IMPROVED AND ENHANCED OIL RECOVERY IN ILLINOIS
THROUGH RESERVOIR CHARACTERIZATION

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By
Donald F. Oltz, Principal Investigator

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U.S. Department of Energy
Assistant Secretary for Fossil Energy

R. Michael Ray, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
Illinois State Geological Survey
615 East Peabody Drive
Champaign, IL 61820-6964

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AUTHORS

Bartelso Field, Clinton County
S.T. Whitaker and A.K. Finley
Boyd Field, Jefferson County
H.E. Leetaru
Southwest Dale Consolidated Field, Franklin, Hamilton, and Saline Counties
D.S. Beaty and J.P. Fagan, Jr.
Energy Field, Williamson County
B.G. Huff
King Field, Jefferson County
H.E. Leetaru
Lawrence Field, Lawrence County
J.P. Grube
Mattoon Field, Coles County
K.R. McGee
Oakdale and Markham City North Fields, Jefferson and Wayne Counties
J.E. Crockett
Parkersburg Area, Richland and Edwards County
Beverly Seyler
Richview Field, Washington County
J.P. Grube and W.T. Frankie
Stewardson Field, Shelby County
R.J. Rice, R.D. Cole, and S.T. Whitaker
Storms Consolidated Field, White County
H.E. Leetaru
Tamaroa and Tamaroa South Fields, Perry County
J.P. Grube
Xenia East Field, Clay County
Jianzhong Xu
Zeigler Field, Franklin County
Beverly Seyler
Diagenesis in the Aux Vases and Cypress Sandstones
Beverly Seyler
Depositional Analysis of the Cypress Formation Outcrop in Southern Illinois
R.D. Cole and W.J. Nelson
I-57 Cypress Study
D.J. Haggerty and R.D. Cole
Techniques for Application of Old Electric Logs
H.E. Leetaru
Pressure, Volume, and Temperature (PVT) Research
S.K. Sim
Dale Consolidated Field Model
E.O. Udegbumam, D.S. Beaty, and J.P. Fagan, Jr.
Energy Field Model
E.O. Udegbumam and B.G. Huff
Zeigler Model
S.K. Sim and Beverly Seyler
Lawrence Model
E.O. Udegbumam and J.P. Grube
Seismic Definition of the Reservoir and Sonic (Acoustic) Log Acquisition
H.E. Leetaru
Clay Minerals
D.M. Moore and R.E. Hughes
Mud Cleanout Acid (MCA)
D.J. Haggerty and Beverly Seyler
Formation Water Chemistry and Modeling of Fluid-Rock Interaction
Ilham Demir

The ISGS has published many of these studies. Contact the ISGS Information Office, 615 East Peabody Drive, Champaign, Illinois 61820-6964. Phone 217-333-4747.

ABSTRACT

Two prolific Mississippian petroleum reservoirs, the Aux Vases Sandstone (Valmeyeran) and the Cypress Sandstone (Chesterian), were targeted by the Illinois State Geological Survey for research that focused on reservoir characterization of 15 oil fields in the Illinois Basin. Methods included geologic mapping, computer-enhanced reservoir simulation, seismic reflection acquisition and interpretation, engineering studies, fluid-fluid and fluid-rock modeling, clay mineral analyses, outcrop analog evaluation, oil and brine analyses, and pressure, volume, and temperature correlations. Technology transfer, interaction with industry, and cooperative studies with operators were major goals. Information was reported through publications, workshops, and other presentations and integrated into a central database. Remote access to the ISGS well database was facilitated by installation of a workstation in Mt. Vernon, Illinois.

Field studies integrated geological and engineering characterization of reservoirs that may serve as analogs for other fields. Elements of characterization include stratigraphy, structure, petrography, mineralogy, diagenesis, and analysis of reserves and depositional environments. The studies show that these reservoirs are heterogeneous and both horizontally and vertically compartmentalized. There may be undrained compartments and banked oil. Improved recovery techniques presented in these studies show that recovery efficiencies can be increased by geologically targeted drilling (as opposed to geometrically mandated well spacing), modified or new completion practices, and enhanced recovery and reservoir management strategies.

EXECUTIVE SUMMARY

Grants from the Illinois Department of Energy and Natural Resources and the U.S. Department of Energy partially supported an integrated geological, geophysical, and engineering research project that defined the architecture, rock, mineral, and fluid properties of two hydrocarbon-bearing formations in 15 Illinois oil fields. This research has established the kinds of data and techniques needed for optimal reservoir characterization assessment and management in Illinois. Results of the project are presently being applied to improve reservoir management and recovery of hydrocarbons from Illinois Basin reservoirs. Improvement in oil recovery will continue, provided technology transfer is adequate, research is continued, and research results are effectively applied.

Small, independent oil companies are the foundation of operations for the present and future in the Illinois and similar mature basins. For most of these small companies, the time and expertise needed to keep abreast of science and technology are unaffordable and capital is unavailable to fund a research staff. With their limited resources, the small independents are forced to focus on routine operational activities, yet they require practical information to expand their production capability.

Participation by industry representatives on two advisory committees helped the project address significant issues. This successful, integrated, multidisciplinary approach has made the project a model in design, application, and results. Two workshops were sponsored, each drawing more than 145 industrial attendees. More than 140 oral presentations, published abstracts and papers, in combination with convention booth presentations and in-office discussions, contributed to the success of what has been called the "Illinois model."

Advanced geologic and engineering investigations of 15 Illinois oil fields in this project have demonstrated several key points:

- several million barrels of oil remain in the Illinois reservoirs studied;
- data availability and integration are of major importance for understanding reservoirs;
- reservoir management is important for efficient, economic reservoir redevelopment and maximized recovery from new reservoirs;
- heterogeneity within reservoirs leads to compartmentalization and bypassed oil, and can be an impediment to oil recovery. Changes in the state regulatory authority's position on well spacing will improve oil recovery. In regulations under consideration for adoption (on the basis of input from this project), the current spacing requirements may be waived when detailed geologic and engineering studies show recovery will be optimized by different well spacing.

These studies have influenced numerous changes in field operations. Acting on the conclusions from detailed field studies, some operator(s)

- initiated water injection in new reservoirs for early pressure maintenance;
- introduced peripheral injection in an isolated portion of the reservoir and initiated a waterflood into an underdeveloped, compartmentalized reservoir;
- used reserve estimates and maps developed during this project (and after the ISGS workshops) to drill new wells—one completed at 100 barrels of oil per day;
- used a concept developed in this project to explore for similar reservoirs;
- chose to use a customized (as opposed to "standard") MCA (mud cleanout acid) completion treatment with successful results;
- used data and results from an Aux Vases field study to improve management of the reservoir. Within the past 12 months, oil production in this field has increased to two to three times the previous rate;
- are considering shooting high-resolution seismic to delineate reservoirs similar to the published model;

Other important concepts transmitted to the industry include the following:

- additional reservoir characterization analogs are necessary;
- technology transfer methodologies must be evaluated;

- reservoirs within a particular formation vary with respect to the type and amount of heterogeneity both vertically and horizontally as the geology of that formation changes across the state;
- cross-lease migration of oil may indicate the importance of unitization to maximize recovery;
- data can be shared through a neutral third party;
- core saved and archived at the ISGS facilitates applied research.

Several "firsts" were demonstrated by this project:

- the first public exposure to three-dimensional (3-D) geologic and reservoir modeling in Illinois;
- the first pressure-volume-temperature (PVT) correlations for Illinois oils made available to the public;
- establishment of remote access to the ISGS database.

Almost 6 billion barrels of known oil remain in the ground in Illinois, a portion of which is mobile and therefore recoverable by conventional methods. This is a significant resource for the state and particularly the economy of southern Illinois. Support of reservoir characterization research will generate more relevant data and examples, support efforts to increase the number of field analogs and allow continued transfer of results. Additional research and use of the techniques developed in this project will allow producers to maximize economic production and are likely to decrease the ultimate cost per barrel of increased reserves.

Areas for further advanced research include improved reservoir management techniques, predictive models to demonstrate the effects of adopting alternative management procedures, more advanced reservoir characterization, and identification of different effective approaches to technology transfer between operators and research institutes such as the ISGS.

INTRODUCTION

The objectives of this research project were to investigate selected Illinois reservoirs, document the existence of unrecovered oil, determine the most appropriate technologies to recover the oil, develop and demonstrate advanced geological, geophysical, and engineering appraisals of Illinois reservoirs, and transfer applied research results to Illinois' oil industry.

Oil and gas exploration and development are "high-tech" industries. Technology played a key role in the historical development of the Illinois Basin. Major production peaks shown in figure 1 can be correlated to technological advancements. Production began in 1899; however, the first large increment of production began in 1904 as a result of geological exploration along the La Salle anticline in southeast Illinois. Production dropped off through the mid-1930s. Use of the new exploration technology called "seismic" in 1937 resulted in the largest discovery/production peak in the basin's history in 1940. Subsequently, production dropped off. Use of two new production technologies, waterflooding and hydraulic fracturing, reversed the production decline in the mid-1950s. Except for the price peak that caused a small increase in the early 1980s, production continues to decline. Appendix IV presents Illinois' annual production.

The major oil companies have left control of production in the Illinois Basin to the small companies. These independent oil producers and operators do not maintain research staffs or have easy access to advanced or other technology.

The U.S. Department of Energy (DOE) has appraised the hydrocarbon resources in all the oil-producing states. Illinois ranks eighth in the volume of resources remaining in known oil fields. In this state, there are 1.45 billion barrels of "mobile" oil, most of it at depths of less than 3,000 feet (fig. 2). A portion of this oil can be recovered using known technology. The 4.4 billion barrels of "immobile" oil in Illinois can only be recovered using more expensive technologies and more advanced reservoir characterization.

In 1990, U.S. consumers spent more than \$300 billion on natural gas and oil; 5.5% of the gross domestic product. For more than 20 years, costs for imported oil have contributed to

Figure 1 Annual oil production in Illinois.

Figure 2 The oil resource in Illinois.

more than 60% of the trade deficit. The United States paid \$742 billion (in 1987 dollars) to import crude oil and petroleum products between 1980 and 1992. Trends point to increasing reliance on foreign oil, up to 41% of consumption in 1992 and as much as 49% in 1993. The Energy Information Agency (EIA) projects imports will supply more than 50% of consumption by 1995 or 1996.

Estimates are that in 1994, U.S. oil production will decrease by 160,000 barrels of oil per day, and that our production capacity will average 6.7 million barrels per day. Last year, production declined by 330,000 barrels per day. Since 1985, U.S. production has declined by 2.27 million barrels of oil per day.

Most of the United States, including Illinois, is classified as a mature producing province. Illinois production peaked in 1940 at 147.6 million barrels; in 1993, production was less than 20 million barrels. For Illinois, 20 million barrels at \$17.00 per barrel (the OPEC target price is \$21 per barrel) represents \$340,000,000 to its economy. An economic multiplier of 3 indicates that the oil industry contributes at least \$1 billion to the state's economic well-being. In southern Illinois, this inflow of dollars and jobs is critical. Jobs in the oil industry are typically higher paying than are average industrial jobs. An Illinois oil industry organization estimates that almost one-half of the jobs related to the oil industry have been lost in the past 8 years.

REGIONAL GEOLOGIC SETTING

The Illinois Basin was a shallow embayment deepening to the south during deposition of late Valmeyeran and Chesterian (Mississippian) rocks (Cluff and Lineback 1981, Leighton et al. 1991). Depositional slope in the basin during Valmeyeran and Chesterian time averaged less than ½ degree. This typical intracratonic basin contains more than 50 producing intervals. This project addressed two of the most productive units.

Cypress Sandstone

The Cypress Sandstone has produced more than 1 billion barrels of oil in the Illinois Basin. This sandstone is the most widespread, thickest, and productive Chesterian (late Mississippian) sandstone in the basin. The Cypress can be 200 feet thick locally. Traps solely due to structure occur, but combination traps such as those at Tamaroa and Bartelso Fields are more common. The distribution of all known Cypress production is shown in figure 3. Cypress oil fields and plays are listed in Appendix III.

Earlier work described the Cypress sediments as fluvial-deltaic in origin (Potter 1962 1963, Potter and Pryor 1961, Swann 1963, 1964, Seyler 1982a, 1982b); whereas studies in this program have shown that deposition varies from deltaic to coastal to offshore marine. The systems are complex and interpretation is hindered by rapid lateral and vertical changes in depositional environments, a characteristic of low-slope, stable, intracratonic basins.

The geometry and trends of sand bodies are critical to exploration and development strategies. Interpretations from outcrop work conducted during this project place the deposition of the Cypress sandstones in a deltaic to shallow marine setting. Data combined from studies of subsurface and outcrop geology established that a basinwide, low sea level event occurred during Cypress deposition. The low sea level event separates the sand-rich lower and middle sandstones from shale-rich upper Cypress rocks. The thick lower and middle Cypress sandstones are interpreted to have been deposited in both tide-dominated deltaic and shallow offshore open-marine regimes. Overlying lower middle Cypress units is a thin zone representing a low sea level event, as interpreted from rooted zones, coal, carbonaceous shale, and variegated mudstones. These sediments, in turn, are overlain by a thin, shale-rich upper Cypress zone containing transgressive sandstones typically encapsulated by shale. Both the Lower Cretaceous Viking Formation and the Lower Cretaceous Dakota Group "J" Sandstone of the Western Interior Basin have been suggested as Cypress analogs.

Figure 3 Distribution of Cypress Sandstone hydrocarbon production in the Illinois Basin (Leighton et al. 1991).

Reservoir studies in this project showed a sequence of stacked or imbricated sandstones in the upper Cypress (Grube 1992, Seyler in press, Whitaker 1992, Whitaker and Finley 1992, Xu 1994). McGee (in prep.) interpreted the Cypress in Mattoon Field to be stacked linear bars. Hydrocarbon-bearing facies within these stacked or imbricated bar sandstones commonly occur as compartmentalized sandstones. Separate bar compartments within a stacked sequence can be relatively thin. Because they are commonly unrecognized, they are rarely produced as different reservoirs. Multiple primary and secondary production opportunities are created by recognition and exploitation of a compartmentalized geologic model.

Two significant outcrop studies were conducted during the project. First, the major Cypress outcrops were studied along the outcrop belt in southern Illinois. The second study analyzed the sedimentology, porosity, and permeability of four parallel roadcuts in the Cypress along Interstate 57 in southern Illinois.

Aux Vases Sandstone

The Aux Vases Sandstone (Valmeyeran) occurs as a thick belt of sandstone deposited in deltaic and shoreline environments and as shallow marine sediments, including tidally reworked bars. The Aux Vases sandstones are offshore marine tidal sand bar complexes deposited in a mixed siliciclastic-carbonate setting. The mixed siliciclastic-carbonate depositional environment resulted in a large amount of lateral and vertical compartmentalization. The generally nonproductive carbonates can inhibit fluid flow. Along the eastern margin of the basin, the formation becomes more carbonate-rich. In the most oil-productive portion of the Aux Vases, the sandstone reservoirs are generally 20 to 45 feet thick, fine to very fine grained sandstone that can be interbedded with shale, siltstone or carbonate. Nearly 1 billion barrels of oil have been produced from the Aux Vases Sandstone. The distribution of Aux Vases production from the Illinois Basin is shown in figure 4. Aux Vases fields and plays are listed in Appendix II.

Outcrop analyses indicate that the Aux Vases reservoir sandstones are shallow marine quartz arenites. They can be locally calcareous (especially near the base) and may locally contain clay drapes. Primary sedimentary features suggest that tidal and long-shore currents coupled with possible wave activity commonly deposited ripple-laminated sands as offshore bars, interbar and tidal channel fillings, and sandy and mixed intertidal flats (Cole 1990).

Some calcareous facies are calcite-cemented sandstones dominated by transported allochems, some whole and undistorted, and some distorted. The allochems are mostly echinoderm plates, other bioclastic fragments, and ooids (Cole 1990).

RESERVOIR CHARACTERIZATION: RESULTS

This project was initiated as a result of interviews and conversations with industry representatives during the mid-1980s. The Illinois State Geological Survey, receptive to the needs of the independent oil industry, submitted a proposal and negotiated with the U.S. Department of Energy to establish a final statement of the research plan. The plan to address some of the needs identified by industry comprised 12 tasks. In this report, some tasks have been grouped for discussion. The discussion of task 2, subsurface reservoir studies, also incorporates task 4, petrographic studies. Task 11, reservoir classification based on plays, is included within the individual reservoir reports. Task 7, seismic acquisition, is discussed along with task 9, seismic mapping, and task 8, sonic log acquisition. Tasks 3, 5, 6, 10 and 12 are each reviewed separately. Task 1, treated briefly here, was the subject of a topical report submitted for review in 1990.

TASK 1: PROGRAM PLAN

This initial task required planning and prioritization of two reservoirs for the program, design of a project database, and preparation of a project management plan.

Figure 4 Distribution of Aux Vases hydrocarbon production in the Illinois Basin (Leighton et al. 1991).

Management

To reach the project goals, a multidisciplinary integrated team was assembled and the work divided into 12 tasks. Figure 5 illustrates the management approach. The members of the two advisory committees, the Petroleum Advisory Committee (PAC) and the Technical Advisory Committee (TAC), are listed in the acknowledgments. The PAC, as advisors to the project management, monitored project performance and made recommendations regarding the project. The TAC advised the principal investigator and the technical staff regarding sources of data, relevancy of studies, and significance of conclusions. A short definition of each research task follows.

Subsurface work in task 2 required advanced geological and engineering expertise. Interpretations of spatial variations in reservoir rocks were based on wireline logs, core analyses, petrography, and engineering data such as production information or pressure tests, when available. Cross sections were constructed to illustrate syndepositional facies variations within a single genetic unit (or formation). The overall logic path used for integrated reservoir analysis is shown in figure 6.

Selection of fields was followed by geological, geochemical, and engineering characterization (tasks 2, 3, 4, 6, and 10) that allowed flow-unit definition for engineering models. Both geologic and engineering input occurred during weekly coordination meetings where field and other studies were deliberated. This interchange promoted integration of geologic and engineering knowledge.

Recommendations for exploitation based on field studies have been initially limited to geologically targeted infill drilling, improvements to existing waterfloods, or suggestions for new and prioritized stimulation techniques. The field studies could later serve as a basis for enhanced oil recovery (EOR) modeling and further recommendations. EOR or field-scale testing were not conducted in the current project, but would be a highly desirable step in the subsequent application of research results.

Engineering analyses of results from porosity, permeability, and core-flow research were used to aid in reservoir assessment and characterization, determination of changes in permeability caused by the interaction of minerals and fluids, and evaluation of various completion and stimulation techniques. The PVT experiments provided data for reserve estimates and reservoir simulation modeling. Task 3 results, when combined with the results from tasks 2, 4, 6, and 10, provided necessary data for recommending changes in current exploitation practices.

Task 4, petrographic studies, used polarized light, cathodoluminescence, electron microscopy, and x-ray diffraction (XRD) techniques to describe the reservoir rock and determine the geometries and pore throat distributions in reservoir rocks. The geometry and size of pore throats are dominant factors in control of fluid flow.

Database creation and management, parts of task 5, were essential for a project of this magnitude. Well information and laboratory results have been made available to the public in publications, at EGS offices, and from digital databases. Task 5 also makes these data available to the USDOE Bartlesville Project Office (BPO).

Some of the fields in this project were selected to study the application of the flow-unit concept in reservoir models. The integrated geological and engineering studies of task 6 used flow units in 3-D modeling of selected reservoirs. Task 6 also included engineering appraisals of reserves and economics. When new procedures were analyzed (infill drilling, waterflood projects), an economic analysis might be developed (for example, Udegbum et al. 1993).

Tasks 7, 8, and 9 represent individual portions of the geophysics module. Task 7 demonstrated the use of high resolution 2-D reflection seismic as a development geology tool. This example seismic study was disseminated to operators in the state. Task 8 allowed acquisition of sonic (acoustic) logs, which are normally not run in Illinois. These logs will be used to improve seismic interpretations in Illinois reservoirs by allowing modeling and correlation with seismic reflection data. Task 9 used the data from task 7 for advanced

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Figure 5 Project management plan.

Figure 6 ISGS integrated reservoir analysis logic diagram.

interpretation and mapping. This demonstration project showed the application of reflection character analysis to the understanding of reservoir architecture.

Knowledge of the bulk and clay mineralogy of reservoir rocks is useful for four purposes: (1) reaction-path modeling of chemical reactions adjacent to the bore hole; (2) applying clay corrections to log interpretations; (3) predicting the effect of fluids introduced into the reservoir; and (4) an aid in determining the degree of maturation and diagenetic history. Formation damage can be ameliorated through adaptation of completion practices to known variations in clay minerals. Brine and oil chemistries were assayed to complement the analytical and modeling effort for task 10 and make the data available to the industry.

Task 11, incorporated as part of the field studies, was an element of the pool study outline in Appendix I. Task 12 was cross-linked to all the other tasks. Technology transfer involved oral presentations, maps, research publications, databases, and public workshops. Interchange with operators was maintained throughout the project.

The performance schedule for each of the 12 tasks appears in figure 7.

Reservoir Prioritization and Selection

The work plan for task 1 specifies selection of two representative reservoirs for assessment of oil recovery potential. Two clastic Mississippian formations, the Valmeyeran Aux Vases Sandstone and the Chesterian Cypress Sandstone, were selected for the project. Both are major productive strata in the basin. Figure 8 illustrates the locations of the selected Aux Vases and Cypress field studies. Figure 9 shows the locations of project outcrop sections and the I-57 outcrop study. Table 1 lists the field studies and the Illinois counties in which they were conducted.

Table 1 Project field studies

Cypress Sandstone reservoirs		Aux Vases Sandstone reservoirs	
Field	County	Field	County
Bartelso	Clinton	Boyd	Jefferson
Lawrence	Lawrence	SW Dale Cons.	Franklin, Hamilton, and Saline
Mattoon	Coles	Energy	Williamson
Parkersburg	Richland and Edwards	King	Jefferson
Richview	Washington	Oakdale	Jefferson
Storms	White	Stewardson	Shelby
Tamaroa	Perry	Storms	White
Xenia East	Clay	Zeigler	Franklin

Field Pool Study Analyses

Fields selected for detailed analyses were chosen to reflect the full range of data available in this mature basin. At one extreme are fields for which data are incomplete or sparse (no core, core analysis reports, or samples) and old electric logs may or may not cover the target reservoir. At the other extreme are fields for which cores, modern log suites, and engineering test data are available for almost every well. Fields with abundant data allow the development of models that help with the interpretation of fields with less-than-optimum control. Field selection was also based on the potential to develop analogs. Because every reservoir in the state could not be studied in detail, analogs proved helpful in the transfer of improved oil recovery concepts.

Figure 7 Project performance schedule.

Figure 8 Locations of the selected Cypress and Aux Vases field studies.

As part of the planning phase, a pool study outline was developed for the project. It includes all the facets of information required to bring each of the 12 tasks to conclusion (Appendix I). All types of data may not be available for each field. Using the data from pool studies with more than adequate control to help analyze the fields lacking sufficient data is a long-term effort. The project reservoir summaries developed using the pool study outline as a guide are presented in Appendix V.

Database

All research-derived data are recorded on digital spreadsheets that are easily exported to other computer databases, for example, to the Bartlesville Project Office (BPO) or into mapping and modeling software at the ISGS.

TASKS 2, 4, AND 11: SUBSURFACE AND OUTCROP STUDIES

The ISGS project concentrated on two of the most significant sandstone reservoirs in Illinois: the Mississippian Cypress and Aux Vases Sandstones (fig. 10). Detailed oil field reservoir studies were a key component of the program. State-of-the-art computer workstations running integrated geological and engineering modeling software were used to analyze available reservoir data and determine the effects of heterogeneities on production. Reservoir simulation has also been used to help determine the optimum methods for achieving improved oil recovery (see task 6).

Selection of fields for study was based on the availability of data, geographic distribution, and geologic significance. The accuracy with which each study could be conducted was dependent on the abundance and quality of the data available. The procedures used in the characterization of these oil fields varied with the heterogeneity of the reservoir, the lateral extent of the field, and the availability of data.

Each field study entailed analysis of data at three different scales: macro, meso, and micro. Macro- and meso-scale examinations use wireline log correlations and available petrographic and engineering data from several wells to determine whether heterogeneities within the reservoir could be identified and mapped. Micro-scale examinations helped determine diagenetic alterations and other factors that affect smaller scale heterogeneities such as pore throat diameters and the presence and mineralogy of clay coatings.

Interpretations of reservoir compartmentalization were based on porosity and permeability data, production data, pressure tests, cores, well cuttings, and wireline log analyses that indicated correlatable barriers to vertical and horizontal fluid flow. Isopach maps of reservoir lithofacies for each compartment were combined with petrographic analyses and wireline log characteristics to provide further data to interpret environments of deposition.

Geologic data and interpretations were entered into computer workstations housing state-of-the-art geologic mapping and modeling software. Virtually any geologic (or petrophysical) parameter could then be mapped, e.g. structure, distributions of lithofacies, porosity, and permeability. Computer-generated slice maps in 3-D views could be manipulated in ways that permitted the research team to achieve a greater understanding of the evolution and complexity of reservoir architecture.

Engineering models of the reservoirs used computer-derived 3-D geologic models for fully interactive engineering simulations. History matching of past production performance within the simulation model improved predictive modeling under various development scenarios. Reservoir simulations indicated possible effects on field performance of various reservoir development strategies such as well placement, infill drilling, and injection patterns, volumes and rates. Time constraints limited the application of this procedure to only a few fields where both substantial data and excellent operator cooperation were available.

Detailed reports of many of these studies have been published by the Illinois State Geological Survey. Requests for those documents may be directed to the ISGS Information Office, 615 East Peabody, Champaign, Illinois 61820, 217/333-4747.

Figure 9 Locations of the selected outcrop study locations, drill holes and the I-57 outcrop study (see also Appendix IX).

Figure 10 Generalized stratigraphic column (Whitaker 1992).

SUMMARY RESULTS OF TASKS 2, 4, AND 11

Bartelso Field, Cypress Sandstone Reservoir

- Bartelso is an example of multiple deposystems within the same formation. Each deposystem contains a reservoir type that possesses a unique set of characteristics.
- Shingled bars in one Cypress reservoir are not effectively drained by the 10-acre spacing required by current regulations.
- Recovery programs to optimize recovery efficiency must be designed according to reservoir type.

Boyd Field, Aux Vases Sandstone Reservoir

- In Boyd, a combination of high permeability thief zones and low permeability zones of laterally continuous shales and calcareous layers forms a vertically compartmentalized reservoir. Many of the 48 Aux Vases wells penetrated only the top 5 feet of the reservoir; therefore, not all vertical compartments have been drained.
- Relatively impermeable layers of shale, siltstone, and carbonate separate the Aux Vases reservoir into four distinct lateral compartments that have little or no communication with each other.
- The dual completion of all Aux Vases producing wells in the Benoist reservoir also probably hindered Aux Vases production. The Benoist, a water drive reservoir, has a higher sustainable pressure than the Aux Vases reservoir, which is predominantly a depletion drive.

Southwest Dale Consolidated Field, Aux Vases Sandstone Reservoir

- The Aux Vases reservoirs consist of shallow marine sandstone bars that formed as shoals against older carbonate paleotopographic highs.
- The bars are either "shingled," separated by shale beds that are as thin as 2 feet and prevent hydraulic communication, or they are partially overlapped without shale separation and thus in hydraulic communication.
- Bar sandstone grades laterally into less permeable shaley sandstone.
- Reservoir quality is controlled more by the degree of diagenetic modification than by textures developed during deposition.
- Use of hydraulic fracturing techniques in recently drilled areas of the field has resulted in intersecting fracture networks between wells, conditions that adversely affect waterflooding. A waterflood failure in one unit was due to an unrecognized fracture network.
- Where induced fracture networks have been recognized, carefully planned waterfloods may substantially improve recovery.
- Strategically placed infill wells are needed to recover the bypassed mobile oil.

Energy Field, Aux Vases Sandstone Reservoir

- The study of Energy Field demonstrated that paleotopography resulting from early depositional environments controlled later depositional geometries and thus the lateral extent and development of reservoirs and seals within the studied interval.
- Predictable periodicity observed in present sand deposits may be used as an exploration strategy to locate similar deposits in the Mississippian Aux Vases Sandstone.
- Stacked reservoirs in the Aux Vases are both regressive and transgressive, and the development of these reservoirs is related.
- Waterflood development without understanding of reservoir geometry resulted in unswept oil.
- More than 500,000 barrels of recoverable oil remain.

King Field, Aux Vases Sandstone Reservoir

- The Aux Vases at King Field was deposited in a mixed carbonate-siliciclastic nearshore, shallow marine environment.
- The reservoir is laterally compartmentalized because of a mixed lithofacies system. Clean, porous sandstone, within one well location (660 feet), may laterally grade into nonporous calcareous sandstone, limestone, siltstone, or shale.
- Because of lateral and vertical heterogeneity, there are multiple oil water contacts within the field.
- The original oil in place (OOIP) is estimated to have been about 17 million barrels of oil of which 4.1 million barrels have already been produced. An estimated 1 to 2 million barrels of recoverable reserves may still remain in this field.

Comparison Between the Boyd and King Field Aux Vases Bar Complexes

- Reservoir quality varies within a deposystem.
- Postdepositional alterations that control reservoir quality are expected to vary across the basin.
- A reservoir classification system should incorporate depositional environments and post-depositional alterations.
- Both fields produce from intervals within the upper 30 feet of the Aux Vases.
- The Aux Vases was deposited in a nearshore, marine environment of mixed carbonate-clastic sediments.
- The Boyd Field producing interval is not dominated by carbonates to the same degree as that of King Field.
- Boyd Field may have been closer to a clastic source.
- Calcareous lithofacies, siltstones, and shales at King Field are barriers to fluid flow.
- Calcareous lithofacies at Boyd Field are not present in appreciable amounts and thus do not contribute to reservoir compartmentalization.

Lawrence Field, Cypress Sandstone Reservoir

- Lawrence Field Cypress reservoirs consist of sandstone deposited in a shallow marine, tidally influenced environment during a marine regressive event and contain abundant shale laminae that impede fluid flow.
- Reservoir characterization shows the principal producing interval to be a composite of up to five stacked sandstones, the upper four showing an elongated ridge/sheet geometry trending northeast to southwest.
- Compartments are formed by the horizontal and vertical boundaries of the stacked sandstones.
- Bypassed, banked oil may exist from waterflooding a portion of a particular stacked sandstone that is truncated horizontally and isolated vertically from a production well.
- The uppermost stacked sandstone may not be swept as effectively as more permeable and widespread underlying sandstones.
- Volumetric calculations indicate that 14% of mobile oil is bypassed.
- CO₂ flooding may be a viable EOR technique, given the fact that immobile oil constitutes 46.5% of the original OOIP and significant reserves remain because of the large size of the field.

Mattoon Field, Cypress Sandstone Reservoir

- Five different Cypress reservoirs were identified; they are not uniformly developed or distributed over the field.
- Waterflood units do not coincide with the limits of the sandstone bodies; unflooded portions of the field remain.

- Each Cypress reservoir has unique characteristics.
- Because the limits of the Cypress sandstone bodies had not been previously mapped, there is some potential for primary recovery.
- Because the distribution of the Cypress reservoirs is highly variable across the field, several opportunities exist for producing unrecovered mobile oil.
- The results of this field study were extensively used in a PON 1, CO₂ WAG demonstration at Mattoon Field. The CO₂ project is not reported here.

Oakdale and Markham City North Fields, Aux Vases Sandstone Reservoir

- Reservoir compartmentalization is related to depositional facies and structural position in this combination stratigraphic/structural trap.
- The reservoir is composed of a mixed siliciclastic and carbonate lithology modified by tidal reworking.
- Compartments are formed of pods of reworked bar-crest sands, which generally have limited lateral extent (¼ square mile) and are limited by sand-shale pinchouts. Structure and shale pinchouts limit the downdip extent of the compartments. The updip limits are also facies changes (pinchouts) to shale or limestone.
- Early pressure maintenance programs did not adequately adjust to depletion of the natural drive mechanism.
- Development and recovery strategies were apparently limited to lease blocks, rather than based on reservoir architecture and geologic compartmentalization.
- The reservoir management strategy appears to also have been restricted to individual lease blocks, and waterflood production under this strategy has resulted in bypassed oil.

Parkersburg, Cypress Sandstone Reservoir

- Sandstone reservoirs are distributed throughout lower, middle, and upper Cypress intervals in the Parkersburg area.
- Different environmental conditions prevailed during deposition of the lower, middle and upper Cypress units resulting in different types of reservoirs.
- Recovery efficiencies have been relatively poor in Cypress reservoirs at Parkersburg. This has been attributed to rapid reservoir pressure depletion, reservoir heterogeneity, and many operators operating a single reservoir.
- There is good potential for additional recovery from existing Cypress reservoirs as well as for future exploration opportunities for Cypress reservoirs in the Parkersburg area.
- Detailed description of reservoir characteristics show that facies variations and subsequent diagenetic alteration control reservoir quality of the Cypress Formation in the Parkersburg area.
- Sequence stratigraphy may provide an explanation for these lateral and vertical facies variations.

Richview Field, Cypress Sandstone Reservoir

- Reservoirs occur in thin, lenticular, stacked sandstones that lie in a structural saddle.
- Well developed, clean, barrier bar-type sandstones yield high recovery efficiencies, approaching 45%.
- Reservoirs were compartmentalized by the stacking of two bar-forming events.
- Banked, bypassed oil may be present.
- Standardized well spacing within the field has not optimized production.
- Infill drilling on 5-acre spacing and strategic location of infill wells to drain banked oil appear promising as techniques to improve recovery.
- Fresh-water "shocking" of kaolinite appears to have caused formation damage problems.

Stewardson Field, Aux Vases Sandstone Reservoir

- Shoreface sheet sands represent a different deposystem from other Aux Vases fields in the project.
- Sands are relatively homogeneous laterally and extremely heterogenous vertically.
- Sands have relatively low porosity (13%) and permeability (36.5 millidarcies).

Storms Consolidated Field, Aux Vases Sandstone Reservoir

- Neither the Aux Vases nor the Cypress Sandstones have been fully exploited.
- Subsurface data is not always available in the detail necessary for environmental analogs to be useful.
- Four different scales of heterogeneity simultaneously affect oil recovery from the reservoir; the relative importance varies with different phases of field development.
- The traps for both the Aux Vases and Cypress reservoirs are formed by the stratigraphic pinchout of offshore marine bars over structural noses.

Tamaroa Field, Cypress Sandstone Reservoir

- Lack of understanding of drive mechanism or the need to use pressure maintenance decreased recovery efficiency.
- Oil saturation data were successfully used to confirm the separation of bar facies.

Xenia East Field, Cypress Sandstone Reservoir

- The Cypress pool trapping mechanism is predominantly structural; reservoirs are interpreted as marine bar sandstones.
- Initial oil saturation, as determined from E-log interpretation, ranges from 40% to 72%.
- STOOIP is estimated to be 2.02 to 2.54 million bbls by volumetric and Monte Carlo methods.
- There is a high potential for improved oil recovery from the Cypress pool as more than 75% of the STOOIP remains and the reservoir has not been waterflooded.

Zeigler Field, Aux Vases Sandstone Reservoir

- Aux Vases reservoirs were deposited in a mixed carbonate-siliciclastic environment.
- Zeigler Field is made up of several isolated sandstone bars encased in nonporous and impermeable siliciclastics. There is no fluid communication between some of the bars and only limited communication between others.
- Surveillance of pressure during reservoir development permitted determination of reservoir limits and aided in the geologic interpretation of the reservoirs.
- Surveillance of reservoir parameters through time is an essential element for high recovery efficiencies.
- Integration of geologic and engineering data led to effective reservoir management.

Petrographic Analysis of Cypress and Aux Vases Reservoirs

- Precipitation of diagenetic clay mineral coatings has inhibited formation of quartz overgrowths and resulted in preservation of intergranular porosity in Aux Vases reservoirs.
- Precipitation of quartz overgrowths around quartz grains has reduced intergranular porosity in Cypress sandstone reservoirs.
- Different clay mineral suites have precipitated in Cypress and Aux Vases reservoirs; Cypress reservoirs contain kaolinite, iron-rich chlorite, illite, and mixed-layered illite/smectite in discrete phases. Aux Vases reservoirs contain mixed-layered illite/smectite, magnesium-iron (Mg-Fe) chlorite, and illite as grain coatings.

- Specific depositional environments may have undergone different levels of diagenetic modification.
- Petrographic differences in Cypress and Aux Vases reservoirs are partly attributed to differences in the original composition of these units. Aux Vases sandstones probably had a different, greater amount of alterable feldspars than Cypress sandstones.

Outcrop Studies

- Outcrops, detailed analogs for the subsurface, show the geometry and lateral heterogeneity of subsurface reservoirs.
- Extensive geologic and engineering data collected from an outcrop study form the basis of a 3-D computer model simulating an actual reservoir. These models are instrumental in the evaluation of recovery strategies.

EXPANDED TECHNICAL SUMMARIES

BARTELSON FIELD, CLINTON COUNTY

The Cypress Sandstone is approximately 100 feet thick at Bartelso and comprises fine grained to very fine grained sandstones interbedded with dark brown to light greenish gray shales. Individual Cypress sandstones in the field may be up to 60 feet thick, although beds about 10 feet thick more commonly form the hydrocarbon reservoirs (Whitaker 1992).

Reservoir Geometry

A structure map on the Beech Creek (Barlow) Limestone at Bartelso reveals two small structural domes with approximately 75 feet of closure. These structures are due to differential compaction around a Silurian pinnacle reef and the resultant draping of younger strata over the reef (Bristol 1974, Whitaker 1992). Production is concentrated on the crests and northern flanks of the structures, with the bulk of the Cypress production situated on the western of the two domes.

In this study, the Cypress Sandstone was divided into four individual sandstone intervals, each separated by thin shale layers; detailed stratigraphic correlations were based on available wireline logs obtained within the field (fig. 11). The four sandstone intervals were informally labeled, in ascending order, pink, purple, gray, and red. All but the lowest of these sandstone intervals produce hydrocarbons at Bartelso, and the youngest (red) sand is the major reservoir.

Four cross sections showed the relationships between the four major sandstone intervals within the Cypress at Bartelso. The lowest interval (pink) is a relatively clean sandstone package that displays a characteristically blocky signature on the spontaneous potential (SP) and resistivity logs run in the field. The interval is approximately 40 to 50 feet thick and contains numerous discontinuous shale beds. The distribution of sandstone within the pink interval is impossible to accurately determine because of the lack of well penetrations into the interval, and the lack of cores and wireline logs. Semiregional mapping indicates the sandstones from this interval underlie the entire field area. No production from this interval has been recorded in this field.

The second sand interval (purple) is generally 10 to 15 feet thick and relatively continuous throughout the field. Interpretations of wireline logs indicate that shales are rare in this interval and that distinct compartments, if present, are difficult to document because of the lack of adequate control. Relative homogeneity of this sandstone interval is indicated by a consistent oil-water contact at -550 feet.

The distribution pattern of the sandstones within the purple interval (fig. 12) suggests a shoreface deposit that was influenced by tidal currents. This sandstone probably represents a slightly shallower environment than that represented by the pink interval and suggests continued progradation of the Cypress delta complex.

Figure 11 Type log of Cypress Formation at Bartelso Field (Whitaker 1982).

Figure 12 Isopach map of "purple" clean sand interval at Bartelso Field (Whitaker 1992).

The third sand interval (gray) is dominated by siltstones and shales, although thin sandstone beds are present locally. On wireline logs, these sandstones display a suppressed SP deflection caused, in large part, by thin-bed resolution problems of the SP-resistivity tools used. The distribution of sandstone within the gray interval (fig. 13) suggests a small clastic influx into quiet water. Apparently, the sandstone is derived from a northwesterly source and may represent a very small delta formed by ebb tidal currents or by a small crevasse splay. The original oil-water contact for this interval was at approximately -540 feet mean sea level (msl).

The youngest Cypress sandstone interval (red) comprises well formed, discontinuous sand lenses that are locally multistoried (stacked) (fig. 14). Relatively thick shales separate this interval from the underlying sands of the gray interval and the overlying Beech Creek (Barlow) Limestone. Northwest-southeast cross sections show that the red interval is characterized by distinct and separate sand bodies. These cross sections also suggest that the sandstone lenses may have been deposited in subtle paleo-lows. The northeast-southwest sections show that the sands are more continuous in that direction.

Because data for the red interval are more abundant, sandstone distribution is more easily defined for it than for the other intervals. Detailed stratigraphic correlations enable differentiation of several individual sandstone lenses within this interval, each separated by thin shale layers. The isolated nature and distinct orientation of these sandstones in a northeast-southwest direction suggest that they are marine bars. Two hypotheses for the origin of these bars are that they are (1) offshore bar complexes oriented shore-parallel, or (2) shore-normal tidal shoals. We favor the second hypothesis, which was originally suggested for some Chesterian sandstones by several workers (Potter 1962, 1963, Baker 1980 Williams et al. 1982, Specht 1985, Treworgy 1988).

The northern sand body or tidal bar complex comprises at least two separate, stacked bars that are separated by a thin shale layer. This thin shale acts as an effective seal, as exhibited by drill-stem tests that indicated gas in the lower unit; whereas the upper unit in the same wells tested only oil. These gas-oil relationships can best be explained if the updip, gas-saturated edge of the lower bar underlies an oil-saturated part of the overlying bar. In fact, the sandstone thicknesses shown on isopach maps suggest that the bar trends could be further subdivided into several smaller, shingled sand lenses. Unfortunately, further subdivision is difficult because of the poor resolution characteristic of the types of logs run in the field and the lack of cores from the interval.

Trap Type

The trap type at Bartleso Field varies from structural to stratigraphic, depending on the Cypress interval involved. The continuous nature of communication of the sands within the pink and purple intervals indicates that entrapment of hydrocarbons in these intervals would require a positive structural position. The distribution and thin bedded nature of the gray interval sands suggests that stratigraphy is at least as important as structure. Hydrocarbon entrapment within the red interval is dependent, however, on stratigraphic rather than on structural factors. The cleanliness of these sandstones and their position within a bar are of primary importance regarding reservoir development, oil-water ratios, and producibility.

Reservoir Lithofacies

Evidence such as drilling cuttings, two cores from the field area, and cores from other fields suggests that the various sandstones within the Cypress Sandstone are remarkably similar in their lithologic characteristics. The sandstones are generally clean, moderately to fairly well sorted, fine grained to very fine grained quartz arenite to subarkose. Cementation is primarily due to silica, and lesser amounts of calcite and minor amounts of clay minerals, feldspar, and limonite.

Figure 13 Isopach map of "gray" clean sand interval at Bartelso Field (Whitaker 1992).

Figure 14 Isopach map of "red" clean sand interval at Bartelso Field (Whitaker 1992).

Petrographic and mineralogic analyses revealed that silica is the primary cementing agent of Cypress sandstones at Bartelso. Quartz overgrowths are common and minor amounts of chert are also present. Calcite cement is rare and restricted to syntaxial cement around echinoderm fragments.

Clay minerals constitute less than 2% of the total rock and consist mainly of kaolinite with lesser amounts of iron-rich chlorite and illite. Porosity enhancement has resulted from the partial dissolution of potassium feldspars and calcium-rich plagioclases.

Depositional Environment

The various intervals of the Cypress at Bartelso display evidence of several environments of deposition. In general, it appears that the Cypress was deposited as a prograding sequence that was eventually inundated during, or shortly after, deposition of the gray interval.

The Ridenhower Formation, which consists of thin limestones and intercalated limestones and shales and directly underlies the Cypress, represents a maximum flooding surface, according to the sequence stratigraphy nomenclature of Mitchum (1977) and Van Wagoner et al. (1990). The pink interval thus represents the initial progradational phase of the Cypress at Bartelso (the lower part of the highstand systems tract). Sandstones in this interval apparently were deposited across the shallow Illinois Embayment in a delta-front setting. Today, these sandstones comprise a relatively thick, continuous sequence that may be 40 to 50 feet thick in the Bartelso area. Small shale drapes can be observed in the few wireline logs that have been run in this interval in the field.

The shoreface sandstones within the purple interval (fig. 12) are much thinner. Apparently, they were affected by currents flowing northeast to southwest. The evidence indicates that these currents were probably tidal and possibly shore-normal (i.e., perpendicular to the advancing delta-induced shoreline).

The gray interval (fig. 13) formed in a low-energy environment apparently affected by periods of minor clastic influx. The abundance of gray to green shales and rare coal fragments in this interval suggests that the main environment of deposition was shallower than the underlying purple interval. The gray interval may represent a lowstand caused by a relative sea level fall and thus mark the beginning of another sequence. The depositional setting is interpreted to be either tidal flat, coastal plain, or possibly a combination of the two. The source for the clastics within this interval apparently was from the northwest, and these deposits may represent small crevasse splays.

Sandstones within the red interval (fig. 14) were probably deposited as tidal shoals or bars located seaward of the underlying gray interval and oriented shore-normal. This interval represents the beginning of retrogradational deposits in the transgressive systems tract. The bars in the Bartelso area exhibit shingled overlap that can be seen in cross sections and isopach maps. Currents tended to winnow out most of the clay-sized particles, leaving behind relatively clean, porous sandstones separated by thin shale layers. Continued transgression covered the sands of the red interval with shales, which are in turn overlain by the Beech Creek (Barlow) Limestone. The shales directly overlying the Beech Creek Limestone may represent another maximum flooding surface.

Classification and Identification of Plays

There are at least four plays in the Cypress Sandstone in this field. Each play may require different strategies for exploitation.

Delta Front Sandstones deposited in this play, represented by the pink interval, are subject to the depositional patterns and reservoir compartmentalization that occur in this depositional environment (occasional clay drapes, moderate current direction indicators, potentially large sandstone deposits, and possible communication over large areas, depending on effectiveness of shale seals). Outcrop studies of the Cypress Sandstone by the Illinois State

Geological Survey (R. D. Cole, personal communication, 1990) and examinations of samples from this interval suggest that these delta-front sandstones were deposited in a shallow sea, but in the subtidal realm. This play requires an associated structural closure because there appears to be sufficient communication between individual sand lenses to preclude stratigraphic entrapment of hydrocarbons. The fact that this interval contained no commercial hydrocarbons at Bartelso, despite the presence of a structure, suggests that the shale layer overlying the pink sands was not an adequate seal. Correlations with wireline logs in the field verify this supposition. Although at Bartelso, this interval contains no hydrocarbons, it is nevertheless a viable play, provided adequate seals and structures can be defined.

Upper Shoreface The second play, represented by the purple interval, is characterized by sediments deposited in shallow marine conditions along the upper shoreface slightly seaward from the overlying gray interval. Reworking of the sands by what we interpret to be tidal currents has given a northeast-southwest orientation to this sandstone. Sandstones in this play are relatively thin, contain a moderately small amount of clay, and may be laterally continuous over their area of deposition. In general, an associated structure would be necessary for hydrocarbon entrapment because of the continuity of the sandstones. The thin nature of these deposits may provide the conditions for stratigraphic pinchouts.

Coastal Plain A third play, represented by the gray interval, involves sandstones deposited in low-energy environments associated with proximity to a shoreline. These environments include coastal plains, tidal flats, and possibly lagoons and/or estuaries. The thin and discontinuous sandstones within this play could be the result of tidal reworking, small tidal channels, or possibly small crevasse splay deposits. The geometry of these sandstones will be variable, depending on the particular geologic process responsible for their creation. Hydrocarbon traps in this play could be numerous, not requiring structural closure; but reserves are probably limited because of the discontinuous nature of the sands. In general, this play would not be economical except as a secondary target.

Marine Bars The fourth Cypress play is illustrated by the sandstones in the red interval. These sandstones may be very clean in the bar core and are generally deposited as elongate, isolated lenses oriented northeast to southwest. The sandstone bodies are commonly stacked and/or shingled, and separated by thin clay layers that may preclude communication between sandstones. The strong northeast-southwest orientation of the sands should make exploration and development of the sands relatively straightforward. Hydrocarbon entrapment in this play would be mainly stratigraphic.

The source of these sandstones was either an offshore bar, which would result in bars oriented shore-parallel, or it was a tidal shoal/bar, which would lead to bars forming seaward of distributary mouths oriented shore-normal. We believe the latter interpretation should be pursued as an exploration model.

Drilling and Completion Practices

Most wells in Bartelso Field have been rotary-drilled using fresh-water-based muds, although some wells were drilled with cable tools. The Cypress sandstones were commonly fractured with 20 to 40 quarts of nitroglycerin and completed as open-hole producers. Wells drilled after the mid-1950s were generally perforated through casing set through the pay zone. Little to no acidization was performed within the Cypress wells at the field. Pumping units are the main extraction tools for both primary and secondary recovery operations.

Injection and Production Data

Cypress production in this field was established in 1936 and peaked in the early 1940s. Enhanced recovery operations in the Cypress began in 1952 with the introduction of three

waterfloods involving 24 injection wells on the crest of the Bartelso structure. The waterfloods were based on 10-acre well spacing and 5-spot injection patterns. The production curve shows a standard decline from 1939 to 1952, when waterflooding was first initiated. Additional wells, both injector and producer, were drilled off-pattern to enhance the effectiveness of the flood. Production peaked in the mid-1950s and then gradually declined again, but at a slightly higher level than would be projected from the pre-1952 curve. This suggests that the flood was improving recovery rates within the Cypress. Many of the Cypress wells were temporarily shut-in during the early 1970s for pressure maintenance purposes, leading to a dramatic drop in production in those years. Cypress production resumed in 1975 under a coordinated fieldwide flood, and a few more wells were drilled to enhance efficiency. Production decline rates from that period to the present were noticeably more gradual and suggest that the waterflood efficiency had increased.

Injection of approximately 7.2 million barrels of water resulted in the production of about 1.25 million barrels of oil and 5.25 million barrels of water from Cypress reservoirs. Injection water has consisted of a 50% mixture of produced Cypress and Bethel brines. No data or analyses have been published pertaining to the compatibility of this mixture with formation fluids in the Cypress.

Analyses of three oil samples (EOR-16, EOR-17, and EOR-69) collected in 1990 from Bartelso Field are listed in Appendixes VII-A and VII-B. Chromatograms of analyses of the saturated hydrocarbons are presented in Appendix VIII. These samples are from red-interval reservoirs subjected to waterfloods. The sample characteristics are consistent with Illinois Basin samples, for which the source was the New Albany Shale (Upper Devonian). Sample EOR-69 contains more than 1% asphaltenes, significantly different from other samples in the field. Asphaltenes can cause some production problems, particularly when using CO₂ injection for enhanced oil recovery projects (Newberry and Barker 1985).

Water Characteristics

The composition of seven samples of the formation brine from Cypress reservoirs at Bartelso is summarized in Appendix VI. Because of the mixtures of Bethel and Cypress brines for waterflooding, these samples do not indicate true Cypress brine characteristics for this field. Because they are from relatively shallow depths, the relatively low concentrations of chlorine in these brines are not surprising.

Original Volumetrics

We calculated the values of reservoir acre-feet from the isopach maps, assigned porosity by using average values obtained from core analyses in the area, and calculated water saturation from wireline logs. The results are as follows:

purple interval: shoreface	$7758 \times 2954 \times 0.20 \times 0.6 =$	2,750,000 BO
gray interval: coastal plain	$7758 \times 551 \times 0.20 \times 0.7 =$	598,000 BO
red "A" interval: marine bar	$7758 \times 588 \times 0.20 \times 0.8 =$	729,870 BO
red "B" interval-north: marine bar	$7758 \times 782 \times 0.20 \times 0.8 =$	971,000 BO
red "B" interval-south: marine bar	$7758 \times 443 \times 0.20 \times 0.8 =$	550,000 BO

$$\text{Original oil in place (OOIP)} = 5,598,870 \text{ BO}$$

The commonly used formation volume factor for Cypress reservoirs in the basin is 1.15 (B. Podolsky, Podolsky Oil, personal communication 1991). We therefore calculated the original stock tank barrels of oil in place for the Cypress to be 4.869 million barrels of oil.

Primary recovery from the Cypress at Bartelso, estimated from operators' estimates, was 1.25 million barrels of oil. Secondary recovery accounts for another 1.25 million barrels of oil. The recovery factor for combined primary and secondary methods is thus approximately 52%. This extraordinarily high recovery rate may be a result of an erroneously optimistic

estimation of the Cypress portion of the total reserves produced, inaccurate assumptions on the volumetric calculations leading to erroneously low estimates of reserves, or the high efficiency of the primary and secondary recovery methods used. We believe that the recovery efficiency figures are relatively accurate and, if anything, slightly conservative. The combination of the coordinated flood and other recovery methods used in the field was more effective than is commonly the case in the Illinois Basin.

Development and Production Strategy

The lack of cores from the field precludes obtaining engineering data on flow measurements or flow modeling. Therefore, we limit our discussion on development and production strategies to conclusions and observations made from the existing data.

The production practices used at Bartelso Field led to an overall recovery efficiency for the Cypress of more than 52%. If, as we assume, the calculations are relatively accurate, these observations indicate that a 10-acre well spacing and 5-spot waterflood program with infill drilling was adequate to effectively drain the Cypress red interval at Bartelso. The recovery rate probably would have been higher had the sandstones in the purple and gray intervals been waterflooded adequately.

Recommendations

Standard 10-acre well spacing is apparently not adequate to efficiently drain all the sandstones within the Cypress, if they are distributed as at Bartelso Field. In the red interval, the bar complexes exhibited reservoir shingling, indicating the potential benefits of closer spacing in this environment. Off-pattern producers drilled for the waterflood project almost certainly encountered compartments that would otherwise not have been effectively drained. In addition, the western limit of the reservoir within the gray interval at Bartelso is of a peculiar geometry that may not lend itself to efficient drainage by a 10-acre well spacing. It is always important to recognize the Cypress reservoir type to plan an optimum recovery strategy.

Secondary recovery methods should likewise be influenced by the type of reservoir that is being exploited. Separate waterflood projects may be required for each reservoir. Sweep efficiencies will obviously be affected by the geometries and internal architecture of the individual reservoir. As a result, uniformly spaced wells on a secondary recovery project would probably not efficiently drain multiple reservoir types. This was probably the case at Bartelso.

BOYD FIELD, JEFFERSON COUNTY

Integration of the local reservoir geology with development history and production engineering suggests a strategy for improving oil recovery in Boyd Field. The field is located in the northwest corner of Jefferson County at the western limit of oil production from the Mississippian Aux Vases Sandstone. The 1,200-acre field produces mostly from the Yankeetown (Benoist) and Aux Vases Sandstone at depths of about 2,050 feet and 2,150 feet, respectively. (The Yankeetown Sandstone in the Illinois Basin is referred to as the Benoist sandstone by the oil industry; therefore, Benoist sandstone is the name used in this report.)

The principal axis of the Boyd Anticline trends generally north. The structure is approximately 2½ miles long and 1 mile wide.

This study evaluated reservoir heterogeneity and prospects of improved oil recovery in a field where previous reservoir management techniques have complicated the analysis. Most wells at Boyd Field were completed in both the Aux Vases and Benoist reservoirs. Consequently, no accurate way exists to separately estimate annual production from each zone. Boyd Field has produced more than 15 million barrels of oil since its discovery in 1944. By 1990, 116 wells had produced oil at Boyd Field; 48 of the wells were Aux Vases producers.

Depositional Facies

The Aux Vases at Boyd Field is interpreted to have been deposited in a broad nearshore environment that includes lithofacies of several subenvironments, including marine offshore sandstones and tidal flat shales.

Sandstone Facies The reservoir sandstone is classified as a quartz arenite grading to subarkose. Analyses of selected samples by XRD and estimates of mineral percentages from thin sections of other samples indicate that the reservoir sandstone contains 80% quartz and less than 10% feldspar. The sandstone is cemented by calcite and clay minerals. The amount of calcite in reservoir-quality rock ranges from 1% to 28%.

Within the sandstone reservoir are numerous calcareous zones. Most calcareous zones occur as thin laminae (0.2 in. thick) of limited lateral extent. These thin calcareous zones formed where concentrations of calcite cement precipitated preferentially along the boundaries of laminae sets. Calcareous-rich zones occur not only as bed set laminae, but also as thicker, sandy cross-laminated limestones. These sandy limestones contain fossil fragments, ooids, and shale clasts that suggest high-energy transport from nearby areas. This type of calcareous interval may be laterally extensive, especially if it was deposited as a result of storm surge into an otherwise siliciclastic depositional system.

A structure map on top of the Aux Vases reservoir sand is shown in figure 15.

A contour map of the distribution of reservoir-quality sand in the upper 20 feet of the formation shows sandstone bodies elongated north-south. The map suggests the existence of at least four lateral compartments, labeled B1, B2, B3, and B4. The variation in oil-water contact elevations indicates that at least three of the four compartments are not in communication with each other. They are probably separated by siltstones, shales, and mudstones.

Siltstone and Shale Facies The siltstone and shale facies, which also includes some mudstone, is generally light green and has no porosity or effective permeability. The siltstone and shale facies forms effective vertical and lateral barriers to fluid flow and plays a major role in reservoir heterogeneity. In places, beds representing this facies have a lateral continuity of more than two 10-acre well spacings (a distance greater than 1,320 feet), thereby compartmentalizing the reservoir sandstone.

Facies Architecture and Reservoir Continuity

Comparisons between Boyd Field and King Field (see p. 48) are useful because they are only 10 miles apart and in a similar depositional system; yet each has a different facies architecture. The producing interval of the Aux Vases Sandstone at both fields occurs within the upper 30 feet of the formation and was deposited in a mixed carbonate-clastic, nearshore marine environment. The well control suggests the producing interval at Boyd Field was not dominated by carbonates to the same degree as the producing interval at King Field. This relationship suggests that Boyd Field may have been closer to a source of clastic sediments than was King Field. There are other differences: the calcareous lithofacies and the siltstone and shale facies at King are impermeable barriers to fluid flow. At Boyd, the calcareous lithofacies is not a significant factor in reservoir compartmentalization because it is not present in appreciable amounts.

Development and Production Strategies

Boyd Field was unitized in 1954 and production from both formations was increased by the water injection program instituted at that time. The Benoist sandstone, the base of which is less than 50 feet above the Aux Vases reservoir, was the principal target during development of Boyd Field. The Benoist is a water drive reservoir, whereas the Aux Vases has a combination of solution gas and weak water drive. This difference in drive mechanisms is of critical

Figure 15 Structure map on top of Aux Vases reservoir sandstone at Boyd Field (Leetaru 1993).

importance to recovery efficiency in the Aux Vases because production from the Benoist and Aux Vases reservoirs was commingled. Not only does the Benoist have a greater reservoir efficiency, but its reservoir pressure decline is also much slower. After a few years of commingled production, the higher reservoir pressure of the Benoist inhibited or stopped fluid flow from the Aux Vases. Backflow from the Benoist into the Aux Vases probably occurred. In this report, two wells are used to illustrate the problems that commingling of the two reservoirs may have had on production.

In April 1956, a packer was used to isolate the Aux Vases production in the Superior Oil Co. Friedreich No. 15 well, a dual Benoist and Aux Vases producer. After the packer was set, oil production increased nearly fivefold from 3.4 to 16 barrels of oil per day (fig. 16). The amount of produced water decreased from 98% to 68%. The significant increase in production after the Aux Vases was isolated implies that Aux Vases production was impeded by the higher pressure flow of reservoir fluids from the Benoist. The Friedreich No. 15 should have produced water from the Aux Vases. It was only 660 feet from the Superior Oil Co. Friedreich No. 10, a well used to inject more than 200,000 barrels of water into the Aux Vases for 2 years. The possible water breakthrough, shown by increased water production during the 36th month, implies that either a permeability barrier existed between these two wells or that the injected water was not going into the Aux Vases reservoir. The injected water could instead have entered the Benoist reservoir through upward leakage behind the casing. Campbell and Rickman (1954) reported difficulties in obtaining good cement jobs in the field. Strong communication between the two reservoirs probably exists because of completion practices. Although a completion record was not available for the Friedreich No. 10, most wells in Boyd Field were treated with nitroglycerin, which shattered the rock and could easily have weakened and fractured the 50 feet of limestone and shales separating the two formations.

The Superior Oil Company, High No. 5 well had an even more dramatic increase in production when the Aux Vases was isolated after 10 years of commingled production. Production surged from an average 23 to 131 barrels of oil per day (fig. 17) and stabilized at 50 barrels per day during the following months. The proportion of produced water dropped from 86% to 65% of total fluid flow. It took 1½ years for water production to return to values before packer installation.

Recommendations and Conclusions

Significant amounts of recoverable oil probably remain in the Aux Vases reservoir at Boyd Field. Since it was a secondary target, the Aux Vases was ineffectively waterflooded. Several wells penetrated only the top 5 feet of the formation. The Aux Vases reservoir is composed of at least three major flow units (fig. 18); the lower flow units cannot be drained nor can they be waterflooded from wells that only penetrate the upper 5 feet of the reservoir.

Actual well spacing for Aux Vases production in the field considerably exceeds 660 feet. Because the primary target during the development of this field was the Benoist reservoir, many good Aux Vases locations were ignored. The scale of geologic heterogeneity in the Aux Vases reservoir is significantly smaller than the current minimum 660-foot well spacing. Correlation of strata is sometimes difficult in wells that are only 660 feet apart. This difficulty in correlating strata is a qualitative indicator of poor reservoir continuity. The relatively low well density and limited number of injection wells in the Aux Vases make this reservoir an excellent target for additional infill drilling and secondary recovery at Boyd Field.

SOUTHWEST DALE CONSOLIDATED FIELD FRANKLIN, HAMILTON, AND SALINE COUNTIES

The first well in the study area to encounter commercial quantities of Aux Vases oil was the J. W. Everhart, Wesley Foundation No. 1, drilled in the Cantrell sandstone bar in the fall of

Figure 16 Average daily fluid production for each month versus time for the Superior Oil Co. Friedrich No. 15 well. The first month is May 1955 (Leetaru 1993).

Figure 17 Average daily fluid production for each month versus time for the Superior Oil Co. High No. 5 well. The first month is May 1955 (Leetaru 1993).

Figure 18 Cross section A-A' through compartment B1 shows flow units as defined by permeability variations within the Aux Vases sandstone (Leetaru 1993).

1949. The well was drilled to 3,216 feet total depth (-2,699 feet subsea) and was completed open hole for 525 barrels of oil per day with the top of the productive sandstone at a depth of 3,201 feet (-2,684 feet subsea).

Portions of the Cantrell sandstone bar and most of the Cantrell South sandstone bar were developed in the early 1950s. Within 5 years oil production had decreased to less than 3,000 barrels of oil per month.

Waterflood programs initiated by the operators of the Cantrell Waterflood Unit in 1955 and the operators of the Cantrell South Waterflood Unit in 1959 resulted in increased oil production. In 1969, two wells were drilled in the McCreery portion of the McCreery/McCullum sandstone bar. In 1984 and 1985, 16 producing wells were drilled in the McCreery/McCullum sandstone bar. Additional production resulted from the drilling of the Osburn Waterflood Unit (Section 7, T7S, R5E) in the southern Cantrell sandstone bar and the northernmost area of the Cantrell South sandstone bar.

Reservoir Facies

The Aux Vases Sandstone was deposited on a shallow shelf, in a mixed siliciclastic-carbonate marine environment (Swann and Bell 1958, Cole 1990). The conditions necessary for limestone formation in an environment with varying degrees of terrigenous clastic influx are outlined in Pilkey et al. (1988). These conditions call for relatively shallow water containing a high level of carbonate in solution.

In the study area, porous and permeable oil-bearing sandstone bodies are part of a shallow marine sandstone bar complex. As in the Aux Vases interval at King Field in Jefferson County, sandstone distribution was strongly influenced by paleotopography (Leetaru 1991) and sandbars formed as shoals against paleotopographic highs on the underlying limestone. These sandstones contain a high percentage of allochemical bioclasts. Several well spacings to the southeast of the Cantrell South sandstone bar are limestone beds that were deposited contemporaneously with the sandstone of the bar interval. Their presence suggests that the conditions necessary for limestone development during earlier Ste. Genevieve time also were present during Aux Vases time. Aux Vases sandstone reservoirs are structurally modified stratigraphic traps.

Within the Aux Vases sandstone bar facies, permeable oil-saturated sandstone was mapped as productive sandstone. In the McCreery/McCullum bar, only the sandstone that is above the oil-water contact was mapped as net productive sandstone. An isopach map of productive sandstone (fig. 19) shows that the sandstone bars are more than 25 feet thick. Productive sandstone typically consists of loosely cemented, texturally mature, oil-saturated quartz arenite with measured air permeability greater than 50 millidarcies and measured or log-derived porosity greater than 16%. In general, the most productive wells occur in areas where productive sandstone thickness exceeds 15 feet.

Stratigraphic influences on Aux Vases oil production are evident in wells along the periphery of the sandstone bar facies. Cross sections show individual sandstone bars grading laterally to less permeable shaley sandstone, sandy shale, and shale.

Data Availability

Evaluations of porosity and permeability were performed on cores from 12 wells in the Cantrell South Waterflood Unit and from two wells in the McCreery Waterflood Unit. These evaluations of porosity allowed for normalization of log porosity by the use of crossplots and also permitted the development of porosity distribution maps. Core sample permeability analyses were used in the determination of flow unit continuity.

Other data obtained from core analyses include residual liquid saturations. The values are not directly usable as measurements of connate water saturation for volumetric

Figure 19 Net productive Aux Vases reservoir facies: Southwest Dale Consolidated Field (Beaty 1994).

calculations because fluids measured are composed, in part, of invaded drilling and coring fluids. Estimates of water saturation (S_w) were derived from capillary pressure measurements.

In the McCreery/McCullum sandstone bar, drill stem tests (DST) were helpful in establishing pressure conditions for reservoir simulation. Pressure measurements by DST and average wellhead pressures taken by operators during waterfloods were also useful for the determination of sandstone bar connectivity.

Sandstone Bar Connectivity

The Cantrell sandstone bar is located at the north end of the study area. Oil was originally produced from this bar at the Cantrell Waterflood Unit during the 1950s and is currently being produced at the Osburn Waterflood Unit in the southern part of the bar. The Cantrell South sandstone bar was productive during the 1950s at the Cantrell South Waterflood Unit and is currently produced from one well in the Osburn Waterflood Unit in the northernmost part of the bar. That the Cantrell sandstone bar underlies and is not connected to the Cantrell South sandstone bar is confirmed by the fact that a waterflood in the Cantrell Waterflood Unit, which was operated from 1955 to 1962, did not affect oil production in any of the wells in the Cantrell South Waterflood Unit. Differences in average wellhead pressure readings between the two sandstone bars yield additional evidence for their separation. Pressure readings of approximately 100 pounds per square inch (psi) were reported for Aux Vases producers in the Cantrell South Waterflood Unit in late 1960 (prior to its waterflooding); whereas pressures of approximately 900 psi were reported during the waterflood at wells in the Cantrell Waterflood Unit.

The Cantrell South and McCreery/McCullum sandstone bars are isolated from each other by shale and shaley sandstone beds. Their isolation from one another is indicated by DST pressure measurements taken from each sandstone bar in 1985. In July of that year, a DST pressure of 993 psi was recorded at the Vise Brothers, Eason No. 1 well in the abandoned Cantrell South Waterflood Unit. In May 1985, Farrar Oil Company had recorded a DST pressure measurement in the McCreery/McCullum sandstone bar of less than 125 psi at the Mabel Berry No. 2, a well which was not considered commercial within the Aux Vases but contained 9 feet of oil-saturated sandstone.

The pressure of 993 psi measured during the Eason No. 1 drill stem test in the Cantrell South sandstone bar provides additional evidence for sandstone bar isolation in the study area. This reading matches an average wellhead pressure measurement of 1000 psi reported in a fluid injection questionnaire submitted to the Illinois State Geological Survey by the operators in October 1968. The similarity between these pressure readings after 17 years suggests that there was no pressure leakage from the bar.

The McCreery Waterflood Unit and wells in the McCullum area produce from separate sandstone bars that are connected. The evidence for communication between the two is consistently high levels of oil production at the F. L. Strickland, McCullum et al. Community No. 1 well from 1955 to 1984—evidence suggesting that reservoir pressure was sustained for considerable time by a sandstone body of substantial size.

Structure

Dale Consolidated Field lies along a broad regional anticlinal nose that strongly influences oil production from traps developed along its trend. The study area lies at the southwestern end of Dale Consolidated Field. Closures are formed by the convex-up lenticular nature of the bar accumulations and differential compaction of shale, sandstone, and shaley sandstone in the interbar areas.

Lithofacies and Depositional Environments

Interpretation from Wireline Logs Most of the field was developed on a 10-acre well spacing and the majority of wells were logged through the entire Aux Vases interval, thus allowing detailed lithofacies correlations.

Since density and gamma ray logs show that the porosity and clay content of the Cypress Sandstone are relatively uniform throughout the study area, the Cypress log responses were used for SP normalization. In general, Aux Vases Sandstone intervals showing an SP log response equal to at least 50% of the maximum Cypress SP response were interpreted as clean, productive sandstone. Those with a response between 25% and 50% were interpreted as shaley sandstone, and those with a response of less than 25% were interpreted as sandy shale or shale. Responses slightly higher than the shale base line may also represent thin sandstone laminae within shale or silty shale.

For the most part, resistivity values greater than 40 ohm-meters were determined to be limestone. However, because the Aux Vases was deposited in a mixed siliciclastic-carbonate environment and is sometimes highly calcareous, resistivities of 40 ohm-meters were interpreted as calcareous sandstone in sandstone intervals having a noticeable SP deflection. These sandstone intervals have little appreciable porosity or permeability, and in most cases, are not part of the productive sandstone used in volumetric calculations.

Depositional Facies

Lithologic types at southwestern Dale Consolidated Field formed within four distinct depositional facies. Facies were determined on the basis of quantity, types, and sizes of clastic grains and/or the amount of detrital and diagenetic carbonate.

Offshore Sandstone Bar Facies In the study area, the reservoir facies is interpreted to have formed in a shallow marine, sandstone bar complex. Fine grained siliciclastics began to accumulate on the sea floor by settling into paleotopographic lows. These fine grained deposits were succeeded by coarser grained sands that accumulated by shoaling against paleotopographic highs on the sea floor. The geometry of Aux Vases sandstone bodies in the study area as well as the facies relationships within the Aux Vases interval are suggestive of present sandbar accumulations on a shallow shelf (Hubbard et al. 1979).

Reservoir sandstone thicknesses range from 6 to 28 feet. The fragmented nature of carbonate framework grains in this facies indicates that these sands were deposited in a relatively high-energy, clastic, offshore environment. The reservoir quality of the bar sandstone, despite the higher energy of its origin, is largely controlled by diagenesis.

Interbar Shaley Sandstone and Shale Facies Reservoir sandstone of the offshore bar facies grades laterally to shaley sandstone of the interbar facies. Rocks of the interbar facies were deposited in a lower energy environment along the edges of and between sandstone bars; they can be intercalated with cleaner sandstone. Sandstone bars commonly contain an interval of shaley sandstone at their base. Red and green variegated silty shale or siltstone up to 3 feet thick is present below the shaley sandstone through much of the Cantrell and Cantrell South sandstone bars. This shale is nonexistent at the base of the shaley sandstone in the McCreery/McCullum sandstone bar. The presence or absence of the silty shale or siltstone interval controls the degree and types of diagenetic changes that occur within the reservoir. Very fine grained beds such as these provide a barrier to diagenetic reactions between the sandstone bar and underlying limestone by limiting the migration of fluid between the two facies.

Calcareous Sandstone Facies Calcareous sandstone in the Aux Vases interval may exhibit fairly high resistivities (on the order of 30-40 ohm-m). This facies is commonly located above and on the edges of the sandstone bar facies and may actually represent areas of the sandstone bar where calcite dissolution was not prevalent during diagenesis. In many cases, patches of calcareous sandstone occur within the reservoir next to porous and permeable reservoir sandstone. Carbonate framework grains are present in both the permeable producing sandstone facies and in the calcareous sandstone facies.

Limestone Facies The Ste. Genevieve Limestone, directly underlying the Aux Vases interval, was deposited in a relatively high-energy environment. Quartz sand, silt, and clay near the contact with the Aux Vases indicate the first influx of siliciclastics into the study area. In most cases, high resistivities within the limestone allow for easy differentiation between the Aux Vases and Ste. Genevieve intervals since electric log resistivities of the upper portion of the Ste. Genevieve commonly reach 200 ohm-meters. In places, however, sandstone at the base of the Aux Vases is calcareous, making differentiation more difficult.

Diagenetic Clay Minerals

Diagenetic clay minerals that formed as a result of dissolution and re-precipitation in these facies include illite, mixed-layered illite/smectite, and chlorite. Volumetric percent and relative percentages of clay minerals, as determined by x-ray diffraction analysis of core samples from the Farrar Oil Company, McCreery No. 1 and the T.W. George Company, R. Hunro No. 5 and R. Droit No. 5-C wells, are provided in Appendix XI.

Diagenetic clay mineral coatings contain a significant amount of micropores filled with irreducible water. This leads to low resistivity measurements; for example, productive wells in the field commonly have an R_i of 1 to 3 ohm/m as electrical currents are more easily conducted along the connate-water-filled mineral coatings around the sand grains than through the oil (Asquith 1990, Seyler 1988). Water saturation values obtained by using these

low resistivity values in Archie water saturation calculations are erroneously high, even in wells that initially produced no water.

Quartz Overgrowths and Cementation

Minute euhedral quartz overgrowths were precipitated on quartz sand grains in areas where the reservoir sandstone contained grains with thin diagenetic clay mineral coatings. The formation of clay mineral rims on quartz sand grains may be an inhibiting factor in the formation of quartz overgrowths (Cecil and Heald 1971). Quartz cementation is more prevalent in areas of the sandstone containing very thin laminae of fine and very fine grained quartz and feldspar sand that had a low initial permeability due to compaction during early burial. Because of their lack of permeability, these finer grained areas have been subjected to a lesser degree of feldspar dissolution throughout diagenesis than has reservoir sandstone, and they have thinner clay mineral coatings.

Production Characteristics

Drilling and Completion Practices Wells in the study area were generally drilled on a 10-acre spacing. Many pre-1955 wells were completed open hole with casing set and cemented just above the producing interval. Most were stimulated with 30 to 40 quarts of nitroglycerin (Barger Engineering 1959). Wells that were completed open hole were either drilled through the Aux Vases or to a deeper interval in the Ste. Genevieve to test for other potentially productive zones. Wells which tested dry in the Ste. Genevieve were then plugged back to just below the Aux Vases.

More recent wells (1955 to present) in the Osburn and McCreery Waterflood Units and in the McCullum area were also drilled through the Aux Vases interval to test potentially productive Ste. Genevieve Limestone. Wells that were unproductive in the lower zones were plugged back to the base of the Aux Vases where casing was set and perforated and the sandstone was hydraulically fractured.

Hydraulically Induced Directional Permeability Hydraulic fracturing is routinely used throughout the Illinois Basin to stimulate primary production from wells in Aux Vases Sandstone reservoirs. In the McCreery, McCullum, and Osburn Waterflood Units, wells were hydraulically fractured using 5,000 to 13,000 gallons of either gelled salt water, lease oil, or diesel oil with 5,000 to 15,000 pounds of 10/20 and 20/40 mesh sand as a proppant. The effects of previously induced hydraulic fracture orientations on overall waterflood efficiency in Aux Vases Sandstone reservoirs have not been comprehensively examined. At the McCreery Waterflood Unit, a network of hydraulically induced fractures trending east to west has caused significant production problems resulting in lowered recovery efficiency.

The existence of these fractures was first suggested by the production response of wells adjacent to injectors and later confirmed by pressure transient and fluorescent dye tracer tests. The existence of a preferred orientation for the induced fractures was shown by the injection response between two wells.

Stress Orientations and Fracturing Conditions Conditions that result in the formation of both natural and artificially induced fractures are affected by external compressive stresses as well as hydrostatic stresses within the reservoir. Thus, it is important to consider the magnitudes and orientations of regional stresses and their effects on internal hydrostatic stress conditions. Mechanisms leading to the development of regionally extensive natural fracture systems and the types of pore pressure conditions necessary for hydraulic fracturing are discussed by Lorenz et al. (1991). Because induced fractures are known to develop along preexisting natural fractures (Hubbert and Willis 1957), it is important in field development projects to document the existence and orientation of natural fractures as well as to establish the orientation of the axis of maximum compressive stress.

Fractures induced by hydraulic fracturing experiments were observed to propagate subparallel to the maximum horizontal compressive stress orientation, σ_H (Haimson 1974). Natural fractures and hydraulically induced fractures may develop in reservoir rocks in response to uniaxial compressive stresses, as demonstrated by loading experiments in the laboratory (Cleary 1958). When subjected to prolonged unidirectional stress, rocks fail and fracture planes develop subparallel to the maximum and intermediate compressive stresses σ_1 and σ_2 . Because σ_1 is vertical and σ_2 equals σ_H at depths greater than 3000 feet, natural and induced fracture planes are approximately vertical and oriented subparallel to σ_H .

Direct measurements of compressive stress orientation in the Illinois Basin have been obtained by placing strain gauges within joints in shale beds above coal seams (Blevins 1982). Other methods for determining stress orientations include earthquake focal plane analyses (Stauder and Nuttli 1970, Herrmann 1979), borehole deformation gauges in coal mines (Ingram and Molinda 1988), strain relaxation measurements of oil well cores (Pursley et al. 1973), and measurements derived from actual hydraulic fracturing tests (Haimson 1974).

Other interpretive data, such as the orientation of borehole elongation measurements (Dart 1985, Plumb and Cox 1987) and field observations of joint set orientations in coal mines (Nelson and Bauer 1987), are direct indicators of the regional σ_H orientation. Joints in coal mine roof shales in southern Illinois generally trend east to west and parallel σ_H measurements. Within these roof shales, jointing is intense locally; in places, open crevices develop parallel to σ_H in roof limestones (Nelson and Bauer 1991).

In the Aux Vases reservoirs at Dale Consolidated Field, the natural and hydraulically induced fractures are subparallel to σ_H which trends approximately east to west. Results of strain gauge measurements in an underground coal mine near McLeansboro, Illinois, 15 miles northeast of the study area, establish a σ_H trend of N87°E (Blevins, 1982); and strain gauge measurements of borehole deformation in an underground coal mine near Galatia, Illinois, 7 miles east of the study area, establish the average trend of σ_H to be N80°E (Ingram and Molinda 1988). The roof joints at the McLeansboro mine strike N87°E and the roof joints at the Galatia mine strike N80°E. In both cases, they are parallel to the measured σ_H orientation. Induced fractures in hydraulically stimulated wells were augmented both by natural fractures and also by artificially induced fractures that were propagating from older wells and causing an east-trending fracture network. Because of the relationship between compressive stress conditions and the propagation of natural fractures, documenting the existence of natural fractures in reservoir cores and obtaining their orientation provides direct evidence of the σ_H orientation. Fracture identification logs were not available from the field area, but the core from the Farrar Oil Company, McCreery No. 1 well provides some evidence of natural fracturing within the sandstone interval. This core showed that a large, oil-stained, vertical fracture was present in the Ste. Genevieve Limestone below the reservoir. Minor amounts of vertical fracturing in the reservoir interval were also reported in a core description from the Brehm Oil Company, McCreery No. 1 well, as were vertical fractures in the Ste. Genevieve Limestone below the reservoir interval. Both of these cores were from the McCreery Waterflood Unit reservoir. Nonreservoir quality sandstone in a core from the Triple B Evans, et al. No. 1 well in the McCreery Waterflood Unit also contained a large vertical fracture that was not stained with oil. None of the cores were oriented.

Effects of Hydraulic Fractures on Oil Recovery If man-induced fractures from individual wells intersect they allow a direct communication of fluids between wells. Intersecting fracture systems result in an early breakthrough of water at producing wells during waterflood operations. A conceptual diagram of intersecting fractures within a 10-acre well spacing arrangement is shown in figure 20. In addition, it is possible that fractures may extend into underlying aquifers because Aux Vases sandstone bars are typically thin (averaging 14 feet of net pay) and volumes of fluid injected in these intervals at fracturing pressures were sometimes large.

Figure 20 Hypothetical intersection of two fracture planes within a 660-foot well spacing. This is a schematic interpretation that helps explain a waterflood response in Southwest Dale. Recognition that this may be the cause of poor performance has caused the operator to redirect his flood and increase oil recovery.

Simulation results (task 6) show that by the end of the presently configured waterflood, only the regions intersected by hydraulic fractures and the highly permeable upper sandstone layer will have been swept of mobile oil. The waterflood, as presently configured, is producing a tremendous amount of water and reservoir pressures are increasing only in wells east or west of injectors. There is, however, some north-south movement of fluid through the upper permeability zone. At the time of drilling, all wells in the McCreery Waterflood Unit and those in the McCullum area were perforated within the upper, more permeable interval in an attempt to retard the incursion of bottom water into the wells. Because none of the wells were recompleted before waterflooding, injected waters flow through this upper permeable layer as well as through the induced fractures, sweeping oil only from the highly permeable portions of the reservoir. Interpreted reconstructions of induced directional permeability as well as the highly layered permeability were incorporated into engineering simulations based upon a 3-D stratigraphic framework. As predicted by the simulation, oil production response to the present waterflood program is poor.

Estimation of the Original Oil in Place

Original oil in place (OOIP) was determined by the volumetric method. Isopach maps of productive sandstone were prepared to show relationships between the sandstone bars and the distribution of reservoir intervals. Of the three sandstone bars studied, the McCreery/McCullum bar was the only one that had an initial oil-water contact (OWC). Elevation of the OWC in the McCreery/McCullum sandstone bar, as determined from the core analysis for the Farrar Oil Company, McCreery No. 1 well, was -2,715 feet subsea. Reservoir sandstones were planimeted to ascertain volumes of producing sandstone within the individual bars. Estimates of the OOIP were made for all of the sandstone bars (table 2).

Table 2 OOIP and recovery efficiency at Dale Consolidated Field

	Cantrell	Cantrell S.	McCreery	McCullum
STOOIP	2,345,800	3,757,100	1,865,700	825,350
Primary recovery efficiency	15.9%	12.2%	15.5%	24.0%
Secondary recovery efficiency	13/6%	NA	NA	NA

McCreery Unit The available evidence indicates that the unusual recovery responses at the McCreery Unit are due to the presence of an east-trending fracture network created by hydraulic fracturing operations. When permeability trends are incorporated into an engineering simulation of the waterflood using the same three-well perimeter configuration, oil recoveries are low, and high water recoveries make the flood uneconomical. If the waterflood continues as configured and no attempt is made to remedy the situation, the McCreery waterflood is likely to be abandoned in late 1993 or early 1994.

McCullum Area At present, this area contains two leases that have not been unitized, although they are controlled by the same operator. To date, there has been no attempt to waterflood this area. Conditions are similar to those of the McCreery unit, and waterflood plans will need to address the east-west permeability trend induced by hydraulic fracturing.

Osburn Waterflood Unit The Osburn unit drains the southwestern portion of the Cantrell sandstone bar and the northernmost portion of the Cantrell South sandstone bar. Osburn wells, drilled in sandstone 5 to 8 feet thick, are downdip from the Cantrell and Cantrell South Waterflood Units. Because the Osburn wells were drilled after waterfloods in the older units were completed, most wells in the Osburn Waterflood Unit had initial production rates with a significant water cut.

Although most of the wells were drilled in the Cantrell sandstone bar, two of the wells in the unit appear to have been completed in the Cantrell South sandstone bar and are not in communication with the rest of the lease.

All leases are held by one operator and have been unitized for waterflooding, but at this time, the waterflood has not been implemented. As in the McCreery/McCullum sandstone bar, intersecting fracture networks created during hydraulic fracturing operations are probably present in the area. A properly planned waterflood that takes into account induced directional permeability should allow the operators to successfully flood the southern portion of the Cantrell sandstone bar.

Recommendations

In recently drilled areas of the field, the use of hydraulic fracturing stimulation techniques has resulted in east-trending fracture networks between wells. These fractures can cause waterfloods to have poor sweep efficiency and complicate waterflood planning. In these areas, waterflood programs must be carefully planned to ensure sweep efficiency. Drilling of infill injector wells in the interwell regions on an inverted 5-spot pattern and/or a program of selective plugging of induced fractures with crosslinked polymers may be necessary to achieve maximum recovery.

Much oil remains to be recovered throughout the sandstone bars, as shown by the low overall recovery percentages of calculated OOIP. Strategically placed wells are needed to contact mobile oil in undeveloped areas near the edges of the bars.

In the portions of the field that have already been waterflooded but not hydraulically fractured, there is potential for improved secondary recovery. In sandstone underlying the Cantrell and Cantrell South Waterflood Units, mobile oil bypassed in the original waterflood because of high permeability variations apparently exists. To effectively sweep these areas of bypassed mobile oil, operators should drill injection and production wells between existing wells. Injection wells should be treated with matrix-plugging gelled polymers to invade the most conductive sandstone streaks and force injected waters to sweep less permeable zones in the sandstone.

Conclusions

Oil production in the Cantrell, Cantrell South, and McCreery/McCullum Waterflood Units of Southwestern Dale Consolidated is from offshore marine sandstone bars that formed in a

mixed siliciclastic-carbonate environment. The variety of lithofacies deposited in this environment are responsible for the heterogeneity observed in the study area. Sandstone bars are shingled and separated by shale and shaley sandstone intervals as little as 2 feet thick. Stratigraphic influences on oil production are evident at the edges of the bar where the sandstone facies become more shaley.

Microscopic heterogeneity is present in the sandstone in the form of fine grained laminations and patchy calcite cement. Deposition of siliciclastics in carbonate-saturated sea water can cause the sandstone to become cemented with calcite early in the diagenetic sequence. Diagenetic changes within the sandstone bars are responsible for formation of significant porosity. Dissolution of early calcite cement leads to a large amount of secondary porosity, and dissolution of feldspar grains leads to lesser degrees of microporosity both within the dissolved grain and within the precipitated clay minerals. Shale beds between the Aux Vases Sandstone and the underlying Ste. Genevieve Limestone apparently formed a barrier to diagenetic reactions. In areas of the bar where these shale beds are present, dissolution within the sandstone was not influenced by the underlying limestone of the Ste. Genevieve, and calcite cement within the sandstone was destabilized and dissolved. In areas without shale beds between the Aux Vases Sandstone and Ste. Genevieve Limestone, the calcite cement remained stable, as indicated by an increase in the amount of calcite cement toward the base of the sandstone and a corresponding reduction in reservoir permeability.

Operators should keep secondary recovery in mind when using hydraulic fracturing for completion and should consider the regional stress regime when designing completion programs. Induced fractures are oriented subparallel to the maximum horizontal compressive stress axis and commonly develop along preexisting natural fractures. In field development projects, it is important to establish the orientation of σ_H . Natural fractures are aligned parallel to σ_H and can provide direct evidence of the orientation of the stress axis. Fracture identification logs and oriented cores should be taken prior to hydraulic fracturing in order to determine the presence and orientation of natural fractures within the reservoir and establish the trend of σ_H .

ENERGY FIELD, WILLIAMSON COUNTY

Energy Field, 3 miles northwest of the town of Marion and 6 miles south of the Cottage Grove Fault System in Section 4, T9S, R2E, and Section 33, T8S, R2E, Williamson County, contains 220 proven productive acres. Several infill and delineating locations are yet to be drilled within the allowed 10-acre well spacings.

Oil production is from sandstone in the late Valmeyeran (Mississippian) Aux Vases Formation at depths of approximately 2,400 feet and is the southwesternmost Aux Vases production in the state. Two upper and two lower sandstone bodies have been discovered and developed, giving the field four separate reservoir zones. Over most of the field area the upper sandstone bodies are separated from the lower ones by several thin, impermeable, calcareous, argillaceous sandstones and shales.

Lithofacies

The Aux Vases Sandstone at Energy Field ranges from 30 to 50 feet thick and consists of interlayered sandstones, shales, calcareous sandstones, and limestones. The formation is underlain by about 25 feet of the Joppa Limestone Member of the Ste. Genevieve Limestone and conformably overlain by the basal limestone of the Renault Limestone, which varies from absent in some places to 9 feet thick in others.

Figure 21 shows typical electric log responses for the field area, and the major lithofacies of economically important siliciclastic zones within the Aux Vases Sandstone. These lithofacies are (1) lower sandstone bodies, (2) a thin impermeable zone, (3) upper sandstone bodies, and (4) interfingering shale. The lithologic subdivisions, originally defined on the

A. B. Vaughn
Ewaldi-Palchid No. 1
T9S R2E
372 ft SL 416 ft EL NW SE Sec. 4

Figure 21 Electric log of discovery well, Energy Field. Upper and lower sands are separated by an impermeable zone (Huff 1993).

basis of geophysical log characteristics, were subsequently confirmed by examining a core recovered in December 1991 from the Budmark Oil Company, Burr Oak No. 3 well (NE SE NW Section 33, T8S, R2E). Samples of the upper and lower sandstones and the thin, impermeable zone were recovered.

The upper sandstone bodies, usually 4 to 5 feet thick, occur in the field as two discrete pods, $\frac{3}{4}$ mile apart, approximately $\frac{3}{4}$ mile long, and $\frac{1}{2}$ mile wide. On electric logs, the upper sandstone bodies are characterized by a moderate to high SP deflection and a relatively high resistivity. The sandstone body is convex upward, when viewed in cross section.

The thin impermeable zone separating the upper and lower sandstone bodies consists of numerous thin beds of shale, siltstone, algal laminae, and very fine grained sandstone. It is up to 4 feet thick and occurs as lenses with limited areal extent.

The lower sandstone occurs in two discrete pods approximately $\frac{3}{4}$ mile apart. Each pod may be up to 24 feet thick. Logs of this interval show high SP deflections and low resistivities. The lower sandstone bodies both are convex upward in cross section.

The shale unit that interfingers with all these sandstone bodies ranges up to 30 feet thick. Characterized by low SP and resistivity values, this unit laterally seals the sandstones and, when coupled with the thin impermeable zone, effectively isolates the four sandstone bodies into separate reservoirs. Electric log correlations (fig. 22) show the spatial relationships of these lithologies, particularly the compartmentalization of the four reservoir sandstones.

Structure

A structure map contoured on the base of the Renault Limestone (fig. 23) shows a 1-mile-wide structural nose that plunges to the northwest under Section 4, T9S, R2E. Oil wells are located along the broad crest of this nose, but dry holes at some of the highest elevations reflect the absence of reservoir sandstone. Control points outside the field area are sparse and regional mapping reveals a relatively featureless northward dipping ramp that rises to the outcrop belt about 30 miles to the south.

A

Figure 22 Stratigraphic cross section A-A' showing upper and lower reservoirs, impermeable zone, shales and limestones (Huff 1993).

Figure 23 Structure on base of Renault Limestone, Energy Field (Huff 1993).

To the north, in the east half of Section 33, T8S, R2E, is a northward-plunging nose $\frac{1}{2}$ mile wide. Although a producing oil well defines the highest area on this structure, the most productive well in this section is one location to the north and 20 feet structurally lower. This relationship illustrates that the presence of thick reservoir sandstones is more important than structural position in creating productive zones in the field.

Reserves

The stock tank original oil in place (STOOIP) at Energy Field is calculated at 4,004,000 barrels of oil. Cumulative recovery through January of 1992 was 306,000 barrels of oil. The recovery efficiency of at least 20.9%, calculated for the Aux Vases reservoir, leaves an estimated 531,000 barrels of oil to be recovered. Waterflooding in newly discovered areas will produce most of this recovery. Adding injection wells in the previously flooded areas may increase ultimate recovery and, in turn, the recovery efficiency.

Depositional Setting

Petrographic evidence and regional setting indicate that the lower Aux Vases sandstone bodies in Energy Field were deposited as progradational marine tidal bars or ridges (Off 1963). These bars are believed to have been deposited as sand waves (fig. 24a).

As relative sea level lowered, topographically high areas became semiemergent, changing the depositional environment and facilitating accumulation of the sediments that form the thin, impermeable zone. Erosion of these areas was inhibited as the shallowing water allowed the growth of algal mats and stabilization of the substrate. Shallow marine tidal flat sediments were then deposited in the areas subject to intertidal deposition and covered the algal mats (fig. 24b).

The upper sandstones are interpreted as having developed in a subtidal, shallow marine environment where the topographically high areas formed by the lower bars accommodated subtidal winnowing of the sediments by wave action. Interfingering shale is interpreted as contemporaneously deposited marine shale that included winnowed fines from the proto-upper sandstone sediments (fig. 24c).

The two major bar complexes (north and south) are separated by an area that is almost $\frac{1}{4}$ mile wide and lacks sandstone. In a study of present tidal ridge geometry, Off (1963) predicted this relationship for tidal ridges of the thickness of the lower sandstone bodies (24 feet) (fig. 25). The areal association of the upper and lower sands and their similar dimensions and morphologies illustrate a periodicity of tidal bar deposition which, if a bar crest trend and wave length were established, could be a useful exploration strategy (Off 1963).

Development and Production Strategy

Several development and reentry locations could be drilled in the south bar complex if economics warrant. Current spacing is probably adequate for drainage as the four separate reservoirs are horizontally continuous. Also, there is lateral communication among the reservoirs, as inferred from the fact that original pressure in the south part of the field in 1969 was 985 psi and wells drilled during the third stage of field development in 1988 encountered pressures on the order of 350 psi—evidence of pressure bleed-off. A drill stem test (DST) in the north bar complex in 1991 had a final shut in pressure (FSIP) of 927 psi, demonstrating the lack of communication between the north and south complexes.

A high probability that other successful waterflood programs can be implemented in the unflooded reservoirs of Energy Field is supported by the performance of the Energy Field Unit flood to the east. This waterflood could have recovered more oil if other injection wells had been drilled on the western perimeter of the lease because the sweep would have been directed towards the thicker oil columns in the central area of the southeast quarter of Section 4, T9S, R2E. It is probable that the reservoir underlying the western half of the

Figure 24 Depositional environmental models for Energy Field (see text) (Huff 1993).

