



Figure 10: Prototype Directional Valve



Figure 11: Mock-up Test Of Lining While Drilling



Figure 12: Fixture Parts for Testing Liner Material Feed System

alternative method, where the lining material is extruded into a trapped volume, has been chosen instead. This method is depicted in Figure 5.

Current focus has been placed on verifying the fundamental concept of feeding the lining material to the bottom of the borehole through the drilling mud. A test fixture has been built, shown in Figure 12, and the key functions of straining, compacting, and grinding the lining material will be demonstrated in a flow loop.

High Data Rate Communication System

One approach to achieving a high data rate communication system is to use high frequency acoustic signals to traverse one or more sections of drill pipe, and to repeat the transmission at each pipe joint. Fundamental studies have shown that a 4.6 MHz acoustic pulse from a point source travels up to 72 ft in a small diameter steel rod. However, poor propagation occurs in 4-1/2 drill pipe. This difference is assumed to be due to geometrical concerns. More work is needed to quantify gains offered by better matching of source and conductor geometries. Lower frequency acoustic signals (100 kHz range) have been used in some commercial systems to communicate through piping.¹³ These transducers are physically larger than the MHz range transducers and therefore pose some design constraints for use in down-hole systems. However, such transducers may provide for less attenuation of the signal in the given geometry. Further work is needed here as well to determine the range of propagation of these lower frequency signals in drill pipe.

An alternative approach to transmission of acoustic signals over one or more lengths of pipe is to transmit the signal a very short distance (e.g., across the drill joint) and use electrical wire embedded in the drill pipe to carry the signal the rest of the way. At present, acoustic and other means of coupling a signal across drill joints are being investigated. This type of system could offer very good data rates at reasonable power levels. For example, with an acoustic coupling system operating at 4.36 MHz, with a 5 V peak-to-peak drive, 10% duty cycle, and requiring 5 pulses per bit for adequate resolution, a time averaged data rate of 87 kbaud may be obtained. If the drive circuit were 50% efficient it would require 16 milliwatts. An AA alkaline cell driving such a circuit would last about 200 hours.

Application / Benefits

It is believed that significant benefits will derive from the overall system outlined, as well as from the individual subsystems. On a broad scale, the anticipated benefits of the overall system include *faster* drilling and *more effective* drilling. The first of these benefits arises directly from the faster jet-assisted hammer drilling action of the drilling head, and from the ability of the complete system to optimize drilling performance by sensing conditions at and ahead of the drill bit and adapting to those conditions while drilling. Further drilling rate improvements would be seen from reduced borehole problems due to the continuous lining process. Such borehole problems would include most notably caving shale and lost circulation problems.

The second mentioned benefit would be expected from the improved sensing, steering, and communication systems under consideration. The effect of a high data rate communications system alone on the industry's ability to drill more effectively will be great. Not only will it

make it possible for more information to be sent between surface and hole bottom, but it will also enable implementation and development of more sophisticated sensing means. A near-term benefit of such a system would also be a minimization of the dependence on downhole electronics for data processing and storage.

Further benefits are expected because of the potential of the present system to provide a smoother and less tortuous well bore. Since the system does not rely on conventional technology for directional control, a consistent diameter and more continuously directed borehole may be expected. Continuous lining of the borehole further improves the borehole quality. Hence, borehole cleaning is improved, and friction, which limits the reach of wells, is reduced.

Key advantages of the current system over other systems that offer a subset of these functions include:

- 1) Faster steerable drilling, particularly in hard formations. Other rotary steerable systems are available which offer steering without requiring downhole motors and their attendant “sliding mode” problems.¹⁴ These offer significant improvements over current art directional systems but utilize current art drilling methods, which are slower than the proposed methods.
- 2) Lack of special conduits to feed downhole devices. All devices in the system are intended to be fed through existing conduits and means, namely, the drillstring and the drilling fluid. Hence, the high-pressure fluid utilized by the jet-enhanced bit is created downhole, using existing flow. Similarly, the casing material is continuously fed to the bottom of the hole in the drilling mud, eliminating the need for special tubing to provide the material from the surface. This design goal ensures that rig floor operations are kept as simple as possible and that auxiliary surface equipment needs are minimized.
- 3) New sensing capabilities. Current drill bit seismic systems can help locate the drill bit, generate look-ahead images, predict pore pressure at and ahead of the bit, and predict depth to drilling hazards. However, current systems are limited to use with rollercone bits, therefore limiting bit selection and drilling speed in some formations. The proposed system extends the art of drill bit seismic to faster drilling rotary percussion bits. In addition, the hammer rebound sensor mentioned above offers completely new system and formation diagnostic capabilities.
- 4) Extremely high data rate. The proposed system has the potential to provide at least one or two orders of magnitude higher data rate than currently conceived EMMWD, acoustic, or improved mud pulse systems.

Along with the specific fossil fuels application discussed herein, the described technology is expected to have similar application in geothermal drilling, and in a large variety of construction-oriented drilling applications: placing utility conduits under roads, buildings, remote or protected areas, etc.

Acknowledgement

Novatek expresses its appreciation to the U.S. Department of Energy's Federal Energy Technology Center, which is sponsoring this research. Special thanks are given to Mr. Roy Long, the FETC Contracting Officer's Representative, for his support and enthusiasm for this project. This research is carried out under Contract #DE-FC26-97FT34365 (performance period 9/30/1997-9/30/2002). Contract with Novatek, Inc., 2185 South Larsen Parkway, Provo, UT 84606.

References

- ¹ National Research Council, *Drilling and Excavation Technologies for the Future*, National Academy Press, Washington, D.C. (1994), pp. 2-6.
- ² David S. Pixton, David R. Hall, *Integrated Drilling System: Phase I Status Report*, Novatek Report (30 June 1998).
- ³ *Integrated Drilling System*, Novatek Report (14 September 1998).
- ⁴ Harpst, W.E., and E.E. Davis. "Rotary Percussion Drilling." *Oil and Gas Journal* (Mar. 17, 1949), pp. 182-187.
- ⁵ Wanamaker, J.A. "Rotary Percussion Drilling in West Texas." *World Oil* (Sept. 1951), pp. 182-187.
- ⁶ Richard Meehan, Les Nutt, Nader Dutta, James Menzies, "Case Histories Show Real-time Information Reduces Uncertainty," *Oil and Gas Journal* (May 18, 1998), pp 55-59.
- ⁷ David S. Pixton, and David R. Hall, *A Rotary Percussive Drilling Engine*, in *Proceedings of the 1998 ASME Energy Sources Technology Conference*, Houston (February 2-4, 1998).
- ⁸ John W. Minear, Dale R. Heyse, Paul M. Boonen, "Initial Results from an Acoustic Logging-While-Drilling Tool," SPE Paper 36543 (1996).
- ⁹ Santi, P., S. Bell, D.A. Summers, D. Pixton "Waterjet assisted polycrystalline diamond indentation drilling of rock," in *Proceedings, 14th International Conference of Jetting Technology*, Brugge, Belgium (Sept 21-23, 1998).
- ¹⁰ David S. Pixton, David R. Hall, and David Summers, "Development and Testing of a Jet Assisted Polycrystalline Diamond Drilling Bit, *Federal Geothermal Research Program Update, Fiscal Year 1998* (May 1999), pp. 4-9 – 4-20.
- ¹¹ Lawrence J. Leising, *Methods and Apparatus for Controlled Directional Drilling of Boreholes*, U.S. Patent 4,637,479 (Jan. 20, 1987).
- ¹² T. Moen and F. Remvik, "Continuous Cast Lining – A Solution to Downhole Problems," in *Rock Mechanics Contributions and Challenges*, Hustrulid & Johnson (eds), Balkema, Rotterdam (1990), pp 679-686.
- ¹³ Ekhardt Kinderling, "Machines Communicate Wirelessly" (in German), *Elektronik* (December 1992).
- ¹⁴ Tommy M. Warren, "Trends Toward Rotary Steerable Directional Systems," *World Oil* (May 1997), pp. 43-47.

FETC Conference Services
U.S. Department of Energy
Federal Energy Technical Center
P.O. Box 880
3610 Collins Ferry Road
Morgantown, West Virginia 26507-0880

for

1999 Oil and Gas Conference -- Technology Options for Producers' Survival

Dallas, Texas

June 28, 29, & 30, 1999

NEW HIGH STRENGTH AND FASTER DRILLING TSP DIAMOND CUTTERS

Technology International, Inc.

Bob Radtke

Melody Smith

Richard Riedel

Dr. Bill Daniels

FETC Technical Monitor

William Gwilliam

Abstract

The objective of this project is to develop advanced drilling systems which employ thermally stable diamond (TSP) drill bits. New TSP diamond cutters are to be capable of reducing overall system costs by increasing rates of penetration and bit life in abrasive and hard rock applications. Improved performance of unique TSP diamond cutters has been demonstrated in the laboratory, and field tests are planned. The CSS (continuous shelf sharpening) cutter design produced under this DOE FETC project has demonstrated the potential to double both rate of penetration and bit life. Abrasive and hard rock drilling costs could be reduced by about 15%, and the overall drilling project cost could be reduced by 7.5%. Thus, there is the opportunity to allow economic development of remaining natural gas and oil resources in the U.S., and strengthen the development of the U.S. Drilling Industry.

Summary

The Chinese in the year 1700 BC learned how to drill several hundred feet through very abrasive and strong limestone to reach fresh water supplies. They were able to use natural

diamond hand-held cutters developed with new metallurgy. It was the ability to pound a single diamond stone into a suitable brass alloy which composed a tool holder. With this invention, they had a method to hold the diamond and manually impact the rock without shattering the brittle diamond. Many workers would excavate man-sized holes several hundred feet down to gain access to fresh water.

Hundreds of years ago, hard rock was drilled in Pennsylvania using cable drilling tools. Several hundred feet of rock was fractured by the repetitive dropping of a cable suspended steel bar on the formation. Hard rock drilling can be defined as rock which is drilled at penetration rates of less than 3 feet per hour. More definitively, hard rock is formations with a compressive strength in excess of 25,000 psi. Soon after the introduction of cable tool drilling, softer rock was drilled in Texas by rotary drilling using a fishtail drag bit. Custom heat treatments of steel fishtail blades at the rig site created a cutting element suitable for a variety of rock types. Tungsten carbide steel hardfacing replaced steel cutting edges for longer life. After the onset of the Hughes tricone bit 50 years ago, up to 98 percent of the drilling was performed with a more robust roller cone bit. The introduction of the natural diamond bit 40 years ago resulted in up to 2 percent of the petroleum footage being drilled with relatively small diamond cutters.

Twenty-five years ago, the much larger polycrystalline compact diamond (PCD) was introduced as a machine tool. General Electric Superabrasives (G.E.) introduced machine tool grade cutters to the engineering departments of the petroleum drill bit companies and said, here, "make it work." However, no one knew how to satisfactorily attach the PCD to the drill bit. It took years for G.E. to learn how to make the attachment to tungsten carbide, and improve the impact properties for what is now called the polycrystalline diamond compact (PDC) drill bit. Again, it was new material science that created a truly revolutionary new drilling product.

Twenty years ago, the thermally stable (TSP) diamond was introduced by G.E. Just as with the PCD diamond, the petroleum drilling industry did not have a suitable TSP diamond attachment technique in combination with suitably impact resistance. When the TSP diamond became available, the potential advantages were recognized. The TSP has a 1200 degrees C thermal stability compared to 350 degrees C for the PDC. At temperatures greater than 350 degrees C, the PDC wear rate increases exponentially with temperature. PDC diamond is no longer thermally stable at 700 degrees C. Therefore, one limiting factor for the use of PDC drill bits is petroleum drilling applications with higher cutter temperatures associated with drilling abrasive and hard formations.