Figure 25 Predictive model for rhythmic tidal ridges (modified from Off 1963, Huff 1993; reprinted with permission from AAPG).

southeast quarter of Section 4, T9S, R2E, is largely unaffected by waterflooding because of the areal sweep efficiency limitations of the current injection well geometry. A more successful waterflood could be operated if the following circumstances are taken into account. The original waterflood in the field was engineered without the benefit of a complete understanding of the field geometry, particularly the undulating surface defining the top of the sand. A depression in the southern bar complex dips below the oil-water contact and separates the lower sandstone into two distinct, oil-productive reservoir compartments. It should be possible, using either a peripheral or patterned flood, to drain these two reservoirs efficiently as separate entities. The impermeable seal between the upper and lower sandstone would necessitate separate development of the upper sandstone. The calculated secondary recovery efficiency is 13.6% (which might be improved with a better injection well geometry that more effectively sweeps the reservoir); therefore, the nonflooded holdings in the south bar complex could yield an estimated additional 106,000 barrels of secondary oil.

Since the completion of this study, three more wells have been completed in the field; at least one was drilled using information from this study. This well was completed December 1, 1993 and initially produced 100 barrels of oil per day.

An engineering analysis of the field showed that early reservoir pressure maintenance was a key to increasing ultimate recovery in these reservoirs. Water injection was started in the newly discovered northern reservoirs shortly after the first wells were drilled. It is too early to determine what benefit has been gained from this practice.

KING FIELD, JEFFERSON COUNTY

King Field in Jefferson County, Illinois, was discovered in 1942. The trapping mechanism is structurally and stratigraphically controlled, and the principal production is from the sandstone lithofacies of the Mississippian Aux Vases Sandstone at a depth of about 2,750 feet. The field has 40 feet of anticlinal closure and is 3 miles long and 1.5 miles wide (fig. 26). More than 163 wells, including 108 oil wells, have been drilled on a 10-acre spacing.

Lithofacies

Three principal lithofacies are present in the Aux Vases Sandstone at King Field: calcareous lithofacies, a siltstone-shale lithofacies, and a sandstone lithofacies. Each lithofacies was deposited in a distinct depositional environment.

Figure 26 Structure map, top of Renault Limestone at King Field (Lectaru 1991).

Calcareous Lithofacies King Field has at least two types of calcareous lithofacies: a quartzose sandy limestone and a calcareous sandstone. The sandy limestone lithofacies is composed of fossil fragments, ooids, quartz grains, and minor feldspar grains. Many carbonate grains are heavily abraded. This fact, together with the presence of ooids, suggests high-energy marine deposition. The calcareous sandstone lithofacies is composed predominantly of quartz grains, feldspar grains, and local fossil fragments. This lithofacies, which contains some abraded fossil fragments, is also thought to have been deposited in a high-energy environment. Almost all pore space in both lithofacies has been occluded by calcite cement as abundant echinoderm fragments served as nuclei for early precipitation of calcareous cement.

The calcareous lithofacies were probably deposited in an offshore high-energy environment. Sediments deposited in such an environment are commonly widespread (Weber 1982), but at King Field the offshore, high-energy, calcareous facies is apparently restricted. The limited distribution suggests that the calcareous lithofacies were truncated by channels interpreted to be of tidal origin and now filled with Aux Vases reservoir sandstones. There is some minor production from the calcareous facies at King Field. In most areas, however, carbonate cement occludes the pore space in these rocks. Consequently, the calcareous lithofacies generally forms permeability barriers that increase reservoir compartmentalization.

Siltstone-Shale Lithofacies Laminated green shale to light green siltstone makes up the siltstone-shale lithofacies. It has little to no permeability, is not part of the reservoir, and is interpreted to have been deposited in low energy offshore and tidal-flat environments.

The sandstone lithofacies is a fine grained quartz arenite characterized by high spontaneous potential and low resistivity on electric logs. The best reservoir sandstone contains more than 80% quartz and less than 10% feldspar. Core samples from the better reservoir facies had an average porosity of 27% and an average permeability of more than 700 millidarcies.

Clay minerals, identified by x-ray diffraction, constitute less than 10% of the bulk volume of the reservoir rocks. These clays consist of illite, mixed-layered illite/smectite, and chlorite. The best quality reservoir lithofacies has a thin, relatively continuous dusting of clay minerals around each framework quartz grain. In the less porous parts of the Aux Vases, these clay mineral coatings are discontinuous, and calcite and quartz cements are more abundant. In general, continuous clay mineral coatings seem to inhibit the formation of quartz cement (Pittman and Lumsden 1968).

Sandstone Lithofacies The clean sandstone facies, which is defined by an SP that is at least 50% of the SP of a clean Cypress sandstone, is interpreted as either a tidal channel or offshore bar deposit. The north-south-trending sand bodies (X-X' and Y-Y', fig. 27) are interpreted to be part of a tidal channel sequence. The sand body delineated by line X-X' (fig. 27) apparently continues northwestward for a couple of miles away from the study area (Wafer 1955, Whitaker and Leetaru 1992). This linear geometry and an apparent upward-fining or blocky pattern on the SP suggests that the X-X' sand body is a channel. Although the reservoir sandstones within the channel are stratigraphically equivalent, production data indicate that they are not in communication.

Many wells along the axis have an apparent coarsening-upward SP pattern, which suggests an offshore bar deposit. The axis of the postulated offshore bar strikes parallel to the postulated paleoshoreline. Some of the most productive wells in the field are located in the offshore bar facies for two reasons: (1) the best reservoir rock in an offshore bar is near the top of the sand unit where sands are coarser, and (2) the offshore bars are located near the structural crest of King Field.

An isopach map constructed for the interval from the top of the Renault Limestone to the top of the Karnak Limestone Member of the Ste. Genevieve Limestone (fig. 28) shows a pattern of thickening and thinning that is the inverse of the pattern of the percentage of calcareous, offshore, high-energy facies in the Aux Vases. Although differential compaction of the Aux Vases may be responsible for some anomalies, this isopach map may represent

Figure 27 Contoured net thickness of clean Aux Vases sand. X-X', Y-Y' and Z-Z' are the significant sand units in the field. Areas of more than 20 feet of sand are highlighted (Leetaru 1991).

Figure 28 Interval isopach, top of Renault Limestone to the top of the Karnak Member of the Ste. Genevieve Formation (Leetaru 1991).

Figure 29 Hypothetical depositional model for Aux Vases sandstone facies at King Field (Leetaru 1991).

paleotopography during deposition. The areas of thinner Aux Vases-Renault are interpreted to generally represent paleotopographic highs. In these areas, the calcareous facies is relatively thick and the sandstone facies is relatively thin, suggesting topographic control of tidal channels. The correlation between the thick and thin intervals on the net clean sandstone isopach (fig. 27) and the Renault Limestone-St. Genevieve isopach (fig. 28) might have been stronger, except that differential compaction caused by the discontinuous beds of shale and sandstone within the Aux Vases probably has distorted overlying beds. A hypothetical depositional model (fig. 29) shows both tidal channels and barrier bars (Leetaru 1991).

Lithofacies Relationships The mixture of carbonate and siliciclastic lithofacies at King Field was probably caused by temporal fluctuations in the supply of siliciclastic sediment coupled with the presence of an extremely broad tidal zone.

The decrease in the input of siliciclastic sediment could give the appearance of a relative rise in sea level, when base level is raised and marine sedimentation prevails. Also, lateral shifting of the depocenter can cause significant changes in sediment influx and result in many lateral and vertical transitions between siliciclastic and carbonate lithofacies.

Reservoir Management

The mixed carbonate-siliciclastic, nearshore, shallow marine depositional environment of the Aux Vases at King Field formed a heterogeneous reservoir composed of intercalated sandstones, siltstones, shales, and carbonates. Lateral and vertical compartmentalization of the reservoir by facies that change over distances shorter than the interwell spacing make delineation of the true limits of the field difficult.

Dry and abandoned wells do not necessarily signify the limits of the Aux Vases reservoir at King Field. For example, oil production from a separate compartment has been found downdip of dry holes in which the Aux Vases apparently contained water.

Reservoir heterogeneity must be considered in determining the ideal well spacing for primary and especially secondary recovery. The present 10-acre well spacing at King Field has allowed large portions of the reservoir to remain unswept by waterflood projects. Figure 30 (Leetaru 1991) is a porosity-net thickness map of the Aux Vases Sandstones. The stippled areas have good potential for improved recovery through infill drilling and waterflooding.

Figure 30 Porosity net thickness map. Shaded areas have potential for additional recovery through infill drilling and waterflood (Leetaru 1991).

Figure 31 3-D areal distribution of Aux Vases reservoir sandstones at King Field (Leetaru 1991).

Three-dimensional modeling can be used to enhance the understanding of depositional history and the lateral and vertical heterogeneity of this reservoir. The areal distribution of the best reservoir facies and the potential for compartmentalization are shown in three dimensions in figure 31.

Geologically targeted infill drilling, combined with a well designed waterflooding program based on 3-D reservoir modeling, could recover an additional 1 to 2 million barrels of oil from this reservoir.

LAWRENCE FIELD, LAWRENCE COUNTY

Lawrence Field occupies approximately 62.5 square miles in Lawrence County, Illinois, and has produced more than 400 million barrels of oil from 23 separate horizons since its discovery in 1906. The Cypress (Mississippian) and the Bridgeport (Pennsylvanian) sandstones are the most prolific horizons in the field. The Cypress sandstones have yielded an estimated 260 million barrels of oil from more than 4,000 wells. The field, unitized for waterflooding during the mid-1950s, produces mostly from commingled Cypress and Bridgeport intervals; only a few wells produce from the Cypress interval alone. To date, about 39.5% of the estimated original oil in place (OOIP) of 780 stock tank barrels of oil (STB) per acre-foot has been produced; the water cut exceeds 96% after nearly 30 years of waterflooding.

This multidisciplinary study was conducted to evaluate the geologic characteristics of the Cypress reservoirs in a central portion of Lawrence Field. The purpose of the study was to determine the amount and location of any unrecovered mobile oil, and the reason for its being bypassed. An investigation of well patterns and spacings for improving oil recovery through continued waterflooding was also undertaken (task 6). The study area in Sections 19 and 30, T4N, R12W, was chosen on the basis of available core analyses and whole core, in combination with the presence of a Cypress reservoir section that is typical of the field.

Figure 32 Regional structure on the top of the Beech Creek ("Barlow") Limestone and location of Lawrence Field (Bristol 1968; in Udegbumam and Grube 1993).

Structure

Lawrence Field is located on the southern end of the south-southeast-trending La Salle Anticlinal Belt. Two closed structures separated by a saddle define the field (fig. 32). This study focuses on a portion of Sections 19 and 30 along the crest of the northern structure. Approximately 350 feet of closure is indicated on the Barlow structure map for the northern anticline. Depth to the top of the reservoir in the study area starts at 1,350 feet (-850 feet subsea). Cypress reservoirs along the crest of the anticline lie entirely within the oil column and, although oil accumulation is controlled by structure, stratigraphy is a significant factor that affects the ultimate recovery.

Stratigraphy

In the Lawrence Field area, the Cypress Formation is predominantly sandstone and shale. Incorporated within the sandstones are a few distinct beds, less than 1 foot thick, of sandy limestone to very calcareous sandstone. Where present, the reservoir sandstones are generally found about 40 feet below the base of the Beech Creek (Barlow) Limestone (fig. 33). The intervening interval consists of shale, siltstone, and shaley or calcareous sandstone. In some cases, a red and green variegated to mottled mudstone immediately overlies the reservoir sandstone. The reservoir sandstones in Lawrence Field appear to be equivalent to the middle sandstones of the Cypress, whereas many fields produce from thin, lenticular sandstones in the upper portion of the Cypress (Grube 1992, Whitaker 1992).

Figure 33 Log of the Cypress Formation in the study area illustrating five subdivisions (A-E) of the Cypress Sandstone (Grube in prep.).

Observations of core show fine to very fine grained sandstones. Beds, generally less than 6 inches thick and planar, have small-scale wavy and ripple lamination. Wispy to continuous clay laminations, one to several sand grains thick, are common throughout the sandstones. They occur as single laminations or in groups. In thin section, some laminae appear to contain organic material and show carbonized leaf(?) and woody material on core bedding surfaces. The clay laminations combine to form intercalated sandstone and shale zones or shale beds several inches to approximately 10 feet thick. These shale laminae, products of a low-energy environment, can impede fluid flow and form oil-trapping compartments. Marine trace fossils, although rare, occur in both the sandstones and shales.

The thickness of the reservoir sandstones varies by as much as 45 feet. Electric log response, particularly the SP character, core observations, and permeability values are the bases for dividing the sandstones that make up the reservoir interval into five zones, A to E, in ascending order (fig. 33). All zones are not necessarily present in any particular area. The A zone is commonly tight and separated from the others by shale; it does not appear to

Figure 34 Isopach of Cypress "C" sandstone in Lawrence Field. This is an elongated sheet sand with northeast-southwest-trending ridges (Udegbunam and Grube 1993).

contribute significantly to production. Zones B-E, the primary reservoir intervals, appear to be cyclical in nature, particularly on logs; they are separated from each other by thin, low permeability shaley sandstones, shales, or calcareous beds. The thickness of these zones is generally less than 10 feet.

Isopach maps were constructed for the five sandstones. Zones B to E show similar geometric characteristics. Elongate, sheet-like sandstones that form thick, northeast-southwest-trending ridges are common to all four zones. An isopach map of the C sandstone (fig. 34) shows the geometry. The isopach maps were constructed using electric log data from control points on a 5-acre grid.

Diagenesis

Silica cementation, feldspar dissolution, and clay mineral precipitation are the diagenetic characteristics of the Cypress reservoir sandstones that directly influence hydrocarbon production. Quartz overgrowth and cementation were widespread and unimpeded by detrital clay in the cleaner portions of the sandstones. Significant porosity and permeability reduction can be observed in thin section and with scanning electron microscopy (SEM).

Feldspar dissolution not only created secondary porosity, it may also have enriched the brine with the aluminum and silica necessary for the precipitation of kaolinite, iron-rich chlorite, and mixed-layered illite/smectite. The original feldspar content of these sandstones was less than 10%, and apparently only about one-half of that dissolved, thereby increasing porosity by less than 5%. Opposing this porosity increase is the presence of 3% to 6% of added authigenic clay minerals. An additional disadvantage from the presence of the clay minerals is their potential to cause formation damage when subjected to introduced fluids. The resulting porosity for these sandstones averages about 20% and the permeability, generally less than 100 millidarcies.

Depositional Environments

Rare marine trace fossils and thin calcareous beds, evidence for deposition in a marine setting, were observed in Lawrence Field Cypress cores. Supporting this environmental interpretation is the widespread, elongated, parallel-ridged, sheet-like geometry of the Cypress sandstones.

The thin planar bedding with wavy and ripple laminations and wispy to continuous clay laminations are indicative of deposition by moderate currents with slack periods. Tidal currents influenced sedimentation, as indicated by the tidal couplets and flaser bedding that can be observed in most cores. Scattered carbonaceous material was most likely derived from the woody flotsam of a nearby delta.

Thin shale and shaley sandstone beds, and possibly the calcareous beds, were probably deposited during low-energy periods. The carbonate beds may have formed during periods that lacked siliciclastic input.

Variegated, mottled, laminated to structureless mudstones that cap the sandstones appear to be marsh/mudflat sediments that were subjected to subaerial exposure and suggest that the underlying sandstones were deposited in a shallow marine, nearshore setting. A low-stand, sequence stratigraphic boundary is now recognized at this horizon throughout the basin. The paleogeographic setting of the reservoirs at Lawrence Field appears to be that of a large, tidally influenced, marine embayment formed during a regressive phase of the Cypress depositional cycle.

Petrophysical Characteristics

Extensive coring and core analyses accompanied the waterflood phase of development that began in the middle 1950s. Petrophysical data consisting of permeability, porosity, and oil and water residual saturations from 86 cored wells were used in the construction of the 3-D geological models that aided delineation and interpretation of the flow units.

Porosity Statistics A population density function (pdf) of porosity values was prepared with 3,371 Cypress samples from the entire Lawrence Field. The porosity pdf had a normal distribution with a mean value of 18.6% (Appendix XIV-A, -B).

Vertical variation of rock properties Figure 35 shows vertical profiles of rock properties derived from the core analyses of well L-21 in the C.S. Berkshire unit. These profiles are typical of Cypress sandstone intervals in the study area. Whereas porosity varies between 10% and 30%, the interval permeability within the reservoir varies between .1 and 600

Figure 35 Typical rock properties vertically through the Cypress: permeability, porosity, and oil and water saturations (Udegbumam and Grube 1993).

millidarcies. All five sandstone zones, A, B/C, D and E, are present. The more than 3-foot interval between zones A and B is relatively impermeable and suggests noncommunication between zone A and the overlying zones. The highest permeability values are found in zones B/C, and D, which seem to be interconnected. During waterflooding, these zones may be preferentially swept, leaving zones A and E relatively unswept.

Development and Production Implications of Reservoir Characteristics

The most significant production and development implications presented by the reservoir characteristics revealed in this study relate to differential waterflood sweep efficiencies of the sandstone zones. Some uninvaded or partially invaded zones such as zone E may be targets for improved oil recovery. Furthermore, reservoir rocks change facies to nonreservoir rocks within one well spacing and thus create compartments that may not be affected by the

production and injection wells. A producing well may be perforated in a permeable C zone and a tight D zone; however, the offsetting water injector may have good permeabilities in both the C and D zones. Flood waters from the injector would then sweep the C zone while banking oil at the interwell region in the D zone. Improved reservoir characterization and possibly strategically located infill wells hold promise for reaching oil banked in this manner.

Bypassed Oil

As in many mature fields, values for preproduction conditions in the reservoir are mostly nonexistent. Also, there were no primary oil production data for the study area, except for the C.S. Berkshire unit. Oil production from waterflooding was commingled in all but a few of the wells; however, oil production was "allocated" to the Cypress Sandstone by the operator in commingled wells. Plots of reported cumulative oil production volumes relative to the product of permeability and thickness (transmissivity, kh; task 6) showed that the Cypress oil production from noncommingled wells was approximately 40% of the oil production "allocated" to the Cypress Sandstone in commingled wells. The "allocated" oil volumes may thus be too optimistic. In any case, both reported allocations from commingled production and noncommingled oil production data were utilized in the determination of recovery factors and remaining oil volumes in this study.

Original Oil-in-Place OOIP was determined to be 824 reservoir barrels per acre-foot. Given a formation factor of 1.056 reservoir barrels per stock tank barrel (STB), the STOOIP was 780 STB per acre-foot.

Remaining Oil-in-Place ROIP was an estimated 7,761,000 stock tank barrels or 652.35 STB per acre-foot during initialization of the numerical reservoir simulation model. Data for this estimation included prewaterflood fluid saturations and porosity values derived from analyses of cores from 35 wells in the study area and an assumed average gas saturation of 11.5%.

Primary Oil Production and Recovery Factor The primary oil production is the difference between the OOIP and the ROIP at the start of the waterflood phase, or 128 STB per acre-foot. An independent and satisfactory check of this value performed with the available primary production data from the Berkshire lease gave 124 STB per acre-foot. The primary oil recovery factor as a percentage of the OOIP for the study area was found to be 16.3%.

Conclusions

Examination of Cypress cores and detailed geological mapping using geophysical log data showed that sand body trends are consistent with deposition in coastal to near-shore, shallow marine settings. Environments of deposition determine sandbody geometry and sedimentary sequences, key factors that affect the degree of reservoir heterogeneity at Lawrence Field. The study shows the existence of five distinct Cypress sandstones separated by impermeable shaley sandstones. Tight calcareous intervals, typically less than 1 foot thick, occur within the sandstones and act as further barriers to fluid flow.

MATTOON FIELD, COLES COUNTY

Geologic Setting

Mattoon Field along the Mattoon Anticline in southwest Coles County, Illinois, has a structural closure about 9 miles long and almost 2 miles wide (fig. 36). The asymmetrical anticline plunges southward with decreasing axial closure into Cumberland County. As of 1993, 878 wells had been drilled in Mattoon Field; 667 were successful. Electric logs from 684 wells were used in this study. Eight pay zones, ranging from Devonian to middle Mississippian in age, have been established. The Cypress Sandstone is the youngest pay at Mattoon.

Figure 36 Location map of Mattoon Field (McGee in prep.).

The field was developed on 10-acre well spacing and without production allocation restrictions. Wells producing from the Cypress are commonly commingled with the Spar Mountain (Rosiclare Sand) Member of the Ste. Genevieve Limestone and rarely commingled with the Aux Vases Formation. Calculation of volumetrics, reserves, and reservoir efficiency is complicated by multiple completions, recompletions, commingled production, multiple waterfloods, and ownership turnover. The absence of whole core through the Cypress interval hinders reconstruction of the stratigraphic sequence with reliable lateral facies profiles.

Primary production from the field was 9,387,190 barrels of oil. In 1950, secondary waterflooding in Mattoon Field began with injection of various fluids into the Cypress, Aux Vases, and/or the Spar Mountain Sandstones. By 1987, 4,718,565 barrels of oil had been added to the total of produced oil from these zones. Waterflooding was discontinued in 1987 after injecting 51,398,318 barrels of water into the field. A cumulative secondary production

of 4,718,565 barrels of oil and 24,259,207 barrels of water was recorded. As of March 1993, the cumulative production from all eight pay zones at Mattoon Field was 21,987,774 barrels of oil, which made Mattoon the 18th most prolific oil field in the state. It was also the state's leading gas producer from 1973 to 1988. As of December 1991, cumulative production in Mattoon Field was 308 billion cubic feet of gas (BCFG).

Structure

Mattoon Field is classified as a structural-stratigraphic trap that produces hydrocarbons from multiple horizons. The field is defined by an area of structural closure underlying the elongate and south-plunging Mattoon Anticline. This structure has more than 40 feet of closure on top of the Beech Creek (Barlow) Limestone at a depth of 1,681 feet (-950 feet subsea). Reservoirs stratigraphically pinch out against adjacent shales and have structural closure along the crest and flanks of the Mattoon Anticline. Most of the reservoirs are elongate sandstone bodies that are subparallel to the anticlinal crest. Although vertically coincident, the closure within each successive overlying unit extends farther northward, suggesting continuing deformation through geologic time. Oil-water contacts are observed at various depths in the separate Cypress reservoirs, especially along the nose of the south-plunging anticline—evidence that the relatively thin shale caprock and lateral shale barriers form effective reservoir seals. The Barlow Limestone also forms an effective caprock, as shown by a small original gas cap in the highest point of closure in the field. The earliest Cypress wells initially flowed water-free and at high rates of oil. Rapid reduction of the gas cap resulted, however, in most wells being completed on pump and with a continuous increase in water production.

General Stratigraphy

The Cypress in Mattoon Field ranges in thickness from 64 feet in the northeast to 103 feet in the south. The Cypress was divided into separate intervals for interpretation and mapping. In ascending order, these are the A, B/C, D, and E (Lower and Upper) intervals (fig. 37). Reservoirs within these intervals are not uniformly present across the field. These reservoirs can range from 5 feet to greater than 40 feet thick, $\frac{1}{4}$ to $\frac{3}{4}$ mile wide, and up to 2½ miles long. They exist as single, multiple, en echelon, stacked or coalesced, north-south-oriented, lenticular sandstone bodies encased in shale (fig. 38).

A Interval In this interval, reservoirs are characteristically less porous and permeable than reservoirs in other Cypress intervals. Reservoirs in the A interval are a diversity of mixed carbonate-siliciclastic lithofacies; cement and fossil assemblages differentiate them from reservoirs in other Cypress intervals in Mattoon Field. The separate, elongate sand bodies are 2 to 3 miles long, $\frac{3}{4}$ mile wide, and 3 to 13 feet thick. Smaller (10–40 acre) isolated pods are oriented in various directions. Sandstone bodies typically have a clean sandstone lithology in the central core and laterally grade into mixed clastic/bioclastic and fossiliferous limestone along their edges. The average thickness ranges from 5 to 9 feet in the sandstone facies, 4 to 10 feet in the calcareous sandstone facies, 6 to 8 feet in the sandy limestone facies, and 3 to 4 feet in the limestone facies. Several isolated and untested sandstone bodies in the A interval offer potential for discovery of bypassed oil.

B/C Interval This composite interval stratigraphically overlies the A interval and underlies the D interval. It is a heterogeneous mosaic of interbedded sandstone and shale and the most areally extensive and productive of the Cypress reservoirs. These sandstone bodies typically range from 2 to 5 miles in length, $\frac{1}{4}$ to $\frac{1}{2}$ mile in width, and 20 to 40 feet in thickness. In some locations, sandstones are absent in the upper B/C interval.

D Interval Sand bodies in this interval have excellent porosity and permeability in the northern half of the field. Reservoir quality in this interval deteriorates in the southern half of

TYPE LOG: API 1301 (34/12N/7E)

Figure 37 Type log illustrating intra-Cypress intervals (McGee in prep.).

of the field where interbedded shale and siltstones predominate. Depending on geographic location in Mattoon Field, this interval may be completely shale or appear as a single sandstone characterized by a coarsening-upward (progradational) grain-size profile.

Figure 38 Cypress Sandstone isopach and distribution map of a portion of Mattoon Field (McGee in prep.).

E Interval This Cypress interval consists of two sandstones separated by shale and mapped individually as the upper and lower E intervals. Depending on geographic location in the field, either the upper or lower sandstone body may be replaced by shale or the two may be coalesced and the separating shale absent. Sandstones of the lower E interval are best developed in the southern half of Mattoon Field, whereas sandstones within the upper E interval extend throughout the length of the field. Where developed, sandstones within both intervals may have basal coarsening-upward profiles commonly capped by a fining-upward sequence. These elongate sandstone bodies are encased and generally compartmentalized by interbedded shales. They are typically well sorted, silty to very fine grained quartz arenites, but generally form the lowest quality reservoirs in the Cypress Sandstone because of the abundance of interbedded shale layers in the interval.

Lower E Interval Sandstone bodies, 5 to 12 feet thick in this interval, range from lobate to elongate. Orientation is generally north to south in T12N and S50°W in T11N, slightly offset from the Mattoon Field anticlinal axis. Isopach maps indicate sediment dispersal was less confined eastward. Production from this interval is limited to the northern half of the field.

Upper E Interval Sandstone bodies in the upper E interval are generally oriented S15°E and vary from lobate to elongate; they range from 5 to 12 feet thick. A maximum thickness of 18 feet of sand was interpreted where upper and lower E sandstone bodies appear to coalesce.

Petrography and Diagenesis

Thin section microscopy indicates that the upper portions of the coarsening-upward Cypress sandstones consist of well sorted, fine and medium grained quartz arenites. The framework grains are composed of 90% quartz and up to 5% plagioclase and K-feldspar. Traces of muscovite, heavy minerals, calcite, and up to 5% kaolinite and other clay minerals are also present. Heavy mineral lag deposits clearly delineate low-angle cross laminations. Feldspar grains are commonly degraded and many are almost completely dissolved.

The average bulk volume of clay minerals is 2% of the lower and 4% of the upper sandstones. The clay fraction is kaolinite, illite, mixed-layered illite/smectite, and chlorite. Kaolinite generally appears as granulated clusters, accounting for 80% of the clay mineral total. Mixed-layered illite/smectite ("swelling") clay minerals may constitute up to 5% of the total.

Primary cementation is syntaxial quartz overgrowths followed by intergranular calcite. Clay minerals occur as pore fillings rather than as effective cementing agents. Calcite content is generally less than 1%, but may constitute up to 6% of the upper Cypress B/C interval, 20% of the lower D interval and greater than 50% of the lower Cypress A interval. Calcite, in the form of fossils, matrix cement and fracture-fill, is primarily concentrated in the lower Cypress A interval as either bioclastic limestone, sandy limestone, calcareous sandstone, or sandstone with patchy and poikilotopic cement. The calcite is generally iron-rich.

Porosity averages 16% of bulk volume. Air permeability ranges from less than 1 to 256 millidarcies. Intergranular porosity prevails over intragranular and hairline-fracture porosity.

Lithofacies

A Interval The A interval is the most heterogeneous of the Cypress in Mattoon Field. This mixture of clastic and carbonate lithologies represents reworked deposits of shale, sandstone, calcareous sandstone, sandy limestone, fossiliferous limestone, and packstone deposited on a scoured contact with the underlying Ridenhower Formation. The high percentage of calcite (as cement, fossils, and limestone layers) is responsible for the below-average permeability and above-average acid sensitivity of the A interval as compared to other Cypress intervals. The greatest concentration of carbonates is found along the base of these reservoirs. Various combinations and concentrations of bryozoan, crinoidal, echinodermal packstones, and wackestones define the nonreservoir bioclastic limestone; whereas various combinations of

very fine to fine grained, calcareous, argillaceous, feldspathic, micaceous, well sorted, fossiliferous sandstone characterize the reservoir facies. Euhedral quartz overgrowths and feldspar dissolution occur mostly in interstitial areas devoid of calcite cement. Sandy wackestones and packstones of the lower Cypress A interval appear to be reworked marine or high-energy storm deposits that contain abundant fragments of crinoids, echinoderms, bryozoans, brachiopods, and other bivalves in nongrowth and abraded condition.

B/C Interval Reservoirs within the B/C interval are typically well sorted, very fine to fine grained, micaceous quartz arenites with quartz overgrowths and local patchy calcite cement. The sandstone bodies are interbedded and underlain by siltstone and silty shale. They are the most widespread and exploited reservoirs in the Cypress Sandstone at Mattoon Field and show the greatest range of porosity and permeability. These coarsening-upward sandstones typically have a basal transition zone of thin interbedded shale including prominent horizontally oriented, en echelon ribbons of micaceous, shaley laminations that are prone to (natural and induced) open hairline fractures. The B interval exhibits a greater concentration of patchy and poikilotopic ferroan calcite cement. An inverse relationship exists between the abundance of plagioclase in the C interval and high concentrations of illite, mixed-layered illite/smectite and kaolinite in the B interval, probably due to variations in diagenesis. Kaolinite fills a significant percentage of large solution vugs, especially in the upper half of the sand bodies.

D Interval Reservoirs in the D interval are characteristically well sorted, coarsening-upward sandstones that have well developed euhedral quartz overgrowths and abundant altered feldspar grains. The highest quality reservoir is developed in the northern part of the field along the updip structural axis. Total clay mineral content ranges between 5% and 10% of the bulk volume. Diagenetic kaolinite may constitute up to 4% of the bulk volume in the reservoir facies. Both iron-rich chlorite and calcite are concentrated in the basal very fine grained, lower quality reservoir facies. Optimal reservoir quality may equal that of the B/C interval and generally exceeds the reservoir quality observed in the A and E intervals.

Lower E Interval Thin ripple-laminated and flaser-bedded sandstones and shale compose this interval. The reservoirs have well developed intergranular porosity locally occluded by scattered patches of poikilotopic ferroan calcite. Sorting is fair and heavy mineral lags were observed along the base of low-angle cross laminations. Clay content is primarily diagenetic kaolinite (3.8%). Plagioclase shows various states of dissolution. Reservoir quality generally exceeds that of the upper E interval. Large woody fragments, carbonaceous debris, pyritized fossils, local bioturbation, and thin interbedded shale layers are present. Production from wells completed in this interval typically commingle with that from other reservoirs.

Upper E Interval The upper E interval is typically a fining-upward, well sorted, tight, slightly calcareous, argillaceous, very fine grained sandstone that forms poor reservoirs.

Diagenesis

Cypress reservoir quality varies with respect to geographic location and lithofacies. The most pervasive types of burial diagenesis influencing reservoir quality are quartz overgrowths, feldspar alteration and dissolution, and calcite cementation. Reservoir quality has been improved by feldspar dissolution; however, it has been impaired by calcification, compaction, quartz and calcite cementation, and the swelling and precipitation of clay minerals. The calcite cements that impair secondary porosity are commonly iron-rich.

Environments of Deposition: Overview

These north to south sand bodies may be the result of shore parallel (strike-aligned along an aggradational to progradational strandline) or shore normal (dip-oriented within a paleotopographic low) depositional processes.

The stratigraphic cross sections and transitional lithofacies map of the lower Cypress A interval indicate that discontinuous and irregularly elongate sandstone bodies disconformably overlie the Ridenhower Formation. Encased by shale, these sandstone bodies appear to be confined in a mixture of basal and flanking arenaceous bioclastic grainstones and fossiliferous sandstones that contain a rich variety of abraded marine fossil debris. Rapid decreases of the sand to carbonate ratio in a lateral direction are characteristic of (1) erosional scouring and bedload deposits confined in prograding distributary channels, or (2) sediment reworking in high-energy, progradational, shallow fluvio-marine and/or estuarine environments. The bioclastic grainstones scattered along the disconformable basal contact of the A interval may be derived from updip scouring and rip-up of the underlying Ridenhower (Beaver Bend Limestone Member) or from lateral reworking of shallow marine strandline sediments.

The overlying stacked sandstones of the regressive B/C, D, and E intervals are generally separated by thin, laterally persistent, interbedded siltstone and shales. These interbedded shales may have been deposited in deeper water by cyclic marine transgressions. Conversely, their gradational contacts with the overlying sands indicate that they may be either prodelta shales related to overlying progradational sands or interdistributary delta muds. The facies can change from sandstone to shale within one well spacing for sandstone bodies in the B/C interval. The sandstone bodies of the B/C interval appear to be channel-bound. By contrast, those of the D interval appear to be more gradational and bar-like.

Overlying the Cypress D interval are "shoestring" sands of the lower E interval—elongate bodies aligned slightly more to the southeast than to the south. Confined to the southern two-thirds of Mattoon Field, they are much narrower than those in other Cypress intervals.

The sandstone bodies of the upper E interval are thin, discontinuous small lobes in distinct shaley fairways in the northern part of the field; but they become well developed, thick, and elongate to irregularly lobate in the south. Abundant sand-filled burrows and large woody fragments have been observed in this interval. The sandstone bodies of the upper E interval appear to be channel-like in the north. In the southern half of the field, however, they appear to coalesce with the lower E-sandstone bodies and may represent bar finger, distributary mouth bar, or even barrier bar deposits. In some areas, these linear sandstone bodies appear on maps to have either lobate, irregular elongate, or bifurcating geometries.

Volumetrics

Gas saturation data were unavailable; therefore, the original oil in place (OOIP) at Mattoon field was calculated using the volumetric method rather than the material balance method. A formation volume factor (B_o) of 1.209 for the Cypress Sandstone was extrapolated from Carter Oil Company reservoir and fluid analyses for Project No. 500, the largest waterflood operation in Mattoon Field (Simmons 1956). Core analyses, DSTs, and production data in the field indicate that separate and compartmentalized reservoirs within the Cypress A, B/C, D, and E intervals are characterized by individual (compartment-specific) oil-water contacts (OWC), water saturations, and porosity data.

Reservoir volumetrics were determined for each intra-Cypress interval. As many as 15 separate sandstone bodies were planimetered within one Cypress interval. Water saturations (S_w , percent) and porosity (ϕ , percent) data were averaged from original core analyses, historical waterflood records, and ISGS analyses of 1-inch diameter plugs. Observed and estimated OWC were delineated from available production tests, DSTs, core, and electric log analyses. Volumetrics were determined for all reservoirs above the original OWC and for proved-production reservoirs above the original OWC. The latter estimate is conservative because it does not include potential reservoir volume from untested compartments. Nonreservoir lithofacies were excluded, to the extent possible, from the volumetric calculations.

Table 3 Volumetrics for all intra-Cypress reservoirs in Mattoon Field

Interval	(ϕ %)	(1-S _w %)	Acres	Acre-ft	OOIP (bbl)	STOOIP (bbl)
Upper E	14.1	0.65	1,174.49	4,235.29	3,011,379	2,490,802
Lower E	17.0	0.65	2,145.19	9,752.82	8,360,693	6,915,379
D	16.4	0.457	1,748.58	8,679.33	5,547,592	4,588,579
B and C	15.8	0.435	4,588.18	58,179.63	34,033,901	28,150,455
A-1*	14.6	0.65	824.41	3,338.75	2,458,101	2,033,170
A-2**	14.1	0.65	1,713.38	5,166.17	3,673,254	2,513,034
Total	-	-	12,194.23	89,351.99	57,084,920	46,691,419

* A-1 = sandstone lithofacies in the A interval

** A-2 = calcareous sandstone lithofacies in the A interval

Commingled primary oil production in the field at the end of October 1950 was 9,387,190 barrels of oil. Neither the recovery efficiency nor the remaining oil in place could be determined exclusively for the Cypress Sandstone because production records are commingled, recorded on a lease basis (not individual wells), and histories involve multiple recompletions as producers, injectors, or disposal wells in various reservoir intervals.

Well Completions

About every possible combination of well completion and recompletion exists in Mattoon Field, partly because of abundant Mississippian- and Devonian-age reservoirs. Most wells are 45 to 50 years old and have complex histories of workover reentries, temporary abandonments, conversions to injection or disposal wells, and uphole recompletions. Several wells have been drilled deeper, and most wells completed between 1964 and 1986 targeted new objectives, particularly the Osage and Carper Sandstones of the lower Mississippian Borden Siltstone or the Middle Devonian Geneva Dolomite, and Cedar Valley Limestone ("Devonian Lime"). Almost all hydraulic fracturing treatments were water-based after 1962. Lease-crude fracture treatments were successful in the Cypress and Rosiclare Sandstones.

Reservoir Temperature and Pressure

Prior to the initiation of the first waterflood operation in Mattoon Field (Project No. 500), Humble Oil Company reported a bottom hole temperature (BHT) of 85°F at a depth of 1,800 feet (-1,037 feet subsea) for this solution-gas drive reservoir.

Formation pressures from drill stem tests (DST) in Mattoon Field were seldom reported to the ISGS. Of the 22 known DSTs in the Cypress, however, four recorded bottom-hole shut-in pressures (BHSIPs) averaging 647 psig and ranging from 150 psig to 703 psig. The differential BHSIPs may document either the natural changes in a reservoir undergoing production or the presence of separate Cypress reservoir compartments at any one point in time. Humble Oil Company also reported an original reservoir pressure of 707 psig at a depth of 1800 feet (-1,037 feet subsea) and a hydrostatic pressure gradient of 0.392 psig per foot of depth. The Cypress Sandstone in Mattoon Field is slightly underpressured, as compared with the hydrostatic pressure gradient for fresh water (0.433 psig per foot of depth).

Oil Characteristics

Chromatograms were generated for saturated components in Cypress reservoirs at Mattoon (Appendix VIII). Humble Oil Company reported the viscosity of oil from the Cypress as 1.63 centipoise (cp) at original reservoir conditions. API oil gravities ranged from 38.4° to 39°.

Viscosities from oil samples for this study measured at 1.63 cp at 42°C and 4.32 cp at 25°C.

Three Cypress oil chromatograms have profiles similar to those in the basin having potential source rocks in the New Albany Shale (G.L. Salmon, ISGS, pers. comm. 1994). The asphaltene content was low (0.23% and 0.85%). The C17/pristane and C18/phytane ratios were low, indicating little degradation of volatiles. The low fraction of paraffins and asphaltenes in oil samples lessens the risk of plugged perforations in the production string.

Water Characteristics

More than 51 million barrels of various treated and untreated fluids have been injected into nine pre-1987 Cypress waterflood projects. This total does not include potential contaminants introduced through several decades of commingled production. Waterflood injection fluids in the field have included fresh water, produced Cypress brine, and Pennsylvanian-age brine from salt-water disposal wells, untreated lease water, and treated sewage effluent. Records show that some operators conducted tests before commencing full-scale injection of new and unproven fluids. Also applied were filtration, chlorination bactericides, and other remediation and quality control measures of injection fluids.

Water resistivities (R_w) ranged from a minimum of 0.0692 ohms from a well outside a waterflood project area to 0.0869 ohms from a well influenced by fresh waterflood injection (Appendix VI). These differences in measured R_w may be influenced by variations in injection fluid chemistries in Cypress reservoirs.

Formation Damage and the Potential for Improved Oil Recovery

Early recognition of reservoir vulnerabilities and implementation of measures to maintain quality and minimize damage during drilling, completion, stimulation, injection, production, and workover operations can prolong the life of a well while sustaining improved hydrocarbon production. Optimum reservoir management must be sensitive to changes in performance, technology, and economics; it is of little value unless reliable data are furnished (Stiles 1992). Almost every field operation is a potential source of damage to well productivity; an important common denominator is filtration of all injection fluids (Krueger 1990).

Several formations in Mattoon Field have potential for improved oil recovery by secondary waterflooding. Virgin primary and bypassed secondary pay in Cypress and non-Cypress reservoirs may be improved by attention to reservoir heterogeneity, waterflood design, and placement of wells. Several Cypress reservoirs are undergoing feasibility pilot-testing for tertiary oil recovery by immiscible CO_2 -injection methods.

Recommendations

Improved Primary Recovery A high probability of bypassed pay and excellent potential for improving primary recovery exists in Mattoon Field because of reservoir heterogeneity, oil-water contacts within multiple and isolated reservoirs, poor well completions, numerous untested intra-Cypress reservoirs with oil and gas shows, and the wide diversity of operators who have focused on different objectives and completion agendas. Successful recompletions by current operators continue to provide evidence for bypassed pay potential in this field.

The very fine grained texture of the Cypress reservoirs at Mattoon Field creates a vulnerable, pore space microenvironment as a result of the high surface area to volume ratio. Diagenetic clay mineral coatings are exposed to physical and chemical imbalances during drilling, stimulation, completion, or injection. "Water shock" and/or scale deposition from brine can occur with every change in the chemical, temperature, or pressure equilibria that control the amount of minerals held in solution (Shaughnessy and Kline 1983, Demir 1994). Any acid introduced into the well bore should be retrieved before it becomes spent; this procedure should prevent induced scaling (and production decline), especially in the lower Cypress A interval and the basal portions of the overlying inter-Cypress sandstone reservoirs

where high concentrations of iron-rich calcite in the form of fossils and cement are prone to dissolution and reprecipitation. Oxygen scavengers and iron-chelating agents, often added to hydrochloric acid (HCl) treatments, are effective chemical deterrents to precipitation of a carbonate ferric hydroxide scale buildup in Cypress reservoirs containing iron-rich chlorite and calcite. Potassium-based drilling and workover fluids offer many advantages for clay mineral stabilization and reduce shale heaving and wellbore washouts (Krueger 1990).

The potential of discovering primary production from untapped reservoirs in Mattoon Field appears to be impractical at first, if one considers the current 10-acre well spacing, production decline curves, extent of waterflooding, and overall field maturity. A more detailed investigation of each individual intra-Cypress structure-isopach map reveals that a multitude of isolated and potentially hydrocarbon-bearing sandstones are behind pipe and remain untested. Sandstone body geometry and reservoir heterogeneity denote several compartmentalized areas possibly containing unswept mobile oil. Potential reservoir sand bodies flanking the edge of the field are not fully delineated or tested. There is proven potential for deeper multiple pay intervals in the field. The Cypress may be a candidate for horizontal drilling where structurally aligned linear sandstone bodies are suitable for the technique.

Improved Secondary Recovery Approximately 70% of Mattoon Field has undergone secondary waterflooding in Cypress, Aux Vases, and Rosiclare Sandstone reservoirs. Several Cypress and non-Cypress reservoirs in the central and northern field areas remain unexposed to waterflooding. Cypress reservoirs dip below their respective oil-water contacts along the south-plunging nose of the Mattoon Anticline.

Sweep efficiency in any secondary or tertiary flood is directly proportional to the percentage of reservoir exposed. No single reservoir completely encompasses any of the 20 separate waterflood projects in the field, and recompletions in existing production and injection wells will be necessary to completely expose the reservoir or increase perforation density for improving waterflood performance. Obtaining the maximum production potential requires that well bore perforations must penetrate well beyond proximal well bore damage (Klotz 1990). Improving recovery efficiency in compartmentalized reservoirs may require that injection patterns conform with reservoir facies.

Cypress reservoirs have the potential for additional waterflooding from some of the 11 non-Cypress waterfloods (covering 40% of the field area). When sandstone body geometry is compared to a waterflood outline map, it is evident that (1) several shale-bound and isolated sandstone bodies have either not been flooded or are only partially flooded as a result of ineffective placement of injection and production wells; (2) several Cypress reservoirs within Cypress waterflood project areas remain undrilled and bypassed; (3) previous waterfloods designed for a particular Cypress reservoir interval are technically inadequate for waterflooding other Cypress intervals; and 4) workover conversions with alternating line drive injection of existing wells or 5-acre infill patterns could improve sweep efficiency.

Recommendations for Improved Tertiary Recovery

Several alternative methods for tertiary oil recovery include thermal, microbial, surfactant, polymer and gas displacement. Miscible and/or immiscible carbon dioxide (CO₂) gas injection have proved effective as tertiary oil recovery mechanisms, but maintaining optimum performance requires recognizing abnormal declines and early detection of CO₂ breakthrough through an integrated surveillance program and periodic update of the geologic model. The primary consideration before implementing a CO₂ flood is mobility control of the injected medium. A CO₂-water alternating gas (WAG) process is favored for maintaining mobility control in mature and previously waterflooded reservoirs such as those in Mattoon Field.

Incremental oil recovery from CO₂ flooding often exceeds than 10% of the OOIP, and miscible processes ultimately recover more oil than immiscible ones. Slim-tube tests by the ISGS defined a minimum miscibility pressure (MMP) of 1780 psi in the upper Cypress Sand-

Figure 39 Structure map on Karnak Member of Ste. Genevieve Formation (Crockett in prep.).

stone. At Mattoon Field, this pressure is well above that which can be contained in the Cypress reservoirs, a condition that makes a miscible CO_2 impossible (Sim 1993). Injection pressures must also be kept below formation parting pressure to prevent fracturing, viscous fingering, or channeling of CO_2 through "thief" zones.

OAKDALE AND MARKHAM CITY NORTH FIELDS, JEFFERSON AND WAYNE COUNTIES

These fields (fig. 39) produce from a combination of stratigraphic and structural traps in sandstones of the Aux Vases Formation. The study area is on the northwest flank of the Fairfield Basin, the deepest part of the Illinois Basin. Subtle anticlinal structural noses form the main traps, and stratigraphic pinchouts of sandstones laterally seal the reservoir. Markham City North Field was discovered in 1943 and nearby Oakdale Field in 1956. Oil production is from sandstone bars in the Aux Vases at approximately -2500 feet (subsea) and from deeper carbonate reservoirs in the Ste. Genevieve Limestone about 100 feet below.

At Oakdale, 30 wells have produced from the Aux Vases as have eight wells at Markham City North. Today, one Aux Vases well continues to produce at Oakdale, but no Aux Vases wells remain at Markham City North after primary and secondary recovery. At Oakdale, recovery efficiency in the Aux Vases was calculated at 23% after primary and secondary

operations. At Markham City North, commingling of Aux Vases and Ste. Genevieve reserves makes the formational assignment of a total of 1,621,688 barrels of produced oil problematic.

The Aux Vases sandstone reservoirs at Oakdale and Markham City North are part of a bar complex. The reservoirs, 10- to 30-foot-thick sandstone bodies in the uppermost sandstones, are interpreted to be reworked crests of tidally modified offshore bars.

At Oakdale, the total sand body is approximately 2½ miles long and up to 1 mile wide. The elongation is oriented northeast to southwest, like many other Aux Vases fields in Illinois. The bar pinches out laterally to shale on the west. The reservoirs are discrete sandstone bodies oriented perpendicular to the overall bar trend. Each sandstone body is commonly less than 40 acres. The Markham City North reservoirs are also oriented northeast to southwest, generally parallel to the main bar, and are interpreted to be reworked bar sandstones. Shale-filled tidal channels intersect the bars at both fields and contribute to stratigraphic entrapment and reservoir compartmentalization.

Commonly, the upper 10 feet of the Aux Vases reservoir is perforated, but in some cases, as much as 20 feet of reservoir sandstone may be produced. The compartmentalized bar crest reservoirs, coupled with operating practices, have resulted in inefficient hydrocarbon recovery. Geologic studies indicate heterogeneities between well locations, and development of the field would have been more effective if geologic barriers had been recognized.

At Oakdale, development was based on lease blocks, and each block appears to have been treated as a relatively homogenous reservoir. At Markham City North, development of the Aux Vases reservoir was pursued after the production in the underlying Ste. Genevieve was established. The Ste. Genevieve commonly has a stronger drive mechanism and more prolific reserves. State regulations restrict development of a carbonate reservoir (at the depths these wells produce from) to 20-acre well spacing; whereas sandstones can be developed on 10-acre spacing. Therefore, a large part of the Aux Vases was developed as infill drilling on acreage held by Ste. Genevieve production. Initial development of Markham City North took place in the 1940s before the widespread use of hydraulic fracturing techniques that increased economic production of the Aux Vases pay. Both fields apparently flared the associated solution gas, depleting the natural drive mechanism.

Geologic Setting

The Aux Vases section thickens and the sandstone content increases to the north and west of the Oakdale and Markham City North Fields (Collinson 1975, Seyler 1986). The Aux Vases paleoshoreline is interpreted to have existed northwest of the study area and to have wrapped around the basin margin to the northeast. Offshore bars formed along the northeast to southwest trend parallel to the ancient shoreline. Sites of deposition of the bars were apparently influenced by subtle local paleotopographic relief of the carbonates of the Ste. Genevieve and on the middle and lower Aux Vases. Sites of bar deposition also depended on sediment sources from the northwest. The regional distribution of sandstone in the Aux Vases suggests that the sandstone bodies at Oakdale and Markham City North are part of an offshore bar complex that formed basinward from a source to the northeast. Regional maps from this study and by Whitaker and Leetaru (1992) also suggest this relationship.

Subsurface

Figure 39 depicts local structure on the Karnak Limestone Member of the Ste. Genevieve Limestone in the study area. The two fields lie on a structural nose with 10 feet of closure at Markham City North and no closure at Oakdale. At Oakdale, the oil column lies between -2,495 and -2,470 feet subsea. Aux Vases oil production corresponds well with positive structural features. It is not limited to positive structures or noses, however, as shown by production from Texas Company leases at Oakdale in the northeast quarter of Section 11, T2N, R4E. The trap in this area was apparently formed by an updip pinchout of sandstone to the northwest along regional dip.

Figure 40 Oakdale and Markham City North Fields "yellow" sand isopach (Crockett in prep.).

The sandstones in the upper Aux Vases comprise two mappable units, as indicated by SP character. Arbitrarily labeled, the "yellow" upper sandstone (fig. 40) overlies the "orange" sandstone (fig. 41), which commonly overlies a middle Aux Vases limestone. The yellow sandstone, separated from the orange sandstone by an SP deflection, commonly has a well developed, clean SP signature immediately above the contact with the orange sandstone. The yellow sandstone log signature changes from a blocky SP to a fining-upwards SP character near the contact with the overlying lower Renault Limestone, and the sandstone may be capped by a thin shale bed. The resistivity in the yellow sandstone is typically quite low, on the order of 2 to 5 ohms, regardless of whether the sandstone is oil- or water-bearing.

Pods of the orange and yellow sandstone are laterally offset from one another within the overall sandstone trend. The orientations of the sandstone bodies at Oakdale suggest that the yellow sandstones represent parts of the offshore orange sandstone bar that were reworked by tidal currents generally perpendicular to the shore. At Markham City North, which lies slightly basinward of Oakdale, the yellow sandstone bodies are offset from the thick orange sandstone bodies; but their orientation is subparallel to the elongate sandstone body trend. It appears that the orange sandstone was initially deposited as a bar and the yellow sandstone was deposited along the flanks of the orange bar.

Figure 41 Oakdale and Markham City North Fields "orange" sand isopach (Crockett in prep.).

A line of cross section from the Oakdale and Markham City North Fields (fig. 42), oriented approximately east to west, depicts isolated pods of clean yellow sandstone draped over subtle structures at the two fields. The combined structural and stratigraphic nature of the traps is evident from this section. The yellow sandstone may pinch out within one 10-acre (660 feet) well spacing, whereas the orange sandstone is widespread across the field.

Petrography and Petrology

The only continuous core available for this study is from the Elmo Holder, Breeze No.1 well, a dry hole with a show of oil in the Aux Vases. The 20-foot cored interval represents almost the entire upper Aux Vases Sandstone from just beneath the contact with the lower Renault to just above the middle Aux Vases Limestone. The well lies on the west margin of the main Oakdale bar.

The predominant sedimentary features observed in the core are thinly laminated, inclined to subhorizontal crossbeds (1/4 inch or less in thickness) that appear to abruptly change orientation, and a small-scale (approximately 4 inches thick) scour and fill structure. The fine grained to very fine grained sandstone may be oil-stained golden brown. Although

Figure 42 West-east cross section illustrating isolated sand bars, Oakdale Field to Markham City North Field (Crockett in prep.).

the sandstone may be cemented with calcite, more commonly it is poorly cemented and friable. Where fine grained shaley sandstone is well cemented, it is grayish green to beige.

Individual shale laminae and disseminated green clay minerals give the core an overall greenish cast. Very fine grained sandstones (laminae sets) with abundant interbedded claystone laminae may be impermeable or only slightly permeable to vertical migration of oil.

The core appears to break preferentially along the shales and, as a result, the change in orientation of crossbeds is not commonly preserved. An oriented core was not obtained, so the azimuthal changes in crossbed orientation are unknown.

Interpretations of the environment of deposition of the reservoirs are based on a combination of subsurface mapping, observations of the sedimentary features in the continuous core, and petrographic observations. The repetitive sandstone and shale laminae (rhythmites) are interpreted to be tidal deposits, and the scour structure is interpreted to be a cut and fill deposit at or near the margin of a tidal channel. The sandstone (orange) beneath the scour is interpreted to be a shallow offshore tidal bar, elongated northeast to southwest, subparallel to the paleoshoreline. The sandstone (yellow) above the scour is interpreted to be part of a tidally reworked bar-crest sandstone body in which small pods or compartments are oriented subperpendicular to the underlying bar (generally elongate northwest to southeast).

The lower Aux Vases (orange sandstone) is predominantly a very fine to fine grained sandstone. The sandstone grains are angular to subrounded, stained brown with dead oil, and heavily coated with clay minerals (primarily illite and chlorite). Rare iron-rich calcite cement was also observed. This sample is not from an oil-productive zone; however, the oil stain shows that oil was at one time present in the lower Aux Vases "orange" sandstone. Core analysis measured no residual oil saturation and 75.3% water saturation.

A thin section from the basal portion of the upper yellow sandstone shows that grain size increases slightly but noticeably upwards. The sandstone is composed of angular grains with brownish coatings of clay minerals and possible oil residues. Sandstone grains, in point contact, provide abundant pore spaces with angular geometries. The sandstone appears to have "floating grains," a phenomenon suggesting that calcite cement once occupied the pores but has since been leached. Microcrystalline calcite cement is sparse. The sample has excellent reservoir properties with measured porosity of 25.2% and permeability of 546 millidarcies; however, the sample came from the water-saturated zone, 8 feet beneath the perforated zone. Residual saturations determined by traditional core analysis are 10.7% oil and 58.9% water.

A sample from the top of the yellow sandstone, about 3 feet beneath the contact with the overlying lower Renault Limestone (a potential seal) also was examined. It is a clean, fine grained sandstone with scattered calcite cement, rare fossil fragments, and grains coated by iron-rich calcite. Core analysis reported 14.7% porosity and 788 millidarcies of permeability in this oil-productive zone near the top of the perforated interval. Residual saturation measurements were 26.9% oil and 51.6% water. The SP log signature of the interval represented by this sample is from the coarser grained sandstone.

Mineralogy

The bulk mineralogical composition of the Aux Vases sandstones at Oakdale includes minor amounts of carbonates, feldspars, and clay minerals. The sandstone is predominantly quartz and contains less than 2% potassium feldspar and less than 4% plagioclase. The Breeze core contains dolomite cement at the base of the sandstone, transitional to the contact with the Joppa limestone. Calcite is more abundant at the top and base of the Aux Vases sandstone and present in thin zones within the sandstone. An increase in calcite within the sandstone facies is associated with the presence of fossil fragments. Some calcite cement may be a product of the dissolution of fossil debris located in thin laminae.

The clay mineral fraction of the Aux Vases Sandstone in cores from Oakdale consists of illite, mixed layered illite/smectite, and chlorite. Clay minerals make up approximately 2% of any sample. Illite and illite/smectite make up the largest proportion of the clay minerals in the Oakdale cores, whereas chlorite makes up a small proportion of the samples. The volume of illite and illite/smectite increases as the bulk mineral percentage of feldspar increases.

Plagioclase (sodium and calcium-rich) feldspars are the more readily dissolved feldspars, in contrast to orthoclase (potassium-rich) feldspars. At Oakdale, the plagioclase feldspars are the more abundant type. Clay minerals are interpreted to have formed as a result of diagenetic dissolution of feldspars. Presence of grain-coating clay minerals is thought to have inhibited later cementation by quartz overgrowth or calcite.

Core Analyses

Standard core analysis measurements from plugs from four wells sampled at 1-foot intervals reveals that the permeability of the Aux Vases at Oakdale has a wide horizontal and vertical range. Vertical permeability is generally less than horizontal permeability, which ranges from a low of 62.2 millidarcies to a high of 584 millidarcies. Vertical permeability ranges from 1.4 to 486 millidarcies. Porosity ranges from 15.6% to 26.3%. An average value of 21.9% porosity in the pay zone was determined for use in calculating oil in place.

Vertical barriers to permeability are attributed to several interrelated factors. The thinly laminated rhythmic crossbeds are attributed to tidal cyclicity; the result of ebb tides is deposition of finer grained materials. Higher energy flood tides winnow out finer materials and redeposit slightly coarser grained sediments. The coarser flood tide sediments probably correlate with higher permeability. A single lamination may be one or more grains thick, but the lamination may extend as a thin sheet across a broad area. Cyclic packages of ebb and flood tidal sediments thus result in greater horizontal than vertical permeability. Crossbeds commonly have reactivation surfaces that may lower permeability across the boundaries.

The minipermeameter measures a point surface and records permeability variations at a much finer scale than that of 1-foot core plug analysis. Minipermeameter measurements were obtained in the horizontal plane on a slabbed core face. Results demonstrate that permeability changes occur at a very fine scale and vary from one laminae to the next in the vertical sequence within the reservoir.

The change from oil- to water-bearing zones in the cores correlates well with the slight shale breaks in the SP log response. The resistivity log shows little or no detectable response between the water-bearing and oil-bearing zones, despite the fact that a core analysis showed

a strong contrast in the pore fluid from oil-bearing to brine-bearing. This lack of resistivity contrast is attributed to the presence of irreducible clay-bound water (Seyler 1986).

Although the well records do not show oil, gas, and brine ratios, the drill stem tests from both Oakdale and Markham City North reported gas recoveries during the tests.

Drilling and Completion Practices

Drilling and completion practices at Oakdale and Markham City North were generally similar. Wells were perforated, usually four jets per foot; then 200 to 500 gallons of mud cleaning agent (MCA) was applied, followed by hydraulic fracturing with a combination of frac-sand and oil, followed by application of acid. In many instances, the operators reported using lease oil to fracture the well.

Reports of initial production from the Aux Vases range from 3 barrels to as high as 170 barrels of oil per day. The Aux Vases Sandstone in these two fields almost always produced water with the oil. Aux Vases wells in this area of the basin commonly yield average cumulative production of about 25,000 barrels of oil.

Reserve Calculations

Reserves at Oakdale were calculated using this equation:

$$\text{Stock tank original oil in place (STOOIP)} = 7,758 \times H \times A \times \phi \times (1-S_w)/B_{oi}$$

where:

- 7,758 = conversion factor for acre-feet to barrels
- H = height (feet) of net reservoir sandstone
- A = area (acres) of net reservoir sandstone
- ϕ = average porosity of reservoir sandstone
- S_w = water saturation of reservoir sandstone.
- B_{oi} = initial oil formation volume factor (1.15)

Core analyses from four wells in the central portion of the field were used to estimate the average porosity in the oil-producing zone. The estimated OOIP is 3,516,269 stock tank barrels of oil. Actual production from the Aux Vases at Oakdale to date (1992) is 831,437 stock tank barrels of oil from 31 producing wells, including primary and secondary recovery; hence the estimated recovery efficiency of 23%.

An average two-thirds of the oil may remain in the reservoir when conventional recovery methods are used (basin rule-of-thumb). It appears that production at Oakdale has not achieved this estimate, possibly bypassing an additional 10% of the recoverable oil. The OOIP was calculated using a conservative estimate, a 12.5-foot average thickness of perforated pay, as opposed to a mapped estimate of an average 15-foot pay thickness. If these calculations are reasonable, Oakdale may remain an attractive target for improved and enhanced recovery operations under favorable economic conditions. However, several mitigating factors need to be considered. The field is nearly entirely plugged. An improved recovery program at Oakdale will require permit variances for irregular well spacing, unless unitized.

Other factors should be considered in an economic assessment of Oakdale as a potential improved or enhanced recovery project:

- the potential for Oakdale as a candidate for horizontal drilling;
- costs of the improved or enhanced recovery technologies most likely to optimize recovery, such as improved waterflood and microbial or carbon dioxide injection;
- costs (and estimated return on investment) of acquiring the geologic and engineering data required for scientifically based management strategies (including taking cores, conducting traditional and special core analyses, field tests, and modeling studies).

Summary and Conclusions

The Aux Vases reservoirs at Oakdale and Markham City North fields are part of a northeast-southwest-trending offshore, shallow marine sandstone bar complex that has been modified by tidal processes. The thinly laminated sandstones in the reservoirs exhibit small-scale heterogeneities, such as the presence of claystone laminations and carbonate cementation, which affect vertical distribution of porosity and permeability. Horizontal permeability is likely to strongly depend on the areal distribution of the yellow sandstone.

Distribution of the yellow sandstone facies suggests that individual reworked bar crest sandstones may cover approximately 40 acres. If horizontal permeability is more likely to affect secondary recovery processes by waterflood, then unitization of small acreage blocks based on descriptive geologic and engineering models (as opposed to development based on surface ownership of mineral rights) is recommended for improved efficiency of recovery.

Regional comparisons made using the Oakdale and Markham City North reservoirs should also account for styles, other structural factors such as faulting or the presence of natural fracture networks, drive mechanism, and diagenetic history.

PARKERSBURG AREA, RICHLAND AND EDWARDS COUNTY

The Parkersburg area is located in the region of multiple thin sandstones. Initial Cypress Sandstone production began in the mid-1940s. Interest in the area was renewed in the late 1970s and mid-1980s.

Petroleum reservoirs are found in a wide variety of sandstone facies in the lower, middle, and upper Cypress. In a regional study, typical electric log responses were recognized in the Cypress (fig. 43). The Cypress Sandstone in the Parkersburg area was divided into three intervals—lower, middle, and upper (fig. 44). The most productive Cypress reservoirs are deltaic deposits in the middle Cypress interval. These deltaic deposits are the thickest and volumetrically the largest reservoirs in the Cypress in the study area. Although they are the most heterogeneous reservoirs, with some of the lowest porosity and permeability values of Cypress reservoirs in the area, they also have the best recovery efficiencies at 15% of the original oil in place (OOIP). This low maximum recovery efficiency suggests that a large amount of mobile oil has been left in these reservoirs. Some of it could have been recovered if reservoir limits and other reservoir characteristics and pressure maintenance techniques had been incorporated into management plans.

Many reservoirs in the lower interval of the Cypress were deposited in a mixed carbonate-siliciclastic environment. Reservoir qualities largely depend upon the amount of calcite in the rocks. Limey sandstones and sandy limestones in the lower Cypress have no porosity and permeability because all pores are filled with calcite. Better porosity and permeability are developed in the center of these carbonate-rich sandstone bodies where the amount of calcite cement is low. The edges of reservoirs in sandstone lenses in the lower Cypress are commonly carbonate-rich and grade laterally to limestones. Production from these compartmentalized lower Cypress reservoirs has been more limited because of their small size and diminished porosity and permeability. Recovery efficiencies in lower Cypress reservoirs are less than the 15% estimated for middle Cypress reservoirs.

Upper Cypress sandstone reservoirs in the study area differ markedly from lower and middle Cypress reservoirs in terms of shape, volume, reservoir qualities, isolation, quality of reservoir seal, and environments of deposition. Sandstone bodies in the upper Cypress are elongate, up to 3 miles long and less than ¼ mile wide. They are encased in shales and marked by abrupt lateral changes from sandstone to shale lithologies. Upper Cypress sandstone bodies have been interpreted to be barrier bars drowned during a major marine flooding event, after which began the shallow marine deposition of the Barlow Limestone. Sandstone bodies in the upper Cypress are well defined with a distinctive and predictable north-south orientation, which can be used as an exploration model. There is well developed porosity and permeability in many upper Cypress sandstones; however, some are extremely

Figure 43 Log responses used to map regional Cypress depositional units (Seyler in prep.).

fine grained sandstones or siltstones with minimal porosity and permeability. There has been only a minor amount of production from a few wells with completions in the upper Cypress. Recovery efficiencies of less than 10% indicate that large amounts of recoverable mobile oil probably remain in these reservoirs, and they are excellent candidates for waterflooding.

Reservoir sandstone bodies in the Cypress at Parkersburg are quartz arenites tightly cemented by intermediate to advanced stages of quartz overgrowth. The porosity, which

Figure 44 Structure, base of Beech Creek ("Barlow") Limestone, in the Parkersburg area (Easton 1943, in Seyler in prep.).

averages 15%, is largely intergranular. Dissolution of the least stable feldspars has created varying amounts of secondary porosity and provided quantities of alumina-silica that precipitated as diagenetic clay minerals in pores. Kaolinite, illite, iron-rich chlorite, and mixed-layered illite/smectite are the four diagenetic clay minerals identified by XRD and SEM/EDX analyses. Incomplete dissolution of feldspar and the precipitation of diagenetic clay minerals has created significant amounts of microporosity. Most of it is unconnected with other pores; and as it does not contain mobile oil, is not effective porosity.

Production History

Parkersburg Consolidated Field was discovered in 1941. Ooid shoals in the McClosky are the primary drilling target, and most wells are drilled through this portion of the Ste. Genevieve Limestone. Before 1943, 2,500,000 barrels of oil were produced from McClosky oolite shoal reservoirs and 1,000 barrels of oil from Chesterian sandstone reservoirs (Easton 1943). Since 1943, Chesterian sandstones have become an increasingly important secondary target in the area; an additional 600,000 barrels of oil has been produced from Cypress Sandstone reservoirs. There were 504 wells drilled in the region before 1990. Of these, 105 produce from the whole Cypress Sandstone, 70 from the middle Cypress, seven from the upper Cypress, 29 from the lower Cypress, and 11 from the combined middle and lower Cypress.

Structure has played a major role in the entrapment of petroleum in the Parkersburg area (fig. 44). Within this structurally high framework, the location of facies favorable to the preservation and development of good permeability and porosity has secondarily controlled the location of the best reservoirs in the Ste. Genevieve Limestone and Cypress Sandstone.

Much of the Cypress production in the area is marginal; most wells have been accumulating 5,000 barrels of oil or less at depths of approximately -2,300 feet subsea. Although production from the Cypress dates back to 1942, much of the Cypress production in the area is from wells drilled in the 1970s or later. Shallower zones such as the Cypress were often overlooked in the pursuit of more potentially lucrative horizons below. Exploration success in the Cypress has been sporadic in this area. Cypress reservoirs occur in sandstone bodies of limited volume and varying geometries, lithologies, and reservoir quality.

Measured porosity in Cypress reservoirs in the study area ranges from 12% to 18%, and permeability ranges from 20 to 200 millidarcies. The thickest, cleanest Cypress sandstones that coincide with the most pronounced structural closures are the most productive Chesterian reservoirs in the study area. The quality (porosity and permeability) of Cypress Sandstone reservoirs is controlled by environments of deposition, microfacies, and diagenesis.

Geologic Setting

Lower Cypress Sandstone A lower Cypress Sandstone isopach illustrates two facies: lower delta plain distributary channel deposits with associated interdistributary bays, and shallow marine sandstone bars. The demarcation between lower and middle Cypress sandstones was arbitrary by necessity because many of the thickest lower Cypress sandstones originated in the lower Cypress and extended through the middle Cypress. In these cases, sandstones were included in the lowest interval in which they occurred. Therefore, some major distributary channels extend vertically through the lower and middle Cypress intervals. Distributary channels are commonly filled with interbedded fine grained sandstone and siltstone, but localized zones deposited under high-energy conditions contain cleaner, coarser grained sandstone. These coarser grained distributary channel deposits have some of the best reservoir characteristics in middle and lower Cypress sandstones.

Portions of the lower Cypress may represent a period of relatively shallow water during which lower delta plain sediments were deposited. A distributary channel filled with sandstone and siltstone, a major feature of this lower delta plain environment, has been oil-productive. Elsewhere in the area, there is a distributary mouth bar that has not been tested for oil to date. This is a relatively clean, medium thick, isolated sandstone body that has

good potential for oil entrapment. However, the best reservoirs in the lower Cypress are found in sandstone bars containing fossil fragments indicative of an open marine environment. Juxtaposition of lower delta plain and marine bars containing sandy limestone and limy sandstone is evidence of a strong marine influence during some phases of lower Cypress sandstone deposition. Marine influence is found at the toes of distributary channels and distributary mouth bars in some modern analogs of fluvial-dominated deltaic deposits. Lower delta plain distributary channel and distributary mouth bar deposits in a fluvial dominated environment, such as existed during lower to middle Cypress time, were deposited into coastal waters where deltaic, coastal, and marine processes mixed to form a complex variety of reservoirs and seals.

Middle Cypress Net Sandstone Isopach Map The largest middle Cypress sandstone bodies have been mapped in the west-central portion of the study area; these sandstone bodies are among the most extensive and thickest in the Cypress Sandstone (fig. 45).

Most of the middle Cypress sandstones have been interpreted as lower delta plain deposits, primarily distributary channel fill, crevasse splays, overbank, and bay-fill deposits. There is less marine influence evident in middle Cypress siliciclastics than in lower Cypress deposits. The lowermost portions of the middle Cypress are the only units that contain evidence of possible marine influence.

Although the isopach of middle Cypress sandstones shows relatively thick sandstone bodies, the upper portions of some of the thickest of these sandstones are made up of several thin sandstones interbedded with finer grained siltstones and shales. Where this occurs, the thin sandstones were combined, tested, and mapped as a single sandstone body.

Lower Delta Plain Deposits in the Middle and Lower Cypress Varying types of lower delta plain sediments include distributary channels, distributary mouth bars, crevasse splays, interdistributary bays, and sand bodies reworked by marine processes located at the toes of delta lobes. Many of these sand bodies have potential for petroleum entrapment. Only a few had been exploited at the time of this study.

In areas that have no sand in the lower and middle Cypress, the interval is made up of shale and siltstone. Areal distribution and petrographic characteristics in well cuttings of this lithology indicate that many of these regions were distributary bays. As the locus of active sand sedimentation shifted, distributary bays formed, representing the destructive and abandonment phases of deltaic deposition. These sediments are important because they serve as reservoir seals for adjacent, underlying and overlying sandstones. Their importance in this capacity is reinforced when the lack of production in massive Cypress sandstones in the broad facies belt is considered. The reason these sandstones are not highly productive is the lack of effective seals to trap petroleum. Much of the best production from lower Cypress sandstones is found in relatively clean, areally limited sandstone bodies possibly located at the toes of delta lobes where they were reworked by marine processes.

Upper Cypress Sandstone The upper Cypress contains thin (5 to 10 feet) elongate sandstone bodies interpreted as barrier bars, sand ridges, or (less likely) sand-filled channel sandstones. There is a more abrupt lateral lithofacies change in the upper Cypress from sandstones to shale than that found in lower and middle Cypress sandstones.

Petrologic and petrographic analyses of well cuttings show that the top of the middle Cypress sandstone is marked by a zone of red shale and/or red hematitic sandstone, an indication of subaerial exposure. These red beds separate the more massive middle Cypress sandstones from the more shale rich upper Cypress interval. Evidence of subaerial exposure at the top of the middle or, in drillers' terminology, the massive sandstone has been observed in this zone in several other fields across the basin (Louden, Lawrence, and Tamaroa Fields) and suggests a basinwide lowstand period. Analyses of well cuttings show open marine fossils in shale cuttings in the uppermost Cypress to lowermost Barlow Limestone transition.

Figure 45 Isopach of middle Cypress, Parkersburg area (Seyler in prep.).

C. I. = 10ft

Therefore, it is believed that the upper Cypress from the top of red bed shales capping the middle Cypress massive sandstone to the Beech Creek ("Barlow") Limestone represents a gradual rise in sea level culminating in a marine transgression or marine flooding stage during deposition of the Barlow Limestone.

Petrography

Framework grains in Cypress Sandstone reservoirs in the Parkersburg area are composed of nonundulose quartz, undulose quartz, plagioclase feldspar, muscovite mica, heavy minerals (primarily zircon), hematite and magnetite, polycrystalline quartz, chert, and fossil fragments. XRD results show that Na-plagioclase feldspar is the most common feldspar in Cypress Sandstone reservoirs, orthoclase is rare.

Petrographic analyses of upper, middle, and lower Cypress reservoir sandstones included thin section analysis, SEM/EDX analysis, XRD, and cathodoluminescence. The paragenetic sequence was similar for all reservoir sandstones analyzed. Petrographic variations observed among the reservoirs in the Parkersburg area were caused by differences in original mineral composition due to facies variations or differences in depositional processes.

Environments of Deposition

Lower Cypress Petrographic study of well cuttings, core biscuits, and cores, combined with study of variations in electric log signatures for the Parkersburg area, show a complex array of depositional environments for the lower portion of the Cypress Sandstone. Deltaic distributary channel, overbank, crevasse splay, and bay-fill deposits are in proximity, vertically and laterally, to shallow marine sandstone bars. The lower and middle to lower Cypress contain nearshore marine, carbonate-rich, thin sandstone bodies. These marine sandstones are bar-shaped, oriented approximately east to west, and twice as long as they are wide. Some sandstone bars grade laterally to limestones or limey sandstones; others are carbonate-rich throughout; a select few, composed of clean porous sandstone, are highly productive.

These sandstone bars were deposited in a mixed carbonate-siliciclastic environment. Fossil fragments such as echinoderms, crinoids, brachiopods (*Composita* sp.), and fenestrate bryozoa, indicative of an open marine environment, are common in some locations. Some samples from lower Cypress sandstones are cemented with iron-rich calcite. Highly porous samples contain only a minor amount of calcite cement and few or no fossil fragments. Some wells in these sandstones have been highly productive and others have not produced to full potential, probably because of multiple controlling interests in a single sandstone reservoir. It is also possible that these sandstone bodies overlap.

Middle Cypress The depositional system and resultant reservoir facies are more complex in the middle Cypress than in the upper or lower Cypress. A large variety of facies are oil-productive, whereas others form reservoir seals. Many producing sandstone bodies were deposited in deltaic facies, whereas others were deposited in coastal or marine environments. Most Cypress production in the study area is from middle Cypress sandstone reservoirs and is distributed between deltaic and marine beach facies. Middle Cypress sandstone bodies are thicker, more widespread and display greater heterogeneity (more shale and siltstone intervals within reservoirs) than upper Cypress sandstones. There is also a high degree of lateral heterogeneity within middle Cypress sandstone bodies.

Upper Cypress Preliminary examination of electric log characteristics primarily on spontaneous potential and long and short normal resistivity logs revealed several basic patterns within the basinwide, multiple, thin sandstone category associated with most Cypress sandstone production. These patterns were used to subdivide this category for detailed mapping in the Parkersburg area. One observation was of the localized development of relatively thin (3 to 15 feet thick), clean, permeable sandstone lenses in the upper portion of

the Cypress Formation at depths ranging from directly below to 30 feet below the Beech Creek ("Barlow") Limestone. The top and basal depths of these upper Cypress sandstone units were recorded and mapped. Electric log characteristics and petrographic examination of well cuttings show that lithologies adjacent to upper Cypress sandstones were most commonly medium to dark gray shales or interbedded shales and siltstones.

The narrow elongate geometry of these sandstone bodies suggests deposition as sand bars, possibly as barrier bars, or as tidal channels cutting into fine grained tidal flat siliciclastics. Tidal channels usually contain meander belts similar in size and shape to those formed by fluvial systems (Weimer 1982). A cross section through one of these elongate upper Cypress sandstone bodies illustrates, however, a concave-downward shape usually associated with channel-deposited sandstones. In contrast, sandstones deposited as bars typically display a convex-upward shape. It is possible that, with such a thin sandstone encased in shales, compaction caused the concave-downward shape, not that this geometry was caused by deposition in a tidal channel system. Some upper Cypress sandstones, particularly those in structurally favorable locations, have been good producers.

Petrographic examination of thin sections made from well cuttings of upper Cypress Sandstones show that they are composed of fine grained, clean, quartz arenites cemented by quartz overgrowths and that the porosity is good in localized areas. Heavy minerals including zircon, hematite, or magnetite may be abundant. Feldspar is present but most of the least stable varieties have been dissolved; albite is the most common remaining feldspar. Although diagenetic clay minerals are found sporadically in pores, they are an important component of the pore mineral system. The most common diagenetic clay mineral is kaolinite, followed by iron-rich chlorite and lesser amounts of illite. Because well cuttings were the only samples available for upper Cypress sandstone reservoirs, XRD analyses were not possible; therefore, mixed-layered illite/smectite could not be identified.

The thickest and best developed upper Cypress sandstone bodies in the study area are not oil-productive. Some of these clean, isolated sandstone bodies may not be in structurally favorable locations and may be wet; others may be potentially overlooked reservoirs, particularly if updip extremities can be located and exploited.

Upper Cypress sandstone reservoirs are encased in relatively impermeable shales and siltstones. Fluid communication within individual sandstone bars is apparently good. Electric logs show clean sandstones devoid of shale, siltstone, or limestone intervals that would form partitions in these reservoirs and potentially impede the flow of fluids. The lack of partitioning, the limits of elongate bar geometry, and the fact that these bars are encased in impermeable shales make these upper Cypress Sandstone reservoirs ideal candidates for water-flooding and other secondary recovery operations.

Although the geometry of upper Cypress sandstone bodies is similar, the variation in the thickness of the shale interval separating upper Cypress sandstone bodies from the overlying Beech Creek ("Barlow") Limestone suggests several phases of bar deposition at different times. It also suggests that a similar depositional setting persisted from the end of middle Cypress sandstone deposition until the beginning of Beech Creek ("Barlow") Limestone deposition. The depositional pattern and electric log characteristics of siliciclastics in the middle Cypress differ markedly from those in the upper Cypress.

Volumetrics

Volumetrics were estimated in selected examples of upper, middle, and lower Cypress reservoirs. Because of the limited availability of data on reservoir quality volumetrics, reserves and recovery efficiencies are approximations that would be more accurate if measured porosity, water saturation, and oil-water contact data were available. Net sandstone isopachs of each sandstone body were constructed for calculation of reservoir volumes and reserve estimates. The grid method was used to estimate volume of net sandstone isopachs.

The marine bars in the lower Cypress have an average porosity of 17% based on estimates from thin sections of well cuttings and a core analysis report from one well. The lower Cypress reservoirs are volumetrically the smallest in the study area.

An average porosity of 14% in the middle Cypress reservoir was estimated from log and core analysis data. Porosity in middle Cypress reservoirs is generally lower than that in upper and lower Cypress reservoirs because more porous, high-energy, sand-filled distributary channel deposits alternate with very fine grained, nonporous, low-energy channel fill and distributary bay-fill sediments. This creates a greater heterogeneity than is found in the marine bars in the lower Cypress and the drowned barrier bars in the upper Cypress.

The elongate, north-south-oriented sandstone bodies in the upper Cypress are volumetrically the second largest in the study area. An average porosity of 16% for upper Cypress reservoirs was estimated from thin sections of well cuttings and a single core analysis report from the Central Pipeline Company, Estella Blackford No. 2 well.

An average water saturation of 60% was estimated from electric logs and used to estimate reserves for all Cypress reservoirs in the study area. The limited log data available shows no evidence of an oil-water contact in these reservoirs; therefore the entire reservoir interval was presumed to be oil-filled. It is acknowledged, however, that some of these reservoirs may contain an oil-water contact.

The recovery efficiencies of Cypress reservoirs in the study area show that much of the producible oil remains in these reservoirs. A lower Cypress marine bar has the best recovery efficiency, 14.6%. This is attributed to the fact that these are small, discrete reservoirs with relatively good porosity. The other two marine bars in the lower Cypress for which volumetrics were calculated had recovery efficiencies of 8.5% and 2.6%; these bars were not as efficiently drained, probably due to well placement or greater depletion of pressure than that which occurred in the lower Cypress bar with better recovery efficiency.

Well Pressure and Completion Data

Drill stem tests (DST) for middle Cypress reservoirs show bottom-hole pressures ranging from 245 to 920 psi. Most DSTs run for 60 minutes or more had final shut-in pressures between 800 to 920 psi in lower, middle, and upper Cypress reservoirs. There was less DST data available for upper Cypress reservoirs; however, one of three DSTs recorded a final shut-in pressure of 882 psi and the other two tests recorded 245 psi and 479 psi of bottom-hole pressure. These values are significantly lower than those for most middle and lower Cypress Sandstone reservoirs; it is likely that these lower readings may have been taken after pressure was depleted by production.

Completion practices used for Cypress reservoirs were largely dependent upon the individual operator; most Cypress reservoirs were perforated at the rate of one to 12 shots per foot—two shots per foot being most common. Most completed wells were hydraulically fractured. Fracture treatments varied from moderate to heavy. The typical hydraulic fracture treatment used 9,000 gallons of gelled or salt water and 18,000 pounds of sand for a 10-foot interval. Wells were commonly treated with 300 to 500 gallons of 15% mud clean-out acid. Lower and middle Cypress intervals were more frequently completed than were upper Cypress intervals.

Brine Analysis

Brines from six oil wells in the Parkersburg area were sampled and analyzed. The results are given in Appendix VI.

Conclusions

Cypress Sandstone reservoirs are scattered throughout the Cypress sandstone interval at Parkersburg. They are found as a wide variety of facies representing lower delta plain to

shallow marine environments. The best reservoir qualities are found in upper Cypress reservoirs in elongate sandstone bodies interpreted as drowned barrier bars. These reservoirs, which usually have the greatest spontaneous potential deflection, are the most porous and permeable Cypress Sandstone reservoirs in the Parkersburg area. It is also likely that they contain the greatest amount of unrecovered mobile oil. The lack of data on oil saturation in the upper Cypress Sandstone intervals introduces a large degree of uncertainty in determining the amount of oil originally in place in these reservoirs. However, excellent production from several wells in upper Cypress reservoirs suggests that there is good potential in these reservoirs for implementation of secondary recovery strategies. Because upper Cypress Sandstone bodies are isolated and encased in shale, they are well suited for infill drilling and well planned waterflood programs, once the limits of the sandstone body has been defined. The consistent shape and orientation of upper Cypress Sandstone reservoirs may be used to facilitate delineation of reservoir limits. These two strategies offer the best opportunity for improved oil recovery from these reservoirs. There are also exploration opportunities for upper Cypress reservoirs in the area.

Middle Cypress reservoirs are comprised of a variety of lower delta plain facies. This introduces a large degree of reservoir heterogeneity. Middle Cypress distributary channel reservoirs display a large amount of diversity in reservoir quality over short lateral and vertical distances. The variations are caused by alternating low-energy depositional cycles of fine grained, relatively nonporous and impermeable siliciclastics interbedded with higher energy depositional cycles of coarser grained more porous and permeable siliciclastics. These cyclic variations are controlled by environmental factors common in many lower delta plains. Crevasse splays and overbank deposits are also a highly variable component of middle Cypress reservoirs in the Parkersburg area. These environmentally produced features have resulted in highly compartmentalized, middle Cypress reservoirs in the area. Reservoir heterogeneity is a major factor for low recovery efficiencies in these reservoirs. Although in terms of ultimate recovery of petroleum, recovery from middle Cypress reservoirs in the study area has been more successful than it has been from upper and lower Cypress reservoirs in the area, recovery efficiencies are less than would ordinarily be expected.

Another factor contributing to the low recovery efficiencies in Cypress reservoirs is the large number of operators producing from individual sandstone bodies. This may lead to disjointed, uncoordinated, and counterproductive recovery programs. Well spacing is another aspect that may inadvertently bring about less than optimum recovery from all levels of Cypress reservoirs in the study area. Sandstone reservoirs are drilled on 10-acre well spacing in Illinois. The irregular shapes and small size of most Cypress sandstone reservoirs may be best exploited when spacing is designed to accommodate the shape and size of the reservoir.

Lower Cypress reservoirs exhibit reservoir qualities intermediate between those of relatively poor middle Cypress reservoirs and the clean, porous and permeable upper Cypress reservoirs. Selected lower Cypress reservoirs, composed of clean sandstones, have very good porosity; however, lower Cypress reservoirs are more calcite-rich than middle or upper Cypress reservoirs. Lower Cypress reservoir qualities are in large part controlled by diagenetic events immediately following deposition in a shallow marine mixed carbonate-siliciclastic environment. Either primary or secondary calcite cement may be extensive enough to occlude porosity. Some lower Cypress sandstone reservoirs grade laterally to impermeable limy sandstones or sandy limestones. Large amounts of calcite cement diminishes the quality of many lower Cypress sandstone reservoirs relative to upper Cypress reservoirs. Lower Cypress reservoirs have no distinctive shape, size, orientation, or distribution. Therefore, predicting reservoir limits of lower Cypress reservoirs is much less certain than predicting the limits of upper Cypress reservoirs. However, lower Cypress reservoirs have fewer compartments and are less heterogeneous than deltaic middle Cypress reservoirs. Poor recovery from lower Cypress reservoirs may be due to their small size and lack of knowledge concerning limits of individual sandstone bodies. For example, the amount of communication between marine sandstone bars mapped in the detailed area of this study is not

known, which may result in poor placement of waterflood injectors or miscalculation of reserve estimates.

This study has shown that a small amount of carefully analyzed rock data can be used to interpret environments of deposition, a good aid in mapping reservoir boundaries. The limits of the data become obvious when attempts are made to calculate reserves. Calculations of reservoir volumetrics are approximations with a large degree of uncertainty due to the lack of water saturation and porosity data. Pressure data are also very limited. Given the similarity of reservoir behavior in this area with other Cypress reservoirs, it is likely that these reservoirs are also slightly underpressured. Estimates of the original oil in place and recovery efficiencies confirm that a large amount of recoverable oil remains in all levels of Cypress reservoirs. It is not known whether it is economically feasible to initiate secondary recovery programs or to drill infill wells in the area for Cypress reservoir targets. Although diagenetic clay minerals form only a small percentage of the total bulk mineralogy of these reservoirs, they must be considered during the design of drilling, completion, and recovery treatments. The diagenetic clay mineral suite in these Cypress reservoirs is composed of kaolinite, chlorite, illite, and mixed-layered illite/smectite. These clay minerals are a potential source of formation damage in these reservoirs. These problems have been addressed in greater detail in the literature. Iron-rich chlorite may cause iron-chelating problems during acid treatments, if the acid doesn't contain clay stabilizers. The chlorite is particularly susceptible to precipitation of iron hydroxide gels, if pure 15% HCl is used.

Fractures in thin sections made from cores suggest that there may be a regional fracture system in the Parkersburg area. At present, maximum horizontal compressive stresses are oriented north to south. Fractures induced by hydraulic fracturing will be oriented sub-parallel to maximum horizontal compressive stresses (Beatty and Fagan 1994). Until directly measured fracture data become available, earthquake focal plane data provide the best approximation for orientation of fractures induced by hydraulic fracturing. This information should be extremely useful during all phases of reservoir management and particularly during design of waterflood programs.

RICHVIEW FIELD, WASHINGTON COUNTY

Richview Field in northeastern Washington County, south-central Illinois, was discovered in 1946; it has produced more than 3 million barrels of oil. The field trends northeast and includes part of Section 35, T1S, R1W, and parts of Sections 2, 3, 10, 11, and 15, T2S, R1W (fig. 46). The field is approximately 3 miles long and $\frac{1}{2}$ to $\frac{3}{4}$ mile wide, and its center lies directly under the town of Richview. The field is located on the east side of a localized topographic high area with the same northeast trend as the field.

A comprehensive geologic investigation integrated with modern engineering analysis of all production-related reservoir characteristics is necessary to evaluate and determine producibility of remaining recoverable reserves. Drilling, completion, stimulation methods, well spacing, pressure maintenance, and waterflood designs are all highly dependent on characteristics of individual reservoirs. This study was conducted to geologically characterize and evaluate the Cypress Sandstone reservoir of the Richview Field, identify the factors that control recovery efficiency, and recommend techniques that may improve oil production.

Geologic Setting

A structure map of the top of the Beech Creek ("Barlow") Limestone (fig. 46) shows the location of Richview Field. Regional dip on the base of the Barlow varies from 50 to 200 feet per mile on the east side of the field to 25 to 50 feet per mile on the west side of the field. The top of the Barlow structure map shows the Richview reservoir associated with a local structural high that is a southern extension of the Irvington Anticline, although not previously mapped as such. The field sits on the west flank of the present structural basin and west of the DuQuoin Monocline. The DuQuoin Monocline, a major structural feature in the basin,

Figure 46 Top of Beech Creek (Barlow) structure map and location of Richview Field (Frankie and Grube in prep).

• Oil	✱ Gas Injection	✱ Junked
✱ Oil & Gas	✱ Gas Storage	✱ Temporarily Abandoned
✱ Gas	✱ Salt Water Disposal	✱ Observation
✱ D&A Oil Show	✱ Water Injection	✱ Other Injection
✱ D&A Gas Show	✱ Water Supply	✱ Confidential
✱ D&A Oil & Gas Show	○ Permit	✱ Other Well Type
✱ D&A	○ Water	+ Status Unknown

— through any symbol indicates well is currently plugged

strikes north-south for 50 miles and defines the east edge of the Sparta Shelf, a structural terrace on which Richview Field is located. Subsidiary folds on the east edge of the Sparta Shelf form the structural component of the hydrocarbon trap for the Richview reservoir. The Irvington, Richview, and Ashley Fields are located along the Irvington Anticline and its southern extension.

Changes in thickness of Cambrian to Pennsylvanian strata across the DuQuoin Monocline indicate that recurrent movement has taken place along a system of basement faults (Nelson 1988, Hopkins and Simon 1975). Folding that formed the Irvington Anticline and the subsequent structural and stratigraphic traps in the Irvington, Richview, and Ashley areas may have resulted from tectonic events that created the DuQuoin Monocline; therefore, deformation and trap formation occurred during the Pennsylvanian Period (Siever 1951).

The coexistence of Cypress reservoir rock and structural highs along the trend are responsible for many Cypress oil fields. In general, hydrocarbon production in these fields has been restricted to the stratigraphically highest Cypress Sandstone, even though structural closure may exist throughout the Cypress section.

Production History

Richview Field contains 63 producing wells, ten injection wells, and one disposal well. To date, there are 20 abandoned oil wells in the field. The productive reservoir facies is geographically outlined by the 53 dry and abandoned wells that encompass the field. The Cypress sandstone reservoir lies at an average depth of 1,500 feet below the surface.

Yearly production data were obtained from *Pipeline Production Reports* published by Petroleum Information (PI). Production for each year is based on December totals. The first 15 years of production from 1947 to 1961 was from one well (or lease), which produced 169,000 barrels of oil. In 1962, the number of wells within the field increased to 39, and in 1963, to 53 wells. A second production increase, starting in 1966, was the result of secondary waterflood operations. Cumulative production from Richview is 3.3 million barrels from 1947 to 1992. Currently, 63 wells are producing in the field.

Reservoir Characterization

The total thickness of the Cypress Sandstone at Richview Field averages 140 feet and consists of interlayered sandstones, shales, calcareous sandstones, and limestones. The Cypress Sandstone is underlain by shales and thin limestones of the Ridenhower Formation and conformably overlain by the Beech Creek ("Barlow") Limestone, averaging 10 feet thick over most of the reservoir.

Cypress sandstone beds in Richview Field consist of four distinguishable units that can be traced and mapped using SP and resistivity log signatures (fig. 47). They are identified for this study, from lowermost to uppermost, as beds A, B/C, and D. Only a small number of wells penetrated the entire formation. The oil-water contact is -961 feet.

Cypress A Sandstone A net thickness map of 50% clean sandstone in the lower Cypress A interval (fig. 48) shows a northeast-southwest trend of sandstone up to 40 feet thick in the northern part of the field. This unit, absent in the southern portion of the field, is not penetrated by all the wells; however, it appears to be laterally persistent within the northern field area. The geometry of the isopach map indicates that the source of clastic material was from the north and east. Wireline log responses suggest the A sandstone is a fining-upward sequence. This sand is not productive because it is stratigraphically below the oil-water contact in the field.

Charles T. Evans
 McDonald-Richardson Unit #2
 T2S, R1W Sec. 2 NE SW NW
 Washington County, IL
 K.B. 540'
 IPP 60 BOPD

Figure 47 Type log of Cypress at Richview Field (Frankie and Grube in prep.).

Cypress B and C Sandstones The middle Cypress B and C sandstones are commonly separated by a shale unit ranging from less than 1 to 4 feet thick. The separation between the B and C sandstones decreases towards the middle of the reservoir. A net thickness map of 50% clean sandstone in the middle Cypress B interval (fig. 49) also shows a northeast trend. Average thickness of the B sandstone is 10 feet; maximum thickness is 19 feet in the northern and central part of the field. These two areas of thick sandstone are separated by an area of thin sandstone. The B sandstone potential for reservoir development is restricted to the central, structurally higher portion of the field. Most of this sand along the flanks of the field is stratigraphically below the oil-water contact.

Figure 48 Cypress "A" interval isopach
(50% clean sand) at Richview Field (Frankie
and Grube in prep.).

• Oil	* Gas Injection	□ Junked
* Oil & Gas	⊙ Gas Storage	◇ Temporarily Abandoned
* Gas	⊖ Salt Water Disposal	⊞ Observation
⊕ D&A - Oil Show	⊗ Water Injection	⊘ Other Injection
⊙ D&A - Gas Show	⊡ Water Supply	□ Confidential
⊙ D&A - Oil & Gas Show	○ Permit	⊞ Other Well Type
◇ D&A	⊖ Water	+ Status Unknown
- / through any symbol indicates well is currently plugged

Figure 49 Cypress "B" interval isopach (50% clean sand) at Richview Field (Frankie and Grube in prep.).

● Oil	✱ Gas Injection	✧ Jorked
✱ Oil & Gas	⊙ Gas Storage	◇ Temporarily Abandoned
✱ Gas	⊙ Salt Water Disposal	⊙ Observation
✱ O&A - Oil Show	✱ Water Injection	✱ Other Injection
✱ O&A - Gas Show	⊙ Water Supply	□ Confidential
✱ O&A - Oil & Gas Show	○ Permit	✱ Other Well Type
◇ O&A	○ Water	+ Status Unknown

/ through any symbol indicates well is currently plugged

A net thickness map of 50% clean sandstone in the middle Cypress C interval (fig. 50) shows a sandstone trending northeast, similarly to the trend of the B sandstone. Average thickness of the C sandstone is 12½ feet; maximum thickness is 15 feet in the northern part of the field and 28 feet in the central part of the field. These two areas of thick sandstone, like the underlying B sand, are separated by a thin sand. The C sandstone has the greatest potential for reservoir development; most of it is above the oil-water contact. The maximum thickness of the B and C sandstones occurs where they are stacked, one on top of the other.

Cypress D Sandstone The upper D sand is 2 to 12 feet above the top of the C sandstone and 4 to 6 feet below the base of the overlying Barlow limestone. A net thickness map of 50% clean sandstone in the Upper Cypress D interval (fig. 51) shows a trend in thickness of 2 to 13 feet to the northeast. The D sand is thinner and less continuous than the B and C sands.

The log signatures for the A sandstone indicate that, on average, it is less clean than the B and C sandstones in the field. For the southeastern portion of the field, log signatures indicate that the D sandstone has better reservoir quality than the B or C sandstones; production from this part of the field is restricted to the D sand. The C sandstone has little potential for reservoir development in the remainder of the field. Although most of this sandstone is stratigraphically above the oil-water contact, it is shaley.

Detailed descriptions from core analysis reports indicate that many of the sandstones contain thin shale laminations and can be calcareous towards the top and at the base. Some of the sandstones contain thin limestone beds. Percentages of net clean sand in the Cypress Sandstone were calculated using the overlying Tar Springs Sandstone as a base line representing 100% clean sandstone. Net sandstone maps of both 25% and 50% were constructed for Cypress Sandstone beds A through D.

Beech Creek Limestone The Beech Creek ("Barlow") Limestone varies in thickness between 8 and 20 feet within the field (fig. 52). The thickness of the Beech Creek ("Barlow") decreases over the top of the field. An inverse relationship exists between its thickness and the thickness of underlying Cypress sandstones.

A structural cross section illustrates the relationships between productive sand and structure within the field. The B and C sands shown in the center of the cross section are capable of production; however, parts of the B sand at either end of the section are located below the oil-water contact. The cross section also illustrates the stacking of B and C sands in the center of the field, and a shale parting that separates the sands near the ends.

Summary Heterogeneity within Richview Field can best be described in terms of stratigraphy and petrophysics. Stratigraphically, compositional differences in the sandstones are evident by the variations between the shaley, calcareous sandstones of the lowermost and uppermost sandstones: sands A and D to the cleaner B and C sands. Vertical changes within individual sands, such as coarsening-upward sequences, are indicated on SP log curves.

The lateral variations largely resulted from facies changes within each of the sandstones at or near the limits of deposition. Deposition of the Cypress sandstones was controlled by the presence of a paleotopographic high. Core analyses show vertical and horizontal changes that can be related to differences in porosity and permeability within individual sandstones.

Productive facies in Richview field are both stratigraphically and structurally controlled. The productive sandstones are restricted to clean sandstones above the oil-water contact. Heterogeneities are a result of stratigraphic position within the original depositional environment, and subsequent structural placement with respect to the modern oil-water contact.

The sands of the Cypress were deposited during a marine regressive phase substantiated by the occurrence of the underlying and overlying limestones of the Ridenhower and Beech Creek ("Barlow") Limestone. The lowermost and uppermost sandstones were deposited during the initial and last stages of the marine regression, respectively. The thin limestones

Figure 50 Cypress "C" interval isopach (50% clean sand) at Richview Field (Frankie and Grube in prep).

• Oil	✱ Gas Injection	◻ Jinked
✱ Oil & Gas	⊗ Gas Storage	◊ Temporarily Abandoned
✱ Gas	⊕ Salt Water Disposal	✱ Observation
✱ D&A Oil Show	⊗ Water Injection	✱ Other Injection
✱ D&A Gas Show	⊗ Water Supply	◻ Confidential
✱ D&A Oil & Gas Show	○ Permit	⊗ Other Well Type
◊ D&A	○ Water	+ Status Unknown
- / through any symbol indicates well is currently plugged

Figure 51 Cypress "D" interval isopach (50% clean sand) at Richview Field (Frankie and Grube in prep.).

• Oil	* Gas Injection	□ Junked
* Oil & Gas	⊙ Gas Storage	◇ Temporarily Abandoned
* Gas	⊗ Salt Water Disposal	⊠ Observation
◇ O&A - Oil Show	⊖ Water Injection	⊞ Other Injection
◇ O&A - Gas Show	⊕ Water Supply	□ Confidential
◇ O&A - Oil & Gas Show	○ Perme	⊞ Other Well Type
◇ O&A	⊖ Water	+ Status Unknown
- / through any symbol indicates well is currently plugged

Figure 52 Isopach of Beech Creek (Barlow) Limestone at Richview Field (Frankie and Grube in prep.).

• Oil	* Gas Injection	◻ Jailed
* Oil & Gas	⊗ Gas Storage	◊ Temporarily Abandoned
☆ Gas	⊙ Salt Water Disposal	⊞ Observation
◆ D&A Oil Show	⊗ Water Injection	⊞ Other Injection
☆ D&A Gas Show	△ Water Supply	□ Confidential
☆ D&A Oil & Gas Show	○ Permit	⊞ Other Well Type
◊ D&A	⊗ Water	+ Status Unknown

/ through any symbol indicates well is currently plugged

within these sediments indicate a marine influence. The middle Cypress sandstones, sands B and C, were deposited during maximum marine regression, which resulted in deposition of relatively cleaner sandstones.

Identification of Play

The reservoir at Richview Field is a combination trap comprising stacked, compartmentalized barrier sandstones and structural control.

Production Characteristics

The oil-water contact in Richview field is -961 feet below sea level. The reported API gravity of the oil varies between 37.9° and 39°.

Production and Waterflood Data Richview Field has five waterflood projects. There are ten water injection wells: six of these are in the north-central portion; three are in the central portion; and one is in the southern portion of the field. Injection wells in the north-central waterflood project are configured in a five-spot pattern. Injection wells in the central waterflood project are located at the southern end of the major production trend in the Richview Field; these three wells are spaced between producing wells to the north, and dry and abandoned wells to the south. The single injection well in the southern portion of the field is on the west edge of an area of producing wells. This southern producing area is not in communication with the northern producing area. A limited amount of data exists for the waterflood projects in the central and southern portion of the field.

The north-central waterflood project is called the Richview Unit by its operator. This injection project started on October 27, 1966. The Richview Unit contains six injection wells, 12 producing wells, three plugged wells, and one water supply well. Daily average injection is 962 barrels of water at an average well-head injection pressure of 874 psi. The injection fluid is a combination of Tar Springs Sandstone water and Cypress Sandstone produced water. As of December 31, 1986, the total volume of water produced was 4,662,534 barrels; net volume of water injected was 11,920,009 barrels; and the total amount of oil produced since the beginning of the waterflood project was 493,745 barrels. The average reservoir pressure was 1,005 psi. For 1986, produced water was 227,836 barrels; volume of water injected was 350,969 barrels; and total oil produced was 4,225 barrels.

Volumetrics The amount of original oil in place (OOIP), stock tank original oil in place (STOOIP), and recovery factors were determined for the B/C, and D Cypress sandstones. The OOIP was calculated using the standard volumetric formula:

$$\text{OOIP} = 7,758 \times H \times A \times \phi \times (1 - S_w)$$

where: 7,758 = barrels of oil per acre-foot

H = height (feet) of net reservoir sandstone

A = area (acres) of net reservoir sandstone

ϕ = average porosity of reservoir sandstone

S_w = water saturation of reservoir sandstone

Core analyses from 12 wells in the field were available for use in determining reserve calculations. Values for porosity and water saturation (S_w) were averaged from the core analyses. Average thickness and area of net reservoir sandstones were calculated from isopach maps. A reduction in oil volume can be caused by the release of solution gas from the oil in the reservoir as the confining pressure is reduced as the oil is pumped. The conversion factor (OOIP to STOOIP) or formation volume factor (B_o) commonly used for the Illinois Basin for oils with API gravity similar to that of the Richview Field is 1.15 (Grube 1992).

Figure 53 Stewardson Field with respect to Ste. Genevieve Limestone structure (Rice et al. 1993).

The volumetric calculations using the above formulas are as follows: C sandstone = 4,129,971 barrels of oil; B sandstone = 4,006,072 barrels of oil; D sandstone = 214,759 barrels of oil. The total OOIP is 8,350,802 barrels of oil, and the total STOOIP is 7,261,567 barrels of oil. Cumulative production at Richview is 3.3 million barrels. The total amount of oil produced in the field represents 45% of the estimated STOOIP.

STEWARDSON FIELD, SHELBY COUNTY

In southeastern Shelby County, $\frac{1}{2}$ mile north of Stewardson lies Stewardson Field, midway between the Mattoon Anticline to the northeast and Loudon Anticline to the southwest (fig. 53). The discovery well was spudded in December 1938 and completed in April 1939. The Wabash Railroad, J. A. Aylward No. 1 well (660 feet from the north line, 2,640 feet from the west line, Section 27) was drilled to a total depth of 1,969 feet and completed in sandstones in the Aux Vases Formation at 1,938 feet. The initial production of this well was 28 barrels of oil per day and 3 barrels of water per day.

Cumulative oil production from Stewardson Field is 1.09 million barrels of oil. Most wells in the field were drilled between 1956 and 1959. Twenty-four wells have produced from the Aux Vases reservoir, four from commingled Aux Vases and Spar Mountain sandstones, and one from the Spar Mountain. Swab tests and initial production rates indicate that about 13% of the total oil produced is from the Spar Mountain.

The field, developed on 10-acre well spacing, comprises approximately 638 acres. According to ISGS records, oil is currently produced from 23 wells in the Aux Vases and five wells in the Spar Mountain. Produced water is injected into two others. Daily oil production for the field ranges from 20 to 45 barrels of oil per day.

Secondary oil recovery via waterflood in the Aux Vases began in September 1959; a second waterflood was initiated in 1962. Estimated remaining recoverable reserves are 838,800 barrels of oil.

Reservoir Geometry

Structure Stewardson Field occurs within a slightly elongate (1 mile long, $\frac{3}{4}$ mile wide) dome on a southeastward-plunging structural nose. A structure map of the top of the Ste. Genevieve Limestone (fig. 54) shows closure of 20 feet. Regional dip is to the southeast.

At Stewardson Field, the Aux Vases is predominantly sandstone interbedded with shale and some limestone. The Aux Vases directly overlies carbonates of the Ste. Genevieve Formation and underlies shale and carbonate of the Renault Formation.

A subtle topographic high at Stewardson may have also affected deposition of the Aux Vases Formation (fig. 55). This interpretation is based on an isopach map that shows the thickness of the Aux Vases Formation decreasing over the area that generally coincides with the present structure at Stewardson Field. A relatively thick accumulation of sandstone that trends northeast across the south margin of the field may be due to infilling of a slight paleo-topographic low, or may represent a bar-like feature generated in a shoaling environment.

Depositional Intervals and Environments of Deposition Correlations of wire-line log character indicate that the Aux Vases Formation at Stewardson Field can be subdivided into four intervals, each separated by shale or carbonate. Three to five sandstone beds occur within these intervals. The two uppermost sandstone bodies are referred to as the upper sandstone interval. Underlying this interval is a shale and limestone interval that ranges from $1\frac{1}{2}$ to 8 feet thick. Sandstones underlying this shale and limestone interval are collectively called the lower sandstone interval. Underlying the lower sandstone interval is the basal interval of intercalated shales and limestones. The upper interval contains the only sandstones in the Aux Vases Sandstone that produce hydrocarbons at Stewardson, although shows of oil have been reported in the lower sandstone interval in two wells.

The upper interval comprises two sandstones commonly separated by a thin, intermittent shale and carbonate layer. Although no permeability or pressure data are available to determine whether this thin shale is a barrier to fluid flow, production characteristics indicate that the sandstones in the interval behave essentially as one reservoir and were thus combined in mapping and descriptions. Thickness maps of 50% clean sandstone were constructed for the upper and lower sandstone intervals within the Aux Vases Sandstone. (Clean sandstones are defined in this report as those sandstones that have an SP deflection of at least 50% of the total deflection between the cleanest sandstone on the log and the shale base line.) An isopach map of the clean sandstones within the upper interval of the Aux Vases showed a relatively consistent distribution of sand across most of the mapped area. This sheet-sand geometry, in addition to petrographic evidences cited later, suggests that the environment of deposition for this interval was a subtidal shoreface.

The sheet-like distribution of sandstones within the lower interval is similar to that in the upper interval except that the lower interval sandstones are more extensive. The thickness of sandstones within the lower interval in the field ranges from 20 to 35 feet. Shale beds are more common in the sandstones of the lower interval than they are in the upper interval; the vertical heterogeneity is greater in these lower sandstones than it is in their stratigraphically higher counterparts. The distribution and thickness of the lower sandstones, together with the presence of more numerous shale beds, indicate that the environment of deposition of the lower interval was also subtidal shoreface. Perhaps it was in slightly deeper water than was the upper interval.

Although not productive at Stewardson, sandstones from the lower interval locally contain some oil, as indicated by core and a drill stem test.

Petrography and Diagenesis Although no whole cores were available from the field area, petrographic analyses were performed on core biscuits and well cuttings. Microscopic examinations included optical microscopy and scanning electron microscopy (SEM). Energy

Figure 54 Structure contour map on top of Ste. Genevieve Limestone, Stewardson Field. Contour interval is 5 feet (Rice et al. 1993).

dispersive x-ray (EDX) and x-ray diffraction (XRD) analyses were also carried out. Correlations based on wireline log signatures were used to extrapolate lithofacies across the field.

Diagenetic clay minerals in the Aux Vases at Stewardson Field were identified by XRD as illite, illite/smectite, chlorite, and mixed-layered chlorite. The clay minerals ranged from 0.4% to 5.2% (commonly less than 2%) of total rock volume, and their presence may be due to diagenetic alteration of feldspars.

Porosity and Permeability Early in the development of Stewardson Field, the Aux Vases was cored in eight wells near the crest of the structure in the most productive part of the field. Commercial laboratory analyses of four cores showed that porosity ranged from 9.7% to 17.1% and averaged 13%. Permeabilities in these same cores ranged from 2 to 122 millidarcies and averaged 36.5 millidarcies. Little relationship between porosity and permeability is apparent. For example, wells 1273 (SW SE NE, Section 27) and 1138 (NW SW SW NE, Section 27) have average permeabilities of 43 and 42 millidarcies and average porosities of 12.6% and 12.9%, respectively. Wells 1115 (SW SW NE, Section 27) and 1241 (NE NW NE, Section 27) have slightly higher porosities of 13% and 14.3%, respectively; but their permeabilities are only 33 and 28 millidarcies, respectively.

Allochests transported to the flanks of the paleostructure by waves and tidal currents may account for slightly greater amounts of calcite cement. The presence of calcite in this region was interpreted from logs. Abundant quartz overgrowths, interstitial calcite cement, and minor diagenetic clays, as discussed in the petrography section, have partially occluded porosity and permeability. The apparent lack of relationship between porosity and permeability at Stewardson can probably be attributed to diagenetic overprinting.

Effects of Petrophysical Properties on Reservoir Quality Log correlations and petrographic evidence indicate that the originally deposited, subtidal sheet sands of the Aux Vases at Stewardson were relatively homogeneous and contained little clay. Migrating fluids were perhaps able to flow more extensively through these sandstones than through the sandstones of the more heterogeneous Aux Vases reservoirs farther south. The lack of clay minerals coating sand grains enabled cements, particularly silica, to develop more thoroughly at Stewardson (Pittman et al. 1992) than in more clay-rich Aux Vases reservoirs. Diagenetic alterations occluded the porosity and permeability at Stewardson to a greater degree than they did in Aux Vases reservoirs farther south.

Portions of the upper sheet sands draped over the paleostructure at Stewardson appear to be slightly more permeable than sheet sands on the flanks of and off the structure, as indicated by production data and log characteristics. This slight permeability advantage may have been caused by hydrocarbons migrating into the pores of the upper sheet sands and displacing the brines responsible for the precipitation of silica cements and the formation of clay minerals. The slightly higher porosity and permeability values on the paleostructure may also be due to winnowing of fines during deposition.

Trap Type The homogeneous nature of subtidal sheet sands in the Aux Vases at Stewardson precludes significant local stratigraphic entrapment of oil. Normally, sandstones such as these require a structural closure for entrapment of hydrocarbons. The structural closure at Stewardson is probably not sufficient, however, for a significant accumulation of hydrocarbons. The pinchout of the upper interval sandstones 2 miles to the northwest of the Stewardson structure is most likely a critical factor in this hydrocarbon accumulation. Thus, the trap type is structural-stratigraphic.

Production Characteristics

Drilling and Completion Methods With the exception of the discovery well at Stewardson Field, which may have been drilled with a cable-tool rig, all wells were drilled with rotary

Figure 55 Reservoir limit map, Stewardson Field. Limit of two effective reservoir zones, one with 42.7% recovery efficiency and one with 18% recovery efficiency are shown (Rice et al. 1993).

tools using fresh-water muds. During early development of the field in the 1940s, the standard completion practice was to complete the well open-hole and artificially fracture the reservoir using 15 to 40 quarts of nitroglycerine. During later development of the field, from the mid 1950s to the present, the majority of the wells were cased through the producing zone and then shot with two to four perforations per foot. Following this procedure, a mud cleanup acid (MCA) was used, followed by hydraulic fracturing.

Oil did not flow from any wells at Stewardson Field during drill stem tests or production. Artificial lift was necessary for all wells, and all associated gas was flared.

Wells on the periphery of the field and drilled off structure tested mainly water with some oil, even when the tested interval was structurally higher than the oil-water contact (OWC) at -1,330 feet. Total fluid recoveries were fairly low in these wells. Results of the tests indicate that the reservoir quality in wells off the structure deteriorates sufficiently to prevent adequate recoveries of hydrocarbons. The quality of the reservoir is thus more important than the OWC in delineating the extent of the reservoir.

The extent of the effective reservoir at Stewardson is difficult to determine without more engineering data. Recoveries from wells indicate that the line of effective reservoir extends around the field roughly between the -1,310 and -1,320 contour lines (fig. 55). The area

defined by this line is approximately 638 acres. The reservoir quality beyond this area is not adequate to allow economic hydrocarbon recovery using conventional methods.

Fluid Characteristics Samples of oil and brine from two wells, the Doran Chaffee No. 9 Chaffee and the Brown Rinker No. 2 (wells 1115, SW SW NE, Section 27, and 1366, NW NW NE, Section 27) were analyzed for this study. Data from these analyses are given in Appendix VIII-A. Results of oil analyses indicate that the oil is typical for Mississippian reservoirs in Illinois and that it exhibits relatively low resins and asphaltenes.

Volumetrics

Original Oil in Place The OOIP was calculated using a standard volumetric equation. Reservoir oil volumes were then converted to surface volumes or STOOIP by dividing the OOIP by the formation volume factor of 1.15. The effective reservoir area for the Aux Vases was planimeted by using the sandstone thickness from the upper sandstone interval isopach. The following calculations show the best estimates for OOIP and STOOIP:

$$\begin{aligned} 7758 \times 9067 \times 0.132 \times 0.70 &= 6,499,581 \text{ barrels of oil (OOIP)} \\ 6,499,581 \div 1.15 &= 5,651,809 \text{ barrels of oil (STOOIP)} \end{aligned}$$

Production records from Stewardson Field include wells that produce from the Spar Mountain Sandstone Member of the Ste. Genevieve Limestone. Consequently, the total production attributable to the Aux Vases had to be estimated by using initial production figures. The portion of the production that comes from Spar Mountain was estimated and subtracted from the total reported production. On this basis, the corrected cumulative production from the Aux Vases in Stewardson Field was estimated to be 948,300 barrels of oil.

Assuming present production methods continue, then remaining recoverable reserves of the field can be estimated by extrapolating the decline curve, which renders 83,800 barrels of oil. This estimate is made on the assumption that the economic limit for production is about 10 barrels of oil per day for the field. Recovery efficiency was calculated at 18.3% for the entire effective Aux Vases reservoir. This relatively low number indicates that significant amounts of hydrocarbons may remain in the Aux Vases reservoir at Stewardson.

This study showed that considerably more oil had been recovered from the central portion of the field than from peripheral areas of the field. Calculations for the more productive area suggest that the central portion of the field has a recovery efficiency of 42.7%. Two probable reasons for the higher recovery in the central part of the field are (1) slightly less interstitial calcite in the center than in the periphery of the field, and (2) the relative absence of a very fine grained fraction in the same area. This portion of the field was along the paleo-high that existed during deposition of the Aux Vases Sandstone. From log character and limited petrographic examinations, it is postulated that waves and tidal currents winnowed the finer grained components (both carbonate and clastic) off the paleostructure during deposition. The result was a well sorted deposit with better permeability and porosity characteristics than in deposits in other areas of the field.

Remaining Oil in Place The remaining oil in place, calculated by subtracting the total produced oil from the STOOIP, gives a total of 4,703,509 barrels of oil. The amount of remaining oil that is ultimately recoverable depends on the cost of the extraction method used and the price of oil.

Developmental and Production Strategy

Improved Recovery Techniques Wells that penetrated the sandstones in the lower interval of the Aux Vases and were plugged back to the upper interval produced more water than those that penetrated only the upper interval. Modern cementing techniques may prevent

problems with communication and thereby prevent unnecessary production of water from holes drilled at Stewardson in the future.

Generally, homogeneous sandstones are easily and effectively waterflooded, although optimum recovery from any waterflood operation requires coordination across the entire reservoir. Injection wells placed near the higher quality reservoir will not drain any significant part of the inferior portion because the injected water will seek the greatest permeability and bypass the areas with lower permeability.

Additional drilling would be required to improve the drainage of the Aux Vases reservoir at Stewardson because of the variations in reservoir-quality sandstones. In particular, additional wells should be drilled into the lower quality sandstones, which have had poor recovery efficiencies. Higher well densities would be required to increase production. Modern hydrofracturing methods or horizontal drilling may enhance the recovery potential of these sandstones. If the area is oil-saturated, as the authors believe, then the main factor preventing oil production in the inferior part of the reservoir is lack of permeability. Any method that can improve the permeability, or the amount of reservoir open to the borehole, has potential for recovering additional quantities of hydrocarbons.

Conclusions

Sandstones in the Aux Vases Sandstone at Stewardson Field exhibit less porosity and permeability than Aux Vases reservoirs that the ISGS has studied in the more southern part of the Illinois Basin; for example, King Field (Leetaru 1991), Boyd Field (Leetaru 1993), Zeigler Field (Seyler, in press), Energy Field (Huff 1993), and Dale Consolidated Field (Beaty and Fagan 1994). The relatively poor reservoir quality of Stewardson Field has not translated, however, to equally poor recovery efficiency. Part of the answer to this incongruity is that the environment of deposition for the Aux Vases at Stewardson (subtidal shoreface sheet sands) differs from the environments interpreted for other Aux Vases fields (shallow marine bars from mixed clastic-carbonate environments).

Although the depositional conditions of the Aux Vases Formation at Stewardson caused some vertical compartmentalization, the sandstones are relatively homogeneous laterally. These characteristics are unlike the Aux Vases sandstones in southern Illinois where greater lateral and vertical compartmentalization is caused by interfingering sandstone, shale, and limestone facies.

Observed differences in reservoir quality across Stewardson Field are apparently due to the significant diagenetic overprinting that has occluded pore throats and reduced permeability. The reduced permeability is prevalent in the periphery of the field where slightly finer material may be present.

The clay content of reservoir sandstones at Stewardson is not as great as that of the Aux Vases reservoirs farther south. Clay coatings on the sand grains bind water and reduce the accuracy of resistivity measurements of formation fluids from wireline logs. Consequently, resistivity measurements from wireline logs at Stewardson are more accurate than those typically observed for the Aux Vases elsewhere in the basin. The lack of clays also means that clay-related production problems prevalent in many Aux Vases reservoirs are not a major concern at Stewardson.

STORMS CONSOLIDATED FIELD, WHITE COUNTY

Near the center of the Illinois Basin and close to the town of Carmi is Storms Consolidated Field. Extending over 19,000 acres, the field produces mainly from the Waltersburg Formation (Mississippian) at a depth of approximately 2,200 feet. It also produces from the Mississippian Cypress, Bethel, Aux Vases, and Ste. Genevieve Formations. Storms Consolidated Field has produced more than 20 million barrels of oil since its discovery in 1939.

The Mississippian Aux Vases and Cypress reservoirs at Storms Consolidated Field are the focus of this study on the significance of different scales of reservoir heterogeneity in

improved oil recovery. The four scales used in reservoir characterization are microscale (grains and pores), mesoscale (near a well bore), macroscale (interwell), and megascale (field-wide) (terminology after Krause et al. 1987).

Since the 1930s, there have been 65 well completions in the Aux Vases; initial productions ranged from 3 to 800 barrels of oil per day. Initial production of the 23 well completions in the Cypress ranged from 2 to 130 barrels of oil per day. During most of the life of this field, the Waltersburg Formation was the principal target of development. The structure map on top of the Beech Creek Limestone (fig. 56) shows a large anticlinal nose with more than 200 feet of relief. The principal axis of Storms Consolidated Field trends roughly north to south, and the field is about 7 miles long and 5 miles wide.

Storms Consolidated Field is bounded on the east by the Herald-Phillipstown Fault, part of the Wabash Valley Fault System. The Herald-Phillipstown Fault is characterized by a high-angle normal fault that generally trends north to northeast; its maximum displacement of 350 feet occurs at Storms (Bristol and Treworgy 1979).

Aux Vases Reservoirs

The discussion on lithofacies and depositional environments for the Aux Vases Formation has been subdivided into microscale, mesoscale, macroscale, and megascale. The heterogeneities of lithofacies within each scale are related to each other and to the potential for improved oil recovery.

Microscale Heterogeneities (Petrography) Analysis of XRD data and estimates based on thin section show that the Aux Vases reservoir sandstone typically contains at least 80% quartz and less than 10% feldspar. Microscale heterogeneities within the reservoir are produced primarily by diagenetic changes. Clay minerals and calcite are the two most important cements that control reservoir quality. Silica cement is not common in the better quality Aux Vases reservoir facies because clay mineral coatings are present around many grains. These clay coatings are approximately 3 microns thick and inhibit the formation of silica cement in many other subsurface formations (Pittman et al. 1992).

The Aux Vases sandstone at Storms Consolidated is unusual in that it contains patches of pyrite cement that follows bedding planes and is mixed with calcite cement. Cores from other Aux Vases wells in the Illinois Basin generally do not have the same abundance of pyrite (B. Seyler, ISGS, personal communication 1993).

Mesoscale Heterogeneities In the Rudolph No. 26 tract 11A well, the oil-water transition zone at approximately 2,940 feet is defined by a greater than 50% water saturation measurement from the core. Devolatilized oil particles or oil staining characterizes the transition zone. Such oil staining at the oil-water contact can be found in many other oil fields around the world, and it ranges from a few feet to 30 feet in thickness (Dickey 1979). As shown in the Rudolph No. 26 tract 11A core, the devolatilized oil has precipitated in the coarsest siliciclastic intervals, clogged pore throats, and decreased permeability.

The permeability of a core slab of the cross-laminated bedding interval from 2,936.5 to 2,937.1 feet (Rudolph No. 26 tract 11A) was measured at closely spaced intervals along cross laminae (fig. 57). Readings were made with a minipermeameter. On a flat surface, a minipermeameter is reasonably accurate for a range of 10 to 500 millidarcies (Weber 1982). Only within the individual cross laminae sets were permeabilities similar. The upper two laminae sets had average permeabilities of 116 and 74 millidarcies. The lower two sets had average permeabilities of 42 and 40 millidarcies. The difference in reservoir quality between laminae sets may have been due to variations in tidal energy at deposition. In a cross-laminated sequence with abrupt permeability variations, there is a significant amount of oil still left in the reservoir (Van de Graff and Baley 1989). There is no easy, inexpensive solution for recovering this oil.

Figure 56 Structure on top of Beech Creek (Barlow) Limestone at Storms Consolidated Field (Leetaru in prep.).

The top of the Aux Vases reservoir in the Rudolph 26 tract 11A contains a moderately bioturbated zone that formed when sand influx decreased. At the time, quiet-water conditions prevailed. Because the area was not inundated by siliciclastics, benthonic fauna began to rework the sediment. The core contains some large burrows (up to 1 inch in circumference) of unknown origin. The most distinctive trace fossil is *Terebellina*, characterized by ¼ inch or smaller, pale, white-walled tubes that are commonly crushed and incompletely filled (fig. 58). *Terebellina*, commonly found in both inner and outer shelf offshore environments, may have been formed by foraminifera (Bromley 1990). The *Terebellina* zone of the Aux Vases in the Rudolph No. 26 Tract 11A is composed of lower quality reservoir sandstone.

Macroscale Heterogeneities A cross section (fig. 59) suggests that the Aux Vases reservoir can be separated into distinct compartments that may not be in communication with each other; for example, the left reservoir compartment is separated from the right compartment by well 31165. The Aux Vases interval in this well is composed of shale.

As previously noted by Leetaru (1990), the SP wireline log can be an effective tool for evaluating reservoir quality in the Aux Vases Sandstone. The relatively low SP deflection in well 7589 in the cross section suggests a poor quality reservoir. This well had an initial production of 3 barrels of oil per day from the Aux Vases Sandstone—a rate significantly lower than the adjoining wells' production of 200 barrels of oil per day. This rapid variation in reservoir quality is typical of the Aux Vases Sandstone in Storms Consolidated Field.

Production pressure values of almost 1,000 psi were measured from the recently drilled Tract 11A well. This relatively high pressure suggests that the reservoir is separated from other older Aux Vases reservoirs. After decades of production, these older Aux Vases producers should have effectively depleted the reservoir and the pressures should have been much lower. In fact, the initial pressure from the Tract 11A well was probably originally higher than measured because the pressure tests were taken after 2 months of oil production.

Megascale Heterogeneities Clean reservoir sandstone intervals are separated from each other by intervals of low permeability shaley sandstone and shale. The clean sandstone thickens and thins across the field (fig. 60).

Initial Production Rates The most likely value for an initial production flow test from the Aux Vases Sandstone at Storms Consolidated Field was graphically estimated using a cumulative frequency distribution curve. This curve suggests that an average initial production rate should be approximately 65 barrels of oil per day, and that there is no more than a 20% chance of its being less than 10 barrels or more than 100 barrels of oil per day.

Cypress Reservoirs

No whole core was available for the Cypress reservoirs at Storms Consolidated Field; therefore, the depositional systems are interpreted by using other Cypress reservoirs in Illinois as analogs. This discussion will concentrate on the megascale or fieldwide distribution of reservoir facies because data are inadequate for an effective study of smaller scale heterogeneities.

The erratic distribution and small areal extent of Cypress reservoirs at Storms Consolidated Field has been mapped. The Cypress has been subdivided (from bottom to top) into four different sandstone packages: C, B, A1, and A2. The Cypress A1 and A2 intervals are the most productive within Storms Consolidated Field. The laterally continuous shale layers separating these sandstone packages are interpreted to be transgressive events; whereas the sandstones represent deposition during regressive events. Sandstone reservoirs from the Cypress Sandstone have not been as prolific as those of the Aux Vases reservoirs at Storms Consolidated, and the Cypress should be considered a secondary target in this field.

Figure 59 Cross section showing separation of reservoir compartments in Aux Vases sandstones at Storms Consolidated Field (Leetaru in prep.).

Figure 60 Isopach of net Aux Vases sandstone, Storms Consolidated Field (Leetaru in prep.).

Macroscale Heterogeneities The Cypress A2 is thicker, more extensive, and more productive than the A1. The two sandstones are probably not connected. Hydrocarbons in Cypress A reservoirs are trapped by updip pinchouts of the sandstone. Cypress A2 sandstone is well developed in the Dull Storms Land No. 1 well, which had an initial production of 50 barrels of oil per day. A well to the south showed an increase in resistivity, indicating an increase in pore-filling calcite cement in this direction; a well to the southwest, the Herndon Drilling Land No. 2, contains no Cypress A2 sandstone.

Megascale Heterogeneities and Depositional Environments Unlike that of the Aux Vases, the Cypress depositional environment is based on the megascale morphology of the sandstone bodies. Other Cypress studies with similar morphologies are used as a model of the proposed depositional system at Storms Consolidated Field.

Cypress C Sandstone Underlying the Cypress A and B intervals is the Cypress C, deposited as two separate lenticular sandstone bodies at least 5 miles long, less than 1 mile wide (fig. 61), and more than 60 net feet thick. Cypress C sandstones on wireline logs are characterized by a high SP response and a blocky pattern. No hydrocarbons have been produced from the Cypress C sandstone, which lacks four-way closure in either the Barlow or the Renault intervals. The thick Cypress C sandstones lack the lenticular nature necessary for the stratigraphic trapping of hydrocarbons.

Cypress B Sandstone Overlying the Cypress C sandstone is the Cypress B, composed of at least four different horizons that are separated from each other by shales (fig. 62). The isopach map of the Cypress B does not show distinct sandstone bodies because the different horizons have been combined for purposes of mapping. The areas with no sandstone consist of interfingering siltstones and shales. Although there is no whole core of the Cypress B interval, apparent paleosols indicative of subaerial exposure have been described in core from equivalent stratigraphic Cypress B sandstones in other fields throughout the basin (Whitaker 1992, Grube in press, Seyler in press). The paleosols indicate that there was a relative drop in sea level after deposition of the Cypress B sandstone.

There is a minor amount of production from the Cypress B sandstone adjacent to the Herald-Phillipstown Fault. When compared with overlying Cypress A sandstone reservoirs, the Cypress B reservoirs are more strongly controlled by structure than by stratigraphy.

Cypress A1 and A2 Sandstone The Cypress A2 sandstone is separated from the underlying Cypress B sandstone and the overlying Cypress A1 sandstone by laterally continuous shales. Cypress A sandstones are thin (up to 14 feet), lenticular reservoirs that, because of their geometry, are interpreted to be offshore marine bars. They are nearly identical in morphology and long axis trend to the Cypress reservoirs at Tamaroa Field in Perry County (Grube 1992) and Bartelso Field in Clinton County (Whitaker and Finley 1992). The Cypress A2 and A1 sandstones represent the culmination of Cypress Sandstone deposition.

Initial Production Rates and Cumulative Reserves The average initial production test for the Cypress reservoirs in Storms Consolidated Field is 30 barrels of oil per day, approximately half the average initial potential from the Aux Vases. The best Cypress wells tested at more than 100 barrels of oil per day; whereas some Aux Vases wells were capable of 800 barrels of oil per day.

Cypress reservoirs at Storms Consolidated Field were drilled on a 10-acre spacing. Small in areal extent (less than 40 acres), these reservoirs usually have one or two successful completions and recoverable reserves of 10,000 to 15,000 barrels of oil per well.

Classification of Aux Vases and Cypress Reservoirs

A common assumption in reservoir characterization is that identical depositional environments will have identical types of heterogeneity; therefore, the evaluation of analog reservoirs will be useful in trying to improve oil recovery (Geoscience Institute for Oil and Gas

Figure 61 Isopach of net Cypress "C" sandstone, Storms Consolidated Field (Leetaru in prep.).

Figure 62 Isopach of net Cypress "B" sandstone, Storms Consolidated Field (Leetaru in prep.).

Recovery Research 1990). In this report, the producing interval in both the Aux Vases and Cypress Sandstone is postulated to have been deposited as an offshore bar, and yet Aux Vases reservoirs are more abundant and better in quality than the Cypress reservoirs. These differences are due to the source of sediment, relative sea level fluctuations during deposition, and location of these bars relative to the shoreline. Alexander (1993) pointed out that, in many cases, subsurface data are not available to classify a reservoir in the detail necessary for environmental analogs to be useful. At Storms Consolidated Field, as in other Illinois fields (Whitaker and Leetaru 1992), the application of analogs as models for improved oil recovery must be done with care. Classification of the depositional environments of reservoirs into "pigeonholes" may still be useful because, as in the case of the Cypress Sandstone, the data may be insufficient to understand the depositional system without comparing models.

The Aux Vases reservoir sandstone at Storms Consolidated Field is interpreted to have been deposited as a tidally influenced offshore bar. Bar deposition for the Aux Vases Sandstone has also been interpreted for many other areas (Cole 1990, Huff 1993, Leetaru 1991).

The Cypress C zone is not productive within the field and is interpreted to be either an estuarine valley fill or a distributary channel deposit. Under either set of conditions, the resulting morphology is due to a drop in sea level during deposition of the lower Cypress.

Cypress B sandstone bodies are interpreted to be in a similar depositional system as the main pay horizon at Lawrence Field (J. P. Grube, ISGS, personal communication 1993). In several areas of the basin, the Cypress B interval is characterized by paleosols.

Cypress A sandstone bodies are interpreted to be offshore marine bars. The Cypress A2 sandstone is more abundant than the Cypress A1 and may have been deposited closer to the shoreline. Subsurface correlations suggest that the Cypress A1 sandstone interfingers with the Beech Creek Limestone and may have been deposited during the same transgressive event.

Conclusions and Recommendations

The four scales of heterogeneity affect oil recovery in the reservoir simultaneously; however, their relative importance varies with different phases of field development. Microscale heterogeneity is most important when outside fluid contacts the reservoir during drilling, completion, and waterflooding. Mesoscale and macroscale heterogeneities are important in developing the most efficient well locations and designing an effective waterflood. Megascale heterogeneities are crucial for delineating discrete reservoir compartments within a field. Understanding the megascale is crucial in finding isolated reservoir compartments such as the newly discovered Tract 11A reservoir.

These Cypress and Aux Vases reservoirs have few similarities. There is almost twice as much clay in the Aux Vases as in the Cypress. Aux Vases clay mineral suites contain illite, mixed-layered illite/smectite, and chlorite, which tend to form continuous coats around the detrital grains and impede the formation of quartz overgrowths. The Cypress clay mineral suite is primarily kaolinite, which has a booklet morphology. Cypress framework grains lack a continuous clay coating. As a result, the pores are largely occluded by silica cement in the form of quartz overgrowths. Porosities in the Aux Vases Sandstone exceed 25% and, in some cases, permeability exceeds 200 millidarcies; whereas Cypress porosity is rarely more than 20% and permeability rarely exceeds 100 millidarcies. Diagenetic clay mineral coatings contribute to abundant microporosity, which results in the Aux Vases having anomalously high water saturation calculations from wireline log measurements.

Calcite cementation can extend parallel to bedding and create baffles that reduce waterflood efficiency. The permeability variation between cross laminae sets creates channels for injected fluid during secondary recovery and reduce the amount of recovered mobile oil.

On the megascale, neither the Aux Vases nor the Cypress Sandstone has been fully exploited. Traps are formed by the stratigraphic pinchout of offshore marine bars over structural noses. Detailed mapping of Storms Consolidated reservoir horizons suggests that both formations may contain additional undrilled reservoirs.

Reservoirs in the Aux Vases and Cypress Sandstones are quite different even though they have been deposited as marine bars. The Aux Vases Sandstone reservoir has a greater lateral continuity, commonly extending over 300 acres and accommodating as many as 15 producing wells. Cypress reservoirs exceed 40 acres and usually accommodate one to two wells on a 10-acre spacing.

Although the reservoirs are interpreted to have been deposited in similar depositional systems, they are not the same in quality. This lack of similarity illustrates the problem of directly using analog depositional systems as models for improved oil recovery. The reason that there is not a good correlation between the quality of the reservoir and the depositional system is related to the level of classification. The data for Storms Consolidated, as for many other fields in mature areas, are not extensive enough for adequate classification. Comparison of the Aux Vases and Cypress reservoirs in Storms Consolidated with reservoirs of the same formation in other fields can be used to create models for improving oil recovery.

Analysis of different scales of heterogeneity at Storms Consolidated Field suggests that there are additional recoverable hydrocarbon reserves. A program for improved oil recovery at Storms Consolidated Field must take into account all the scales of heterogeneity.

TAMAROA AND TAMAROA SOUTH FIELDS, PERRY COUNTY

Tamaroa Field, discovered in 1942, and Tamaroa South Field, discovered in 1956, are located in northeastern Perry County. Primary development and secondary waterflooding have drained most recoverable oil from these reservoirs; however, the unswept mobile oil (UMO) that remains in these reservoirs may be economically recoverable. A comprehensive geologic investigation integrated with engineering analysis of all production-related reservoir characteristics is a necessary precursor to production of the remaining recoverable reserves. Drilling, completion, and stimulation methods; well spacing; pressure maintenance; and waterflood design depend on the characteristics of the individual reservoirs.

Reservoir Characterization

Stratigraphy In the vicinity of Tamaroa and Tamaroa South Fields, the Cypress Sandstone is predominantly sandstones and shales. The Cypress Sandstone ranges from 65 to 127 feet thick. A thickness map of the Cypress Sandstone shows significant thickening coincident with and enhancing the present Barlow structural highs. A well defined, thin interval trends north to south and occupies the western portion of the area. This thin interval correlates closely with a Beech Creek (Barlow) structural depression that forms the structural rollover on the western side of Tamaroa South Field and part of the southern extension field (fig. 63).

For mapping reservoir facies and interpreting depositional facies in the study area, it was advisable to informally divide the Cypress Sandstone into lower, middle, and upper intervals. Defining criteria included (1) similarity of log character, (2) stratigraphic position of sandstones within the Cypress Sandstone, and (3) stratigraphic position of shale breaks within the Cypress Sandstone.

Figure 64 is an electric log from Tamaroa Field showing the Cypress Sandstone divisions used for geologic mapping in the Tamaroa area. Hydrocarbon reservoirs in the Tamaroa area are limited to sandstones in the upper interval, which was therefore subdivided into four units to establish the relationships and determine the geometries of individual sandstone bodies. These sandstones are, in ascending order, the Y1, Y2, Y3, and Y4. Separate sandstones in the lower and middle Cypress intervals were grouped and mapped as net sandstones within their respective intervals.

Thickness maps of 25% and 50% clean sandstone were constructed; thickness data were estimated from normalized spontaneous potential (SP) and gamma ray logs. The SP logging tool cannot record total deflection of thin, clean sandstone beds; thus the thickness values of these beds are underestimated.

Figure 63 Structure map of the top of the Beech Creek (Barlow) Limestone at the Tamaroa Fields showing the three structures that control production (Grube 1992).

Similar characteristics of the sandstones in each of the four units in the upper Cypress suggest that cyclical depositional conditions stacked four separate lenticular sandstones at some locations. Each sandstone is separated by a shale, although coalescing or shingling of two sandstone units appears to occur. The type log in figure 64 shows the Y1, Y2, and Y3 sandstones of the upper Cypress interval. The Y4 sandstone, which forms at the base to several feet below the base of the Beech Creek (Barlow) Limestone, is not present at this

J. N. Harsh
Newborn No. 1
T4S R1W Sec. 22 SE SE NW

Figure 64 Type log of the Cypress Formation showing lower, middle, and upper divisions of the Cypress and four subdivisions of the upper interval (Grube 1992).

location. This particular sandstone develops less frequently than the Y1, Y2, and Y3 sandstones and is generally too tight to be an effective reservoir rock.

The Y3 and to a lesser degree the Y2 are the primary reservoir sandstones. Figure 65 is a thickness map of the Y3, a 50% clean sandstone. These sandstones are typically less than 10 feet thick, $\frac{1}{4}$ to $\frac{1}{2}$ mile wide, and less than 2 miles long. The northeast-southwest trend and the en echelon pattern of these sandstones is very apparent. A map that superimposes the portions of the Y2 and Y3 sandstones greater than 4 feet thick shows that the trend and geometries of both units are quite similar.

Selected drill cuttings from reservoir sandstones of the Tamaroa fields and small diameter core plugs from the Y2 and Y3 reservoirs in the Stockton No. 1 well (NW SW SW Section 28) in Tamaroa South are composed of light gray, oil stained to light brown, moderately well

Figure 65 Thickness of the 50% clean Y3 sandstone, Tamaroa Field (Grube 1992).

well sorted, mostly fine grained to very fine grained sandstone. Scattered medium gray, flat shale clasts, generally less than 1 millimeter in thickness by less than 1 centimeter in diameter, and wispy shale laminations are a minor lithologic component. The reservoir sandstones appear to be very clean and silica is the dominant cement. Quartz constitutes an estimated 90% of the samples; feldspar, clay minerals, chert, calcite, mica, and a minor amount of heavy minerals make up the remaining 10%.

Porosity measured from the above mentioned core plugs ranges from 18% to 23% and averages 20% for sandstone of reservoir quality. Permeability ranges from 88 to 183 millidarcies and averages about 146 millidarcies. Although this particular well was completed for only 24 barrels of oil per day and 40 barrels of water per day, cumulative production from 1957 through 1989 was approximately 55,000 barrels of oil. The well is one of the larger cumulative producers in the Tamaroa area.

Structure A comparison of structure maps constructed on the top of the Beech Creek (Barlow) limestone and the Ridenhower marker limestone bed establishes that both tectonics and thickness variations in the Cypress Sandstone are responsible for the structural relief of the Beech Creek (Barlow) in the study area. The structure map of the Ridenhower limestone marker shows that the structural grain of this horizon is similar to that of the overlying Beech Creek (Barlow), although an offset of structural crests in the Tamaroa South extension field and, to a lesser extent, in Tamaroa Field is apparent. This suggests that the axial planes of the folds are not vertical, possibly as a result of tectonic deformation related to drape folding of the sedimentary section over tilted basement fault blocks.

Structural relief of the Beech Creek (Barlow) folds is enhanced in the Tamaroa area, particularly over Tamaroa and Tamaroa South Fields, as the Barlow drapes over underlying Cypress thick areas and into thin areas. Thinning of the Cypress Sandstone is a function of the sandstones thinning and changing facies to shales. Thinning of the shales by differential compaction has increased the divergence between sandstone thicks and shale-dominated thins, thereby increasing structural relief of the Barlow.

Trap Type

The trapping mechanism for the Tamaroa area reservoirs is a combination of structure and stratigraphy. As previously discussed, the upper Cypress reservoirs are in lenticular, stacked sandstones separated by shales. Oil trapped in these sandstones occurs in that portion of sandstone that drapes across the crest of a structural fold. Sandstone lenses that lie along the flanks of folds without crossing the crest are not productive. The shales, or possibly the Beech Creek (Barlow) Limestone, overlying the reservoirs provide the ultimate permeability seal. Although correlation of these sandstones is subject to several possible interpretations, it appears that in some locations, the lenticular sandstones coalesce vertically, possibly in a shingle-like manner. Middle Cypress sandstones coalesce with the upper Cypress Yi sandstone in the northern field area, as determined from electric log interpretations (fig. 66). Interconnection of these sandstones without development of a vertical permeability barrier would create a conduit for hydrocarbon migration from the widespread middle Cypress Sandstone to the upper Cypress reservoirs.

Depositional Environments The Cypress Sandstone in the Tamaroa Field area records a flood of sand- to clay-sized siliclastic material into the Ridenhower sea. The classical interpretation of a southwestward-prograding delta set forth by Swann (1963) for deposition of the Chesterian Series can be applied to the lower and middle Cypress intervals.

Lenticular sandstone geometry, shale encasement, burrowing, heavy mineral lags, and SP log character are consistent with deposition of the upper Cypress reservoir sandstones in a marine setting, possibly as tidal shoals or offshore bars. The northeast to southwest trend of these sandstone bars generally parallels the regional alignment of the thick, middle and lower Cypress deltaic sandstones. The upper Cypress tidal bars apparently were oriented shore-normal, if the shoreline or delta front trended northwest to southeast. Alternatively, the Cypress thickness patterns suggest that distributaries in the Tamaroa area may have directed sediments toward the northwest, thereby creating an embayment with a local northeast-southwest-trending shoreline. In this case, the northeast-trending upper Cypress marine bar system would have been oriented parallel to the shore of the embayment.

Stacking of Cypress sandstones would occur if the shoreline remained somewhat stationary while coastal processes and sediment influx remained constant during bar deposition. Stacking also depends on the rate of sedimentation equaling the rate of subsidence.

Petrophysical Characteristics That Influence Reservoir Quality Upon deposition, the lenticular sands of the upper Cypress interval were apparently very clean and probably had a porosity of at least 35% and permeability of more than 1 darcy (Almon and Davies 1981).

Figure 66 Y2 and Y3 lenticular sands may coalesce forming a single thicker upper Cypress sandstone interval at Tamaroa Field (Grube 1993).

Postdepositional processes have reduced porosity to an average of 20% and permeability to between 100 and 200 millidarcies. Permeability, a function of pore throat size, has been significantly reduced by quartz overgrowth. Also, pore throat restriction has increased flow path tortuosity, which may explain the low production rates and longevity of some wells.

Reservoir quality is also affected by reservoir compartmentalization due to depositional processes. Although these sandstones generally stack and appear to coalesce, they are commonly separated by vertical permeability barriers. Marine bars commonly migrate, creating a "shingling" effect where one bar laps onto or over another. The presence of a shale at this contact causes a permeability barrier to develop along the onlap, transitional contact. The

result is a reservoir consisting of separate compartments. The SP-resistivity log commonly used in the Illinois Basin may not discern the presence of thin, intervening shale beds or impermeable zones that separate the shingled bars; but core observations, gamma-ray logs, and neutron-density logs confirm their presence. Although not common, the shingled bars may also form a single interconnected compartment.

Although porosity has been decreased by quartz overgrowths, secondary porosity (at least several percent) has been created by partial to total feldspar dissolution. Feldspars constitute up to 10% of these sandstones. Microporosity created by selective dissolution of the calcium-rich laths of the plagioclase feldspars may not be effective porosity and appears to be a residual oil trap.

Authigenic clay minerals in the reservoir are essentially inactive and stable under the natural, unaltered, predrilled reservoir conditions. The quantity of clay minerals in the clean portion of these reservoirs appears to be less than 2% of the sample. For optimal development of the reservoirs, however, it is crucial to determine the types and locations of clay minerals present in the reservoirs. The dominant clay minerals in the Tamaroa reservoirs are iron-rich chlorite and kaolinite. In their natural state, grain-coating iron-rich chlorite and kaolinite tend to generally reduce reservoir porosity and permeability. Further serious reservoir damage may result from improper treatment of these clay minerals by procedures that affect the reservoir during drilling, completion, stimulation, and production.

Classification and Identification of Play The upper Cypress sandstone reservoirs that constitute the Tamaroa fields appear to be nearshore marine bars produced by the reworking of a prograding delta system that was submerged by a marine transgression. Up to four lenticular sandstone bars can be stacked, but the middle two sandstones commonly form the productive reservoirs. These bar-type reservoirs appear to require a structural component to trap hydrocarbons. In no instances have hydrocarbons accumulated solely by stratigraphic trapping. Structural rollover associated with a physical flexure of the reservoir is a characteristic of all Tamaroa pools. Vertical migration of hydrocarbons into the lenticular sandstones may have been accommodated by a flexure-induced, fracture system. The fact that the Trenton produces from a fractured reservoir at Tamaroa Field supports the concept that fracturing, most likely flexure-induced, has assisted migration. The juxtaposition of the Du Quoin Monocline may also be a component of this play through the possible creation of a fault-fracture, hydrocarbon migration conduit.

Production Characteristics

Production and Completion Procedure Records indicate that rotary drive rigs were used to drill wells in the Tamaroa area. Mud systems utilized fresh water with gel, a particle suspension additive. Several completion and stimulation techniques were practiced. The more productive wells were drilled to the top of the sandstone and cased. Cable tools were then used to chip through the reservoir to approximately the oil-water contact and the wells were completed open hole. Other wells were rotary-drilled into the reservoir, cased to the top of the reservoir, and completed open hole. Commonly, this type of completion was followed by a 10-quart nitroglycerin fracture treatment to stimulate production. Wells were also drilled through the reservoir, in some instances to deeper horizons. These wells were cased and perforated, usually with two shots per foot through the reservoir interval. A few of the cased wells were hydraulically fractured using 900 to 2000 pound water-sand combinations. Records indicate that few acid treatments penetrating deep into the formation were performed. Almost all wells were pump-produced from initial completion.

Production and Waterflood Data Data are available for one waterflood and one pressure maintenance, salt-water disposal project in the Tamaroa Cypress pools. Another unrecorded pressure maintenance, salt-water disposal project with one injector and two production wells

was established in the south extension field. The Tamaroa Waterflood in Sections 14 and 23 was initially designed as a peripheral injection project with six injectors partly encircling five production wells. Water was injected into the reservoir at the structurally lowest part of the field, midstructure, and into the structurally highest well within the gas cap. In effect, this procedure concentrated the oil into a central area of production. Water was injected at 700 to 750 psi and consisted of 90% produced water and 10% pond water. The project was initiated in December 1961 after primary production had yielded 200,000 barrels of oil. By the end of 1985, the last year of consistent records, an additional 139,000 barrels of oil had been produced by this secondary waterflooding. A total of 3,244,000 barrels of water was injected; 2,490,000 barrels of this water had been produced through 1985.

Reservoir Temperature and Pressure Drill stem tests (DST) and electric logs are the only sources of pressure and temperature data. DST data show that the highest shut-in pressures are in the range of 435 psi at an approximate depth of 1,130 feet. The standard hydrostatic pressure gradient of 0.43 psi per foot is slightly greater than that of 0.38 psi per foot, as calculated from the DST data; these reservoirs are underpressured. Bottom-hole temperatures up to 100°F were measured during logging operations. The primary drive mechanism appears to be solution gas.

Oil Characteristics Oil samples were collected for analysis in 1990 from one well in Tamaroa South and two wells in the south extension pool. Analyses, including chromatograms, are included in Appendixes VII-A and VII-B. Oil gravity and viscosity values reported for samples taken from the Tamaroa waterflood in Sections 14 and 23 were 31.5° and 9.01 cp at formation temperature. For the Bagwell project in Section 28, the reported values were gravity 27.6° and viscosity 26 cp at 42°F. The sample taken in 1990 from the Hempelman No. 1 well in the south extension pool yielded an API gravity of 27.4° and a viscosity of 11.2 cp at 95°F.

Water Characteristics In 1990, reservoir brine samples were collected along with the oil samples. The same wells sampled for oil were also sampled for brine. Another sample was collected from the Hempelman No. 2, the injection well in the Tamaroa South extension field. Although reinjection of Cypress reservoir brines occurred in the vicinity of the sampled wells, the analytical data shown in Appendix VI closely represent the composition of the brine from the two reservoirs sampled. The resistivities of the brine samples are between 0.088 and 0.095 ohm-meters and may be useful for calculations requiring an R_w value.

Volumetrics Original oil in place (OOIP), stock tank original oil in place (STOOIP), and recovery factors were determined for both the Y2 and Y3 sandstones in each of the four, structurally separate, Tamaroa area pools. Values were calculated using the standard volumetric formula: $OOIP = \text{porosity} \times (1 - \text{water saturation}) \times \text{reservoir thickness} \times 7,758$ barrels of oil per acre-foot. A 20% porosity value was used, based on the average of measured porosities from the Stockton No. 1 core. A conservative value of 40% water saturation was assigned. Water saturations calculated from logs were inaccurate, mostly because of thin bed effects and some invasion complications. Reservoir volume was estimated using the 50% clean sandstone maps of the reservoir intervals.

The conversion factor or formation volume factor, B_{oi} , commonly used in the Illinois Basin for oils with API gravity similar to that of the Tamaroa oil is 1.15. This value was used to calculate the STOOIP for Tamaroa South and the Tamaroa South extension fields. Because of a gas cap on the two pools in Tamaroa Field, a formation volume factor of 1.20 was used to calculate the STOOIP for these pools. The larger B_{oi} value maintains a conservative estimation for the STOOIP in this pool.

Also calculated for Tamaroa Field was the estimated volume of oil displaced by the gas cap on the two pools. Discounting this volume yields a more accurate estimation of OOIP and recovery factors. Volumetric results using the factors described above are as follows:

Tamaroa Field Sections 14 and 23 (eastern pool)

OOIP = 982,000 barrels of oil (BO)

STOOIP = 818,000 BO

Primary recovery = 218,000 BO (26.7%)

Secondary recovery = 134,000 BO (16.4%)

Total recovery = 352,000 BO (43%)

Tamaroa Field Sections 22 and 23 (western pool)

OOIP = 1,157,000 BO

STOOIP = 964,000 BO

Total recovery (estimate) = 50,000 BO (5%)

Tamaroa South Field

OOIP = 1,404,000 BO

STOOIP = 1,221,000 BO

Total recovery = 310,000 BO (25%)

Tamaroa South Extension Field

OOIP = 253,000 BO

STOOIP = 220,000 BO

Total recovery = 71,000 BO (32%)

Volumetric calculations based on residual water and residual oil saturation data from the Stockton No. 1 core analysis were also performed. If it is assumed that the average of the residual water saturation values from the Stockton No. 1 core analysis approximates the original water saturation for Tamaroa South Field ($Y3 S_w = 45.6\%$, $Y2 S_w = 31.1\%$), then the recovery factor for the field is 22.7%. This figure supports the above calculations. Also, if it is assumed that the average of the residual oil values from the Stockton No. 1 core analysis approximates the residual oil saturation for the entire field ($Y3 S_{or} = 26.6\%$, $Y2 S_{or} = 31.1\%$), then 395,000 barrels of movable oil remain in the Tamaroa South Field.

Development, Production Strategy, and Recommendations

The separate pools of the Tamaroa Field area show similarities in lithology as well as in the size and geometry of sandstone bodies. Depositional processes and settings for these lenticular sandstones were most likely similar as well. Consequently, similar recovery efficiencies might be expected. The differences between the fields with respect to cumulative production and particularly field recovery efficiency are therefore a function of drilling, completion, stimulation or development programs or a combination of these programs. A strategy that optimizes production should be employed at each stage—from drilling the discovery well to abandoning the reservoir.

Some recommendations for optimum production can be derived from this study of the Tamaroa fields. Waterflood and pressure maintenance programs show the most positive effects on increasing cumulative production. Drilling and completion techniques, especially those designed to prevent formation damage due to alteration of indigenous clay minerals, also may influence the amount of recoverable reserves. Enhanced oil recovery (EOR) programs (e.g. carbon dioxide treatment) are gaining in technical and economical merit. As Fisher and Galloway (1983) discovered in Texas, however, intensive development and infill drilling are the most effective means of extending and increasing production from an oil

field. Their conclusions are based on the amount of oil recovered by EOR techniques, 90% of which are miscible gas flood programs.

Waterflood and pressure maintenance records show that production in Tamaroa Field in Sections 14 and 23 has benefited significantly from the peripheral design waterflood program. Sections 14 and 23 have produced 352,000 barrels of oil, as compared with 35,000 barrels of oil from Section 22. Production records are inconsistent, however, and the actual production figure for Section 22 could be twice that amount.

Three factors may contribute to the difference between these two volumetrically and lithologically similar pools:

1. No secondary pressure maintenance or waterflood program was established in the western pool (Section 22). Unlike the conditions in the eastern pool (Sections 14 and 23), in which the gas cap and reservoir energy were maintained, the drive energy in the western pool was probably depleted. Retaining reservoir energy is crucial to maximizing recovery efficiency, particularly in a reservoir of limited extent and correspondingly limited drive.

2. Correlation of separate, vertically stacked reservoir sandstones is not obvious in this area. Miscorrelation and consequent misinterpretation of the character of these discontinuous and coalescing sandstones may have inhibited development, particularly that of the western pool. The fact that only gas was found in the upper reach of this pool may also have inhibited development. It is recommended that reservoir continuity and flow unit correlation be evaluated through use of field pressure analyses, including pulse, interference, build-up, draw-down, and tracer tests (Lee 1982). Pressure maintenance and other reservoir management requirements can also be evaluated through the use of field tests and accurate, per-well production histories that include water and, if possible, gas production.

3. Development of the eastern pool appears to have been a coordinated effort, incorporating all operators from separate leases into the waterflood program. The western pool does not show a similar record of coordinated development. It appears likely that moveable hydrocarbons remain in this reservoir, although a detailed engineering evaluation of reservoir conditions is necessary to confirm the presence and volume of remaining mobile oil. Also, a coordinated development program, similar to that used in the eastern pool, incorporating the whole reservoir and including multiple sandstone lenses, may be the most feasible and economically sound approach.

Although the effects are less obvious, Tamaroa South and the extension pool also have benefitted from water injection. Tamaroa South has experienced little secondary development. This field more than likely has secondary recoverable reserves remaining in place. Records indicate that only one water injector well has operated in this field and the recovery efficiency is low, as calculated from volumetrics. Several factors must be considered, however, before undertaking extensive development activities in Tamaroa South Field. There is a lack of production data for six wells and a possibility of unrecorded waterfloods. Also, most wells appear to be plugged.

Another significant factor, with respect to waterflooding, is illustrated by a geologic model of Tamaroa South Field. The compartmentalization caused by the shingled character of the marine bars must be thoroughly assessed. Although a sandstone encountered in one well may appear to correlate with sandstone in an adjacent well, the sandstone may represent two separate bars and therefore two separate, noncommunicating reservoirs. Some wells in Sections 28 and 32 intersect only the Y3 sandstone. An attempt to waterflood into a Y2 sandstone from a well that intersects only the Y3 sandstone will probably fail.

Although their effects on cumulative production are not as obvious as waterflooding, drilling and completion techniques may be significant factors in terms of short-term initial production and overall cumulative production. As previously mentioned, wells that had open-hole completions and were not drilled deeper than the reservoir, and particularly wells that were completed using standard tools (cable) to penetrate the reservoir, generally showed the greatest cumulative production and higher initial production rates. By contrast, wells

drilled deeper than the reservoir and completed with casing through the reservoir tend to show lower initial production rates and lower cumulative production.

The Cypress sandstones may be susceptible to formation damage, either by drilling fluids or completion procedures. Drilling fluids, both the filtrate and the fines, can reduce permeability during invasion. They do this either by dislodging clay-sized fines, usually kaolinite, that migrate and catch in pore throats or by clogging pore throats near the well bore with drilling fines.

During drilling, completion, and other development procedures, fluids introduced into the reservoir can interact with the diagenetic chlorite and kaolinite and significantly reduce the permeability of the reservoir. Although clay minerals are minor constituents in these sandstones, their presence as pore and pore throat linings causes them to be in total contact with drilling, completion, and development fluids.

Because clay minerals also possess a high surface area to volume ratio, they are very susceptible to alteration and consequent formation damage. The high iron-content chlorite prevalent throughout these sandstones is extremely sensitive to acid and to oxygenated waters (Almon and Davies 1981). Chlorite dissolves readily in dilute HCl and the liberated iron reprecipitates as an iron hydroxide, as the acid is spent. This iron hydroxide clogs pore throats and effectively blocks production flow paths. This potential problem can be avoided if an oxygen scavenger and an iron-chelating agent are added to the acid, and all the treatment fluid introduced into the reservoir is recovered. Because of the minor amount of calcite observed in the Tamaroa reservoirs, the only practical use of acid is for mud clean-up during completion. Even then, it is recommended that an oxygen scavenger and an iron-chelating agent be used and that all acid be removed from the hole rapidly. Almon and Davies (1981) further recommend that if ferric hydroxide has been precipitated in the reservoir as the result of an inadequately designed acid job, it can be removed by treatment with weak (5%) HCl combined with appropriate iron-chelating agents and an oxygen scavenger. It is strongly recommended that all acid be recovered before it is spent.

Kaolinite, the other dominant clay mineral in the Tamaroa reservoirs, is chemically stable in the presence of the commonly introduced drilling, completion, and development fluids as long as the salinity of the fluids does not greatly differ from the original brines. Kaolinite is loosely attached to the surface of host grains, however, and can be easily dislodged and moved by fluids. Kaolinite particles can migrate and lodge in pore throats. Permeability is thus decreased and production flow reduced. This occurs, particularly in the area close to the wellbore, where fluid flow rates reach velocities capable of transporting these particles. Clay stabilization systems are available to easily resolve this problem, as long as treatment is applied early (Almon and Davies 1981). Damage from kaolinite migration also occurs as a result of the mixing incompatible brines (Vaidya and Fogler 1990). Water shock, the abrupt change in salinity in a reservoir, leads to a rapid and drastic decline in permeability. The shock is caused by introducing fresh or low salinity water into a reservoir containing normal to highly saline brine. Studies show that this problem can be avoided by gradually lowering the salinity of the injection fluid during waterflood, or by using drilling fluids containing brine compatible with the reservoir being drilled.

Almon and Davies (1981) further recommend that any program for introducing fluids into a reservoir also be designed for the specific variety of clay mineral(s) in that reservoir. A mineralogical analysis of the reservoir, particularly the clay mineral(s), is required prior to introduction of fluids into the system. Brine analysis, although not mentioned by Almon and Davies (1981), should be included. The composition of the introduced fluids must also be known to evaluate potential chemical reactions between the components of the reservoir, particularly reservoir fluids, and the introduced chemicals. Iron materials used in oil well installations should be considered to be reactive material that can affect the reservoir.

An optimum drilling and development program to avoid formation damage can then be designed using the results from the previously mentioned tests. The suggested clay mineral analysis includes four steps: (1) scanning electron microscope (SEM) with energy dispersive

x-ray (EDX) analyzer; (2) x-ray diffraction (XRD) analysis of the fine fraction (reservoir clays alone); (3) petrographic analysis by thin section; and (4) bulk x-ray diffraction analysis. At the very minimum, analysis by SEM/EDX will reveal the location of clay minerals and indicate the type of clay minerals and their relative iron contents.

Infill drilling of the Tamaroa area fields may prove to be economically feasible. Whitaker and Finley (1992) found that for Bartelso Field in Clinton County, Illinois, drill spacing of 5 acres or less, combined with waterflooding, yielded an estimated recovery efficiency of 53% for all the Cypress reservoirs and possibly 60% (S.T. Whitaker, personal communication 1992) for the marine bar reservoirs in the field. The similarity of the reservoir characteristics at Bartelso and Tamaroa and Tamaroa South Fields suggests that, even in the most effectively drained, eastern part of Tamaroa Field, infill drilling may be warranted to increase the recovery efficiency from 43% to 60%. Ten-acre spacing, even when combined with a waterflood program, may therefore be inadequate to effectively drain the bar-type reservoirs. Assessing the effective drainage spacing for these reservoirs requires the use of pressure and production data that are not available.

Infill drilling may also be required to assess the degree of reservoir compartmentalization that exists throughout the Tamaroa area. The coalesced and stacked nature of these reservoirs may conceal bypassed reservoirs or entirely separate reservoirs. Most wells in Section 14 of Tamaroa Field and many of the wells in Tamaroa South Field were never drilled below the first oil-producing horizon that was encountered.

There is good potential for development drilling in the Tamaroa area. A combined thickness-structure map shows an undeveloped eastern extension of the Section 22 pool. The Texaco John Majewski No. 2 well (SW NW Section 23, T4S, R1W) penetrated Cypress Y2 and Y3 coalesced reservoir rock, although production records indicate that this well produced only from the Trenton. Even if the well had been recompleted in the Cypress, standard offset drill spacings still exist. As mentioned previously, an engineering assessment and a thorough geologic evaluation of this pool is recommended to confirm these preliminary observations. Pressure depletion and complications caused by coalescing and splitting of these lenticular sandstone reservoirs should be considered in developing this field.

XENIA FIELD, CLAY COUNTY

Reservoir and Trap Characteristics

The Cypress Sandstone reaches a maximum thickness of 160 feet in this study area. Of the total Cypress interval, 50% to 70% is clean sandstone, which locally can be as much as 130 feet thick. (A clean sandstone is defined as having an SP response that is at least 50% of the SP response of clean, thick sandstone.)

Seven sand bodies were recognized, on the basis of well log correlations of the Cypress Sandstone at Xenia East Field. From the top down, the units were sequentially numbered 1 through 7. The upper part of the Cypress (units 1 to 6) is more shaley than the lower part (unit 7) and consists of thin sandstone units interbedded with shale. Unit 7, which consists of thick sandstone with thin shale breaks, makes up about one-half of the total thickness of the formation. Unit 4 is the major pay zone for the Cypress Sandstone at Xenia East Field, but unit 2 has been a minor oil-producer. Shows of oil have been reported in units 5 and 6.

Reservoir Geometry Xenia East Field lies on the Kenner Anticline, more or less aligned with the Iola Anticline. The structure appears consistently in major mapping horizons, but the crests in other horizons are not coincident with the structure in the Cypress Sandstone. The area that contains the greatest thickness of sandstone in the Cypress lies on the crest of this structure; consequently, both structural activity and differential compaction of sandstones and shales have probably contributed to the morphology of the anticline.

The term reservoir, as used here, refers to that part of Xenia's Cypress Sandstone that has been found to be an oil pay zone or that has the lithologic characteristics of the oil-producing zone. As discussed below, all the Cypress Sandstone units, except unit 1, are considered to be part of the reservoir, although units 2 and 4 are the only pays in the field.

Although each sandstone unit is areally limited, the sand bodies are elongated in two directions: north to south in units 6 and 7 and north-northeast to south-southwest in all other units. Unit 7, a highly complex sand body, is present throughout the mapped area, which is about 3 miles long and 2½ miles wide. Unit 7 increases in thickness and width to the north and south of Xenia East Field in Section 11. Unit 6 occupies a smaller area (3 miles long and about 1½ miles wide) than unit 7, and its major part shows a north-south elongation axis. Unlike the nearly constant thickness of unit 7 in the cross sections, unit 6 is wedge-shaped and pinches out eastward. Units 1, 2, 3, 4, and 5 are narrow (more than 1 mile long and about 1/3 to 1½ miles wide) and a lenticular shape in cross section. Their elongation axes trend north-northeast and their greatest thicknesses are mostly coincident with the structural crest in Xenia East Field. Units 2 through 5 each consist of two parallel sand bodies.

Trap Type Two types of traps were identified in the Cypress at Xenia East Field, one structural and the other stratigraphic. The structural trap, composed of the unit 4 sand body, contains almost all of the oil reserves in this Cypress field. The isopach of the unit 4 pay zone shows that commercial production was established only where the pay zone is thicker than 5 feet. According to the structure map on the top of the "Barlow limestone," structural closure is about 19 feet. The crest of the structure on the top of the reservoir sandstone is slightly offset from the crest of the "Barlow limestone" structure because of the different sandstone thicknesses. Consequently, the reservoir sandstone in the East Central Developing Company, Baltrukonis No. 1 well (SW SW SW Section 12, T2N, R5E) is below the oil-water contact (OWC), although it is located on the structural high of the Barlow limestone.

A stratigraphic trap controlled by the distribution and thickness of clean sand in unit 2 was located in the East Central Development Company, Goad No. 1 (SW SE SE Section 11, T2N, R5E) well; but this is the only illustration of this trapping mechanism. Adjacent wells do not contain the unit 2 clean sand and are therefore not productive. About 19,000 of the 470,000 barrels of Cypress oil were produced from this well.

Reservoir Lithofacies Reservoir lithofacies descriptions and analyses of reservoir characteristics were determined, in part, from studies of drill cuttings from nine wells. Because pay zone cuttings were unavailable from open-hole Cypress wells, most of the drill cuttings used in the study came from non-Cypress-producing wells. From one core, taken from the upper Cypress in the Keystone Oil Company, Campbell Heirs No. 3 well located in the center of the field (NW NW SE Section 11, T2N, R5E), 23 small-diameter plugs were available. Of the 23 core plugs, eight were thin-sectioned and analyzed by XRD, and three were examined using SEM/EDX. Conventional porosity and permeability analyses were done on all plugs. Thin sections also were made from the drill cuttings.

The 23 core plugs from the Keystone Oil Company, Campbell Heirs No. 3 well (NW NW SE Section 11, T2N, R5E) were taken at 1-foot intervals from 2,525.5 to 2,548.5 feet in the unit 4 and 5 sandstones. Porosity values, which do not change significantly from sample to sample, range from 13.5% to 17% and average 15.3%. Conversely, permeabilities show a large variation between 4.4 and 88 millidarcies (averaging 37 millidarcies); modal permeability is about 60 millidarcies. Because the plot of permeability versus depth generally mimics the shape of the SP log in this field, it seems likely that permeability is affected by the clay matrix content of the rock. The low permeabilities at the top and bottom of the reservoir are probably caused by compaction of oriented grains, finer grain size, and large amounts of calcite cement. These features are common in shale-sandstone sequences and have been observed in other cores and thin sections from Cypress reservoirs in the Illinois Basin (Cole, personal communication 1992).

The major type of porosity is intergranular with pores averaging about 50 μm in width. Several types of dissolution pores, as defined by Schmidt and McDonald (1979), were identified; for example, oversized pores, granular molds, and elongate pores. Secondary porosity has developed mainly from the dissolution of feldspar.

The clay minerals in the samples appear to be typical of other Cypress reservoirs studied (this volume). Clay mineral varieties were determined from $<16\ \mu\text{m}$ size separations of disaggregated sandstone. Illite, mixed-layered illite/smectite (I/S), chlorite, and kaolinite are present. SEM/EDX analysis determined the chlorite to be an iron-rich variety. Relative amounts of these clay minerals are shown in Appendix XI. Total clay content in the clean sandstone samples is less than 3%.

Depositional Environment As the geometry of the sandstone units, lithologic successions, and the overall geologic setting indicate, the sediments that became the Cypress Sandstone at Xenia East Field were delivered to and deposited in an extensive, shallow marine environment in what is now the southern part of the Illinois Basin (Swann 1963).

The characteristic features of units 6 and 7 include thickly bedded sandstone, carbonaceous shale, and plant fossils commonly associated with deposition near the mouth of a fluvial source. They could be interpreted as deltaic or estuarine sand bodies. Estuarine sandstones tend to be elongate in the flow direction; whereas the observed lobate form of these sandstones is more characteristic of delta front sand bodies, probably reworked by wave and tidal processes (Miall 1984).

The lack of fines and high degree of maturity of the framework components in the unit 4 and 5 sandstones suggest that these units were formed in a relatively high-energy environment. Their elongate, convex-upward lenticular shape and low-angle crossbedding are characteristics of marine bar sandstones (Davis 1983). The presence of red shale in this interval suggests a shallow water, oxidizing depositional environment. Based on these features, it is likely that the sandstones in units 4 and 5 were deposited as nearshore marine bars.

Unit 6 represents a transitional environment between units 7 and 5. It may have resulted from a shift in depositional geometry as the main body of unit 7 sandstone trended northward and the new sand bar (unit 5) formed with a north-northeast to south-southwest orientation.

Units 1, 2, and 3 (siltstone and sandstone) are similar in geometry to units 4 and 5, but thinner and less extensive areally. Because these sand bodies lack clean sandstone and the sandstone to shale ratios are low in this interval, the units are interpreted as having been deposited in a relatively low-energy environment, possibly an offshore bar environment.

The Cypress Sandstone in this area is interpreted to have been deposited in environments that ranged from the delta front to nearshore and offshore marine. The overlying "Barlow limestone" establishes a complete depositional cycle from regression to transgression. Other Cypress field studies showing depositional features similar to those observed at Xenia East field are Bartelso (Whitaker and Finley 1992), Tamaroa (Grube 1992), and Mattoon Fields (K.R. McGee, personal communication 1992).

Diagenesis The most important aspects of diagenesis controlling reservoir quality at Xenia East field are quartz overgrowths, feldspar dissolution, and diagenetic clay mineral precipitation. Other diagenetic features such as calcite cementation are not as critical because of their limited distribution.

Factors Controlling Reservoir Quality The major factors affecting the reservoir quality are the matrix content of the rock and diagenesis. All the Cypress wells in the field produce from clean sandstones with little matrix, a facies deposited under relatively high-energy conditions. These clean sandstones have higher effective porosity and permeability than dirty sandstones, which were originally low in porosity and permeability because of the presence of clay- and silt-size matrixes. A sample from the Keystone Oil Company, Campbell Heirs

No. 3 well (NW NW SE Section 11, T2N, R5E) at 2,535.5 feet has a permeability of 88 millidarcies and only a trace (less than 0.5%) of clay; whereas a sample from 2,529.5 feet in the same well has 4.4 millidarcies of permeability and approximately 2.6% clay.

Diagenetic processes that affected reservoir quality include cementation, feldspar dissolution, and precipitation of diagenetic clay minerals. Quartz overgrowths and, to a much lesser extent, calcite precipitation have reduced reservoir porosity, especially the effective porosity. Feldspar dissolution has not only increased secondary porosity but more importantly, enhanced the permeability. High permeability values always occur in samples that have a high number of dissolution pores, although total porosities remain nearly constant throughout the interval. The effect of diagenetic clay minerals on reservoir quality depends on whether the geochemical environment in which they are chemically stable is disturbed. Consequently, the selection of completion and production treatments is critical for preventing reservoir damage.

Sandstone geometry also affects reservoir quality by inhibiting or diminishing fluid communication within the sandstone. Vertical permeability barriers and lateral heterogeneities that resulted in sandstone compartmentalization apparently were formed by lateral and vertical differences in depositional conditions. Offshore bars such as units 1 to 3, present in the National Associated Petroleum Company, Schel Bryan No. 1 well (NE NW SE Section 14, T2N, R5E), are strongly compartmentalized. Examination of SP logs shows that thin shales sandwiched between sandstone bodies separate the sandstones into compartments. The stratigraphic trap in unit 2 of the East Central Development Company, Goad No. 1 well (SW SE SE Section 11, T2N, R5E) is confined laterally by dirty sandstone. The unit 4 (nearshore bar) reservoir also contains some low-permeability intervals. These low-permeability intervals, which may be shaley sandstone layers deposited between stacked bars, do not appear to impede fluid flow because a uniform OWC level was observed for this trap.

Classification and Identification of Plays

A structural, nearshore-bar play and a stratigraphic, offshore-bar play were identified in this field. The structural nearshore-bar play has the more significant reserves in this field.

Production Characteristics

Drilling and Completion Practices All wells in Xenia East Field were drilled with conventional rotary tools. Drilling fluids used in the Cypress productive wells were water-based bentonite mud. Most of the wells were completed open-hole with casing placed at the top of the reservoir.

About one-half of the wells were hydraulically fractured at the time of completion; 1,000 gallons of lease oil was typically used as the fracturing fluid and sand as a proppant. Primary production was by pump. Initial bottom-hole pressures were up to 915 psi and the bottom-hole temperature, estimated from scout tickets and log header records, was 95°F.

Reserve Calculations For comparison, two methods were utilized to calculate the OOIP. One uses a volumetric calculation combined with a Monte Carlo technique and the other employs a volumetric calculation based on planimeter measurements. Only the reserves in the major reservoir, the unit 4 sandstone, were calculated. The unit 2 (stratigraphic trap) reserves were not calculated because only one well encountered the trap.

The Monte Carlo method is a statistical model that uses random numbers to simulate sampling based upon the distribution function(s) of variable(s). This method has been widely used in the quantitative estimation of petroleum resources since the 1960s (Zhao 1988). The U.S. Geological Survey (USGS) has employed the Monte Carlo method for petroleum resource appraisal for the entire United States (Harbaugh et al. 1977, Dolton et al. 1981).

Figure 67 Pickett plot, Cypress reservoir at Xenia Field (Xu 1994).

For the Monte Carlo estimation, the pay zone thickness and oil saturation were chosen as variables because they have wide ranges; the other parameters in the volumetric equation are constant:

$$\begin{aligned}\phi &= 0.153 \\ A &= 416 \text{ acres} \\ B_{oi} &= 1.02\end{aligned}$$

The value of ϕ is an average from core testing and A is from grid counting. The value of B_{oi} is based upon engineering estimates.

No oil saturation (S_o) data are available from this field. The S_o data used to construct the distribution function were determined using a Pickett Plot (fig. 67). When compared with the range of 41% to 90% for initial oil saturations from statistical data for fluvial-dominated deltaic deposits (USDOE 1991), the range for the Xenia East Field is low (40% to 72%). Data calculated using this method are not as accurate as direct measurement, but this was the only way to estimate initial S_o values. When compared with the results from other Cypress fields, which have an average S_o of 60%, the results seem reasonable.

Calculations were made by direct sampling, using 2,000 random trials on each variable function. Because all the data are from actual drilling and/or geophysical measurements, their reliability is good and no uncertainty analysis was done for the calculation. The calculated result (probability distribution of OOIP) is shown in figure 68.

The method used by USGS geologists (Harbaugh et al. 1979, Dolton et al. 1981) was followed for these estimates:

- The low reserve estimate, with a 95% probability, is 0.98 million barrels STOOIP; i.e., there is a 95% probability that the STOOIP was not less than this amount.
- A high reserve estimate with a 5% probability is 4.88 million barrels STOOIP; i.e., there is only a 5% probability that the STOOIP in this field exceeded 4.88 million bbls.
- The modal estimate of the STOOIP is 1.77 million barrels, a value associated with the greatest frequency of occurrence among all the estimated reserve intervals. This amount is the one most likely, based on available data, to be present in the field.

Figure 66 Probability distribution of oil reserves at Xenia Field based on a Monte Carlo simulation using 2000 random trials on each variable (Xu 1994).

- The statistical mean value for the STOOIP is 2.54 million barrels, calculated by adding the low, high, and modal values and dividing the sum by 3. The mean estimate lies close to the exact middle of the probability distribution. There is a 45% probability that the STOOIP totals 2.54 million barrels.

The same volumetric equation used for the Monte Carlo calculation was used to calculate volumetrics for the field from the planimeter measurement of total reservoir volume. Total reservoir volume ($A \cdot H$) (utilizing the planimeter-generated 2,897.7 acre-feet) was used to calculate a value of 2.02 million barrels STOOIP. Averages of the other variables were used as constants:

$$\begin{aligned}\phi &= 0.153 \\ S_o &= 0.6 \\ B_{oi} &= 1.02\end{aligned}$$

This estimate is equivalent to the 60% probability based on the distribution function of STOOIP generated by the Monte Carlo method.

Although the Monte Carlo calculation yields a STOOIP range from 0.98 to 4.88 million barrels, the mean estimate of 2.54 million barrels is fairly close to the volumetric estimate of 2.02 million barrels, which is based on the planimetered measurement. About 451,000 barrels of oil have been produced from the structural trap; these two reserve values (2.54 and 2.02 million barrels) yield a primary recovery efficiency of 18% and 22%, respectively. Other Cypress fields have been found to have primary recovery efficiencies of about 20% (Grube 1992, Whitaker and Finley 1992). Because the petrographic characteristics and geological origins of these other fields are similar to those of Xenia East, a similar recovery efficiency could be expected at Xenia East, if similar production practices were carried out. Therefore, a

range of 2.02 to 2.54 million barrels of STOOIP is an acceptable estimate for this structural pool. It corresponds to the 45% to 60% probability range on the STOOIP distribution curve.

The amount of producible mobile oil greatly depends upon recovery techniques applied; for example, if operators can increase recovery efficiency to as much as 40% of STOOIP, there should be 360,000 to 570,000 barrels of mobile oil remaining in this field. Although the recoverable amount may vary, the remaining reserves (more than 75% of STOOIP) suggest a substantial additional recovery potential.

Development and Production Strategy

Secondary recovery techniques such as waterflooding are recommended, based on calculations of the STOOIP and remaining mobile oil in the Cypress reservoir at Xenia East Field. Waterfloods have been successful in other Cypress fields such as Tamaroa in Perry County (Grube 1992) and Bartelso in Clinton County (Whitaker and Finley 1992). Most Cypress production wells have been plugged, thus new wells will be needed for an effective injection and production program. Primary production has apparently exhausted the original energy in the reservoir, and waterflooding is an ideal method to build and maintain reservoir pressure.

Secondary recovery programs in the Xenia East Field must involve careful selection of drilling and injection fluids. Clay minerals such as kaolinite, mixed-layer illite/smectite, and iron-rich chlorite may react with fluids introduced during drilling, completion, and other treatments (Eslinger and Pevear 1988). Leetaru (1991) and Grube (1992) discussed formation damage that can result from use of fresh water and dilute HCl in wells. Fluids for field use should undergo laboratory core flood tests for compatibility with the formation. Grube (1992) also concluded that wells with open-hole completions in Cypress Sandstone units at Tamaroa tended to show the highest cumulative production. The fact that these wells also had higher initial production rates than the cased wells suggests that open-hole completions produce less formation damage and may be preferable to perforated completions in Cypress reservoirs.

Conclusions

The Cypress reservoir in Xenia East Field consists of sandstone deposited as nearshore and offshore marine bars. This sandstone, when combined with structural closure, constitutes the most important reservoir interval and controls almost all the reserves in the Cypress reservoirs. Stacked marine bars form vertically and horizontally heterogeneous reservoirs.

Original oil reserves in this Cypress pool ranged from an estimated 2.02 to 2.54 million barrels; the primary recovery efficiency at Xenia East was about 20% of the STOOIP. Between 360,000 and 570,000 barrels of remaining mobile oil may be producible, if a well designed secondary recovery program is implemented. Secondary recovery programs should include infill drilling, perforating Cypress intervals in nonplugged existing wells, waterflooding, and proper completion and treatment procedures.

ZEIGLER FIELD, FRANKLIN COUNTY

Zeigler Field is located in southwestern Franklin County, Illinois, primarily in Section 18, T7S, R2E, Section 13, T7S, R1E, and Section 19, T7S, R2E, approximately 3½ miles north of the Cottage Grove Fault System. The field produces from the middle Mississippian Aux Vases Sandstone and lies in an area of historical mining of the Herrin No. 6 Coal (Pennsylvanian). The field is developed over the abandoned Zeigler No. 1 and No. 2 underground coal mines owned by the Zeigler Mining Corporation.

The purposes of this study are to (1) describe the geologic controls on the Aux Vases reservoirs at Zeigler Field, (2) develop models for use in additional Aux Vases reservoir studies, (3) assess the influence of diagenesis in development of reservoir qualities such as porosity and permeability, and (4) provide geologic information for use in examination of the

concept of similarity within a reservoir class. These studies provide geologic input to petroleum engineering models, and may be used for assessment of improved oil recovery opportunities in the Illinois Basin.

Zeigler Field has produced about 2.1 million barrels of oil from 37 wells in the Aux Vases since the field was discovered in 1963. A single operator, Gallagher Drilling, Inc., drilled and completed all leases. Conventional analysis was conducted on cores from every well in the field and resulted in an exceptional database for study of the Aux Vases in a single field. Although most cores from the early discovery and development phases of the field were no longer available, core descriptions, porosity and permeability analyses, and cores from several wells on the recently developed leases (1980s) were donated to the ISGS by Gallagher Drilling, Inc. The company strongly supported the ISGS study by providing data, insights, and interpretations of field performance.

Zeigler Field was selected for several reasons:

- availability of cores from several closely spaced wells;
- abundant data (well logs, core analyses, and production information);
- opportunity to study a single producing horizon (noncommingled);
- location of the field in southern Illinois on the north flank of the Cottage Grove Fault System and near two other field studies conducted for the reservoir characterization program, Southwest Dale Consolidated (Beaty and Fagan, in press) and Energy Field (Huff 1993).

Production History

The discovery well was the Victor Gallagher, South Plumfield No. 1. During 1963 and 1964, the Plumfield, South Plumfield, and West Plumfield leases were developed, forming the main body of Zeigler Field. A decade later the field was expanded with a discovery on the Bend lease approximately 2 miles to the southeast. The three producing wells on the Bend lease, surrounded by dry and abandoned wells, form an isolated pod of reservoir quality Aux Vases Sandstone that is separated from the main body of Zeigler Field.

The field was further expanded in 1987 with the discovery of the V.R. Gallagher, Mack No. 1 well in the Mack lease, another isolated pod of production surrounded by dry and abandoned wells. The V.R. Gallagher, Mack No. 2 is the only other producing well in the pod. Improved knowledge of the small size and degree of isolation possible for excellent producing wells has led the Gallagher Company to conduct further exploration nearby.

At least three separate lenses have been identified in the main body of the field. Most wells were completed natural; some were shot with 10 to 60 quarts of nitroglycerin gel and, shortly after discovery, placed on waterflood by converting peripheral wells that had reached their economic limit into salt-water injection wells. Injected brines were from Pennsylvanian and Cypress sandstones and produced water from the Aux Vases Sandstone. Because all wells were cored with porosity and permeability analyses made at 1-foot intervals, accurate volumetric calculations were possible.

The major elements of this study included a subsurface study, a petrographic study with a detailed examination of diagenesis, and an evaluation of oil production strategies, involving a study of comprehensive reservoir management.

Stratigraphy

Marker beds used for mapping purposes in this study include the Joppa Limestone, a member of the Ste. Genevieve Limestone. In most instances, depths to the top of the Joppa have been verified by examination of cores or core descriptions. If these data were not available, depths were calculated using the abrupt transition on wireline logs of low resistivity sandstone in the Aux Vases to the highly resistive dense limestone.

The Renault Limestone, another mappable marker horizon in the study area, can be used for structural analysis. The Renault limestone directly overlies the Aux Vases Sandstone,

but the Renault was rarely cored and most depth calculations for this unit are based upon SP and resistivity log signatures. Because the lithology of the lower Renault can vary from a dense limestone to calcareous marine shale, determining the base of the Renault using electric logs becomes difficult. In these cases, electric logs from offsetting wells with correlative horizons of dense limestone and shale horizons were used.

A cross section of the northern portion of Zeigler Field illustrates several of the correlation problems encountered in this area. The Beech Creek ("Barlow") Limestone is the uppermost marker horizon for this study. Although this unit ordinarily has one of the most consistent, widespread, and easily distinguishable electric log signatures in the Illinois Basin, it is difficult to map in the Zeigler area. The widespread, thin limestone beds, which are easily recognized on electric logs in most other regions, are replaced by localized occurrences of thick "lower" Beech Creek Limestone (known as the "false Barlow"). This "false Barlow" underlies a very thin and, in some cases, undetectable "upper" Beech Creek ("Barlow") Limestone. Examination of well cuttings shows that the "false" Barlow consists of brown micritic limestone.

Another correlation problem occurs within a local, extremely thick (100 feet or greater) salt-water aquifer in the Cypress Sandstone. Individual sandstone bodies within the Cypress cannot be correlated across the field.

Early strike-slip movement along the nearby east-west-oriented Cottage Grove Fault System, in addition to the up-down movement of concomitant splinter faults oriented approximately perpendicular to the major fault trend, may have caused periodic movement and subsequent depositional compensation in the region. The abrupt, local changes in lithofacies noted in Chester units in Zeigler Field are attributed to tectonic factors.

Structure

Zeigler Field is 3½ miles north of the Cottage Grove Fault System, a major tectonic structural system in southern Illinois. The east-west-trending master fault system is composed of high-angle faults with strong indications of strike-slip movement (Nelson and Krausse 1981). Subsidiary splinter faults are roughly perpendicular to the trend of the fault, striking mainly northwest to southeast. Nelson and Krausse (1981) suggest that a fault trending northeast to southwest may intersect the Cottage Grove master fault about 4 miles west of Zeigler Field. Subsurface mapping does not provide a clear interpretation of this fault.

Nelson and Krausse attribute the development of secondary faults along the Cottage Grove Fault System to the release of extensional and compressional forces. A minor atypical northeast-southwest-trending fault has also been mapped on the Renault Limestone (Nelson and Krausse 1981) on the northwest periphery of the field. This fault is thought to have formed in response to present maximum horizontal compression (Nelson and Krausse 1981).

In the study area, the north side of the Cottage Grove Fault System is downthrown. The postulated fault on the northwest side of Zeigler Field is on the upthrown side of the secondary northeast-trending fault 4 miles northwest of the field. The proximity of these faults suggests that the Aux Vases Sandstone reservoirs at Zeigler have been subjected to regional stresses and localized tectonic activity that cause natural fracturing and render hydraulic fracturing an unnecessary procedure.

Regional stresses (Nelson, ISGS personal communication 1993) include strain gauge measurements of maximum horizontal compressive stress of $S_{67^\circ E}$ in shale beds above coal seams in the vicinity of Zeigler Field. According to Beaty and Fagan (in press), maximum horizontal compressive stresses (σ_H) may trend approximately east to west through the study area. There are some indications that σ_H may trend west-northwest throughout the study area (Nelson and Bauer 1987) parallel to the trend of the Cottage Grove Fault system. The impact of this phenomenon on recovery efficiencies and well placement is discussed in Udeghunam et al. (1993).

Trap Mechanism

Zeigler Field is located on a structural plateau, as mapped on the Joppa Limestone member of the Ste. Genevieve Limestone (fig. 69). A structural nose south and a depression northeast of the field have been mapped on the Beech Creek Limestone ("Barlow"). These structures have been mapped in more detail on a Joppa Limestone structure map of Zeigler Field. Production is limited to porous and permeable portions of bar sandstones. Thus, Zeigler is classified as a combination stratigraphic and structural trap. Subsurface mapping at Zeigler suggests that stratigraphic entrapment (where reservoir sandstones pinch out laterally to shale or impermeable limestone) is the primary trapping mechanism.

Middle Mississippian Faulting in the Vicinity of Zeigler

Evidence suggests that local faulting influenced deposition of Chesterian siliciclastics in the region. Because there is an abrupt change in thickness of the Cypress Sandstone across the field, it is possible that faulting occurred during Chesterian time at Zeigler Field. Thicknesses of the Cypress Sandstone vary from more than 100 feet on the east side of the field to less than 30 feet on the west side. The break in Cypress sandstone thickness roughly coincides with a pressure barrier that separates the east from the west side of the field. A thick "false Barlow" also coincides with this pressure break and the thinner Cypress Sandstone. Healed calcite-filled microfractures in the Ste. Genevieve limestone below the Aux Vases and the

Figure 69 Zeigler Field, structure on top of the Joppa Limestone Member of the Ste. Genevieve Limestone (Seyler in prep.).