Today, 65 percent of the petroleum footage is drilled with a roller cone bit and 35 percent with a PDC diamond cutter. About 20 percent of the drilling is using carbide insert roller cone bits. There is over 5,000 kilometers of hard rock drilled a year worldwide. Eighty percent of abrasive and hard rock drilling is done in the continental U.S.A. and 11 percent in Canada. The current hard rock drill bit market forecast is a 7 percent annual growth rate to 2002.

TSP diamond drill bits can potentially increase the rate of penetration in abrasive and hard rock by a factor of two. Resulting efficiency savings could produce a potential drilling product value to the petroleum industry in the range of \$200 million to \$500 million a year. So, there is a high incentive to develop hard rock drilling technologies in terms of the economy and in terms of what we need to do to reduce petroleum drilling costs.

Currently, Technology International, Inc., with financial support by the U.S. Department of Energy and GRI, has created a unique TSP diamond cutter. The cutter features proprietary MicroWave[™] TSP-to-tungsten carbide attachment and wear resistant continuous self-sharpening CCS cutter designs. Current project work is focused on the development of a more fracture resistant TSP diamond cutter.

Technology International, Inc. would like to acknowledge work performed by key project personnel at the NASA Jet Propulsion Laboratory, Colorado School of Mines, DOE Sandia National Laboratories, GE Superabrasives, Baker-Hughes Christensen, and Drilling Products International.

New Lightweight Fluids for Underbalanced Drilling

by

William J. McDonald, Ph.D. (mcdonald@maureng.com)

John H. Cohen (jhc@maureng.com)

C. Mel Hightower (hightower@maureng.com)

MAURER ENGINEERING INC.

2916 West TC Jester

Houston, Texas 77018-7098

713-683-8227

INTRODUCTION

The production of oil and gas in the USA is declining rapidly because the economics of many onshore fields are marginal due to high drilling costs and low well productivity. New reserves are located primarily in deep water where drilling costs are high and new technology must be developed.

As a result, there is a need for techniques to significantly reduce drilling costs to allow economical development of deep water reservoirs, and to increase well productivity by reducing formation damage during drilling and completion operations. These problems are addressed on this DOE project.

This project was sponsored by the U.S. Department of Energy's Federal Energy Technology Center under contract DE-AC21-94MC31197 with Maurer Engineering Inc., 2916 West TC Jester, Houston, Texas; fax: 713-683-4618; email: mei@maureng.com.

OBJECTIVE

The objective of this project is to develop a new lightweight drilling fluid additive that will significantly reduce underbalanced and deep water drilling costs, and reduce formation damage during drilling and completion operations.

APPROACH

The approach being taken is to utilize hollow glass microspheres to reduce the density of drilling fluids and overcome major problems encountered with current air/mist/foam drilling systems. The Russians initially used these microspheres in the 1970s to overcome severe lost circulation problems in the Ural mountains. This project consists of transferring the Russian technology to the USA and utilizing microspheres currently manufactured by 3M to reduce underbalanced drilling costs.

PROJECT DESCRIPTION

Hollow glass spheres manufactured by 3M are added in volumetric concentrations up to 50 percent to reduce the density of drilling and completion fluids. For example, adding 50 percent microspheres to an 8.5 ppg mud, reduces its density to 5.84 ppg without the addition of air (**Figure 1**).

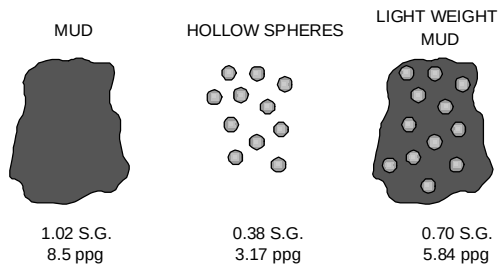


Fig. 1. Lightweight HGS Mud

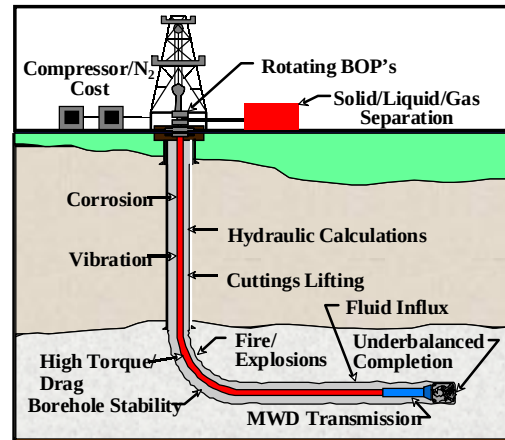


Fig. 2. Hole Problems with Aerated Drilling Fluids

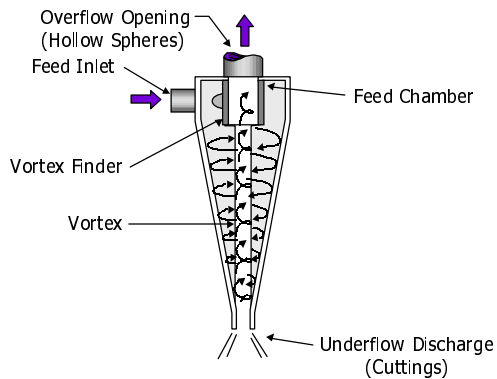


Fig. 3. Oilfield Hydrocyclone

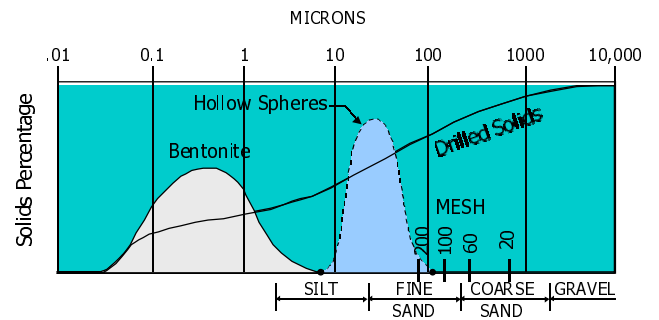


Fig. 4. Solids in Unweighted Water-Base Drilling Mud

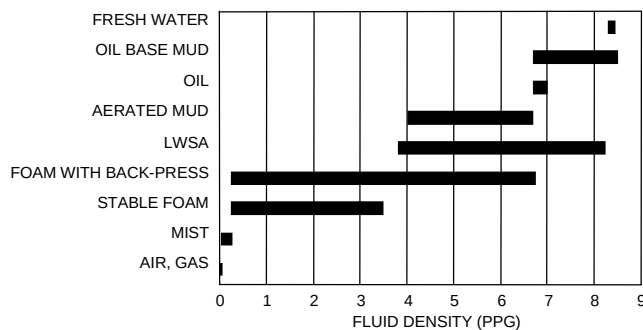


Fig. 5. Drilling Fluid Density

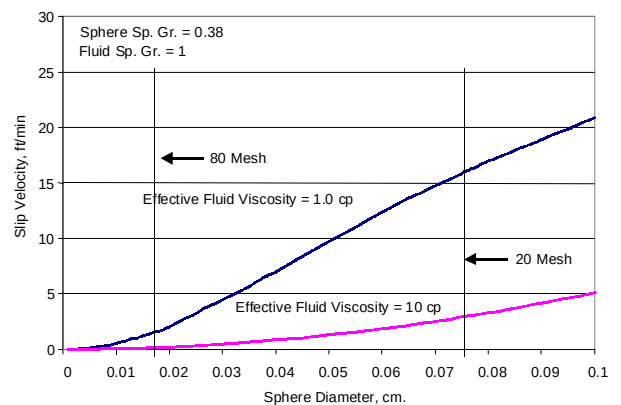


Fig. 6. Sphere Slip Velocity vs. Fluid Density

The microspheres are chemically inert and incompressible and therefore overcome many of the problems encountered with aerated fluids including corrosion, high compressor costs, drill string vibrations, excessive torque and drag, downhole fires, poor hole cleaning, and the inability to use mud pulse MWDs as shown in **Figure 2**.

When a well is completed, the microspheres can be removed with conventional mud solids handling equipment and used in subsequent wells, thus significantly reducing sphere costs. The simplest way to remove the spheres is to dilute water-base muds with water and allow the spheres to float to the top of the mud tank where they can be easily recovered.

Laboratory and field tests showed that the microspheres can also be effectively removed from the mud using drilling rig hydrocyclones. In this case, the heavier rock cuttings came out the underflow at the bottom of the cone and the microspheres came out the overflow (**Figure 3**).

The diameters of commercial hollow glass S38 spheres range from 8 to 125 microns, allowing these spheres to pass through 20- to 80-mesh screens (762 to 177 microns) typically used on oilfield shale shakers (**Figure 4**).

The microspheres have small diameters because they are typically used as fillers in paints, glues and other materials to reduce manufacturing costs. Because of their small diameter, oilfield shale shakers cannot be used to remove the spheres from the mud when they return to the surface. Larger diameter spheres (e.g., 1 mm diameter and larger) are needed in applications where the spheres must be removed from the mud during each circulation (e.g., riserless drilling) so they can be screened out of the mud by conventional oilfield shale shakers.

The fluid density decreases as sphere concentration increases. **Figure 5** shows that microspheres can reduce the density of water from 8.34 ppg to 5.84 ppg, which will allow the microspheres to be used in most underbalanced wells.

If mud circulation is stopped, the spheres will float upward in the drilling fluid, with the upward velocity increasing with increased sphere diameter and fluid density, and with decreased fluid viscosity. **Figure 6** shows that the slip velocity of spheres will be on the order of 5 to 20 ft/min, which is small compared to the fluid annular velocities. This indicates that sphere flotation will not be a major problem.

One of the major advantages of underbalanced drilling is increased drilling rates. Drilling rates in sandstone, limestone and shale are typically reduced by 70 to 80 percent as the differential fluid pressure between the wellbore and formation fluids ($p_b - p_f$) increased from 0 to 1,000 psi (**Figure 7**). The microspheres can therefore significantly increase drilling rates by reducing wellbore pressures.

The S38 spheres will collapse if subjected to pressures in excess of 4,000 psi. The highest fluid pressure occurs at the bottom of the well due to the weight of the column of fluid in the well. When the fluid is circulating, the highest pressure exists inside the drill string, just above the drilling motor and bit.

The spheres will typically be used in lightweight muds weighing less than 7 ppg, in which case the S38 spheres can be used to depths of 8,000 to 11,000 feet (**Figure 8**). S60 spheres, which have collapse pressures of 10,000 psi, can be used to depths of 12,000 to 30,000 ft, but their higher specific gravity (0.60) will require higher sphere concentrations.