Renault Limestone above also suggest periods of fracturing prior to major strike-slip movement along the Cottage Grove Fault System.

Zeigler Field is a typical example of an Aux Vases reservoir deposited in a shallow marine environment in the center of the basin. Facies consist of moderately thick, tidally dominated offshore marine bars. In the field, carbonate framework grains such as micritized pellets, ooids, and echinoderm, bryozoan, brachiopod, and other marine fossil fragments are incorporated into predominantly siliciclastic Aux Vases reservoirs. Rapid lateral facies changes to carbonate grainstone units suggest a large degree of marine carbonate influence. Fine to very fine grained sandstones in this facies were deposited on or adjacent to poorly consolidated ooid shoals in the underlying Joppa member of the Ste. Genevieve Limestone. This facies likely represents a marineward progradation of siliciclastic offshore marine bars deposited within and on top of the shoaling oolitic carbonate environment of the upper Ste. Genevieve Limestone. As siliciclastics were brought into the carbonate environment, oolite and pelloidal shoals were still accumulating nearby. When siliciclastic influx subsided or was diverted, conditions conducive to carbonate formation and accumulation would again prevail in the area. These conditions produced a mixed carbonate-siliciclastic environment.

Rapid shifts between siliciclastic sedimentation and carbonate accumulation were controlled by siliciclastic input and water depth, which together regulated accumulation of carbonate and siliciclastic sediments. Both types of lithology appear to have been deposited and shaped by tidal processes. Siliciclastics were deposited in slightly shallower water and show some indications of subareal exposure.

Many features observed in subsurface core and outcrops of this facies suggest that tidal processes shaped and formed reservoir and nonreservoir siliciclastics of the Aux Vases. Features in cores from the field and in outcrop include tidal couplets, vertical escape burrows, herringbone crossbedding, bidirectional low-angle crossbedding, mud cracks, and flaser bedding. All are indicative of deposition by tidal processes (Weimer et al. 1982, Ginsburg 1975).

Environments of Deposition

Most Aux Vases sandstone reservoirs in the southern part of the oil-producing region of the Illinois Basin formed as regressive, offshore, marine tidal sandbar complexes deposited on upward shoaling Joppa (Ste. Genevieve Limestone) oolite sequences. The reservoirs are interpreted as offshore marine bars deposited by tidal processes in a mixed siliciclastic-carbonate setting. The relationship between interbar and tidal flat deposits is important because these units form impermeable and nonporous seals that encase sandstone reservoir bars. They may also form permeability barriers within reservoirs.

The lowermost facies in the Aux Vases at Zeigler directly overlies the Joppa Limestone and consists of nonporous and impermeable, green, ripple bedded and climbing ripple bedded, extremely fine grained silty sandstone. This silty sandstone facies represents a shallow subtidal environment in a low to moderate energy regime and contains a large amount of clay and silt. Variations in thickness of this facies across the field suggest that this shaley sandstone has filled in areas that were topographically low.

Mud cracks in shale partings of this facies are highly diagnostic features that suggest periods of subareal exposure. Petrographic examination of this facies shows tightly cemented grains with sutured contacts attributed to compaction. Chlorite, the most common clay mineral in the silty sandstone, may be responsible for the green color common in this facies. Other facies with chlorite are not green, however, suggesting that the green color may have another cause, such as the presence of ferrous iron. Small amounts of ferric iron result in red coloration; ferrous iron may result in a green color.

Reservoir Sandstone Bar Facies

Reservoir sandstone bars are composed of fine grained, bidirectionally crossbedded, brown, oil-stained sandstone that overlies the green, ripple bedded, silty sandstone facies. A type log

from the V.R. Gallagher Mack No. 2 well shows the relationship of the permeable sandstone bar reservoir facies with underlying and overlying impermeable nonreservoir facies. Reservoir sandstone contains carbonate framework grains such as ooids, marine fossil fragments (including echinoderms, brachiopods, and bryozoa), and micritized carbonate peloids.

Cores from reservoir sandstone bar intervals contain low- to high-angle bidirectional crossbedding of alternating oil-stained, coarser grained, porous laminae with lighter colored, finer grained, less porous laminae. Sedimentary structures such as these illustrate extensive reservoir heterogeneity on a macroscopic and microscopic scale. Light bands (laminae) of extremely fine grained, nonporous unstained sandstone contrast with the dark bands of oil-saturated coarser grained sandstone laminae.

Evidence of Tidal Deposition

Vertical escape burrows, sedimentary features commonly associated with tidal flat deposits, are found in the silty interval separating two crossbedded, reservoir sandstone bar intervals in the V.R. Gallagher Mack No. 6 well. The vertical escape burrows show several cycles of sedimentation followed by burrowing, suggesting rapid short-lived cyclic sedimentation produced by tidal currents. Tidal flat and sand flat deposits, overlying all bar sandstones in Mack lease wells, are thicker and more fine grained in wells containing the thinnest sandstone bars. The interpretation is that a tidal flat environment followed sandbar deposition. Mud cracks, evidence of subaerial exposure of the tidal flat, are preserved in sediments of red and green variegated shale, silt, and extremely fine grained sandstone. Tidal couplets consisting of thinly laminated cyclic deposits reflect deposition during ebb and flood tides. The presence of what may be rootlets also suggests subaerial exposure.

Some sandstone bars at Zeigler are shingled, partly overlapping each other, and separated by tidal flat deposits that may have formed between episodes of marine transgression after deposition of offshore marine sandbars. Several episodes of sandbar deposition occurred. Three narrowly connected bars in the main body of the field roughly coincide with the limits of the Plumfield, West Plumfield, and South Plumfield leases. Also, there are two totally isolated sandbars in the Mack and Bend leases. The sandbars were not all deposited at the same time, nor are they all laterally equivalent. The amount of overlap and communication varies between bars; for example, the reservoir sandstone bar in the West Plumfield lease partly overlies the sandbar in the Plumfield lease. There is no communication of fluid between these two sandbars. The Plumfield sandbar in turn is partly overlain by the South Plumfield sandbar, which was most likely deposited after the Plumfield and West Plumfield sandbars. The South Plumfield bar is stratigraphically higher than the other two sandbars.

Tidal channel deposits are another possible type of reservoir that would normally be anticipated in this setting; however, all the Zeigler reservoirs are sandstone bar deposits. No downcutting into the underlying green, ripple bedded sandstones is observed; and the gradational contact between the sandstone bar facies and the tidal flat sandstone facies shows no evidence of erosional contacts between sandstone facies.

Reservoir Description and Distribution

Reservoir sandbars at Zeigler are relatively small, typically $\frac{1}{2}$ miles long and $\frac{1}{4}$ mile wide, and achieve a maximum thickness of 15 to 25 feet (fig. 70). The size, shape, and distribution of reservoir sandstone bars across the southern portion of the basin suggest that an analysis of their spacing (periodicity) may be a useful exploration strategy. Periodicity has been suggested as an exploration tool by Huff (1993). A study of spacing and interrelationship of sandstone bars in and around Zeigler Field may lead to the discovery of other reservoirs nearby. Reservoir quality increases near the center of the sandstone bars, where porosities greater than 25% and permeabilities in excess of 400 millidarcies are common. Thinner sandstones with poor reservoir quality are found on the edges of the bars. The bars approximate

Figure 70 Isopach of sandstone reservoir facies at Zeigler Field, illustrating three distinct sandstone bars (Seyler in prep.).

lease lines and are referred to by lease name. Offshore marine tidal sandstone bar reservoirs in Zeigler Field have a convex-upward geometry in cross section.

Pressure data show an incomplete permeability barrier between Plumfield and South Plumfield sandstone bars. Electric logs for the V.R. Gallagher, Plumfield No. 18 well record a minor shaley sandstone break between two thin, more permeable sandstone bodies. The fact that there is no communication of fluid between the reservoirs on either side of the well is evident only when pressure data are used. These data also show that the bar in the Plumfield lease to the north is narrowly connected to another bar in the South Plumfield lease. Communication is via a narrowly constricted pathway of about one well spacing (660 feet).

Petrography

Framework Grains in the Aux Vases Sandstone Reservoirs Siliciclastic framework grains in the Aux Vases Sandstone include, in descending order of abundance, undulose quartz, non-undulose quartz, polycrystalline quartz, K-feldspar (orthoclase and microcline), plagioclase feldspar, and chert. Carbonate framework grains include micritized peloids, ooids, and marine fossil fragments such as echinoderms, bryozoa, and brachiopods. X-ray diffraction

(XRD) analyses of reservoir sandstone bar facies show a range of 81% to 92% quartz, 0.5% to 0.6% K-feldspar, and 3.9% to 6.6% plagioclase feldspar; total feldspar content ranges from 4.4% to 7.7%. Twelve of the 13 samples from the reservoir sandstone bar facies in the V.R. Gallagher, Mack Nos. 1 and 2 wells analyzed by XRD contained between 5.2% and 7.7% total feldspar, thus they are classified as subarkoses; the remaining sample contained 4.4% total feldspar and is classified as quartz arenite. The average sandstone bar sample in Zeigler Field is a subarkose with a minor amount of calcite in the form of framework grains or a patchy calcite cement and 2.5% diagenetic clay minerals coating grains and lining pores.

Microfractures

Vertical microfractures filled with calcite cement are present in the dense Renault Limestone above and the dense Joppa Limestone Member below the reservoir sandbar facies at Zeigler. Microfractures, some filled with residual oil, are also found in the reservoir sandbar facies. Because grains in this sandstone are so weakly bonded, it is not always possible to determine whether microfractures in the reservoir formed in response to regional stress, localized faulting, or disintegration of the sandstone as pressure was released when the core was pulled to the surface. Residual oil in some microfractures, healed microfractures in vertically adjacent limestones, and the proximity of a major fault system and several minor splinter faults all suggest that micro- and macrofracturing have affected reservoir permeability channelling at Zeigler. Production data show a strong flow east to west. Monitored injection wells show breakthrough in east to west offsets before it occurs in north or south offsets.

Computerized Tomography: CAT Scan

Reservoir heterogeneity on a macro- and microscale, in which finer grained, less porous laminae alternate with coarser grained, more porous laminae, is visually highlighted and confirmed by computerized tomography (CAT-scanning) experiments. Imaging was performed by NIPER on a 6-inch section of core from a depth of 2,633 feet in the V.R. Gallagher, Mack No. 1 well. The core contains typical bidirectionally, crossbedded, porous, coarser grained laminae alternating with less porous, finer grained laminae. Figure 71 is an example of the common types of visually obvious heterogeneities caused by crossbedding in Aux Vases Sandstone bar reservoirs. According to minipermeameter measurements of this sample, reservoir quality is relatively poor. The range of permeabilities from 4.6 to 65.7 millidarcies is attributed to an overall finer grain size than is ordinarily found in high quality Aux Vases Sandstone bar reservoirs. The sedimentary structures and relative grain size relationships are similar, however, to those found in all crossbedded Aux Vases Sandstone.

The CAT scan measurements are represented by a graded gray scale related to density and atomic number (fig. 71). The lighter or brighter sequence represents increasing density of the rock material. The closer the color is to white, the greater the corresponding density. This core exhibits a high degree of heterogeneity. If the mineralogical composition is relatively uniform, the denser zones should be less porous than are the other zones shown on the CAT scan image. The darker portions of the core should be the most porous. The relationship of less porous and permeable, finer grained crossbedded laminae alternating with more porous and more permeable, coarser grained laminae has been confirmed by minipermeameter measurements as well as by petrographic observation. The most permeable zones measured by a minipermeameter correspond with darker laminae that are stained with solid hydrocarbons and are coarser grained and more porous than the tan, finer grained, less porous and permeable laminae.

Brines

Three brine samples from Zeigler Field were analyzed (Appendixes VI, VII-B). Two samples from the main body of the field are from wells waterflooded since 1965 with brines from

Figure 71 Computerized tomography (CAT Scan), illustrating high degree of reservoir heterogeneity in a reservoir sample from Zeigler Field. The darker shades represent less dense (more porous) laminae. The lighter shades are denser (less porous) laminae (Seyler in prep.).

both Pennsylvanian and Cypress Sandstones (1,200 feet and 200 feet, respectively, above the Aux Vases). Later, produced Aux Vases brines were also used. It is assumed that the Pennsylvanian brines and Mississippian Cypress brines, which contain fewer total dissolved solids (TDS), have diluted the Aux Vases brine samples from these wells. Therefore, the R_w measured on undiluted brines sampled from the V. R. Gallagher, Alex No. 1 well should be more representative of the original brine in Zeigler Field.

The sample from the Alex No. 1 well contains 137,329 ppm TDS: 82,000 ppm chlorine (Cl), the most abundant anion; and 45,950 ppm sodium (Na), 6,020 ppm calcium (Ca), and 1,900 ppm magnesium (Mg), the most abundant cations. The pH of 6.24 makes this sample more acidic than most brines analyzed to date. TDS concentration is also greater than that of most brines sampled to date. Measured R_w of .061 ohm-meter is well within the range of 0.58 to 0.70 ohm-meter measured in other Aux Vases brines in the region.

Production

Production at Zeigler Field is solely from the Aux Vases Sandstone bar facies. To date, the field has produced approximately 2.1 million barrels of oil from two totally separate bars and three partly overlapping bars with minimal communication. Production per well is extremely variable, ranging from a high of 203,774 barrels of oil from the V. R. Gallagher, Plumfield No. 1 to a low of 646 barrels of oil from the V.R. Gallagher, West Plumfield No. 10. The average cumulative production for all oil wells at Zeigler is 65,540 barrels of oil.

The fact that the two bars are separated has a great influence on petroleum movement and recovery. A design flaw in an early waterflood scheme was noted when eastward fluid movement was not detected from the first injection well in the West Plumfield bar to the

Plumfield bar. Compensation for this design flaw was possible when pressure data showed the location of a permeability barrier. This case demonstrates the value of acquiring pressure data as a relatively inexpensive means of monitoring reservoir behavior. The data are essential for planning and implementing efficient and effective reservoir management techniques.

Bar Edge Effect

Wells with the largest cumulative oil production are generally at the edges of sandstone bars and not necessarily associated with wells into the thickest, cleanest, most porous, and permeable sandstone. Edge production is thought to be caused by very effective waterfloods banking oil at the periphery of individual sandstone bars toward the last well before the sandstone bars pinch out stratigraphically.

Several examples of this phenomenon exist in Zeigler, where the greatest fluid (oil and water) accumulation took place in wells at the periphery of the reservoir. The V.R. Gallagher, Plumfield No. 12 was converted to a salt-water injection well in December 1965. The first well to respond to this waterflood was the southern offset, the V.R. Gallagher, South Plumfield No. 2, which increased in monthly production during 1966. The second well to respond to this waterflood during January 1967 was the V.R. Gallagher, South Plumfield No. 3, which offset the South Plumfield No. 2 660 feet to the west. The third well to increase in monthly production (January 1968) was the V.R. Gallagher, South Plumfield No. 6, which directly offset the South Plumfield No. 3 660 feet to the west near the sandstone bar pinchout.

There was no response in pressure differential in wells to the north for several years after inception of water injection in the Plumfield No. 12. The lack of response suggested that reservoir communication was more limited to the north than to the southwest. As in the West Plumfield bar and Plumfield bar communication barrier example cited earlier, the geological indicators for a delayed and limited response are minimal. Permeability in the injector well is consistently around 200 millidarcies throughout its reservoir sandbar interval; whereas permeabilities in the sandbar interval in offset wells to the north and south fluctuate widely, ranging from 50 to 600 millidarcies. Both north and south offsets display approximately equal fluctuations in permeability, which cannot explain preferential waterflooding directed to the southeast. One possible explanation for a fluid communication barrier is overlapping of sandstone bars or a silty zone separating the Plumfield and South Plumfield sandstone bars. Another possible influence is a natural east-west fracture system that may have developed in the reservoir unit as a result of regional compression.

Comparison of a contoured map of initial production with contoured cumulative production demonstrates that, with few exceptions, the wells with the largest initial productions do not accumulate the most oil. Initial production has not been good measure of overall performance during the life of an oil well.

Volumetrics

Volumetrics were calculated using the following equation:

$$\text{Original oil in place (OOIP)} = 7,758 \times \phi \times Ah \times S_o \div B_{oi}$$

where:

- 7,758 = conversion factor for acre-feet to barrels
- OOIP = original oil in place
- ϕ = average porosity in the bar (21%)
- Ah = volume in acre-feet
- S_o = average oil saturation (40%)
- B_{oi} = formation volume factor (1.068)

Estimates of the OOIP were made for all of the sandstone bars. Other data for the OOIP determination is shown in the reservoir summary (Appendix V).

The West Plumfield sandstone bar is the largest in Zeigler Field. The Plumfield and South Plumfield sandstone bars were combined for volumetric calculations because they overlapped and had minor communication; it was not possible to map their terminus. The sandstone bar in the Mack lease is one of the smallest in the field and totally isolated from the other bars.

Recovery efficiency for the West Plumfield bar was 46%, and the Plumfield and South Plumfield bars together produce 59% of the STOOIP, calculated on the basis of an average oil saturation of 40%, average porosity of 21%, and a formation factor of 1.068.

Because there is no oil-water contact in any sandstone bar at Zeigler, the total volume of each bar was calculated to determine the OOIP and recovery efficiencies. Volume of each bar was based on the planimeter method of using isopach maps of bar thickness contoured on a 5-foot interval.

Excellent recovery efficiencies are in large part attributed to early inception of a pressure maintenance program implemented by converting producers that had reached their economic limit to salt-water injection wells. The field was started on waterflood shortly after field development was completed. The first waterflood was started in 1965, before field pressure was depleted. Careful monitoring of pressure response was another major factor in designing an effective and efficient waterflood program at Zeigler Field. Permeability barriers were known from pressure monitoring—information that permitted effective selection of new injection wells for waterflooding. Current recovery efficiency in the sandstone bar in the Mack lease is 20%, much less than that of the other sandstone bars in the field because it is a newer waterflood unit.

Water saturation calculations are not constant for the entire reservoir interval and may reach as high as 50%; but 40% is probably a good average. Recovery efficiency percentages calculated by using 50% water saturation yield results beyond those normally thought possible by using conventional primary and secondary recovery techniques. Because the porosity has been averaged, it does not necessarily account for variations within the field. A thorough discussion of volumetrics can be found in Sim et al. (1994). Using reservoir simulation techniques that incorporated the massive amount of data available for Zeigler Field, they have achieved an excellent history match.

Drive Mechanism

Solution gas was the drive mechanism at Zeigler Field for the first 6 months of production. Initial pressure in the reservoir was 1000 psi, which diminished to 100 psi after the first year. Pressure drop was rapid, largely because of the limited volume of the reservoir and the location of effective seals on all sides of the small tidal sandstone bars. Sandstone bars placed on pressure maintenance before depletion yielded greater recovery efficiencies than those that had significant pressure depletion before waterflooding was undertaken.

Conclusions

The Aux Vases Sandstone reservoir at Zeigler Field is composed of sandstone bars deposited in a mixed carbonate-siliciclastic, shallow marine environment. A strong tidal influence is evident throughout the Aux Vases interval at Zeigler Field. Deposition of nonreservoir tidal flat sediments was extremely important in forming effective reservoir seals and permeability barriers within sandstone bars in the main body of the field. Two separate reservoir compartments consist of three slightly overlapping and minimally connected sandstone bars. Each bar is encased in impermeable tidal flat and interbar facies. There is no oil-water contact in any sandstone bar.

Monitoring reservoir pressure and production parameters for the field provided the information necessary for efficient reservoir management, which led to efficient well placement during waterflooding. Injection wells were placed to compensate for the permeability

barriers identified within the field. Early pressure maintenance achieved through the conversion of strategically located producers and peripheral wells led to excellent recovery efficiencies, averaging 52%. Banking of petroleum against impermeable nonreservoir units that encase the sandstone bars helped to produce the higher efficiencies and added to the duration of waterfloods in the field. Wells at the edges of sandstone bars generally have the highest cumulative petroleum production, although they may be stratigraphically lower and considerably less porous and permeable.

The sandstone bar reservoirs at Zeigler are stratigraphic traps with approximately a 1/2 to 1 mile periodicity between bars. Similar undiscovered stratigraphic traps are likely to be present in the vicinity.

Original porosity and permeability of the sandstone bars were affected by later diagenetic events, significantly, the precipitation of diagenetic clay minerals that coat sand grains and cause weak cementation at grain point contacts, the dissolution of early calcite cement, and the dissolution of feldspar grains. Dissolution of early calcite cements greatly enhanced porosity and permeability. Dissolution of feldspar grains provided the conditions necessary to precipitate diagenetic clay minerals, which severely restrict precipitation of quartz as cement at grain contacts and as overgrowths, and thus preserve porosity and permeability. Their presence in limiting quartz cement at grain contacts, and as a cementing agent, resulted in a friable, loosely cemented reservoir. The Archie equation does not give accurate water saturations for use in reserve calculations because some diagenetic clay minerals have a low resistivity to electric currents and trap irreducible, unproducable water.

DIAGENESIS IN AUX VASES AND CYPRESS SANDSTONES

Diagenetic alteration has been a major factor in the formation, enhancement, or reduction of porosity and permeability in Aux Vases and Cypress Sandstone reservoirs analyzed to date. Petrographic study of reservoir samples incorporated results from transmitted light microscopy, cathodoluminescence, scanning electron microscopy with energy dispersive x-ray microbeam analysis (SEM/EDX), and x-ray diffraction (XRD) analysis. The Aux Vases Sandstone reservoirs were examined at Zeigler, Oakdale, Southwest Dale, Energy, Boyd, and King Fields. Cypress Sandstone reservoirs were examined at Tamaroa, Bartelso, Parkersburg, Xenia, Lawrence, and Mattoon Fields.

Major differences in the characteristics of Cypress and Aux Vases reservoirs are due, in part, to basic differences in diagenetic alterations. The major diagenetic alteration in Cypress reservoirs was widespread precipitation of quartz overgrowths (fig. 72); silica around each quartz sand grain reduced porosity and permeability. Cypress reservoirs are thus usually less porous and permeable than Aux Vases reservoirs, where quartz overgrowths were inhibited by the precipitation of diagenetic clay mineral coatings around every sand grain (fig. 73).

Reservoir facies in Aux Vases fields have been interpreted as offshore shallow marine sandstone bars reconfigured by tidal processes. These reservoirs exhibit a number of similarities that permit petrographic description of one reservoir to serve as a model for other Aux Vases Sandstone reservoirs. Therefore, the petrographic description and diagenetic history developed for Zeigler Field will serve as a model for Aux Vases Sandstone reservoirs in this report. A paragenetic sequence has been developed for Aux Vases Sandstone reservoirs. Reservoir-to-reservoir variations occur that do not directly follow this model; these will be discussed below. Patterns are present that suggest similar diagenetic alterations are repeated in varying degrees in all these fields.

Much greater diversity is found in Cypress reservoir facies than in Aux Vases reservoirs. Depositional environments ranged from marine bars deposited in a mixed carbonate-siliciclastic environment, to lower delta plain sandstones, to buried barrier bars. Therefore, it is not possible to use single field results to model other Cypress reservoirs.

Figure 72 Quartz overgrowths are the dominant diagenetic alteration observed in Cypress reservoirs (Seyler in prep.).

Figure 73 Grain coatings of diagenetic clay minerals is the most important diagenetic alteration observed in Aux Vases reservoirs (Seyler in prep.).

Framework Grains

Aux Vases Sandstone Reservoirs Siliciclastic framework grains in the Aux Vases Sandstone include (from most to least): undulose quartz, nonundulose quartz, polycrystalline quartz, K-feldspar (orthoclase and microcline), plagioclase feldspar, and chert. Carbonate framework grains include micritized peloids, ooids, and marine fossil fragments such as echinoderms, bryozoa, and brachiopods.

X-ray diffraction analyses of Aux Vases reservoir samples show that the amount of quartz varies from 62% to 92%, potassium feldspar from 0 to 15.6%, plagioclase feldspar from 1.5% to 10.1%, calcite from 0 to 20.8%, dolomite from 0 to 2.0%, and total clay content from .1% to 7.0%. The clay mineral suite in Aux Vases reservoirs is composed of mixed-layered illite/smectite, iron-magnesium chlorite, and illite. Small amounts of kaolinite were found only at Stewardson Field.

Cypress Sandstone Reservoirs X-ray diffraction analyses of Cypress Sandstone reservoir samples from Parkersburg, Mattoon, Lawrence, Xenia, Tamaroa, and Bartleso Fields show that the amount of quartz varies from 69.7% to 98.8%, calcite from 0 to 4.6%, K-feldspar from 0 to 11.1%, plagioclase feldspar from .4% to 27%, dolomite from 0 to 5.0%, and the total amount of clay minerals from .1% to 4.1%. The clay mineral suite in most Cypress Sandstone reservoir samples consists of kaolinite, chlorite, illite and mixed-layered illite/smectite.

Petrographic examination of Cypress Sandstone thin sections shows that these sandstones are most commonly fine grained, well sorted, and clean, containing few silt- and clay-sized detrital particles. The following framework grains occur (from most to least): undulose quartz, nonundulose quartz, chert, k-feldspar, plagioclase feldspar, and trace amounts of heavy minerals and carbonate marine fossil fragments. The heavy mineral suite is composed primarily of zircon and titanium-rich minerals such as rutile, anatase and brookite and lesser amounts of hornblende, tourmaline, and garnet. Heavy mineral lags aligned along cross-bedding planes are common in some samples. These very thin lags have an average thickness of one grain.

Average porosity and permeability for Cypress Sandstone reservoirs are less than those measured in Aux Vases sandstone reservoirs. Porosity ranges from 13% to 20% in high quality Cypress reservoirs, whereas porosity is usually 20% to 30% in high quality Aux Vases reservoirs. Permeability ranges from 50 to 500 millidarcies in Cypress reservoirs and 50 to 800 millidarcies in Aux Vases reservoirs. These variations in reservoir quality are attributed to differences in mineralogic composition and diagenetic alterations.

Paragenetic Sequence in Cypress Reservoirs

The dominant diagenetic event is the addition of silica, primarily as overgrowths on quartz grains (fig. 72), which formed both during early and late paragenetic events. Precipitation of quartz overgrowths was so prevalent that most primary porosity was occluded as the geometry of pore throats was transformed, reducing the size and volume of pores. As a result, most pore throats in these reservoirs are triangular with smooth, slick sides formed from euhedral quartz overgrowths. The smoothness of the pore throats facilitates the flow of petroleum. This contrasts sharply with pore throats in typical Aux Vases reservoirs (fig. 73).

Feldspar Dissolution and Precipitation of Diagenetic Clay Minerals

The first major phase of silica precipitation was followed by feldspar dissolution, providing compounds necessary for precipitation of diagenetic clay minerals. Once precipitated, these clay minerals were relatively stable under prevailing subsurface reservoir temperatures between 80° and 120° F. If the pH was lowered enough, some diagenetic clay minerals dissolved, then reprecipitated as the same or different diagenetic clay minerals. When a feldspar grain is completely dissolved, an oversized pore is left. If the original detrital feldspar

Figure 74 Kaolinite booklets common in Cypress reservoirs (Seyler in prep.).

content is large enough, then dissolution of feldspar grains can significantly increase porosity, unless the resulting clay precipitation offsets the increase in porosity. The hierarchy of stability and susceptibility of feldspar grains to dissolution is as follows: calcite-rich plagioclases are the least stable, potassium-rich feldspars have intermediate stability; and sodium-rich feldspars are the most stable. Cypress sandstone reservoir samples contained less detrital feldspar than Aux Vases reservoir samples. As a result, Cypress reservoirs have less secondary porosity because fewer feldspar grains were dissolved. Additionally, diagenetic clay minerals are less abundant in Cypress reservoirs because of the decreased amount of aluminosilica available for precipitation during these diagenetic phases.

Diagenetic Clay Minerals in Cypress Reservoirs

Kaolinite is the most abundant diagenetic clay mineral in most Cypress sandstone reservoir samples (fig. 74). It frequently fills oversized and enlarged pores, presumably replacing dissolved feldspar grains. Kaolinite is also commonly found in pores, precipitated onto smooth, euhedral faces of quartz overgrowths. Rosettes of iron-rich chlorite are the second most common diagenetic clay mineral observed in pores of reservoir samples during SEM/EDX analysis. Chlorite is not visible in thin section because it occurs as thin, incomplete, and sporadic dustings on euhedral faces of quartz overgrowths. Chlorite rosettes commonly contain 15% to 20% iron in SEM/EDX analyses; thus they are the most iron-rich, acid-soluble (and therefore problematic) pore-filling mineral in Cypress or Aux Vases sandstone samples. The fact that kaolinite and iron-rich chlorite are frequently associated with one another suggests that the timing and conditions for their precipitation onto the quartz overgrowths that lined the sides of pores were similar. Illite and mixed-layered illite/smectite are less commonly observed in pores than are kaolinite and chlorite. Each of these diagenetic clay minerals, with the exception of mixed-layered illite/smectite, can be readily identified using SEM/EDX. Diagenetic clay minerals and quartz overgrowths combine to form the major component of the pore-wall mineral system of Cypress Sandstone reservoirs.

Ferroan Calcite Cement in Cypress Reservoirs

Ferroan calcite occurs infrequently as localized patchy cement. It is thought that much of the ferroan calcite is precipitated early, during shallow burial, because most grains appear to be floating in a matrix of calcite, and grain to grain contact is minimal. Some ferroan calcite cement was dissolved during intermediate diagenesis, possibly during compaction, when organic (carboxylic) acids were introduced from surrounding shales (Surdam et al. 1989). A later phase of ferroan calcite precipitation may have occurred during intermediate burial.

Precipitation of replacement pyrite was another minor, early burial event. Rare occurrences of pyrite framboids on top of diagenetic clay minerals suggest a second, very late stage, minor event of pyrite precipitation. Trace amounts of barite found in many Cypress reservoir samples is an indication of another minor, late stage precipitation event that may be related to pyrite precipitation.

The latest porosity enhancement event observed in some Cypress reservoir samples was the partial dissolution of quartz overgrowths, which were most likely exposed to organic acids, either introduced into the reservoir possibly from surrounding shales or as an early product of petroleum generation.

Early Phase Diagenetic Alterations in Aux Vases Reservoirs

The two phases of diagenetic alteration responsible for porosity and permeability enhancement of the reservoir sandbar facies in the Aux Vases Sandstone in the Illinois Basin are early and intermediate to late phases. The early phase included minor compaction, incipient silica cementation at grain to grain contacts, and pervasive calcite cementation. The intermediate to late phases include several processes that improved porosity and permeability through dissolution, and a few minor late stage events serving to occlude porosity and permeability. These diagenetic changes will be discussed later. Silica cement was formed at grain contacts during shallow burial. Typical grain to grain contacts in the Aux Vases are poorly developed. There is no trace of diagenetic clay minerals on any of the broken contact faces, as would be expected if entire grains were clay-coated at the time of silica cementation at grain contacts. The presence of limited grain-to-grain point-contact cementation suggests that little compaction occurred in the reservoir sandbar facies at Zeigler Field or that calcite cement supported framework grains during compactional phases. Pore-lining clay minerals formed shortly after initial grain-contact cementation because virtually all grain surfaces are coated with diagenetic clay minerals. Later stage quartz overgrowths are extremely rare in reservoir sandstones at Zeigler; for example, they are inhibited by pore-lining clay minerals. Those quartz overgrowths that do occur are minute, usually 10 μm or less in length, and have precipitated where minor breaks occur in clay minerals coating grains. This crystallization indicates that late stage quartz overgrowths were an even later diagenetic event than the latest formation of diagenetic clay minerals.

Analyses by SEM/EDX show that, in some cases, late stage quartz overgrowths are larger and more common in other Aux Vases reservoirs than those found at Zeigler. In particular, the sandstone bar reservoirs at southwest Dale Consolidated field have abundant, unusually shaped quartz overgrowths. The larger size and greater abundance of quartz overgrowths in these reservoirs are most likely due to more incomplete and thinner diagenetic clay mineral coating sand grains and lining pores. However, even the most pronounced quartz overgrowths observed to date in an Aux Vases reservoir are not extensive enough to significantly reduce porosity or permeability.

Evidence for Precipitation of Early Calcite Cement in Aux Vases Reservoirs

The presence of floating, unsupported grains and the lack of grain-to-grain contacts in numerous areas are indications that these grains were supported by a matrix of calcite cement precipitated before compaction of grains. In some instances, even the clay rims in

these areas do not come into contact with other grains. Much of the primary porosity occluded by the precipitation of early calcite cements was subsequently recovered by dissolving the cements later in the paragenetic sequence leading to the development of large amounts of secondary intergranular porosity. Sandstones in the underlying green ripple bedded facies in Zeigler Field have undergone suturing of quartz grains due to compaction. This compaction eliminates nearly all porosity and permeability. At Zeigler field, there is little remaining primary calcium carbonate cement in the reservoir quality sandbar facies; however, some of this cement has been found in the Mack Nos. 3 and 6 wells. These wells are on the outer fringes of the sandstone bar in the Mack lease, where the degree of development of secondary porosity and permeability is reduced due to the presence of a small amount of original, early stage, calcium carbonate cement remains.

Deposition took place in a mixed siliciclastic-carbonate environment. There was an abundance of dissolved calcium carbonate in the sea water and thus ample opportunity for calcium carbonate cementation during early diagenesis at shallow burial depths. In addition to the partially dissolved primary calcite, primary calcite cement completely fills intergranular pores in crossbedded calcareous sandstone in other areas at the outer fringes of the sandbar in the Mack lease. If the calcium carbonate cement were removed, these sandstones would be similar to the alternating laminae found in reservoir quality crossbedded sandstone consisting of porous, coarse grained beds intercalated with finer grained, less porous beds.

For reasons cited above, it is suggested that the reservoir sandstone bar facies at Zeigler and most other similar Aux Vases bar reservoirs originally contained large amounts of calcium carbonate cement, which nucleated around fossil fragments. During later diagenetic alterations, the primary calcite cement was dissolved, secondary porosity developed, and permeability increased.

Intermediate and Late Stage Diagenetic Alterations: Reservoir Sandbar Facies

Intermediate stage diagenetic alterations include dissolution of early calcite cement, dissolution and alteration of feldspar (primarily Ca-plagioclase and K-feldspar) (fig. 75), formation of diagenetic clay minerals, formation of albite overgrowths, precipitation of minor iron-calcite, fracturing, and petroleum migration. Porosity was also enhanced by as much as 7% by the dissolution of feldspar; however, unless dissolution of a feldspar grain was complete or nearly complete, the result would have been microporosity and very little permeability.

Organic acids were responsible for dissolving large quantities of calcite as well as for altering and dissolving feldspar. The presence of large amounts of these acids resulted in greater alteration than would ordinarily be expected, given the relatively shallow burial depths, cool temperatures, and underpressured conditions that these rock units were subjected to.

Precipitation of Diagenetic Clay Minerals in Aux Vases Reservoirs

The formation of diagenetic clay mineral coatings on all sand grains is the dominant diagenetic event in establishing and preserving porosity and permeability in sandstone bar reservoirs in the Aux Vases Formation. Although the formation of clay mineral coatings on sand grains may serve to partly occlude porosity and reduce permeability, these coatings also preserve intergranular porosity developed after dissolution of calcite cement. Clay minerals are also an important consideration when designing drilling, completion, and recovery programs. As the primary cementing agent in the reservoir, clay minerals come into contact and react with treatment fluids, and the result may be formation damage. Introduced fluid interactions with the pore linings are not the only concern. Aux Vases Sandstone reservoirs appear on logs to be water-wet; pore-lining clay minerals affect resistivity logs. (The resulting, misleadingly high estimates of water saturation are discussed in another section.)

XRD and SEM/EDX analyses show that clay minerals in the reservoir sandstone bar facies are primarily (from most to least) chlorite, illite and mixed-layered illite/smectite (I/S).

Figure 75 Feldspar dissolution in Aux Vases reservoirs. Left side shows dissolution and remnant laths of potassium feldspar. Right side shows overgrowths of sodium feldspar (albite) (Seyler in prep.).

Shales from the tidal flat environment above the sandstone bar in the Mack lease contain (in order of abundances) illite, mixed-layered illite/smectite and chlorite.

No examples of discrete clay mineral phases have been isolated after numerous SEM/EDX analyses of Aux Vases Sandstone samples from throughout the Illinois Basin. Neither has a more extensive search of samples from the reservoir at Zeigler yielded examples of discrete clay mineral phases. Clay minerals from the Aux Vases exhibit an unusual morphology when air-dried and critically point-dried. This morphology is present in nearly all air-dried samples from Aux Vases Sandstone reservoirs studied to date, except in those from Stewardson field at the northern limit of Aux Vases production. Fields in which these morphologies are present include Zeigler, Oakdale, Dale Consolidated, Energy, Boyd, King and Storms Consolidated.

Although Cypress samples underwent the same sample preparation procedures, this morphology is not present in Cypress Sandstone reservoir samples. Cypress reservoirs contain diagenetic clay minerals with classic and distinctive morphologies: illite is fibrous; chlorite platelets tend to form rosettes; and kaolinite booklets are common. EDX analyses of clay minerals in Cypress Sandstone samples exhibit elemental spectra and elemental quantities that match well with those of clay minerals expected, based on the morphology of the clay minerals. Fibrous illite has an appropriate amount of potassium (more than 5%); chlorites do not contain potassium; and kaolinite contains only aluminum and silicon. The SEM/EDX results from the Cypress contrast sharply with those from samples of the Aux Vases Sandstone. Therefore, although discrete phases of illite, mixed-layered illite/smectite and chlorite are revealed by XRD analysis, they probably occur as a mixture in grain coatings and pore linings of Aux Vases Sandstones.

Cementation Phases

Other intermediate stage diagenetic events reduced porosity and permeability in varying degrees. Late stage events included precipitation of iron-rich calcite or dolomite cement, formation of minute, late stage quartz overgrowths, and development of minor amounts of albite overgrowths. Taken all together, these were minor events that resulted in a negligible amount of porosity loss.

Albite Overgrowths Partially dissolved plagioclase grains probably acted as seed crystals for these overgrowths, which are common in some Aux Vases samples (fig. 75). An EDX spectrum of the euhedral, albite overgrowths shows that they contain abundant Na, Al, and Si. Despite the occurrence of these overgrowths, most feldspar in the Aux Vases is detrital. Cathodoluminescence and SEM/EDX analyses of Zeigler Field samples show abundant detrital Na-feldspar and K-feldspar in localized areas through the sample. Detrital Na-feldspar luminesces brown and red, whereas detrital K-feldspar luminesces bright blue.

Carbonate Cement Precipitation of late stage, ferroan calcite cement was a minor diagenetic event; therefore, only a negligible amount of porosity was lost. Because late stage calcite usually contains more iron than does the calcite in fossil fragments and primary or early calcite cements, staining with potassium ferricyanide and alizarine red can sometimes be used to distinguish between the two types of calcite. Generally, there is relatively little calcite, either as framework grains or cement, in reservoir sandstones at Zeigler. Both varieties of calcite are much more common in other Aux Vases reservoirs, such as those at Energy, Oakdale, and Dale Consolidated Fields. The amount and location of early and late stage calcite are the most distinctive variations in pore minerals found among the Aux Vases reservoirs studied so far.

Quartz Cement Quartz in the form of quartz overgrowths is extremely rare. Quartz crystals (20 μm) rarely precipitated where there was a break in the diagenetic clay mineral coating. Similar sized, late stage calcium carbonate crystals are rare, although they have been observed at Dale Consolidated and Oakdale Fields. The number of fine calcite and quartz crystals is too small to have influenced porosity and permeability. Embayed quartz grains are diagnostic of an intermediate stage of diagenetic dissolution and also evidence of incomplete coating of sand grains by diagenetic clay minerals at the time of silica dissolution.

Halite Halite is present as a pore-lining, pore-bridging, and pore-filling mineral in some samples of Aux Vases Sandstone reservoir intervals from Zeigler, Dale Consolidated, Energy, and Storms Consolidated Fields. Precipitation of diagenetic clay minerals on top of halite crystals is proof that some diagenetic clay mineral precipitation occurred after precipitation of the halite crystals. Because halite is dissolved during thin section preparation, it is not known whether halite precipitation was extensive enough to have been a pore-filling cement. It was commonly observed by SEM in a few samples but was not present in most samples, particularly in those from good reservoir rock.

Anatase Precipitation of titanium oxide in the form of euhedral anatase crystals is another very late stage event that occurred in some reservoir intervals. Where present, these crystals are usually small and well developed, and are a minor pore-lining and pore-filling component. Anatase crystals are most commonly precipitated on top of diagenetic clay minerals and are only rarely sites of diagenetic clay mineral formation. These petrographic relationships indicate that anatase was one of the latest mineral phases during diagenesis.

Barite and Celestite Barite- and barium-rich celestite precipitated in some reservoirs during another minor, late stage, sporadic diagenetic event. These two minerals have been identified

in samples of the Farrar Oil Company, McCreery No. 1 well from the Dale Consolidated Field. They are among the few sulfur-bearing minerals found in the Aux Vases. Pyrite, the only other sulfur-bearing mineral found in the Aux Vases, is rarer than barite and barium-celestite as a late stage pore mineralization. Pyrite has been observed to form isolated but extensive patches that correspond roughly to bedding planes in samples from Dale Consolidated and Storms Consolidated Fields.

Clay Mineral Effect on Wireline Logs of Aux Vases Sandstone Reservoirs

Diagenetic clay minerals are the source of several problems encountered in exploration for and production from Aux Vases Sandstone reservoirs; for example, clay minerals are responsible for difficulties in calculating water saturations. As a result, estimates of petroleum reserves in Aux Vases reservoirs have a greater degree of uncertainty than is usually acceptable. The problem largely lies in calculating the amount of water adsorbed on clay minerals versus producible or pore-filling water present in the reservoirs. Water bound within the structure and micropores of pore-lining clay minerals is defined as "irreducible" and cannot be produced. The V. R. Gallagher, Mack No. 1 well is typical of an excellent Aux Vases producer; resistivity in the prime reservoir interval is 2 ohm-meters. Irreducible water is included in medium- and deep-focus resistivities. This results in erroneously high water saturation calculations when the Archie equation and its derivatives are used (Asquith 1990). For accurate calculations of petroleum reserves, it is extremely important to use an alternative method of calculating irreducible water saturation in these reservoirs.

Example of Interfield Variations in Aux Vases Reservoirs

Large amounts of early calcite cement have been dissolved in the thicker, central portions of sandstone bars and enhanced porosity and permeability at Zeigler Field. Preservation of porosity and permeability and enhancement of porosity and permeability due to dissolution of early stage calcite cement in the reservoir sandstone bar facies was much more extensive at Zeigler than it was at Dale Consolidated Field. This is because 10 feet of relatively nonporous and impermeable, extremely fine grained sandstone and shale separate the reservoir facies from the underlying Ste. Genevieve Limestone, a potential carbonate cement source. In contrast, there is little or no separation between the reservoir sandstone bar facies and the underlying Ste. Genevieve Limestone at Dale Consolidated Field.

This subtle variation in association of sandstones with limestone lenses in a mixed carbonate-siliciclastic environment resulted in major variations in reservoir quality. Proximal limestone units may have buffered fluids during diagenesis, raising the pH of fluids in the reservoir sandstone bar facies at Dale Consolidated, or it may have led to incomplete dissolution of early stage calcite cement and increased precipitation of late stage calcite cement. In contrast, because of intervening fine grained siliciclastics, there was little to no buffering of subsurface brines at Zeigler. Therefore, dissolution of early stage calcite cement was more complete and little precipitation of late stage calcite cement occurred at Zeigler. This has led to greater porosity and permeability at Zeigler than at Dale Consolidated. X-ray diffraction analyses of 13 samples from the Farrar McCreery No. 1 well indicate that calcite content increases, and thus permeability decreases, with depth (from -3,180 to -3,206 feet) in the reservoir sandstone at Dale Consolidated. X-ray diffraction results from the reservoir sandstone bar facies in the V. R. Gallagher, Mack No. 2 indicate no relationship between calcite content and depth, and overall calcite content is lower in this reservoir at Zeigler field. There are 10 feet of separation between the permeable reservoir facies and the nearest limestone unit. Calcite volumetric percentages were calculated by factoring core-derived porosity into the bulk percentage of calcite determined by x-ray diffraction. The lack of a nearby limestone unit resulted in an unbuffered lower pH, leading to more complete dissolution of primary calcite cement at Zeigler than at Dale Consolidated.

Aux Vases reservoirs with less porosity and permeability at Zeigler, similar to the conditions in the McCreery/McCullum Unit at Dale Consolidated, will be more compartmentalized and thus not as effectively waterflooded as the reservoirs with greater porosity and permeability due to less calcite. These two types of reservoirs, one with abundant calcite and the other with little calcite, are likely to require different completion and recovery treatments.

Conclusions

Most Aux Vases reservoir sandstones in the Illinois Basin were deposited under similar conditions and exhibit similarities. The most prominent is diagenetic clay mineral coatings around every sand grain in the reservoir facies. Subtle variations, such as the amount of calcite between individual bars, may require the use of different drilling, completion, and recovery treatments for optimizing recovery efficiencies. Diagenetic alteration has been a key factor in the preservation and enhancement of intergranular porosity, which usually exceeds 22% and may be as great as 30% in the sandstone bar facies in Aux Vases reservoirs. The unusually large amount of intergranular porosity found in most Aux Vases reservoirs is largely due to the precipitation of diagenetic clay minerals around sand grains, a condition that greatly inhibited the precipitation of quartz overgrowths. (In this project, Stewardson Field was the exception.) The diagenetic clay mineral suite in Aux Vases reservoirs consists of a mixture of mixed-layered illite/smectite, iron-magnesium chlorite, and illite. These clay minerals have only rarely been observed in discrete phases during SEM/EDX analyses.

Cypress Sandstone reservoirs contain less intergranular porosity than Aux Vases Sandstone reservoirs because diagenetic clay minerals did not precipitate as complete coatings around sand grains. This allowed the precipitation of quartz overgrowths around most sand grains in Cypress reservoirs. The addition of quartz overgrowths enlarged these grains and intruded into pores. This alteration has reduced the overall porosity of most Cypress Sandstone reservoirs to 15% to 20%. Kaolinite is the most common diagenetic clay mineral followed by iron-rich chlorite, illite, and mixed-layered illite/smectite. In contrast to the diagenetic clay mineral suite in Aux Vases reservoirs, iron-rich chlorite, fibrous illite, and kaolinite booklets in Cypress samples are readily identifiable using SEM/EDX analyses. Kaolinite has not been found in Aux Vases Sandstone reservoirs, with the exception of Stewardson Field. Although diagenetic clay minerals constitute a small percentage of the bulk mineralogy of samples from Cypress Sandstone reservoirs, they must be considered when designing drilling and recovery programs because of the potential for formation damage. Iron-rich chlorite has been shown to be the most soluble diagenetic clay mineral when exposed to hydrochloric acid (HCl), a chemical commonly used during drilling and completion of oil wells in the Illinois Basin.

DEPOSITIONAL ANALYSIS OF THE CYPRESS FORMATION OUTCROP IN SOUTHERN ILLINOIS

Knowledge of geometry and trend of sand bodies is critical to efficient production from the Cypress. Although some reservoir geometries can be deduced empirically from borehole data, predictive modeling is enhanced by understanding the environments of deposition of the Cypress. Subsurface data of the type and quality needed for interpretation of depositional environments seldom are available. Only electric logs are available for most wells. Continuous cores of producing intervals are rarely taken; therefore, much information on rock body geometry, lateral relationships of facies, and sedimentary structures can more readily be obtained only from the outcrop.

The purpose of this study was to determine depositional environments of the Cypress Formation in the outcrop belt of southern Illinois and to relate depositional facies of the outcrop to reservoir geometry.

Geologic Setting

The study area is located in southern Illinois along the southern margin of the Illinois Basin (fig. 9). Englemann (1863) gave the name Cypress Sandstone to 150 feet of sandstone with shaley interbeds exposed in bluffs along Cypress Creek in Union County, Illinois. Some subsequent workers, including Ulrich (1904), miscorrelated the older Aux Vases Sandstone with the Cypress; but outcrop studies in southwestern Illinois (S. Weller 1913, 1920) established the separate identities of the Aux Vases and Cypress.

S. Weller (1913) gave the name Ruma Formation to an interval of variegated shale and thin bedded sandstone cropping out in Monroe and Randolph Counties, Illinois. When further study showed the Ruma to be a lateral facies of the Cypress, the name Ruma was abandoned (Weller 1920). In Greene County, Indiana, Malott (1919) applied the name Elwren Formation to an interval of variegated shale and sandstone that he believed to be older than the type Cypress. Usage of the name Elwren persists in Indiana, even though equivalence of the Elwren to the prior-named Cypress has been established.

The name Cypress Formation is used here in preference to Cypress Sandstone to emphasize that the unit contains substantial amounts of shale and siltstone, in addition to sandstone. Outcrop locations are listed in Appendix IX.

Previous Research

Many geologists have studied the Cypress Formation. Early studies established the areal distribution, stratigraphy, and paleontology of the Cypress and enclosing strata (S. Weller 1913, 1920, Sutton and Weller 1932, Sutton 1934, J. Weller 1940, 1948, Workman 1940, Dana and Scobey 1941, Atherton 1947, Swann and Atherton 1948, McFarlan et al. 1955). Geologic maps showing the outcrop belt of the Cypress in southern Illinois were published by S. Weller and J. Weller (1939), S. Weller and Krey (1939), and J. Weller and Ekblaw (1940).

J. Weller and Sutton (1940) suggested that much Chesterian siliciclastic sediment came from "Llanoria," a postulated land mass in the region of the present Gulf Coast. Noting both marine invertebrates and terrestrial plant fossils in Chesterian siliciclastic units, they deduced that marine (shallow marine and estuarine) and nonmarine (alluvial or coastal plain) deposits were represented. Citing abundant faunal evidence, they viewed Chesterian limestone-shale intervals as entirely marine. Weller and Sutton further characterized Chesterian strata as cyclic: marine limestone-shale units alternating with partly continental siliciclastic units.

Siever (1953) studied the petrology and sedimentation of upper Chesterian sandstones (above the Cypress). He regarded Chesterian strata as cyclic, similar to Pennsylvanian cyclothems; cyclicity was attributed to repeated shifts of the strandline. Siever favored multiple source areas for upper Chesterian siliciclastics. He proposed that the principal source areas were the Transcontinental Arch northwest of the Illinois Basin and the Canadian Shield north of the basin. A secondary source area northeast of the basin (Appalachian origin?) and a minor contribution from the Ozark Dome were also postulated.

Smoot (1960) noted that the lower part of the Cypress Formation contains marine fossils and occasional limestone beds, whereas the middle and upper Cypress contain terrestrial plant fossils and local coal. Accordingly, Smoot characterized the lower Cypress as marine and the upper part as nearshore to terrestrial.

Current views of Chesterian sedimentation in the Illinois Basin are heavily influenced by the work of Paul E. Potter and David H. Swann. Potter's views of Chesterian paleogeography are presented in a series of papers (Potter 1962, 1963, Potter and Pryor 1961, Potter et al. 1958). His interpretations were based mainly on petrography of the sandstones, geometry of sand bodies in subsurface, and paleocurrent data (principally from cross-bedding). Potter inferred that the Illinois Basin area was a southwest-sloping ramp in Chesterian time and that the primary source of siliciclastics lay to the northeast. He envisioned a large river system that built deltas as depositional sites for the Cypress.

Swann (1963, 1964) concurred with Potter's model and named the postulated fluvial system the "Michigan River." According to Swann (1963), the Michigan River deposited the early Valmeyeran Borden Siltstone, but its delta retreated far to the northeast when sea level rose at the onset of deposition of carbonates of the Mammoth Cave Group. In late Valmeyeran time sea level dropped, the Michigan River delta prograded, and siliciclastic deposition in the Illinois Basin area was renewed. Throughout Chesterian time, the delta repeatedly advanced, retreated, and shifted laterally along the northwest-trending coastline. Each Chesterian limestone represented a transgression and each siliciclastic unit a regression.

More specific environmental interpretations were presented by Swann (1964). Large sand bodies were interpreted as distributary channel and "bar finger" (distributary mouth bar) deposits. Small sandstone bodies were attributed to similar environments or to reworking of abandoned deltas by marine currents and tides. Shales were interpreted as representing prodelta, interdistributary bay, overbank, and marsh environments. Swann now proposed that climate, rather than eustasy, was the primary control on Chesterian "rhythmic" sedimentation. During dry periods, sediment transport increased and the delta prograded. In wet periods, greater plant cover baffled sediment transport and allowed limestone deposition (Swann 1964).

More recent papers on the Chesterian of the Illinois Basin include regional summaries (Atherton and Palmer 1979, Sable 1979, Treworgy 1991) and analyses of individual units in small areas (Treworgy 1988, Wilsey 1984, Cluff and Lasemi 1980). A field guidebook by Seyler (1982) included information on outcrops of the Cypress Formation in southern Illinois including several that were reexamined for this study. Seyler interpreted these Cypress outcrops in the framework of a fluvially dominated delta, as postulated previously by Swann. Focusing on the Golconda Formation (immediately overlying the Cypress), Treworgy (1988) characterized the Illinois Basin as a tidally influenced ramp. Wilsey's (1984) interpretation of Cypress sedimentation in White and Gallatin Counties, Illinois, is similar to interpretations by Potter and Swann. Wilsey assigned sandstones of the Cypress to fluvial and deltaic settings under marine regression. Pryor and others (1991) relied on Wilsey in their treatment of Mississippian reservoir rocks of the Illinois Basin. One of the few papers to diverge from the Michigan River model was Cluff and Lasemi (1980). Using subsurface data, Cluff and Lasemi interpreted the Cypress in the Loudon oil field as barrier-island, lagoonal and dune deposits transected by tidal channels on the crest of a rising anticline.

Method of Study

Outcrop study for this project was conducted in 1990 through 1992. Thirty stratigraphic sections of the Cypress Formation and adjacent beds were measured along the outcrop belt from eastern Pope County to Union County, Illinois. Locations of measured sections are shown in figure 9, and graphic columns of 21 of the sections are on open file at the ISGS. Sedimentary structures were described, fossils identified at each outcrop, and samples collected for petrographic study. In addition, the outcrop belt of the Cypress and adjacent formations in parts of Johnson, Massac and Pope Counties (fig. 9) were mapped by W. J. Nelson. Information from this mapping was used to correlate measured sections.

In the laboratory, thin sections of 70 sandstone specimens were prepared and examined using a petrographic microscope. Clay mineralogy of sandstone samples was determined using x-ray diffraction by D. M. Moore. Porosity and permeability were determined at the ISGS by D. J. Haggerty.

Subsurface study for this report was conducted as part of a regional investigation of the Pope Group in the southern part of the Illinois Basin. All available well records (about 60) were examined in a belt about 5 miles wide along the outcrop from Hardin County on the east to Randolph County on the west. Available cores and well cuttings were reexamined where adequate descriptions did not exist.

Patterns of outcrop and core availability introduced unavoidable bias to this study. Cypress outcrops in southern Illinois are dominantly bluff-forming, thickly bedded sandstone in the lower part of the formation. Shale, mudstone, siltstone, and interlaminated sandstone-shale of the middle and upper Cypress rarely crop out. Nearly all of the available cores of the Cypress near the outcrop belt were taken from fluorspar exploration boreholes in Hardin and Pope Counties, Illinois. These cores sample the Cypress at its thickest and sandiest. At the eastern and western margins of the Illinois Basin, the Cypress becomes thin and shaley; but data for the western margin are scarce, and the eastern margin lies outside the study area. Hence, focus was on the sandstone-dominated lower portion of the Cypress Formation in the basin interior. To achieve a more balanced, basinwide synthesis of Cypress sedimentation will require an intensive search for shaley outcrops and a dedicated program of core drilling.

Regional Relationships

Distribution and Thickness The Cypress Formation underlies a large area of central and southern Illinois, southwestern Indiana, and western Kentucky. The northwestern, northern, and northeastern limits of the Cypress are defined by pre-Pennsylvanian erosion. The only area where the Cypress is absent because of nondeposition is the southeastern corner of the basin in Kentucky.

Thickness trends of the Cypress are only known generally. No regional isopach map of the Cypress in Indiana or Kentucky has been published. A small-scale, generalized isopach map of the Cypress in Illinois is in Willman et al. (1975, p. 155). Additional information was gleaned from various published reports, geologic maps, and cross sections. These sources indicate that the Cypress is thickest in the central and east-central parts of the Illinois Basin, and thins markedly on the western and southeastern margins. In Indiana, the Cypress is thickest along a north-northeast-trending, bifurcating belt called the West Baden clastic belt (Sullivan 1972). In the West Baden belt, the Cypress Formation and the underlying Bethel Sandstone merge into a single undifferentiated unit, the West Baden Sandstone, which is as thick as 300 feet (Sullivan 1972).

Our outcrop and core study, combined with stratigraphic columns on published geologic quadrangle maps, show that the West Baden clastic belt continues into extreme southeastern Illinois and adjacent western Kentucky. The thickest part of the clastic belt in Illinois follows the Dixon Springs Graben, a structure that was active in both pre- and post-Mississippian time (Kolata and Nelson 1991). In southwestern Indiana, where part of the West Baden belt parallels the Wabash Valley Fault System, tectonic control is also implicated.

Another area where the Cypress is thick is in part of the Fairfield Basin of south-central Illinois, west of the West Baden clastic belt. The Cypress is 120 feet or thicker along a broad belt that trends north-northeast from the outcrop in Union and Johnson Counties to the northern subcrop of the Cypress in Jasper and Cumberland Counties (Willman and others 1975). Well data show that the Cypress is as thick as 200 feet in parts of Perry and Franklin Counties, southern Illinois. As in the West Baden clastic belt, the thick Cypress locally merges with the Bethel. In most of Illinois, however, the Bethel is thin or absent where the Cypress is thick.

Additional, detailed subsurface mapping clearly is needed to outline thickness and distributional patterns of the Cypress Formation in the Fairfield Basin.

West of the Fairfield Basin the Cypress thins rapidly. It averages about 40 feet thick along the northwestern subcrop (Willman et al. 1975) and thins to less than 20 feet on the flank of the Ozark Dome. The Cypress also tapers southeastward from the West Baden clastic belt. Farthest from the clastic belt, in the southeastern part of the western Kentucky outcrop belt, the Cypress is reduced to discontinuous bodies of shale and sandstone within the Girkin Limestone (McFarlan et al. 1955).

Lithofacies Patterns The Cypress Formation is dominated by sandstone where it is thick and by shale where it is thin. Abrupt lateral lithofacies changes are evident, however, throughout the outcrop belt.

Where the Cypress is thick, it can commonly be divided into three informal members: a lower sandstone member, a middle shaley member, and an upper sandstone member. The lower member commonly represents two-thirds to three-fourths of the thickness of the formation in the outcrop belt. It is predominantly bluff-forming sandstone that contains scattered laminae and thin interbeds of dark gray shale and siltstone. Most outcrops of the Cypress in southern Illinois reveal only the lower member. The middle shaley member of the Cypress is mostly shale and mudstone with thin interbeds of siltstone and sandstone. These rocks are largely medium to dark gray, but red and green variegated mudstone occurs locally in the middle member. Coal and carbonaceous shale are widespread in the middle member also, particularly at or just above the base of the member. The upper member of the Cypress is largely thin bedded sandstone with interbeds of shale and siltstone; lenses of thick bedded sandstone occur in this member.

Where the Cypress is thin on the eastern and southwestern margins of the Illinois Basin, it is largely shale that contains lenses of sandstone. Dark gray, well laminated shales and red and green variegated mudstones are present. Sandstone is mostly very fine grained and laminated to thinly bedded.

Relationships to Adjacent Units In most of the Illinois Basin, the Beech Creek Limestone Member of the Golconda Formation (commonly called the "Barlow lime") conformably overlies the Cypress Formation. The Cypress-Beech Creek contact typically is sharp; however, in places calcareous sandstone containing fossil fragments grades upward into sandy limestone through an interval a few feet thick. Locally a shaley facies of the Beech Creek ("false Barlow") fills channels eroded into the upper Cypress (Cluff and Lasemi 1980). The Beech Creek is discontinuous where the Cypress is thickest, especially in the West Baden clastic belt. Where the Beech Creek is absent, sandy beds of the upper Cypress grade into fissile clay-shales of the Fraileys Shale Member of the Golconda.

Near the West Baden clastic belt, the lower contact of the Cypress is commonly disconformable. The Cypress overlies the Riderhower Formation with erosional contacts at the Golconda, Bay City, I-24, and Hunkerin' Ditch sections, and at several outcrops near these sections. Erosion is indicated by locally truncated laminations in the Riderhower, and in the basal Cypress, by rip-up clasts of shale and siltstone derived from the Riderhower. At the I-24 section, the basal Cypress contains coal stringers as well as shale clasts. Relief on the contact is slight, no more than a few feet. At most outcrops one must search for clearly truncated laminae in the Riderhower. Commonly, layering in the Riderhower undulates more or less parallel with the base of the Cypress and thus suggests loading but little scouring. No deeply incised channels, such as those reported at the base of the Bethel Sandstone in western Kentucky (Sedimentation Seminar 1969), are known to occur at the base of the Cypress.

In Johnson and Union Counties farther from the West Baden clastic belt, the lower contact of the Cypress appears to be conformable. Sandstone of the Cypress directly overlies a thin limestone bed at the top of the Riderhower in many places. The limestone bed commonly is sandy, suggesting lithologic transition to the Cypress.

Cypress siliciclastics intertongue westward with limestone of the Paint Creek Formation in northern Union and southern Jackson Counties. The Cypress in the transition zone is shaley and calcareous, and contains interbeds of red or variegated mudstone. Only the uppermost tongue of the Cypress, about 20 feet thick, extends across the top of the Paint Creek Formation northwestward into Randolph and Monroe Counties. This upper tongue of the Cypress (Ruma Formation of S. Weller, 1913) is largely variegated shale and claystone with lenses of calcareous sandstone.

The West Baden clastic belt on the outcrop in southern Illinois ranges from about 210 to 300 feet thick. The interval is dominantly sandstone and shaley sandstone, but lenses of shale

and thin, sandy limestone occur at various stratigraphic positions. Variegated claystone is present near the top in places. The contact of West Baden clastics with the underlying Downeys Bluff Limestone is generally disconformable. Many cores and outcrops show a basal conglomerate of shale and limestone clasts, quartz granules, and invertebrate fossil fragments (Baxter and Desborough 1965, Baxter et al. 1963, 1967, Trace and Amos 1984). However, little erosion of the Downeys Bluff has taken place. Although the Downeys Bluff is only 20 to 30 feet thick, it is rarely completely eroded in Illinois.

Paleontology Although not richly fossiliferous, the Cypress Formation contains a variety of fossil evidence suitable for environmental interpretation. These include fragmentary and whole body fossils of marine invertebrates, several types of trace fossils, and casts and carbonized impressions of terrestrial plants, including in situ root casts.

Marine body fossils occur in the lower sandstone member of the Cypress, particularly near the base. Spiriferid brachiopods, fenestrate bryozoans including *Archimedes* sp., conularids, and echinoderm fragments were collected from the lower part of the sandstone at Golconda. Fragments of brachiopods, bryozoans, and echinoderms occur in thin sections from near the base of the Cypress at I-24 and from near the top of the bluff-forming sandstone at Indian Point. Productid brachiopods were found in the core from a borehole in the lower part of the sandstone that overlies a limestone tongue of the Paint Creek Formation. The limestone in this core also contains marine fossils.

Several previous authors reported marine fossils from the Cypress, but generally did not specify what part of the formation is fossiliferous. J. Weller and Sutton (1940) reported the brachiopod, *Camarophoria explanata*, in the Cypress in both southern Illinois and western Kentucky. Marine faunal grains have been identified in core from Lawrence County (Grube and Cole 1992), from sample sets in Clinton County (Whitaker and Finley 1992), from sample sets and core biscuits in Clay County (Jianzhong Xu, personal communication 1992), and from samples from the Loudon oil field in Fayette County (D. Horowitz, personal communication 1991).

Marine fossils also occur in the uppermost part of the Cypress. Crinoid columnals and derbyid, productid, and spiriferid brachiopods were identified in shaley sandstone from near the top of the Cypress at New Columbia Bluff. Sandstone cores from the upper Cypress of the Bartelso oil field in Clinton County contain scattered fossil fragments (Whitaker and Finley 1992). Productid brachiopods were noted in a core of the upper Cypress from Union County. Marine fossils and calcareous beds are most common within a few feet of the contact with the overlying Beech Creek Limestone.

Trace fossils are fairly common in sandstones near the top of the Cypress and also present in the lower bluff-forming sandstone. Bedding-plane tracks and trails, along with vertical burrows, occur in sandstone believed to be basal Cypress in the Reineking Hill section. A diverse assemblage of ichnofossils was described from shaley sandstone near the top of the New Columbia Bluff section. Vertical burrows (*Skolithos*) perforate the thin sandstone layers; cylindrical horizontal burrows are abundant on bedding surfaces. Also present are *Lockeia*, a bivalve resting trace; *Olivellites plumeri*, a crawling trace; *Ucherites*, a bivalve crawling trace; *Aulichnites* sp., a trackway; *Scalarituba missouriensis*, the trace of a polychaete worm; an unnamed shrimp resting trace, and plug-shaped domichnia (Joseph A. Devera, personal communication 1991). The above traces belong to the *Cruziana* ichnofacies, which is typical of open marine waters of the upper subtidal to lower intertidal realm (Frye 1975).

Plant remains are widespread in the Cypress Formation but generally fragmentary and difficult to identify. Casts of *Lepidodendron* sp. are reported to be common in the "Ruma" (upper Cypress) of southwestern Illinois (Weller and Sutton 1940). Casts of logs and bark fragments are common in sandstones of the Cypress, and bits of carbonized stems and foliage occur in shales. Such material may have been transported far from its source and does not necessarily indicate a terrestrial or nearshore environment. In situ root casts of land plants are present in the Cypress, although few examples are documented. Shale at the base

of the middle shaley member of the Cypress in the I-57 section contains poorly preserved root casts. Carbonaceous, illitic "underclay" (rooted ?) and coal occur at the base of the middle member in the Salem Quadrangle, Kentucky (Trace 1962).

Petrology Sandstones of the Cypress Formation are very fine to fine grained, rarely medium grained, moderately to well sorted quartz arenites. Monocrystalline quartz constitutes 95% or more of grains in nearly all slides examined. Grains are dominantly angular to subrounded; a few grains are rounded. Plagioclase feldspar is a minor component, 1% to 3% of most samples. Feldspar grains are commonly decomposed. Accessory and trace minerals include muscovite, chert, and zircon. Most grains are randomly oriented, but some are aligned along microscale cross laminae. A few thin sections exhibited microscale truncation surfaces.

Calcareous fossil grains are uncommon in thin sections prepared from outcrop samples, but are fairly common in thin sections from cores. Bioclasts generally comprise less than 1% of the grains, but in some cases they constitute up to several percent. The most abundant bioclasts are pelmatozoan fragments, followed by brachiopod and bryozoan fragments. Bioclasts range from fine sand-size fragments to whole fossils. Some bioclasts are worn, whereas others appear little abraded.

Outcropping sandstones of the Cypress generally lack calcite grains and cement. Among the few calcareous sandstones found in outcrop are those from the Cache River No. 1 section. A photomicrograph shows that part of the rock contains calcite cement, whereas other parts contain open pore space and no cement. At the Golconda section, calcareous bioclasts (echinoderms, brachiopods, bryozoans) and calcite cement are largely dissolved away, leaving molds of fossils in a highly porous sandstone matrix. Calcite cement and fossil fragments are somewhat more common in cores of Cypress Sandstone from north of the outcrop belt, although most Cypress Sandstone in cores is noncalcareous. Apparently, most calcite originally present in Cypress outcrops was leached or weathered away.

Sandstone in the Cypress is texturally mature. Clay constitutes less than 5% of the rock volume in all samples examined. Four varieties of clay minerals were identified in sandstones from cores: illite, illite/smectite, iron-rich chlorite, and kaolinite (Bosse 1986). Kaolinite makes up 10% to 20% of the clay in sandstones from cores, whereas it is nearly 100% of the clay in samples from the outcrop. Most kaolinite is probably the product of weathering. Other clays in the Cypress appear to be products of breakdown of feldspar during diagenesis (D. M. Moore, personal communication 1992). Thin sections show plagioclase grains in all stages of decomposition from fresh feldspar to "ghosts" completely altered to clay. Before decomposition of feldspar, some Cypress sandstones may have contained about 5% to 7% feldspar, placing them barely in the subarkose category. Little detrital clay is present, implying that the sandstones were thoroughly winnowed by depositional processes.

Silica (in the form of quartz overgrowths) and calcite are the two major cementing agents in sandstone. Diagenetically generated clays and iron oxides also provide some minor, local cementation (Duane M. Moore, personal communication, 1992).

Porosity of the lower sandstone sampled at I-57 outcrops ranges from 13.1% to 21.4%. Cypress sandstones in several Illinois oil fields have measured porosity of 12% to 21%. Permeability of the sandstone in six producing fields varies from 49 to 98 millidarcies, with extreme values between 5 and 200 millidarcies (D. J. Haggerty, personal communication 1992). Some variation can be attributed to weathering.

In summary, Cypress sandstone is very fine to fine, moderately to well sorted quartz arenite. Some sandstone originally may have been subarkose, but much feldspar has been altered to clay. Little detrital clay was originally present. Calcareous bioclasts and calcite cement occur in unweathered samples, such as those from cores. Porosity is relatively consistent, but permeability of the sandstone varies markedly within short distances.

Sedimentary structures The lower, middle, and upper members of the Cypress contain distinct suites of sedimentary structures. Observations are more complete for the lower

member than for the poorly exposed middle and upper members. Sedimentary structures of the middle and upper members are known mainly from cores.

Lower Sandstone Member Low-angle cross lamination and crossbedding, ripple lamination, and planar lamination are the most common sedimentary structures in the lower member of the Cypress. Sandstone bodies commonly take the form of stacked or imbricated bar-form lenses. Shallow scour-and-fill structures, slumped or contorted bedding, amalgamated laminae, and possible tidal laminations are present locally.

Planar and wedge-planar cross lamination or crossbedding are present in nearly every outcrop of the lower sandstone member. Cross lamination is dominantly low angle; medium-angle crossbedding is uncommon. At the Ropers Landing section, low-angle cross lamination occurs in nearly every sandstone interval through more than 200 feet of strata, representing nearly the full thickness of the West Baden clastic belt. At other sections, cross laminated sandstone alternates with intervals of planar and ripple laminated sandstone. Herringbone cross lamination was observed near the top of the lower member at the Cagle Bluff and New Columbia Bluff Northeast sections.

Ripple laminations were observed in most outcrops of the lower member. Common ripple types are asymmetric (current) ripples and interference ripples. At the Golconda section, asymmetric ripples have truncated crests. The sandstone above the medial shale in the Reineking Hill section has ripple laminations with clay drapes, flaser bedding, and burrows. Ripples contain clay drapes at several other sections studied. Climbing ripples occur locally in the I-57 section. Linguloid ripples are well developed at the New Columbia Bluff section. The Bethel Sandstone in the Reineking Hill and Travis Farm sections contains intervals of bluff-forming, shale-free, ripple laminated sandstone as thick as 50 feet.

Planar laminated sandstone occurs at most measured sections as relatively thin intervals that alternate with cross laminated and rippled sandstone. In the Golconda and Golconda South and I-24 sections, intervals of planar laminated sandstone are several feet thick and have undulating upper and lower contacts. Amalgamated planar laminations alternating with ripple laminations were observed in sandstone of the lower Cypress in the Cypress Creek section.

The 60-foot interval of Cypress exposed at Indian Point displays mostly amalgamated laminations, alternating with a few thin intervals of planar- and ripple-laminated sandstone.

Small-scale soft-sediment deformation was found at several sections. Deformed cross lamination, locally overturned, occurs in sandstone near the base of the Cypress at the Cache River No. 1 section. Contorted bedding and small-scale "dish" structures occur near the top of the sandstone exposed at the Seminary Fork section. The features at Seminary Fork most likely are products of rapid dewatering of the sediment. Ball-and-pillow structures and contorted laminations occur in intercalated shales and sandstones at the New Columbia Bluff section.

Small, shallow channels or scour-and-fill structures are present at many outcrops, notably Golconda and Cache River No. 1 and Seminary Fork. The Roper's Landing section also contains good examples. Most channels have amplitudes of less than 5 feet and gently dipping margins.

Alternating thin and thick laminations occur in sandstone near the top of the Ropers Landing and Bethany Church No. 2 sections, and in sandstone at the base of the exposure at Bethany Church No. 1. These laminations resemble tidal couplets described by Kvale and Archer (1989) but were too poorly developed for definitive interpretation.

Some sandstone bodies observed in outcrop are lenticular, convex upward and downward, suggestive of bars. The sandstone exposed at the I-57 section appears to consist of several coalescing lenses that are convex upward and more than 30 feet thick. Similar lenses that appear to be elongate north to south are at the Cache River Nos. 1 and 2 sections. An isolated bar-form lens of cross laminated sandstone about 8 feet thick is at the top of the Golconda section.

Paleocurrent measurements were made at several sites. Only asymmetric ripple marks and three-dimensional exposures of cross laminations or accretionary bedding were considered reliable current indicators. The strike trends of accretionary bedding from the I-57 section are summarized in a series of rose diagrams. With accretionary bedding, paleocurrent is assumed to have been parallel to strike of the inclined beds, rather than downdip as in the case of foreset laminae.

Shale and siltstone in the lower member of the Cypress commonly display planar laminations, discontinuous siltstone or sandstone lenses, ripple lamination, ripple cross lamination, and flaser bedding. Small-scale slumped and contorted bedding, load structures, and ball-and-pillow structures occur in interbedded shales and sandstones at and near the New Columbia Bluff section.

Shale and siltstone intervals in the lower member of the Cypress vary from a fraction of an inch to several tens of feet thick, but most are a few inches to about 2 feet thick. Shale units are lenticular and grade laterally to sandstone. Well defined fining- or coarsening-upward sequences are seldom found in the Cypress. Shale, siltstone, and sandstone of the lower Cypress alternate in seemingly random fashion.

Middle Shale Member The middle member of the Cypress contains features indicative of subaerial exposure; specifically, variegated mudstone that appears to be a paleosol, and coal and carbonaceous shale with rooted underclay.

Variegated mudstone occurs in the middle member at many places in southern Illinois. This lithology is most common away from the West Baden clastic belt. On the eastern and western margins of the basin, multicolored mudstone is a major constituent of the Cypress.

Mudstone of the middle Cypress (and "Ruma" and "Elwren") is mottled in shades of gray, greenish gray, and dark red, and ranges from claystone through silty mudstone and siltstone. Some mudstone is blocky or massive and slickensided, lacking any trace of lamination. Other mudstone is slightly to moderately laminated clay shale, silty shale, and siltstone. Small nodules of impure limestone or dolomite occasionally occur in variegated mudstone, particularly near the base.

Coal and carbonaceous shale are widespread in the middle member of the Cypress in both Illinois and western Kentucky. In Illinois, coal in the Cypress is thin and sporadic but widely distributed. Coal and shale with plant fossils were found in samples from the middle member in the Comanche, Branham No. 1 well. Whitaker and Finley (1992) reported coal in samples from the mid-upper Cypress of the Bartelso oil field in Clinton County. Two thin coal beds were reported in parts of Clay, Richland, and Wayne Counties of southeastern Illinois (Workman 1940). As many as three separate, thin black, carbonaceous shale units were observed in cores of the middle Cypress from Pope and Hardin Counties (in the West Baden clastic belt).

Rooted underclays occur in the middle Cypress. Carbonized root casts were observed in mudstone directly overlying the lower Cypress Sandstone at the I-57 section (Joseph A. Devera, personal communication 1992).

Coal, paleosols, and rooted zones are absent or poorly developed in the West Baden clastic belt in southern Illinois. Locally in the clastic belt, sandstone extends nearly to the top of the Cypress, and the members cannot be recognized. Where present, the middle member in the clastic belt is composed of medium to dark gray, laminated shale with laminae, lenses, and interbeds of siltstone and sandstone.

Upper Sandstone Member The upper member of the Cypress is a thin, poorly exposed interval of shale, siltstone, and shaley sandstone. It cropped out only in the New Columbia Bluff section and a few small, nearby exposures. The upper member also is known from cores in Hardin and Pope Counties, one core in Union County, and to a lesser degree from sample studies (cuttings) of wells north of the outcrop belt.

In the New Columbia Bluff section and nearby outcrops the upper member is composed largely of thinly bedded, burrowed sandstone interlaminated with silty shale and siltstone. Lenses of thick bedded sandstone up to about 2 feet thick occur within the upper Cypress

along the bluff face. Lamination of this rock is largely obliterated by burrowing. Near the top of the exposed section, diverse shallow marine trace fossils were identified, along with fragments of brachiopods and echinoderms.

Cores of the upper member reveal a generally upward-fining succession having shaley, very fine grained sandstone at the base, grading upward through interlaminated siltstone and sandstone to clay shale at the top. This interval ranges from 0 to 30 feet thick, but normally it is 5 to 15 feet thick. In some cases, the uppermost Cypress strata consist of calcareous shale that contains marine fossils and thin interbeds or lenses of limestone grading into the overlying Beech Creek. In other cases, the uppermost Cypress is sandstone, which either grades into or is sharply overlain by the Beech Creek. Sedimentary structures of the uppermost Cypress include planar, lenticular, and flaser laminations, cross lamination, small-scale slump structures, ball-and-pillow, contorted lamination, and burrowing. These features are generally consistent with shallow subtidal sedimentation.

Discussion

Environments of Deposition

Lower Member The marine origin of the lower sandstone member is indicated by (1) mineralogical and textural maturity, (2) presence of marine body fossils, some of which are whole and unabraded, (3) lateral facies relationships, (4) sedimentary structures, and (5) geometry of sandstone bodies.

Sandstone of the lower member is well sorted quartz arenite to borderline subarkose. Petrology suggests provenance largely from recycled older Paleozoic sandstones, extensive deposits of which lay north of the Illinois Basin during Chesterian time. These older sandstones are largely quartz arenites, although some Cambrian sandstones, notably the Mt. Simon, are feldspathic (Willman et al. 1975, Mossler 1987). The scarcity of clay and silt matrix in the Cypress sandstone implies extensive reworking and winnowing by currents. Reworking and winnowing typically take place in shallow marine environments; fluvial processes do not generally remove much of the fine-grained fraction (Reineck and Singh 1975).

Articulate brachiopods, pelmatozoans, bryozoans, and conularids that occur in the lower member imply shallow, clear marine water of normal salinity (not deltaic, tidal flat, estuary, or other brackish water). Although broken, abraded bioclasts might have been transported by storms or high winds or reworked from older formations, whole fossils and large, well preserved fragments of delicate bryozoans probably represent organisms that lived in or near the site of deposition. Such fossils also indicate currents of low to moderate energy.

The lower member of the Cypress is laterally equivalent to limestone of the Paint Creek Formation, which contains a rich and diverse marine fauna. This facies change takes place near the border between the Sparta Shelf and the Illinois Basin. Relatively thin marine limestone of the Paint Creek was deposited on the shelf, while thicker sandstone of the Cypress accumulated in the basin. The thickness change indicates that the basin was subsiding more rapidly than the shelf. This relationship implies that deposition of carbonates versus siliciclastics was controlled by sediment supply rather than water depth. Siliciclastic sediment was funnelled along the axis of the Illinois Basin during Cypress time. The Sparta Shelf was far enough from the source of siliciclastics to allow deposition of limestone.

Sedimentary structures of the lower member are consistent with tidally influenced, shallow marine environments. Paleocurrent trends measured on Cypress outcrops indicate bidirectional currents. Herringbone cross lamination, in particular, strongly indicates tidal ebb and flood. Ripples that bear clay drapes, common in the Cypress, are another reliable indicator of tidal activity (Klein 1970, 1977). Moreover, the style of ripple lamination in the lower Cypress is closely similar to that attributed to shallow marine environments by de Raff and others (1977). The chevron form of many Cypress ripples suggests tidally induced, oscillating currents. Also, ripple crests commonly are absent, suggesting truncation by a subordinate current moving in opposite to the original transporting current.

The lower Cypress lacks sedimentary sequences suggestive of deposition by rivers or fluviially dominated deltas. The lower contact is commonly erosional, but no deep scouring has occurred. Only a few small, shallow, slightly incised channels have been observed. The Cypress lacks upward-fining sequences typical of fluvial or distributary channels, and it also lacks upward-coarsening sequences characteristic of prograding fluviially dominated deltas. Shale and siltstone intertongue with sandstone seemingly at random and with no consistent vertical succession.

Many sandstone bodies in the lower member take the form of bars, linear in plan view and convex-upward in side view. Low-angle cross laminae, plane laminae, both asymmetric and symmetric ripples, and local flaser bedding near the base are the most common sedimentary structures. We have observed sedimentary structures and sequences in the Cypress resembling all three types of bars illustrated by de Raff (1977) and others.

Between or adjacent to bar-form sand bodies of the lower member are intervals of sandstone that bear sets of planar or gently inclined laminae. These sets are separated by distinct undulatory upper and lower surfaces. Such sand, according to Davis (1983), was likely deposited in swales between bars. Littoral and nearshore currents transport sand parallel to bars and deposit it at the downcurrent end. Thus, the depositional lows are passively filled.

Sand bodies at the I-57 section are distinctly "shingled" and display cross strata with sharp set boundaries, parallel laminae, reactivation surfaces, local flaser bedding, clay drapes in ripples, interference ripples and asymmetric ripples, convolute bedding, and load casts. All these features are common in tidal settings (Klein 1970, 1977). Sharp set boundaries and parallel laminae are attributed by Klein to reversing tidal current bedload transport and tidal current phases of subequal flow velocity. Reactivation surfaces are the result of time-velocity asymmetry. Tidal current bedload transport with an alternating tidal current velocity accounts for bar migration and the production of cross strata. Subordinate tidal phases produce reactivation surfaces. Flaser bedding and clay drapes in ripples reflect transport of tidal current bedload and deposition of mud from suspension during periods of slack water at both high and low tides. Interference ripples are generated during late stage runoff, usually during ebb tide. Asymmetric ripples are formed during dominant tidal phases, although the crest of the ripple may be truncated during the subordinate tidal phase. Convolute bedding and load casts develop by differential loading and subsequent compaction during rapid deposition (Klein 1977). Although all of these structures may form in environments other than tidal, the close association of so many such features strengthens the case for tidal processes in the lower member of the Cypress.

Some sandstone bodies in the lower member of the Cypress appear to be bar-form lenses, convex both upward and downward and 10 to more than 30 feet thick. At the I-57 section, the larger bar forms partly coalesce and contain elongate lenticular, very gently inclined, shingled or imbricated bedding. Likely modern analogs of the bar-form sandstones of the lower Cypress are tidal sand bars. Off (1963) described two types of tidal sandbars, which he called tidal sand ridges and sand waves. Tidal current ridges typically are large features, 25 to 100 feet high, 5 to 40 miles long, and spaced 1 to 6 miles apart. They are oriented parallel to tidal currents and best developed near the heads of bays in broad, shallow shelves and embayments such as the North Sea, Bay of Korea, and Persian Gulf. Such embayments commonly have tidal ranges greater than 1 1/3 feet and tidal currents of 1 to 5 knots. Sand waves are smaller, mostly 10 to 20 feet high but reaching 40 feet under favorable conditions. They are essentially giant current ripples that are oriented perpendicular to tidal currents. Tide ranges and current velocities associated with sand waves are smaller than those associated with tidal sand ridges. Off (1963) suggested that certain Chesterian sand bodies in the Illinois Basin might be tidal current ridges; however, most sandbars in the Cypress have the dimensions of sand waves rather than sand ridges.

The tidal bar model is supported by subsurface mapping in Lawrence County, Illinois, where the lower member of the Cypress produces oil. Here the lower member is stacked or coalescing lenticular sand bodies about 800 to 2,000 feet long, 300 to 600 feet wide, and 10 to

15 feet thick. The long axes of these sand bodies strike northeast to north-northeast (see Lawrence Field, this volume). The dimensions of the lower Cypress sand bodies in Lawrence County are similar to those of modern tidal sand waves described by Off (1963).

Sandstones above and below the Cypress exhibit similar geometries, and likewise have been interpreted as tidal bar deposits. Below the Cypress, the Aux Vases Formation in the Energy oil field of Williamson County, southern Illinois, comprises upper and lower sandstone units separated by a thin, shaley, impermeable zone. Both sandstones occur as lenses that are convex-upward and interpreted to be marine bars (Huff 1993 and this volume).

The West Baden clastic belt may comprise deposits of tide-dominated deltas and associated offshore tidal sand waves, or possibly sand ridges. Isopach and net-sand thickness maps by Sullivan (1972) display linear and bifurcating sand bodies that may represent distributaries. That conclusion is supported by Hrabar and Potter's (1969) study of the West Baden Sandstone at the northern outcrop of the clastic belt in Indiana.

The West Baden clastic belt follows grabens in the Wabash Valley Fault System and Dixon Springs Graben. The Dixon Springs Graben is a segment of the Cambrian-age Reelfoot Rift, in which faults have been reactivated repeatedly (Kolata and Nelson 1991). Although mapped faults in the Wabash Valley system are post-Pennsylvanian, this fault system may have earlier ancestry. In any event, the axis of maximum subsidence during Cypress deposition lay along this trend and siliciclastics were funnelled into this area.

Middle Shaley Member The middle shaley member of the Cypress contains evidence of widespread subaerial exposure, including the presence of coal, thick carbonaceous shales with fossil land plants, underclay with root casts, and variegated mudstone that appears to be a paleosol. A 4-foot coal bed represents 12 to 40 feet of peat, depending upon presumed compaction ratios. Widespread occurrence of relatively thick coal and rooted underclays implies that some of the Cypress coal represents in situ peat accumulation in swamps rather than rafts of transported plant debris.

Red and green mudstone commonly occurs in the middle member along the southwestern and southeastern margins of the basin, where the Cypress is thin. Ambers and Petzold (1992) found many sedimentary features indicative of very shallow subtidal, intertidal, and supratidal (subaerial exposure) in variegated mudstone of the Elwren (Cypress) Formation of southern Indiana. Similarly, Weimer and others (1982) attributed variegated mudstone of the Aux Vases Sandstone in southern Illinois to upper tidal flat and marsh sedimentation.

During deposition of the middle member of the Cypress, most of southern Illinois was probably a tract of tidal mudflats dotted by stands of vegetation. Little new sedimentation took place. Sediments, including previously deposited marine sediments, were altered by subaerial exposure under an arid climate (Ambers and Petzold 1992). Subtidal sedimentation apparently persisted along the West Baden clastic belt because more rapid subsidence in the underlying Dixon Springs Graben.

Upper Sandstone Member The upper member of the Cypress Formation records a return to subtidal sedimentation. Ichnofossils and body fossils at the New Columbia Bluff section indicate shallow, open marine conditions. Sedimentary structures are consistent with, although not diagnostic of, subtidal sedimentation. Thin, lenticular sand bodies in the upper member may be marine sandbars. The general upward fining of sediments and locally gradational contact to the Beech Creek Limestone reflects a gradual cutoff of siliciclastic sediment. In the West Baden clastic belt, siliciclastics were still entering during Beech Creek time, inhibiting deposition of the limestone. The Beech Creek itself is interpreted as representing a rapid initial transgression, followed by gradual regression (Harris 1992).

In oil fields north of the outcrop belt in Illinois, the upper member of the Cypress contains lenticular sandstone bodies oriented northeast to east-northeast and interpreted as tidal sandbars. Such bars are present in Bartelso Field, Clinton County (Whitaker and Finley 1992) and particularly well documented in the Tamaroa and Tamaroa South fields in Perry County (Grube 1992).

Analog for Hydrocarbon-Producing Zones Because sandstones of the Cypress Formation are major petroleum reservoirs, a goal of this study was to relate characteristics of the outcrop belt to those of the producing oil fields. Several concurrent subsurface studies conducted by the ISGS provide a framework to delineate depositional facies of pay zones in the Cypress. These studies indicate that characteristics of the producing fields are closely similar to those of the outcrop belt.

The lower sandstone member of the Cypress yields oil in Lawrence County, Illinois. Here the lower member is composed of stacked, elongate, lenticular sandstone bodies that are each 10 to 15 feet thick and trend northeast-southwest. These sand bodies probably are tidal bars. Overlying the lower member in Lawrence County is an interval of variegated mudstone containing features characteristic of subtidal to upper intertidal depositional environments (Grube, personal communication 1994).

Another major field with production from the lower sandstone member is the Loudon oil field in Fayette County. Here the lower member is composed of lenticular sandstone bodies as thick as 60 feet, and encased in and grading laterally to shale. The slightly calcareous sandstone contains scattered bryozoan, brachiopod, and crinoid fragments. Overlying the productive lower member is a shale-dominated interval that includes red and green shale (Cluff and Lasemi 1980). Together, Lawrence County and Loudon Fields probably account for more than one-half of the total oil production from the Cypress in the Illinois Basin. Studies of upper Cypress reservoirs by Grube (1992), Whitaker and Finley (1992), and Xu (1994) all showed successions of stacked or imbricated sandstone bodies, separated by thin shales, in the upper Cypress. Sandstone bodies are lens-shaped in map view; the long axes of the lenses trend generally northeast to southwest. In the Mattoon oil field of Coles County, Illinois, sand bodies in the Cypress trend generally north to south (McGee, in preparation).

The main hydrocarbon-producing facies are apparently stacked or imbricated offshore bar sandstone bodies that prograded southward down the gentle paleoslope of the basin. Generally, structural closure is necessary to create a trap in such sandstones. Plane and ripple laminated, sheet sandstone also may be productive, if petrophysical properties are favorable and structural closure is present.

To summarize, outcrops of the Cypress Formation provide analogs for hydrocarbon-producing zones in the subsurface. An understanding of depositional facies trends, areal distribution, internal architecture, and diagenetic pathways can greatly enhance the success of exploration for these reservoirs. This understanding is best achieved through coordinated studies of the outcrop and subsurface.

Conclusions

The Cypress Formation was deposited in a shallow marine, ramp-like embayment open to the south. The principal source of sediment lay to the north and northeast. The Ozark Dome and Cincinnati Arch were shoal areas that contributed little or no sediment. Sediment was funnelled into an elongate, broad, shallow trough that ran south to southwest from west-central Indiana to southern Illinois. Subsidence of the trough may have been structurally controlled by the ancestral Wabash Valley Fault System and Dixon Springs Graben.

Limestone and shale of the Paint Creek and Ridenhower Formations were deposited in shallow, open marine environments. Widespread erosion took place before Cypress sedimentation, but the erosion surface had little relief. A major influx of siliciclastic sediment, largely sand, entered the proto-Illinois Basin and formed the lower sandstone member of the Cypress; this sand was deposited in tide-dominated deltas and shallow offshore, open marine settings. Evidence for these conclusions includes (1) presence of normal marine fauna of brachiopods, echinoderms, and bryozoans; (2) the lower Cypress intertonguing westward with marine limestone of the Paint Creek Formation; (3) sedimentary structures (typical of shallow subtidal settings) throughout, implying active but relatively gentle currents;

(4) bidirectional and herringbone crossbedding and possible tidal couplets indicating tidal ebb and flood, particularly at the top of the interval; (5) parallel swarms of stacked or imbricate bars analogous to tidal sand waves described by Off (1963); and (6) variable vertical grain-size and bedform trends, as found in present tide-dominated deltas but not in river- or wave-dominated deltas, typically exhibiting well developed coarsening-upward cycles.

The middle shaley member of the Cypress records a regression that led to subaerial exposure and deposition in very shallow subtidal to supratidal and marsh environments. These deposits include coal (up to 4 feet thick), carbonaceous shale with terrestrial plant fossils, underclay with root casts, and red and green variegated mudstone with features indicative of subaerial exposure. Such features are best developed away from the West Baden clastic belt and near the margins of the Illinois Basin. Within the clastic belt, subsidence may have been rapid enough to prevent exposure.

The upper member of the Cypress reflects a return to shallow subtidal conditions, as signified by laminated, upward-fining sediments that contain marine body fossils and trace fossils. Siliciclastic input gradually waned, allowing deposition of the Beech Creek Limestone, except locally in the West Baden clastic belt. By this time, tectonic subsidence appears to have stabilized over most of the basin. The rift area no longer subsided more rapidly than surrounding areas.

The above model differs from the fluviially dominated "Michigan River" delta model of Swann (1963, 1964) and Potter (1962, 1963). Although the middle member contains nonmarine strata, the bulk of the Cypress is a subtidal deposit. The Cypress was deposited in shallow shelf, tide-dominated delta, estuarine, and tidal flat settings. Although Cypress siliciclastics came from the north or northeast, evidence of a long-lived Michigan River system is lacking. Clastic sources for the Pope Group periodically shifted to different areas of the basin. Older Aux Vases Sandstone had a source west or northwest of Illinois (Cole 1990), whereas the younger Big Clifty Sandstone had a source east of the basin (Sable and Dever 1990).

Instead of a single regression indicated by Swann (1963), the Cypress reflects two episodes of relatively high sea level separated by an episode of low sea level for the middle member. Siliciclastic and carbonate rocks were deposited simultaneously in different parts of the basin during Cypress time. As Swann (1964) suggested, sediment supply not water depth, was probably the major factor controlling siliciclastic versus carbonate sedimentation. Sand was funnelled toward the tectonically controlled axis trending north-northeast to south-southwest, where subsidence was greatest. Little sand reached the stable eastern and western margins of the basin.

Bar-form sand bodies probably representing tidal current ridges and sand waves are the most favorable lithofacies for hydrocarbon production. Such bars have formed combination traps in several of the project field studies. Ripple and planar laminated sheet sandstones can be productive, but structural closure generally is required. Both types of sandstones commonly have good porosity, but permeability varies greatly in response to diagenetic history.

I-57 CYPRESS OUTCROP STUDY

Multiple roadcuts along Interstate 57 (I-57), 1 mile south of the Illinois highway 146 interchange in Union County, Illinois (fig. 9), provide excellent exposures of the Cypress Sandstone, a prolific oil-producing reservoir in the subsurface. These sandstones are lithologically homogeneous, but depositionally heterogeneous laterally and vertically. The rocks are exposed in four parallel roadcuts extending approximately 1,000 feet horizontally and ranging from 7 to 27 feet thick. The I-57 roadcuts provided a unique opportunity for detailed study of the Cypress in three dimensions. The field part of the investigation began in July 1991 and was completed in March 1992. The laboratory portion of the investigation was completed in September 1992.

A detailed reservoir characterization study of a petroleum reservoir requires a substantial quantity of data. Utilizing information from outcrops analogous to hydrocarbon reservoirs is one technique both geologists and engineers use to gather data for reservoir characterization research. Core samples are easily extracted from outcrops and processed in the same manner as subsurface core. Use of a light-weight minipermeameter facilitates the gathering of many permeability measurements in the field. Data from closely spaced outcrop measurements can lead to understanding the behavior and past performance of analogous reservoirs.

Variability of rock properties in the outcrop data can be statistically modeled and used in detailed reservoir modeling; however, using outcrop data as a universal measure for petrophysical continuity is not suggested. Modifications are necessary for each analog.

A limitation of using outcrop data for a subsurface analog concerns the extent to which near-surface and surface influences have altered the outcrop. Meteoric water can leach calcite, wash out exposed shale, and degrade feldspars and clay minerals. Oxidation of minerals that contain iron can also cause pronounced changes in outcrop porosity and permeability.

The main purpose of this study was to develop an analog for Cypress reservoirs, and subsequently, to model the sandstones in the roadcuts as if they were a reservoir. Elements of an established model would then be available for future simulation modeling of analogous reservoirs. A waterflood simulation model was employed, using the outcrop permeability values and subsurface data from Lawrence Field, to show how an analog reservoir would behave under various conditions. A comparison of outcrop to subsurface may allow the development of a realistic subsurface Cypress reservoir model. This study evaluates the Cypress Sandstone outcrops along a section of I-57 (fig. 9) also for the purpose of determining the minimum data necessary to define optimum well spacing and finding a relationship between sandstone depositional characteristics and porosity and permeability.

Methods

A 700-foot-long segment of each roadcut was selected because well spacing in Illinois for sandstones is 660 feet (10 acres). A grid was then surveyed along each of the four segments and a vertical section was measured and described every 50 feet. This produced a total of 60 measured sections, the equivalent of well control every 50 feet (fig. 76). After each section was measured and described, a fresh surface was chipped to remove the hard weathering rind every 6 inches, vertically. Each of these surfaces was then analyzed with a hand-held gamma ray spectrometer/scintillometer, and air permeability measurements were taken with a field minipermeameter. These data provided a "log" of relative cleanness of each interval similar to a borehole gamma ray log and permeability control every 6 inches.

Core plugs were also acquired in the field. Acquisition consisted of using a rotary hammer to take two plugs, 2 inches in diameter and 4 inches long, at each section. The plugs were drilled as close to the section line as possible; 95 plugs were taken from 60 measured sections. Porosity and permeability of the plugs was measured in the lab.

Nearly 200 paleocurrent measurements were obtained from low-angle cross laminae. These measurements were used to verify depositional trends and processes.

A photomosaic was created for each roadcut. On a mylar overlay, interpreted depositional breaks were delineated. Each discrete depositional package was then transposed to a transparent overlay. Graphic representation of gamma ray and permeability data were added on a second overlay. These mosaics display a stacked sequence of sandstone beds that may compartmentalize a reservoir similar to, but on a smaller scale than, the stacked sandstone bodies described in subsurface studies by Grube (1993), Grube and Cole (1992), Whitaker and Finley (1992), Seyler (in press), and Xu (1994).

Figure 76 I-57 outcrop sample grid (Cole and Haggerty in prep.).

Sedimentology and Depositional Features

The major sedimentary features identified in the I-57 roadcuts are low-amplitude lenticular scour-and-fill structures, planar and ripple laminated beds, and wedge planar bed sets. The assemblage of sedimentary structures present, the geometries of the various sandstone bodies, and their relationships to one another are indicative of shallow marine bars.

Offshore bars are typically linear and have a convex-upward geometry. The most common sedimentary structure present is low-angle cross laminae; however, there may also be asymmetric or interference ripples on the uppermost surface, and where the top of the bar has been periodically exposed, desiccation cracks. Lenticular scour-and-fill structures are composed of trough cross-laminated beds or low- to medium-angle tabular or tangential cross-laminated beds. The typical geometry for scour-and-fill structures is generally linear in plan view, and in cross section, they tend to be slightly concave upward.

Planar and ripple laminae beds have sheet-like geometries. Mica (usually muscovite in the Cypress) is present in these sandstones and common to abundant in shaley intervals within these beds.

Wedge planar sandstone bodies are generally plane-laminated, but the laminations tend to mimic the bounding surfaces of each deposit. This lends a cross-laminated appearance to the sandstones. The wedge planar sandstones may appear somewhat sheetlike in plan view, but they are actually restricted in areal distribution and thin along depositional slope, thus giving them their wedge-like shape when viewed in cross section. These sandstones tend to be stacked or imbricated and are commonly separated by a very thin shaley interval at the top of the bed sets. Several sets may be superimposed and appear as one thick sandstone deposit on a geophysical log. This stacking or imbrication becomes an important consideration when only well logs are available to delineate reservoir compartmentalization.

Along the I-57 outcrop only a few of these discrete sandstone packages are continuous over the 700-foot length of the study site. Nearly all the individual bed types pinch out, some within 50 feet or between the measured sections. Between these discrete intervals, thin discontinuous shale lenses may be present. The shaley intervals separating the cleaner sandstone bed may act as baffles to fluid flow and impede hydrocarbon recovery, even though they may be only 1 or 2 inches thick. Reservoir compartmentalization at the scale of bed thickness is also established by the presence of these thin shaley intervals.

Although the sandstones along these roadcuts are lithologically homogeneous, the restricted distribution and intercalated nature of the various bed types renders the sandstones heterogeneous from a depositional standpoint. Depositional processes impart an inherent permeability when the sediments are initially deposited and the subsequent diagenetic pathway becomes the ultimate control on the permeability and thus reservoir quality.

Paleocurrent indicators were also measured at three different sites along each roadcut. The sites were chosen based on the availability of cross laminae for measurements. Variation measured in Sw3A (the designation identifies the location as being on top west side of the southbound half of I-57 at section 3A, fig. 76) is a result of measurements of cross laminae on an offshore bar deposit (the northwest-southeast trend). This bed set is locally truncated by a scour-and-fill structure. In section Sw4A (100 feet south of Sw3A), all measurements were taken from low-amplitude, lenticular scour-and-fill structures. In section Sw8, the measurements were taken on low-angle cross laminae in wedge planar beds.

Along the east side of the southbound lanes, paleocurrent directions show different trends than those along the west side. All the sections show a slightly north of due west paleocurrent direction with little variation. Along the west side of the northbound lanes about 80 feet to the east, the paleocurrent directions are more north to south. Most of these measurements were taken near the top of the Cypress Sandstone. On the east side of the northbound lanes, the paleocurrent measurements taken near the top of the Cypress are quite similar to those along the west side.

The most significant aspect suggested by the paleocurrent data is that sediment transport directions vary. There is no single dominant direction, only a general trend north to south, probably a function of nearshore and tidal currents influencing the ultimate distribution and appearance of the deposits.

Engineering Measurements and Analyses

In this study, 1,705 minipermeameter (millidarcies) and 1,726 gamma ray measurements (counts per second) were taken from 54 of 60 grid sections and plotted as a function of elevation from the base for each section. Two hundred minipermeameter measurements to determine lateral continuity were taken horizontally every 1 foot between sections Se4 and Se5 and sections Sw4 and Sw5.

A total of 95 plugs, 2¼ inches in diameter, were drilled at random elevations from the base of the sections. Two plugs were drilled per measured section, trimmed to 1 inch in diameter, tested for various rock properties in the laboratory, and used to calibrate the minipermeameter. The rock properties evaluated were air permeability, helium porosity, saturation porosity, electrical resistivity, permeability anisotropy, and liquid permeability. Thin sections of core plugs with known permeability and porosity were made and examined using a petrographic microscope.

The minipermeameter, gamma ray, and lithologic data were modeled using Strata-model™ software, a 3-D modeling package designed for visual examination. Data for fluid-flow simulation of the outcrop were obtained from the outcrop and engineering reports on Lawrence Field. An inverted five-spot pattern waterflood was simulated using Western Atlas' VIP™ software. Core analysis data from other Illinois Cypress reservoirs were also compiled for comparison (Appendixes XIV-A and -B).

Core Plug Analysis Porosity values for the outcrop core plugs were measured using Boyle's Law based on helium porosimeter. Values ranged from 13% to 21%, similar to the range in values for other Cypress sandstone reservoirs in the basin. A gas permeameter (with a conventional Hassler-type core holder) recorded a range of 0.25 to more 900 millidarcies for the gas permeability of the plugs. These values tended to be higher than most values for the Cypress in the subsurface. A cross plot of permeability and porosity showed that the porosity range for the outcrop is similar to that for the subsurface, although there are small clusters of slightly higher permeability values for the outcrop.

Porosity values acquired by helium expansion agreed to within 5% of porosity values acquired by vacuum saturation. This finding indicates that the number of unconnected pores was minor and that the samples were relatively uniform. Comparison of the results of a gas permeability test and a mineral oil permeability test on the same outcrop plug showed that the sample was relatively homogeneous. An anisotropy test, two horizontal permeability measurements 90° apart, was performed on 20 cylindrical plugs and indicated that flow direction showed no preference.

Formation resistivity factor versus porosity values were plotted for the outcrop plugs and plugs from Lawrence, Mattoon, and Xenia Fields (fig. 77). There was a close correlation between the values for the subsurface and those for the outcrop plugs—an indication of similar pore characteristics, particularly the cementation factor (m).

Minipermeameter and Scintillometer Results For each minipermeameter measurement, values were calculated using Darcy's equation for gas flow. The equation included a geometric factor based on the size of the minipermeameter probe tip and the surface area of the rock. The relationship between gas permeameter and minipermeameter permeability for the outcrop plugs was plotted and used to adjust minipermeameter values to the gas permeability values determined in the laboratory.

Composite minipermeameter profiles were plotted to show the variation in permeability from the base to the top of each measured section. These plots show that permeability tended to increase from top to bottom of each section, and that values reached more than 300 millidarcies. The continuity of lateral permeability was determined by measuring permeability at 1 foot intervals, horizontally within the same bed set, from section Sw4 to Sw5 and from section Se4 to Se5. Permeability increased along the outcrop from north to south.

Gamma ray profiles for each section show a narrow range (80 to 120 counts per second, approximately 5 to 10 API Units) for most of the outcrop and indicate a clean sandstone with a low clay content. Values for the shale-dominated northeast corner reached 260 counts per second (approximately 95 API Units). Permeability and gamma ray emissions changed inversely from north to south in the westernmost roadcut: permeability increased and gamma ray emissions decreased.

Semivariogram Analysis Permeability data and their locations can be used to develop semivariograms for determining range of influence, sill, and nugget. The range of influence (or correlation length) is the distance at which the variogram reaches a constant value or sill. Range defines the distance within which permeability values are related to one another. Within the range of influence, the permeability at any location may be estimated from the semivariogram relationship. The nugget is also determined from a semivariogram. Significant heterogeneity exists over distances less than the sampling interval, if a semivariogram displays a high nugget value. Permeability patterns of the measured sections showed that an east-to-west trend prevailed over a north-to-south trend, which may imply continuity and suggest that resistance to flow is weaker east to west. Therefore, a waterflood program designed with the water injectors and oil producers oriented in a north-south pattern would be most effective, provided there are no adverse effects due to natural or induced fractures.

Two horizontal semivariograms of permeability, measured at 1-foot intervals between sections Sw4 and Sw5 and sections Se4 and Se5 (100 feet each) on the same sand body,

indicated a range of influence of about 50 feet and an average nugget of 38 millidarcies (fig. 78). The longest range of influence of the vertical readings was, conversely, less than 8 feet.

Three main conclusions can be drawn from the vertical and horizontal semivariograms: (1) adjacent, vertical bed-set permeability measurements in the outcrop can range widely and show no relationship; (2) horizontal bed-set permeability is predictable for several feet (50 feet for Sw4 to Sw5); and (3) wells must be within 100 feet of each other for interwell permeability to be predictable from the semivariogram model.

Statistics of Cypress Reservoirs Cypress Formation production can be found throughout the Illinois Basin from depths as shallow as 300 feet to as deep as 3,000 feet. The bulk of reservoir quality Cypress core has 16% to 18% porosity. From measurements and core analysis reports on six Cypress fields, the following data were tabulated: number of observations, average permeability, permeability range, average porosity, average depth, number of horizons (based on clusters at different depths), harmonic and geometric averages for both porosity and permeability, a coefficient of variation (ratio of standard deviation to the arithmetic mean), and Dykstra-Parsons and Lorenz coefficients for each field. All fields have at least two separate Cypress sandstone intervals; some have as many as five. The fields with very low harmonic permeability averages have correspondingly have higher Dykstra-Parsons and Lorenz coefficients. For example, New Harmony field data indicate a good arithmetic average permeability of 89.18 millidarcies but a poor harmonic average of 2.02 millidarcies. This may indicate zones of low quality reservoir (low permeability siltstone or calcareous sandstone) within the field.

Computer-Enhanced Visualization and Simulation

Three-dimensional models of geological and petrophysical data (porosity, permeability, and gamma ray) were constructed using the Stratigraphic Geocellular Modeling (SGM)TM software. Lithology and bedding types were assigned discrete numbers for the purpose of modeling. Also used for the modeling were attributes of porosity, permeability, and water saturation measured at the outcrop and obtained from reports on cores taken from the Cypress at Lawrence Field. A 3-D evaluation of the permeability distribution versus bedding type showed no relationship. Histograms of permeability values measured from particular bedding types or sedimentary features also corroborate the independent nature of the permeability (fig. 79). Each bedding type shows a similar distribution pattern. The permeability distribution of the outcrop shows low, consistent values from the north to the middle of the outcrop, and then a consistent increase to the south; the highest values were obtained near the base of the exposure. The gamma ray distribution looked uniform in all but the northeast corner, where shale is prominent.

The Stratamodel data was transferred via GeolinkTM to the VIP simulator. The VIP simulator uses the grids and attributes (porosity, permeability, water saturation) and takes input such as well placement, initial pressures, production/injection rates, cut-off limits, and fluid properties to predict reservoir drainage. The high density of minipermeameter data was utilized for a simulation of an inverted five-spot waterflood pattern (simulating a subsurface Cypress oil reservoir) run on the outcrop. The same limiting factors were set on all four producers and the injection of water in the center was held constant.

The simulation predicted 33,000 barrels of oil production after 8 years. The simulation did not include the effects of the thin shaley intervals found between some of the bed sets. These shales restrict vertical communication and consequently decrease production. In an actual field, cumulative oil production may differ because of production practices that affect the efficiency of oil recovery. Formation damage due to interactions between extraneous fluids and the formation rock and fluids may lower the oil recovery. On the other hand, hydraulic fracturing and/or acidization could increase the oil production.

Figure 77 Plot of both reservoir and outcrop formation resistivity and porosity (Cole and Haggerty in prep.).

Figure 78 Semivariogram, I-57 Cypress roadcut (Cole and Haggerty in prep.).

Figure 79 Permeability relationships to sedimentary features in the I-57 outcrop (Cole and Haggerty in prep.).

Sandstone Production Characteristics

It was observed that separate bed sets could be identified and measured on the outcrop. If there were no vertical cross flow, a well drilled within the confines of the study area would have a 50% probability of communicating with 80% of the sets. A plot was made of the number of bed sets in the outcrop relative to thickness at each of the 60 locations. The data were used to compare I-57 outcrop Cypress sandstones with subsurface Cypress sandstones and to demonstrate their similarity. A plot of bed set thickness versus permeability in the study area showed no correlation; therefore, production potential cannot be predicted from bed set thickness.

Also observed in the study area were a few bed sets that extend less than 50 feet and represent slightly more than 1% of the total volume. Production from these sets will be bypassed unless fracturing or other mechanism creates a permeable avenue to a well bore. Add other production-limiting factors such as relative permeability effects, permeability anisotropy within sand bodies, fracturing (macro and micro), and 10-acre well spacing to these conditions, and considerable oil could be bypassed in a reservoir deposited in a similar setting with similar characteristics.

Summary of Results

Permeability distributions in this Cypress outcrop are not related to bedding types; this conclusion is based on extensive data tabulation and computation using SGMTM as a primary tool. No claim can be made here, as was reported by Goggin et al. (1988), that each bed type exhibited permeability distributions unique unto itself.

Permeability ranges from .1 millidarcy to 1 darcy on the outcrop. High permeability values measured in some plugs may be explained by removal of some clay minerals and shale laminae by surface weathering. The shale laminae present between beds set are capable of inhibiting flow between the sandstone beds in the outcrop. Porosity, which ranges between 13% and 21.4% (Appendixes XIV-A, -B), has been reduced by quartz overgrowths.

Visual examination of the four outcrop faces along I-57 revealed that some bed sets pinch out between the 50-foot sections and would be completely bypassed in a subsurface reservoir analog, if waterflooded on 10-acre spacing. A well drilled in the confines of the study area has a 50% probability of being in communication with 80% of the reservoir (if the outcrop were an approximate analog to a subsurface oil reservoir). Four percent of the time, drilling a well within the reservoir geometry of this outcrop-like reservoir would contact only 25% of the reservoir. (This assumption is based on the number of bed sets penetrated and assumes total horizontal connectivity.) This may help explain why wells within the same Cypress reservoir have different production capacities.

Dykstra-Parsons and/or Lorenz coefficients are commonly used in reservoir engineering to qualify the vertical variation in permeability and to predict displacement performance. Both coefficients vary from 0 (homogeneous porous medium) to 1 (very heterogeneous porous medium). Dykstra-Parsons coefficients for nearby producing Cypress sandstone reservoirs in Akin and Benton North Fields, about 45 miles away, and Lawrence Field, about 110 miles away, ranged between 0.75 and 0.83. The I-57 outcrop datum was determined to be 0.54. This difference stems from a high number of low permeabilities (less than 10 millidarcies) in the subsurface core. Quartz overgrowth, diagenetic clay minerals, and shale laminae reduce permeability in subsurface Cypress reservoirs. The clay mineral component has been depleted in the outcrop, a fact substantiated by the low gamma ray readings.

The waterflood simulation (using VIPTM software) of an inverted five-spot centered on the outcrop was based on outcrop minipermeameter and Lawrence Field data. The results showed that 10% or more oil was produced in the southern corners and permeability distribution was the prime control. The same limiting factors were imposed on all four producers and the injection of water in the center of the outcrop was held constant. The simulation results could be different if formation damage or hydraulic fracturing were factored in. Channeling could also occur as a result of fracture orientation and well placement. The presence of shale laminae would reduce both production rates and cumulative production determined by the simulator by increasing tortuosity and creating isolated compartments.

Porosity values acquired by the saturation method and those acquired by helium expansion were in close agreement. Permeability values acquired by gas tests agreed closely with those acquired by liquid tests and indicated that the samples were relatively homogeneous.

Conclusions

This study shows (1) the geometries of some Cypress sandstone bed sets on the I-57 outcrop; (2) the possibility of barriers that inhibit fluid flow and may form compartments; (3) spatial distribution of sandstone porosity and permeability; (4) some differences between the outcrop and the subsurface; (5) that surface weathering has altered the outcrop; (6) that Cypress sandstone reservoirs have a low sweep efficiency for waterflooding, as indicated by permeability variation coefficients; (7) outcrop porosity is approximately 17% and correlates poorly with permeability; and (8) well spacing greater than 100 feet (¼ acre) can result in uncertainty when predicting permeability between wells.

Figure 80 Study area for old electric log application and location of wells with both core and logs available (Leetaru 1990).

TASK 3: ENGINEERING APPLICATIONS

TECHNIQUES FOR APPLICATION OF OLD ELECTRIC LOGS

- The empirical normalized spontaneous potential (NSP) technique is more accurate for estimating porosity in the Aux Vases from old electric logs than are other previously published methods such as the short normal and Rocky Mountain method.
- The measured (mud resistivity) R_m from old electric logs in the Illinois Basin does not appear to be reliable; corresponding calculations using measured R_m are therefore suspect. For instance, R_m is an intrinsic part of estimating the resistivity of formation water (R_w) from spontaneous potential (SP) and in estimating porosity using micrologs.
- Water saturations can be estimated by using Pickett plot analysis. The major advantage of Pickett plots over the basic Archie equation is that Pickett plots do not need a pre-defined cementation exponent or resistivity of the formation water.

An understanding of old electric logs is important for reservoir analysis of Aux Vases oil fields because many of these reservoirs were discovered before 1960. The better Aux Vases oil fields, which have each produced more than 1 million barrels of oil, were discovered between 1938 and 1955. Logging tools for measuring porosity were rarely used; for example, in a typical field such as King Field in Jefferson County, Illinois, less than five neutron or micrologs were run out of 163 wells drilled. One suite of modern logs was available, but this well did not penetrate the reservoir facies. A subregional project in Franklin, Hamilton, Jefferson, and Wayne Counties (fig. 80) in the southern part of the Illinois Basin was designed to test application of new methods to old electric logs for definition of reservoir heterogeneity.

Old electric logs are wireline logs that combine the SP and the normal and lateral resistivity curves. By 1956, the induction log began replacing the electric log as the primary resistivity measurement tool (Hilchie 1979), although in the Illinois Basin, electric logs continued to be run during the early 1960s.

The SP measures the potential that has developed opposite a permeable bed in a natural electrochemical cell composed of shale, fresh water, and salt water (Hilchie 1979). Griffiths (1952) showed an inverse relationship between the amount of clay and the magnitude of the SP. The SP-clay relationship is the basis for the technique of estimating porosity presented in this report. Although the SP measures the amount of clay, not porosity and permeability, an increase in clay implies a corresponding decrease in porosity and permeability.

The normal, which refers to a log introduced by Schlumberger in 1931, became the primary resistivity curve in the early electric log suite (Hilchie 1979). The type of normal is

defined by the electrode spacing, usually referred to as the AM spacing, which determines the depth of investigation. In the Illinois Basin, many different electrode spacings were used, of which the most common ones were the 16-inch short normal (AM = 16 inches) and the 64-inch long normal (AM = 64 inches).

The depth of investigation of the normal is assumed to be twice the AM spacing (Hilchie 1979). At an AM spacing of 16 inches, resistivity is measured 32 inches from the borehole. At an AM spacing of 64 inches, resistivity is measured 120 inches (about 10 feet) from the borehole. The short normal usually measures average resistivity of the invaded zone (R_i), which is saturated with a mixture of mud filtrate and original formation fluid. The long normal measures the apparent resistivity (R_a) of the formation. Invasion and thin bed effects can still affect the long normal. Simply stated, the long normal accurately measures formation resistivity if beds are thicker than 10 feet and invasion is less than 5 feet (Frank 1986).

Data Analysis and Methodology

The distribution of the 70 wells from which both Aux Vases core data and electric log data were collected is shown in figure 80. Within each well, the log response of the Aux Vases was subdivided into zones of similar electrical properties that were calibrated with core analyses. Most wells in this study had core from only one zone. In total, 73 zones (or data points) from the 70 Aux Vases wells were used to define the SP resistivity-core relationship.

Although the average SP and short normal were measured for each zone, the relation of the short normal to porosity was determined for only 47 wells because not all wells had a measured drilling mud resistivity (R_m). For each zone, porosity and permeability values were taken from commercial core analyses. All core analyses used in this report were pre-1960.

For log analysis, R_m and the temperature at which R_m was measured are two of the most important pieces of information required. Because the resistivity of the mud changes with temperature, R_m must be corrected to formation temperature before it can be used in any log calculations. Almost 40% of the 70 wells do not have the mud temperature listed, and therefore, these wells have no usable R_m . As will be discussed later, some wells may also have had the R_m or the temperature measured incorrectly.

Porosity The three methods of predicting porosity from old electric logs are short normal, Rocky Mountain, and normalized SP (NSP). The first two methods are commonly used in the industry, but have several limitations. Of the three, the NSP appears to provide the best results for the Aux Vases in the study area.

Short Normal Method Pirson (1957) and Hilchie (1979) describe procedures and provide nomographs for estimating porosity from the short normal. The techniques are empirical and based on short normal measurements of the resistivity of the invaded zone. The calculation of porosity from the short normal curve requires accurate R_m measurements (Hilchie 1979) because this method derives porosity from the short normal by using a ratio of the resistivity of the invaded zone to R_m . Aux Vases Sandstone porosities calculated using the short normal generally correlate poorly with the actual measured porosity from core when R_m is taken from the log heading (fig. 81).

An approximate R_m was calculated from the logs to determine whether the measured R_m was the major source of error. This method of estimating R_m uses clean Cypress sand and assumes that the Cypress has a relatively constant porosity. The porosity of the Aux Vases calculated using the estimated R_m is a somewhat better approximation of the measured core porosity than the porosity calculated using the R_m from the log heading (fig. 82). This observation indicates that the R_m values on the log headings are incorrect for a significant number of the evaluated wells.

It is important to realize when R_m is in error, because many critical log interpretation calculations use this value. For instance, it is an intrinsic part of estimating resistivity of formation water (R_w) from SP and of estimating porosity using micrologs (Hilchie 1979).

Figure 81 Measured core porosity versus porosity calculated from the short normal (R_m from the log heading) (Leetaru 1990).

Figure 82 Measured core porosity versus porosity calculated from the short normal (R_m estimated from the Cypress) (Leetaru 1990).

Figure 83 Measured core porosity versus porosity calculated using the Rocky Mountain method (Leetaru 1990).

Figure 84 Measured core porosity versus normalized spontaneous potential (NSP) (Leetaru 1990).

Rocky Mountain Method The Rocky Mountain (Tixier) method permits the determination of water saturation and porosity when only R_t , R_i , and SP are known (Schlumberger 1989, Tixier 1949). The porosity values calculated from the Rocky Mountain method were compared with core porosity measurements (fig. 83). All porosity values calculated at greater than 30% were plotted at 30% porosity. The Rocky Mountain method produces better estimates of porosity than does the short normal method.

Normalized Spontaneous Potential Method Because the actual value of SP on the log is not an absolute number, SP values cannot be directly compared among different wells. Normalizing SP values against an internal standard can compensate for changes in the scale of the log, the mud resistivity, and size of the borehole, and thus allows direct comparisons of SP values among different drill holes.

Figure 85 Measured core permeability relative to NSP for Jefferson County, Illinois (Leetaru 1990).

The first step to normalize the SP measurements is to establish a shale base line through the average SP curve in a thick shale. Similarly, a clean sand base line is established. For this study, the sand base line was defined from sandstones with the largest negative millivolt value, which usually would be one of the basal Cypress sandstones. NSP for the Aux Vases is a ratio of the SP measurement of the Aux Vases to that of the shale and sand base line, and the resulting number is unitless, ranging from 0 to 100 in value.

The relation between NSP and measured core porosity in 73 zones had a Pearson correlation coefficient (r) of 0.83 (fig. 84). The data exhibit considerable scatter or deviation from the least-squares regression line. More than a 5% porosity difference can occur between the core analysis and predicted porosity calculated using the best fit regression line; however, most wells show a significantly smaller amount of error. The calculated standard error of estimate is 2.6% porosity. Modern tools, such as density and neutron logs, can also introduce errors of the same magnitude. Lang (1980) determined that 58% of the wells in a 360-acre area in the San Joaquin Valley of California needed an average correction of 3% in porosity.

Permeability A logarithmic relationship exists between average core permeability and NSP (fig. 85). In local areas such as Jefferson County, the NSP permeability method is more accurate than on a regional scale because all of the Aux Vases sandstones formed in a similar diagenetic and depositional environment.

Water Saturation A Pickett plot analysis was used to determine the water saturation of King Field, which has produced more than 4 million barrels of oil from the Aux vases sandstone. All the wells with usable logs were plotted. The porosity was calculated using the NSP method; resistivity was measured from the long normal device.

The Pickett plot may be a better method of estimating water saturations than the conventionally used Archie equation (Archie 1942); it is a graphic derivation of the Archie equation. The advantage of using a Pickett plot is that the cementation exponent and R_w values of the Archie equation do not have to be determined.

Porosity and resistivity from wells that either tested water or were drilled below the oil-water contact should ideally plot along a straight line (fig. 86). At King Field, the oil-water contact is not well defined, and some wells interpreted to be wet may contain oil. All wells were drilled into the postulated water zone plot below a water saturation of 50%. The data are more scattered than on modern logs. This scatter probably resulted from error in using estimated porosity from the SP. Constant water saturation lines are plotted to the right of the R_o line and parallel to it. Hydrocarbon-bearing zones occur to the right of the R_o line.

Figure 86 Pickett plot of estimated porosity relative to apparent R_t , King Field, Jefferson County. The slope of R_0 is equal to a cementation exponent of approximately 1.7 (Leetaru 1990).

Summary

For the study area, the NSP technique was significantly better than the short normal and Rocky Mountain methods for predicting porosity in the Aux Vases Sandstone. The relationship between NSP and core porosity had a correlation coefficient of 0.83. The short normal using measured R_m , the short normal using calculated R_m , and the Rocky Mountain method had correlation coefficients of 0.23, 0.44, and 0.66, respectively. The measured R_m reported on old electric logs in the Illinois Basin is not reliable, so calculations using R_m may be in error.

PRESSURE, VOLUME, AND TEMPERATURE RESEARCH

Petroleum engineers require knowledge of physical properties of petroleum fluids for both reservoir and production system calculations. These properties must be determined at reservoir temperatures and various pressures for reservoir performance studies, and at conditions of both changing pressure and temperature for well bore hydraulics, surface separation, and flow line calculations. The physical properties of a representative reservoir fluid sample, obtained either by subsurface sampling or recombination of separator oil and gas, are measured with special laboratory equipment designed for determining the pressure, volume, and temperature (PVT) of the sample at reservoir conditions. The results of these analyses are then used to (1) estimate the volume of original oil and gas in place; (2) calculate flow properties of the reservoir fluid under reservoir or pipeline conditions; (3) design separator conditions for optimization of liquid recovery; and (4) provide information on solution gas drive energy and timing of pressure maintenance.

Although PVT analysis can be obtained from one of the several oil and gas service companies throughout the United States, many independent operators in Illinois have been reluctant to pay for an analysis and have relied on published PVT correlation charts to obtain the needed PVT properties for their engineering calculations. Although several PVT correlation methods that have been published (Standing 1952, Lasater 1958, Vasquez and Beggs 1980) provide sufficiently accurate PVT data for most engineering decisions, they are not

applicable to a significant number of Illinois reservoir oils, especially those containing high gravity solution gas or a large amount (>10%) of nitrogen (Meents 1981).

To assist independent oil and gas operators of the Illinois Basin, the ISGS conducted investigations with the following objectives: (1) provide needed PVT property data input for reservoir engineering studies; (2) accumulate a PVT database for the Illinois Basin; (3) evaluate the adequacy of the existing PVT property correlation charts and equations for Illinois reservoir crude oils; and (4) provide independent oil and gas producers with a more accurate method for estimating PVT relationships when other published methods prove inadequate.

Several PVT analyses were performed using crude oil and gases from three different Illinois reservoirs. The results were used to evaluate the applicability of the commonly used correlation methods for PVT properties and to validate an equation of state computer program that can be used to calculate PVT properties at other pressure and temperature conditions. One oil-swelling test with carbon dioxide (CO₂) was performed to evaluate the potential for CO₂ flood-enhanced oil recovery from the Aux Vases Formation of the Illinois Basin.

Additional data have been published in a study by Sim (1993). The equation of state (EOS) used by the petroleum industry for simulation of phase behavior and PVT properties has been discussed in several papers (e.g., Whitson 1982). Although the most important application of EOS is in the field of enhanced oil recovery through gas-miscible flood, it can also be used to check the consistency of PVT and phase behavior results.

Limited experimental PVT data from Illinois reservoirs are available for the derivation of a reliable equation for the calculation of physical properties such as bubble-point pressures, oil and gas formation volume factors, and compressibilities. Consequently, an EOS computer program was used to check the consistency of new correlation equations and to extend the PVT relationships beyond the limits of the available data.

Simulation of PVT Analyses

Table 4 compares the EOS-calculated PVT properties with experimental data. Deviation between calculated bubble-point pressures and experimental bubble-point values ranges from 1% to 13%; the average deviation is 4.8%. Deviation between calculated oil formation volume factors and experimental values ranges from 0.1% to 10%, and the average deviation is 3.2%.

Table 4 Comparison between measured and calculated PVT parameters for oil samples from three Illinois Basin fields

	R _s scf/stb		P _b psig			B _o rb/stb			ρ _o gm/cc		
	data	calc	data	calc	% dev	data	calc	% dev	data	calc	% dev
McCullum Unit	319.4	312.3	350.0	342.0	0.1	1.213	1.217	-3	0.763	0.782	-5
	245.0	222.0	150.0	150.0	-10	1.130	1.135	-10	0.784	0.809	-14
	0.0	0.0	0.0	0.0		1.017	1.010		0.822	0.831	
Energy Field	419.4	381.0	1600.0	1600.0	-10	1.187	1.183	-8		0.781	
	210.1	208.0	910.0	900.0	0.1	1.124	1.123	-1	0.783	0.781	-1
	85.1	80.0	100.0	100.0	-8	1.039	1.040	-8	0.795	0.811	-10
	0.0	0.0	0.0	0.0		0.017	0.010		0.821		
Zeigler Field	195.1	214.0	707.0	707.0	9	1.138	1.121	10	0.787	0.789	7
	114.6	112.0	180.0	200.0	-13	1.065	1.070	-3	0.794	0.815	-5
	0.0	0.0	0.0	0.0		1.017	1.010		0.815	0.831	

data = experimental data measured with the ISGS PVT equipment.

calc = EOS calculated results

R_s = solution gas oil ratio

P_b = bubble-point pressure

B_o = relative oil volume

ρ_o = oil density

New Correlations

One objective of this study was to provide Illinois Basin producers with a means of calculating essential PVT properties from more readily measurable physical properties such as oil API, gas composition, and gas to oil ratios. Although a tuned EOS program is a good vehicle for performing these tasks, not many independent operators have access to these types of computer programs. Thus, several correlation equations, based on experimental data and properties calculated from the tuned EOS program, have been derived for use in the basin.

In addition to providing the Illinois oil and gas operators with the much needed PVT data, this study included a new correlation equation (equation 1) for the calculation of bubble-point pressure for crude oil containing high content of nonhydrocarbon or high gravity gas. This equation, which uses the pseudo-critical temperature to represent the physical properties of solution gases, was found to be superior to the commonly used correlation methods.

$$P_b = 65.23 * T_r \frac{0.679 * \text{Exp}(2.786 * Y_g) - 0.323}{T_{cm} + 60} \quad [1]$$

where:

- P_b = bubble-point pressure (psi)
- Y_g = mole fraction of gas (calculated from solution gas to oil ratio, molecular weight of oil and oil density)

$$Y_g = \frac{R_s/3.79.3}{R_s/379.3 + 350 \gamma_o/M_o}$$

T_{cm} = pseudo-critical temperature of the solution gas (°F)

$$T_{cm} = \sum Y_i * T_{ci}$$

- Y_i = mole fraction of individual gas components
- M_o = molecular weight of stock tank oil
- R_s = solution gas oil ratio (SCF/STB)
- T_{ci} = critical temperature of gas components (°F)
- T_r = reservoir temperature (°F)
- γ_o = oil density (gm/cc)

A second equation (2) was also derived for the prediction of isothermal compressibility of Illinois crude oils and showed better agreement with experimental values than the method of Vasquez and Beggs (1980).

$$C_o = (\text{Exp}(1.85 + 0.0043 * (T - 84) - 0.0001122P) + R_s \text{Exp}(-3.7 - 0.00074P)) * 10^{-6} \quad [2]$$

where:

- R_s = solution gas to oil ratio (SCF/STB)
- P = pressure of interest (psi)
- T = reservoir temperature (F)

Summary

Illinois crude oil samples frequently contain solution gas that has a nonhydrocarbon content higher than 10% and gravities higher than 1.2. The samples are thus outside the range of applicability of the commonly used methods for estimating bubble-point pressures. A simple equation (1) for bubble-point pressures agrees with both the limited PVT data, and the calculated results of a tuned EOS has been derived for these types of crude oils.

The method of Vasquez and Beggs (1980) commonly used for the estimation of isothermal oil compressibility has been found to be inadequate for the samples analyzed. Equation 2 shows better agreement with experimental values. For the estimation of saturated oil formation volume factors, the method of Vasquez and Beggs (1980) was found to be adequate. The relationship derived by Standing (1952) consistently overestimates oil swelling by CO₂ for crude oil from the Aux Vases Formation in the Illinois Basin.

Values for saturated oil viscosity values, estimated on the basis of the Beggs and Robinson (1975) method from the viscosity of gas-free crude oil, were found to be closer to experimental values than those based on the Chew and Connally (1959) equation.

Values for gas-saturated oil density calculated using the Katz (1942) method agreed closely with experimentally determined values.

As a result of this study, Illinois Basin operators now have an improved methodology to calculate more applicable PVT properties for use in reservoir management.

TASK 5: DATABASES

Data generated in this project are reported in appendixes at the end of the report. The following list is for reference. All samples are keyed to the unique API number of the individual wells.

APPENDIXES

- I Pool Study Outline
- II Aux Vases Reservoirs and Plays in Illinois
- III Cypress Reservoirs and Plays in Illinois
- IV Historical Oil Production in Illinois
- V Reservoir Summary Information
- VI Formation Water Chemistries
- VII-A Oil Analysis Results
- VII-B Oil Sample Locations
- VIII Selected Oil Chromatograms
- IX Cypress Formation Outcrop Locations and Summaries
- X Aux Vases Formation Outcrop Locations and Summaries
- XI Summary of Aux Vases and Cypress Mineralogical Data
- XII-A Identification of Core Samples with Mineralogical Data
- XII B-Q Geochemical Modeling Data
- XIII ENR/DOE Project Data File
- XIV-A Porosity and Permeability Data
- XIV-B Porosity and Permeability Plots

All data and physical specimens (e.g., petrographic slides) are on file at the ISGS. Throughout the project, these data have been exhibited at workshops and various industry conventions regionally and nationally. The ISGS maintains an open-office policy. The Geologic Records Unit is open to the public during normal office hours and holds all records, including wireline logs, that pertain to oil and gas wells.

A workstation accessing the ISGS well database system is on loan to the Illinois Oil and Gas Association for their library. This database includes well header data and provides an

opportunity to search the ISGS well database through a commercially available database management system called Questor. Data on microfiche have also been provided to the association. Access to these materials is unrestricted.

TASK 6: INTEGRATED GEOLOGIC AND ENGINEERING STUDIES

Integrated geologic and engineering studies were conducted in four Illinois fields. McCreery and McCullum Units in Dale Consolidated Field, Energy Field, and Zeigler Field produce from the Aux Vases Sandstone intervals; whereas in one field, Lawrence Field, the Cypress Sandstone was modeled. These fields were chosen because of data availability and operator accessibility. The primary source of geologic and geophysical data is the Geologic Records Unit (GRU) of the Illinois State Geological Survey. GRU well files contain SP and resistivity logs; additional information may include well completion information, core analysis reports, well test reports, and other geophysical logs, notably porosity logs, if available. Field operators provided past and current production data such as oil and water production. Pressure measurements are rare; gas production was never reported for the fields studied to date.

A third source of data is direct measurements of properties of samples taken from fields that were studied. For example, all crude oil PVT data reported in Sim (1993) were measured during the course of this project and applied in the field studies. Also, when core samples were available, as in the case of Dale, Lawrence and Energy Fields, additional core information such as relative permeability or capillary pressure values were measured.

RESERVOIR CHARACTERIZATION

The spatial distribution of reservoir attributes was determined using well data. Relevant well data such as core properties, well test information, waterflood and oil production information, and porosity logs were necessary for reservoir characterization. Availability of these relevant data varied from field to field. Lawrence (Cypress) and Zeigler (Aux Vases) reservoirs have the highest cored well density and the largest variety of geophysical logs. For fields with limited cored well data, cross plots of permeability and porosity were used to extend permeability data to uncored wells.

OBJECTIVES

The major objective in each field study was to develop comprehensive geologic and reservoir models from all available geological, petrophysical, geophysical and field data for these uses:

- to determine estimated reserves, recovery factors and the amount of unproduced mobile oil (UMO);
- to understand the reservoir architecture of the respective fields and the dominant features affecting field performance through examination of the 3-D geologic models;
- to identify flow units that affect reservoir performance;
- to serve as input into the reservoir simulator, used to study different reservoir management scenarios and how they affect reservoir performance and project economics;
- to analyze, synthesize and compare field practices, simulated scenarios, and corresponding field performance and provide analogs for development of similar reservoirs in the Illinois Basin.

METHODOLOGY

A geologic model of each field was generated with the Stratigraphic Geocellular Model (SGM™) software (fig. 87 is an example from Lawrence Field). Input data for the SGM include tops and bases of the reservoir imported as grids generated by the Zycor™ mapping package and reservoir attribute data such as well logs and core data. The spatial distribution of these data are determined by approximation of well data within a specified search radius.

Figure 87 Stratigraphic 3-D model of Lawrence Field (Udegbumam and Grube 1993).

The geologic model thus generated provides the stratigraphic framework for the reservoir simulator. Through GeoLink™, the geologic model is subdivided into layers that correspond to perceived hydraulic flow units. In the VIP™ software, the model is subdivided into grids, each grid consisting of attribute data such as structure top and base, porosity, permeability, and oil, water and gas saturations. Also needed in the initialization and execution of the reservoir simulator are relative permeability, saturation, capillary pressure, reservoir pressure and temperature, and PVT data as well as reservoir production history. Initialization of this reservoir model involves the determination of the initial fluid volumes. The original oil in place (OOIP) was determined by the volumetric method. Recovery factors and the unproduced mobile oil (UMO) volumes were also determined at this point.

Each field study involved a black-oil, fully implicit 3-D model and consisted of a history-match phase, and a predictive stage in which hypothesis or future production options were investigated. The VIP™ simulator displays the simulation results in the form of plots, maps, 3-D visualizations, and simulates the field performance as a function of time.

SUMMARY OF RESULTS

Dale Consolidated Field Model

McCreery and McCullum Waterflood Units (Udegbumam et al. 1993):

- Comparison of field production data from the reservoir simulation model with historical production indicates the McCreery and McCullum Units are hydraulically connected.
- Core data and a semivariogram model show two flow units within the reservoir interval. A two-layer simulation model was created to correspond to the observed flow units.

- Calcite cement increases with depth and occludes much of the permeability and porosity in the lower reservoir interval.
- Hydraulic fracturing in the McCreery and McCullum Units may have produced an east-west network of fractures, possibly intersecting between some wells. When planning hydraulic fracturing, operators should be aware of regional compressive stress orientations.
- Simulated results of water:oil ratio versus cumulative water injection and water:oil ratio versus time for the reservoir simulation model with an intersecting fracture network trending east to west compared well with observed field data. This suggests that fractures induced by hydraulic fracturing may be partly responsible for the historical low sweep efficiencies and poor waterflood oil recovery.
- Analysis of 15 months of actual waterflood performance data show poor oil recovery response, which is thought to result from an inefficient reservoir sweep due to several causes including the following:
 - injectors and producers are open only in the more permeable, upper sandstone;
 - induced fractures conduct water to the producers and bypass the banked oil;
 - injection well arrangement is not optimal; existing injection wells should be reperfected to increase their efficiency as injectors.
- Suggested strategies for improved oil recovery from the McCreery and McCullum Units include the following:
 - perform reservoir tests to define flow units and directions;
 - recompleat wells;
 - place water injection wells in a repeated line-drive pattern oriented east to west;
 - plan a selective plugging program to mitigate the bypassing of oil by injected water;
 - drill infill well(s) for water injection in a five-spot pattern or line-pattern arrangement.
- Data and results from this study have resulted in improved management of the reservoir by the unit operator. Within the last 12 months, oil production has increased by two to three times over earlier rates.

Energy Field Model

- Of the estimated 2,208,000 barrels of oil originality in the southern portion of Energy Field, about 15% has been recovered after 23 years of production; the A.B. Vaughn unit yielded 13% and the Budmark unit, 2%.
- The unproduced mobile oil in Energy Field is about 50% of the OOIP and provides sufficient reason for investigating future recovery opportunities from the field through improved waterflood strategies and drilling infill wells.
- The performance of various strategies for improved waterflooding in Energy Field was predicted using a reservoir simulation model.
- Independent development strategies for Budmark and A.B. Vaughn leases showed that the most productive options always involved more than one water injection well.
- The simulations showed that migration of oil across lease boundaries occurred when the units were independently developed in an unsynchronized manner. Across-lease migration of oil makes field unitization advisable.
- Comparisons among the various simulated strategies for future development of Energy Field showed that field unitization and waterflooding with one or two carefully placed infill wells would be the optimum approach for improving recovery at Energy Field.
- This case study for Energy Field demonstrates that, despite the limited data available, computer simulations can be used to characterize and manage reservoirs, evaluate performance of past development practices, and identify opportunities to improve recovery.
- Increased utilization of similar integrated geologic and engineering studies will allow oil producers to make prudent choices among possible field development strategies.
- Many of the techniques and results of this study are transferable and can be used as analogs for the study of similar reservoirs.

Zeigler Field Model

- The Plumfield leases of the Zeigler field encompass 500 acres. During 29 years, approximately 2 million barrels of oil has been produced from 30 wells. The reservoir comprises three narrowly connected and slightly overlapping offshore marine sandstone bars in the Mississippian Aux Vases Formation.
- Reservoir data collection and waterflood management were excellent at Zeigler Field. Almost every well was cored; detailed DST data and bottom-hole pressure surveys were obtained; and production and injection surveillance was maintained.
- Interpretation of data from the surveillance enabled the operators to locate a permeability barrier between wells P18 and P19 (figs. 88, 89). This information guided the placement of injectors in the eastern portion of the field.
- The Plumfield lease (Zeigler Field) contained an estimated 4.560 million stock tank barrels of oil, of which 43.07% had been produced by February 1992. With only two wells still pumping, daily oil production is now below 28 barrels of oil per day. The waterflood recovery, relatively high for the Aux Vases Sandstone at the Plumfield lease, is attributed to good reservoir management by the operator. The strategies used in this successful waterflood project should be applicable to similar reservoirs in Illinois.
- Simulation of reservoir management scenarios showed that placement of two water injectors (wells P8 and P24, fig. 89) at the start of oil production instead of a year or so later would have recovered about 1.05% more oil than was recovered in the actual case.
- Reserve calculations in this study suggest that more than 50% of the OOIP still remains at the Plumfield leases and that 14% of the OOIP is probably bypassed, moveable oil. Results of the reservoir simulation suggest that the bulk of the recovered oil was produced from the uppermost permeable sand. The bypassed lower layer of the reservoir may have the best potential for future oil recovery.
- Future development opportunities at the Zeigler field include selective plugging of the channelized, highly permeable upper sandstone layer(s) with polymers or cross-linked polymers, microbial enhanced oil recovery techniques, and targeted infill drilling.

Lawrence Field Model

- Examination of Cypress cores and detailed geological mapping using geophysical log data showed that sand body trends are consistent with deposition in coastal to near-shore, shallow marine settings.
- Interpretations of geophysical and petrophysical data indicated five sandstone intervals in the Cypress separated by impermeable shaley sandstones and tight calcareous streaks.
- Lack of connectivity between the uppermost sandstone interval and the middle zones suggests that these zones might have been unevenly swept by the injected flood water.
- Sodium chloride concentration profiles from several observation wells in the study area showed that most of the oil-sweeping by injected water occurred in the middle sandstone intervals; the uppermost and lowermost intervals were either uninvaded or only partially invaded.
- Results of simulated infill drilling with waterflooding showed that most oil production came from the uppermost sandstone interval in all leases in the study area—a finding that points to a possible target for the recovery of bypassed oil.
- Recovery calculations showed that 39.5% of the OOIP has been produced; 14% of the OOIP is unproduced mobile oil and 46.5% of the OOIP is immobile oil. These findings suggest there is considerable immobile oil in the Cypress reservoirs at Lawrence Field.
- Recommended approaches for future development of the Cypress reservoirs at Lawrence Field include improved reservoir characterization through well testing to verify reservoir continuity, infill drilling with bypassed oil as the target, and application of chemical EOR methods such as CO₂ injection for recovery of immobile oil.

Note: contour line labels are in feet

Figure 88 Isopach field map, Plumfield lease, Zeigler Field showing location of permeability barrier (Sim et al. 1994).

Figure 89 Simulation model basis; two injectors, P8 and P24, in the northeast corner of the field (Sim et al. 1994).

Figure 90 Variation of permeability and calcite cement, McCreery No. 1, Dale Consolidated Field (Udegbunam et al. 1993).

TECHNICAL SUMMARIES

McCreery and McCullum Units, Dale Consolidated Field

The McCreery and McCullum Units in southwestern Dale Consolidated Field in Franklin County, Illinois, have produced more than 400,000 barrels of oil from two reservoirs in the Mississippian Aux Vases Sandstone. The marine sandstones that constitute the reservoirs were deposited as bars in a mixed siliciclastic-carbonate environment: they formed by shoaling against paleotopographic highs in the underlying limestone. Studies of petrographic thin sections, XRD analyses, and petrophysical analyses of Aux Vases sandstone cores taken from the McCreery Unit show that all producing sandstone was deposited within the bar facies. Calcite content increases with depth (fig. 90), thereby reducing the porosity and permeability. The vertical reduction in permeability limits the influence of bottom-water drive on oil production.

The original oil in place (OOIP), estimated using the model developed in this study, was 1,798 and 652 thousand stock tank barrels of oil (MSTBO) for the McCreery and McCullum Units. Prewaterflood oil recovery factors were 14.6% and 30.5% of the OOIP, respectively.

Analyses of monthly waterflood data from the McCreery Unit reveal a poor waterflood oil recovery response; the additional incremental oil production is only 0.56% of the OOIP. This waterflood program has not been profitable to date. As this study suggests, an oil price above \$35 per barrel will be required for economic recovery, unless there are improvements in field development strategies (fig. 91).

Field production evidence suggests that hydraulic fracturing adversely affected secondary oil production from these bars by creating high permeability fracture channels oriented east to west. A 3-D, black oil, full-field simulation model was developed, based on the assumption that hydraulic fracturing techniques created preferential fracture orientations (fig. 20). These fractures align themselves subparallel to the maximum horizontal compressive stress direction oriented N76°E to N90°E. Simulated water-oil ratio versus cumulative water injection results (fig. 92) from an idealized reservoir model with higher permeability values along the line of wells from east to west compared favorably with observed field data. The results indicate that fractures induced by hydraulic fracturing are responsible for the low sweep efficiencies and poor waterflood oil recovery.

The following strategies are suggested for improving oil recovery from the McCreery and McCullum Units:

- perform fieldwide reservoir tests, such as tracer and pressure transient tests, to further define highly permeable flow channels and their directions in the reservoir;

Figure 91 Cost analysis of the McCreery Unit waterflood (Udegbunam et al. 1993).

Figure 92 Water-oil ratio versus cumulative water injection, McCreery Unit waterflood (Udegbunam et al. 1993).

- squeeze existing perforations in all water injectors and reperforate in the lower zone;
- place water injection wells in a repeated, staggered line-drive pattern oriented east to west so that all producers are either north or south of water injectors;
- use selective plugging techniques (polymers or microbes) to reduce bypassing of oil by injected water.

Infill drilling for waterflood locations north or south of existing well locations may be more effective for incremental oil recovery than implementing the above strategies alone, but it is also more costly. If infill drilling were combined with these strategies, the existing wells could serve as oil producers while the new infill wells serve as water injectors.

Energy Field

The geology, development, pressure and production history, and predictions of performance have been integrated in this study. Energy Field, discovered in 1968, produces from Aux Vases Sandstone (Mississippian) reservoirs and consists of separate southern and northern bar complexes. Each complex contains two stacked sandstone bars separated by an interval of impermeable, calcareous siltstone and shale (fig. 21). The northern sandstone bars are not part of this reservoir modeling study because their discovery is relatively recent.

This study demonstrates how limited available data for reservoir characterization and management were put to maximum use in order to evaluate the performance of past development strategies and to identify opportunities for future recovery from Energy Field.

Description of the reservoirs in the southern sandstone bar is based on geologic interpretations of reservoir sandstone distribution, structure, depositional history, porosity, permeability and fluid saturation values from core analyses, and correlation of core data to wireline logs. A 3-D geologic model, generated using a stratigraphic modeling program, served as input into a 3-D full-field, black oil, reservoir simulation model. The simulation was used to analyze past development strategies and predict incremental oil recovery opportunities at Energy Field. Simulated strategies for future improved oil recovery from the study area included no further development, separate development of the two leases, and unitization of the two leases. Predictions (table 5) are that more oil could be produced with fewer water injection wells under a unitization program rather than under separate operation.

The estimated OOIP in the study area is 2,208,000 barrels. About 15% of the OOIP was recovered after 23 years of production. The unproduced mobile oil is about 50% of the OOIP. Analysis of the past pressure maintenance programs showed that they were not optimal and could not sustain reservoir pressure above the bubble-point pressure (fig. 93). Comparisons

Figure 93 Simulated pressure decline and bubble-point pressure at Energy Field showing that the reservoir pressure dropped below the bubble-point pressure soon after the start of production. To maximize oil production using the dissolved gas energy, water injection should have started earlier. This would keep the reservoir pressure above the bubble-point pressure. Historically, water injection in the Energy Field was not sufficient to bring reservoir pressure above the bubble-point pressure (Udegbunam and Huff in press).

among the options for improving future recovery of mobile oil from Energy Field showed that a combination of field unitization and waterflooding with one or more strategically located infill wells would yield the greatest oil recoveries.

Integrated geologic and engineering studies lead to prudent field development strategies and greater oil recovery. Many of the results and techniques used in this study may be analogs and guide reservoir management plans for similar reservoirs (table 5).

Table 5 Predictions of 5-year incremental waterflood oil recovery from Energy Field under various programs

Program	Cumulative oil recovered × 1,000 STBO	Number of water injectors
No further development in Energy field	38.7	2
Separate A.B. Vaughn Unit development	128.0	5
Separate Budmark Unit development	62.0	4
Unitized Energy Field development	203.0	5

Zeigler Field

Zeigler Field is located in the southern half of Franklin County in the south-central portion of the Illinois Basin (fig. 9). Although Zeigler Field consists of several leases, only the Plumfield lease was considered in this study. Since its discovery in 1963, the Plumfield lease had produced close to 2 million barrels of oil from the Mississippian Aux Vases sandstone reservoir intervals (fig. 88). The reservoir extends over 500 acres and contains 30 productive wells on a 10-acre spacing. The Plumfield reservoir is near the end of the waterflood recovery stage; most of the wells have been abandoned since the mid-1970s because of their high water-cut.

The reservoir zone comprises three slightly overlapping and narrowly connected off-shore marine sandstone bars. Reservoir management strategies used at Zeigler Field included obtaining cores from almost every well, bottom-hole pressure (BHP) surveys, and production and injection surveillance. The bottom-hole pressure surveys and production/injection surveillance were used to locate permeability barriers and place water injectors optimally in the field (fig. 89).

The waterflood performance of the Plumfield lease at Zeigler Field was evaluated with an integrated 3-D geologic and reservoir simulation model (fig. 94). A two-layer model was used to characterize the reservoir. Estimates from reservoir analyses showed that the Plumfield lease contained 4.56 million stock tank barrels of oil, of which 43.07% was produced between 1963 and February 1992. Simulation of other reservoir management scenarios showed that placement of two water injectors at the start of oil production would have recovered about 1.05% more oil than was recovered in the historical case. The predicted ultimate oil recovery factor without waterflood is 23%.

Reserve calculations suggest that more than 50% of the OOIP still remains at Plumfield lease and that 25% of the remaining OOIP is moveable oil that has been bypassed. The results of the reservoir simulation suggest that the bulk of the recovered oil was produced from the upper, more permeable sand.

Figure 94 Cross sectional simulation model of flow units at Zeigler Field. P = Plumfield lease, WP = West Plumfield lease. Lighter area is permeability >50 millidarcies (Sim et al. 1994).

Future development opportunities at Plumfield could include improvement of sweep efficiency with polymers or cross-linked polymers and use of microbial EOR techniques. Targeted infill drilling, as part of an improved oil recovery project, should also be considered if economics permit. It is strongly recommended that fieldwide tracer tests or other tests to define flow units be conducted to identify various scales of heterogeneities that were not detected by previous reservoir management programs in the field. The information gathered will provide a better understanding of the reservoir architecture and show the best ways to recover the remaining oil through improved oil recovery techniques.

Oil recovery during waterflood in this lease is relatively high for the Aux Vases Sandstone and attributable to the good reservoir management practices.

Lawrence Field

This study was conducted to evaluate the Mississippian Cypress Sandstone reservoirs in a central portion of Lawrence Field in Lawrence County, Illinois. The purpose of the study was to determine the amount and location of any unrecovered mobile oil, the reason for its having been bypassed, and the well patterns and spacings required for improving oil recovery through continued waterflooding.

Examination of Cypress cores and detailed geological mapping using geophysical log data showed that sand body trends are consistent with deposition in coastal to nearshore, shallow marine settings. Based on the SP character, core descriptions, and permeability values, the sandstones that make up the reservoir interval can be divided into five zones, A-E, in ascending order (fig. 33). Not all zones are necessarily present in any particular area. The A zone, commonly tight and separated from others by shale, does not appear to contribute significantly to oil production. Zones B-E are productive and show similar geometries—elongate, sheet-like sandstones with thick, northeast-southwest-trending ridges. An isopach of the C sandstone (fig. 34) illustrates the geometry.

Three-dimensional visualizations of a pilot study area showed alternating layers of permeable sandstones and thin shaley to calcareous, nonpermeable zones—conditions further indicating that some permeable zones in the Cypress may not communicate vertically in the interwell region. Profiles of sodium chloride concentrations in observation wells spaced 50 to

500 feet apart also helped to delineate flow units in the study area (fig. 95). In these wells, lower concentrations of sodium chloride in the middle Cypress Sandstone units than in the top and bottom sandstones indicate greater sweep efficiency in the middle units. Oil bypassing may have been caused by differential sweeping of various flow units by injected water.

Reserve estimates showed that the Cypress Sandstone originally contained about 780 stock tank barrels of oil per acre-foot in the study area, and that about 39.5% of the OOIP has been produced. The bypassed mobile oil volume was estimated to be 14% of the OOIP, whereas the immobile oil volume was estimated to be 46.5% of the OOIP. These results show that the immobile oil in the Cypress reservoirs at Lawrence field is significant. Several water-flood strategies for improved oil recovery and the sensitivity of the combined effects of the sand body orientations and injection and production well patterns on oil production from the Cypress sandstones were investigated using a reservoir simulator. Results from the simulation model suggested that, for optimum oil production from the Cypress sandstones, the well pattern arrangement should take sand body orientations into account. Changes in facies from reservoir to nonreservoir rocks within one well spacing result in banked oil that may be inaccessible to existing production and injection wells. The production potential of the Cypress sandstones at Lawrence Field, according to predictions made with the reservoir simulator, may be improved by more effectively placed infill wells, strategically located with respect to geology, and by closer well spacing using a line-drive pattern (fig. 96). The top-most zone contributed most of the predicted bypassed oil production.

These results may serve as analogs for understanding the past performance and evaluating future development opportunities from Cypress reservoirs in Lawrence Field.

TASKS 7, 8, AND 9: SEISMIC DEFINITION OF THE RESERVOIR AND ACQUISITION OF SONIC (ACOUSTIC) LOGS

SONIC (ACOUSTIC) LOG ACQUISITION

The ISGS contracted for acquisition of six sonic (acoustic) wireline logs during the project (table 6). Criteria for selecting the wells for acquisition were (1) that they were from deeper parts of the Illinois Basin, or (2) that they were from areas with no nearby sonic (acoustic) log control. The logs were run as part of standard operations in new industry-owned wells. The program and logs were presented and discussed at workshops and meetings with representatives of the industry.

Wireline logging companies were contacted and asked to help with the program. These companies were very cooperative. The original program was to acquire 40 sonic wireline logs. Only six logs were purchased because operators were often reluctant to release rig time to run the logs, and not all proposed wells were in areas that needed more sonic control.

Purchase of these logs will benefit future exploration and exploitation programs in the Illinois Basin. Sonic (acoustic) tools provide a continuous velocity profile of subsurface formations. Operators in the basin will be able to convert sonic logs to synthetic velocity logs and help resolve seismic correlation problems. Accurately linking well control to seismic is critical in regional sequence stratigraphy and both 2-D and 3-D seismic development programs.

The logs can also be used to measure the porosity of the formation. There is a linear relationship between transit time, measured by the sonic log, and porosity. The sonic log, combined with other logs (such as the density and neutron log), can be helpful in evaluating carbonate reservoirs. The sonic log usually cannot measure porosity created by vugs and fractures; therefore, the variation in porosity measurements between the sonic and density logs reflect variations in secondary porosity. Different porosity tools respond to mineralogy of the formation in different ways; therefore, a combination of different porosity logs can be used to estimate lithologic changes in the borehole. An improved oil recovery program needs to be able to tie seismic reflection data to the subsurface structure and stratigraphy and to estimate porosity and lithology.

Boyd - Baltzell Unit well MI-12

Figure 95 Vertical profile of sodium chloride concentration in observation wells at Lawrence Field. Data used to define these flow units from Udegbum et al. 1993.

Figure 96 Simulated incremental oil recovery using various well spacing scenarios (Udegbum et al 1993).

Table 6 Sonic (acoustic) logs acquired during the project

Date	Well name	Company
4/26/91	Darnell No. 2	Bernard Podolsky
9/07/91	McMillen B No. 4	Bernard Podolsky
9/19/91	USX-Eastern No. 7-1	Demier Oil Company
10/02/91	Kollak No. 2	C. McDowell Oil, Inc.
10/20/91	Porter-Weaver Community No. 1	Booth Oil Company
11/26/91	A. Goodwin No. B-1	Larrabee Oil Company

SEISMIC ACQUISITION AND INTERPRETATION

- High-resolution seismic reflection data can be used to distinguish reservoir from nonreservoir facies.
- Old wireline electric logs can be converted into pseudo-velocity logs and used in creating realistic seismic models of the facies variations within a reservoir interval.
- Seismic modeling, as well as the data, suggest seismic reflection character can be used to differentiate nonpermeable calcareous facies from permeable Aux Vases sandstone.
- Seismic data were used to identify stratigraphic units.

The resolution of seismic reflection data has improved during the last decade. Seismic data used for field redevelopment can be interpreted to show stratigraphic horizons, structural control, and subtle facies changes. Seismic stratigraphy has three major subdivisions (Sheriff 1989): (1) seismic sequence analysis, which is the analysis of seismic sequences associated with depositional systems; (2) seismic facies analysis, which is the analysis of reflection character and depositional environment; and (3) reflection character analysis, which emphasizes the trace-to-trace waveform variation caused by changes in stratigraphy. The emphasis in this study was to show how to use reflection character analysis to identify and understand reservoir heterogeneity—critical information for improving oil recovery.

Ten miles of seismic data were collected over King Field, located 75 miles east-southeast of St. Louis near the western limit of production from the Aux Vases Sandstone (Mississippian). The field covers 1,700 acres in southeastern Jefferson County. Most production is from the Aux Vases at a depth of about 2,750 feet. This field has produced more than 4.1 million barrels of oil since its discovery in 1942. Because of reservoir heterogeneity, an estimated 1 to 2 million barrels of unrecovered oil still remains in the reservoir (Leetaru 1991).

Copies of the seismic lines are available at the ISGS. Test records, special plots, and the contractor report (SD Consultants 1992) are also on open file at the ISGS. All four lines showed seismic reflection character changes that could be related to facies variations in the Aux Vases Sandstone. These facies were mapped. The relationship between the seismic reflection character and facies changes ranged from obvious to subtle. Previous geologic facies maps of King Field were based on wireline logs and illustrated the mixed carbonate-siliciclastic deposition of the Aux Vases. This study shows that character changes interpreted from high resolution seismic can be used to map the location of Aux Vases carbonates and reservoir sandstones. Facies maps based on seismic character changes can enhance the information mapped from wireline logs.

Acquisition Program

The 60-fold data were acquired using a 120 channels, 37.5-foot station spacing and a 37.5-foot shot spacing (SD Consultants 1992). The shots were centered halfway between stations using

Figure 97 Spectral analyses of field test shots (various dynamite charges in a single hole) were used to select the dynamite source and parameters for acquisition. This test using two 1/4 lb dynamite charges was judged to give the best frequency response (Leetaru in prep.).

a split spread of 2,212.5–18.75–2,212.5 feet. The data were collected with a low cut filter of 12 Hz and a high cut filter of 256 Hz and a 2-millisecond sample rate. The dynamite source was located at the bottom of 10-foot-deep drill holes to minimize ground roll. Examination of data from seven experimental test shots indicated that the best impulse source used two 1/4-pound charges in a single hole (fig. 97). Ten miles of seismic were acquired using these parameters. Line 1 is the north-south tie line, and lines 2, 3 and 4 are east-west lines.

Seismic Interpretation

Geologic modeling of the seismic response at King Field is restricted because of the vintage of wireline logs. Most wells at King Field were drilled in the 1940s and 1950s. Velocity logs were not developed until the late 1950s, and no velocity logs of the reservoir interval are available for this field. For most of the wells, the old electric log is the only wireline tool that was run. A good relationship between resistivity measurements and velocity has been demonstrated in the Illinois Basin (Rudman et al. 1975, 1976). They showed that in the Mississippian section, the relative changes in velocities were correct; however, the absolute value for the velocity was not necessarily correct. Velocity logs from nearby areas can be edited to produce more accurate synthetic seismic models than direct conversions of resistivity to velocity. The new pseudo-velocity logs should be more accurate than straight resistivity-to-velocity conversion because the velocities are from actual wireline logs.

Velocity logs were available for Markham City Field 5 miles to the northeast. With old electric logs from King Field as control, a typical velocity wireline log from Markham City was extensively edited to create new pseudo-velocity logs of different wells at King Field. There should be no significant difference in the velocities of the different formations in the

Figure 98 Synthetic seismogram for a portion of line ISGS-92-04 (Leetaru in prep.).

two fields because the lower Chesterian and upper Valmeyeran facies were originally deposited in similar environments (Whitaker and Leetaru 1992).

Synthetic seismic models were used to evaluate the effect of stratigraphic changes on seismic reflection character. Three different bandpass filters were used to generate the seismic wavelet during synthetic seismic modeling. The first two filters generated minimum-phase wavelets, referred to as wavelets A and B (in this report). Wavelet A comprises higher frequencies than wavelet B. Wavelet C was created using a zero-phase bandpass filter.

The Gulf Oil Company, Ford No. 1 well near seismic line ISGS-92-04, was one of the best Aux Vases producers at King Field; it is used as a type well in all the synthetic models in this report. The synthetic seismogram for the Ford No. 1 was generated using wavelet A because the best overall tie between the synthetic seismogram and the acquired seismic was with this wavelet (fig. 98).

Figure 99 Geologic model using pseudo velocity logs to illustrate gradation from clean, porous permeable (well 20) to increasingly calcareous sandstone (well 1) (Leetaru in prep.).

The reflection coefficient was calculated by taking a ratio of the acoustic impedance in an upper zone with that of the lower zone. The reflection coefficient determines the reflection amplitude of the seismic trace.

The stratigraphy of the upper Mississippian section is cyclic with alternating carbonates and siliciclastics. The carbonates are high-velocity intervals that should be peaks on the plotted seismic section; whereas the low-velocity siliciclastics should be displayed as troughs. The cyclicity causes the reflections to be regularly spaced and produces similar reflection characteristics, making it difficult to tie the synthetic to the acquired seismic. Also, different stratigraphic intervals seismically interfere with each other because they are closer than 200 feet, the approximate length of the seismic wavelet. Seismic interference will be discussed in more detail in the discussion on the seismic reflection characteristics in the Aux Vases Sandstone.

A geologic model was generated to evaluate the importance of lithofacies changes in the Aux Vases Sandstone. Figure 99 shows the interpolated pseudo-velocities between two wells; one will always be an unmodified Ford No. 1 pseudo-velocity log. Figures 100 and 101 are the synthetic seismic models generated from the geologic model using wavelets A and B. There is a difference between the synthetic model generated by using each wavelet. The most discernible difference in all the synthetic models is that the reflectors are broader in models generated using wavelet B because it has lower frequencies than wavelet A. The faint horizontal lines on each illustrated model are correlation lines used by the computer modeling program to control the interpolation between individual wells.

A model of the variation between reservoir sandstones and nonreservoir calcareous Aux Vases is illustrated in figure 99. The Ford No. 1 (well 20), the right well in the model has a clean, porous Aux Vases reservoir sandstone. This clean sandstone is gradational with the calcareous Aux Vases in pseudo-well No. 1. This variation in lithofacies is common in King Field and a significant cause for reservoir compartmentalization. Both wavelet A (fig. 100)

Figure 100 Synthetic model (wavelet "A") based on the model in figure 99 (Leetaru in prep.).

Figure 101 Synthetic model (wavelet "B") based on the model in figure 99 (Leetaru in prep.).

and wavelet B (fig. 101) synthetic models show variations in seismic amplitude with changes in the Aux Vases facies. Wells with reservoir sandstone should have higher amplitudes at the Ste. Genevieve reflector. This amplitude increase, present with all three wavelets, suggests that amplitude variation can be used to delineate reservoir from nonreservoir lithofacies in the Aux Vases Sandstone.

Line ISGS-92-04 was selected to demonstrate the correlation between geology and seismic data (fig. 102) for three reasons: (1) the lateral facies change rapidly (at least within one well spacing) along this line; (2) all the wells were located near the line; and (3) most important, all the wells from along shot points 164 to 255 penetrated the entire Aux Vases reservoir. Many of the wells on the other seismic lines partially penetrated the Aux Vases.

A geologic model of line ISGS-92-04 shot points 164 to 255 was constructed using wireline logs from five different wells (fig. 103). The resistivity logs from these five wells were used as control to edit velocity log and create new pseudo-velocity logs. Unlike the single lithofacies models discussed previously, the model of line ISGS-92-04 includes the lithofacies changes in all the formations and also their structural relationships.

Figure 102 A portion of seismic line ISGS-92-04 illustrating stratigraphy, changes in seismic character, and seismic response of the Aux Vases Sandstone reservoir (Leetaru in prep.).

Three different synthetics of the geologic model were created using wavelets A, B, and C (figs. 103, 104, 105). As stated earlier, synthetic models generated using wavelet A gave the best overall tie with the acquired seismic; but there is a 30% drop in the higher frequencies from 100 to 500 milliseconds where the Aux Vases is located. Because of this drop, wavelet B was the best for simulating reflection character changes in the Aux Vases Sandstone. A zero-phase wavelet C model was generated to evaluate the differences between zero and minimum-phase data because seismic data can be zero, minimum, or mixed phase.

The Cypress Sandstone thickens by more than 30 feet between wells 488 and 550 (fig. 106). The low-velocity Ridenhower shale has been scoured and replaced by the Cypress sandstones. Because of the Cypress scouring, all three synthetic models show a change in seismic reflection character between the two wells. Line ISGS92-04 (fig. 102) and the synthetic models both show a discontinuity in the same time interval; however, the seismic character change between seismic and synthetic models is not identical in each interval. Lack of a perfect match could be due to an imperfect geologic model or a wavelet that is not identical to the actual seismic.

The Yankeetown calcareous sandstones stratigraphically above the Renault Limestone are discontinuous along line ISGS-92-04. As shown in the single lithofacies models, these

Figure 103 Synthetic seismic model based on the geologic model using wavelet "A" (see text) (Leetaru in prep.).

Figure 104 Synthetic seismic model based on the geologic model using wavelet "B" (Leetaru in prep.).

sandstones will modify the reflection characteristics of the Aux Vases interval for higher frequency data. However, for the lower frequency wavelet A model, which is closer to the acquired seismic in frequency, these changes in reflection character would be minimal.

The thickness of the Renault Limestone varies by a few feet along line ISGS-92-04, but in other areas of King Field, the thickness of the Renault Limestone varies by more than 10 feet. The seismic reflection character changes should have responses similar to those produced by varying the thickness of the Yankeetown calcareous sandstone.

Along line ISGS-92-04, wells 488 and 2377 have the thickest clean Aux Vases sandstone reservoir. Well 1337 is a dry hole because the Aux Vase reservoir is calcareous. Wells 550 and 478 have thick Aux Vases limestone below the reservoir, and the reservoir interval is thinner. As also shown by the simpler geologic model, the better quality Aux Vases reservoirs are characterized on the seismic section by amplitude increases at the Ste. Genevieve reflector.

Figure 105 Synthetic seismic model based on the geologic model using wavelet "C" (Leetaru in prep.).

Figure 106 Geologic model along ISGS-92-04. Note thickening of Cypress and scouring of the Ridenhower (Leetaru in prep.).

The variation of seismic character with lithofacies was also present on the other three seismic lines; however, the change was more subtle. Not all the mapped changes in lithofacies could be discerned by seismic. This lack of correlation may have been due to incorrect geologic extrapolation of the well data because none of the wells were located directly on the seismic line. A second reason for a different relationship between seismic character and lithofacies is that the lithofacies changes were occurring below the lateral seismic resolution.

Data Quality and Economics

The seismic program was acquired as 60-fold data. As of this report, the cost of acquiring and processing 2-D 60-fold data is approximately \$7,000 to \$8,000 per mile; whereas 30- and 15-fold data cost \$5,500 to \$6,500 and \$4,500 to \$5,500 per mile, respectively. (Fifteen-fold data are no longer commonly run, and these costs are subject to the size of the program and shooting conditions [Allen Lever, Signature Geophysical, personal communication 1994].) During processing, every other trace was removed from the original data to approximate 30-fold data and again to approximate 15-fold data. The results of the processing indicate that although 60-fold data are better quality, the 30-fold data could be used for seismic stratigraphy (fig. 107). The 15-fold data had too much noise and too little stratigraphic information to be recommended for a stratigraphic seismic acquisition program.

The quality and resolution of seismic varies with the geology. Reservoirs shallower than 2,750 feet should have a substantially higher dominant frequency and thus greater resolution than the King Field seismic program. At 200 milliseconds or less, the dominant frequency is 80 Hz, and the high frequency component of the seismic wavelet may approach 120 Hz.

Reflection Character Analysis and Improved Oil Recovery

Problems in prediction of reservoir continuity have been reported. Barber et al. (1983) showed that reservoir heterogeneity cannot be accurately predicted from wireline logs and that the closer the well spacing, the greater the reservoir heterogeneity. Waterfloods in the Aux Vases do not match expectations based on the geologic model (B. Podolsky, Podolsky Oil, personal communication 1990). Seismic reflection character analysis using high frequency data can be used to evaluate reservoir continuity, define boundaries between reservoir and nonreservoir lithofacies, and develop a better geologic model for reservoir continuity in the Aux Vases reservoir. Correct evaluation of reservoir boundaries would enable an operator to accurately place injector and producer wells in a waterflood or secondary recovery project.

Changes in reflection character can be used to map reservoir compartmentalization. The Aux Vases reservoir at King Field can be used as an analog for other reservoirs in cratonic basins where a significant change in seismic impedance relates to changes in lithofacies. Seismic character analysis within cratonic basins can only be accomplished with high-frequency seismic data. The higher the frequencies, the better the resolution of seismic events.

An analysis of this 2-D seismic data suggests that high resolution seismic could be an effective tool for reservoir studies in mature oil fields. The 2-D seismic is limiting in that lithofacies changes in the reservoir are rapid (within one well spacing of 660 feet); it is impossible to accurately project changes between the lines. An effective seismic program for reservoir characterization should evaluate closer spacing of lines or a 3-D seismic program.

TASK 10: CLAY MINERALS, MUD CLEANOUT ACID EXPERIMENTS, AND REACTION PATH MODELING

CLAY MINERALS

- Aux Vases and Cypress reservoirs can be distinguished on the basis of clay content.
- Aux Vases clay minerals are distinguished by chlorite; Cypress clay minerals are distinguished by kaolinite.

Figure 107 Experimental differences (see text) between 15-, 30- and 60-fold data (Leetaru in prep.).

- Clay minerals affect log interpretations and thus oil recovery.
- New clay mineral analytical methods were developed for this project.

To study and classify reservoirs in the Illinois Basin for the purpose of improving the recovery of in-place mobile oil, it was necessary to characterize the clay and associated nonclay minerals of both the Aux Vases and Cypress Sandstones. Clay minerals are relatively simple to analyze, yet a single sample yields considerable information.

Possible effects of clay minerals on managing a reservoir and recovering oil are detailed elsewhere (Eslinger and Pevear 1988). Understanding clay minerals, although present only in

small amounts, is critical for several reasons: (1) They are the most accessible indicators of the diagenetic history of these units. (2) They occur as grain coatings and pore linings, so fluids moving through the rock are more often in contact with clay minerals than with framework grains. (3) Clay mineral coatings preserve porosity by inhibiting development of overgrowths on framework grains (Heald 1965, Cecil and Heald 1967, Pittman and Lumsden 1968, Stackelberg 1986, McBride 1989), specifically in the Cypress Sandstone of the Illinois Basin (Bosse 1986). Clay mineral content in the approximate range of 4% to 10% is optimal—enough clay to coat pores and prevent overgrowths, but not so much as to reduce permeability (Houseknecht and Ross 1992). (4) On the negative side, clay minerals can collapse, expand, or break loose, thus blocking pore throats. (5) Clay mineral reactions with well treatment fluids can reduce oil recovery because of precipitation of silica, alumina, or FeO , gels and the "opening" of nonswelling clay minerals to produce expandable clay minerals.

We examined 245 samples from 16 fields. XRD analyses were made of 167 Aux Vases, 72 Cypress, and six Bethel samples. The original goal was to develop and modify analytical methods that would generate an approximate analysis of the clay and nonclay mineral content. In the course of the project, we modified our goals to establish XRD methods that would provide results comparable in accuracy and precision with those from chemical analyses. Quantitative representations of illite, mixed-layered illite/smectite (I/S), chemically and structurally variable chlorite, kaolinite, quartz, calcite, normal and ferroan dolomite, K-feldspar, plagioclase, and pyrite-marcasite were required. The improved techniques were applied retroactively so that earlier results would remain comparable with later findings.

Many of the chlorites are actually mixed-layered clay minerals composed of a 7Å layer epitaxially intergrown with a chemically variable, 14Å chlorite layer. This discovery and the XRD patterns of illite and mixed-layered illite/smectite required the collection of XRD scans from <2 µm and finer fractions and the development of XRD peak measurement methods and heat treatments designed to refine analyses of these clay minerals.

Clay minerals have conventional morphologies in the Cypress (figs. 74, 113, 114) but indistinct morphologies in the Aux Vases (figs. 73, 112). In these two siliciclastic reservoirs, clay minerals occur as pore linings and grain coatings, within calcite cement and carbonate framework grains, and beneath quartz overgrowths (Howard and Whitaker 1988). Our methods adequately measure clay mineral content and variety on a total clay basis.

Methods

Sample preparation and quality assurance procedures are on open file at the ISGS (Oltz 1993).

XRD data were obtained using a Scintag® diffractometer with a DMS® operating system. This diffractometer uses CuK_α radiation, a liquid N_2 -cooled Germanium detector, two Solier slits, a 2-millimeter (mm) divergence slit, and a 4-mm slit at the detector. The Profile Fitting® program used to measure peak areas is part of the DMS® system. Peak width measurements from <2-µm samples were made at one-half the peak height above background. Peak widths from <16-µm samples were obtained from the Profile Fitting® program. Widths measured by this program were compared with those made by measuring the peak width from a graphic display of a $3^\circ 2\theta$ increment, including the peak of interest. The latter provided more reproducible results, so most values used in this report have been measured by the latter method.

The width of the chlorite 003 peak divided by the chlorite 004 peak was used as a measure of the 7Å layers present (Reynolds et al. 1992). The area of the chlorite 004 peak divided by the area of the chlorite 003 peak was used as a measure of Fe content. The method of measurement of the amount of illite in I/S was that of Moore and Reynolds (1989). The percentage of I/S in the <16-µm samples was determined as the increase in peak intensity of the 10Å peak after heating at 325°C, when compared with the illite peak on the trace of the ethylene glycol-solvated sample.

General Results

Appendix XI gives the relative percentages of each clay mineral, the estimate of total clay mineral content (CI), the clay and nonclay mineral percentages on a whole-rock or bulk basis, and, for measurable chlorite peaks in <16- μ m and <2- μ m fractions, peak area ratios (004/003) and peak width ratios (003/004) (figs. 108, 109). Scanning electron microscope (SEM) images show the clay minerals to be pervasive, coating virtually every grain in the reservoir facies in the Aux Vases Sandstone (figs. 73, 112). They also show scattered examples of flame structures of illites, rosettes of chlorite, and euhedral vermicules or books of kaolinite in the Cypress Sandstone (fig. 74). In both reservoirs, partly decomposed feldspars among the framework grains create secondary porosity. Carbonates, as cement and framework grains, occur erratically. Clay-mineral-rich layers, fairly common in the Aux Vases as clay drapes, are a concern because they may distort the average composition of the strata.

The 149 samples of the Aux Vases Sandstone from nine producing fields, in which XRD peak measurements of chlorite W3/W4 and A4/A3 were made, contain relatively Mg-rich chlorite in the clay-sized fraction (Appendix XI). All samples contain significant amounts of illite and illite-rich I/S. The average illite: I/S: chlorite is 40:30:30. Two samples from the base of the reservoir in a Stewardson Field well contain detectable amounts of kaolinite. As in most other Paleozoic shales in the Illinois Basin, illite dominates the clay-sized fraction of shales associated with the Aux Vases and Cypress Sandstones. The 44 samples of Cypress Sandstone used for chlorite determinations are from five producing fields, and they contain subequal amounts of kaolinite and illite and lesser amounts of I/S and comparatively Fe-rich chlorite. The kaolinite: illite: I/S: chlorite is approximately 30:30:20:P20. A few of the 167 <16- μ m samples of the Aux Vases contain traces of smectite; none of the XRD-analyzed samples from the Cypress contains smectite.

Chlorite Only one of the fields sampled, Richview Field, had no detectable chlorite in the Cypress Sandstone. Chlorite content varies more in the Cypress ($1.1 \pm 1.1\%$) than in the Aux Vases reservoirs ($1.0 \pm 0.8\%$). The sample with a maximum amount of chlorite (4.7%) is from the Tamaroa Field.

Ratios of odd-ordered and even-ordered peaks in the 00l series for chlorites of the Aux Vases and Cypress Sandstones show significant variation when both areas and peak widths at half-peak height above background are compared. Of 193 samples (149 Aux Vases and 44 Cypress) for which such measures were made, 106 Aux Vases and all 44 Cypress samples have width 003 / width 004 > 1.06, 80 (Appendix XI). For comparison, chlorites in 124 samples from eight other reservoirs in five other petroleum provinces were examined. There is a rough, positive correlation between Fe-content of the chlorite and the amount of broadening in the Aux Vases and Cypress samples: the more Fe-rich, the broader the 003 and the greater the W3/W4 (fig. 110). However, several samples with approximately 0.5 Fe/3 octahedral sites (relatively Mg-rich) had 003 peaks approximately twice as broad as their 004 peaks.

SEM/EDX analysis of individual grains of eight samples of Aux Vases selected to represent the maximum variation in Fe and 7 $\text{\AA}$ layer content (based on XRD and SEM/EDX analysis of individual grains) confirmed this assessment. EDX results also showed that chlorites from the Aux Vases are more Al³⁺-rich than those reported from most reservoir studies. The weak 14 $\text{\AA}$ chlorite peaks of the Fe-rich samples were unchanged after heating to 550°C; whereas the intensity of strong 14 $\text{\AA}$ peaks of the Mg-rich chlorites increased, which accords with previous observations that some chlorites show increased 14 $\text{\AA}$ peaks after 550°C and some do not. Table 8 includes the elemental compositions of representative chlorites for comparison with natural samples. Figure 111 compares the EDX-derived Al: Mg: Fe with calculated ones for chlorites with dioctahedral 10 $\text{\AA}$ layers and trioctahedral brucite-like sheets (i.e., di, tri chlorite). This comparison shows that Aux Vases chlorites are closer to di, tri chlorites.

Figure 108 Three XRD traces of a representative sample of the Aux Vases Sandstone, prepared as an air-dried, a glycol-solvated, and a heated sample of the <16 μm fraction (Hughes and Moore in prep.).

Figure 109 An XRD trace of the air-dried sample of the <16 μm fraction from the Cypress (Hughes and Moore in prep.).

Figure 110 Individual samples of Aux Vases (●) and Cypress (■) showing the relation of percent 7 Å layers intergrown in chlorite plotted against the amount of Fe in octahedral sites (Hughes and Moore in prep.)

Figure 111 Average of Aux Vases fields (□) and Cypress fields (▲) of the same two variables plotted in figure 110. The variables W3/W4, or width of 003 over width of 004, is our measure of 7 Å layers intergrown in chlorite (Hughes and Moore in prep.).

Table 7 Chemical composition of minerals, as determined by SEM/EDX

Sample, mineral	% Si	% Al	% Mg	% Fe	% K	% Na	% Ca
3209A, chlorite	17.9	13.0	10.5	12.6	0.5	1.6	—
3209A, chlorite	11.6	14.7	7.9	22.1	—	3.5	—
3209A, chlorite	11.8	14.4	7.2	21.9	0.2	4.4	—
3209A, chlorite	18.3	11.0	11.1	14.0	0.6	1.7	—
3209A, chlorite	13.0	14.1	5.9	24.4	0.2	2.4	—
3261, chlorite	15.7	12.1	10.8	16.0	0.3	2.7	—
3261, chlorite	18.6	14.2	7.4	14.2	1.0	0.9	—
3261, chlorite	17.2	12.2	8.5	13.5	1.7	3.7	0.3
3261, chlorite	16.3	13.2	9.6	13.9	0.9	3.0	0.1
3261, chlorite	14.1	14.2	8.1	15.7	1.1	4.7	—
muscovite, theoretical	41.2	39.6	—	—	19.1	—	—
3261, illite*	57.7	20.8	0.0	0.0	20.6	0.9	—
3261, illite*	57.0	20.1	0.0	0.3	21.8	0.8	—
3261, illite*	47.0	17.6	4.4	17.5	11.1	2.3	—
3261, illite*	57.0	20.3	0.0	1.1	20.1	1.4	—
3209A, illite*	47.1	38.2	0.0	3.8	10.9	0.0	—
3209A, illite*	54.3	33.0	1.5	4.5	6.7	0.0	—
3209A, illite*	46.0	36.5	1.6	3.1	12.7	0.0	—
3209A, illite*	43.9	36.1	1.5	6.6	11.8	0.0	—
3209A, illite*	47.5	36.1	2.2	2.1	12.1	0.0	—
3209A, illite*	46.9	28.8	3.8	8.1	12.3	0.0	—
albite, theoretical	62.8	20.1	—	—	—	17.1	—
3209A, albite*	59.8	18.5	0.0	1.0	0.0	21.7	—
3209A, albite*	59.8	18.4	0.0	1.0	0.0	21.7	—
3209A, albite*	58.2	20.2	0.0	1.7	0.0	21.6	—
3261, albite*	56.2	21.2	0.0	0.4	1.0	22.7	—

* normalized to 100%

Illite and Illite/Smectite Occurrence of these two minerals is widespread in the samples; however, the illitic clay minerals of these reservoirs have weak peaks relative to chlorite and kaolinite, so that characteristics of illite and I/S were difficult to measure. In most samples, illite and I/S coexist. Of 38 samples in which the percentage of illitic layers in the I/S could be measured, illite varies from about 50% to 85%. Amounts of I/S are small enough so that these measurements have a probable margin of error of $\pm 10\%$ to 15% . Most XRD traces of air-dried samples had an I/S peak on the low-angle side of the $10\text{\AA}$ peak of illite (fig. 109). Upon glycolation, the I/S peak disappeared, and after heating at 325°C , it formed a poorly defined shoulder on the low-angle side of the $10\text{\AA}$ peak (fig. 108).

For all Aux Vases samples, illite averages $1.5 \pm 1.4\%$ and I/S averages $1.1 \pm 1.1\%$. For all Cypress samples, illite averages $1.8 \pm 2.0\%$ and I/S averages $1.3 \pm 1.3\%$. The clay fraction of Aux Vases samples from the Oakdale Field is dominated by illite. (Even in these samples on a whole rock basis, it averages only about 2%.) This field is distinct in another way. In 13 of 33 samples, no I/S was detected.

Table 8 Chlorite compositions compared to theoretical

	Al*	Al*9	Mg*	Mg*9	Fe*	Fe*9	Si*	Si*9	Mg*	Mg*9
di,tri Mg	0.57		0.43		0.00		0.42		1.00	
" Mg2Fe	0.48	0.36	0.24	0.29	0.28	0.35	0.42	0.58	0.47	0.46
" Mg1.5 Fe1.5	0.44	0.33	0.17	0.18	0.39	0.49	0.42	0.44	0.30	0.26
" MgFe2	0.41	0.33	0.10	0.16	0.48	0.50	0.42	0.45	0.18	0.25
" Fe	0.36	0.30	0.00	0.31	0.64	0.39	0.42	0.63	0.00	0.44
Si2Al4Mg1.05Fe2.15	0.43	0.32	0.10	0.13	0.47	0.55	0.34	0.47	0.18	0.19
.9Al-di,tri(2Fe:1Mg)	0.38		0.11		0.51		0.43		0.18	
.8Al-di,tri(2Fe:1Mg)	0.34		0.12		0.54		0.45		0.18	
.7Al-di,tri(2Fe:1Mg)	0.31		0.12		0.57		0.46		0.18	
.6Al-di,tri(2Fe:1Mg)	0.28		0.13		0.59		0.48		0.18	
tri,triMg6	0.22		0.78		0.00		0.62		1.00	
tri,triMg5Fe	0.19		0.55		0.25		0.62		0.69	
tri,triMg4Fe2	0.17		0.39		0.44		0.62		0.47	
tri,triMg3Fe3	0.15		0.26		0.59		0.62		0.30	
tri,triMg2Fe4	0.13		0.15		0.71		0.62		0.18	
tri,triMgFe5	0.12		0.07		0.81		0.62		0.08	
tri,triFe6	0.11		0.00		0.89		0.62		0.00	

Unless otherwise stated, Me ratios of std chlorites(di,tri tet = Si2.44 Al1.56)

Al* = Al/Al+Mg+Fe; Al*9 = ratio for sample 3209; Mg*, Mg*9 = Mg/Al+Mg+Fe;

Fe*, Fe*9 = Fe/Al+Mg+Fe; Si*, Si*9 = Si/Al+Si; Mg*, Mg*9 = Mg/Mg+Fe;

di,tri = dioctahedral, trioctahedral chlorite; tri,tri = both layers trioctahedral;

Mg2Fe, Mg3Fe3 = positions occupied by Mg or Fe in chlorite; .9Al, .8Al, etc. = Mg2Fe, Mg3Fe3 ratio Al in octahedral sheet of 10Å layer of chlorite.

Bold = best chlorites from real data; bold and italics = best match of theoretical with real data.

Kaolinites As examination by SEM indicated, all the kaolinites in samples from fields in the Cypress and Bethel Sandstones occur as euhedral, vermiform, or finely intergrown, structurally well ordered crystallites. According to XRD, the kaolinite is without interstratified expandable layers, and as observed with the petrographic microscope, often closely associated with altered feldspar framework grains.

Quartz Most samples from the Aux Vases and Cypress reservoirs are dominated by quartz. The average for the Aux Vases is $78 \pm 21\%$ quartz, much of the variation resulting from six or so calcareous zones. The average quartz content of the Cypress samples is $83 \pm 11\%$.

Feldspars Most samples contain both K-feldspar and plagioclase. The average feldspar content of the Aux Vases is $1.5 \pm 1.1\%$ K-feldspar and $2.6 \pm 1.5\%$ plagioclase. Feldspars in the

Cypress average $0.8 \pm 2.0\%$ K-feldspar and $5.2 \pm 7.0\%$ plagioclase. The average and standard deviation for plagioclase in the Cypress is skewed by high plagioclase values for samples from Tamaroa Field (Appendix XI). The determinations were made before we obtained new grinders, and the sample was insufficient to regrind the original materials; therefore, these values are less reliable than those for other fields. Both feldspars were also typically enriched relative to quartz in the $<16\text{-}\mu\text{m}$ separates.

Carbonates Calcite is widely present as cement in these sandstones ($14 \pm 21\%$ in the Aux Vases, $4.6 \pm 8.0\%$ in the Cypress). Dolomite is an order of magnitude less abundant ($0.9 \pm 4.7\%$ in the Aux Vases, $0.2 \pm 0.6\%$ in the Cypress). Calcite and dolomite are also sometimes present as framework grains. In a few cases, ferroan dolomite seems to be abundant. However, the determination of iron content of dolomite probably was not made with adequate consistency to evaluate occurrences of the two types of dolomite.

Halite and Pyrite-Marcasite Halite was detected in some bulk analyses by XRD. Analysis by SEM/EDX has shown that these samples contain euhedral halite cubes. A form of FeS_2 was observed in several samples. It is fairly abundant in a few, but not present in enough samples to justify calculation of percentages. Because the XRD peaks were weak, no determination could be made of whether the phase is pyrite, marcasite, or both.