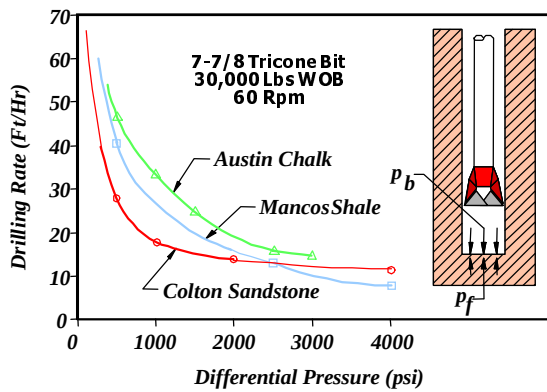


Fig. 7. Differential Pressure and Drilling Rate

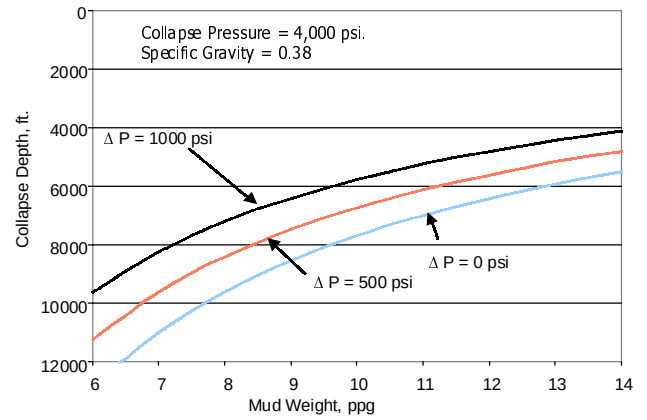


Fig. 8. S38 Hollow Sphere Collapse Depth

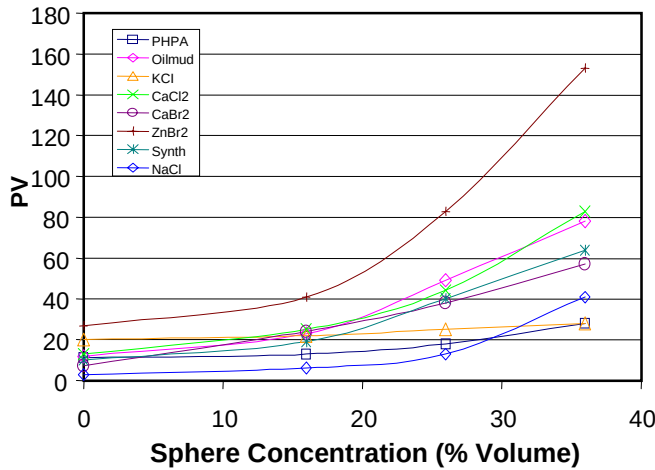


Fig. 9. PV vs. % Sphere Concentration

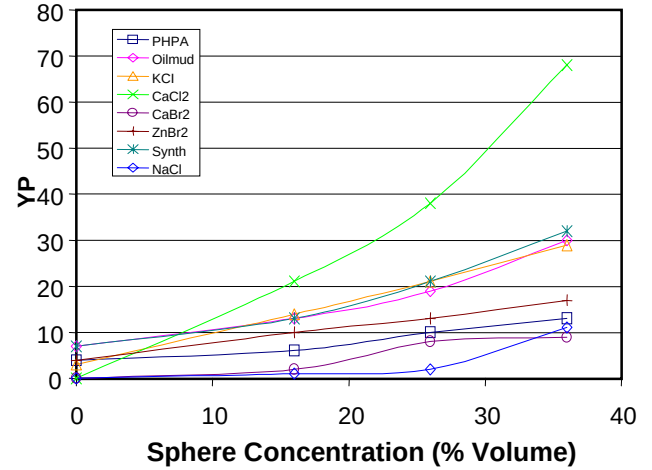


Fig. 10. YP vs. % Sphere Concentration

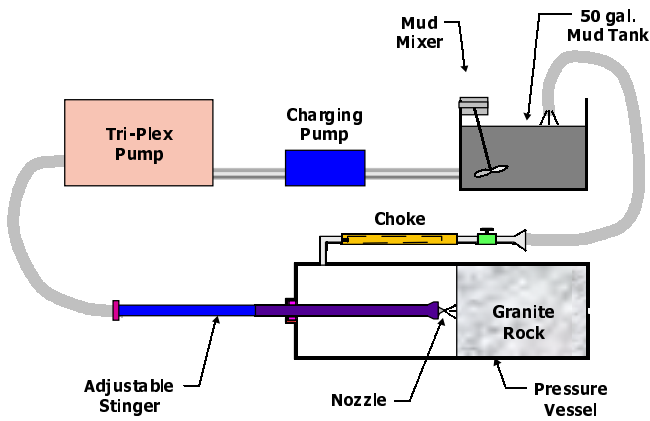


Fig. 11. HGS Breakage Test Flow Loop

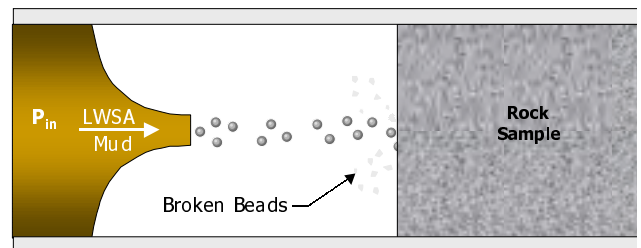


Fig. 12. HGS Spheres Impacting Rock

PROJECT ACCOMPLISHMENTS

Laboratory tests showed that fluid rheology with the microspheres is within an acceptable range at sphere concentrations of 30 to 50 percent provided the drill solid concentrations are kept low (**Figures 9 and 10**).

Laboratory tests showed that the microspheres were not damaged by conventional mud pumps or rig mud handling equipment. Laboratory tests were conducted at the Drilling Research Center (DRC) in Houston, Texas, to determine if the microspheres will break when they exit bit nozzles and impact the rock (**Figures 11 and 12**). These tests showed that with proper nozzle selection and standoff, sphere breakage can be minimized once malformed spheres (typically 5 to 10 percent) break during their initial pass through the nozzles.

Drilling tests were conducted in the DRC high-pressure drilling stand to determine the effect of the microspheres on drilling rate (**Figure 13**). This drilling stand simulates deep oil-well drilling by applying higher fluid pressure in the wellbore than in the formation ($P_w > P_f$) to create a differential pressure across the hole bottom (**Figure 14**).

Drilling rates with and without the microspheres were identical with no differential pressure applied. With differential pressures of 750 and 1,500 psi, the microspheres reduced drilling rates slightly in three of the four tests, possibly due to reduced jet impact and increased chip hold-down effects (**Figures 15 and 16**).

A series of formation damage tests was conducted with the microspheres in Berea sandstone cores using the formation damage test apparatus shown in **Figure 17**. Results showed that the microspheres can significantly reduce formation damage. These tests showed that the microspheres (8 to 100 microns) form a tight filter cake and cause less formation damage than water-base muds without spheres (**Figure 18**).

With water-base fluids, the microspheres produced no permanent damage whereas without the microspheres, the fluid produced 45% permanent damage around the wellbore (**Figure 19**). With oil-base and synthetic fluids, the microspheres had no effect on formation damage.

This shows that the microspheres have potential to significantly increase oil and gas flow from wells drilled and completed with water-base fluids. This phenomenon will be studied in more detail in the next phase of this project.

Two field tests were successfully conducted with microsphere muds in Mobil wells in Kern County, California, in September 1996. **Figure 20** shows the mud pit system used in these 1,700-ft Mobil wells. Two to four hundred barrels of mud containing 10 to 20 percent microspheres were used on these wells. These field tests showed that the microspheres can be easily mixed into the mud and that the rheological properties of the lightweight mud were similar to conventional muds. The success of these tests demonstrates the high potential of using microspheres for underbalanced drilling.

Another important application of these microspheres is for offshore riserless drilling.

A major problem with deep-water offshore drilling is that the pore and fracture pressure gradients are typically close together, making drilling very difficult (**Figure 21**). If the annulus pressure exceeds frac pressure, lost circulation will occur; if it falls below pore pressure, fluid influxes from the formation ("kicks") will occur.