Statistics

We used an approximate t-test, sometimes known as the separate-variance t-test, for independent samples because the sample sizes n for the two populations are different and the smaller sample size has the larger variance (Ott 1988):

$$t' = \frac{\bar{X}_1 - \bar{X}_2}{\sqrt{\frac{s_1^2}{n_1} + \frac{s_2^2}{n_2}}} \quad [3]$$

The t' values in table 9 show that characteristics measured from the $<2\text{-}\mu\text{m}$ preparations from two independent, approximately normal populations, the widths of the chlorite (003) and chlorite (004), the ratio of their widths, and the ratio of their areas can be used to distinguish one population from the other at a confidence level of 99.9%.

Table 9 Statistics for distinguishing the Aux Vases from the Cypress Sandstone

	C(003)	C(004)	W3/W4	A4/A3
For all Cypress, $n = 26$				
Ave	0.57	0.295	1.95	3.74
Std dev	0.157	0.065	0.47	1.72
t'	196	-4.4	38.46	14.77
	3.37	3.28	3.31	3.37
t' for $\alpha = 0.001$	31	44	40	31
mdf				
For all Aux Vases, $n = 95$				
Ave	0.498	0.364	1.43	1.85
Std dev	0.103	0.089	0.42	1.16

*mdf = modified degrees of freedom

Figure 112 demonstrates accuracy and precision for measuring the quantity of carbonates in our samples. A set of samples, for which the carbonate content was zero to nearly 100%, was chosen. After standard bulk and clay mineral XRD determinations were made, 2 g of each sample was weighed and reacted with acetic acid, and then reweighed after drying. The calcite-dolomite content determined by acetic acid weight loss exactly correlated with that determined by XRD, a correlation coefficient of 0.98.

Measures of reproducibility from bulk XRD analyses averaged about $\pm 5\%$ of nonclay minerals in the 20% to 100% range. Variation increased to about $\pm 10\%$ or more as the amount of nonclay minerals decreased below 20%. Although we have satisfactory precision in our measurements of quantities of clay minerals, our accuracy is unmeasured.

General Discussion

The Aux Vases and Cypress Sandstones can be distinguished on the basis of their clay mineral content. The chlorites of the Aux Vases are more Mg-rich than those of the Cypress. They also are unusual in that chlorites from both formations are mixed-layered 7Å/chlorites, the 7Å component present up to about 20%. All but three of the 72 Cypress samples contain kaolinite; whereas kaolinite is present in only two of the 167 samples of Aux Vases; all five of the exceptions may be misclassified stratigraphically or may represent analytical errors.

The clay mineral suites in both reservoirs appear to be primarily diagenetic rather than detrital. The main evidence for this is the SEM photographs showing distinct, euhedral crystal forms or fiber morphologies. XRD and SEM/EDX data from Aux Vases samples are anomalous in this study; the best explanation for the anomalous occurrences in the Aux Vases is that chlorite, illite, and I/S exist as intergrown, not interstratified or mixed-layered, crystallites that make up the pore linings. The EDX determinations of higher-than-normal Al_2O_3 in chlorite in the Aux Vases suggest that this mineral may be made up of a dioctahedral 10Å layer and a trioctahedral brucite-like layer; that is, it is di-tri chlorite (table 8). Most chlorites from oil reservoirs described in the literature are Fe-rich and have tri-tri structures.

Other questions of origin and diagenetic reaction pathway are whether detrital feldspars, detrital clay minerals, diagenetic clay minerals such as smectite, or more than one of these were the precursor of the illite, I/S, and chlorite in these units. Kaolinites appear to be closely associated with altered feldspars and the reaction sequence seems obvious. For the more widespread and abundant pore-lining, pore-filling, and grain-coating clay minerals, the parent materials are far less obvious.

Chlorite Broadening of the odd-ordered peaks of the 001 series is the most striking feature of the chloritic minerals in the Aux Vases and Cypress Sandstones. This broadening, quantified by dividing the width of the 003 peak by the width of the 004 peak ($W3/W4$), indicates that there is a 7Å layer epitaxially intergrown with the 14Å chlorite layers. Reynolds et al. (1992) have shown that this is the only acceptable interpretation.

General agreement is lacking on the nature of the 7Å layer in these mixed-layered chlorites. Reynolds et al. (1992), in their study of samples from the Tuscaloosa Formation, refer to it as serpentine, a general term that includes berthierine. Hillier and Velde (1992) interpret it to be kaolinite because of the relatively high Al content in their samples from the North Sea. Lahann et al. (1992) suggest, again based on samples from the North Sea, that it is odinite. We think it is berthierine.

Statistical comparison of characteristics of the 7Å/chlorite mixed-layered clay mineral in these two reservoirs clearly distinguishes one from the other (table 7). Similar comparisons show promise for distinguishing one field from another. Because we chose to measure peak width of the chloritic minerals for a large number of samples, these measurements are presented without an adjustment for instrumental broadening, which would decrease the measured width, or for the variation of peak width by the cosine of the angle of diffraction, which would increase the width. Such adjustments for large numbers of samples require too much

Figure 112 Diagenetic clay minerals coating sand grains in a typical Aux Vases reservoir sample. Sample was prepared using critical point drying technique to preserve morphology of clay minerals (Hughes and Moore in prep.).

Figure 113 Typical rosette of Fe-rich chlorite in a Cypress sandstone Reservoir sample from Mattoon Field (Hughes and Moore in prep.).

Table 10 Structural formulas for chloritic minerals

Range for sedimentary chlorites (Curtis et al. 1984, Hillier and Velde 1991)

Berthierine (A. from Hughes et al. 1992, B. from Brindley 1982)

Odinite (Bailey 1988)

time compared to the increased usefulness of the measurements (Reynolds et al. 1992). These measurements, therefore, are approximate but conservative.

The amount of broadening of odd-order chlorite peaks in project samples and samples from other provinces representing a variety of environments of deposition (table 11) varies from zero or subtle to broad enough to smear the (001) peak beyond recognition. Of 121 project samples for which measurements of the widths of the chlorite peaks were made, 106 had $W3/W4 > 1.06$. Any value greater than 1.00 for a ratio of an odd-order basal reflection divided by an even-order basal reflection indicates that there are 7Å layers intergrown with the 14Å layers of chlorite. Because precision for the width of chlorite peaks had a first standard deviation of ± 0.06 , we assumed that any ratio of the widths of $W3/W4 > 1.06$ indicates interstratified 7Å layers. In the absence of 7Å material, all chlorite peaks of the basal series

Figure 114 Typical fibrous illite in a Cypress reservoir sample from Parkersburg (Seyler in prep.).

should have had the same width (Reynolds et al. 1992). Those values in Appendix XI that fall below 0.94 are aberrations, usually associated with the interference of the kaolinite (002) peak with the chlorite (004) peak. Because all the Cypress samples had kaolinite in them, we consider the measurements of the width of the chlorite (004) peak for Cypress samples less precise than those for the same peak in the Aux Vases samples. There are two other factors influencing peak width measurements. For samples with large amounts of illite and small amounts of chlorite, the (002) peak of illite, especially if quite broad, interferes with the (003) peak of chlorite. The other factor is that if the peaks are smaller than approximately 100 cps, precision is poor.

Table 11 Reservoirs with 7Å/chlorite mixed-layered clay mineral

Formation	Age	Province & Bally type ^a	Depositional environment	No. samples (fields)	% with chl	% with 7Å/chl
Aux Vases	Miss	IL, 121	SMOB	95 (8)	98	84
Clearwater	Cret	AL, 221		—	—	
Cypress	Miss	IL, 121	SMOB	26 (6)	100	100
Tilje	Jur	NS, 1211	TDDS	17	100	
Udang	Olig	IND	Lacustrine	28	100	89
"Angola"	Cret	CUA, 1141	Cont. rift	6	**	**
Tar Springs	Miss	IL, 121	SMOB	8	87	87
Terry	Cret	DB, 221	SMOB	7	86	86
Tuscaloosa	Cret	GC, 1143		5	100	100
Rotliegende	Pm	NS, 1211	Aeolian	53 (2)	79	75

AL = Alberta; Cont. rift = continental rift basin; CUA = offshore Angola; DB = Denver Basin; GC = U.S. Gulf Coast; IL = Illinois Basin; IND = offshore Indonesia; NS = North Sea; SMOB = shallow marine offshore bar; TDDS = tide-dominated delta system.

**Measurements of W003/W004 average 1.04 ± 0.017 , too close to our margin of error to us to conclude that 7Å layers are definitely present. In the Rotliegendes, samples are from the South Valiant and the Vanguard Fields. ^aType of depositional basin from Bally (1980).

Illite and I/S In most fields, the illitic clay minerals of these reservoirs are present in small amounts relative to chlorite and kaolinite, so that characteristics of illite were difficult to measure. Higher levels of K⁺ and Al³⁺ observed by EDX in individual grains from Oakdale Field relative to the levels observed for Zeigler Field may reflect detrital versus diagenetic origin. The fibrous illite, as well as the rosettes of chlorite, seen in SEM photographs of the Cypress are clearly diagenetic. The indistinct morphologies of illite and I/S in the Aux Vases makes an interpretation less clear. We assume that the mixed-layered chlorites are diagenetic and therefore either illite or I/S or both are diagenetic.

Kaolinite Why is there kaolinite in the Cypress but not in the Aux Vases? There are remnants of partly altered framework feldspar grains in both formations, and we assume that the Al³⁺ and Si⁴⁺ ions from dissolution of the feldspars are the most logical source for formation of kaolinite. Chesterian-Pennsylvanian sediments are noted for an almost universal occurrence of kaolinite (Hughes, DeMaris, and White 1992). This occurrence is associated with the establishment of swamps that resulted in the thick coals of the Pennsylvanian sequence. The

swamps may reflect a change from pre-Chesterian paleosols that developed under arid conditions to Chesterian and Pennsylvanian paleosols that developed as humid laterites. This change would have caused large increases in the amount of H^+ -rich fresh water that percolated into recently buried sands of the Cypress; the lower pH and higher organic acid content of this water may have promoted kaolinite formation. Perhaps the Aux Vases, which was located below the Chesterian rocks and contained high carbonate, pH-neutralizing concentrations, was too far from these percolating, H^+ -rich fresh waters to be significantly altered.

A second possibility (or one that works with the explanation above) is that kaolinite in the Cypress Sandstone suggests a nearby fluvial environment (Stonecipher and May 1990), whereas the Aux Vases was deposited in a more marine environment.

Smectite Smectite rarely occurs in these samples. In every case in which the cores or biscuits were resampled (from nonexposed surfaces), no smectite was detected in the second sample. Drilling mud routinely penetrates the edges of cores and cuttings, and sampling procedures must be well designed and carefully practiced to avoid this problem. It should be noted too that, when present in small amounts, smectite from drilling mud had noticeably broadened XRD peaks, which might otherwise seem to support the erroneous conclusion that this occurrence of smectite was part of the mineral suite of the sandstone.

Feldspars The observed enrichment of feldspars relative to quartz in the <16- μ m separates, as compared to the whole sample, indicates that the feldspar grains are smaller on average than the quartz grains in the same sample. This difference is partly explained by feldspar framework grains undergoing postdepositional alteration, which breaks them into smaller fragments. The size difference may also reflect, in part, original differences in the size of quartz and feldspar framework grains.

Carbonates and Others We found no strong correlations between carbonate content and other features of the mineral suite. This may partly reflect the inadequacy of our methods to distinguish carbonate cement from carbonate framework grains and normal ferroan dolomite. A greater understanding of the distribution of carbonate and associated clay minerals is possible; however, this understanding would require an expanded experimental approach, including separation of clay minerals from pores, carbonate cement, and carbonate framework grains, and correlation of numerical measures of petrographic details with results from XRD and SEM/EDX. Halite occurs as a product of evaporation of natural pore-filling brines after sampling. Pyrite-marcasite may result from diagenesis shortly after deposition or during oil emplacement.

Mineralogical Effects on Oil Recovery

The many potential effects of clay and nonclay minerals on recovery of oil are both positive and negative (Eslinger and Pevear 1988). Even taking into account the possible bias that we have selected siliciclastic reservoir rocks containing chlorite, mixed-layered 7Å/chlorite appears to be the grain coating that most often inhibits overgrowths on framework grains and preserves porosity in the process. We have seen them on plagioclase, K-feldspar, and biotite as well as on quartz. Apparently, some surfaces are selectively coated, although when and how is variously interpreted. Most of the arguments about the origin of chlorite, illite, and I/S also could be applied to interpretations of clay mineral coatings of framework grains.

Clay minerals are colloidal particles and extremely sensitive to changes in pore water chemistry. In particular, replacement or dilution of brines with fresh water can result in complete dispersion of clay minerals and loss of permeability. Conversely, it is theoretically possible to force flow through low-permeability zones in a reservoir by first dispersing the clays in high-permeability conduits and plugging those avenues of flow.

Chlorite, in reacting with acid, has been shown to form alumina, FeO_x , and silica gels at other well bores (Curtis et al. 1984, Simon and Anderson 1990). These clog flow units and contribute to loss of production. Chlorite, illite, and other nonswelling clay minerals also can "open up" to form expandable clay minerals during treatment of the well with cleanout and enhanced recovery fluids, and thus plug pore throats. That "opening up" happens in natural situations can be seen in the reaction or opening up of chlorite to vermiculite that is common in some soils (Hughes et al. 1994).

In an oil-water system, clay minerals may be dispersed in the oil (oleophilic) or water (hydrophilic) phase. Surfaces coated by either of these phases repel each other. Therefore, oil recovery might be enhanced by making oleophilic clay mineral surfaces repellent to oil.

Future Directions

A need exists for analysis of mineral content of shales associated with Aux Vases and Cypress Sandstones and of these sandstones where they are not reservoirs. Shales associated with these sandstones and shaley partings within them seem to contain more illite and I/S than the reservoirs contain on average. This observation might suggest that shale-rich intervals and nonreservoir sandstones contain mostly detrital illite, whereas clay minerals in the reservoir are primarily diagenetic. Conclusive evidence in this area could provide a new level of control for studies of individual fields and strata throughout the Illinois Basin.

Further refinements in the chlorite and illite-I/S determinations could be made either by isolating the chlorite and illite-I/S fractions with a magnetic separator or by selectively dissolving the clay minerals with a stepwise dissolution technique. More details about the clay minerals could also be obtained from high-resolution transmission electron microscopy. Because few size fractionations and SEM/EDX and XRD experiments were made for this study, we believe more determinations of this type should be made and the entire database should be evaluated to better define "types" of chlorite and illite-I/S.

Even though chlorites containing 7Å interlayering have just been recognized and explained, there is every reason to believe that they are diagenetic or maturity indices. Therefore, further study of this variable seems imperative. In particular, we seem to have caught a glimpse of a transformation from a 7Å mineral to a 14Å mineral. We need to compare this maturity indicator with other types of maturity indicators. Furthermore, because this 7Å/chlorite mixed-layered clay mineral is so often found as a grain coating that inhibits quartz overgrowths, it deserves to be better understood just from the standpoint of preserving primary porosity and general reservoir quality. In addition, ^{18}O and H/D isotopic measures of hydroxyls from the outer parts of the structure of these clay minerals, compared with those from the interior of the structure, might reveal patterns of oil migration and "hot" versus "cold" areas of oil emplacement.

Conclusions

The Aux Vases and Cypress reservoirs can be distinguished on the basis of their clay mineral content. The clay mineral suite in the Aux Vases Sandstone is composed of illite, I/S, and Mg-rich chlorite. The Cypress contains subequal amounts of kaolinite and illite, and lesser amounts of I/S and Fe-rich chlorite. XRD data proved that pore-filling clay minerals in the Aux Vases samples, as seen on SEM/EDX images, resulted from intimate intergrowths of chlorite, illite, and I/S, not from some sort of mixed layering. The average clay and mineral content in the Aux Vases reservoirs is $3.5 \pm 2.8\%$. The average nonclay mineral content in the same reservoirs is $78 \pm 21\%$ quartz, $1.5 \pm 1.1\%$ K-feldspar, $2.6 \pm 1.5\%$ plagioclase, $14 \pm 21\%$ calcite, and $0.9 \pm 4.7\%$ dolomite. Cypress samples contain abundant, euhedral diagenetic kaolinite, illite-I/S with flame structures, and characteristic rosettes of chlorite. The average clay mineral content of Cypress samples is $5.4 \pm 3.7\%$. The average nonclay mineral composition for the Cypress is $83 \pm 11\%$ quartz, $0.8 \pm 2.0\%$ K-feldspar, $5.2 \pm 7.0\%$ plagioclase, $4.6 \pm 8.0\%$ calcite, and $0.2 \pm 0.6\%$ dolomite.

Chlorites of the Aux Vases and Cypress Sandstones are mixed-layered 7Å/chlorite clay minerals. This is shown by broadening of the odd-ordered peaks compared with the even-ordered peaks in the 00l series. Fe-rich chlorite and mixed-layered 7Å/chlorite lose XRD peak intensity or "breakdown" at lower temperatures (350–400°C) than do Mg-rich and noninter-layered chlorites. The dehydroxylation of 7Å interlayers causes intensity loss in the 7Å/chlorite. It is partly on this basis that we concluded that the 7Å layer in 7Å/chlorite is berthierine, which responds similarly to heating.

The mixed-layered chlorites in the Aux Vases and the Cypress range from Mg-rich to Fe-rich. There is a correlation between Fe-content of the chlorite and the amount of broadening, although several relatively Mg-rich samples have a W003/W004 of about 2. Analyses by SEM/EDX and XRD of the eight fractionated Aux Vases samples confirmed earlier XRD estimates of their Fe: Mg, Al in chlorites. These results also showed that chlorites from the Aux Vases are more Al_2O_3 -rich than those for Cypress samples and those reported in most reservoir studies.

The percentage of illitic layers in I/S, as measured in 38 samples, varies from about 50% to 85%. The EDX data for individual illite crystallites from the Oakdale and Zeigler Fields indicate that two types of illite are present. It seems reasonable to interpret these two types as detrital (high K^+ and Al^{3+}) and diagenetic.

K-feldspar, plagioclase, calcite, and dolomite are common in all fields. Calcite is present as cement and in framework grains, and ferroan dolomite is abundant in at least one field.

Clay minerals in these reservoirs may affect oil recovery by (1) coating grains, which inhibits quartz overgrowths thereby preserving porosity; (2) dispersing in fresh water and plugging pore throats causing loss in primary production; (3) reacting with well cleanout and enhanced recovery fluids and plugging the well bore with iron oxides and chlorite-derived expandable clay minerals; and (4) increasing recovery by changing oleophilic clay mineral surfaces to a hydrophilic state.

The new methods of analysis designed for this study have been shown to be comparable in accuracy to many chemical methods. We need improved methods that (1) use loss-on-ignition and/or x-ray fluorescence (XRF) to determine the clay mineral to nonclay mineral ratio; (2) distinguish the compositions of clay minerals at different sites (pores, grain coatings, carbonate cement, carbonate framework grains, and beneath quartz overgrowths); (3) use heat treatment and stepwise dissolution to improve prediction of the reactions of clay minerals with well cleanout and enhanced recovery fluids; (4) allow specific adjustments of the quantitative XRD factors for the clay minerals; and (5) isolate individual clay minerals for more detailed chemical and structural analysis; for example, to determine polytypes.

MUD CLEANOUT ACID

- The experiments conducted in this study are the first published research on the interaction between mud cleanout acids (MCA) and the Aux Vases Sandstones.
- Clay minerals constitute only 1% to 6% of the bulk mineral content of Aux Vases reservoir samples; however, they have very high relative exposure to natural or induced reservoir fluids because they line or bridge every pore. Therefore, the composition and response of these diagenetic clay minerals are of utmost importance when selecting drilling, completion, and injection fluids.
- With respect to acids, calcite is the most reactive pore mineral present in Aux Vases sandstone reservoirs. No calcite remained in Aux Vases experimental core samples after 4 hours of exposure to an MCA of 15% HCl and various additives or to 15% HCl alone. This suggests that use of MCA or only 15% HCl should increase the permeability of Aux Vases sandstone reservoirs; however, other factors may have a negative impact on reservoir permeability. These factors include the effects of acid on chlorite and mixed-layered illite/smectite, and the formation of sludges by reactions between poorly formulated mud acids and the Aux Vases crude oil. Our experiments showed that precipitates

derived from the reaction of pore minerals with 15% HCl were more numerous in variety and amount than those formed with MCA; 15% HCl alone should not be used in treating Aux Vases reservoirs.

- Fines were detected in the effluent from the coreflood experiments. Removal of calcite cement by MCA allowed sand and clay particles to be dislodged and migrate.
- The results of the static core soak experiments suggested that prolonged contact of acid with the reservoir rock could also result in leaching and disintegration of pore-lining diagenetic clay minerals. Rock-acid contact times of less than 1 day created fewer precipitates than those exceeding 2 days. Furthermore, abundance and variety of potential pore-occluding precipitates were greater in core samples soaked in pure 15% HCl than in samples injected with 15% HCl; overflushing of a well could reduce the detrimental effects of an acid cleanout.
- Results of oil-acid compatibility tests demonstrated that an oil sample from the Energy Field Aux Vases reservoir is acid-sensitive. No sludges were formed when crude oil was mixed with MCA. The MCA was probably compatible with the crude oil, whereas the 15% HCl was not.
- Mixed-layered illite/smectite in the Aux Vases reservoir rocks was sensitive to the salinity of injected waters in the samples tested. Injection of water with less salinity than the formation brine severely impaired permeability; and injection of water with additional salinity did not reverse the impairment. In Aux Vases reservoirs, it is necessary to inject only waters that have salinities equivalent to those of formation brines. If fresh water must be used, the reservoir should be preflushed with clay-stabilizing solutions.

The effects of mud cleanout acids (MCA) and injection waters on oil productivity of Aux Vases Sandstone reservoirs were investigated using cores from Zeigler, Dale Consolidated, Energy, and Boyd Fields. Aux Vases Sandstone reservoirs were chosen for the experiments because their oil production has been problematic. Sample studies using thin section petrography, scanning electron microscopy with energy dispersive x-ray analysis (SEM/EDX), and x-ray diffraction (XRD) analysis showed that diagenetic clay minerals consisting of a mixture of illite, mixed-layered illite/smectite, and chlorite are ubiquitous and line almost every pore. Consequently, introduced fluids such as MCAs and certain injection waters may preferentially react with the clay minerals or calcite cement rather than with the framework grains.

Coreflood experiments involved injection of a commercial MCA containing 15% HCl coupled with corrosion inhibitors, surfactants, and clay stabilizers; a second acid solution consisting of 15% HCl without these additives; and water of varying salinities. These experiments were conducted on Aux Vases core plugs, each 1 inch in diameter. Changes in the pore mineralogy of the samples caused by the impact of the two acid solutions were qualitatively evaluated by comparing treated and untreated samples with SEM/EDX analyses. All calcite was dissolved after about 4 hours of contact with the acid and resulted in an increase in permeability of 25% or more (fig. 115). Secondary byproducts formed and precipitated when one of the samples was treated with the 15% HCl. Available evidence suggests that leaching and disaggregation of chlorite and other diagenetic clay minerals occurred.

On contact with Aux Vases crude oil, the 15% HCl solution formed sludges, indicating that use of 15% HCl without proper additives will contribute to formation damage in Aux Vases Sandstone reservoirs.

Injection of water of lower salinity than the formation brine resulted in decreases in the permeability of the samples (fig. 116). The decrease is apparently caused by swelling of mixed-layered illite/smectite and migration of fines. Permeability reductions caused by injection of low-salinity water mixtures could not be reversed by later injection of water with higher salinities. Traditionally, operators have overcome formation damage caused by these fluids around the well bore by hydraulic fracturing.

Core flood experiments and qualitative analysis methods such as those described in this report should be used to determine compatible drilling, completion, and injection fluids that will enhance oil productivity from Illinois Basin Aux Vases reservoirs.

Figure 115 Plot of permeability increase versus contact time with MCA (Seyler and Haggerty in prep.)

Figure 116 Results of injection of varying brine salinities on permeability (Seyler and Haggerty in prep.).

FORMATION WATER CHEMISTRY AND MODELING OF FLUID-ROCK INTERACTION

- Geochemical characterization of oil reservoir formation waters is important in the study of the diagenetic history of sedimentary basins, and in reservoir analysis for application of improved oil recovery techniques.
- High salinities in Aux Vases and Cypress Sandstone brines originated at least partly as a result of halite dissolution, and subsequently, were modified by diagenetic reactions.
- Clay minerals and feldspars have apparently released potassium (K) and magnesium (Mg) into formation waters; the implication is that clay minerals in the Aux Vases and Cypress formations are largely detrital and/or were formed diagenetically prior to the emplacement of present subsurface waters.
- Variations in solute concentrations in different wells producing from the same formation in the same field can indicate a lack of communication between different parts of the same reservoir.
- Electrical resistivity and total dissolved solids content (TDS) data for formation waters can be used to calculate water saturation and porosity, two important parameters for reservoir analysis and management.
- Empirical relationships between the resistivity, TDS, and temperature of the Aux Vases and Cypress formation waters were developed.
- Computer simulations of mineral precipitation and/or dissolution reactions and accompanying porosity changes that would take place in improved oil recovery processes were conducted using several scenarios.
- These simulations were used to assess potential formation damage that can be caused by disturbance of the original physical-chemical state of an oil reservoir as a result of primary production or improved oil recovery processes.

Assessing the chemical composition of saline formation waters can be important in delineating the diagenetic history of sedimentary basins which, in turn, is useful for oil exploration and production. Because of the marine origin of most sediments, the origin of saline formation waters was generally thought to be seawater trapped in the pores of the sediments. However, recent studies by Bethke and Marshak (1990) have provided evidence that, in many cases, the dissolution of evaporites in gravity-driven groundwater may be the primary mechanism for generating saline formation waters. They proposed that tectonic deformations along the continental margins of North America induced long-range, subsurface water migration. Long range migration implies that the migrating fluids (trapped seawater or meteoric water) may evolve chemically as a result of reaction with the host sediments mixing with waters of different composition, and as a result of the changes in pressure and temperature. During each process, existing minerals may dissolve and new ones precipitate, changing the porosity and permeability of the host rocks and leaving various chemical signatures in the fluid composition.

Attempts to use the chemical composition of formation waters to infer paleoflow and/or diagenetic reactions have been made by numerous investigators (Clayton et al. 1966, Graf et al. 1966, Collins 1975, Hitchon et al. 1971, Carpenter 1978, Frape et al. 1984, Morton and Land 1987, Sanders 1991, Stueber and Walter 1991, Land and Macpherson 1992, Macpherson 1992, Moldovanyi and Walter 1992, Stueber et al. 1993). Because the chemical composition of formation waters often reflects the mineralogical composition of their host reservoirs, maps of geochemical parameters help to delineate changes in permeability, lithologic variations, diagenetic changes and, therefore, possibly identify stratigraphic traps and structural features. Collins (1975) reported that petroleum accumulation is often correlated with salinity transition zones. Moldovanyi and Walter (1992) perhaps summarized the issue best by stating that "a more complete understanding of processes active during the evolution of sedimentary basins emerges when diagenetic studies of sedimentary rocks are integrated into geochemical trends in subsurface waters."

A knowledge of the formation fluid chemistry can also be used as a basis for preventing formation damage and improving the recovery of oil from existing fields. Differences in formation fluid composition from different wells in a given reservoir in the same field can indicate mineralogical heterogeneity or lack of communication, and thus help in delineating separate flow units within a reservoir. Formation water chemistry can be used to determine whether or not injection water has reached a producing well during secondary oil recovery. Mineral precipitation and dissolution reactions that occur in reservoirs as a result of water, CO_2 , and alkali-flooding, acidizing, and other enhanced oil recovery processes can be investigated by using geochemical data as input for geochemical modeling.

This study demonstrated how formation water chemistry can be used to improve oil production in the Mississippian Aux Vases and Cypress Sandstones in Illinois. Chemical data on the formation waters were used for geological interpretation, determination of reservoir properties (porosity, permeability, water saturation) and assessment of formation damage. Also, the mineral dissolution and precipitation reactions during improved oil recovery processes were simulated using a computerized mathematical and geochemical model. The effects of the mineral dissolution and precipitation on reservoir porosity were determined by using the computer simulation results; implications for oil production were also assessed.

Analytical Procedures

Sampling of Formation Waters and Field Measurements A total of 99 formation water samples was collected directly from oil wells producing from the Aux Vases (52 samples) and Cypress (47 samples) Sandstones. Two additional samples (one from the Cypress Formation and another from the Waltersburg Formation) that were used as injection waters for the Aux Vases and Cypress reservoirs were collected from separation tanks. Each sample is identified by well API number and field name in Appendix VI. Arrangements with oil companies were made to discontinue chemical treatments (corrosion inhibitors, acidizing) in the wells at least 4 hours (usually 24 hours) before sampling. The samples were isolated from the atmosphere as much as possible to minimize oxidation and degassing before taking field pH, Eh, and resistivity measurements and processing the samples for laboratory analyses. The procedure is based on a U.S. Geological Survey procedure (Lico et al. 1982, Oltz 1993).

Analyses of Formation Waters and Reservoir Rocks An inductively coupled plasma spectrometer was used to analyze the samples for sodium (Na), calcium (Ca), magnesium (Mg), potassium (K), strontium (Sr), barium (Ba), lithium (Li), iron (Fe), manganese (Mn), boron (B), silicon (Si), aluminum (Al), lead (Pb), titanium (Ti), vanadium (V), cobalt (Co), nickel (Ni), copper (Cu), zinc (Zn), zirconium (Zr), cadmium (Cd), beryllium (Be), chromium (Cr), arsenic (As), selenium (Se), molybdenum (Mo), and antimony (Sb).

The concentrations of anions and ammonium (NH_4^+) were determined using standard ASTM-EPA procedures (ASTM 1976, EPA 1975, 1985): chloride (Cl^-) by the titrimetric-mercuric nitrate method, bromide (Br^-) and iodide (I^-) by a titrimetric method, sulfate (SO_4^{2-}) by the turbidimetric method, nitrate (NO_3^-) by spectrophotometric-cadmium reduction method, carbonate (CO_3^{2-}) and bicarbonate (HCO_3^-) by a titrimetric method, and ammonium (NH_4^+) by potentiometric ion selective electrode method. The details of these methods are all given in Oltz (1993).

Mineralogical data for the reservoir rocks were determined using XRD techniques (Oltz 1993). The sources of the samples and mineralogical data are given in Appendix XII-A.

Formation Water Chemistry The total dissolved solids (TDS) content of the Aux Vases and Cypress formation waters is significantly higher (43,325 to 151,399 mg/kg, Appendix VI) than that of sea water (approximately 35,400 mg/kg [Drever 1988]), and it tends to increase toward the deeper parts of the basin. The origin of high TDS levels in the Illinois Basin has been debated extensively in the literature.

The dissolved K and Mg levels in the brines were controlled by partial dissolution of K-feldspar and clay minerals, and in the case of Mg, also by the dolomitization of calcite. Dissolution of calcite, induced by increased partial pressure of CO₂ gas resulting from the breakdown of kerogen, would release Ca²⁺ into solution; however, the calcite dissolution reaction would increase bicarbonate (HCO₃⁻) in addition to the calcium ion (Ca²⁺) in solution, and the HCO₃⁻ concentration is too low to balance Ca²⁺ in Aux Vases and Cypress Sandstone waters. Calcite dissolution could only be partly responsible for the concentration of Ca in solution. Therefore, in addition to calcite dissolution, albitization of detrital plagioclase and probably dolomitization have released Ca²⁺ into the brines of the Aux Vases and Cypress Sandstones.

Because strontium (Sr) substitutes for Ca in the crystal structure of Ca-bearing minerals, Ca and Sr would be released at the same time when such minerals dissolve. This mechanism alone would result in a statistically significant positive correlation between Ca and Sr in the solution. Such a correlation exists for the Cypress Sandstone but not for the Aux Vases Sandstone. Furthermore, the fact that Sr is enriched in Cypress as well as Aux Vases formation waters relative to the sea water evaporation trajectory indicates that dissolution of Ca-bearing minerals raised Sr levels in the Cypress formation waters. In the Aux Vases formation waters, however, calcite recrystallization—known to replace Sr with Ca in the crystal structure of calcite—was probably an important mechanism for raising Sr levels in the solution.

Heterogeneity Studies

Formation water chemistry can be used for heterogeneity studies in oil-producing fields. Variations in solute concentrations in wells producing from the same reservoir in the same field can indicate a lack of communication or mineralogical heterogeneity between different pools within the field; for example, at Dale Consolidated field, the sulfate (SO₄²⁻) concentration in sample EOR-13 and iron (Fe) concentrations in samples EOR-B13 and EOR-B107 are much higher than those in other Aux Vases samples from the same field (Appendix VII). Bicarbonate (HCO₃⁻) and SO₄²⁻ concentrations in sample EOR-B34 (a Cypress sample) are considerably lower than those in other Cypress samples in Mattoon field (Appendix VI).

Formation Water Chemistry and Reservoir Properties

Resistivity-TDS-Temperature Relationships An empirical relationship between the water resistivity (R_w) and TDS content was established using direct field measurements of formation water resistivities (in ohm-meters) and laboratory TSDS data (in mg/L) that were available for 56 oil wells:

$$\log R_w = 2.841 - 0.788 \log (\text{TDS}) \text{ at } 25^\circ \text{ C} \quad [4]$$

The water resistivity values for more than 300 additional wells with known TDS values (obtained from USDOE and ISGS databases) were calculated using equation 4. The areal distribution of all measured and calculated resistivities for Aux Vases and Cypress formation waters unaffected by waterflooding or other improved oil recovery processes were mapped (figs. 117, 118).

Two additional empirical equations were developed for the Aux Vases and Cypress formation waters: one is used to determine the resistivity at different water temperatures if the resistivity at 25°C is known, and the other is used to determine the resistivity at a given temperature if the TDS value is known. The equations are based on laboratory and field measurements of temperatures (from 18° to 60°C), resistivities (from 0.0362 to 0.1832 ohm-meters), and TDS (from 48,697 to 148,028 mg/L) of ten different samples.

Figure 118 Contoured Cypress Formation water resistivities (Demir in prep.).

If the TDS is known, the resistivity at a given temperature can be calculated by using the expression:

$$R_{w(T)} = 957 / ((TDS)^{0.778} \times (1.017)^T) \quad [6]$$

where: $R_{w(T)}$ = water resistivity in ohm-m at temperature T (°C)
 TDS = total dissolved solid concentration in mg/L

For these computations, the formation water resistivities were determined in the field before degassing and oxidation could affect sample composition. Therefore, the measured formation water resistivities in this study are more accurate than those measured in the laboratory or estimated from SP logs. The formation water resistivities calculated by using the above equations are also fairly accurate because there is little scatter in the data used to calculate the R_w to TDS relationships (fig. 119). Furthermore, these equations do not require correction factors for the ionic composition of the water, which are needed when resistivities are calculated from published charts for artificial brines (Schlumberger 1989).

Resistivity and Reservoir Properties Accurate resistivity values are important when calculating water saturation and porosity, two important parameters that affect oil production. Commonly, the water saturation in nonshaley rocks is calculated using the Archie water saturation equation (Archie 1942):

$$S_w = (F_R R_w / R_t)^{1/2} \quad [7]$$

where: S_w = water saturation (%)
 R_w = water resistivity(ohm-m)
 R_t = total resistivity of formation (ohm-m)
 F_R = formation resistivity factor

The formation resistivity factor is related to the porosity by

$$F_R = 1 / \phi^m$$

where: m = cementation exponent
 ϕ = porosity (%)

The value of m is 2.0 for sandstones with no clay matrix and can be as low as 1.5 in sandstones with substantial amounts of clay matrix (Leetaru 1990). Rock permeability may also be estimated from empirical relationships that relate permeability to porosity and water saturation (Schlumberger 1989).

The resistivity maps (figs. 117, 118) can be used to estimate formation water resistivities in the Aux Vases and Cypress Sandstones in undrilled areas or in wells for which no resistivity data are available.

Formation Water Chemistry and Formation Damage Knowledge of the formation water chemistry is important in diagnosing and solving hydrocarbon production problems such as formation damage. Disturbance of the physical-chemical state of oil reservoirs as a result of temperature and pressure changes and reactions with externally introduced fluids can result in serious formation damage.

Minerals that commonly precipitate in reservoirs and boreholes and thus reduce oil production are calcite or aragonite ($CaCO_3$), gypsum ($CaSO_4 \cdot 2H_2O$) or anhydrite ($CaSO_4$), celestite ($SrSO_4$), barite ($BaSO_4$), and various Fe-sulfide minerals (Collins 1975, Collins and Kayser 1985). Therefore, concentrations of Ca^{2+} , Sr^{2+} , Ba^{2+} , Fe^{2+} , SO_4^{2-} , HCO_3^- , and CO_3^{2-} and

Figure 119 Relationship between Aux Vases and Cypress resistivity and TDS (Demir in prep.).

the pH and Eh of formation waters and injection fluids should be taken into consideration when designing improved oil recovery processes.

Saturation indices of these minerals in five Aux Vases and five Cypress formation water samples (randomly chosen from the north, south, west, east, and center of the oil-producing area of the state) were calculated by applying the geochemical model SOLMINEQ.88 (Kharaka et al. 1988) to reservoir conditions. Not only the chemical composition of the formation waters, but also the reservoir temperature and pressure must be known for input into the geochemical modeling program. Reservoir temperatures were estimated using a geothermal gradient of 0.67°C per 100 feet (Pollack and Watts 1976). Fluid pressures were estimated using a hydraulic potential gradient of 0.465 psi per foot (0.032 bar/ft) (Dickinson 1953). Concentrations of dissolved organic species (acetate, oxalate, succinate, methane) commonly found in oil waters and that of dissolved hydrogen sulfide (H_2S) were arbitrarily chosen to fall within the concentration ranges published in the literature (Carothers and Kharaka 1978, Kharaka et al. 1986, Moldovanyi and Walter 1992, Duan et al. 1992): 93 mg/L for each of acetate, oxalate, and succinate, 800 mg/L for methane, and 680 mg/L for H_2S were used. The saturation indices (Appendix XII-B) suggest that most samples are saturated or supersaturated with respect to calcite, barite, and Fe-sulfides. The thermodynamic potential for mineral precipitation exists if physical and chemical parameters, such as temperature, pressure, pH, Eh, and ionic strength, change. The solubility of anhydrite ($CaSO_4$), for example, was reported to decrease with decreasing pressure in solutions having dissolved NaCl concentration ranges (Fulford 1968, Collins 1975, Collins and Kayser 1985) commonly encountered in the Illinois Basin formation waters. Decreased reservoir pressure during normal primary production, or the pressure drop around a borehole due to degassing, could trigger anhydrite precipitation.

The pH and Eh of formation waters are important parameters influencing the solubilities of minerals. If pH is lowered enough as a result of processes such as injection of CO_2 or acid,

calcite dissolves. In general, the dissolution of calcite improves porosity and permeability in reservoirs containing clean calcite. For reservoirs containing a substantial amount of clay minerals dispersed within the calcite cement, however, calcite dissolution can release clay minerals that migrate, plug pore throats, and cause a reduction in permeability. The change in Eh, commonly caused by the introduction of injection fluids with Eh values different from that of the reservoir, could lead to oxidation or reduction of certain aqueous species. For example, oxidation of H_2S in high Ca brines could lead to precipitation of calcium sulfate.

The solubility of Ca, Ba, and Sr sulfate minerals generally increases with increasing ionic strength in dominantly NaCl solutions (Davis and Collins 1971, Collins 1975, Collins and Kayser 1985) at the TDS ranges of Aux Vases and Cypress formation waters. This is mainly due to decreased ionic activities of Ca, Ba, Sr, and SO_4 as a result of the formation of ion complexes, ion pairs, and ionic interactions in the solution. Decreased ionic activity in a solution generally promotes dissolution of minerals that contain the elements in which thermodynamic activity has decreased. Diluting reservoir waters by injection of less saline waters in waterflood operations reduces their overall ionic strength. This greatly increases the chance of sulfate mineral precipitation in the reservoirs, especially when the injection and/or formation waters contain a substantial amount of sulfate.

Ionic strength also affects the swelling of clay minerals and the anhydrite-gypsum transformation, both of which can also cause formation damage. Injection of fresher (lower TDS) waters into a reservoir can cause clay minerals to swell, depending on the ionic strength of the injected water. Furthermore, lowering of the TDS content of a brine increases the activity of water in it. This promotes conversion of anhydrite (if present) to gypsum, which has a molar volume 1 to 1.5 times greater than that of anhydrite. Both swelling of clay minerals and transformation of anhydrite to gypsum can reduce the permeability of the reservoir rock and thus the production of petroleum.

Using the geochemical data produced by this study (Appendix VI) and the general guidelines discussed above, oil-field service companies can evaluate the potential production problems for each well, pool, or field. Once a potential problem is identified, preventive measures, such as using scale inhibitors or choosing compatible fluids, can be taken.

Simulation of Fluid-Rock Interactions During Improved Oil Recovery

The consequences of chemical reactions that take place during improved oil recovery processes are difficult to predict because the systems are complex. The vast number of reactions that may take place simultaneously in such systems can be simulated only with the help of quantitative, computerized mathematical-geochemical models. Important advances have been made in computerized geochemical modeling since the pioneering works of Garrels and Thompson (1962) and Helgeson et al. (1969, 1970). The purpose of computerized geochemical modeling is to understand solution chemistry and predict the results of fluid-rock interactions.

There are two main types of geochemical models: speciation solubility models and reaction path models. The speciation solubility models are used to describe the equilibrium/distribution of aqueous species and the saturation state of the solution with respect to various minerals. The mineral saturation states provide a measure of the thermodynamic potential of mineral precipitation or dissolution. Commonly used speciation solubility models include SOLMINEQ (Kharaka and Barnes 1973, Kharaka et al. 1988), the WATEQ series (Truesdell and Jones 1974, Plummer et al. 1976, Ball et al. 1981, Ball and Nordstrom 1991), the MINEQL and MINTEQA series (Westall et al. 1976, Felmy et al. 1984, Allison et al. 1991), and EQ3NR (Wolery 1992a, b). Speciation solubility models are static models; that is, they treat aqueous systems as isolated systems and ignore the exchange of mass and energy with the surrounding environment. Reaction path models, on the other hand, are dynamic because they model reversible and irreversible reactions by which mass and energy are exchanged between aqueous solutions and their surroundings in an open system. Reaction path models are used to

Figure 120 Contoured Aux Vases Sandstone water TDS (Demir in prep.).

predict dissolution and precipitation of minerals and the evolution of fluid composition during consecutive stages (reaction steps) of fluid-rock interaction en route to complete equilibrium. Reaction path models can be instructed not to precipitate a mineral, thus putting that mineral into disequilibrium with the water-rock systems. Rate data (rate of the dissolution or precipitation of a mineral), if available, can be included in reaction path calculations to interpret the kinetics of water-rock interactions. The first published reaction path model, called PATH1, was developed by Helgeson et al. (1970). Since then, reaction path modeling

Figure 121 Contoured Cypress Sandstone water TDS (Demir in prep.).

has progressed significantly. Reaction path models commonly used at present are EQ3/6 (Wolery 1979, 1992b), REACT (Bethke 1992), PHREEQE (Parkhurst et al. 1980), PHRQPITZ (Plummer et al. 1988), and SOLVEQ/CHILLER (Reed 1982, Spycher and Reed 1989a, b).

The reaction path model REACT (Bethke 1992) was used in this study to simulate the chemical aspects of improved oil recovery processes in the Aux Vases and Cypress Formations. Analytical concentrations, pH, Eh, density, and the temperatures of the formation and injection fluids, and the mineralogical composition of the reservoir rocks were used as input data for the reaction path modeling. The density of the fluids was calculated using the geochemical model SOLMINEQ88 (Kharaka et al. 1988). Changes in the volumes of minerals that were predicted by the reaction path model to precipitate and/or dissolve were calculated. The change in mineral volume was, in turn, used to calculate change in porosity. The reaction path model used in this study cannot calculate changes in permeability. Because the dissolution and precipitation reactions take place in those pores that are accessible to the injection fluids, however, the change in porosity implies change in permeability. Predicted changes in other parameters such as pH, oxygen fugacity, iron concentration, and TDS are reported and their implications for reservoir properties are discussed.

When data on the mineralogy and fluid chemistry were incomplete, certain assumptions had to be made (Demir in prep.).

Model 1: Acid Treatment of a Production Well in Energy Field The Morgan Coal No. 3 well in Energy Field, Williamson County, Illinois, was treated with 500 gallons of mud cleanout acid (MCA), which contained about 15% HCl. The field operator told the ISGS that the fluid production declined after the treatment; however, the treatment of other wells in the same field with MCA containing 7.5% HCl helped production somewhat. Experimental data on the effect of MCA and injection waters are reported by Seyler et al. (1994).

The MCA was assumed to be composed of 15% HCl and 0.1 molal KCl (clay stabilizer); the type and concentrations of the other components of MCA were not provided by the suppliers. Chlorite in the reservoir rock was assumed to be in the form of daphnite, an Fe-chlorite, to test whether the dissolution of an Fe-rich chlorite would lead to ferric oxide precipitation during the MCA treatment. The smectite in the reservoir rock was assumed to be beidellite; and because of the high Ca content of the formation water, the dominant interlayer cation in the smectite was interpreted to be Ca. Despite flushing by the operator, some residual acid was arbitrarily assumed to have remained for about 2 days in the reservoir to react with the formation before it was consumed completely or flushed away by formation fluid.

The analytical determinations of the formation water samples (sample EOR-B6, Appendix VI) that provided data for the geochemical modeling were conducted at room temperature (about 25°C). Therefore, as a first step for the reaction path modeling, the heating of the formation water to reservoir temperature (36°C) was simulated. This step calculates the distribution of the aqueous species at the reservoir temperature. In the second step, the reaction of MCA with the formation water and minerals at the reservoir temperature was modeled. The mineralogical compositions used in the modeling are given in Appendix XII-C. Quartz, amorphous silica, and plagioclase (low albite) were set to form or dissolve according to a kinetic rate law using the rate data of Rimstidt and Barnes (1980) and Knauss and Wolery (1986). K-feldspar, calcite, and clay minerals were allowed to react freely until the system reached equilibrium. The calcite was expected to react quickly with the MCA. Within the time scale of the acid treatment, chlorite was suspected to react with acid relatively quickly, and other clay minerals probably reacted very slowly. Rate data were available for the precipitation or dissolution of quartz but not for chalcedony, a cryptocrystalline quartz. Therefore, chalcedony was suppressed to allow the precipitation or dissolution of quartz to proceed only according to the rate law. Precipitation of hematite was also suppressed because the first ferric iron minerals to form would normally be ferric hydroxides, not hematite. Reaction path computations (geochemical modeling) of the MCA treatment process discussed above were made for four different arbitrary, hypothetical zones.

Zone 1 In the well bore, the formation water and MCA were assumed to be mixed at a ratio of 5 parts MCA to 1 part formation water.

Zone 2 Immediately next to the well bore, MCA was presumably flushed out in the formation water and reacted with the reservoir rock. The volume of MCA that reacted with the reservoir rock was arbitrarily assumed to be ten times that of the pore water flushed out.

Zone 3 Surrounding zone 2 in the reservoir was a fluid mixture of 90% MCA and 10% formation water, which presumably reacted with the reservoir minerals.

Zone 4 Further into the reservoir, a mixture of 10% MCA and 90% formation water was assumed to be present, and this mixed fluid reacted with the reservoir minerals.

Geochemical reactions in the four zones were simulated twice, once for 15% HCl MCA and once for 7.5% HCl MCA. MCA mixed with HF acid is not commonly used in Illinois.

Results of Mud Cleanout Acid Treatment Model for Energy Field First, the reaction path computations predicted the original equilibrium concentrations of reservoir minerals before reaction with the injection fluid began (column 3, Appendixes XII-D, -E). Entering the feldspars as reactants (out of equilibrium with the system) in the input file prevented the model from adjusting the concentration of these minerals during the equilibrium step. In addition to the analytically determined minerals (original measured mineralogy, column 2, Appendixes XII-D, -E), the model predicted that kaolinite and trace amounts of pyrite and strontianite would be present in the reservoir. This prediction was consistent with the results of Nesbitt (1980, 1985), who suggested that formation waters from Pennsylvanian and Mississippian strata in the Illinois Basin are in equilibrium with kaolinite.

In summary, the geochemical model predicted an increase from the average original porosity of 22% (Appendix XII-C) to 32.4% (Appendix XII-D) and 25.7% (Appendix XII-E) in zone 2, immediately surrounding the wellbore, in response to treatment with 15% and 7.5% HCl MCA, respectively. For zone 4 somewhat farther away from the well bore, no noticeable increase in the pore volume was predicted. Excess acidity and dissolved iron species generated when the well was treated with 15% HCl MCA increased the chance of asphaltene precipitation, which would reduce the permeability. The amount of acidity and dissolved iron species generated in response to treatment with 7.5% HCl MCA was predicted to be considerably smaller than those generated in response to treatment with 15% HCl MCA (Appendix XII-F); the smaller the amount of acidity and dissolved iron, the smaller the chance of asphaltene precipitation. Considering the amount of acidity and dissolved iron predicted by the model and perhaps the amount of fine clay particles likely to be released as a result of the dissolution of calcite, one can argue that the plugging of pores with possible precipitation of asphaltene and migration of fine particles would be less during treatment with 7.5% HCl MCA than with 15% HCl MCA. This argument is consistent with the field observations that indicated increased production (permeability) in response to treatment with 7.5% HCl MCA rather than with 15% HCl MCA. Both treatments generate a significant amount of CO₂ gas (Appendix XII-F), which would initially reduce permeability. The CO₂ gas pressure, however, would dissipate relatively quickly, allowing restoration of the permeability. The model did not predict the expected ferric oxide precipitation resulting from dissolution of Fe-chlorite.

Model 2: Waterflood Operations in Dale Consolidated Field Water produced from an average depth of about 2,959 feet in the Cypress Formation was injected into the deeper Aux Vases reservoir to increase oil production in Dale Consolidated Field in Franklin County (Udegbunam et al. 1993b). The chemical composition of the injection water is given in Appendix VI (sample EOR-B101). The composition of Aux Vases formation water was represented by that of water produced at an average depth of about 3,172 feet (Appendix VI, sample EOR-B107). The average mineralogical composition and porosity of a core sample from McCreery No. 1 well (Appendix XII-G) represented the Aux Vases reservoir in this field.

Geochemical reactions of the waterflood operation were simulated to estimate the effect of the waterflood on reservoir properties. For Aux Vases formation water, the pH of 5.34

Figure 122 Reaction path simulation of mixing injection and pore waters (1:10) at Dale Consolidated Field (Demir in prep.).

measured in the field had to be adjusted to 5.85 in the geochemical modeling input file to make the simulation run converge. The minerals reported in Appendix XII-G under the generic names chlorite and smectite (smectite portion of illite/smectite) were assumed to be ripidolite (Fe-Mg-chlorite) and beidellite, respectively.

Two different scenarios were modeled: (1) the injection water, with a volume ten times that of the pore water, flushed out the pore water and reacted with the reservoir rock during the course of waterflood operations; and (2) somewhere in the reservoir, the injection and pore waters were mixed at a 1:1 ratio, and then reacted with the reservoir rock. It was assumed that all reactions would continue until thermodynamic equilibrium was attained.

Results of the Waterflood Operation Model for Dale Consolidated Field

Replacement of pore water by flushing This model predicted relatively small changes in volume, as compared to original volumes (Appendix XII-H, fig. 122), of the major components (quartz, calcite, illite) of the reservoir rock after flushing of pore water with injection fluid. The volumes of minor mineralogical components were predicted to vary as a result of reaction with the injection fluid. Feldspars were altered to illite, smectite, and kaolinite, and some of the silica released by dissolution of feldspars and chlorite apparently precipitated as quartz in the simulation. A small amount of pyrite was predicted to precipitate because of the reaction of ferrous iron with H_2S . The original measured volume of the reservoir rock (column 2, Appendix XII-H) decreased by about 1 cm^3 (an increase of 0.1% in pore volume), which would not significantly change the original porosity of 20% (Appendixes XII-G, -H).

Mixing of formation and injection waters Mixing the injection and pore waters at a ratio of 1:1 resulted in a decrease of 20.4 cm^3 in total measured rock volume, which translates to an increase in average porosity from 20% (Appendix XII-G) to 20.2% (Appendix XII-I). Again, the changes in the volume of the major mineralogical components (quartz, calcite, and illite) of the reservoir rocks were small compared to their original measured volumes (compare columns 2 and 4, Appendix XII-I).

The pH during both waterflooding scenarios ($\times 10$ flush and 1:1 mixture) was predicted to remain nearly neutral during the reaction of injection fluid with the reservoir (fig. 122). This reduces the probability of asphaltene precipitation, which could take place in more acidic environments.

In summary, if the model assumptions and parameters were reasonable, the injection water used in the Dale Consolidated Field was compatible with the formation water and the reservoir minerals, and thus should not result in any chemical damage to the formation. Furthermore, the TDS and chemical composition of the injection water were comparable to those of the formation water and should not cause a severe clay mineral swelling problem.

Model 3: Waterflood Operations in Tamaroa Field Water produced from the Cypress Formation has been reinjected into the reservoir to maintain pressure and increase production at Tamaroa Field in Perry County (Grube 1992). The chemical composition of injection water is given in Appendix VI (sample EOR-B23). The composition of the Cypress formation water was represented by that of water from the Gosper Stockton No. 1 well, which produces at an average depth of 1,159 feet in Tamaroa Field (Appendix VI, sample EOR-B22). The average mineralogical composition and porosity of Stockton No. 1 were assumed to be representative of those of the Cypress reservoir in the Tamaroa Field (Appendix XII-J). The types of chlorite and smectite (smectite portion of illite/smectite) reported in Appendix XII-J were assumed to be ripidolite and beidellite, respectively. The concentrations of Br, I, and SO_4 in the injection water were arbitrarily set to 100, 5, and 20 mg/L, respectively; values are within the ranges reported for Cypress formation waters (Appendix VI). Scenarios of waterflood processes modeled for Tamaroa Field were similar to those for Dale Consolidated Field.

Results of the Waterflood Operation Model for Tamaroa Field

Replacement of pore water by flushing In a simulation of replacement of pore water by flushing with injection fluid, the model predicted only small changes in quartz, albite, calcite, and illite concentrations, as compared with their original measured concentrations (Appendix XII-K, fig. 123). As a result of reaction with the injection fluid, some of the albite, all of the chlorite, and a relatively small amount of quartz were predicted to either dissolve or be altered, leading to the precipitation of kaolinite and smectite. A small amount of pyrite was predicted to form because of the reaction of ferrous iron with H_2S . Calcite was predicted to dissolve slightly, leading to the precipitation of a small amount of strontianite.

The original measured unit rock volume increased by 17.3 cm^3 and pore volume decreased by 0.7%, which would change the original porosity of 19% (Appendix XII-J) to 18.9% (Appendix XII-K).

The pH remained relatively neutral during the reaction path. Therefore, asphaltene precipitation (promoted by low pH) would not be expected to be initiated during the waterflood operation. Although the formation of smectite (Appendix XII-K) creates a potential problem with clay swelling, this was not expected to be a concern because the TDS remained high during the reaction path (fig. 123). High TDS would reduce the electrical double layer around and in the interlayer regions of the smectite, and thus prevent clay swelling.

Mixing of formation and injection waters Mixing the injection and pore waters with a 1:1 ratio resulted in the partial dissolution of quartz, albite, chlorite, and illite (Appendix XII-L) and resulted in the formation of kaolinite and smectite. The average original porosity (19%) was predicted to change $<0.1\%$ (Appendix XII-L). As in the case of flushing the pore water with the injection fluid, the change in pH as a result of mixing the fluids at a 1:1 ratio was very small; asphaltene precipitation should not be a concern. In addition, the TDS remained high during the reaction path, reducing the chance of clay mineral swelling.

In summary, the modeling of the waterflood operation in Tamaroa Field predicted no significant change in reservoir porosity under the conditions modeled. If the model assumptions and parameters were reasonable, the injection water used in the Tamaroa South Field was compatible with the formation water and the reservoir minerals.

Figure 123 Reaction path model of flushing pore water with injection fluid (1:10) at Tamaroa Field (Demir in prep.).

Figure 124 Reaction path model of the reaction of 1 mol CO₂ with 1 kg formation water (Demir in prep.).

Model 4: CO₂-flood Operation in Tamaroa Field Carbon dioxide (CO₂) flooding, injected alone or alternated with water injection, is one of the enhanced oil recovery methods used to increase oil production in mature fields.

Two scenarios were modeled: (1) reaction of 1 mol of CO₂ with the reservoir, and (2) reaction of 5 mol of CO₂ gas with the reservoir. It was assumed that albite, quartz, and amorphous silica reacted according to a kinetic rate law (Rimstidt and Barnes 1980, Knauss and Wolery 1986) and all other minerals reacted freely until thermodynamic equilibrium was achieved. The duration of the CO₂-flood was arbitrarily set to 30 days, which is within the span of time common in field applications of CO₂-flooding.

Results of the CO₂-flood Operation for Tamaroa Field

Reaction with 1 mol CO₂ Reacting 1 mol of CO₂ with a unit volume of reservoir containing 1 kg formation water was predicted to result in the partial dissolution (or alteration) of chlorite and illite, and the formation of smectite, kaolinite, gibbsite, siderite, and dawsonite (Appendix XII-M, fig. 124). The precipitation of siderite and a small amount of pyrite was a consequence of the reaction of ferrous iron with CO₃²⁻ (or HCO₃⁻) and H₂S, respectively. The quantities of the two other minerals (strontianite and witherite) predicted to form were too small to warrant further discussion.

The original measured rock volume increased by about 15.3 cm³, yielding a decrease of 0.6% in pore volume, which would result in an average final porosity of 18.9% (Appendix XII-M), not significantly different from the average original porosity of 19% (Appendix XII-J).

The pH along the reaction path (fig. 125) remained higher than the original pH (6.5). Therefore, asphaltene precipitation (promoted by low pH) would not be expected to be initiated during treatment of the reservoir with 1 mol of CO₂. Although formation of additional smectite could create a potential for swelling of clay minerals, this would not be a concern because the relatively high TDS that remained after the reaction path ended (fig. 126) would prevent swelling of clays.

Reaction with 5 mol CO₂ The reaction of the reservoir with 5 mol of CO₂ gas was predicted to result in either total dissolution or alteration of chlorite, illite, and smectite (Appendix XII-N). Some of the calcite present was also predicted to dissolve. Increased concentrations of the aluminum and silica released from the dissolution of clay minerals resulted in the precipitation of clinoptilolite, dawsonite, and mordenite. The dissolution of CO₂ gas provided excess carbonate that was consumed as dawsonite, siderite, and magnesite precipitated. It was predicted, on the basis of changes in the original measured mineral volumes, that the average porosity would decrease from 19% (Appendix XII-J) to 18.4% (Appendix XII-N).

The reaction of the reservoir with 5 mol of CO₂ lowered the pH significantly along the reaction path relative to the original pH (fig. 125). The low pH could initiate asphaltene precipitation in some crude oils. In this case, however, the asphaltene problem would probably be minimal because of the peptizing effect of resins, which are relatively high (about 10% to 18%) in Tamaroa Field oils (Appendix VII-A, -B). Again, the TDS increased significantly during the reaction path, reducing the probability of swelling of clay minerals.

In summary, geochemical modeling of the CO₂-flood operation in Tamaroa Field predicted that, at thermodynamic equilibrium, the clay minerals chlorite, illite, and smectite present in the reservoir rock would dissolve to varying degrees depending on the concentration of CO₂ gas. The increased concentrations of carbonate, aluminum, and silica in the formation water derived from dissolution of CO₂ gas, calcite, and clay minerals would lead to precipitation of clinoptilolite, dawsonite, siderite, magnesite, gibbsite, and mordenite. Overall, changes in the mass and type of the reservoir minerals were predicted to result in a decrease of 0.6% or less in the reservoir porosity.

Model 5: Alkali-flood Operation in Tamaroa Field When alkali solutions are introduced into an oil reservoir, they react with organic acids in the oil and generate organic salts that can act

Figure 125 Plot of pH along the reaction path of the model in figure 124 (Demir in prep.).

Figure 126 Plot of TDS remaining after reaction path model of CO₂ injection at Tamaroa Field (Demir in prep.).

as surfactants (Jennings et al. 1974, Bethke 1992). The surfactants reduce the surface tension of water and thus increase the effective permeability of the reservoir to oil. This type of oil recovery process can be especially useful for old oil fields, such as most of the Illinois Basin fields, where primary production has preferentially extracted lighter oils and left relatively heavy oils in the reservoirs. The most commonly used alkali-flood agents are sodium hydroxide (NaOH), sodium carbonate (Na_2CO_3), and sodium silicate (Na_2SiO_3).

The reservoir mineralogy, formation water chemistry, and related assumptions for the computer simulation processes were the same as those discussed in the preceding examples of water- and CO_2 -flood operations. Concentrations of alkalis in the solutions used for the simulation runs were the same as those used by Bethke (1992): 0.5 mol NaOH, 0.25 mol Na_2CO_3 , and 0.25 mol Na_2SiO_3 . The 30-day duration and flushing with 10 times the pore volume with the alkali solutions were also arbitrarily set similarly to the other models. Quartz, amorphous silica, and albite were allowed to precipitate or dissolve according to a kinetic rate law using the rate data of Rimstidt and Barnes (1980) and Knauss and Wolery (1986). Other minerals were allowed to react freely until they attained thermodynamic equilibrium with the solution.

Results of the Alkali-flood Operation Model for Tamaroa Field Clay minerals reacted with the alkali-flood to form zeolite minerals; analcime and prehnite in two cases (Appendixes XII-O, -P, figs. 127, 128) and analcime in one case (Appendix XII-Q, fig. 129). The precipitation of zeolites in the pore space during alkali-flooding has been indicated (Sydansk 1982, Bethke 1992) to be of special concern for formation damage. Quartz and albite did not react with the alkali-floods (Appendixes XII-O, -P, -Q). It was predicted that NaOH-, Na_2SiO_3 -, and Na_2CO_3 -floods would decrease the average porosity from 19% (Appendix XII-f) to 18.6%, 17.7%, and 17.9%, respectively (Appendixes XII-O, -P, -Q).

The consumption of alkali metal (Na^+) by mineral precipitation or dissolution is undesirable because the purpose of alkali-flooding for improved oil recovery is to react the alkali metal with oil to form a surfactant. The NaOH-flood was predicted to be most efficient in delivering alkali metal to the reservoir because more Na^+ remained in the fluid to react with oil for this flood than for the other two floods at the end of the reaction paths (fig. 130). As expected, all three alkali-floods raised the pH from 6.5 to more than 9, further reducing the probability of asphaltene precipitation. Because illite and smectite were predicted to dissolve during the NaOH- and Na_2SiO_3 -floods, swelling of clay minerals should not be a concern. Potential for formation damage resulting from the swelling of clay minerals exists for the Na_2CO_3 -flood, however, because of the predicted precipitation of smectite (Appendix XII-Q) and reduced TDS level (2855 mg/kg) relative to the original TDS in the formation water.

Based on the change in pore volume, greater delivery of alkali metal to the formation fluid, and swelling of clay minerals discussed above, it appears that the NaOH-flood may be more efficient than Na_2CO_3 - and Na_2SiO_3 -floods for increasing oil production in the Tamaroa Field under the conditions modeled.

Summary and Conclusions

About 100 formation water samples were collected directly from oil wells producing from reservoirs in the Mississippian Aux Vases and Cypress Formations. The samples were analyzed in the field and laboratory for various geochemical parameters. The geochemical compositions of the formation water samples, along with mineralogical compositions of core samples from the Aux Vases and Cypress Formations, were determined to aid geological interpretation and reservoir analysis to improve oil recovery from these two formations.

- The Cl-Br relationship in waters from the Aux Vases and Cypress Sandstones suggests that these waters have a halite dissolution component and probably also an evaporated sea water component. Formation waters have been depleted in K and Mg relative to the sea-water evaporation trajectory, suggesting that the original trapped sea water was

Figure 127 Reaction path model of a sodium hydroxide flood at Tamaroa Field (Demir in prep.).

Figure 128 Reaction path model of a sodium silicate flood at Tamaroa Field (Demir in prep.).

Figure 129 Reaction path model of a sodium carbonate flood at Tamaroa Field (Demir in prep.).

Figure 130 Reaction path model of Na^{++} consumption in these alkali floods in Tamaroa Field (Demir in prep.).

either replaced or mixed with low-K/Br and low-Mg/Br waters or modified by diagenetic reactions. The dissolved K and Mg concentrations were generally higher in the Aux Vases Formation than those in the Cypress Formation, which is poor in K- and Mg-bearing clay minerals and K-feldspar relative to the Aux Vases Sandstone. The implications are that the K- and Mg-rich clay minerals and K-feldspars in the Aux Vases and Cypress are detrital and/or formed primarily prior to the emplacement of the present subsurface waters. Eventually, they contributed K and Mg to the formation waters through dissolution. Dissolution and recrystallization of calcite appeared to significantly influence Ca and Sr concentrations in solution. The observed Ca concentrations in excess of amounts that would be provided by calcite solubility were probably caused by albitization of detrital plagioclase and possibly by partial dolomitization of calcite.

- Variations in water chemistry in a given reservoir in the same field can indicate a lack of communication between different pools or mineralogical heterogeneity within the reservoir. Therefore, the formation water data provided in this study can be potentially useful for geological interpretations in relation to hydrocarbon production.
- The formation water resistivities and TDS data included in this report can be used to calculate water saturations and permeabilities in oil reservoirs in the Aux Vases and Cypress Sandstones. Empirical relationships were determined to calculate the electrical resistivity from the TDS, or vice versa, at any temperature encountered within the Aux Vases and Cypress Sandstones. The areal distributions of all available resistivity and TDS data for the two sandstones were mapped. These maps are useful for estimating TDS and resistivity in areas where no data are available.
- In oil reservoirs, disturbances produced in water-rock systems by changes in temperature or pressure and by reactions with introduced fluids can result in severe formation damage. Minerals that commonly precipitate in reservoirs and boreholes during primary production and thus reduce production are calcite, aragonite, gypsum, anhydrite, celestite, barite, and various Fe-sulfide minerals. The saturation indices of these minerals, in randomly selected Aux Vases and Cypress formation waters, were calculated under reservoir conditions. The results indicated that most of the samples were saturated or supersaturated with respect to calcite, barite, and Fe-sulfides, suggesting that these minerals can potentially precipitate, if geochemical parameters such as pressure, temperature, ionic strength, and chemical composition of the reservoir water change.
- Computerized geochemical models can help in predicting the results of fluid-rock interactions during improved oil recovery processes. The reaction path model REACT was used in this study to simulate the chemical aspects of improved oil recovery processes in three fields under selected scenarios. The volume of minerals that precipitated and/or dissolved and the accompanying changes in porosity were calculated.
- Geochemical modeling predicted a consistent increase in pore volume in the zone adjacent to a well bore, if a production well in Energy Field was treated with 15% or 7.5% HCl MCA. The higher acidity and dissolved iron concentration caused by treatment with 15% HCl MCA relative to those caused by treatment with 7.5% HCl MCA were predicted to increase the chance of asphaltene precipitation.
- The simulations of geochemical reactions of waterflood operations in the Dale Consolidated and Tamaroa Fields predicted little change in porosity. Therefore, injection waters used in these operations were apparently compatible with the reservoirs.
- CO₂-flood and alkali-flood (NaOH, Na₂CO₃, Na₂SiO₃), two other improved oil recovery operations, were simulated for Tamaroa Field. Geochemical modeling of the CO₂-flood operation predicted a small or negligible decrease in reservoir porosity. Clay minerals reacted with the alkali to form zeolites, which have the potential for formation damage. The purpose of alkali-flooding is to allow the alkali metal (Na⁺ in this case) to react with oil to form a surfactant, which improves the effective permeability. The NaOH-flood was predicted to be the most efficient in delivering alkali metal to the reservoir and to have the least adverse effect on reservoir porosity.

- Because natural processes are complex, extreme caution should be used in geochemical modeling for prediction. The geochemical simulations discussed in this report were based on some unverified assumptions, and only a limited number of scenarios were modeled. The results thus serve only as an introduction and a guide for future work.

Figure 131 The technology transfer model for Illinois (Oltz 1994).

TASK 12: TECHNOLOGY TRANSFER

Reporting the results of improved oil recovery research in the Illinois Basin was the major technology transfer task. To that end, the ISGS produced maps, published reports, and distributed data in several formats. The oil industry, particularly independent operators, were continually informed of research results in a manner that would encourage consistent, optimal reservoir management.

Efforts were directed toward improving operators' understanding of reservoir management by increasing their awareness of the regional variation of reservoir types, reservoir heterogeneity, and production problems and strategies. During the project, the ISGS

- sponsored two workshops, which were well received by the independent oil industry;
- made more data of increased accuracy available to TORIS and the public;
- provided DOE with new data for refining recovery and economic models for the state;
- more accurately defined mobile and immobile reserves at a field scale in Illinois;
- gave DOE a basis for promoting research into improved oil recovery and for supporting technology transfer;
- delivered critical information directly through talks, symposia, publications, workshops, one-to-one conversations, and field installation of a database work station for operators;
- provided input at the state oil industry regulatory control board and changed the concept (and the regulations) of well spacing;
- supported a regional symposium, "Advances in Reservoir Characterization for Improved Oil Recovery."

Technology Transfer Mechanisms

Technology transfer occurs at multiple levels. The ISGS communicates with individuals and groups—-independent operators and others in the oil industry, government agencies, and other researchers. Direct industry participation, a key element in the project, was provided through the establishment of two advisory committees. The Petroleum Advisory Committee (PAC) and the Technical Advisory Committee (TAC) held regular meetings and reviewed ongoing projects. Technology transfer is not unidirectional and participation by such advisory committees is requisite to the success of any technology transfer program.

Direct Contact with Operators One-to-one communication with an operator maximizes the transfer from applied research results to oil field practices. Cooperative working relationships included visits to operators and return visits to the ISGS. Demonstrations and presentations using Illinois reservoir characterization and reservoir management examples provided a common background for discussion. Operators were very cooperative and made reservoir data available as they became acquainted with the benefits of studies that incorporated information with which they were familiar. Cooperative relationships from the inception of the project promoted synergistic communication and feedback.

Workshops Two workshops were held for the petroleum industry to demonstrate application of research results. One major topic was presented at each workshop, which typically utilized multiple formats: talks accompanied by slides, informal "work-in-progress" posters with the investigators at hand to answer questions, and interactive demonstrations on computer workstations.

"Identification of Unrecovered Mobile Oil," the first workshop, was held in 1991. It defined the research, presented an example of one field study, and held discussions on geologic and engineering models from two different fields. Poster demonstrations filled the room and attracted much attention. A presentation of the Cypress outcrop study as a reservoir analog, discussion of how heterogeneity affects recovery, and solicitation for input on operator experiences in both Cypress and Aux Vases reservoirs completed the events. More than 50 people attended the meeting, which was covered by reporters from newspapers and TV.

"Working toward Improved Recovery of Mobile Oil in Illinois Reservoirs," the second workshop, was held 1992. More than 145 participants attended talks on applied research projects and final products. Other presentations included field and outcrop studies, a review of sonic logs and seismic acquisition and interpretation, and several poster exhibits. USDOE's BOAST reservoir simulator, digital access to the ISGS database and computer-generated development maps were also demonstrated. The workshop concluded with a discussion of the USDOE PON program. The TV and print media also covered this workshop.

Publications Publications are a basic method of technology transfer and several studies were published in the course of the project. Most of the publications are in the ISGS Illinois Petroleum (IP) series. Research was also reported in outside journals, conference proceedings, and invited papers.

Conventions and Meetings Regional and national meetings offer prime opportunities to present research and receive peer review and feedback. At regional meetings, ISGS researchers meet and involve local and nearby operators and other researchers. Technology transfer at the national level makes results available to industry members and researchers in other oil-producing basins. ISGS staff members not only present their data and results, but in turn, learn of the advances in research and applications made by their colleagues. Short courses, workshops, and other sessions at national meetings expose Illinois Basin researchers to advances, fresh ideas, and new developments in the reservoir sciences.

More than 140 presentations, publications, and abstracts were produced during the course of the project. The following list represents an active technology transfer agenda and reveals the breadth of expertise made available to the petroleum industry.

Publications and Presentations through 1993

In-office presentations made to independent oil operators and producers, state legislative officials, or other state government representatives are not included on this list. Approximately eight presentations to the annual meetings of industrial associations were also reported in *Northeast Oil World* and the *American Oil and Gas Reporter*.

- Beaty, D. S., and J. P. Fagan, Jr., 1992, Characterization of Mississippian Aux Vases Sandstone reservoirs, southwestern Dale Consolidated Field, Illinois: oral presentation to the ENR/DOE Workshop, November 18, Mt. Vernon, Illinois.
- Beaty, D. S., E. O. Udegbumam, and J. P. Fagan, Jr., 1992, Hydraulically induced fractures and their influence on production in an Aux Vases Sandstone bar, Dale Consolidated Field, Franklin County, Illinois: poster session for ENR/DOE Workshop, November 18, Mt. Vernon, Illinois.
- Beaty, D. S., and J. P. Fagan, Jr., 1992, Characterization of Mississippian Aux Vases Sandstone reservoirs, southwestern Dale Consolidated Field, Illinois: presentation to AAPG Eastern Section Annual Meeting, September 20-23, Champaign, Illinois.
- Beaty, D. S., E. O. Udegbumam, and J. P. Fagan, Jr., 1992, Hydraulically induced fractures and their influence on production in an Aux Vases Sandstone bar, Dale Consolidated Field, Franklin County, Illinois (abstract): Rocky Mountain Association of Geologists Horizontal Drilling Conference, Abstracts with Programs.
- Beaty, D. S., K. R. McGee, and B. Seyler, 1991, Effects of diagenesis on reservoir quality within two Cypress reservoirs in the Illinois Basin: poster for the Indiana-Kentucky Geological Society, September 24, Evansville, Indiana.
- Beaty, D. S., K. R. McGee, and B. Seyler, 1991, Effects of diagenesis on reservoir quality within two Cypress reservoirs in the Illinois Basin: presentation for AAPG Eastern Section meeting, September 8-10, Pittsburgh, Pennsylvania.
- Cole, R. D., and D. J. Haggerty, 1992, The Mississippian Cypress formation on Interstate 57, Union County, Illinois—A demonstration of lateral and vertical heterogeneity: oral and poster presentations for ENR/DOE Workshop, November 18, Mt. Vernon, Illinois.
- Cole, R. D., and D. J. Haggerty, 1992, The Mississippian Cypress Formation on Interstate 57, Union County, Illinois—a demonstration of lateral and vertical heterogeneity: presentation for Symposium on Advances in Reservoir Characterization for Improved Oil Recovery, September 17, AAPG Eastern Section, Champaign, Illinois.
- Cole, R. D., 1991, Marine sandstone facies in the Mississippian Cypress Formation: alternative interpretations of previously described distributary channels in southern Illinois: presentation for Geological Society of America Annual Meeting, October 21-24, San Diego, California.
- Cole, R. D., 1991, Preliminary paleogeographic reconstruction of the Illinois Basin during deposition of the Mississippian Aux Vases Formation: implications for hydrocarbon recovery: presentation for AAPG Annual Meeting, April 7-10, Dallas, Texas.
- Demir, L., 1992, Geochemistry of formation fluids for reservoir characterization and improved oil recovery: poster for ENR/DOE Workshop, November 18, Mt. Vernon, Illinois.
- Fagan, J. P., Jr., 1992, Seismic definition of reservoir heterogeneity in the Aux Vases Formation at King Field, Jefferson County, Illinois: oral presentation for ENR/DOE Workshop, November 18, Mt. Vernon, Illinois.
- Fagan, J. P., Jr., 1992, An experimental seismic reflection study at King Field, Jefferson County: presentation for Illinois Technical Advisory Committee/Petroleum Advisory Committee meeting, July 8, Champaign, Illinois.

- Grube, J. P., 1992, Reservoir characterization and improved oil recovery from multiple bar sandstones, Cypress Formation, Tamaroa and Tamaroa South Fields, Perry County, Illinois: ISGS Illinois Petroleum 138.
- Grube, J. P., 1992, Hydrocarbon production from shallow marine sandstones in the Mississippian Cypress Formation at Lawrence Field: presentation for Illinois ENR/DOE Workshop, November 18, Mt. Vernon, Illinois.
- Grube, J. P., 1992, Reservoir characterization and improved oil recovery from multiple bar sandstones, Cypress Formation, Tamaroa and Tamaroa South Fields, Perry County, Illinois: presentation for ENR/DOE Workshop, November 18, Mt. Vernon, Illinois.
- Grube, J. P., 1992, Reservoir characterization of multiple-bar sandstones in the Mississippian Cypress Formation, Tamaroa Field, Perry County, Illinois: presentation for Kentucky Oil and Gas Association 56th Annual Meeting, June 17-19, Owensboro, Kentucky.
- Grube, J. P., R. D. Cole, and S. T. Whitaker, 1992, Hydrocarbon production from shallow marine sandstones in the Mississippian Cypress formation at Lawrence Field, Illinois: presentation for Eastern Section AAPG Annual Meeting, September 20-23, Champaign, Illinois.
- Grube, J. P., 1991, Reservoir characterization of multiple-bar sandstones in the Mississippian Cypress Formation, Tamaroa Field, Perry County, Illinois: presentation for AAPG Eastern Section meeting, September 8-10, Pittsburgh, Pennsylvania.
- Huff, B. G., 1993, Analysis of the Aux Vases (Mississippian) petroleum reservoirs of Energy Field, Williamson County, Illinois: ISGS Illinois Petroleum Series 141.
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- Huff, B. G., 1992, Analysis of the Aux Vases (Mississippian) Reservoirs of Energy Field, Williamson County, Illinois: presentation for Technical Advisory Committee/Petroleum Advisory Committee meeting, July 8, Champaign, Illinois.
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- Hughes, R. E., and D. M. Moore, 1992, Methods for determination of clay and mineralogical content of reservoir sandstones, AAPG Eastern Section Annual Meeting, September 20-23, Champaign, Illinois.
- Hughes, R. E., and D. M. Moore, 1991, Why are clays important to your reservoir? ISGS Workshop on unrecovered mobile oil, November 18, Mt. Vernon, Illinois.
- Leetaru, H. E. (in press), Seismic character analysis as applied to improved oil recovery at King Field, Jefferson County, Illinois, Illinois State Geological Survey: Illinois Petroleum series.
- Leetaru, H. E. (in prep.), Sensitivity of scales of heterogeneity on increased oil recovery at Storms Consolidated Field in White County, Illinois: ISGS Illinois Petroleum series.
- Leetaru, H. E., 1993, Improved oil recovery from the Aux Vases (Mississippian) Formation at Boyd Field, Jefferson County, Illinois: ISGS Illinois Petroleum 142, 30 p.
- Leetaru, H. E., 1993, Improved oil recovery in mature fields through reservoir characterization and management: invited paper for AAPG International Conference at The Hague, The Netherlands, American Association of Petroleum Geologists Bulletin, v. 77, no. 9, p. 1640-1641.
- Leetaru, H. E., 1993, 3-D model identifies unswept oil in Illinois' King field: Oil and Gas Journal, June 29, v. 91, no. 26, p. 75-80.
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- Leetaru, H. E., 1992, Improved oil recovery in mature fields through reservoir characterization and management: presentation for 3rd Annual Archie Conference, Galveston, Texas, November 8-11.

- Leetaru, H. E., 1992, Reservoir characterization of King Field, presentation to Mr. James Randolph, Assistant Secretary of Fossil Fuels for the Department of Energy and his staff, March 12, Washington, D.C.
- Leetaru, H. E., 1992, Storms Consolidated Field: presentation for ISGS workshop on identification of unrecovered mobile oil, November 18, Mt. Vernon, Illinois.
- Leetaru, H. E., 1992, 3-D modeling of the heterogeneous Mississippian Aux Vases Sandstone reservoir at Jefferson County, Illinois: invited paper at 2nd Annual Conference on Three Dimensional Modeling and Reservoir Characterization, May 10-13, Houston, Texas.
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- Leetaru, H. E., 1991, Depositional facies and hydrocarbon reservoir compartmentalization of the Mississippian Aux Vases Formation at King Field, Jefferson County, Illinois (abstract): 1991 Annual Convention Abstracts, AAPG Bulletin v. 75, no. 8, p. 1386.
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- Leetaru, H. E., 1991, Interactive 3-D modeling at King Field: presentation for ISGS workshop on identification of unrecovered mobile oil, November 18, Mt. Vernon, Illinois.
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- Leetaru, H. E., 1991, Reservoir heterogeneity and improved oil recovery of the Aux Vases (Mississippian) Formation at King Field, Jefferson County, Illinois: *ISGS Illinois Petroleum* 135.
- Leetaru, H. E., 1991, Reservoir heterogeneity at Boyd Field: poster for ISGS workshop on identification of unrecovered mobile oil, November 18, Mt. Vernon, Illinois.
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- Leetaru, H. E., and R. J. Rice, 1992, Heterogeneity of upper Mississippian sandstone reservoirs at Storms Consolidated Field, White County, Illinois (abstract): Eastern Section Meeting, American Association of Petroleum Geologists, Champaign, Illinois, p. 1279.
- Leetaru, H. E., and R. J. Rice, 1992, Heterogeneity of upper Mississippian sandstone reservoirs at Storms Consolidated Field, White County, Illinois: presentation for AAPG Eastern Section Annual Meeting, September 20-23, Champaign, Illinois.
- Leetaru, H. E., and S. T. Whitaker, 1990, Seismic modeling of the Aux Vases and Cypress sandstones: presentation for Illinois Technical Advisory Committee/Petroleum Advisory Committee meeting, December 13, Mt. Vernon, Illinois.
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- Moore, D. M., and R. E. Hughes, 1990, Varieties of chlorites and illites and porosity in Mississippian sandstone reservoirs in the Illinois Basin (abstract): 75th AAPG Annual Meeting, April 7-10, Dallas, Texas, p. 174-175.
- Moore, D. M., and R. E. Hughes, 1989, The clay mineralogy of two Mississippian sandstone reservoirs in the Illinois Basin: poster for 27th Annual Meeting, Clay Minerals Society, October 6-11, University of Missouri, Columbia, Missouri, p. 90.
- Nelson, W. J., and R. D. Cole, 1992, Regional intertonguing of lithologic intervals, Pope (Chester) Group, Illinois Basin: presentation for AAPG Eastern Section Annual Meeting, September 20-23, Champaign, Illinois.
- Oltz, D. F., 1993, Highlights and conclusions reached during the ENR/DOE improved recovery Project: presentation for IOPA Annual Meeting, June 24, Evansville, Illinois.
- Oltz, D. F., 1992, The Survey's reservoir characterization program, new directions toward reservoir management: presentation for ENR/DOE Workshop, November 18, Mt. Vernon, Illinois.
- Oltz, D. F., 1992, Directions in reservoir characterization and management: presentation for IOPA Tri-State Annual Meeting, June 26, Evansville, Indiana.
- Oltz, D. F., 1992, The improved oil recovery and reservoir characterization program in Illinois: presentation for 23rd Annual Appalachian Petroleum Geology Symposium, "Mississippian Plays in the Appalachian Basin—Shallow Targets for Tough Times," April 2, Morgantown, West Virginia.
- Oltz, D. F., 1992, Present efforts toward increasing recovery efficiency—the Illinois improved oil recovery project: invited paper for AIPG Spring Meeting, May 8, New Harmony, Indiana.
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APPENDIXES

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APPENDIX I: POOL STUDY OUTLINE

- I. DISCOVERY AND PRODUCTION HISTORY
 - A. Location Map
 - 1. Geologic setting
 - 2. Geographic setting
 - B. Discovery History
 - 1. Exploration method(s) used
 - 2. Discovery date (discovery well) and development
 - C. Production History
 - 1. Productive acreage (well $\times$ spacing)
 - 2. Well spacing
 - 3. Total productive wells
 - 4. Total injection wells
 - 5. Unitization
 - 6. Cumulative production and injection
 - 7. Annual production and injection
 - 8. Estimated original oil in place
 - 9. Estimated recoverable reserves
 - a. Primary
 - b. Secondary
- II. RESERVOIR AND TRAP CHARACTERISTICS
 - A. Stratigraphic Section
 - 1. Show oil productive zones in field
 - 2. Brief description of lithology
 - B. Reservoir Geometry
 - 1. Structure
 - 2. Top of Barlow (Cypress only)
 - 3. Top of Ste Gen (Aux Vases only)
 - 4. Top of pay sand or interval (both)
 - 5. Show gas and oil-water contact (both)
 - C. Cross sections - show type log(s) for field
 - 1. Structural; oil-water contact
 - 2. Stratigraphic
 - D. Net Sand Isopachs for each separate sand
 - 1. $\geq 25\%$ SP deflection
 - 2. $\leq 50\%$ SP deflection
 - E. Gross interval isopach
 - F. Net sand: gross interval isopachs
 - 1. Cypress net sand: gross interval (sand/shale ratio)
 - 2. Aux Vases net sand: gross interval
 - 3. Aux Vases net limestone: gross interval
 - 4. Aux Vases net sand: net limestone
 - 5. Aux Vases net sand: net shale
 - G. Paleosstructure
 - 1. Base of Aux Vases paleosstructure
 - a. Top Renault - base of Aux Vases interval¹
 - b. Top Downeys Bluff - base Aux Vases interval¹
 - c. A "time marker" - base of Aux Vases interval¹
 - d. Same marker bed above - base Aux Vases sand

¹ choose one only

2. Base of Cypress paleostructure
 - a. Top of Barlow - base of Cypress interval
 - b. Top of Barlow - base of Cypress sand
- H. Porosity $\geq 15\%$ isopach (or $\geq 10\%$ isopach)
- I. Trap Type
- J. Reservoir Lithofacies
 1. Lithologic descriptions—macroscopic
 - a. Core descriptions correlated to log
 - b. Core analyses correlated to log
 - c. Horizontal porosity and permeability profiles (measured)
 - d. Vertical porosity and permeability profiles (measured)
 - e. Sample descriptions (if needed)
 2. Lithologic descriptions - microscopic
 - a. Grain description
 - b. Size and sorting
 - c. Composition
 - d. Roundness
 - e. Grain interrelationships
 3. Porosity description (thin section; SEM)
 - a. Distribution
 - b. Dissolution
 - c. Vuggy
 - d. Intercrystalline
 - e. Intergranular
 - f. Fracture
 4. Clay content from clay analysis (x-ray diffraction)
 5. Cements
- K. Depositional Environment
 1. Evidence supporting interpretation
 2. Illustration
- L. Diagenesis
 1. Photomicrographs
 2. Illustration of interpreted order of events
- G. Summary: Effects of Petrophysical Properties on Reservoir Quality

III. CLASSIFICATION AND IDENTIFICATION OF PLAY

IV. PRODUCTION CHARACTERISTICS

- A. Map of Production (Isoproduction Map-IP adjusted by year or cumulative)
- B. Drilling and Completion Practices
 1. Drilling fluid
 2. Fracture treatment, if any
 3. Acid, if any
 4. Primary extraction method
 5. Secondary extraction method
- C. Injection and Production Data
 - a. Injection and Production History Curves
 - a. GOR
 - b. WOR
 - c. Oil rate
 - d. Water rate
 - e. Cumulative oil
 - f. Cumulative water
 - g. Total liquid

- h. Cumulative gas
 - i. Wells on production
 - j. Water cut
- 2. Recovery Factors
 - a. Primary
 - b. Secondary
 - c. Total
- 3. Drive mechanism
- D. Oil Characteristics
 - 1. API gravity & viscosity
 - 2. Sulfur content
 - 3. Chromatograph
 - a. Suspected source
 - b. Maturity and migration interpretations
- E. Gas Characteristics
 - 1. Gravity and viscosity
 - 2. Density
 - a. GOR
 - b. Chromatograph
 - 3. Gas analyses
- F. Water Characteristics
 - 1. Formation water
 - a. Resistivity
 - b. Eh, pH
 - c. Interpretations, if any
 - 2. Injection water
 - a. Resistivity
 - b. Eh, pH
 - c. Interpretations, if any
 - 3. Produced as water in waterflood
 - a. Resistivity
 - b. Eh, pH
 - c. Interpretations, if any
 - 4. Interpretations, if any
- G. Reservoir Pressure Data
 - 1. Bottom-hole pressure, initial
 - 2. Bottom-hole pressure, present
 - 3. Injection pressure
 - 4. Isopressure map, initial
 - 5. Isopressure map, waterflood
- H. Original Volumetrics
 - 1. Reservoir area (productive acreage)
 - 2. Net thickness (average)
 - 3. Porosity (average)
 - 4. Initial water saturation, connate S_w (average)
 - 5. Initial oil saturation (average)
 - 6. Initial oil formation volume factor (average)
 - 7. Initial free gas volume
 - 8. Initial gas Formation volume factor (B_{gi})
- I. Current Volumetrics
 - 1. Current oil saturation (average in swept zone)
 - 2. Current oil formation volume factor
 - 3. Current water saturation (average in swept zone)
 - 4. Estimated residual oil saturation (S_{or})

5. Current free gas volume
6. Critical gas Saturation (S_g)
7. Initial gas Formation volume factor (B_{gi})

V. DEVELOPMENT AND PRODUCTION STRATEGY

A. Reservoir Parameter Assignments

1. Layer model
2. Flow unit model
 - a. Cross sections
 - b. Map
3. Fieldwide extrapolation

B. Core Test Results

1. Measurement of rock and fluid properties
 - a. Porosity, permeability, and relative permeability
 - b. Pore size distribution
 - c. PVT
2. Drilling fluids
3. Completion fluids
4. Stimulation fluids
 - a. Acidization
 - b. Clay stabilization
 - c. Other
5. Waterflood
6. Microbial
7. Profile modification and polymer
8. CO_2

C. Reservoir Simulation

1. History matching of coreflow tests/field production
2. Waterflood strategy
3. Infill and horizontal drilling strategies
4. Potential EOR strategies

D. Strategy Economics

E. Recommendations

1. IOR
 - a. Drilling and completion
 - b. Stimulation
 - c. Waterflood
 - d. Infill and horizontal drilling
2. EOR
 - a. Microbial
 - b. Profile modification/polymer
 - c. CO_2

VI. RESERVOIR SUMMARY SHEET *continued on next page*

RESERVOIR SUMMARY SHEET

Field:

Location:

Tectonic/Regional Paleosetting:

Geologic Structure:

Trap Type:

Reservoir Drive:

Original Reservoir Pressure:

Reservoir Rocks:

Age:

Stratigraphic unit:

Lithology:

Wetting characteristics (oil/water):

Depositional environment:

Productive facies:

Petrophysics (ϕ , k from unstressed conventional core; S_w from logs)

Porosity type (ϕ total ____ ; primary ____ ; secondary ____)

Average | Range | Cutoff

ϕ

k air

k liquid

S_w

S_{or}

S_{gr}

Cementation factor

Source Rocks

Lithology and stratigraphic unit:

Time of hydrocarbon maturation:

Time of trap formation:

Cypress/Aux Vases Reservoir Dimensions

Depth (absolute and subsea):

Areal dimensions:

Productive area:

Number of pay zones:

Hydrocarbon column:

Initial/present fluid contacts:

Avg net sand thickness:

Avg gross sand thickness:

Net/gross:

Initial reservoir temperature

Fractured: natural ____ artificial (type) ____

Wells

Spacing:

Pattern:

Total:

producer ____ water source ____ observation ____ suspended ____

injection ____ disposal ____ abandoned ____ dry holes ____

Reservoir Fluid Properties

Hydrocarbons:

Type:

GOR:

API Gravity:

FVF (formation volume factor):

Viscosity:

Bubble-point pressure:

Formation water:

Resistivity:

Total dissolved solids (mg/L):

Volumetrics:

In-place:

Cumulative production:

Ultimate recovery:

Primary:

Secondary (incremental):

Tertiary (incremental):

Recovery efficiency (factor):

Primary:

Secondary:

Tertiary:

Typical Drilling/Completion/Production Practices:

Completions: open hole ____ cased ____

Drilling fluid:

Fracture treatment:

Acidization:

Other:

Producing mechanism:

Primary (indicate any period of flow):

Secondary:

Tertiary:

Typical well production (to date):

Average daily:

Cumulative:

WOR (initial/cumulative)

APPENDIX II: AUX VASES RESERVOIRS AND PLAYS

The Aux Vases Sandstone is a problematic oil producer in Illinois. Research suggests that the Aux Vases is prone to formation damage from drilling and completion practices. There are currently 213 Illinois oil fields with production from the Aux Vases. The reservoirs have been grouped into three preliminary "plays." (Numbers in parenthesis following the field name designate the play.) Play (1) is a tidally influenced delta play defined as deltaic deposits heavily reworked by tidal currents such that any fluvial influence is lost or smeared. Play (2) is a tide-dominated shore zone facies and contains strandplain and barrier island type facies. Play (3) is a tide-dominated shelf facies.