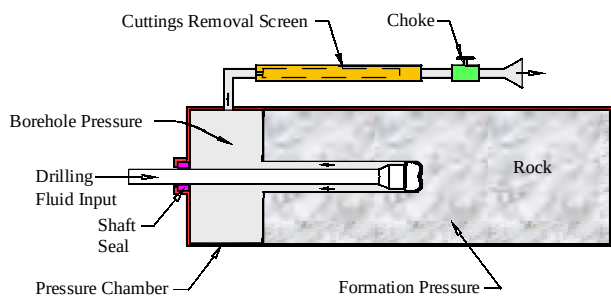


Fig. 13. DRC High Pressure Drilling Stand

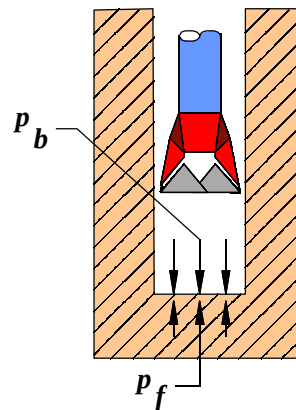


Fig. 14. Simulated Bottom Hole Conditions

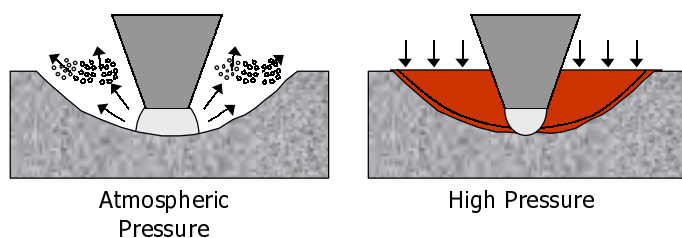


Fig. 15. Chip Hold-Down Effects

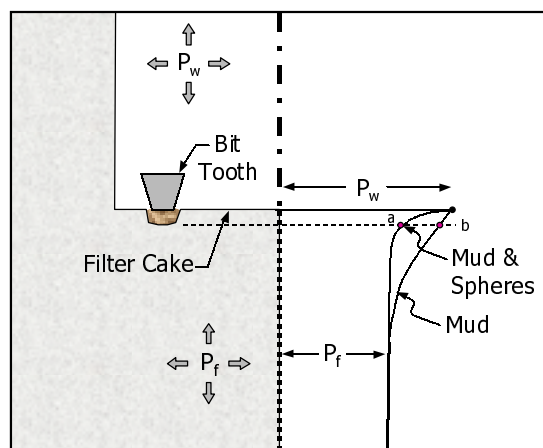


Fig. 16. Chip Hold-Down Pressure Gradients

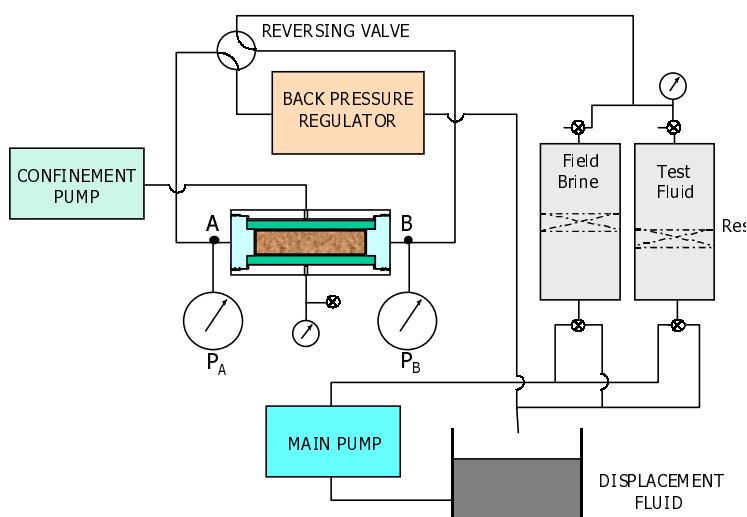


Fig. 17. Formation Damage Test Apparatus

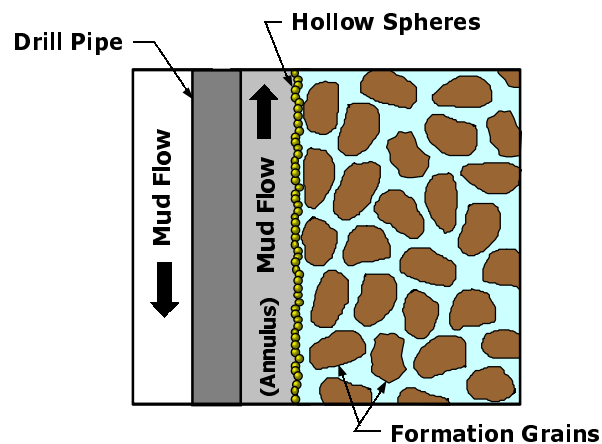


Fig. 18. Hollow Sphere Filter Cake

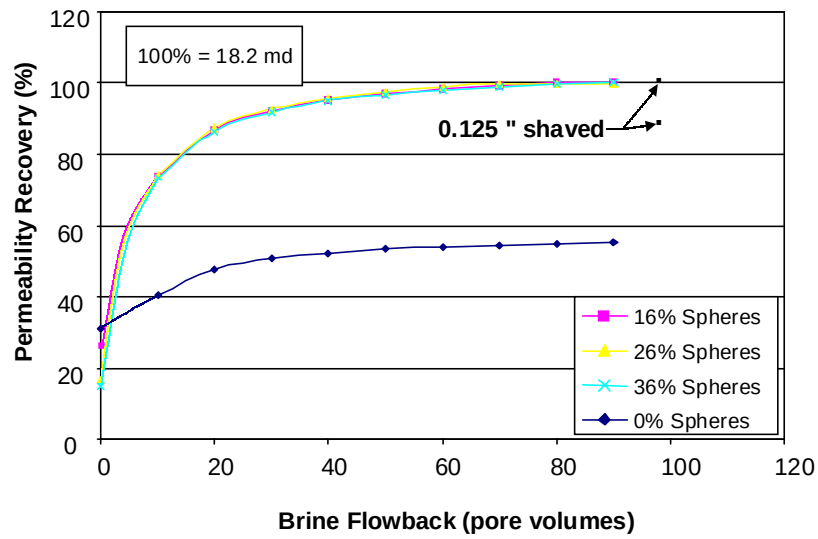


Fig. 19. Permeability Recovery with PHPA Water-Base Drilling Fluid



Fig. 20. Golden State Drilling Rig Mud System

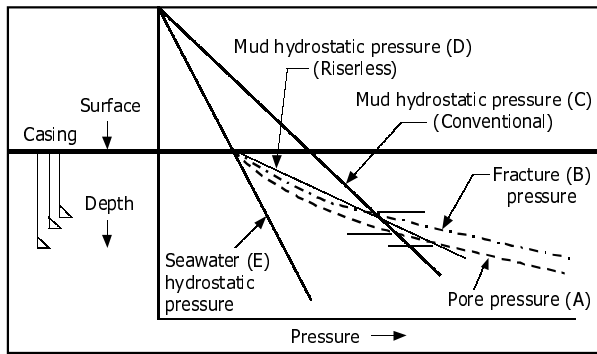


Fig. 21. Hydrostatic Gradients for Conventional and Riserless Drilling (Snyder, 1998)