Ab Lake (3)	Crossville W (3)	Johnson N (2)
Ab Lake South (3)	Dale C (2)	Johnson S (2)
Ab Lake West (3)	Deering City (2)	Johnsonville C (2)
Aden C (2)	Divide C (1,2)	Johnsonville S (2)
Aden South (2)	Elba (3)	Johnsonville W (2)
Akin (2)	Eldorado C (3)	Johnston City E (2)
Albion C (3)	Eldorado E (3)	Johnston City NE (2)
Albion East (3)	Eldorado W (2,3)	Junction N (3)
Allendale (3)	Ellery E (3)	Keenville (2)
Alma (1)	Ellery N (3)	Kenner (2)
Amity (3)	Ellery S (3)	Kenner S (2)
Amity W (3)	Elliottstown N (2)	Kenner W (2)
Bannister (2)	Energy (2)	King (1,2)
Barnhill (2,3)	Enfield (3)	Kimmunity (1)
Bellair (2)	Enfield N (3)	Lakewood (1)
Belle Rive (2)	Enfield S (3)	Lancaster Cen (3)
Beman (3)	Ewing (2)	Lawrence (3)
Beman E (3)	Fehr Lake (3)	Lawrence W (3)
Benton (2)	Fitzgerrell (1)	Locust Grove (2)
Benton N (2)	Francis Mills (3)	Locust Grove S (2)
Blairsville W C (2)	Freemanspur (2)	Logan (2)
Bone Gap C (3)	Friendsville Cen (3)	Long Branch (3)
Bourbon C (1)	Galatia N (2)	Louden (1)
Boyd (1)	Gays (1)	Louisville (2)
Broughton N (3)	Goldengate C (3)	Louisville N (2)
Buckner (1,2)	Goldengate N C (2,3)	Louisville S (2)
Bungay C (2)	Grayson (3)	Main C (2,3)
Burnt Prairie S (3)	Half Moon (3)	Maple Grove C (2,3)
Burnt Prairie Sw (3)	Harco (2)	Marion (2)
Calhoun S (2)	Harco E (2)	Markham City N (2)
Carmi (3)	Herald C (3)	Markham City W (2)
Carmi N (3)	Hickory Hill (2)	Mason N (2)
Centerville (3)	Hidalgo E (2)	Mattoon (1)
Centerville E (3)	Hidalgo S (2)	Maurie E (3)
Christopher S (2)	Hill (2)	Maurie N C (3)
Clarksburg (1)	Hill E (2)	Maurie South C (3)
Clay City C (2)	Hord (2)	Miletus (2)
Clifford (2)	Hord N (2)	Mill Shoals (2)
Coil (2)	Hord S C (2)	Mode (1)
Coil W (2)	Hunt City E (2)	Mt. Carmel (3)
Concord C (3)	Ina (1)	Mt. Erie N (2)
Concord E C (3)	Ingraham C (2)	Mt. Vernon (1)
Cooks Mills C (1)	Inman E C (3)	New Bellair (2)
Corinth (2)	Inman W C (3)	New Harmony C (3)
Corinth N (2)	Iola C (2)	New Harmony S (III) (3)
Crossville (3)	Iuka (2)	New Haven C (3)

New Hebron E (3)	Toliver S (2)
Noble W (2)	Tonti (1)
Oakdale (2)	Trumbull C (3)
Oak Point (2)	Trumbull N (3)
Oak Point W (2)	Valier (1)
Old Ripley (1)	Walpole (2)
Olney C (2)	Walpole S (2)
Omaha (3)	Watson W (2)
Omaha E (3)	West Frankfort C (2)
Omaha S (3)	West Seminary (2)
Omaha W (3)	Whiteash (2)
Omega (2)	Whittington (2)
Orchardville (2)	Whittington W (1)
Orchardville N (2)	Williams C (1)
Orient (2)	Woburn C (1)
Orient N (2)	Woodlawn (1)
Oskaloosa (2)	Xenia (2)
Oskaloosa E (2)	Xenia E (2)
Pankeyville (3)	Yale (2)
Parkersburg C (3)	Zeigler (3)
Parkersburg W (3)	
Passport N (2)	
Passport S (2)	
Patoka (1)	
Phillipstown C (3)	
Pittsburg N (2)	
Raleigh (3)	
Raleigh S (2,3)	
Reservoir (1,2)	
Roland C (3)	
Roland W (3)	
Ruark (3)	
Ste. Marie W (2)	
Sailor Springs C (2)	
Salem C (1)	
Schnell (2)	
Sesser C (1)	
Shawneetown (3)	
Shawneetown E (3)	
Shawneetown N (3)	
Shelbyville C (1)	
Springerton (2,3)	
Springerton S (3)	
Stewardson (1)	
Stewardson E (2)	
Stiritz (2)	
Storms C (3)	
Sumner S (3)	
Sumpter E (3)	
Sumpter N (3)	
Sumpter S (3)	
Sumpter W (3)	
Thackeray (2)	
Thompsonville E (2)	
Thompsonville N (2)	
Toliver E (2)	

APPENDIX III: CYPRESS RESERVOIRS AND PLAYS

Cypress Sandstone reservoirs are major contributors to Illinois oil production. Preliminary examination of geological data suggests that at least four "plays" can be determined using depositional system as a major criterion. Play (1) is deltaic. Play (2) is a tidally influenced delta in which, as in the Aux Vases, the original deltaic fabric is almost gone because of reworking. Play (3) is a tide-dominated shore zone facies that includes strandplain and barrier island facies. Play (4) is a tide-dominated shelf facies. Numbers in parentheses designate the play.

Ab Lake West (2)	Harco (4)	Pankeyville (2)
Akin (4)	Harco E (2)	Pankeyville E (2)
Akin West (4)	Harrisburg S (2)	Parkersburg C (2)
Albion C (2)	Herald C (2)	Parkersburg So (2)
Albion East (2)	Herrin (4)	Passport S (4)
Allendale (2)	Hickory Hill (3)	Patoka (3)
Alma (3)	Hill E (4)	Patoka E (3)
Assumption Cen (1)	Hoffman (3)	Patoka S (3)
Ava-Campbell Hill (3)	Hord N (4)	Phillipstown C (2)
Barnhill (4)	Huey S (3)	Pixley (4)
Bartelso (3)	Inman E C (2)	Posey (3)
Bartelso W (3)	Inman W C (2)	Raccoon Lake (3)
Beaver Creek S (3)	Iola Cen (3)	Radom SE (3)
Beckemeyer Gas (3)	Iola C (3)	Raleigh (2)
Bellair (2)	Irvington (3)	Raleigh S (2)
Benton N (3)	Irvington E (3)	Richview (3)
Berryville C (2)	Irvington N (3)	Roland C (2)
Bone Gap C (2)	Irvington W (3)	Ruark W C (2)
Broughton S (2)	Johnston City E (4)	Rural Hill N (4)
Brown (3)	Junction (2)	St. Francisville E (2)
Browns E (2)	Junction N (2)	St. James (3)
Carlyle (3)	Keensburg S (2)	Sailor Springs C (4)
Carlyle S (3)	Kenner W (4)	Sailor Springs E (4)
Carmi (2)	Langewisch-Kuester (3)	Sandoval (3)
Carmi N (2)	Lawrence (2)	Sandoval W (3)
Centerville E (2)	Lexington (2)	Santa Fe (3)
Centralia (3)	Logan (4)	Sesser C (3)
Centralia W (3)	Long Branch (4)	Shattuc (3)
Clay City C (4)	Long Branch S (2)	Shawneetown (2)
Concord C (2)	Louden (3)	Sparta (3)
Concord E C (2)	Main C (2)	Sparta S (3)
Cooks Mills C (1)	Marissa W (3)	Storms C (2)
Cordes Ne (3)	Mattoon (1)	Stubblefield S (3)
Corinth S (4)	Maunie N C (2)	Sumpter (2)
Crossville W (2)	Maunie South C (2)	Sumpter E (2)
Dale C (4)	Mill Shoals (4)	Tamaroa (3)
Dubois C (3)	Mitchellville (2)	Tamaroa S (3)
Eberle (4)	Mt. Carmel (2)	Tamaroa W (3)
Elba (2)	New Bellair (2)	Thackeray (4)
Eldorado C (2)	New Harmony C (2)	Thompsonville N (4)
Eldorado E (2)	New Harmony S (Ill) (2)	Toliver E (4)
Elliottstown E (4)	New Haven C (2)	Trumbull C (2)
Elliottstown N (4)	Oak Grove (Ind)	Wamac W (3)
Fayetteville (3)	Odin (3)	Whittington (3)
Francis Mills (2)	Omaha (2)	Whittington S (3)
Freeburg (3)	Omaha E (2)	Williams C (3)
Goldengate C (4)	Omaha S (2)	Woburn C (3)
Grayson (2)	Omaha W (2)	Woodlawn (3)
		Xenia E (4)

APPENDIX IV: HISTORICAL OIL PRODUCTION IN ILLINOIS

YEAR	TOTAL	YEAR	TOTAL	YEAR	TOTAL
1899-1904	22000	1944	77413000	1984	28873000
1905	181000	1945	75210000	1985	30265000
1906	4397000	1946	75297000	1986	27245000
1907	24282000	1947	66459000	1987	24096000
1908	33686000	1048	64808000	1988	22476000
1909	30898000	1949	64501000	1989	20389000
1910	33143000	1950	62028000	1990	19900000
1911	31317000	1951	60244000	1991	19069000
1912	28602000	1952	60071000	1992	19137000
1913	23894000	1953	59025000	1993	19050000 est
1914	21920000	1954	66940000		
1915	19042000	1955	81131000		
1916	17714000	1956	82314000		
1917	15777000	1957	76649000		
1918	13366000	1958	80779000		
1919	11960000	1959	76727000		
1920	10774000	1960	77341000		
1921	10043000	1961	77478000		
1922	9383000	1962	78800000		
1923	8707000	1963	74796000		
1924	8081000	1964	70168000		
1925	7863000	1965	63708000		
1926	7760000	1966	61982000		
1927	6994000	1967	60115000		
1928	6462000	1968	56391000		
1929	6319000	1969	50724000		
1930	5736000	1970	43747000		
1931	5039000	1971	39084000		
1932	4673000	1972	34874000		
1933	4244000	1973	30669000		
1934	4479000	1974	27553000		
1935	4322000	1975	26067000		
1936	4445000	1976	26772000		
1937	7426000	1977	25608000		
1938	24075000	1978	23362000		
1939	94912000	1979	21793000		
1940	147647000	1980	23139000		
1941	134138000	1981	25490000		
1942	106590000	1982	27709000		
1943	82256000	1983	29200000		

APPENDIX V: RESERVOIR SUMMARIES

Bartelso Field Reservoir Summary

Location Clinton County, Illinois

Tectonic/ Regional Paleosetting Western flank of Illinois Basin Intracratonic

Geologic Structure Drape over a Silurian pinnacle reef

Trap Type Structural-stratigraphic

Reservoir Drive Gas solution

Original Reservoir Pressure N/A

Reservoir Rocks

Age: Mississippian (Chesterian)

Stratigraphic unit: Cypress

Lithology: Quartz arenite-subarkose

Wetting Characteristics (oil/water): Red = oil-wet; all other intervals water-wet

Depositional environment: Red = tidal bar; br = coastal plain; pur and pink = shoreface

Productive facies: Sandstones of the red, brown, and purple intervals

Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)

Porosity type (ϕ total 20%; primary 15%; secondary 5.0%)

	Average	Range	Economic cutoff
ϕ (%)	20.0	16.0 - 26.0	16.0
k air (md)	200.0	16.0 - 620.0	100.0
k liquid (md)	N/A	N/A	N/A
S_w (%)	30.0	10.0 - 95.0	50.0
S_{or} (%)	70.0	5.0 - 90.0	50.0
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A		

Source Rocks

Lithology and stratigraphic unit New Albany Shale (?)

Time of hydrocarbon maturation Permian-Triassic (?)

Time of trap formation Chesterian (stratigraphic); Penn./Perm. (structural)

Reservoir Dimensions

Absolute depth: 970-1100 ft

Subsea depth

Areal dimensions: 560 acres

Productive area: 440 acres

Number of pay zones: 3

Hydrocarbon column: 70 ft

Initial/present fluid contacts: Gas/oil = -492 ft red, oil/water = -550 ft purple,

O/W = -540 ft brown

Average net sand thickness: Red A = 4 ft, red B = 4 ft, brown = 2 ft, purple = 6 ft

Average gross sand thickness: Red A = 5 ft, red B = 6 ft, brown = 4 ft, purple = 8 ft

Initial reservoir temperature: 100°F

Initial reservoir temperature source

Wells

Spacing 10 acre

Pattern Normal primary with five-spot injection program

Producers: 43 Water source: 2 Observation: 0 Suspended: 0

Injection: 24 Disposal: 3 Abandoned: 37 Dry Holes: 27

Other: 0

Reservoir Fluid Properties

Hydrocarbons

Type: Oil and gas

Reservoir Fluid Properties continued

Gas/oil ratio: N/A

API gravity: 36.00

Formation volume factor: 1.150

Oil viscosity: 6.3 cp @ 71°F

Bubble-point pressure: N/A

Formation water

Average resistivity: 0.14 ohm-m @ 77°F

Total dissolved solids (ppm): 49,900

Volumetrics

In place: 5,062,000 bbl

Cumulative production: 2,500,000 bbl

Ultimate recovery

Primary: 1,250,000 bbl

Secondary (incremental): 1,250,000 bbl

Tertiary (incremental): N/A

Recovery efficiency (factor)

Primary: 25.0%

Secondary: 25.0%

Tertiary: N/A

Typical Drilling/ Completion/ Production Practices

Completions: Open hole and cased

Drilling fluid: Fresh-water mud

Fracture treatment: 20-40 qt nitroglycerin

Acidization: None

Other**Producing mechanism**

Primary Pump

Secondary Pump

Tertiary

Typical well production (to date)

Average daily: N/A

Cumulative: N/A

WOR initial: N/A

WOR cumulative: N/A

Field Wells (API numbers)

120270000600	120270000700	1202700022500	1202700022800	1202700022900	1202700023000
1202700023100	1202700023200	1202700023300	1202700023400	1202700023600	1202700023700
1202700023800	1202700024300	1202700025500	1202700025600	1202700025700	1202700025800
1202700025900	1202700026000	1202700026100	1202700026200	1202700026400	1202700026500
1202700026600	1202700026700	1202700026800	1202700028000	1202700028100	1202700031500
1202700031600	1202700031700	1202700031800	1202700031900	1202700032000	1202700032100
1202700032300	1202700032500	1202700033100	1202700033200	1202700037500	1202700037700
1202700038000	1202700038001	1202700038002	1202700038001	1202700042000	1202700043200
1202700043300	1202700043700	1202700044100	1202700049100	1202700049300	1202700049400
1202700049401	1202700054700	1202700054701	1202700054800	1202700054801	1202700055000
1202700055100	1202700055300	1202700055400	1202700056300	1202700056301	1202700056500
1202700056600	1202700056601	1202700056700	1202700056800	1202700060400	1202700060401
120270110500	120270110600	120270110700	120270111300	120270112600	120270112700
120270112800	120270113001	120270114800	120270115700	120270116000	120270116400
120270120800	120270120900	120270121000	120270121600	120270122000	120270122200
120270122800	120270123700	120270123800	120270128700	120270136600	120270138300
120270154700	120270156000	120270156001	120270184600	120270187500	120270193200
120270195100	120270196100	120270196400	120270196600	120270197000	120270197001
120270197500	120270197600	120270241600	120270242600	120270242700	120270242800

120270242900	120270243000	120270243100	120270243200	120270243300	120270243400
120270243500	120270243600	120270243700	120270244100	120270244200	120270244300
120270244400	120270244500	120270244501	120270244700	120270244800	120270245100
120270245200	120270245300	120270245400	120270245500	120270245600	120270245700
120270245800	120270246100	120270246400	120270246700	120270246800	120270247000
120270247100	120270247200	120270247300	120270247400	120270247600	120270255200
120270262900	120270262901	120270262902	120270296500	120270314200	120270314300
120270314500	120270314600	120270334300	120270351100	120270351500	120270368200
120270393400	120270417500	120270419300	120272420800	120272423900	120272423901
120272424000	120272431700	120272432300	120272502800	120272507200	120272513800
120272542300					

Boyd Field Reservoir Summary

Location Jefferson County, Illinois

Tectonic/ Regional Paleosetting Illinois Basin, intracratonic

Geologic Structure Anticline

Trap Type Structural-stratigraphic

Reservoir Drive Gas depletion drive

Original Reservoir Pressure unknown

Reservoir Rocks

Age Upper Valmeyeran Series of Mississippian System

Stratigraphic unit Aux Vases

Lithology Sandstone

Depositional environment Mixed siliciclastic-carbonate, nearshore

Productive facies

Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)

Porosity type (ϕ total 20%; primary 15%; secondary 5%)

	Average	Range	Economic cutoff
ϕ (%)	18.0	7.0 - 30.0	11.90
k air (md)	240.0	38.0 - 833.0	50.0
k liquid (md)	N/A	N/A	N/A
S_w (%)	45.0	N/A	N/A
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A

Cementation factor 1.70

Source Rocks

Lithology and stratigraphic unit New Albany Shale (?)

Time of hydrocarbon maturation N/A

Time of trap formation N/A

Reservoir Dimensions

Absolute depth 2,140 ft

Subsea depth

Areal dimensions 1200 acres

Productive area 1200 acres

Number of pay zones 3

Hydrocarbon column unknown

Initial/present fluid contacts no clear oil-water contact

Average net sand thickness 15 ft

Average gross sand thickness N/A

Initial reservoir temperature N/A

Initial reservoir temperature source

Wells

Spacing 10 acre

Pattern N/A

Producers: 48

Water source: 0

Observation: 0

Suspended: 0

Injection: 11

Disposal: 0

Abandoned: 0

Dry holes: 0

Other: 0

Reservoir Fluid Properties**Hydrocarbons**

Type Oil

Gas/oil ratio N/A

API gravity 36.80°

Formation volume factor 1.064

Viscosity 4.4 cp @ 90°F

Bubble-point pressure N/A

Formation water

Resistivity N/A

Total dissolved solids (ppm) N/A

Volumetrics

In place 4,400,000 bbl

Cumulative production N/A

Ultimate recovery

Primary N/A

Secondary (incremental) N/A

Tertiary (incremental) N/A

Recovery efficiency (factor)

Primary N/A

Secondary N/A

Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased - N/A

Drilling fluid Bentonite

Fracture treatment 5000 gal oil and 7500 lb sand

Acidization N/A

Other

Producing mechanism

Primary Gas depletion

Secondary Waterflood

Tertiary N/A

Typical well production (to date)

Average daily N/A

Cumulative N/A

WOR initial N/A

WOR cumulative N/A

Field Wells (API numbers)

1208101910	1208100690	1208101387	1208101904	1208101906	1208101950
1208101389	1208123050	1208101925	1208100653	1208101949	1208101922
1208101928	1208101948	1208101921	1208101920	1208101929	1208100692
1208100694	1208100691	1208101924	1208101934	1208101940	1208101936
1208101939	1208101938	1208101916	1208124444	1208101937	1208101915
1208101946	1208101932	1208100696	1208101931	1208122911	1208101972
1208101973	1208101786	1208122921	1208101395	1208101970	1208101970
1208101969	1208101962				

Dale Consolidated Field Reservoir Summary

Location Franklin, Hamilton, Saline Counties, Illinois

Comments Dale is divided into three leases in the study area (summaries of each lease follow)

Tectonic/ Regional Paleosetting Illinois Basin, intracratonic

Geologic Structure

Geologic Play(s) Offshore sandstone bar facies

Trap Type Structural-stratigraphic

Reservoir Drive Solution gas drive

Original Reservoir Pressure approximately 1250 psi

Reservoir Rocks

Age Mississippian (upper Valmeyeran - lower Chesterian Series)

Stratigraphic unit Aux Vases

Lithology Quartz arenite-subarkose

Wetting characteristics Water-wet

Depositional environment Marine bar complex in mixed siliciclastic-carbonate offshore

Productive facies Marine bar facies

Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)

	Average	Range	Economic Cutoff
ϕ (%)	N/A	N/A	N/A
k air (md)	N/A	N/A	N/A
k liquid (md)	N/A	N/A	N/A
S_w (%)	N/A	N/A	N/A
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A		

Source Rocks

Lithology and stratigraphic unit New Albany Shale (?)

Time of hydrocarbon maturation Permo-Triassic (?)

Time of trap formation Chesterian (stratigraphic)

Reservoir Dimensions

Absolute depth 3,110 ft

Subsea depth

Areal dimensions 1,250 acres

Productive area 600 acres

Number of pay zones 1

Hydrocarbon column 25-30 ft

Initial/present fluid contacts

Average net sand thickness

Average gross sand thickness

Initial reservoir temperature 100°F

Initial reservoir temperature source Estimated from logs

Wells

Spacing 10 acre

Pattern Normal; modified five-spot injection Cantrell South; periph. elsewhere

Producers: 59 Water source: 3 Observation: 2 Suspended: 0

Injection: 2 Disposal: 4 Abandoned: 34 Dry holes: 34

Other: 8

Reservoir Fluid Properties

Hydrocarbons

Type Oil

Gas/oil ratio N/A

API gravity 36.60

Reservoir Fluid Properties continued

Oil viscosity 4.1 cp @ 98°F

Bubble-point pressure N/A

Formation water

Resistivity .0585-.0664 @ 77°F

Total dissolved solids (ppm) 123,200-140,500

Volumetrics

In place N/A

Cumulative production N/A

Ultimate recovery

Primary N/A

Secondary (incremental) N/A

Tertiary (incremental) N/A

Recovery efficiency (factor)

Primary N/A

Secondary N/A

Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased - N/A

Drilling fluid N/A

Fracture treatment N/A

Acidization N/A

Other

Producing mechanism

Primary N/A

Secondary N/A

Tertiary N/A

Typical well production (to date)

Average daily N/A

Cumulative N/A

WOR initial N/A

WOR cumulative N/A

Field Wells (API numbers)

120550060600	120550069800	120550094100	120550103100	120550103101	120550103200
120550112600	120550112700	120550112701	120550112702	120550113300	120550115100
120550115200	120550115900	120550116100	120550116300	120550116400	120550116700
120550116800	120550117000	120550117400	120550119300	120550119301	120550119900
120550119901	120550120000	120550120800	120550121000	120550121200	120550123800
120550123801	120550127900	120550129700	120550129800	120550129900	120550130600
120550137600	120550138300	120550139700	120550147800	120550147801	120550151400
120550152200	120550152700	120550153800	120550158100	120550158200	120550158300
120550158400	120550161500	120550186600	120550186700	120550186800	120550186801
120550188000	120550188100	120550188101	120550188200	120550188300	120550188400
120550188500	120550188600	120550188700	120550188701	120550188800	120550188900
120550188901	120550198500	120550244000	120550245300	120550248500	120550255000
120550255200	120550256800	120550256801	120550256802	120550258400	120550258401
120552272000	120552272100	120552273000	120552275300	120552277800	120552326400
120552327400	120552343300	120552344400	120552344401	120552344900	120552345200
120552345500	120552345501	120552345600	120552345700	120552345702	120552346100
120552346200	120552346700	120552347000	120552347100	120552347200	120552347201
120552348100	120552348200	120552348201	120552348700	120552349400	120552349600
120552349700	120552350300	120552350400	120552350401	120552350500	120552351700
120552352500	120552352900	120552352901	120552355201	120552355202	120552356200
120552356600	120552356601	120552362600	120650060400	120650060401	120650060402
120650074600	120650074700	120650074800	120650074900	120650074901	120650078500

120650078600	120650078601	120650078700	120650079900	120650080200	120650080201
120650080300	120650080301	120650080700	120650080701	120650080800	120650081200
120650081500	120650082500	120650083100	120650083900	120650084200	120650084600
120650085500	120650085501	120650085600	120650085900	120650085901	120650087300
120650087301	120650087400	120650087401	120650087500	120650088200	120650092400
120650094400	120650094401	120650102600	120650107400	120650107401	120650108000
120650109200	120650112800	120650114300	120650121000	120650127000	120650142300
120650142400	120650142500	120650142600	120650142700	120650142701	120650142800
120650142801	120650142900	120650142901	120650143000	120650143100	120650163000
120650175100	120650175101	120650307900	120650307901	120650308000	120650308100
120650308101	120650308200	120650308300	120650308400	120650308500	120650308600
120650308601	120650308700	120650308701	120650308800	120650308900	120650308901
120650309000	120650309100	120650309200	120650309201	120650309300	120650309400
120650309500	120650309700	120650309800	120650309900	120650309901	120650310000
120650310001	120650310100	120650310200	120650310300	120650310400	120650310500
120650310600	120650310700	120650310800	120650310900	120650311000	120650311100
120650311101	120650311200	120650311300	120650311400	120650311400	120650311500
120650311600	120650311700	120650311701	120650311702	120650311800	120650311900
120650311901	120650312000	120650312001	120650312002	120650312100	120650312101
120650312200	120650312201	120650312300	120650312400	120650312500	120650312600
120650312700	120650312800	120650312900	120650313000	120650313001	120650313100
120650313101	120650313200	120650313300	120650313301	120650313400	120650313500
120650313600	120650313700	120650313701	120650313800	120650313900	120650313901
120650314000	120650314001	120650314100	120650314200	120650314201	120650314300
120650314400	120650314500	120650314600	120650314700	120650314800	120650314900
120650315000	120650315100	120650315200	120650323800	120650323801	120650343200
120650343201	120650343300	120650343301	120650343302	120650346900	120650360100
120650366400	120652383600	120652383800	120652383900	120652384100	120652387000
120652387900	120652387901	120652438300	120652454000	120652455500	120652455600
120652455601	120652455800	120652455900	120652456000	120652457000	120652457500
120652460300	120652460301	120652482200	120652483400	120652483500	120652483600
120652484300	120652484400	120652485000	120652487900	120652494100	120652494700
120652495400	120652495401	120652495701	120652497500	120652501300	120652502000
120652502800	120652503500	120652503501	121650085500	121650112200	121650113100
121650115900	121650135500	121650135600	121650135700	121650135800	121650135900
121650136000	121650136100	121650136200	121650136300	121650141800	121650215700
121650215800	121650242200	121650266100	121650266900	121650301300	121650302400
121650303000	121650303100	121650303900	121650304000	121650306400	121650322700
121650327700	121650350700	121652397900	121652464900	121652466100	121652537400
121652545400	121652550700	121652558000			

Dale Cantrell South Field Reservoir Summary

Location Franklin, Hamilton, and Saline Counties, Illinois

Comments

Tectonic/ Regional Paleosetting Intracratonic Basin

Geologic Structure

Geologic Play(s) Offshore sandstone bar facies

Trap Type Structural-stratigraphic

Reservoir Drive Solution gas drive

Original Reservoir Pressure Approximately 1250 psi

Reservoir Rocks

Age Mississippian (upper Valmeyeran to lower Chesterian Series)

Stratigraphic unit Aux Vases Formation

Lithology Quartz arenite-subarkose

Wetting characteristics Water-wetting

Depositional environment Marine sandstone bar complex in mixed siliciclastic-carbonate offshore

Productive facies Marine bar facies

Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)

	Average	Range	Economic cutoff
ϕ (%)	21.41	10.0 - 26.0	13.0
k air (md)	125.0	0.1 - 655	10.0
k liquid (md)	N/A	N/A	N/A
S_w (%)	50.0	10.0 - 95.0	60.0
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	
Cementation factor	N/A		

Source Rocks

Lithology and stratigraphic unit New Albany Shale (?)
 Time of hydrocarbon maturation Permo-Triassic (?)
 Time of trap formation Chesterian (stratigraphic)

Reservoir Dimensions

Absolute depth 3,110 ft
 Subsea depth
 Areal dimensions 490 acres
 Productive area
 Number of pay zones 1
 Hydrocarbon column 25-30 ft
 Initial/present fluid contacts No oil-water contact
 Average net sand thickness
 Average gross sand thickness
 Initial reservoir temperature 100°F
 Initial reservoir temperature source Estimated from logs
 Fractured Artificial; nitroglycerin-induced

Wells

Spacing 10 acre
 Pattern Normal; modified five-spot injection utilizing existing wells
 Producers: 20 Water source: 0 Observation: 0 Suspended: 0
 Injection: 0 Disposal: 0 Abandoned: 0 Dry holes: 0
 Other: 0

Reservoir Fluid Properties

Hydrocarbons
 Type Oil
 Gas/oil ratio N/A
 API gravity 36.60
 Formation volume factor 1.150
 Oil viscosity 4.1 cp @ 98°F
 Bubble-point pressure N/A
 Formation water
 Resistivity 0.0585-0.0664 ohm-m @ 77°F
 Total dissolved solids (mg/L) 123,200-140,500

Volumetrics

In place 3,757,100 bbl
 Cumulative production 1,158,000 bbl
 Ultimate recovery
 Primary 646,000 bbl
 Secondary (incremental) 512,000 bbl
 Tertiary (incremental) N/A

Recovery efficiency (factor)

Primary 17.2%

Secondary 13.6%

Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole or cased

Drilling fluid Fresh-water mud

Fracture treatment 30-40 qt nitroglycerin

Acidization None

Other

Producing mechanism

Primary Pump

Secondary Pump

Tertiary N/A

Typical well production (to date)

Average daily 173

Cumulative 57590

WOR initial N/A

WOR cumulative N/A

Field Wells (API numbers): see Dale Consolidated Field Reservoir Summary

Dale Cantrell Field Reservoir Summary

Location Franklin, Hamilton, and Saline Counties, Illinois

Comments

Tectonic/ Regional Paleosetting Illinois Basin, intracratonic

Geologic Structure

Geologic Play(s) Offshore sandstone bar facies

Trap Type Structural-stratigraphic

Reservoir Drive Solution gas drive

Original Reservoir Pressure Approximately 1250 psi

Reservoir Rocks

Age Mississippian (upper Valmeyeran to lower Chesterian Series)

Stratigraphic unit Aux Vases Sandstone

Lithology Quartz arenite-subarkose

Wetting characteristics Water-wetting

Depositional environment Marine sandstone bar complex in mixed siliciclastic-carbonate offshore

Productive facies Marine bar facies

Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)

Porosity (total 21.0%)

	Average	Range	Economic cutoff
ϕ (%)	21.41	10.0 - 26.0	13.0
k air (md)	125.0	0.1 - 655	10.0
k liquid (md)	N/A	N/A	N/A
S_w (%)	50.0	10.0 - 95.0	60.0
S_{wi} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A		

Source Rocks

Lithology and stratigraphic unit New Albany Shales (?)

Time of hydrocarbon maturation Permo-Triassic (?)

Time of trap formation Chesterian (stratigraphic)

Reservoir Dimensions

Absolute depth 3,110 ft
Subsea depth
Areal dimensions 385 acres
Productive area
Number of pay zones 1
Hydrocarbon column 25–30 ft
Initial/present fluid contacts No oil–water contact
Average net sand thickness
Average gross sand thickness
Initial reservoir temperature 100°F
Initial reservoir temperature source Estimated from logs
Fractured Artificial; nitro- and hydraulic-induced

Wells

Spacing 10 acre
Pattern Normal; peripheral injection program in waterflood
Producers: 22 Water source: 0 Observation: 0 Suspended: 0
Injection: 0 Disposal: 0 Abandoned: 0 Dry holes: 0
Other: 0

Reservoir Fluid Properties

Hydrocarbons
Type Oil
Gas/oil ratio N/A
API gravity 36.60
Formation volume factor 1.150
Oil viscosity 4.1 cp @ 98°F
Bubble-point pressure N/A
Formation water
Resistivity 0.0585–0.0664 ohm-m @ 77°F
Total dissolved solids (mg/L) 123,200–140,500

Volumetrics

In place 2,345,800 bbl
Cumulative production 6,067,000 bbl
Ultimate recovery
Primary 373,900 bbl
Secondary (incremental) 232,800 bbl
Tertiary (incremental) N/A
Recovery efficiency (factor)
Primary 15.3%
Secondary 9.6%
Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole or cased
Drilling fluid Fresh-water mud
Fracture treatment Early wells hydrofractured; later wells 30–40 qt nitroglycerin
Acidization Early none; later 500 gal MCA
Other
Producing mechanism
Primary Pump
Secondary Pump
Tertiary

Typical well production (to date)

Average daily	178	Range	276-80 BOPD
Cumulative	48,850	Range	43,340-5,510 bbl
WOR initial	0.2	Range	.002-.300
WOR cumulative	N/A		

Field Wells (API numbers): see Dale Consolidated Reservoir Summary

Dale McCreery-McCullum Units Reservoir Summary

Location Franklin, Hamilton, and Saline Counties, Illinois

Comments

Tectonic/ Regional Paleosetting Illinois Basin, intracratonic

Geologic Structure

Geologic Play(s) Offshore sandstone bar facies

Trap Type Structural-stratigraphic

Reservoir Drive Solution gas drive

Original Reservoir Pressure Approximately 1250 psi

Reservoir Rocks

Age Mississippian (upper Valmeyeran to lower Chesterian Series)

Stratigraphic unit Aux Vases Sandstone

Lithology Quartz arenite-subarkose

Wetting characteristics Water-wetting

Depositional environment Marine sandstone bar complex in mixed siliciclastic-carbonate offshore

Productive facies Marine bar facies

Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)

Porosity (total 21.0%)

	Average	Range	Economic cutoff
ϕ (%)	21.41	10.0 - 26.0	13.0
k air (md)	125.0	0.1 - 655	10.0
k liquid (md)	N/A	N/A	N/A
S_w (%)	50.0	10.0 - 95.0	60.0
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A		

Source Rocks

Lithology and stratigraphic unit New Albany Shale (?)

Time of hydrocarbon maturation Permo-Triassic (?)

Time of trap formation Chesterian (stratigraphic)

Reservoir Dimensions

Absolute depth 3,110

Subsea depth

Areal dimensions 400 acres

Productive area

Number of pay zones 1

Hydrocarbon column 25-30 ft

Initial/present fluid contacts Oil-water -2,715

Average net sand thickness

Initial reservoir temperature 100°F

Initial reservoir temperature source Estimated from logs

Fractured Artificial; hydraulic-induced

Wells

Spacing 10 acre

Pattern Normal; peripheral injection program in waterflood
Producers: 17 Water Source: 0 Observation: 0 Suspended: 0
Injection: 0 Disposal: 0 Abandoned: 0 Dry holes: 0
Other: 0

Reservoir Fluid Properties

Hydrocarbon

Type Oil
Gas/oil ratio N/A
API gravity 36.60
Formation volume factor 1.150
Oil viscosity 4.1 cp @ 98°F
Bubble-point pressure N/A

Formation water

Resistivity 0.0585-0.0664 ohm-m @ 77°F
Total dissolved solids (mg/L) 123,200-140,500

Volumetrics

In place 2,691,050 bbl
Cumulative production 487,900 bbl
Ultimate recovery
Primary 487,900 bbl
Secondary (incremental) N/A
Tertiary (incremental) N/A
Recovery efficiency (factor)
Primary 19.7%
Secondary N/A
Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased
Drilling fluid Fresh-water mud
Fracture treatment Hydraulic
Acidization 500 gal MCA
Other

Producing mechanism

Primary Pump
Secondary Pump
Tertiary

Typical well production (to date)

Average daily 83	Range 96-69.5 BOPD
Cumulative 71,830	Range 49540-22,290 bbl
WOR initial 0.2	Range .042-.345
WOR cumulative N/A	

Field Wells (API numbers): see Dale Cons. Reservoir Summary

Energy Field Reservoir Summary

Location Williamson County, Illinois
Tectonic/ Regional Paleosetting Illinois Basin, intracratonic
Geologic Structure Ramp
Trap Type Stratigraphic
Reservoir Drive Solution gas
Original Reservoir Pressure
Reservoir Rocks
Age Upper Valmeyeran of the Mississippian System

Stratigraphic unit	Aux Vases Sandstone		
Lithology	Sandstone		
Depositional environment	Offshore tidal bar/mixed siliciclastic-carbonate		
Productive facies	Tidal bar; shallow marine bar		
Petrophysics (ϕ , k from unstressed conventional core; S_w from logs)			
	Average	Range	Economic cutoff
ϕ (%)	N/A	N/A	N/A
k air (md)	N/A	N/A	N/A
k liquid (md)	N/A	N/A	N/A
S_w (%)	N/A	N/A	N/A
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A		

Source Rocks

Lithology and stratigraphic unit New Albany Shale
Time of hydrocarbon maturation NA
Time of trap formation Late Valmeyeran

Reservoir Dimensions

Absolute depth
Subsea depth
Areal dimensions 220 acres
Productive area 5,525 acre-ft
Number of pay zones 1
Hydrocarbon column
Initial/present fluid contacts
Average net sand thickness 25 ft
Average gross sand thickness 25 ft
Initial reservoir temperature 84°F

Wells

Spacing 10 acre
Pattern Regular
Producers: 22 Water source: 0 Observation: 0 Suspended: 0
Injection: 3 Disposal: 0 Abandoned: 2 Dry holes: 7
Other: 0

Reservoir Fluid Properties

Hydrocarbons
API gravity 39.40
Oil viscosity 3.9 cp @ 84°F
Bubble-point pressure N/A
Formation volume factor 1.100
Formation water
Resistivity 0.062–0.064 ohm-m @ 74°F
Total dissolved solids (mg/L) 122,400–132,000

Volumetrics

In place 4,400,000 bbl
Cumulative production 285,300 bbl
Ultimate recovery
Primary 346,000 bbl
Secondary (incremental) 13.6%
Recovery efficiency (factor)
Primary 7.3%

Recovery efficiency *continued*

Secondary 13.6%

Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole 2; cased 20

Drilling fluid Bentonite fresh-water mud

Fracture treatment Open holes: 20 qt nitro; cased holes: gel saltwater/sand

Acidization

Other 1 well lease oil-fractured

Producing mechanism

Primary Solution gas depletion, pump

Secondary Waterflood, pump

Tertiary

Typical well production (to date)

Average daily N/A

Cumulative 15,000

WOR N/A

Field Wells (API numbers)

121990102400	121990102500	121990109100	121990187900	121990200800	121990233600
121990234400	121990234500	121990235800	121990235900	121990236900	121990236901
121990237000	121990237700	121990238700	121990239500	121990239700	1219902318100
121992326800	121992342000	121992345500	121992345600	121992345700	121992345900
121992346000	121992346100	121992346500	121992346600	121992346601	121992346700
121992346701	121992347100	121992347200	121992347700	121992348100	121992348200
121992348400					

Energy South Lower Field Reservoir Summary

Location Williamson County, Illinois

Tectonic/ Regional Paleosetting Illinois Basin

Geologic Structure Ramp

Trap Type Stratigraphic

Reservoir Drive Solution gas

Original Reservoir Pressure

Reservoir Rocks

Age Upper Valmeyeran of the Mississippian System

Stratigraphic unit Aux Vases

Lithology Sandstone

Depositional environment Offshore tidal bar/mixed siliciclastic-carbonate

Productive facies Tidal bar; shallow marine bar

Petrophysics (ϕ , k from unstressed conventional core; S_w from logs)

	Average	Range	Economic cutoff
ϕ (%)	20.7	N/A	N/A
k air (md)	N/A	N/A	N/A
k liquid (md)	150.0	N/A	N/A
S_w (%)	50%	N/A	N/A
S_{or} (%)	14.6	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A		

Source Rocks

Lithology and stratigraphic unit New Albany Shale (?)

Time of hydrocarbon maturation N/A

Time of trap formation Late Valmeyeran

Reservoir Dimensions

Absolute depth 2,370 ft
 Subsea depth
 Areal dimensions
 Productive area 1,795 acres
 Number of pay zones 1
 Initial fluid contacts Oil-water -1,923 ft
 Average net sand thickness 24 ft
 Average gross sand thickness 27 ft
 Initial reservoir temperature 84°F

Wells

Spacing 10 acre
 Pattern Regular
 Producers: 18 Water source: 0 Observation: 0 Suspended: 0
 Injection: 3 Disposal: 0 Abandoned: 2 Dry holes: 6
 Other: 0

Reservoir Fluid Properties

Hydrocarbons N/A
 Type N/A
 Gas/Oil ratio N/A
 API gravity
 Oil viscosity N/A
 Bubble-point pressure N/A
 Formation water
 Resistivity N/A
 Total dissolved solids N/A

Volumetrics

In place 1,418,000 bbl
 Cumulative production N/A
 Ultimate recovery
 Primary N/A
 Secondary (incremental) N/A
 Recovery efficiency (factor)
 Primary N/A
 Secondary N/A
 Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole 2; cased 20
 Drilling fluid Bentonite fresh-water mud
 Fracture treatment Open holes: 20 quarts of nitroglycerin; cased holes: gel salt water/sand
 Acidization
 Other
 Producing mechanism
 Primary Solution gas depletion, pump
 Secondary Waterflood, pump
 Tertiary
 Typical well production (to date)
 Average daily N/A
 Cumulative N/A
 WOR N/A

Field Wells (API numbers): see Energy Field Reservoir Summary

Energy South Upper Field Reservoir Summary

Location Williamson County, Illinois

Tectonic/ Regional Paleosetting Illinois Basin, intracratonic

Geologic Structure Ramp

Trap Type Stratigraphic

Reservoir Drive Solution gas

Original Reservoir Pressure 985 lb.

Reservoir Rocks

Age Upper Valmeyeran of the Mississippian System

Stratigraphic unit Aux Vases Sandstone

Lithology Sandstone

Depositional environment Offshore tidal bar/ mixed siliciclastic-carbonate

Productive facies Tidal bar; shallow marine bar

Petrophysics (ϕ , k from unstressed conventional core; S_w from logs)

	Average	Range	Economic cutoff
ϕ (%)	18.8	N/A	N/A
k air (md)	N/A	N/A	N/A
k liquid (md)	150.0	N/A	N/A
S_w (%)	0.5	N/A	N/A
S_{or} (%)	14.6	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A	N/A	N/A

Source Rocks

Lithology and stratigraphic unit New Albany Shale

Time of hydrocarbon maturation

Time of trap formation Late Valmeyeran

Reservoir Dimensions

Absolute depth 2,370 ft

Subsea depth

Areal dimensions

Productive area 1,240 acres

Number of pay zones 1

Initial fluid contacts Oil-water -1,923

Average net sand thickness

Average gross sand thickness

Initial reservoir temperature N/A

Fractured

Wells

Spacing 10 acre

Pattern Regular

Producers: 11	Water source: 0	Observation: 0	Suspended: 0
Injection: 2	Disposal: 0	Abandoned: 0	Dry holes: 5
Other: 0			

Reservoir Fluid Properties

Hydrocarbons

Type oil

Gas/oil ratio N/A

API gravity N/A

Formation volume factor N/A

Oil viscosity

Bubble-point pressure N/A

Formation water
 Resistivity N/A
 Total dissolved solids N/A

Volumetrics

In place 863,000 bbl
 Cumulative production N/A
 Ultimate recovery
 Primary N/A
 Secondary (incremental) N/A
 Tertiary (incremental) N/A
 Recovery efficiency (factor)
 Primary N/A
 Secondary N/A
 Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions
 Drilling fluid Bentonite fresh-water mud
 Fracture treatment Open holes: 20 quarts nitroglycerin; cased holes: gel salt, water/sand
 Acidization
 Other
 Producing mechanism
 Primary Solution gas depletion, pump
 Secondary Waterflood, pump
 Tertiary None to date
 Typical well production (to date)
 Average daily N/A
 Cumulative N/A
 WOR N/A
 WOR cumulative N/A

Field Wells (API numbers): see Energy Field Reservoir Summary

Energy North Lower Field Reservoir Summary

Location Williamson County, Illinois
 Tectonic/ Regional Paleosetting Illinois Basin, intracratonic
 Geologic Structure Ramp
 Trap Type Stratigraphic
 Reservoir Drive Solution gas
 Original Reservoir Pressure 927 lb
 Reservoir Rocks
 Age Upper Valmeyeran of the Mississippian System
 Stratigraphic unit Aux Vases Sandstone
 Lithology Sandstone
 Depositional environment Offshore tidal bar/mixed siliciclastic-carbonate
 Productive facies Tidal bar; shallow marine bar
 Petrophysics (ϕ , k from unstressed conventional core; S_w from logs)

	Average	Range	Economic cutoff
ϕ (%)	21.1	N/A	N/A
k air (md)	N/A	N/A	N/A
k liquid (md)	78.0	N/A	N/A
S_w (%)	0.5	N/A	N/A
S_{or} (%)	14.6	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A	N/A	N/A

Source Rocks

Lithology and stratigraphic unit New Albany Shale
Time of hydrocarbon maturation N/A
Time of trap formation Late Valmeyeran

Reservoir Dimensions

Absolute depth 2,390 ft
Subsea depth N/A
Areal dimensions N/A
Productive area 1,912 acres
Number of pay zones 1
Initial fluid contacts Oil-water -1,974
Average net sand thickness N/A
Average gross sand thickness N/A
Initial reservoir temperature N/A

Wells

Spacing 10 acre
Pattern Regular
Producers: 4 Water source: 0 Observation: 0 Suspended: 0
Injection: 0 Disposal: 0 Abandoned: 0 Dry holes: 5
Other: 0

Reservoir Fluid Properties

Hydrocarbons
Type N/A
Gas/oil ratio N/A
API gravity N/A
Formation volume factor N/A
Oil viscosity N/A
Bubble-point pressure N/A
Formation water
Resistivity N/A
Total dissolved solids N/A

Volumetrics

In place 1,599,000 bbl
Cumulative production N/A
Ultimate recovery
Primary N/A
Secondary (incremental) N/A
Tertiary (incremental) N/A
Recovery efficiency (factor)
Primary N/A
Secondary N/A
Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions
Drilling fluid Bentonite fresh-water mud
Fracture treatment Open hole: 20 qt nitro; cased holes: gel saltwater/sand
Acidization
Other
Producing mechanism
Primary Solution gas depletion, pump
Secondary Waterflood, pump

Producing mechanism *continued*

Tertiary N/A

Typical well production (to date)

Average daily N/A

Cumulative N/A

WOR N/A

WOR cumulative N/A

Field Wells (API numbers): see Energy Field Reservoir Summary

Energy North Upper Field Reservoir Summary

Location Williamson County, Illinois

Tectonic/ Regional Paleosetting Illinois Basin, intracratonic

Geologic Structure Ramp

Trap Type Stratigraphic

Reservoir Drive Solution gas

Original Reservoir Pressure 927 lb

Reservoir Rocks

Age Upper Valmeyeran of the Mississippian System

Stratigraphic unit Aux Vases Sandstone

Lithology Sandstone

Depositional environment Offshore tidal bar/mixed siliciclastic-carbonate

Productive facies Tidal bar; shallow marine bar

Petrophysics (ϕ , k from unstressed conventional core; S_w from logs)

	Average	Range	Economic cutoff
ϕ (%)	21.1	N/A	N/A
k air (md)	N/A	N/A	N/A
k liquid (md)	19.0	N/A	N/A
S_w (%)	0.4	N/A	N/A
S_{or} (%)	14.6	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A	N/A	N/A

Source Rocks

Lithology and stratigraphic unit New Albany Shale

Time of hydrocarbon maturation

Time of trap formation Late Valmeyeran

Reservoir Dimensions

Absolute depth 2,390 ft

Subsea depth N/A

Areal dimensions N/A

Productive area 578 acres

Number of pay zones 1

Initial fluid contacts Oil-water -1,974

Average net sand thickness N/A

Initial reservoir temperature N/A

Fractured: N/A

Wells

Spacing 10 acre

Pattern Regular

Producers: 4

Injection: 0

Other: 0

Water source: 0

Disposal: 0

Observation: 0

Abandoned: 0

Suspended: 0

Dry holes: 3

Reservoir Fluid Properties

Hydrocarbons

Type N/A
Gas/Oil ratio N/A
API gravity N/A
Formation volume factor N/A
Oil viscosity N/A
Bubble point pressure N/A

Formation water

Resistivity N/A
Total dissolved solids N/A

Volumetrics

In place 5240000 bbl
Cumulative production N/A
Ultimate recovery
 Primary N/A
 Secondary (incremental) N/A
 Tertiary (incremental) N/A
Recovery efficiency (factor)
 Primary 7.3%
 Secondary 13.6%
 Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions

Drilling fluid Bentonite fresh-water mud
Fracture treatment Open hole: 20 qt nitro; cased holes: gel saltwater/sand
Acidization N/A

Other

Producing mechanism

Primary Solution gas depletion, pump
Secondary Waterflood, pump
Tertiary N/A

Typical well production (to date)

Average daily N/A
Cumulative N/A
WOR N/A
WOR cumulative N/A

Field Wells (API numbers): see Energy Field Reservoir Summary

King Field Reservoir Summary

Location Jefferson County, Illinois

Tectonic/ Regional Paleosetting Illinois Basin, intracratonic

Geologic Structure Anticline

Geologic Play(s) Tidal channel and bars

Trap Type Structural-stratigraphic

Reservoir Drive Gas depletion drive

Original Reservoir Pressure N/A

Reservoir Rocks

Age Upper Valmeyeran Series of the Mississippian System

Stratigraphic unit Aux Vases Sandstone

Lithology Sandstone

Depositional environment Mixed siliciclastic-carbonate nearshore

Productive facies Tidal channel offshore bar

Reservoir Rocks *continued*Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)

Porosity type (total 18.0%)

	Average	Range	Economic cutoff
ϕ (%)	18.0	7.0 - 27.0	11.0
k air (md)	N/A	N/A	N/A
k liquid (md)	N/A	N/A	N/A
S_w (%)	45.0	N/A	N/A
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	1.79	N/A	N/A

Source Rocks

Lithology and stratigraphic unit New Albany Shale

Time of hydrocarbon maturation N/A

Time of trap formation N/A

Reservoir Dimensions

Absolute depth 2,750 ft

Subsea depth 2,250

Areal dimensions 1,700 acres

Productive area 1,700 acres

Number of pay zones 4

Hydrocarbon column Unknown

Initial/present fluid contacts No clear oil-water contact

Average net sand thickness 15 ft

Average gross sand thickness N/A

Initial reservoir temperature N/A

Initial reservoir temperature source N/A

Wells

Spacing 10 acre

Pattern

Producers: 108	Water source: 0	Observation: 0	Suspended: 0
Injection:	Disposal: 0	Abandoned: 0	Dry holes: 55
Other: 0			

Reservoir Fluid Properties

Hydrocarbons

Type N/A

Gas/oil ratio N/A

API gravity N/A

Oil viscosity N/A

Bubble-point pressure N/A

Formation water

Resistivity 0.062–0.064 ohm-m @ 77°F

Total dissolved solids (mg/L) 129,700–141,500

Volumetrics

In place 17,000,000 bbl

Cumulative production 4,100,000 bbl

Ultimate recovery

Primary 3,500,000 bbl

Secondary (incremental) 600,000 bbl

Tertiary (incremental) N/A

Recovery efficiency (factor)

Primary 22.0%

Secondary 18.0%

Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased

Drilling fluid Bentonite

Fracture treatment 5,000 gallons oil; 7,500 lb sand

Acidization

Other

Producing mechanism

Primary Gas depletion

Secondary Waterflood

Tertiary N/A

Typical well production (to date)

Average daily 80

Cumulative N/A

WOR initial N/A

WOR cumulative N/A

Field Wells (API numbers)

12081009000	120810016700	120810019700	120810019701	120810037400	120810037401
120810037402	120810037403	120810042900	120810045800	120810045900	120810045901
120810045902	120810045903	120810046000	120810046001	120810046100	120810047500
120810047600	120810047700	120810047800	120810047801	120810047802	120810048700
120810048800	120810048900	120810048901	120810049000	120810049100	120810049101
120810049200	120810049700	120810049701	120810049800	120810049801	120810050100
120810050101	120810050200	120810050201	120810050202	120810050300	120810050301
120810053900	120810053901	120810054800	120810054900	120810054901	120810055000
120810055001	120810056300	120810057400	120810057401	120810077000	120810077100
120810088500	120810088700	120810088701	120810088800	120810088801	120810089301
120810090100	120810092500	120810092600	120810092601	120810093400	120810095100
120810095400	120810095600	120810096400	120810098500	120810114900	120810115500
120810119200	120810119300	120810122600	120810122601	120810132800	120810132900
120810133000	120810133200	120810133201	120810133400	120810133500	120810133800
120810133900	120810141600	120810142400	120810142401	120810144100	120810165401
120810173400	120810176401	120810180500	120810181100	120810181101	120810181200
120810183100	120810183300	120810185100	120810231400	120810231600	120810231601
120810231700	120810231900	120810232000	120810232100	120810232700	120810232800
120810232900	120810233000	120810233100	120810233200	120810233300	120810233400
120810233500	120810233600	120810233700	120810233800	120810233900	120810234000
120810234100	120810234200	120810234300	120810234400	120810234500	120810234800
120810235100	120810235300	120810235400	120810235500	120810235600	120810235601
120810235700	120810235701	120810235800	120810235900	120810236000	120810236001
120810236100	120810236200	120810236300	120810237000	120810237100	120810237200
120810237300	120810237301	120810237700	120810237800	120810237900	120810238000
120810238001	120810238200	120810238201	120810238400	120810238500	120810238600
120810238601	120810238700	120810238701	120810238800	120810238900	120810239000
120810239100	120810239200	120810239400	120810239401	120810239500	120810239600
120810239601	120810239700	120810239701	120810239800	120810239900	120810239901
120810240000	120810243800	120810243900	120810244100	120810254400	120812313100
120812448000					

Lawrence Field Reservoir Summary

Location Lawrence County, Illinois

Tectonic/ Regional Paleosetting Intracratonic Basin

Geologic Structure Anticline

Trap Type Structural-stratigraphic

Reservoir Drive Gas dissolution

Original Reservoir Pressure N/A

Reservoir Rocks

Age Mississippian (Chesterian)

Stratigraphic unit Cypress Sandstone

Lithology Quartz arenite

Wetting characteristics N/A

Depositional environments Marine bars (tidal), vertically stacked

Productive facies Sandstones of the active, central bar

Petrophysics (ϕ , k and Sw from unstressed conventional core)

	Average	Range	Economic cutoff
ϕ	18.6%	16 - 23%	16%
k air (md)	76	50 - 200	
k liquid	N/A	N/A	N/A
Sw 43.5	N/A	N/A	
Sor 21%	N/A	N/A	
Sgr N/A	N/A	N/A	
Cementation factor	N/A	N/A	N/A

Source Rocks

Lithology and stratigraphic unit New Albany Shale (?)

Time of hydrocarbon maturation Permian (?)

Time of trap formation Chesterian (stratigraphic); Penn./Perm. (structural)

Cypress Reservoir Dimensions (study area only)

Depth Approximately 1,300-1,450 ft

Areal dimensions Study area 2 square miles; northern structure about 62 square miles

Productive area As above

Number of pay zones 1 (up to four stacked sands constitute reservoir)

Hydrocarbon column Study is entirely within the oil column

Initial fluid contacts Oil-water contact is approximately at a depth of 1,650 ft (-1,200 ft) for the northern structure

Average net sand thickness 25 ft (B,C,D,E sands), maximum, 45 ft stacked sands (B,C,D,E) average 7 ft in thickness with a maximum of 15 ft

Initial reservoir temperature N/A

Fractured Natural N/A

Wells

Spacing 10 acre primary; 5 acre infill and secondary

Pattern Normal primary and secondary

Total N/A

Reservoir Fluid Properties

Hydrocarbons

Type oil and gas

GOR N/A

API Gravity 38°

Formation volume factor 1.056

Viscosity N/A

Bubble-point pressure 250 est

Formation water

Resistivity 0.1447 @ 77°F

Total dissolved solids (mg/L) 48,460

Volumetrics (within study area)

In place 780 STBO/acre-foot

Cumulative production 307.8 STBO/acre-foot

Ultimate recovery

Secondary N/A

Tertiary N/A

Recovery efficiency 39.5%

Typical Drilling/ Completion/ Production Practices

Completions Open hole or cased

Drilling fluid Fresh-water mud with gel additive

Fracture treatment N/A

Acidization None

Producing mechanism Primary pump; secondary pump

Typical well production (to date)

Average daily IP Initial production unrecorded

Cumulative production N/A

Water/oil ratio (initial) N/A

Field Wells (API numbers)

121010017700	121010017701	121010017800	121010017900	121010020000	121010020100
121010020200	121010020300	121010020400	121010020500	121010020600	121010020700
121010020800	121010020900	121010021000	121010043700	121010043701	121010045600
121010046000	121010094400	121010094500	121010094600	121010097000	121010097100
121010103000	121010103800	121010103900	121010104000	121010106000	121010106100
121010106200	121010106300	121010106400	121010106500	121010106600	121010106700
121010106800	121010106900	121010107000	121010107100	121010107200	121010108300
121010114300	121010114400	121010115100	121010115200	121010115300	121010115400
121010116700	121010117500	121010117600	121010117700	121010118200	121010118800
121010118900	121010119000	121010119100	121010119200	121010119300	121010119400
121010119500	121010119600	121010120700	121010120800	121010121600	121010122000
121010122100	121010122200	121010122201	121010130400	121010133100	121010134000
121010135100	121010135300	121010136700	121010136900	121010137100	121010139200
121010139300	121010139600	121010139700	121010139800	121010141000	121010141100
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Mattoon Field Reservoir Summary

Location Coles County, Illinois

Tectonic/ Regional Paleosetting Illinois Basin, intracratonic

Geologic Structure Anticline

Trap Type Structural-stratigraphic

Reservoir Drive Solution gas

Original Reservoir Pressure 707 psig @ -1,037 ft (subsea @ API no. 1750)

Reservoir Rocks

Age Mississippian (Chesterian)

Stratigraphic unit Cypress Sandstone

Lithology Quartz arenite, feldspathic

Depositional environment Shallow marine

Productive facies Siliciclastic

Petrophysics (ϕ and k from unstressed conventional core and core plugs)

Porosity type

Upper E Sand	Average	Range
ϕ	14.1	11 - 18
k air (md)	14.5	14.5
k liquid	N/A	
Sw	43.5	35.0
Sor	21%	N/A
Sgr	N/A	N/A
Cementation factor	N/A	N/A
Lower E. Sand	Average	Range
ϕ	16.15	15.3 - 17
k air (md)	14.5	14.5
k liquid		
Sw	35.0	35.0
Sor	N/A	N/A
Sgr	N/A	N/A
Cementation factor	N/A	N/A
D Sand	Average	Range
ϕ	16.4	16 - 18
k air (md)	22.18	<1.0 - 77.4
k liquid		
Sw	54.3	50.9-59.0
Sor	13.35	2.5 - 23.6
Sgr	N/A	N/A
Cementation factor	N/A	N/A
B/C Sand	Average	Range
ϕ	15.8	12.8 - 20.3
k air (md)	39.2	<1.0 - 189.0
k liquid		
Sw	44.5	38.7 - 61.0
Sor	13.90	0.8 - 26.0
Sgr	N/A	N/A
Cementation factor	N/A	N/A
A Sand	Average	Range
ϕ	18.6%	14.1 - 14.6
k air (md)	N/A	N/A
k liquid		
Sw	35.0	35.0
Sor	0.8	0.8
Sgr	N/A	N/A
Cementation factor	N/A	N/A

Source Rocks

Lithology and stratigraphic unit N/A
Time of hydrocarbon maturation N/A
Time of trap formation
Stratigraphic (Mississippian (Chesterian)
Structural (late Mississippian to early Pennsylvanian)

Reservoir Dimensions

Absolute depth 1,696 ft (-965 ft) to approximately 1,831 ft (-1,100 ft)
Subsea depth N/A
Areal dimensions 6,680 acres
Productive area <6,680 acres
Number of pay zones 5 (A, B, C, D, E intervals)
Hydrocarbon column Between 0 and 50% of net clean sand isopach
Initial/present fluid contacts Gas-oil Oil-water
Upper E sand N/A not known
Lower E sand N/A -1,095 est.
D sand N/A -1,080 est.
B/C sand N/A -1,130 est.
A sand N/A not known
Average net sand thickness (Maximum @ 50% net clean sand/average):
Upper E sand 19 ft (API No. 23265)/5 to 10 ft
Lower E sand 15 ft (API No. 2026)/5 to 10 ft
D sand 15 ft (API No. 801)/10 ft
B/C sand 42 ft (API No. 1296)/25 to 30 ft
A sand 13 ft (API No. 23271)/6 to 8 ft
Average gross sand thickness N/A
Initial reservoir temperature 85°F
Initial reservoir temperature source
Fractured Natural: trace-healed hairline vertical fractures; artificial: nitroglycerin-induced or hydraulic

Wells

Spacing 10 acre
Pattern Normal primary and secondary
Producers: 356* Water source: 0 Observation: 0 Suspended: 25
Injection: 61 Disposal: 5 Abandoned: Dry holes: 105**
Other: 0
*Oil 338, gas 16, oil and gas 2
**D&A: no shows 109; shows 41

Reservoir Fluid Properties

Hydrocarbons
Type Oil and gas
Gas/oil ratio 322 @ Mattoon Waterflood Project No.500
API gravity 38° (Illinois Pipeline Report) 38.4 to 39° (three waterflood reports)
Oil viscosity 1.63 cp @ 42°F; 4.32 cp @ 25°C
Bubble-point pressure N/A
Formation water
Resistivity 0.0692 to 0.0869 ohm-m @ 25°C
Total dissolved solids (mg/L) 88,800-120,700

Volumetrics

(A) Downside case—based on established productive acreage only:

	Acres	Acre-ft	OOIP	STOOIP
U Yellow Sand (E)	115.13	427.56	304,004.01	251,450.79

Volumetrics**(A) Downside case—continued**

	Acres	Acre-ft	OOIP	STOOIP
L Yellow Sand (E)	814.21	2,052.17	1,759,241.20	1,455,120.90
Brown Sand (D)	1,461.08	7,665.07	5,066,670.50	4,190,794.40
Green Sand (B/C)	4,588.18	45,413.16	26,739,310.00	22,116,882.00
Purple Sand (A)	2,537.79	8,504.92	6,131,354.80	4,546,203.30
TOTAL		64,062.88	40,600,581.00	32,560,451.00

(B) Upside case—based on all reservoir acreage above their respective OWCs:

U Yellow Sand (E)	859.62	4,235.38	3,001,454.60	2,490,864.00
L Yellow Sand (E)	2,145.19	9,752.82	8,360,692.70	6,915,378.60
Brown Sand (D)	1,743.57	8,679.33	6,409,357.80	4,586,245.20
Green Sand (B/C)	4,588.18	45,413.16	26,739,310.00	22,116,882.00
Purple Sand (A)	2,537.79	8,504.92	6,131,354.80	4,546,203.30
TOTAL		76,585.61	50,652,170.00	40,655,573.00

Cumulative production 21,952,952 BO @ March, 1993

Ultimate recovery

Primary 10,090,951 BO (prior to first Cypress Waterflood-5/52)

(A) 24.49% OOIP (for production-proved acreage only)

(B) 19.92% OOIP (for all reservoir acreage above OWC)

Secondary 11,788,715 BO (production since first Cypress Waterflood)

(A) 29.03% OOIP (for production-proved acreage only)

(B) 23.27% OOIP (for all reservoir acreage above OWC)

Tertiary Three intra-Cypress Pilot Projects: CO₂-WAG and Huff-and-Puff**Recovery efficiency (factor)**

Primary N/A (commingled production/incomplete records)

Secondary N/A (commingled production/incomplete records)

Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased (single or commingled)

Drilling fluid Fresh-water mud

Fracture treatment Nitroglycerin and/or water/sand

Acidization None to 1000 gal 15% HCl or MCA preflush (variable)

Other

Producing mechanism

Primary Flowing or pump

Secondary Pump

Tertiary Pump

Typical well production (to date)

Average IP Older wells: IPF = 400–1,200 BOPD; young wells: IPP = up to 150 BOPD

Cumulative N/A complex records (commingled, recompletions)

WOR initial N/A

WOR cumulative N/A

Field Wells (API numbers)

120290000100	120290000200	120290000300	120290000400	120290000500	120290001700
120290001800	120290001900	120290001901	120290001902	120290004800	120290005100
120290008400	120290008401	120290008402	120290008500	120290008501	120290008502
120290008800	120290009200	120290019100	120290024400	120290024500	120290024600
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120290026201	120290026202	120290026300	120290026301	120290026302	120290026400
120290026700	120290026701	120290026702	120290026800	120290026801	120290026900

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120290032301	120290032302	120290032400	120290032500	120290032600	120290032601
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120290037301	120290039400	120290039401	120290041900	120290041901	120290042900
120290042901	120290043000	120290043100	120290043200	120290043300	120290048200
120290049000	120290049001	120290049100	120290049101	120290049800	120290049801
120290050200	120290050300	120290050400	120290050401	120290050500	120290050501
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120352227100					

Oakdale and Markham City North Fields Reservoir Summaries

Location Jefferson and Wayne Counties, Illinois

Tectonic/ Regional Paleosetting Fairfield Basin of the Illinois Basin (Eastern Interior Basin), an intracratonic basin

Geologic Structure Positive structural nose

Trap Type Combination structural-stratigraphic

Reservoir Drive Solution gas, depleted by early flaring of gas.

Original Reservoir Pressure Discovery well's drill stem test reported initial shut-in pressure after 30 minutes at 1098 psi

Reservoir Rocks

Age Mississippian, Valmeyeran Series

Stratigraphic unit Aux Vases Sandstone

Lithology Mixed siliclastic-carbonate

Depositional environment Sand bodies deposited in tidally reworked, offshore, shallow marine setting.

Productive facies Crests of reworked sandbar, ridge, or sand waves

Petrophysics ϕ , k and S from core analysis of Breeze core (continuous core) at Oakdale

	Average	Range	Cutoff
ϕ	22.54	15.6 - 25.9	N/A
k air (md)			
k liquid	136.6	1.7 - 455	N/A
k (H)	202.6	64 - 584	N/A
S _w	54 (52 in perf zone)	34.9 - 76	N/A
S _o	8.5 (10.4 in perf zone)	0 - 18.6	N/A
S _g %			

Cementation factor m = 2 est.

Source Rocks

Lithology and stratigraphic unit Devonian New Albany Shale (?)

Time of hydrocarbon maturation Permian-Triassic (?)

Time of trap formation Major basinwide structural activity during Permian-Triassic

Reservoir Dimensions

Absolute depth Oakdale 2,860 ft; Markham City North 2,950 ft

Subsea depth -2,470, structure, top of Aux Vases; -2,510 for Markham City North

Areal dimensions Oakdale bar 2.5 miles long in NE-SW orientation, 1 mile wide;

Markham City North, sandbar 2 miles long, 0.5 mile wide

Productive area 410 acres at Oakdale; 120 acres at Markham City North

Number of pay zones 2 potentially (Aux Vases and Ste. Genevieve "McClosky")

Hydrocarbon column Average perforation zone thickness is 9 ft, but column ranges 2-20 ft; used 12.5 ft for volumetrics

Initial fluid contacts 2,858-2,868 (-2,407-2,417 subsea) at Oakdale

Average net sand thickness Used average pay thickness of 12.5 ft for volumetrics

Average gross sand thickness 58 ft (clean sand > 50% of clean Cypress)

Initial reservoir temperature N/A

Initial reservoir temperature source N/A

Wells

Spacing 10 acre

Pattern Conversion of poorer producing downdip well to injector; other development strategies were conversion of poor producers to salt water disposal wells(?)

Oakdale:

Producers: 30 Water source: Observation: Suspended:
 Injection: 6 Disposal: 2 Abandoned: 29 (P&A) Dry holes: 217

Markham City North

Producers: 8 Aux Vases

Reservoir Fluid Properties**Hydrocarbons**

Type Oil and solution gas (depleted early by flaring?) replaced by water drive

Gas/oil ratio N/A

API gravity 38

Oil viscosity N/A

Bubble-point pressure N/A

Formation water

Resistivity 0.0601 ohm-m @ 77°F

Total dissolved solids (mg/L) 148,028

Volumetrics (Oakdale only; data not available for Markham City N—commingled production)

In place 3,877,529 bbl

Cumulative production 830,324 bbl

Ultimate recovery

Primary 703,829 bbl

Secondary 127,033 bbl

Tertiary N/A

Recovery efficiency (factor)

Primary Not known

Secondary Not known; cumulative recovery factor 21%

Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole

Drilling fluid Fresh water

Fracture treatment Lease oil fracture with 2000-4000 gal oil and 2000-4000 lb sand

Acidization 200-500 gal MCA

Other**Producing mechanism**

Primary Pumping

Secondary Water injection/pressure maintenance and pumping

Tertiary N/A

Typical well production (to date)

Average daily Varied with operation strategies; field nearly abandoned today

Cumulative Total cumulative from field 830,324 bbl from primary and spotty
 waterflood methods; average production for one well (of 30 primary producers
 in the field) 23,443 bbl

WOR initial Wide range

WOR cumulative N/A

Field Wells (API numbers)

1208101070	1208101543	1208123825	1208101513	1208101081	1208102211
1208101139	1208101544	1208101575	1208102566	1208102576	1208102552
1208101062	1208101046	1208101551	1208101054	1208101047	1208101071
1208101618	1208101080	1208101521	1208124035	1208101546	1208124399
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1208102461	1208122963	1208122989	1208122994	1208101842	1208101850
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1208102476	1208123289	1208123451	1208124342	1208102575	1208122974
1208123045	1208101314	1208101050	1208122979	1208122993	1208101008

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1208124261	1208124268	1208124728	1219131917	1219100650	1219131253
1219129804	1219103293	1219107674	1219101471	1219106616	1219100647
1219101469	1219106566	1219101470	1219101470	1219101472	1219100646

Parkersburg Field Reservoir Summary

Location Richland and Edwards Counties, Illinois

Tectonic/ Regional Paleosetting Intracratonic basin

Geologic Structure Anticlinal domes

Trap Type Structural-stratigraphic

Reservoir Drive Gas dissolution

Original Reservoir Pressure Variable; drill stem test shut-in pressures up

Reservoir Rocks

Age Mississippian (Chesterian)

Stratigraphic unit Cypress

Lithology Quartz arenite

Depositional environment Variable; lower delta plain deposits in middle Cypress; shallow marine and deltaic in lower Cypress, Coastal and shoreface in upper Cypress

Productive facies Dependent upon depositional environment: lower Cypress reservoirs are shallow marine sandstone bars, middle Cypress distributary channels, distributary mouth bars, crevasse splays, upper Cypress drowned barrier bar sandstones.

Petrophysics (ϕ and k from unstressed conventional core)

	Average	Range	Economic cutoff
Porosity type: Upper Cypress			
ϕ (%)	16	13 - 19	13
k (md)	93	0 - 125	12
S_w (%)	26	N/A	N/A
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	38	N/A	N/A
Cementation factor	N/A	N/A	N/A

Porosity type: Middle Cypress			
ϕ (%)	14	N/A	N/A
k (md)	N/A	N/A	N/A
S_w (%)	N/A	N/A	N/A
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A	N/A	N/A

Porosity type: Lower cypress			
ϕ (%)	17.1	15 - 18.5	15
k (md)	181	67 - 252.2	N/A
S_w (%)	35.3	26 - 43	26
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A	N/A	N/A

Source Rocks

Lithology and stratigraphic unit N/A

Time of hydrocarbon maturation N/A

Time of trap formation Chesterian (stratigraphic); Penn./Perm. (structural)

Reservoir Dimensions

Lower Cypress

Absolute depth 2,850-2,900 ft

Subsea depth N/A

Areal dimensions Northern lower Cypress 143 acres; middle lower Cypress 166 acres;
southern lower Cypress 180 acres

Productive area As above

Number of pay zones 1

Hydrocarbon column 10-15 ft

Initial/present fluid contacts No gas cap reservoirs, presumed oil-filled

Average net sand thickness Northern lower Cypress 5-10 ft; middle lower Cypress 5-8
ft; southern lower Cypress 5-10 ft

Average gross sand thickness

Initial reservoir temperature 100°F

Initial reservoir temperature source estimated from logs

Middle Cypress

Absolute depth 2,820-2,880 ft

Subsea depth 557 acres

Areal dimensions Northern lower Cypress 143 acres; middle lower Cypress 166 acres;
southern lower Cypress 180 acres

Productive area As above

Number of pay zones 1

Hydrocarbon column 10-15 ft

Initial/present fluid contacts No gas cap reservoirs, presumed oil-filled

Average net sand thickness Northern lower Cypress 5-10 ft; middle lower Cypress 5-8
ft; southern lower Cypress 5-10 ft

Average gross sand thickness

Initial reservoir temperature 100°F

Initial reservoir temperature source Estimated from logs

Upper Cypress

Absolute depth 2,790-2,830 ft

Subsea depth Upper Cypress 718 acres

Areal dimensions Northern lower Cypress 143 acres; middle lower Cypress 166 acres;
southern lower Cypress 180 acres

Productive area As above

Number of pay zones 1

Hydrocarbon column 15 ft

Initial/present fluid contacts No gas cap reservoirs, presumed oil-filled

Net sand thickness Upper Cypress 5-15 ft

Average gross sand thickness

Initial reservoir temperature 100°F

Initial reservoir temperature source Estimated from logs

Wells

Spacing 10 acre primary

Pattern Normal primary and secondary

Total: 104 of 506 wells in study area produce from Cypress

Producers: 104 Water source: N/A Observation: N/A Suspended: N/A

Injection: N/A Disposal: N/A Abandoned: N/A Dry holes: N/A

Other: N/A

Reservoir Fluid Properties**Hydrocarbons**

Type Oil and gas

Gas/oil ratio N/A

API gravity Upper Cypress 38°

Oil viscosity

Bubble-point pressure N/A

Formation water

Resistivity 0.067-0.072 ohm-m

Total dissolved solids (mg/L) 116,400-123,800

Volumetrics

Lower Cypress 1,695,810 bbl STOOIP

Cumulative production 89,950 bbl

Recovery efficiency 8.5%

Middle Cypress 1,379,522 bbl STOOIP

Cumulative production 166,575 bbl

Recovery efficiency 11.24%

Upper Cypress 1,662,123 bbl STOOIP

Cumulative production 166,575

Recovery efficiency 9.3%

Typical Drilling/ Completion/ Production Practices

Completions Cased 1-4 perforations per foot

Drilling fluid Fresh-water mud with gel additive

Fracture treatment Hydraulic fracturing 5,000-9,000 gallons gelled or salt water 17,000 lb sand

Acidization 300-500 gallons MCA

Other

Producing mechanism

Primary Pump

Secondary Pump

Tertiary

Typical well production (to date)

Average daily N/A

Cumulative N/A

WOR initial N/A

WOR cumulative N/A

Field Wells (API numbers)

120470000100	120470002400	120470002401	120470002601	120470002700	120470002701
120470002800	120470002801	120470002900	120470003000	120470003001	120470003500
120470003501	120470003600	120470003601	120470003700	120470003800	120470003900
120470004000	120470004001	120470004100	120470004200	120470004300	120470004400
120470004401	120470004402	120470004500	120470004501	120470004600	120470004700
120470004800	120470004900	120470005000	120470005001	120470005200	120470005201
120470005202	120470005203	120470005204	120470005205	120470005206	120470005207
1204700053701	1204700053702	1204700056100	1204700056200	1204700077800	1204700077801
1204700084000	1204700098401	1204700099500	120470101300	120470101400	120470101500
120470102000	120470102001	120470102100	120470102101	120470102102	120470102200
120470102201	120470104000	120470104001	120470104002	120470104100	120470104200
120470104300	120470104400	120470104401	120470104500	120470105100	120470106400
120470106700	120470106800	120470106801	120470109400	120470109500	120470109501
120470112600	120470113100	120470114000	120470114001	120470114800	120470114900
120470115000	120470115002	120470115900	120470115901	120470116000	120470116200
120470116201	120470120100	120470120101	120470120300	120470120400	120470120401
120470120500	120470120600	120470120601	120470120700	120470126200	120470126300
120470126400	120470126600	120470126601	120470126700	120470126701	120470126800

120470126801	120470126900	120470126901	120470127100	120470127200	120470127201
120470127301	120470127400	120470127500	120470127600	120470127700	120470127900
120470128700	120470128800	120470128900	120470129000	120470129100	120470129200
120470129300	120470129400	120470129500	120470129501	120470129600	120470129601
120470129700	120470129800	120470129801	120470129802	120470129900	120470130000
120470130100	120470130200	120470130300	120470130400	120470130500	120470130600
120470130700	120470130800	120470130801	120470130900	120470131000	120470131100
120470131200	120470131300	120470131400	120470131400	120470131400	120470131400
120470134400	120470134500	120470134501	120470134600	120470134700	120470134800
120470134900	120470135000	120470135100	120470135200	120470135201	120470135300
120470135400	120470135401	120470135500	120470135600	120470135700	120470135701
120470135800	120470136000	120470136100	120470190200	120470193300	120470193600
120470200001	120470213400	120472218700	120472221100	120472225700	120472230100
120472236800	120472238800	120472238900	120472239000	120472241901	120472243000
120472243100	120472244300	120472244800	120472246900	120472248600	120472252700
120472252900	120472253200	120472254000	120472254001	120472256000	120472256100
120472256200	120472256900	120472257600	120472257601	120472257700	120472259300
120472259400	120472259800	120472260400	120472260401	120472260700	120472261000
120472261300	120472264300	120472264400	120472265600	120472265700	120472265900
120472272400	120472272700	120472272800	120472274000	120472274801	120472275500
120472278200	120472283600	120472283700	120472284700	120472284701	120472284702
120472285200	120472285700	120472286300	120472287100	120472289600	120472290000
120472292500	120472292600	120472297500	120472297600	120472298300	120472299500
120472301600	120472302900	120472303000	120472304400	120472304401	120472306000
120472306700	120472306801	120472306900	120472307000	120472307300	120472307400
120472307800	120472309200	120472309800	120472312300	120472312800	120472313200
120472313700	120472315501	120472315600	120472315601	120472316400	120472316900
120472316901	120472318300	120472321400	120472324800	120472326800	120472330200
120472334200	120472334300	120472336300	120472339300	120472342500	120472343600
120472345500	120472345600	120472345700	120472345701	120472345800	120472345900
120472348100	120472348200	120472348700	120472353300	120472355700	120472356300
120472356400	120472359800	120472359900	120472360000	120472362500	120472362700
120472362701	120472362800	120472362801	120472365900	120472365901	120472365902
120472366000	120472366100	120472368200	120472369400	120472369401	120472371300
120472371400	120472375700	120472378300	120472382100	120472383200	120472383201
120472384000	120472385100	120472386600	120472386700	120472386701	120472386800
120472386900	120472387900	120472388000	120472388700	120472390200	120472390300
120472391200	120472391300	120472391400	120472391500	120472392100	120472392200
120472394700	120472394800	120472395300	120472395400	120472395500	120472395501
120472395600	120472395700	120472397100	120472397600	120472399400	120472399500
120472401200	120472401800	120472401900	120472402000	120472402001	120472402700
120472403600	120472403900	120472404200	120472404300	120472404800	120472406300
120472406400	120472406501	120472407000	120472407001	120472407300	120472407400
120472408100	120472408200	120472408700	120472409800	120472409900	120472410000
120472410200	120472410300	120472416500	120472416700	120472417200	120472417300
120472417400	120472417500	120472417600	120472417601	120472418100	120472418300
120472418500	120472418600	120472418700	120472418800	120472419500	120472419600
120472419700	120472419800	120472420200	120472420500	120472420600	120472420900
120472421000	120472421001	120472421300	120472422200	120472422600	120472422700
120472423200	120472423400	120472424500	120472425100	120472425201	120472426000
120472427600	120472432400	120472433400	120472509000	121590000800	1215900002400
1215900002401	1215900002500	1215900002600	1215900002700	1215900002800	1215900002801
1215900002900	1215900003000	1215900003100	1215900003200	1215900003201	1215900003300
1215900003301	1215900003500	1215900003501	1215900003600	1215900003700	1215900003800
1215900003801	1215900003900	1215900004000	1215900004100	1215900004101	1215900004200
1215900004300	1215900004400	1215900004401	1215900004500	1215900004600	1215900004700
1215900004701	1215900004800	1215900004900	1215900004901	1215900005000	1215900005001
1215900005100	1215900005101	1215900005100	1215900005101	1215900005300	12159000052000
1215900032800	1215900032900	1215900033100	1215900037200	1215900037300	1215900037400
1215900037500	1215900039100	1215900039200	1215900039201	1215900043800	1215900056700
1215900057400	1215900072500	1215900072600	1215900072700	1215900072800	1215900073000

121590091200	121590112000	121590119000	121590119100	121590119200	121590119300
121590119400	121590119500	121590119600	121590119601	121590119700	121590119701
121590119800	121590119801	121590119802	121590119900	121590120000	121590120001
121590120100	121590120200	121590120300	121590120400	121590120500	121590120600
121590120700	121590120701	121590120800	121590120900	121590121000	121590121100
121590121200	121590121300	121590121400	121590121401	121590121402	121590121500
121590121600	121590121700	121590121800	121590121801	121590121900	121590122000
121590122100	121590122200	121590122300	121590122400	121590122500	121590122600
121590122700	121590122800	121590122900	121590123000	121590123100	121590123200
121590123300	121590123400	121590123500	121590123600	121590123700	121590123800
121590123900	121590123901	121590124000	121590124001	121590124100	121590124200
121590124300	121590124400	121590124500	121590124600	121590124700	121590124800
121590124801	121590124900	121590125000	121590125001	121590125100	121590125200
121590125300	121590125400	121590125500	121590125600	121590125700	121590125800
121590125900	121590125901	121590126000	121590126001	121590126100	121590126101
121590126200	121590126300	121590126400	121590126500	121590126600	121590126700
121590126800	121590126900	121590127000	121590127100	121590127101	121590127200
121590127300	121590127400	121590127500	121590127600	121590127700	121590129000
121590129001	121590129100	121590129200	121590129300	121590129301	121590129400
121590129500	121590129600	121590129601	121590129700	121590129701	121590129702
121590129800	121590129900	121590129901	121590130000	121590130100	121590130200
121590130300	121590130301	121590263000	121590273800	121590273801	121590277400
121590306200	121590314500	121590318300	121592342300	121592342301	121592346400
121592346401	121592347100	121592347200	121592348500	121592370600	121592372700
121592373300	121592373900	121592373901	121592374500	121592375000	121592375300
121592392000	121592392600	121592392601	121592393300	121592395400	121592395500
121592395501	121592395600	121592395601	121592396401	121592399100	121592411500
121592415000	121592415200	121592419300	121592424500	121592425300	121592429300
121592432700	121592436400	121592436500	121592450000	121592452200	121592456500
121592456900	121592461900	121592473300	121592475000	121592502100	121592502300
121592502600	121592502700	121592502800	121592503300	121592503400	121592503600
121592504100	121592504500	121592505000	121592505200	121592505300	121592505400
121592505800	121592505900	121592506000	121592506300	121592506400	121592506500
121592506600	121592506800	121592507100	121592507300	121592507400	121592507500
121592507600	121592507700	121592507701	121592507800	121592508700	121592508800
121592509000	121592509100	121592509101	121592509200	121592509201	121592509600
121592510800	121592510801	121592510900	121592511100	121592511300	121592511400
121592511500	121592511600	121592512100	121592512700	121592513000	121592513200
121592513201	121592513300	121592513400	121592513900	121592515000	121592517100
121592517300	121592518200	121592518400	121592518500	121592520400	121592529300
121592530100	121592533500	121592533600	121592544600	121592544900	

Richview Field Reservoir Summary

Location Washington County, Illinois

Tectonic/ Regional Paleosetting Illinois Basin, intracratonic

Geologic Structure Crest of anticline

Trap Type Structural-stratigraphic

Reservoir Drive Gas dissolution

Original Reservoir Pressure N/A, drill stem test shut-in BHPs up to 915 psi

Reservoir Rocks

Age Mississippian (Chesterian)

Stratigraphic unit Cypress Sandstone

Lithology Quartz arenite

Depositional environment Marine barrier bars, elongated and vertically stacked

Productive facies Sandstones of the upper bar

Petrophysics (ϕ and k from 12 core analyses)

	Average	Range	Economic cutoff
ϕ (%)	21.7	19.7 - 23.5	N/A
k air (md)	200	94 - 343	N/A

Petrophysics *continued*

	Average	Range	Economic cutoff
k liquid (md)	N/A	N/A	N/A
S _w (%)	N/A	N/A	N/A
S _{or} (%)	N/A	N/A	N/A
S _{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A	N/A	N/A

Source Rocks

Lithology and stratigraphic unit New Albany Shale (?)
Time of hydrocarbon maturation N/A
Time of trap formation Chesterian (stratigraphic); Penn./Perm. (structural)

Reservoir Dimensions

Absolute depth 1500 ft
Subsea depth -920 to -970 ft
Areal dimensions 800 acres
Productive area 680 acres
Number of pay zones 3
Hydrocarbon column 50 ft
Initial/present fluid contacts Oil-water -963 ft
Average net sand thickness B sandstone 10 ft; C sandstone 14 ft
Initial reservoir temperature 91°F
Initial reservoir temperature source Circulated mud

Wells

Spacing 10 acre primary
Pattern Normal primary with five-spot secondary water injection
Producers: 63 Water Source: Observation: Suspended: 0
Injection: 1 Disposal: 1 Abandoned: 20 Dry holes: 53
Other:

Reservoir Fluid Properties

Hydrocarbons

Type Oil and gas
Gas/oil ratio N/A
API gravity 37.9°-39°
Oil viscosity
Bubble-point pressure N/A

Formation water

Resistivity 0.0676 to 0.0788 ohm-m @ 77°F
Total dissolved solids (mg/L) 104,200-123,000

Volumetrics

In place
Cumulative production 3,303,705 bbl (as of 1992)
Ultimate recovery
Primary N/A
Secondary N/A
Tertiary None
Recovery efficiency (factor)
Primary N/A
Secondary N/A
Tertiary None

Typical Drilling/ Completion/ Production Practices

Completions

Drilling fluid

Fracture treatment Halliburton jel fracture: 4,900 gal lease oil, 7500 lb sand, 50 lb walnut hulls

Acidization

Other

Producing mechanism

Primary N/A

Secondary N/A

Tertiary N/A

Typical well production (to date)

Average daily

Cumulative

WOR initial N/A

WOR cumulative N/A

Field Wells (API numbers)

121890048700	121890048701	121890048702	121890084800	121890109300	121890109400
121890147800	121890148000	121890148101	121890148300	121890179101	121890180200
121890180300	121890180400	121890180500	121890180700	121890180800	121890181000
121890181100	121890181200	121890181300	121890181800	121890181900	121890182000
121890182001	121890182100	121890182101	121890182200	121890182300	121890182500
121890182700	121890182900	121890183000	121890183001	121890183200	121890183400
121890183401	121890183600	121890183700	121890183800	121890183801	121890184000
121890184200	121890184201	121890184202	121890184300	121890184400	121890184500
121890185000	121890185100	121890185200	121890185201	121890185300	121890185400
121890185500	121890185501	121890185600	121890185800	121890186500	121890186700
121890186800	121890187000	121890187100	121890187300	121890187400	121890187700
121890188100	121890188101	121890188300	121890188301	121890188302	121890188500
121890188600	121890188700	121890188800	121890189200	121890189300	121890189400
121890189600	121890189900	121890190200	121890190900	121890191200	121890191201
121890191500	121890191900	121890192000	121890192500	121890192600	121890192901
121890193500	121890193700	121890193800	121890194100	121890194400	121890194401
121890195900	121890196000	121890196100	121890196200	121890196300	121890196400
121890197800	121890197900	121890198100	121890199400	121890200100	121890200101
121890200102	121890200400	121890203300	121890228600	121890228601	121890234300
121890234400	121890234500	121890234600	121890234900	121890235000	121890242200
121890260200	121890260300	121890274100	121892329900	121892340200	121892359200
121892359300	121892370800	121892370900	121892376801	121892383700	121892407200
121892407300	121892407400				

Stewardson Field Reservoir Summary

Location Shelby County, Illinois

Tectonic/ Regional Paleosetting Illinois Basin, intracratonic

Geologic Structure Anticline, shoreface play

Trap Type Structural-stratigraphic

Reservoir Drive Gas dissolution

Original Reservoir Pressure N/A

Reservoir Rocks

Age Mississippian (Valseyeran/Chesterian)

Stratigraphic unit Aux Vases

Lithology Calcareous quartz arenite

Depositional environment Upper: subtidal sheet sand complex; lower: subtidal sheet sand complex

Productive facies Upper sandstone

Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)

	Average	Range	Economic cutoff
ϕ (%)	13.0	10.0 - 17.0	N/A
k air (md)	36.0	5.0 - 122.0	N/A
k liquid (md)	N/A	N/A	N/A
S_w (%)	41.0	36.0 - 46.0	N/A
S_{or} (%)	28.0	26.0 - 30.0	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A		

Source Rocks

Lithology and stratigraphic unit New Albany Shale (?)
 Time of hydrocarbon maturation Permo-Triassic (?)
 Time of trap formation Valmeyeran/Chesterian

Reservoir Dimensions

Absolute depth 1,940 ft
 Subsea depth N/A
 Areal dimensions 638 acres
 Productive area 290 acres
 Number of pay zones 1
 Hydrocarbon column Unknown, probably 25 ft
 Initial/present fluid contacts Gas-oil unknown; oil-water unknown
 Average net sand thickness Upper 14.5 ft; lower 27.8 ft
 Average gross sand thickness Upper 15.2 ft; lower 30.2 ft
 Initial reservoir temperature 85°F
 Initial reservoir temperature source Estimated from logs

Wells

Spacing 10 acre
 Pattern Normal primary with five-spot injection program
 Producers: 29 Water source: 0 Observation: 0 Suspended: 0
 Injection: 2 Disposal: 0 Abandoned: 0 Dry holes: 2
 Other: 0

Reservoir Fluid Properties

Hydrocarbons
 Type Oil and gas
 Gas/oil ratio N/A
 API gravity 35.60
 Formation volume factor 1.100
 Oil viscosity 6.8 cp @ 77°F
 Bubble-point pressure N/A
 Formation water
 Resistivity 0.0693-0.0705 ohm-m @ 77°F
 Total dissolved solids (mg/L) 108,800-114,800

Volumetrics

In place 5,651,809 bbl
 Cumulative production 948,300 bbl
 Ultimate recovery
 Primary 216,980 bbl
 Secondary (incremental) 815,120 bbl
 Tertiary (incremental) N/A

Recovery efficiency (factor)

Primary 18.3%

Secondary N/A

Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased

Drilling fluid Fresh-water mud

Fracture treatment 20 to 40 qt. nitroglycerin

Acidization 100-1,500 gal mud cleanout acid

Other

Producing mechanism

Primary Pump

Secondary Pump (waterflood)

Tertiary N/A

Typical well production (to date)

Average daily N/A

Cumulative N/A

WOR initial N/A

WOR cumulative N/A

Field Wells (API numbers)

121730007600	121730007800	121730007900	121730043400	121730043600	121730043601
121730044100	121730107600	121730107601	121730107900	121730108000	121730108001
121730109000	121730111500	121730113800	121730113900	121730114400	121730115300
121730115500	121730115600	121730115700	121730115800	121730115900	121730119200
121730124100	121730127300	121730128800	121730131200	121730131201	121730133000
121730136600	121730136601	121730163100	121730186200	121732200600	121732200900
121732247300					

Storms Consolidated Field (Cypress) Reservoir Summary

Location White County, Illinois

Tectonic/ Regional Paleosetting Illinois Basin

Geologic Structure Anticline nose

Trap Type Structural-stratigraphic

Reservoir Drive Gas depletion drive

Original Reservoir Pressure Unknown

Reservoir Rocks

Age Lower Chesterian Series of the Mississippian System

Stratigraphic unit Cypress Sandstone

Lithology Sandstone

Depositional environment Offshore shelf

Productive facies Offshore marine bars

Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)

Porosity type (ϕ total average 15.3%; primary 13.3%; secondary 2%)

	Average	Range	Economic cutoff
ϕ (%)	16	11 - 22	13
k air (md)	60	10 - 100	80
k liquid (md)	N/A	N/A	N/A
S_w (%)	N/A	N/A	N/A
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A	N/A	N/A

Source Rocks

Lithology and stratigraphic unit New Albany (Devonian) Shale or older
Time of hydrocarbon maturation N/A
Time of trap formation N/A

Reservoir Dimensions

Absolute depth 2,700 ft
Subsea depth
Areal dimensions N/A
Productive area N/A
Number of pay zones 3
Hydrocarbon column Unknown
Initial/present fluid contacts No clear oil-water contact
Average net sand thickness 5 ft
Average gross sand thickness 40 ft
Initial reservoir temperature N/A

Wells

Spacing 10-acre
Pattern N/A
Producers: 23 Water source: 0 Observation: 0 Suspended: 0
Injection: 0 Disposal: 0 Abandoned: 0 Dry holes:
Other: 0

Reservoir Fluid Properties

Hydrocarbons
Type Oil
Gas/oil ratio N/A
API gravity N/A
Oil viscosity N/A
Bubble-point pressure N/A
Formation water
Resistivity N/A
Total dissolved solids (mg/L) N/A

Volumetrics

In place N/A
Cumulative production N/A
Ultimate recovery
Primary N/A
Secondary N/A
Tertiary (incremental) N/A
Recovery efficiency (factor)
Primary N/A
Secondary N/A
Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased
Drilling fluid Bentonite
Fracture treatment 5,000 gals oil and 7,500 lb sand
Acidization N/A
Other N/A
Producing mechanism
Primary Gas depletion
Secondary Waterflood

Producing mechanism *continued*

Tertiary N/A

Typical well production (to date)

Average daily 100 BOPD

Cumulative N/A

WOR initial N/A

WOR cumulative N/A

Field Wells (API numbers)

1219300312	1219330203	1219303078	1219302904	1219305044	1219329938
1219331163	1219302713	1219302727	1219328875	1219302589	1219302902
1219305219	1219331140	1219300827	1219305221	1219303342	1219301069
1219307222	1219301676	1219305527	1219325538	1219306001	1219301069
1219306120	1219329853	1219306224	1219307707	1219303381	

Storms Consolidated Field Reservoir (Aux Vases) Summary

Location White County, Illinois

Tectonic/ Regional Paleosetting Illinois Basin

Geologic Structure Anticline nose

Trap Type Structural-stratigraphic

Reservoir Drive Gas depletion drive

Original Reservoir Pressure Unknown

Reservoir Rocks

Age Upper Valmeyeran Series of the Mississippian System

Stratigraphic unit Aux Vases Sandstone

Lithology Sandstone

Depositional environment Nearshore marine

Productive facies Nearshore siliciclastic

Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)

Porosity type (ϕ total average 15.3%; primary 13.3%; secondary 2%)

	Average	Range	Economic cutoff
ϕ (%)	20	12 - 23	N/A
k air (md)	100	50 - 234	N/A
k liquid (md)	N/A	N/A	N/A
S_w (%)	50	36 - 63	N/A
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A	N/A	N/A

Source Rocks

Lithology and stratigraphic unit New Albany (Devonian) Shale or older

Time of hydrocarbon maturation N/A

Time of trap formation N/A

Reservoir Dimensions

Absolute depth 2,900 ft

Subsea depth

Areal dimensions N/A

Productive area N/A

Number of pay zones 1

Hydrocarbon column Unknown

Initial/present fluid contacts No clear oil-water contact

Average net sand thickness 15 ft

Average gross sand thickness 20 ft

Initial reservoir temperature N/A

Initial reservoir temperature source

Wells

Spacing 10-acre

Pattern N/A

Producers: 29	Water source: 0	Observation: 0	Suspended: 0
Injection: 2	Disposal: 0	Abandoned: 0	Dry holes: 2
Other: 0			

Reservoir Fluid Properties**Hydrocarbons**

Type Oil

Gas/oil ratio N/A

API gravity N/A

Oil viscosity N/A

Bubble-point pressure N/A

Formation water

Resistivity 0.0639 ohm-m @ 77°F

Total dissolved solids (mg/L) N/A

Volumetrics

In place N/A

Cumulative production N/A

Ultimate recovery

Primary N/A

Secondary (incremental) N/A

Tertiary (incremental) N/A

Recovery efficiency (factor)

Primary 15%-20%

Secondary 15%-20%

Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased - N/A

Drilling fluid Bentonite

Fracture treatment 5,000 gals oil and 7,500 lb sand

Acidization N/A

Other N/A

Producing mechanism

Primary Gas depletion

Secondary Waterflood

Tertiary N/A

Typical well production (to date)

Average daily 100 BOPD

Cumulative N/A

WOR initial and cumulative N/A

Field Wells (API numbers)

1219329779	1219302581	1219305049	1219303430	1219330338	1219330354
1219330355	1219301742	1219302088	1219301971	1219302175	1219302045
1219302046	1219301994	1219301975	1219307200	1219330150	1219305099
1219330261	1219330150	1219330057	1219305234	1219305232	1219305233
1219305242	1219305243	1219305244	1219305239	1219305237	1219305227
1219305256	1219305262	1219302048	1219301248	1219302707	1219302829
1219301046	1219307277	1219307581	1219303311	1219302801	1219301650
1219307630	1219307656	1219303440	1219306029	1219306035	1219303366
1219302885	1219303419	1219331141	1219331112	1219306046	1219306048
1219306051	1219331143	1219331145	1219303373	1219307380	1219307651
1219306063	1219302050	1219301180	1219306227	1219306226	

Tamaroa Field Reservoir Summary

Location Perry County

Tectonic/ Regional Paleosetting Intracratonic Basin

Geologic Structure Anticline

Geologic Plays Offshore bars

Trap Type Structural-stratigraphic

Reservoir Drive Gas solution

Original Reservoir Pressure N/A, drill stem test shut-in pressure range up to 435 psi

Reservoir Rocks

Age Mississippian (Chesterian)

Stratigraphic unit Cypress Sandstone

Lithology Quartz arenite

Depositional environment Marine bars, vertically stacked

Productive facies Sandstones of the central bar

Petrophysics (ϕ and k from unstressed conventional core; Sw from logs)

Porosity (total 20.0%; primary 17.0%; secondary 3.0%)

	Average	Range	Economic cutoff
ϕ (%)	20.0	16.0 - 23.0	16.0
k air (md)	131.0	4.0 - 183.0	100.0
k liquid (md)	N/A	N/A	N/A
S _w (%)	N/A	N/A	N/A
S _{or} (%)	N/A	N/A	N/A
S _{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A		

Source Rocks

Lithology and stratigraphic unit N/A

Time of hydrocarbon maturation Permo-Triassic (?)