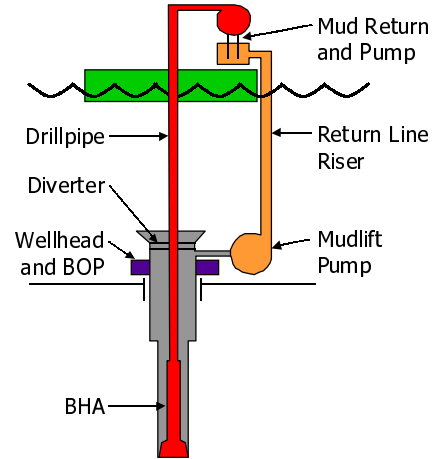


Fig. 22. Riserless Drilling System

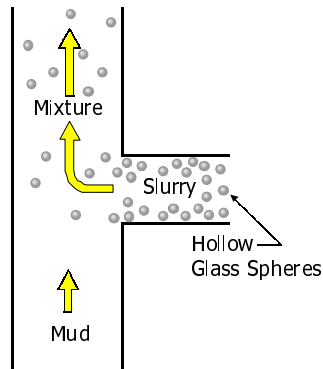


Fig. 23. Hollow Glass Sphere Technique

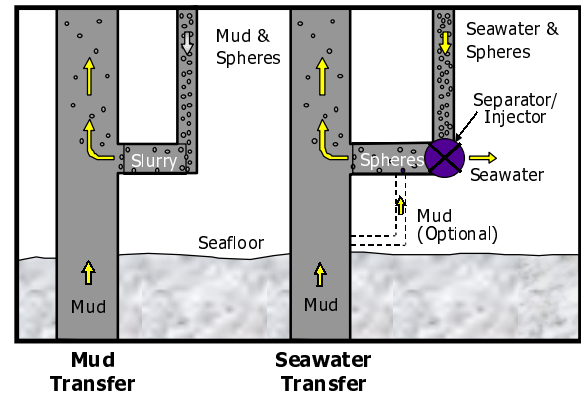


Fig. 24. Hollow Glass Sphere Injection Systems

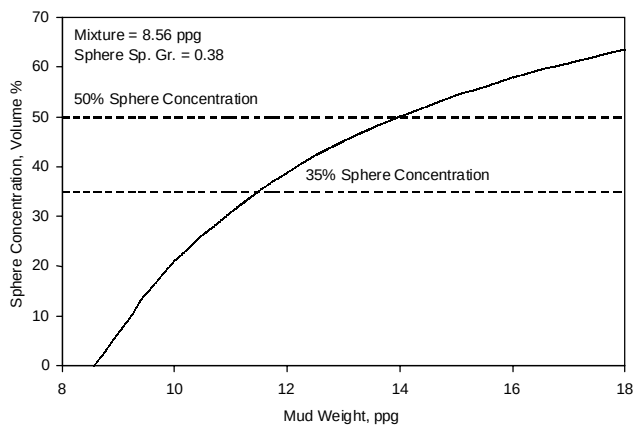


Fig. 25. Mud Weight vs. Sphere Concentration

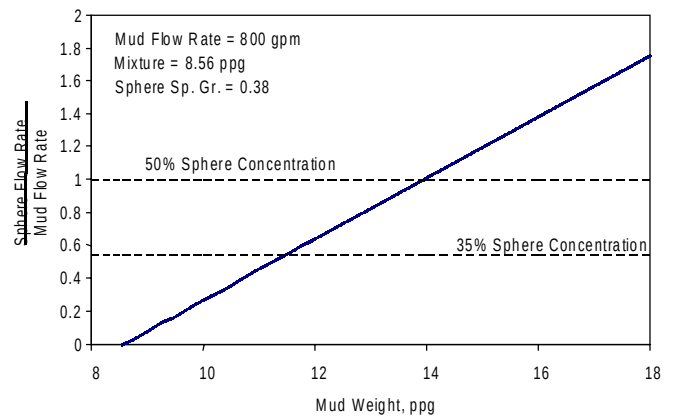


Fig. 26. Mud Weight vs. Sphere Concentration

With “riserless” drilling, a pump is used on the seafloor to reduce the wellbore annular pressure at the seafloor (**Figure 22**). With conventional riser drilling, the mud hydrostatic pressure gradient (C) is a straight line extending from the surface of the water whereas with a seafloor pump, the hydrostatic curve (D) is a straight line that extends from the sea floor. The flatter gradient with the seafloor pump allows a much greater vertical distance to be drilled between the pore and fracture gradient curves, significantly reducing the number of casing strings required. In an example well, riserless drilling reduced the number of casing strings from 8 to 5, saving \$3 million since each casing string costs \$1 million (Gault, 1996).

With this technique, the microspheres would be injected into the riser at the sea floor to reduce the density of the mud in the riser (**Figure 23**), eliminating the need for expensive and troublesome seafloor pumps.

Major advantages of the microspheres in this application are 1) they are chemically inert and incompressible, 2) they can be pumped with conventional mud pumps, and 3) they can be easily removed and recirculated at the surface.

The microspheres can be mixed with the mud at the surface and pumped to the sea floor as a slurry and injected directly into the riser, or pumped to the sea floor with seawater where they will be separated from the seawater using a sea-floor separator (screen) and injected into the riser using an injector (e.g., Moineau pump). Mud can be diverted from the annulus to the injector, if needed, to facilitate injecting the spheres into the riser (**Figure 24**).

The goal of riserless drilling is to reduce the effective mud weight to that of seawater (8.56 ppg). **Figure 25** shows that a sphere concentration of 18% reduces the density of a 10-ppg mud to that of seawater whereas a 52% sphere concentration is required with a 14-ppg mud. This shows that it is feasible to use microspheres as an alternative to riserless drilling for a wide range of mud weights.

Figure 26 shows that a sphere flow rate equal to the mud flow rate (i.e., 50% sphere concentration) will reduce the density of a 13.8 ppg mud to that of seawater (8.56 ppg), showing that the seawater transfer technique could be effective with most muds. The microspheres can be easily removed from the drilling mud and recirculated at the surface using conventional oilfield mud solids handling equipment.

ACKNOWLEDGMENTS

The authors appreciate the contributions of the FETC Contracting Officer’s Representative, Roy Long. The period of performance for this project was September 30, 1994, through September 30, 1998. Chevron Research Technology Center and MUDTECH Laboratories, Inc., both participated as subcontractors.

REFERENCES

- Bourgoyne Jr., Adam T., Millheim, Keith K., Chenevert, Martin E., and Young Jr., F.S., 1986: *Applied Drilling Engineering*, 1st Printing, Society of Petroleum Engineers, Richardson, Texas.
- Duda, John R., and Medley Jr., George H., 1996: “Strong Growth Projected for Underbalanced Drilling,” *Oil & Gas Journal Special*, September 23.

- Gault, Allen, 1996: "Riserless Drilling: Circumventing the Size/Cost Cycle in Deepwater," *Offshore*, May.
- Goldsmith, Riley, 1998: "MudLift Drilling System Operations," OTC 8751, presented at the 1998 Offshore Technology Conference, held in Houston, Texas, May 4-7.
- Medley, Jr., George H., Haston, Jerry E., Montgomery, Richard L., Martindale, I. Dylan, and Duda, John R., 1997: "Field Application of LightWeight Hollow Glass Sphere Drilling Fluid," SPE 38637, presented at the 1997 SPE 72nd Annual Technical Conference and Exhibition, held in San Antonio, Texas, October 5-8.
- Medley, Jr., George H., Maurer, William C., Liu, Gefei, and Garkasi, Ali Y., 1995: "Development and Testing of Underbalanced Drilling Products," report DOE/MC/31197-5129, Topical Report for U.S. Department of Energy, Morgantown, West Virginia, September.
- Moffitt, Stan, 1991: Personal Communication, Reed Tool Company Data, Houston, Texas, September 5.
- Peterman, Charles P., 1998: "Riserless and Mudlift Drilling - The Next Steps in Deepwater Drilling," OTC 8752, presented at the 1998 Offshore Technology Conference, Houston, Texas, May 4-7.
- Snyder, Robert E., 1998: "Riserless Drilling Project Develops Critical New Technology," *World Oil*, January.