Time of trap formation Chesterian (strat) Penn/Perm (structural)

Reservoir Dimensions

Absolute depth 1,095 ft

Subsea depth

Areal dimensions 340 acres

Productive area 340 acres

Number of pay zones 2

Hydrocarbon column 30 ft

Initial/present fluid contacts Gas-oil -638 ft; oil-water -665 ft

Average net sand thickness Y3 = 4.6 ft; Y2 = 3.4 ft

Average gross sand thickness Y3 = 6 ft; Y2 = 5 ft

Initial reservoir temperature 100°F

Initial reservoir temperature source Drill stem test and drilling data.

Wells

Spacing 10 acre

Pattern Normal primary and secondary

Producers: 23 Water source: 0 Observation: 0 Suspended: 0

Injection: 6 Disposal: 0 Abandoned: 12 Dry holes: 12

Other: 0

Reservoir Fluid Properties

Hydrocarbons

Type Oil and gas

Gas/oil ratio N/A

API gravity 31.50

Oil viscosity 9.01 cp@ 100°F

Hydrocarbons continued

Bubble-point pressure N/A

Formation water

Resistivity 0.088 ohm-m @ 77°F

Total dissolved solids (mg/L) 85,200-87,500

Volumetrics

In place 1,782,000 bbl

Cumulative production 387,000 bbl

Ultimate recovery

Primary 200,000 bbl

Secondary (incremental) 134,000 bbl

Tertiary (incremental) N/A

Recovery efficiency (factor)

Primary 26.7%

Secondary 16.4%

Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased

Drilling fluid Fresh-water mud with gel additive

Fracture treatment 10 qt nitro or 900-2,000 lb water-sand combination

Acidization None

Other**Producing mechanism**

Primary Pump

Secondary Pump

Tertiary

Typical well production (to date)

Average daily 17

Range 1-105 BOPD

Cumulative 22,000

Range 1,000-65,000 bbl

WOR initial N/A

WOR cumulative N/A

Field Wells (API numbers)

121450203300	121450203301	121450204300	121450204500	121450204600	121450216800
121450218400	121450218700	121450222600	121450223500	121450223600	121450224200
121450224300	121450224301	121450227300	121450227900	121450228700	121450228800
121450229200	121450240300	121450242200	121450242300	121450242400	121450242600
121450242900	121450248200	121450248800	121450248801	121450248900	121450264600
121450264700	121450264701	121450264900	121450265000	121450265600	121450265601
121450265602	121450265900	121450270700	121450270800	121450270900	121450271001
121450271100	121450271200	121450271300	121450271301	121450271400	121450271401
121450271501	121450271800	121450272000	121450272200	121450272400	121450272500
121450272600	121450272700	121450272800	121450272900	121450273000	121450273001
121450279600	121450279601	121450279602	121450279700	121450279800	121450279801
121450279900	121450280300	121450280400	121450281400	121450294600	121450295001
121450295200	121450299700	121450302300	121452324500	121452390500	121452390501
121452425000	121452440400	121452442900	121452471100	121452472000	121452472100
121452496601	121452496700	121452599500	121452599501	121452599600	121452599700

Tamaroa South Extension Field Reservoir Summary

Location Perry County, Illinois

Tectonic/ Regional Paleosetting Intracratonic Basin

Geologic Structure Anticline

Geologic Plays Offshore bars

Trap Type Structural-stratigraphic

Reservoir Drive Gas solution

Original Reservoir Pressure N/A, drill stem test shut-in pressure range up to 435 psi

Reservoir Rocks

Age Mississippian (Chesterian)

Stratigraphic unit Cypress Sandstone

Lithology Quartz arenite

Wetting characteristics (oil/water) N/A

Depositional environment Marine bars, vertically stacked

Productive facies Sandstones of the central bar

Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)

Porosity (total 20.0%; primary 17.0%; secondary 3.0%)

	Average	Range	Economic cutoff
ϕ (%)	20.0	16.0 - 23.0	16.0
k air (md)	131.0	4.0 - 183.0	100.0
k liquid (md)	N/A	N/A	N/A
S_w (%)	N/A	N/A	N/A
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A		

Source Rocks

Lithology and stratigraphic unit N/A

Time of hydrocarbon maturation Permo-Triassic (?)

Time of trap formation Chesterian (strat) Penn/Perm (structural)

Reservoir Dimensions

Absolute depth 1,095 ft

Subsea depth

Areal dimensions 52 acres

Productive area 52 acres

Number of pay zones 2

Hydrocarbon column 10 ft

Initial/present fluid contacts Oil-water -661 ft

Average net sand thickness Y2 only = 4.9 ft

Average gross sand thickness Y2 only = 6 ft

Initial reservoir temperature 100°F

Initial reservoir temperature source Drill stem test and drilling data.

Wells

Spacing 10 acre

Pattern Normal primary and secondary

Producers: 4 Water source: 0 Observation: 0 Suspended: 0

Injection: 0 Disposal: 1 Abandoned: 2 Dry holes: 8

Other: 0

Reservoir Fluid Properties

Hydrocarbons

Type Oil and gas

Gas/oil ratio N/A

API gravity 27.40

Formation volume factor 1.150

Oil viscosity 11.2 cp@ 42°F

Bubble-point pressure N/A

Formation water

Resistivity .09 @ 77°F

Total dissolved solids (mg/L) 84,000

Volumetrics

In place 220,000 bbl
 Cumulative production 71,000 bbl
 Ultimate recovery
 Primary N/A
 Secondary (incremental) N/A
 Tertiary (incremental) N/A
 Recovery efficiency (factor)
 Primary N/A
 Secondary N/A
 Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased
 Drilling fluid Fresh-water mud with gel additive
 Fracture treatment 10 qt nitro or 900-2,000 lb water-sand combination
 Acidization None
 Other
 Producing mechanism
 Primary Pump
 Secondary Pump
 Tertiary
 Typical well production (to date)
 Average daily 17 Range 1-105 BOPD
 Cumulative 71,000
 WOR initial N/A
 WOR cumulative N/A

Field Wells: see Tamaroa South Reservoir Summary

Tamaroa South Field Reservoir Summary

Location Perry County, Illinois
 Tectonic/ Regional Paleosetting Intracratonic Basin
 Geologic Structure Anticline
 Geologic Plays Offshore bars
 Trap Type Structural-stratigraphic
 Reservoir Drive Gas solution
 Original Reservoir Pressure N/A, drill stem test shut-in pressure range up to 435 psi
 Reservoir Rocks

Age Mississippian (Chesterian)
 Stratigraphic unit Cypress Sandstone
 Lithology Quartz arenite
 Wetting characteristics (oil/water) N/A
 Depositional environment Marine bars, vertically stacked
 Productive facies Sandstones of the central bar
 Petrophysics (ϕ and k from unstressed conventional core; Sw from logs)
 Porosity (total 20.0%; primary 17.0%; secondary 3.0%)

	Average	Range	Economic cutoff
ϕ (%)	20.0	16.0 - 23.0	16.0
k air (md)	131.0	4.0 - 183.0	100.0
k liquid (md)	N/A	N/A	N/A
S _w (%)	N/A	N/A	N/A
S _{or} (%)	N/A	N/A	N/A
S _{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A		

Source Rocks

Lithology and stratigraphic unit N/A
Time of hydrocarbon maturation Permo-Triassic
Time of trap formation Chesterian (strat) Penn/Perm (structural)

Reservoir Dimensions

Absolute depth 1,095 ft
Subsea depth
Areal dimensions 180 acres
Productive area 180 acres
Number of pay zones 2
Hydrocarbon column 14 ft
Initial/present fluid contacts Oil-water -668 ft
Average net sand thickness Y3 = 4.7 ft; Y2 = 5 ft
Average gross sand thickness Y3 = 6 ft; Y2 = 5 ft
Initial reservoir temperature 100°F
Initial reservoir temperature source Drill stem test and drilling data.
Fractured Artificial; nitro-induced or sand-water

Wells

Spacing 10 acre
Pattern Normal primary and secondary
Producers: 18 Water source: 0 Observation: 0 Suspended: 0
Injection: 0 Disposal: 1 Abandoned: 7 Dry holes: 14
Other: 0

Reservoir Fluid Properties

Hydrocarbons
Type Oil and gas
Gas/oil ratio N/A
API gravity 27.60
Formation volume factor 1.150
Oil viscosity 26.2 cp @ 42°F
Bubble-point pressure N/A
Formation water
Resistivity 0.091-0.095 ohm-m @ 77°F
Total dissolved solids (mg/L) 83,500-84,300

Volumetrics

In place 1,221,000 bbl
Cumulative production 310,000 bbl
Ultimate recovery
Primary N/A
Secondary (incremental) N/A
Tertiary (incremental) N/A
Recovery efficiency (factor)
Primary N/A
Secondary N/A
Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased
Drilling fluid Fresh-water mud with gel additive
Fracture treatment 10 qt nitro or 900-2,000 lb water-sand combination
Acidization None
Other

Producing mechanism
 Primary Pump
 Secondary Pump
 Tertiary
 Typical well production (to date)
 Average daily 17 Range <1-105 BOPD
 Cumulative 22,000 Range <1,000- 65,000 bbl
 WOR initial N/A
 WOR cumulative N/A

Field Wells (API numbers): see Tamaroa Field Reservoir Summary

Xenia East Field Reservoir Summary

Location Clay County, Illinois
 Tectonic/ Regional Paleosetting Illinois Basin, intracratonic
 Geologic Structure Anticline
 Geologic Play(s) Near-shore and offshore bar
 Trap Type Structural-stratigraphic
 Reservoir Drive Water drive
 Original Reservoir Pressure N/A, drill stem test shut-in BHIPs up to 915 psi
 Reservoir Rocks

Age	Mississippian (Chesterian)		
Stratigraphic unit	Cypress Sandstone		
Lithology	Quartz arenite		
Depositional environment	Near-shore and offshore marine bars, vertically stacked		
Productive facies	Sandstones of the central bar		
Petrophysics (ϕ and k from unstressed conventional core; S_w from logs)			
Porosity type (ϕ total average 15.3%; primary 13.3%; secondary 2.0%)			
	Average	Range	Economic cutoff
ϕ (%)	15.3	13.5 - 17	13.5
k air (md)	71	4 - 88	N/A
k liquid (md)	N/A	N/A	N/A
S_w (%)	40	60 - 28	60
S_{or} (%)	N/A	N/A	N/A
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	N/A	N/A	N/A

Source Rocks

Lithology and stratigraphic unit New Albany Shale (?)
 Time of hydrocarbon maturation Permo-Triassic (?)
 Time of trap formation Chesterian (stratigraphic); N/A (structural)

Reservoir Dimensions

Absolute depth 2,520 ft
 Subsea depth -2,015 ft
 Areal dimensions 425 acres
 Productive area 360 acres
 Number of pay zones 2
 Hydrocarbon column Structural 17 ft, stratigraphic 9 ft
 Initial/present fluid contacts Structural trap: oil-water -2,030 ft; stratigraphic trap none
 Average net sand thickness Unit 4 = 15 ft, unit 2 = 5 ft
 Average gross sand thickness Unit 4 = 17 ft, unit 2 = 9 ft
 Initial reservoir temperature 100°F
 Initial reservoir temperature source Log header

Wells

Spacing 10 acre

Pattern Normal primary

Producers: 18 Water source: 0 Observation: 0 Suspended: 2

Injection: 0 Disposal: 3 Abandoned: 16 Dry holes: 14

Other: 12

Reservoir Fluid Properties

Hydrocarbons

Type Oil

Gas/oil ratio N/A

API gravity N/A

Formation volume factor N/A

Oil viscosity

Bubble-point pressure N/A

Formation water

Resistivity 0.046 @ 100°F

Total dissolved solids (ppm) 128,380

Volumetrics

In place 2,000,000 bbl

Cumulative production 470,000 bbl

Ultimate recovery

Primary 470,000

Secondary (incremental) N/A

Tertiary (incremental) N/A

Recovery efficiency (factor)

Primary 23.0%

Secondary N/A

Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased

Drilling fluid Fresh-water mud with gel additive

Fracture treatment 1,000 gallon lease oil with sand combination

Acidization None

Other

Producing mechanism

Primary Pump

Secondary N/A

Tertiary N/A

Typical well production (to date)

Average daily 56

Range 8-152 BOPD

Cumulative 2,6100

Range N/A

WOR initial 0.7

Range 0-4

WOR cumulative N/A

Field Wells (API numbers)

120250053400	120250113200	120250116500	120250119600	120250120000	120250120001
120250120300	120250121300	120250121500	120250143500	120250145400	120250145700
120250145701	120250147500	120250149600	120250149700	120250154000	120250167900
120250197400	120250198200	120250199200	120250199700	120250201100	120250201700
120250203300	120250203400	120250203401	120250203500	120250203600	120250203601
120250203700	120250203800	120250203900	120250204000	120250204100	120250204101
120250204200	120250204300	120250204301	120250204400	120250204500	120250204600
120250204700	120250204800	120250207500	120252572200	120252622900	120252623000
120252683600	120252800800				

Zeigler Field Reservoir Summary

Location Franklin County, Illinois

Tectonic/ Regional Paleosetting Illinois Basin, intracratonic

Geologic Structure None

Trap Type Stratigraphic

Reservoir Drive Solution gas drive

Original Reservoir Pressure Approximately 1100 psi

Reservoir Rocks

Age Middle Mississippian (upper Valmeyeran)

Stratigraphic unit Aux Vases Sandstone

Lithology Quartz arenite-subarkose

Wetting characteristics Water-wetting

Depositional environment Offshore tidal marine bar complex in mixed siliciclastic-carbonate environment

Productive facies Marine sandstone bar facies

Petrophysics (ϕ and k from unstressed conventional core; S_w from core analyses)

Porosity type (ϕ total 21%; primary ?; secondary ?)

	Average	Range	Economic cutoff
ϕ (%)	21.0	19.0 - 28.0	
k air (md)	125	0.1 - 800	
k liquid (md)			
S_w (%)		40	60
S_{or} (%)		60	40
S_{gr} (%)	N/A	N/A	N/A
Cementation factor	1.97	N/A	N/A

Source Rocks

Lithology and stratigraphic unit New Albany Shale (?)

Time of hydrocarbon maturation Permo-Triassic (?)

Time of trap formation Upper Valmeyeran (stratigraphic)

Reservoir Dimensions

Absolute depth top of sandstone 2,600-2,700 ft

Subsea depth -2,215 to -2,264

Areal dimensions 1,250 acres

Productive area Approximately 600 acres

Number of pay zones 1

Hydrocarbon column 5-25 ft

Initial/present fluid contacts Oil-water (OWC), none measured in field. No OWC in any producing sandstone bar

Average net sand thickness 14 ft W. Plumfield bar; 15 ft Plumfield and S. Plumfield bars

Average gross sand thickness 15 ft

Initial reservoir temperature 100°F (estimated from logs)

Initial reservoir temperature source Estimated from logs

Fractured Natural fractures present; some wells shot with 10-60 quarts of nitroglycerin

Wells

Spacing 10 acre

Pattern Injection program utilizing peripheral and converting poor producers

Total 37

Producers: 37 (12 producers in W. Plumfield 3 injectors; 9 producers 2 injectors Plumfield bar during early development, 3 producers; 2 injectors in S. Plumfield during early phase of development, 2 producers; many producers were converted to injector wells during later phases of development in the Plumfield leases; 2 injectors in Mack lease bar from initial production to present). Cannot distinguish primary from secondary recovery because waterfloods were started early to maintain pressure.

Producers: 37	Water source:	Observation:	Suspended:
Injection:	Disposal:	Abandoned:	Dry holes:
Other:			

Reservoir Fluid Properties

Hydrocarbons

Type Oil
 Gas/oil ratio N/A
 API gravity 36.6°
 Oil viscosity 4.1 cp @ 98°F
 Formation volume factor 1.068
 Bubble-point pressure N/A

Formation water

Resistivity 0.061–0.068 ohm-m @ 77°F
 Total dissolved solids (mg/L) 121,200–37,300

Volumetrics

Bar Plumfield¹ Plumfield/S. Plumfield² Mack³
 In place ¹1,716,859 (φ=21.0%) ²1,996,901 (φ=21.0) ³571,981 (φ=21.0%)
 Cumulative production (STBO) ¹791,828 bbl ²1,170,573 bbl ³133,000 bbl
 Ultimate recovery
 Primary 2,095 bbl
 Secondary (incremental) 4,000 bbl
 Tertiary (incremental) N/A
 Recovery efficiency (factor)
 Primary and secondary ¹46.12% ²58.62% ³23.25% to date
 Tertiary N/A

Typical Drilling/ Completion/ Production Practices

Completions Open hole and cased
 Drilling fluid Fresh-water mud
 Fracture treatment ¹0-50 qt nitroglycerin ²0-60 qt nitroglycerin ³none
 Acidization None
 Other
 Producing mechanism
 Primary Pump
 Secondary Pump
 Tertiary N/A

Typical well production (to date)

Unit	Fluids produced per day	Water/oil
W. Plumfield	276.0 BOPD; 0.5 BWPD	0.002
Plumfield	173.0 BOPD; <1.0 BWPD	0.006
S. Plumfield	96.0 BOPD; 4.0 BWPD	0.042
Mack	69.5 BOPD; 24.0 BWPD	0.345

Cumulative production to 11/91 (average bbl—primary and/or secondary)

Unit	No. wells	Average production
W. Plumfield	12	72,874 bbl/well
Plumfield	13	60,910 bbl/well
S. Plumfield	3	94,669 bbl/well
Mack	2	66,500 bbl/well

Field Wells (API numbers)

120550132800	120550206100	120550206400	120550207200	120550207800	120550208100
120550208201	120550208700	120550209000	120550209500	120550209800	120550209900
120550209901	120550210000	120550210700	120550210800	120550211200	120550211500
120550212000	120550212100	120550212500	120550212600	120550212700	120550213900
120550213901	120550214400	120550214401	120550214900	120550216800	120550217000

120550217201	120550217400	120550217700	120550218200	120550218500	120550218800
120550220000	120550220001	120550220400	120550232300	120550232500	120550232700
120550233200	120550233900	120550245500	120552370900	120552373600	120552373700
120552374400	120552375000	120552375300	120552375500	120552376700	120552376900
120552377000	120552384800	120552384900	120552387100	120552387200	

APPENDIX VI. FORMATION WATER CHEMISTRIES

Well Identification and Chemical Composition of Aux Vases and Cypress Formation Waters (Solute Concentrations are in mg/L)

Sample No	API No	Field Name	Strat. Unit	Average				Major Constituents (mg/L)											
				Depth (ft)	Recess (cm-in)	Eh (mV)	pH	TDS (mg/L)	Cl	Br	I	SO4	NO3	Ca	CO3	HCO3	NH4	Na	Cu
EDR-8115	120532381800	ALON	Cyp	2825	0.0601	-106	6.44	145333	87000	160	3.50	270	0.62	0.04	140	31	52.900	4010	
EDR-892	121813194400	BARHILL	Aux V	3380	0.0838	-234	6.88	132780	78000	110	13.00	1300	0.08	0.10	110	23	45400	5170	
EDR-817	120270141300	BARTELSON	Cyp	987	0.1382	-318	7.01	49667	25000	84	5.60	2.5	0.10	0.06	460	23	18160	892	
EDR-846	120270140600	BARTELSON	Cyp	995	0.1389	-197	7.05	49352	29750								17670	856	
EDR-819	120270141700	BARTELSON	Cyp	991	0.1384	-111	6.95	51519	31057								18620	1013	
EDR-826	120270141700	BARTELSON	Cyp	985	0.1401	-271	6.9	48809	28366								17650	935	
EDR-829	120270141700	BARTELSON	Cyp	980	0.1427	-275	7.2	48716	29377								18000	980	
EDR-830	120270140600	BARTELSON	Cyp	973	0.1425	-142	6.87	48584	29000	85	4.70	7.5	0.10	0.24	280	21	17480	991	
EDR-831	120270140600	BARTELSON	Cyp	979	0.1435	-335	6.87	51339	30935								18550	985	
EDR-898	120625060500	BUNGAY C	Aux V	3317	0.0627	-280	6.93	137213	82000	170	7.80	990	0.28	0.39	130	24	47300	4790	
EDR-870	121832941500	CARLIN NORTH	Aux V	3236	0.0676	-150	6.92	126480	74000	180	7.00	304	0.60	0.05	80	21	43830	5340	
EDR-872	121932855300	CARLIN NORTH	U Cyp	2835	0.0689	-128	6.28	122960	72000	160	6.40	64	0.32	0.28	93	17	43740	5230	
EDR-850	121913184700	CLAY CITY C	Aux V	3189	0.0606	-300	6.74	145056	85000	180				0.16	110	31	50850	5820	
EDR-861	121813089200	CLAY CITY C	Aux V	3234	0.0782	-335	7.24	100788	59000	130				0.09	170	28	35580	3770	
EDR-876	121862444800	CLAY CITY C	Aux V	2819	0.0689	-279	6.05	126289	76741								44630	3300	
EDR-879	121862444700	CLAY CITY C	Aux V	2823	0.0667	-270	6.46	132052	79000		5.70	1.1	0.23	0.09	94	37	45770	3600	
EDR-880	120252804100	CLAY CITY C	Aux V	2918	0.0728	-277	6.99	115063	68000		4.30	1500	0.27	0.32	170	38	42020	3740	
EDR-881	120300289100	CLAY CITY C	Aux V	2911	0.0614	-283	6.92	144658	89000		8.80	510	0.27	0.38	160	23	52030	5170	
EDR-888	120782485800	CLAY CITY C	Aux V	2743	0.0636	-202	6.8	136339	81000	150	7.70	1800	0.19	0.11	180	37	48800	4750	
EDR-893	121810390800	CLAY CITY C	Aux V	3402	0.0692	-287	6.96	116826	65000	140	7.70	1200	0.01	0.13	180	30	42100	3780	
EDR-892	121813114800	CLAY CITY C	Cyp	2940	0.0679	-283	7.24	124254	72000	140				0.34	220	28	45940	3490	
EDR-895	120252768900	CLAY CITY C	Cyp	2878	0.0731	-288	6.37	104955	61000	140	4.40	870	0.70	0.19	260	41	36060	2740	
EDR-898	121550326100	CLAY CITY C	Cyp	2555	0.0798	-280	6.82	101482	80000	96	4.40	1900	1.40	0.81	880	17	38280	1690	
EDR-897	121862553200	CLAY CITY C	Cyp	2890	0.0907	-99	7.71	84584	51000	94	3.80	1.4	0.28	0.14	230	15	30600	1670	
EDR-8102	121552532000	CLAY CITY C	Cyp	2890	0.0801	-103	6.46	83707	50000	96	3.90	4.8	0.27	0.14	160	26	30890	1730	
EDR-811	12052348700	DALE CONS	Aux V	3182	0.0654	-226	7.08	125875	74684								28	43650	5230
EDR-812	12052345500	DALE CONS	Aux V	3189	0.0678	-329	8.02	123181	72506								29	42800	5540
EDR-813	120625487700	DALE CONS	Aux V	3232	0.0585	-135	6.08	135649	78000	220	15.00	700	0.25	0.01	30	48	48310	6350	
EDR-892	120625487700	DALE CONS	Aux V	3210	0.0935	-280	7.63	135048	77000	100	11.00	140	1.30	0.02	900	29	44080	6170	
EDR-8107	12052347200	DALE CONS	Aux V	3172	0.0616	-134	6.34	137444	84000	180	9.90	9.8	0.41	0.00	84	36	44880	5820	
EDR-8108	12052348700	DALE CONS	Aux V	3178	0.0636	-124	7.08	128440	78000	150	12.00	19	0.43	0.01	94	32	42990	5630	
EDR-8101	12052272100	DALE CONS	Cyp	2969	0.0621	-270	6.24	140637	83000	160	2.40	930	0.36	0.08	80	26	50700	4650	
EDR-8114	120625607900	DALE CONS	Cyp	2724	0.0825	-173	5.88	137161	61000	140	3.10	920	0.60	0.04	160	31	49530	3670	
EDR-885	120812435800	DAVIDE CONS	Aux V	2870	0.0624	-206	6.78	137870	83000		8.80	480	0.06	0.06	84	18	46570	5380	
EDR-836	120812418800	DAK SOUTH	Aux V	2044	0.0684	-104	6.17	125882	76000	140	8.40	130	0.04	0.02	87	31	42460	4910	
EDR-899	121852490500	ELDRORADO W	Aux V	2864	0.0746	-213	6.56	108586	65000	180	10.20	430	0.24	0.29	210	23	38200	4030	
EDR-84	121952345800	ENERGY	Aux V	2400	0.0633	-205	7.02	122431	72453								26	42370	4630
EDR-85	121852345500	ENERGY	Aux V	2371	0.0633	-202	7.12	124000	73377								24	42900	4510
EDR-86	121852345700	ENERGY	Aux V	2400	0.0623	-106	5.79	131352	78000	190	9.70	2.1	0.29	0.04	85	36	43350	5300	
EDR-860	121852346600	ENERGY	Aux V	2349	0.0639	-146	7.26	122629	73063								21	42720	4700
EDR-8103	121853344800	ENERGY	Aux V	2354	0.0632	-102	6.63	132040	79000	180	10.00	1.8	0.25	0.01	60	31	44210	5370	
EDR-890	121913142200	GOLDEN GATE C	Aux V	2589	0.0635	-305	8.87	137970	79000	160	9.20	1300	0.25	0.27	230	25	48600	5030	
EDR-891	12047242800	GOLDEN GATE C	Aux V	3179	0.0688	-58	6.96	122771	73000	190	13.00	950	0.23	0.10	170	26	26800	6060	
EDR-8109	121852581700	HARCO	Cyp	2584	0.0855	-270	7	124101	74000	150	8.80	480	0.46	0.20	170	23	43070	4840	
EDR-877	121833050200	HERALD CONS	Aux V	2886	0.0673	-288	6.38	125828	72000	200	11.00	1400	0.26	0.41	140	18	46880	3280	
EDR-884	121910515800	JOHNSONVILLE W	Aux V	2973	0.0883	-278	6.31	181289	88000		8.20	280	0.18	0.10	180	23	54660	5280	
EDR-88	120810016700	KING	Aux V	2720	0.0648	-236	6.35	129783	78815								33	48020	3260
EDR-89	120810016700	KING	Aux V	2744	0.0621	-287	6.81	141529	85000	180	3.90	720	0.06	0.11	120	36	48540	4710	
EDR-887	121012389300	LAWRENCE	Cyp	1593	0.1447	-258	6.67	48460	28000	80	4.40	830	0.01	0.01	20	10	18400	633	
EDR-833	121912816100	MAPLE GROVE C	Aux V	3145	0.0617	-210	6.28	142269	85000	160		1200	0.13	0.01	30	40	47000	6750	
EDR-889	120472231500	Bennington B	Aux V	3195	0.0714	-201	6.84	116870	67000	180	8.50	1800	0.55	0.04	83	27	41700	4450	
EDR-814	120252300800	MATTOON	L Cyp	1866	0.0762	-258	7.62	107006	64599								26	38670	3180
EDR-816	120250182200	MATTOON	Cyp	1794	0.0785	-284	7.35	98074	59276								33	34810	2790
EDR-815	120252310100	MATTOON	Cyp	1882	0.0715	-333	7.4	112214	68475								28	38840	3400
EDR-834	120250054300	MATTOON	Cyp	1762	0.0700	-95	6.3	113311	67000	140	13.00	280	0.15	0.15	100	33	40290	3690	
EDR-835	120252340200	MATTOON	Cyp	1820	0.0682	-278	6.83	117089	65000	140	4.70	600	0.10	0.26	140	25	40550	4490	
EDR-837	120252316200	MATTOON	Cyp	1971	0.0708	-157	6.05	120878	72890								42500	3785	
EDR-843	120252322100	MATTOON	Cyp	1859	0.0689	-132	6.35	135781	52000	100	3.90	630	0.13	0.08	170	24	31980	2780	
EDR-844	120250062400	MATTOON	Cyp	1780	0.0727	-280	7.17	110591	65000	120									

Major And Trace Constituents (mg/L)

Hg	K	Sr	Ba	Li	Fe	Mn	B	Si	Al	Pb	Ti	V	Co	Ni	Cu	Zn	Zr	Cd	Be	Cr	As	Se	Mo	Sb
1370	105	130	0.68	3.90	3.00	0.43	2.89	1.50	0.2	+0.4	+0.04	+0.08	+0.07	+0.1	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1310	182	145	0.22	6.88	0.40	0.73	4.10	4.80	0.1	+0.4	0.03	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
601	69	101	252.00	4.80	0.19	1.07	2.50	4.80	+0.4	+0.4	0.02	+0.08	0.15	+0.1	+0.05	+0.02	0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
558	82	98	85.40	8.41	0.80	0.80	2.67	3.90	+0.4	+0.4	0.07	+0.07	+0.15	+0.05	+0.02	0.05	+0.05	0.0018				1.3	+0.08	+0.3
588	88	103	28.10	37.80	0.23	0.23	2.82	3.81	+0.4	+0.4	0.07	+0.07	+0.15	+0.05	+0.02	0.05	+0.05	0.0028				1.3	+0.08	+0.3
545	70	92	140.00	0.23	0.23	0.23	2.97	5.10	1.45	+0.4	0.09	+0.05	+0.15	0.11	+0.02	0.05	+0.05							+0.3
585	70	92	3.18	0.20	0.23	0.23	2.62	4.88	+0.4	+0.4	0.08	+0.08	+0.15	0.11	+0.02	0.05	+0.05							+0.3
592	95	90	35.10	4.72	22.70	0.79	2.30	4.40	+0.4	+0.4	0.03	+0.08	+0.07	0.10	+0.05	+0.02	+0.08	+0.05	0.003	+0.07	+0.5	+0.7	+0.08	+0.3
580	70	97	92.00	0.25	0.25	0.25	3.43	8.36	+0.4	+0.4	0.08	+0.08	+0.15	0.10	+0.02	0.05	+0.05							+0.3
1460	174	150	0.61	6.44	0.20	0.50	4.30	4.30	0.1	+0.4	0.06	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	0.1	+0.5	+0.7	+0.11	+0.3
1210	170	313	2.10	7.10	0.15	1.25	3.70	3.20	+0.1	+0.4	+0.04	+0.07	+0.07	+0.1	0.04	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1180	140	257	8.54	6.10	10.40	2.55	3.10	10.70	+0.1	+0.4	+0.04	+0.07	+0.07	+0.1	0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1700	239	190	0.78	10.70	0.06	0.61	3.40	4.30	+0.4	+0.4	0.04	+0.08	+0.07	+0.1	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1040	173	192	0.51	8.27	+0.06	0.34	3.00	0.70	0.2	+0.4	0.03	+0.08	+0.07	+0.1	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1280	184	542	7.50	5.40	+0.06	0.80	3.30	4.70	+0.4	+0.4	+0.04	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1430	193	958	9.00	5.20	0.50	0.33	3.40	4.10	0.2	+0.4	+0.04	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1260	180	133	0.50	8.10	+0.06	0.51	4.00	4.20	+0.4	+0.4	+0.04	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1380	214	178	0.90	7.10	0.40	0.34	3.70	2.40	+0.4	+0.4	+0.04	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	0.05	+0.5	+0.7	+0.08	+0.3
1210	268	117	0.17	7.61	1.94	0.86	4.40	8.70	0.2	+0.4	0.05	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	0.05	+0.5	+0.7	+0.08	+0.3
1180	187	130	0.77	5.93	0.60	0.52	5.40	6.20	0.1	+0.4	0.04	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1140	174	106	0.26	6.77	0.17	0.87	2.20	6.20	0.2	+0.4	0.03	+0.08	+0.07	+0.1	+0.05	+0.02	+0.08	+0.05	0.006	+0.07	+0.5	+0.7	+0.08	+0.3
1400	213	77	1.30	15.50	0.10	0.43	2.70	4.70	0.2	+0.4	0.03	+0.07	+0.07	+0.15	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1030	158	75	0.14	6.40	0.10	1.36	2.72	6.90	0.3	+0.4	+0.04	+0.07	+0.07	+0.15	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
772	124	55	2.16	3.53	12.40	0.83	2.50	6.40	0.1	+0.4	0.02	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
782	100	54	2.47	2.80	12.00	1.28	2.62	7.40	0.3	+0.4	+0.04	+0.08	+0.07	0.18	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1740	266	274	0.74	1.20	0.69	4.88	4.46			+0.4	0.21	+0.01	+0.15	0.09	+0.02	0.10	+0.05							+0.3
2190	358	145	0.06	0.97	0.34	9.21	4.21			+0.4	0.21	+0.05	+0.15	0.09	+0.02	0.10	+0.05							+0.3
2180	394	312	0.57	15.00	0.40	0.73	4.50	4.50	0.2	+0.4	0.05	+0.08	+0.07	+0.15	0.01	+0.02	0.11	+0.05	0.03	+0.07	+0.5	+0.7	+0.08	+0.3
1810	247	247	4.13	11.10	+0.06	0.41	3.80	4.30	+0.2	+0.4	0.05	+0.08	+0.07	+0.15	0.02	+0.02	0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1930	175	322	2.77	7.10	34.90	1.43	3.94	8.70	0.3	+0.4	+0.04	+0.08	+0.07	+0.1	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1740	241	251	8.28	8.70	62.30	2.28	3.45	7.40	0.3	+0.4	+0.04	+0.08	+0.07	+0.1	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1270	149	149	0.29	5.62	5.00	1.20	2.30	4.00	0.1	+0.4	0.03	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1280	112	118	0.29	3.70	6.80	1.10	3.21	1.90	0.2	+0.4	+0.04	+0.08	+0.07	+0.1	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1490	171	258	0.80	7.40	0.80	0.88	3.30	2.70	0.1	+0.4	+0.04	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1680	182	272	1.88	8.61	0.40	0.84	2.80	3.90	0.3	+0.4	0.05	+0.08	+0.07	+0.1	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1080	216	321	0.81	12.60	1.40	0.62	2.80	4.40	0.1	+0.4	0.03	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
2200	173	659	0.63	6.70	0.68	0.79	2.47			+0.4		+0.07	+0.15	0.19	+0.02	0.10	+0.05							+0.3
2380	174	831	0.69	10.40	0.92	4.06	2.17			+0.4		+0.07	+0.15	0.19	0.04	0.10	+0.05							+0.3
2580	181	574	17.40	13.80	2.80	0.71	4.02	3.80	0.1	+0.4	0.04	+0.08	+0.07	+0.15	+0.05	+0.02	0.03	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
2290	180	614	4.63	21.80	1.92	4.00	6.91			+0.4		+0.07	+0.15	0.19	+0.02	0.10	+0.05							+0.3
2510	190	441	12.50	12.00	6.00	0.74	1.80	3.30	+0.2	+0.4	0.04	+0.08	+0.07	+0.15	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
2480	188	452	3.92	9.91	0.60	0.94	2.20	3.80	0.1	+0.4	0.02	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1290	176	133	0.76	7.00	0.60	0.75	3.60	4.50	0.1	+0.4	0.03	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1420	148	125	0.17	5.77	2.30	0.68	3.30	6.50	0.1	+0.4	0.05	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1150	130	247	3.17	8.60	0.30	0.39	2.16	6.40	0.4	+0.4	+0.04	+0.08	+0.07	+0.1	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1420	219	157	0.17	11.70	0.30	0.28	5.80	2.80	+0.1	+0.4	+0.04	+0.07	+0.07	+0.1	0.03	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1080	211	218	2.20	7.10	0.30	1.15	3.30	3.70	0.2	+0.4	+0.04	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	0.1	+0.5	+0.7	+0.08	+0.3
1260	205	173	0.40	5.70	0.62	3.80	4.68			+0.4	0.15	+0.07	+0.15	0.11	+0.02	0.08	+0.05							+0.3
1720	280	195	0.78	10.70	+0.06	0.56	3.40	4.40	0.3	+0.4	0.04	+0.08	+0.07	+0.1	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
378	70	32	0.15	1.70	12.70	4.42	2.72	+0.5	+0.4	+0.4	+0.04	+0.07	+0.15	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3	
1700	184	146	0.27	10.10	20.20	1.77	2.80	4.40	0.3	+0.4	0.06	+0.08	+0.07	+0.1	+0.05	+0.02	+0.08	+0.05	0.006	+0.07	+0.5	+0.7	+0.08	+0.3
1180	146	95	0.13	5.83	3.00	1.30	4.20	4.70	0.1	+0.4	0.04	+0.07	+0.07	+0.1	+0.05	+0.02	+0.07	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3
1114	68	130	2.28	0.78	0.32	2.94	3.83			+0.4	0.15	+0.07	+0.15	0.04	+0.02	0.08	+0.05							+0.3
913	66	141	16.30	0.69	0.50	2.86	5.08			+0.4	0.14	+0.07	+0.15	0.02	+0.02	0.08	+0.05							+0.3
1113	97	151	0.90	0.74	0.25	3.01	3.97			+0.4	0.15	+0.07	+0.15	0.03	+0.02	0.08	+0.05							+0.3
1290	112	144	2.83	4.50	4.00	1.02	2.54	3.30	+0.4	+0.4	0.03	+0.07	+0.15	+0.05	+0.02	+0.08	+0.05	+0.003	+0.07	+0.5	+0.7	+0.08	+0.3	
1330	102	173	0.62	0.20	0.19	0.89	1.87	3.50	0.1	+0.4	0.03	+0.07	+0.15	+0.05	+0.02	+0.								

APPENDIX VII-A. OIL ANALYSIS RESULTS

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Sample	C17/ Pristane	C18/ Phytane	C17/ C18	Pristane/ phytane	C.P.I.	% sats	% aros	Resins	% asphs	% normal paraffin	% mono paraffin	% dicyclo paraffin	% naph- thalene	C # extent	Max para C #
EOR-2	1.180	1.160	1.084	1.820	0.972	64.27%	20.93%	9.35%	5.45%	26.40%	7.31%	4.48%	4.02%	8-39	20
EOR-3	1.307	1.984	0.880	1.487	0.977	69.11%	21.15%	9.04%	0.70%	30.81%	8.82%	3.91%	1.62%	11-39	26
EOR-5	1.450	2.120	1.065	1.556	0.974	68.82%	21.39%	8.79%	1.00%	38.83%	7.41%	3.31%	5.45%	10-38	21
EOR-6	1.539	2.072	0.987	1.330	0.970	64.15%	20.19%	12.95%	2.72%	41.13%	9.26%	2.81%	3.19%	10-39	22
EOR-7	2.431	2.197	1.106	1.000	0.976	72.26%	20.10%	6.80%	0.85%	47.19%	6.62%	2.47%	2.22%	9-38	19
EOR-16	1.240	1.529	1.175	1.448	0.980	63.47%	32.49%	3.71%	0.33%	25.47%	8.99%	5.22%	1.47%	10-34	17
EOR-17	1.545	1.736	1.209	1.358	1.010	69.99%	24.77%	4.58%	0.66%	27.84%	11.72%	6.83%	2.25%	11-36	17
EOR-18	1.407	2.125	0.988	1.462	0.967				2.33%					9-38	19
EOR-19	1.502	2.100	1.003	1.402	0.992				2.33%					9-38	19
EOR-20	1.090	1.353	1.029	1.278	0.988				2.33%					9-38	19
EOR-31	1.240	1.160	1.069	1.390	0.880	74.27%	20.10%	5.40%	0.23%	35.86%	9.02%	2.28%	4.83%	9-39	17
EOR-32	1.110	1.529	0.968	1.338	0.930	74.61%	21.84%	2.80%	0.85%	39.54%	9.19%	2.34%	4.77%	9-38	19
EOR-33	1.180	1.587	0.991	1.275	0.990	72.26%	20.08%	4.39%	3.27%	41.40%	8.83%	5.86%	3.01%	10-38	19
EOR-48	1.466	2.433	1.033	1.713	0.930	84.41%	8.44%	5.90%	1.25%	30.57%	7.55%	4.19%	1.96%	8-35	16
EOR-49	1.110	1.587	1.001	1.431	0.990	74.51%	22.84%	2.45%	0.20%	32.11%	5.55%	2.99%	1.07%	9-35	20
EOR-50	0.984	1.629	0.809	1.338	0.930	77.84%	15.74%	5.60%	1.01%	27.86%	22.98%	16.44%	2.03%	10-36	18
EOR-51	0.138	0.289	1.053	2.204	0.900	61.22%	14.82%	32.44%	1.51%	25.46%	6.84%	4.68%	0.79%	10-35	30
EOR-52	1.851	3.111	1.195	2.008	1.160	74.02%	18.44%	4.39%	3.15%	48.22%	19.54%	5.60%	0.58%	8-35	17
EOR-53	0.755	1.100	0.875	1.275	0.900	53.94%	11.95%	33.57%	0.54%	37.36%	4.92%	3.40%	4.64%	8-35	15
EOR-54	1.035	1.598	0.869	1.326	0.990	74.27%	20.08%	5.40%	0.25%	8.75%	5.70%	4.68%	2.24%	8-35	19
EOR-55	1.375	1.790	0.999	1.301	1.050	50.54%	18.10%	30.80%	0.58%	28.48%	8.99%	4.30%	0.53%	9-35	20
EOR-56	0.560	1.002	0.694	1.242	0.900	46.88%	15.05%	37.80%	0.26%	25.47%	6.86%	5.99%	1.67%	9-35	24
EOR-57	1.619	2.460	1.249	1.898	0.970	71.14%	22.11%	4.68%	2.05%	38.06%	9.11%	5.22%	0.64%	11-34	17
EOR-58	1.306	2.123	1.030	1.673	0.970	64.67%	21.18%	23.55%	0.80%	31.29%	8.26%	5.99%	1.11%	8-37	17
EOR-59	1.372	2.458	1.097	1.964	1.190	37.27%	15.29%	47.27%	0.17%	20.59%	6.47%	3.11%	0.45%	8-34	17
EOR-60	1.767	2.672	1.218	1.841	0.880	80.21%	12.44%	6.98%	0.37%	42.25%	10.22%	5.86%	1.61%	8-34	15
EOR-61	2.297	3.822	1.116	1.857	1.140	79.77%	13.79%	2.86%	1.66%	44.34%	14.66%	8.34%	0.67%	10-33	17
EOR-62	1.631	2.720	1.163	1.940	1.170	70.87%	20.42%	6.25%	2.38%	41.23%	13.00%	5.00%	0.60%	11-34	15
EOR-64	1.424	2.534	1.125	2.001	1.120	68.68%	22.62%	7.25%	1.43%	37.66%	9.64%	5.57%	0.77%	11-33	15
EOR-65	1.504	3.780	1.254	3.134	1.140	71.01%	20.42%	7.32%	1.25%	38.96%	8.89%	3.64%	0.92%	9-34	15
EOR-66	1.417	1.785	1.215	1.530	1.100	77.86%	14.47%	6.85%	0.82%	41.14%	10.04%	5.15%	1.61%	10-32	15
EOR-67	2.738	6.463	0.967	2.328	1.020	81.32%	15.18%	2.52%	0.98%	48.60%	13.13%	7.35%	0.98%	11-32	17
EOR-68	2.289	2.861	1.155	1.444	1.187	78.69%	16.59%	3.92%	0.49%	45.77%	16.16%	9.08%	1.01%	10-36	17
EOR-69	1.950	3.589	0.883	2.613	1.080	74.91%	18.15%	5.60%	1.34%	27.84%	11.80%	6.15%	2.37%	8-34	19
EOR-71	2.431	2.197	1.106	1.000	0.976	72.26%	20.10%	6.80%	0.85%	47.19%	6.62%	2.47%	2.22%	9-38	17
EOR-72	1.545	1.736	1.209	1.358	1.010	69.99%	24.77%	4.58%	0.66%	27.84%	11.72%	6.83%	2.25%	11-36	17

C.P.I. = carbon preference index; para = paraffin

APPENDIX VII-B. OIL SAMPLE LOCATIONS

API	Field	Operator, well name	County	S-T-R	Quarter	Brine	Oil	Pay	Depth, sampled
121730113800	Stewardson	Chalee C-4 Doran Oil	Shelby	27-10N- 5E	SW NW NE	EOR-B1	1	AV& SPM	1949-2024
121732247300	Stewardson	Chalee C-9 Doran Oil	Shelby	27-10N- 5E	SW NE NE	EOR-B2	2	AV	1953-1967
121730128800	Stewardson	Pinker 2 Ray Brown	Shelby	22-10N- 5E	SE SW SE	EOR-B3	3	AV	1948-1958
120552376000	Zeigler	Mack 2 V. Gallagher	Franklin	19- 7S- 2E	NE		4	AV	2603-2621
121992345800	Energy	Morgan Coal 1 Budmark Oil	Williamson	4- 9S- 2E	SE SW NW	EOR-B4	5	AV	2400-2408
121992346500	Energy	AP Mrgn Coal 1 Budmark Oil	Williamson	4- 9S- 2E	NW SW NW	EOR-B5	6	AV	2371-2378
121992345700	Energy	AP Mrgn Coal 2 Budmark Oil	Williamson	4- 9S- 2E	SW SW NW	EOR-B6	7	AV	2400-2408
121992346800	Energy	AP Mrgn Coal 3 Budmark Oil	Williamson	4- 9S- 2E	NE SW NW	EOR-B7	8	AV	2389-2394
120810016700	King	StateGameF A-2 Baldridge Oil	Jefferson	28- 3S- 3E	NW NE	EOR-B9	9	AV	2744-2752
120552345700	Data Cons	McGrary 2 Farrar Oil	Franklin	13- 7S- 4E	NW SE	EOR-B11	10	AV	3182-3182
120552345500	Data Cons	Berry 11 Farrar Oil	Franklin	13- 7S- 4E	NE SE	EOR-B12	11	AVA ST.L.	3158-3163
120852467700	Data Cons	Smith 1 Farrar Oil	Hamilton	9- 7S- 5E	NE NW	EOR-B13	12	AV	3232-3245
120292300800	Mattoon	Erler 3 Mel-Pel(Sledge)	Coles	36-12N- 7E	NE NW NW	EOR-B14	13	L CYP	1858-1878
120290182200	Mattoon	Ida Martin 6 Scheeler Oil	Coles	34-12N- 7E	NE NE NE	EOR-B15	14	CYP	1784-1802
120292310100	Mattoon	Erler 4 Meko Pel	Coles	36-12N- 7E	SE NW NW	EOR-B16	15	CYP	1882-1890
120270314300	Bartleso	Gross 5 Ben Ober	Clinton	5- 1N- 3W	SW SE SW	EOR-B17	16	CYP	987- 987
120270314300	Bartleso	Maddux 9 T.R. Kenwin	Clinton	4- 1N- 3W	SW NE SW	EOR-B19	17	CYP	991 -996
121450294600	Tamara 8	Hampelman 1 Baldridge	Perry	4- 5S- 1W	SW SE SE	EOR-B20	18	CYP	1180-1166
121450302300	Tamara 5	Zielinski 1-A Baldridge	Perry	4- 5S- 1W	NE SW SE	EOR-B21	19	CYP	1148-1160
121450227300	Tamara 6	Goepr Stokn 1 Baldridge	Perry	33- 4S- 1W	NE NW NW	EOR-B22	20	CYP	1155-1162
121890191900	Richview	Thompson, G. 7 Thompson & Evans	Washington	35- 1S- 1W	NE NW SE	EOR-B24	21	CYP	1532-1542
121890182700	Richview	Weisbechr Cm 1 Baldridge	Washington	2- 2S- 1W	NW SW SW	EOR-B25	22	CYP	1482-1497

APPENDIX VII-B. *continued*

API	Field	Operator, well name	County	S-T-R	Quarter	Brine	Oil	Pay	Depth, sampled
121890183600	Richview	Edwards unit 1 Baldridge (Cank)	Washington	3- 2S- 1W	SE SE SE1	EOR-B26	23	CYP	1474-1495
121892407200	Richview	Pitchford 1 Elmer Oelze	Washington	10- 2S- 1W	SE SE SW	EOR-B27	24	CYP	1530-1538
120270115700	Bartleso	Schlarmann O.7 Robben (Oelze)	Clinton	6- 1N- 3W	SW SE SE	EOR-B28	25	CYP	985-986
120270112700	Bartleso	Kohrmann O.5 Robben (Oelze)	Clinton	5- 1N- 3W	SW NE SE	EOR-B29	26	CYP	980-981
120270110600	Bartleso	Schlarmann O.3 Robben (Oelze)	Clinton	5- 1N- 3W	NW SE SE	EOR-B30	27	CYP	973-974
120270110500	Bartleso	Schlarmann O.4 Robben (Oelze)	Clinton	5- 1N- 3W	NE SE SE	EOR-B31	28	CYP	978-979
120550209000	Zeigler	ZigicCoal&Coke 9 V. Gallagher	Franklin	18- 7S- 2E	SW NE SE	EOR-B32	29	AV	2623-2628
120550206100	Zeigler	Zeigler-Plumfield 1 V. Gallagher	Franklin	18- 7S- 2E	NW NE SE	EOR-B33	30	AV	2611-2640
120290054300	Mattoon	Oliver 10 Walker Duncan	Coles	2-12N- 7E	SW NE SW	EOR-B34	31	CYP	1752-1754
120290127300	Mattoon	Brining, GA 14 Gordon (Covington)	Coles	34-12N- 7E	NW SE NE	EOR-B35	32	AV	1806-1810
120292340200	Mattoon	Rothwell 7-A Schaefer Oil	Coles	10-11N- 7E	SW NW NE	EOR-B36	33	CYP	1820-1837
120812389600	Oakdale	Woodworth 1 E.Holder (Huron)	Jefferson	15- 2S- 4E	SE NE SE	EOR-B38	34	AV	2870-2874
120472248900	Parkersburg	Brandt, O. 1 Brinkley (Bunn &)	Edwards	6- 1N-14W	SE NW NW	EOR-B39	35	CYP& BETHL	2842-2848
120472418300	Parkersburg	Judge A-3 Podolsky	Edwards	31- 2N-11E	NE NE SE	EOR-B40	36	CYP	2893-2924 Corad
120472399500	Parkersburg	Koertge et al 1 Viking (Titan)	Edwards	5- 1N-14W	SW NE SW	EOR-B41	37	L.CYP	2804-2812
121592517100	Parkersburg	Childs Trst 6 Titan Oil	Richland	20- 2N-14W	NW SE NE	EOR-B42	38	M.CYP	2798-2808
121592508000	Parkersburg	Wilson, L. 4 Bunn & Bunn	Richland	30- 2N-14W	NW SW NE	EOR-B43	39	LCYP	2890-2900
121592509000	Parkersburg	Harrison, J. 1 Bunn & Bunn	Richland	30- 2N-11E	SW SW NE	EOR-B44	40	M.CYP	2880-2870
120552357400	Thompson- ville N	Midyett 4 Budmark Oil	Franklin	8- 7S- 4E	SW NE NW	EOR-B47	41	AV	2968-2988
120552372500	Thompson- ville N	Midyett 10 Budmark Oil	Franklin	5- 7S- 4E	NE SW SW	EOR-B49	42	AV	2946-2958
121812918101	Maple Grove C	J. Schott 1 Shekspir (Basnet)	Wayne	12- 1N- 9E	NE NE NE	EOR-B53	43	AV	3148-3212
120812468600	Dix South	Dobbs 1 John Prior	Jefferson	10- 1S- 2E	NW NE NW	EOR-B56	44	AV	2039-2049 High temp

APPENDIX VII-B. *continued*

API	Field	Operator, well name	County	S-T-R	Quarter	Brine	Oil	Pay	Depth, sampled
120252759000	Clay City Cons	Campbell hr 1 Murvin Oil	Clay	9- 2N- 8E	NW SE SE	EOB-865	45	CYP	2826-2830
121013012400	Rusk	Stevens 1F. Yockey et al	Lawrence	9- 2N-12W	SW NW NE	EOB-866	46	CYP	2009-2020
121590326100	Clay City	Fleming, A. 2 Murvin Oil	Richland	30- 4N-10E	NW NW	EOB-869	47	CYP	2549-2560
121832941500	Carmi N	Zimmerman 1 Joe Dull	White	10- 5S- 9E	W/2 SW NW	EOB-870	48	AV	3230-3241
121932575700	New Har- mony C	Ford C-28 Super (Equinox)	White	35- 4S-14W	SW SW NW	EOB-87349		CYP	2606-2616
121933102400	Roland Cons	Whipple-Star 1 Quad B Oil	White	21- 8S- 8E	SW NE SE	EOB-876	50	CYP	2764-2792
121933050200	Herald Cons	Knight 2 Herr & Miller	White	10- 7S- 9E	SE SW SW	EOB-877	51	AV & ST.L?	2883-2888
121592447000	Clay City Cons	Bromm 2 Fryburger	Richland	38- 6N- 8E	SE NW NE	EOB-879	52	AV	2820-2828
120252804100	Clay City Cons	Harley 17 Karen Revalla	Clay	15- 3N- 8E	NE SE	EOB-880	53	AV	2903-2933
120250298100	Clay City Cons	Duff 1 Shaffer (Booth)	Clay	18- 3N- 8E	SW NE	EOB-881	54	AV	2887-2924
120252756000	Sailor Springs	Armstrong B-1 J.S. Rudy	Clay	29- 3N- 7E	NE NE NE	EOB-882	55	AV	2921-2927
121910515800	Johnson- ville W	Burgess 1 Charles Booth	Wayne	13- 1N- 5E	SW NE SW	EOB-884	56	AV	2889-2975 Cored
120812435900	Divide Cons	Scribner 1 Gary W (Hrbstn)	Jefferson	20-1S-4E	NE NW SW	EOB-885	57	AV	2667-2672 Cored
120792465900	Clay City Cons	Kocher-Ochs 1A Lakes Oil	Jasper	22- 6N-10E	SE SW NW	EOB-886	58	AV	2739-2747
121592531400	Pasport N (INGRM)	John Weber 2 Monarch Prod.	Richland	30- 5N- 9E	SE NW SE	EOB-887	59	AV	2850-2868
120472231800	Bennett (MPLC GC)	Bennett 1A Frank Yockey	Edwards	29- 1N-10E	SW NW NW	EOB-889	60	AV	3153-3158
121913142200	Goldengate Cons	Dale West 1 Mid-Am (Finite)	Wayne	20- 2S- 9E	NW NE NW	EOB-89061		AV	3294-3298
120472428800	Elery (GGC)	Chalcraft 2 Jasper Oil	Edwards	25- 2S-10E	NW SE NE	EOB-891	62	AV	3177-3181 New well
121910790600	Clay City Cons	Crippen 4 Shufman Bros.	Wayne	4- 1S- 7E	SE NW	EOB-893	63	AV	3094-3110
120252743700	Sailor Springs	Carter A-3 Robison	Clay	24- 5N- 7E	NE SE SW	EOB-896	64	CYP	2563-2573
121592532000	Clay City Cons	Kern-Mann-Moss 1	Richland	30- 5N-10E	NW NW SE	EOB-897	65	CYP	2485-24940
121592532000	Clay City Cons	K-M-M 1 Murvin Oil	Richland	30- 5N-10E	NW NW SE	EOB-8102	66	CYP	2486-24940

APPENDIX VII-B. *continued*

API	Field	Operator, well name	County	S-T-R	Quarter	Brine	Oil	Pay	Depth, sampled
121562532000	Clay City Cons	K-M-M 1 Munin Oil	Richland	30- 5N-10E	NW NW SE	EOB-B103	67	CYP	2486-24941
120552345600	Dale Cons	McCreary 1Farrar Farrar	Franklin	13- 7S- 4E	NW NW SE		66	AV	3180-3186
120272459000	Bartleso	C. Robinson 1 Oelze	Clinton	6-1N-3W	SE SW SE		69		
121933111200	Storms Cons	Rudolph 11A 25 J. Haley Prod	White	12-6S-9E	SW NW SW	EOB-B106	70	AV	2958
120552347200	Dale Cons	Eaton et al. 2 Farrar Oil	Franklin	13-7S-4E	SE SE SW	EOB-B107	71	AV	3168
126052348700	Dale Cons	Eaton 3 Farrar Oil	Franklin	24-7S-4E	NE NE NW	EOB-B108	72	AV	3172
121652581700	HARCO	Henn 3 Mitchell Prod	Saline	23-8S-6E	SE SE NE	EOB-B109	73	CYP	2581
120252742400	Sealor Springs	Dunlap 3 Booth Oil	Clay	18- 3N- 7E	SW SE SE	EOB-B83		AV	2905-2912
120270166000	Bartleso	Trame Ben Ober	Clinton	8- 1N- 3W	NE NE NW	EOB-B18		CYP	956-960
120292318200	Mattoon	Brining, A 5 Schlr (Covington)	Coles	3-11N- 7E	SE NE NW	EOB-B37		CYP	1971-1977
120292322100	Mattoon	Gray O-1 Mat Engr (Covington)	Coles	3-11N- 7E	NW SE NE	EOB-B63		CYP	1809-1815
120290082400	Mattoon	Litwiler 7 Gordon (Covington)	Coles	3-11N- 7E	SE NW SE	EOB-B64		CYP	1780-1784?
120552272100	Dale Cons	Potter Comm 2 Farrar	Franklin	13- 7S- 4E	SW SW SE	EOB-B101		CYP	2938-2950?
120552370200	Thompson- ville N	Midyett 7 Budmark Oil	Franklin	5- 7S- 4E	NE SE SW	EOB-B45		AV	2991-2999
120552370100	Thompson- ville N	Bennet 5 Budmark Oil	Franklin	5- 7S- 4E	NW SW SE	EOB-B46		AV	3020-3024
120552374200	Logan (Thompsonville)	Midyett 13 Budmark Oil	Franklin	5- 7S- 4E	NW NW SW	EOB-B48		AV	2938-2950
120552387700	Zelgher	Alex 1 V. Gallagher	Franklin	19- 7S- 2E	NE NW SW	EOB-B59		AV	2629-2634
120652506500	Bungay Cons	Leebetter 1 Richard Beeson	Hamilton	21- 4S- 7E	NE SE NW	EOB-B98		AV	3314-3320
120652484200	Dale Cons	York-Demler 1 McFarland	Hamilton	33- 6S- 5E	SW NW SE	EOB-B62		AV	3219-3225
120610049600	King	Bumpus 2 Bakbridge Oil	Jefferson	34- 3S- 3E	SW NW	EOB-B8		AV	2720-2739
	King	Tank Battery Bakbridge	Jefferson	38-3E		EOB-B10		AV	
121012359300	Lawrence	Jackman et al. 1 E.L. Whitmer	Lawrence	15- 3N-12W	SW SW SE	EOB-B67		CYP	1588-1597

APPENDIX VII-B. *continued*

API	Field	Operator, well name	County	S-T-R	Quarter	Brine	Oil	Pay	Depth, sampled
Injection water	Tamara South	Beldridge	Perry	4- 5S- 1W	NW SE SE	EOR-B23		CYP	
121892444800	Clay City Cons	Bronn 1 (3) Magan (Fryberg)	Richland	36- 5N- 9E	SW NE NE	EOR-B78		AV	2816-2822 No anion
121892532000	Clay City Cons	K-M-M 1 Murvin Oil	Richland	30- 5N-10E	NW NW SE	EOR-B104		CYP	2486-2494.5
121892490500	Eldorado W	Farris 1 Richard Season	Saline	24- 8S- 9E	SE NW SW	EOR-B99		AV	2861-2866
121913194800	Barnhill	Plarcy 1 Republic	Wayne	1- 3S- 8E	SW NW NE	EOR-B92		AV	3366-3384
121913164700	Clay City Cons	Barnett 13 Barnett Oil	Wayne	20- 1S- 7E	SE SW SE	EOR-B50		AV	3169-3175
121913099200	Clay City Cons	Zurflene 2 Jerry E. Friend	Wayne	17- 2S- 8E	SW NE SE	EOR-B51		AV	3234-3244
121913114900	Clay City Cons	Zurflene 3 Jerry E. Friend	Wayne	17- 2S- 8E	NE SE NE	EOR-B52		CYP	2940-2946
121932855300	Carni North	Green Corn 1 Joe Dull	White	10- 5S- 9E	SW NW NW	EOR-B72		U. CYP	2932-2940
121933106800	New Har- mony C	Hon 7 Mobil (Equinox)	White	32- 4S-14W	NE NW SE	EOR-B74		AV	2880-2886 Cored
121933110800	Sumpter East	Mokler 4 Richard Season	White	4- 6S-10E	SE SW SW	EOR-B76		AV& SP.M	3023-3031
121892347700	Energy	Evid-Fitch 3 Vaughn A B Oil	Wilkinson	4- 9S- 2E	NW NW SE	EOR-B60		AV	2364-2370
121893348100	Energy	Morgan Coal 6 Budmark Oil	Wilkinson	4- 9S- 2E	SE SE NW	EOR-B100		AV	2366-2371

APPENDIX VIII. SELECTED OIL CHROMATOGRAMS

BARTELSON FIELD

SW DALE CONSOLIDATED FIELD

ENERGY FIELD

KING FIELD

MATTOON FIELD

sample EOR-33

sample EOR-32

sample EOR-31

retention time

STEWARDSON FIELD

TAMAROA FIELD

APPENDIXES IX AND X. OUTCROP LOCATIONS

Appendix IX. Cypress Sandstone Outcrops

- GL Golconda; Ohio River bluff, NE $\frac{1}{4}$ SE $\frac{1}{4}$ NW $\frac{1}{4}$, Section 30, T13S, R7E, Pope County, Golconda Quadrangle.
- GLS Golconda South, Ohio River bluff, NW $\frac{1}{4}$ NE $\frac{1}{4}$ NW $\frac{1}{4}$, Section 31, T13S, R7E, Pope County, Golconda Quadrangle.
- RL Ropers Landing, Ohio River bluff, SE $\frac{1}{4}$ NE $\frac{1}{4}$ NE $\frac{1}{4}$, Section 14 and NW $\frac{1}{4}$ NW $\frac{1}{4}$, Section 13, T14S, R6E, Pope County, Brownfield Quadrangle.
- BC Bay City, roadcut in bluff, SW $\frac{1}{4}$ NW $\frac{1}{4}$ NE $\frac{1}{4}$, Section 1, T15S, R6E, Pope County, Smithland Quadrangle.
- RH Reineking Hill, cut along east side of Illinois Central Railroad, SE $\frac{1}{4}$ SE $\frac{1}{4}$ NE $\frac{1}{4}$, Section 23, T14S, R4E, Massac County, Reevesville Quadrangle.
- CB Cagle Bluff, southeast-facing bluff, SE $\frac{1}{4}$ NW $\frac{1}{4}$, Section 10, T14S, R4E, Massac County, Mermet Quadrangle.
- I-24 Interstate 24, roadcut along I-24, NE $\frac{1}{4}$ NE $\frac{1}{4}$ SW $\frac{1}{4}$, Section 10, T14S, R4E, Massac County, Mermet Quadrangle.
- NCB New Columbia Bluff NE, New Columbia Bluff, and New Columbia Bluff SW (sections too closely spaced to separate at scale of Fig. 6). *New Columbia Bluff NE* is southeast-facing bluff in NW $\frac{1}{4}$ NE $\frac{1}{4}$ NW $\frac{1}{4}$, Section 15, T14S, R4E, Massac County, Mermet Quadrangle. *New Columbia Bluff* is a roadcut and adjacent bluff face in W $\frac{1}{2}$ SE $\frac{1}{4}$ NW $\frac{1}{4}$, same section.
- TF Travis Farm 1, 2, and 3. *Travis Farm 1* is west-trending ravine in NE $\frac{1}{4}$ NW $\frac{1}{4}$ SE $\frac{1}{4}$, Section 7, T14S, R4E, Massac County, Mermet Quadrangle. *Travis Farm 2* is a west-trending ravine in NE $\frac{1}{4}$ SW $\frac{1}{4}$ SE $\frac{1}{4}$, same section. *Travis Farm 3* is west-trending ravine in SW $\frac{1}{4}$ SW $\frac{1}{4}$ SE $\frac{1}{4}$, same section.
- HD Hunkerin' Ditch, ditch and natural exposures on north side of county road in SE $\frac{1}{4}$ NE $\frac{1}{4}$, Section 1, T14S, R3E, Massac County, Mermet Quadrangle.
- IP- Indian Point, railroad cut and south-facing bluff in S $\frac{1}{2}$ SE, Section 32 and S $\frac{1}{2}$ SW $\frac{1}{4}$, Section 33, T13S, R3E, Johnson County, Karnak Quadrangle.
- BT Bethany Church 1 and 2, both along southwest-facing bluff in W $\frac{1}{2}$ SE $\frac{1}{4}$ NE $\frac{1}{4}$, Section 24, T13S, R1E, Union County, Cypress Quadrangle.
- CC Cypress Creek, streambanks and bluffs along Cypress Creek just east of Interstate Highway 57, E $\frac{1}{2}$ SW $\frac{1}{4}$, Section 30, T12S, R1E, Union County, Anna Quadrangle.
- I-57 Interstate 57, box cuts along I-57 in NW $\frac{1}{4}$ SW $\frac{1}{4}$ and SW $\frac{1}{4}$ NW $\frac{1}{4}$, Section 31, T13S, R1E, Union County, Anna Quadrangle.
- CR Cache River 1 and 2. *Cache River 1* is streambed, banks and bluffs of Cache River in NW $\frac{1}{4}$ NE $\frac{1}{4}$ NW $\frac{1}{4}$, Section 9, T12S, R1W, Union County, Anna Quadrangle. *Cache River 2* is a stream bank and bluffs along Cache River in NW $\frac{1}{4}$ SE $\frac{1}{4}$ NW $\frac{1}{4}$, same section.
- SF Seminary Fork, northeast bank and bluffs of Seminary Fork in NW $\frac{1}{4}$ SE $\frac{1}{4}$ SE $\frac{1}{4}$, Section 16, T11S, R2W, Union County, Cobden Quadrangle.

Appendix X. Aux Vases Sandstone Outcrops*

- 1 Aux Vases Type Section: E 1/2, Sec. 13, T. 37 N., R. 9 E. and SW 1/4, SW 1/4, Sec. 18, T. 57 N., R. 10 E., Ste. Genevieve County, Missouri (STS, LIF, TCF, OB, STS, LIF).
- 2 Buehler Road Section: SE 1/4, NW 1/4, Sec. 13, T. 37 N., R. 9 E., Ste. Genevieve County, Missouri (STS, TCF, STS, LIF).
- 3 Tipton Church Section: N 1/2, N 1/2, Sw 1/4, Sec. 28, T. 3 S., R. 9 W., Monroe County, Illinois (HED, MIF, TCF or ICF, OB, STS, LIF).
North Prairie Du Rocher Section: NW 1/4, NE 1/4, Sec. 10, T. 5 S., R. 9 E., Randolph County, Illinois (STS, TCF, TCF or ICF, LIF).
- 5 Prairie Du Rocher Modoc Historic Site Section: SW 1/4, Sec. 26 extended, T. 5 S., R. 9 W., Randolph County, Illinois (BEF, STS, ICF, OB, TCF or ICF, OB).
- 6 Prairie Du Rocher (north of Modoc, Illinois): SE 1/4, NW 1/4, Sec. 36, T. 5 S., R. 9 W., Randolph County, Illinois (TCF or ICF, STS, TCF or ICF).
- 7 Altenburg Section 1: SE 1/4, NE 1/4, Sec. 11, T. 34 N., R. 13 E., Perry County, Missouri (STS, ICF).

- 8 Altenburg Section 2: S 1/2, NE 1/4, Sec. 11, T. 34 N., R. 13 E., Perry County, Missouri (ICF, STS, TCF).
- 9 Altenburg Section 3: SW 1/4, SE 1/4, Sec. 2, T. 34 N., R. 13 E., Perry County, Missouri (ICF, STS, ICF, STS, LIF).
- 10 Altenburg Section 4: NW 1/4, SE 1/4, Sec. 11 extended, T. 10 S., R. 14 E., Perry County, Missouri (STS).
- 11 Altenburg Section 5: SE 1/4, NW 1/4, Sec. 34, T. 35 N., R. 13 E. Perry County, Missouri (STS, ICF, LIF).
- 12 Cobden Section: W 1/2, NW 1/4, Sec. 5, T. 12 S., R. 1 W., Union County, Illinois (STS, STS, LIF).
- 13 Illinois highway 127 Section: NW 1/4, SE 1/4, Sec. 22, T 11 S., R. 2 W., Union County, Illinois (HED, UTF, STS, LIF).
- 14 West Pit, Anna Quarry Section: SW 1/4, SE 1/4, Sec. 17, T 12 S., R. 1 W., Union County, Illinois (UTF, STS, LIF, MIF).
- 15 Illinois highway 51 Section: SE 1/4, SE 1/4, Sec. 8, T. 12 S., R. 1 W., Union County, Illinois (UTF, HED, UTF, MIF, UTF, STS, TCF, OB, STS).
- 16 Union county road 1275 Section: NW 1/4, SW 1/4, Sec. 9, T 12 S., R. 1 W., Union County, Illinois (UTF, STS, LIF).
- 17 Interstate 57 Section: NW 1/4, SW 1/4, Sec. T. 13 S., R. 1 E., Union County, Illinois (STS, ICF, STS, LIF).
- 18 Porterfield Creek Section: SW 1/4, SE 1/4, Sec. 8, T 13 S., R. 1 E., Union County, Illinois (STS to LIF).
- 19 Shetlerville Quarry Section: NW 1/4, SW 1/4, Sec. 35, T. 12 S., R. 7 E., Hardin County, Illinois (UTF, STS, STS, ICF, TCF, TCF or ICF, LIF, MIF).
- 20 Hastie Quarry Section: NW 1/4, NW 1/4, Sec. 3, T. 12 S., R. 9 E., Hardin County, Illinois (OSM, STS, ICF, STS, ICF, STS).
- 21 Cave-in-Rock Section: SW 1/4, SW 1/4, Sec. 1, T. 12 S. R. 9 E., Hardin County, Illinois (STS, includes shallow marine carbonates).
- 22 Dravos Quarry Section: SW 1/4, NE 1/4, Sec. 17, T. 12 S., R. 10 E., Hardin County, Illinois (STS, ICF, STS, includes shallow marine carbonates).
- 23 Marion, Kentucky: 1 mile north on 297 off Kentucky Highway 60, (Salem, Kentucky 7 1/2 min. Quadrangle), Crittendon County, Kentucky (shallow marine shelf calcareous sandstones).
- 24 Three Rivers Quarry Section: E 1/2, SE 1/4, Sec. 21 extended, T. 15 S., R. 7 E., McCracken County, Kentucky (very thin shallow marine shelf calcareous sandstones).
- 25 Blue River Gap Section: NW 1/4, NW 1/4, Sec. 26, T. 3 S., R. 1 W., and NE 1/4, NE 1/4, Sec. 27, T. 3 S., R. 1. W., Perry County, Indiana (slightly silty micrite - shallow marine).
- 26 Beal's Farm Section: NW 1/4, NW 1/4, SE 1/4, Sec. 31, T. 3 S., R. 2 E., Crawford County, Indiana (shallow marine shelf calcareous sandstones).

* Key to Designation of Depositional Type

LIF	Lower intertidal flat
TCF	Tidal channel fill
STS	Subtidal sheet sands
OB	Offshore bars
ICF	Interbar channel fills
MIF	Middle intertidal flat
HED	High energy deposit
BEF	Bay or estuarine fill
UTF	Unspecified tidal flat deposit
OSM	Offshore muds

APPENDIX XI. SUMMARY OF AUX AND CYPRESS MINERALOGICAL DATA

Mineralogical Data for All Aux Vases Fields*

Sample, API no.	%I	%I/S	%C	% CI	% Iblk	% I/Sblk	% Cblk	%Q	% Kf	% Pf	% Cc	%D	W3/ W4	A4/ A3	Cc +D
1. Aux Vases/ King Field															
3199A	54	42	4	0.027	1.5	1.2	0.1	64	2.1	0.8	28	2.1	nm	nm	31
3199B	58	34	8	0.150	8.7	5.1	1.2	47	1.3	3.7	17	16	1.37	1.46	33
3199C	47	40	13	0.163	7.7	6.5	2.1	77	2.3	4.4	0.1	0.0	1.29	1.01	0
3200A	45	37	18	0.030	1.3	1.1	0.5	84	2.4	1.9	8.8	0.0	1.07	0.95	9
3200B	40	37	22	0.035	1.4	1.3	0.8	78	1.9	1.8	15	0.0	1.08	1.03	15
3200C	42	28	29	0.010	0.4	0.3	0.3	86	2.1	1.5	9.1	0.0	1.40	1.00	9
3200D	24	25	52	0.001	0.0	0.0	0.1	86	1.0	0.9	12	0.0	1.45	1.78	12
3200E	38	46	16	0.024	0.9	1.1	0.4	32	0.8	0.6	64	0.0	1.36	1.34	64
3200F	42	46	12	0.053	2.2	2.4	0.6	38	1.3	0.7	54	0.0	1.44	1.26	54
3200G	22	28	51	0.000	0.0	0.0	0.0	82	1.2	1.0	16	0.0	1.28	1.95	16
3201	27	23	49	0.009	0.3	0.2	0.5	89	0.3	0.4	9.3	0.1	1.69	3.12	9
3202A	43	25	32	0.049	2.1	1.2	1.6	88	1.7	3.3	2.2	0.0	1.42	1.57	2
3202B	37	28	35	0.067	2.5	1.9	2.3	69	2.1	3.7	18	0.0	1.56	2.95	18
3202C	54	32	14	0.000	0.0	0.0	0.0	0.8	0.0	0.0	99	0.4	1.29	1.94	99
3203	17	10	73	0.027	0.4	0.3	1.9	95	0.8	0.6	0.6	0.0	1.99	3.52	1
3204A	31	24	45	0.020	0.6	0.5	0.9	89	2.1	1.8	5.5	0.0	1.22	1.27	5
3204B	29	36	35	0.007	0.2	0.3	0.3	90	0.7	0.4	8.5	0.0	1.02	2.11	8
Ave	37	31	31	0.040	1.8	1.4	0.8	71	1.4	1.7	21	1.1	1.37	1.77	22
2. Aux Vases/ Zeigler															
3205A	57	24	19	0.057	3.3	1.4	1.1	88	1.6	2.5	1.8	0.0	1.57	1.31	2
3205B	37	24	39	0.024	0.9	0.6	0.9	90	1.5	4.1	1.7	0.0	1.41	1.21	2
3205C	23	12	65	0.018	0.4	0.2	1.1	93	0.8	3.8	0.2	0.0	1.64	1.61	0
3205D	26	25	49	0.028	0.7	0.7	1.4	91	1.4	3.2	1.6	0.0	1.15	1.39	2
3205E	13	7	79	0.015	0.2	0.1	1.2	87	1.3	2.7	7.2	0.0	1.70	2.13	7
3206A	59	29	11	0.014	0.9	0.4	0.2	77	1.2	3.1	18	0.0	0.97	1.16	18
3206B	43	31	26	0.054	2.3	1.7	1.4	83	1.6	3.9	6.5	0.0	0.92	0.89	6
3206C	48	20	32	0.026	1.2	0.5	0.8	89	1.1	3.5	4.0	0.0	1.14	0.91	4
3206D	39	24	37	0.020	0.8	0.5	0.7	88	0.9	4.0	4.7	0.0	1.17	1.05	5
3206E	39	18	43	0.031	1.2	0.6	1.3	88	0.9	4.6	3.4	0.0	1.08	1.27	3
3206F	45	20	35	0.026	1.2	0.5	0.9	88	0.6	3.9	4.9	0.0	1.05	1.29	5
3206G	32	17	51	0.026	0.8	0.4	1.3	88	1.1	5.4	2.8	0.0	1.15	1.45	3
3206H	21	13	66	0.034	0.7	0.4	2.3	89	0.9	3.6	3.0	0.0	1.17	1.35	3
3206I	20	10	70	0.030	0.6	0.3	2.1	89	0.5	3.2	4.4	0.0	1.11	1.42	4
3206J	20	20	60	0.009	0.2	0.2	0.5	92	0.7	3.6	3.0	0.0	1.20	1.46	3

continued on next page

* %I, %I/S, %C = percentage of illite, I/S, and chlorite on 100% basis of the clay minerals from <16 μ m smear; CI = clay index or ratio clay: nonclay; %Iblk, %I/Sblk, %Cblk = bulk percentage of illite, etc.; %Q, %Kf, %Pf, %Cc, %D = absolute percentage of quartz, K-feldspar, plagioclase, calcite, and dolomite; W3/W4 = width 003 chlorite peak divided by width 004 chlorite peak; A4/A3 = area 004 chlorite peak divided by area 003 chlorite peak; Cc+D = absolute percentage of calcite + dolomite; nm = not measured; for Cypress, %K and %Kblk = relative and absolute % kaolinite; +3279C, D = bulk percentage of kaolinite.

Mineralogical Data for All Aux Vases Fields* continued

Sample, API no.	%I	%I/S	%C	% Cl	% IbklI/Sbkl	% Cblk	%Q	% Kf	% Pf	% Cc	%D	W3/ W4	A4/ A3	Cc +D	
3206K	22	7	71	0.007	0.2	0.0	0.5	92	0.7	3.8	3.0	0.0	1.17	1.38	3
3206L	25	22	54	0.026	0.6	0.6	1.4	86	0.4	1.5	9.0	0.0	1.19	1.63	9
3206M	25	19	55	0.031	0.8	0.6	1.7	92	1.2	3.1	1.0	0.0	1.26	1.50	1
3206N	25	25	50	0.025	0.6	0.6	1.2	89	0.8	4.7	2.8	0.0	1.23	1.27	3
3206O	20	22	58	0.028	0.5	0.6	1.6	85	0.8	3.1	8.8	0.0	1.33	1.46	9
3207A	20	15	65	0.041	0.8	0.6	2.7	90	1.4	4.1	0.3	0.0	1.16	2.12	0
3207B	21	31	48	0.017	0.3	0.5	0.8	92	0.8	2.8	2.8	0.0	1.13	1.47	3
3207C	37	10	54	0.017	0.6	0.2	0.9	91	0.9	2.8	3.2	0.0	1.17	1.29	3
3207D	26	17	58	0.016	0.4	0.3	0.9	91	0.9	2.8	3.5	0.0	1.16	1.36	4
3207E	18	21	61	0.008	0.1	0.2	0.5	89	1.4	3.4	4.9	0.5	1.23	1.50	5
3207F	25	34	41	0.036	0.9	1.2	1.5	91	0.4	3.3	1.6	0.0	1.19	1.41	2
3207G	27	25	48	0.024	0.7	0.6	1.2	90	0.4	2.9	4.7	0.0	1.05	0.97	5
3207H	41	36	23	0.032	1.3	1.2	0.7	8.6	0.0	0.0	88	0.0	1.25	1.97	88
3207I	47	38	15	0.000	0.0	0.0	0.0	1.1	0.0	0.0	99	0.0	1.23	1.80	99
3207J	55	38	7	0.004	0.2	0.1	0.0	1.3	0.0	0.0	98	0.0	1.49	1.16	98
3208A	41	48	10	0.020	0.8	0.9	0.2	1.9	0.0	0.0	96	0.0	1.50	1.36	96
3208C	45	27	28	0.054	2.4	1.4	1.5	86	2.3	6.7	0.1	0.0	1.24	1.29	0
3208D	39	25	37	0.005	0.2	0.1	0.2	89	0.4	2.1	7.8	0.0	1.18	1.01	8
3208E	31	47	22	0.003	0.1	0.1	0.1	93	0.8	2.1	3.3	0.0	0.89	0.93	3
3208F	40	28	32	0.016	0.6	0.4	0.5	82	0.4	1.9	14	0.0	0.91	0.85	14
3208G	45	23	32	0.098	4.4	2.3	3.2	80	1.8	3.5	4.5	0.7	1.26	1.60	5
3208H	29	24	47	0.049	1.4	1.2	2.3	85	1.0	2.3	6.1	0.5	1.51	1.12	7
3208I	39	28	32	0.026	1.0	0.7	0.8	89	1.4	4.8	2.2	0.0	1.13	1.02	2
3208J	21	16	64	0.036	0.7	0.6	2.3	88	0.7	2.5	5.1	0.0	1.21	2.15	5
3209A	40	28	32	0.052	2.1	1.4	1.7	85	1.6	7.9	0.0	0.0	1.42	1.39	0
3209B	32	37	31	0.035	1.1	1.3	1.1	92	0.4	2.9	0.3	0.3	0.97	0.82	1
3209C	42	24	34	0.028	1.2	0.7	1.0	86	6.0	4.0	0.6	0.7	1.32	1.08	1
3209D	18	12	70	0.027	0.5	0.3	1.9	92	1.2	2.5	1.7	0.3	1.20	1.58	2
3209E	28	36	36	0.031	0.9	1.1	1.1	65	1.3	2.1	28	0.4	1.55	1.65	29
3209F	15	17	68	0.041	0.6	0.7	2.8	82	0.9	2.8	9.6	0.2	1.92	1.50	10
3209G	26	18	56	0.049	1.3	0.9	2.7	88	1.2	4.8	0.7	0.0	1.61	2.34	1
3209H	20	16	64	0.032	0.6	0.5	2.0	88	0.0	3.6	5.6	0.0	1.57	2.07	6
3209I	16	14	70	0.018	0.3	0.3	1.3	88	1.1	3.1	6.1	0.0	0.99	1.01	6
3209J	31	33	36	0.001	0.0	0.0	0.0	0.8	0.0	0.0	99	0.3	1.45	1.72	99
3209K	36	30	34	0.046	1.6	1.4	1.6	46	0.4	1.9	46	1.3	1.16	2.95	48
Ave	32	24	44	0.028	0.9	0.6	1.2	78	1.0	3.1	15	0.1	1.25	1.43	15
3. Aux Vases/ Energy Field															
3217A	32	19	49	0.022	0.7	0.4	1.1	84	1.0	4.7	8.3	0.0	1.00	0.72	8
3217B	28	27	45	0.023	0.7	0.6	1.0	79	0.1	3.5	15	0.0	1.01	0.76	15
3217C	31	15	54	0.018	0.6	0.3	1.0	85	0.1	5.1	8.0	0.0	1.11	0.80	8
3217D	28	10	62	0.033	0.9	0.3	2.1	83	0.3	4.3	9.3	0.0	1.29	0.89	9
3217E	22	11	67	0.023	0.5	0.2	1.5	82	0.0	3.2	12	0.0	1.35	0.99	12
3217F	24	13	63	0.024	0.6	0.3	1.5	71	0.0	3.6	23	0.0	1.32	1.09	23
Ave	28	16	57	0.024	0.7	0.4	1.4	81	0.3	4.1	13	0.0	1.18	0.88	13
4. Aux Vases/ Oakdale Field															
3258A	81	15	5		2.0	0.4	0.1	93	1.0	3.1	0.7	0.0	nm	nm	1
3258B	82	0	18	0.017	1.4	0.0	0.3	95	1.0	2.3	0.1	0.0	nm	nm	0

Mineralogical Data for All Aux Vases Fields* continued

Sample, API no.	%I	%I/S	%C	% Cl	% Iblk	% I/Sblk	% Cblk	%Q	% Kf	% Pf	% Cc	%D	W3/ W4	A4/ A3	Cc +D
3258C	62	26	11	0.042	2.6	1.1	0.5	93	0.6	2.0	0.1	0.0	nm	nm	0
3258D	81	0	19	0.013	1.1	0.0	0.2	90	1.0	2.1	6.0	0.0	nm	nm	6
3258E	66	22	11	0.000	0.0	0.0	0.0	93	1.3	2.7	3.1	0.0	nm	nm	3
3258F	87	0	13	0.022	1.9	0.0	0.3	91	1.1	2.5	3.7	0.0	nm	nm	4
3258G	69	12	18	0.061	4.2	0.7	1.1	86	1.4	2.8	3.5	0.0	nm	nm	4
3258H	41	36	23	0.090	3.7	3.2	2.1	84	2.1	3.0	1.8	0.0	nm	nm	2
3259A	68	30	2	0.018	1.2	0.5	0.0	91	0.5	2.6	3.7	0.0	nm	nm	4
3259B	62	30	8	0.021	1.3	0.6	0.2	86	0.7	3.1	7.8	0.0	nm	nm	8
3259C	86	1	13	0.036	3.1	0.0	0.5	87	1.2	3.5	4.3	0.0	nm	nm	4
3259D	49	38	13	0.010	0.5	0.4	0.1	86	1.3	3.6	8.3	0.0	nm	nm	8
3259E	48	38	14	0.024	1.2	0.9	0.3	88	0.9	1.3	7.7	0.0	nm	nm	8
3259F	32	56	12	0.005	0.2	0.3	0.1	48	0.0	0.0	52	0.0	nm	nm	52
3261A	70	7	23	0.020	1.4	0.1	0.5	54	0.6	1.0	2.2	41	1.07	0.82	43
3261B	82	0	18	0.002	0.1	0.0	0.0	92	1.8	5.5	0.2	0.0	1.02	0.89	0
3261C	83	0	17	0.015	1.3	0.0	0.2	86	1.7	4.3	6.3	0.0	1.17	0.98	6
3261D	80	0	20	0.031	2.5	0.0	0.6	86	1.9	4.9	4.4	0.0	1.32	0.77	4
3261E	28	37	35	0.035	1.0	1.3	1.2	78	1.8	3.3	13	0.0	1.30	0.67	13
3261F	75	4	21	0.043	3.2	0.2	0.9	85	2.0	4.0	4.6	0.0	1.35	0.79	5
3261G	70	0	30	0.033	2.3	0.0	1.0	75	1.4	3.1	18	0.0	1.33	0.87	18
3261H	39	46	15	0.035	1.3	1.6	0.5	81	1.5	4.1	9.6	0.0	1.36	0.76	10
3261I	87	0	13	0.040	3.5	0.0	0.5	78	1.4	3.1	14	0.0	1.28	0.74	14
3261J	88	0	12	0.023	2.0	0.0	0.3	82	1.3	2.2	12	0.0	1.12	0.93	12
3261K	40	51	9	0.024	1.0	1.2	0.2	86	2.1	4.5	4.7	0.0	1.14	0.72	5
3261L	50	43	7	0.016	0.8	0.7	0.1	90	1.3	3.7	3.7	0.0	1.03	0.83	4
3261M	38	58	4	0.012	0.5	0.7	0.0	73	1.6	3.4	21	0.0	1.34	0.72	21
3261N	62	18	21	0.024	1.5	0.4	0.5	84	1.8	3.1	8.8	0.0	1.24	0.73	9
3261O	79	15	7	0.029	2.3	0.4	0.2	86	1.6	3.8	5.9	0.0	1.24	0.72	6
3261P	87	0	13	0.024	2.1	0.0	0.3	91	0.8	1.9	3.9	0.0	1.26	0.72	4
3261Q	76	10	14	0.038	2.9	0.4	0.5	87	1.4	3.0	4.7	0.0	1.29	0.71	5
3261R	60	23	17	0.015	0.9	0.3	0.3	65	0.6	0.9	20	12	1.24	0.78	32
3261S	70	0	30	0.015	1.0	0.0	0.4	62	1.0	1.5	2.4	32	1.09	0.82	34
Ave	66	19	15	0.026	1.7	0.5	0.4	83	1.3	2.9	7.9	2.5	1.22	0.79	13

5. Aux Vases/ Boyd Field

3271A	10	69	21	0.027	0.3	1.8	0.6	94	2.1	0.9	0.6	0.2	1.14	4.10	1
3271B	13	48	39	0.030	0.4	1.4	1.2	91	3.5	2.0	0.5	0.3	2.22	2.78	1
3271C	24	36	40	0.015	0.4	0.5	0.6	88	1.3	0.4	8.2	0.2	2.02	2.79	8
3271D	28	58	14	0.084	2.3	4.9	1.2	81	1.2	0.7	8.4	0.2	1.93	2.46	9
3271E	11	62	27	0.018	0.2	1.1	0.5	67	1.2	0.6	29	0.1	1.75	2.74	29
3272A	20	63	18	0.027	0.5	1.7	0.5	80	2.6	0.6	14	0.5	1.89	5.87	14
3272B	29	21	50	0.015	0.4	0.3	0.8	84	2.7	1.1	11	0.4	2.44	3.64	11
3272C	18	51	31	0.042	0.8	2.1	1.3	84	3.4	1.4	6.4	0.4	1.99	4.96	7
3272D	19	46	36	0.025	0.5	1.2	0.9	88	3.0	1.0	4.9	0.5	2.37	3.28	5
3273	10	60	30	0.035	0.3	2.1	1.1	68	3.4	1.4	23	0.1	2.14	3.04	23
Ave	18	51	31	0.032	0.6	1.7	0.9	83	2.4	1.0	11	0.3	1.99	3.57	11

6. Aux Vases/ Stewardson Field

3278A	10	7	83	0.004	0.0	0.0	0.3	68	2.8	2.1	27	0.0	1.74	2.32	27
3278B	35	26	39	0.024	0.8	0.6	0.9	52	1.8	0.8	43	0.0	1.73	2.71	43

Mineralogical Data for All Aux Vases Fields* continued

Sample, API no.	%I	%I/S	%C	% Cl	% Ibik	% I/Sbik	% Cblk	%Q	% Kf	% Pf	% Cc	%D	W3/ W4	A4/ A3	Cc +D
3278C	7	5	88	0.030	0.2	0.2	2.7	88	2.6	1.8	4.5	0.0	2.47	2.43	4
3278D	18	13	70	0.022	0.4	0.3	1.6	89	2.4	1.6	4.6	0.0	2.24	2.77	5
3278F	42	30	28	0.052	2.2	1.6	1.4	65	3.1	2.6	24	0.0	0.62	3.79	24
3279A	43	31	26	0.027	1.2	0.9	0.7	76	0.5	0.7	20	1.0	1.03	2.81	21
3279B	39	29	32	0.011	0.4	0.3	0.4	81	1.2	0.8	16	0.0	1.57	2.57	16
3279C	49	36	15	0.026	1.3	0.9	0.4	83	1.4	1.2	11	1.0	1.68	1.59	12
3279D	39	28	34	0.027	1.1	0.8	0.9	86	1.7	3.4	6.2	1.0	2.48	1.47	7
Ave	31	23	46	0.025	0.8	0.6	1.0	76	1.9	1.7	17	0.3	1.73	2.50	18

7. Aux Vases/ Dale Consolidated Field

3330A	53	44	3	0.051	2.7	2.3	0.1	84	1.1	3.0	6.7	0.0	1.54	0.37	7
3330B	40	47	13	0.059	2.4	2.7	0.8	80	1.1	3.3	9.7	0.0	1.68	0.37	10
3330C	43	48	9	0.043	1.9	2.1	0.4	84	0.9	5.2	5.9	0.0	1.36	0.43	6
3330D	43	48	9	0.035	1.5	1.7	0.3	85	0.9	3.4	7.6	0.0	1.25	0.45	8
3330E	44	49	7	0.046	2.1	2.3	0.3	83	0.9	3.8	7.6	0.0	1.07	0.49	8
3331A	42	51	7	0.050	2.1	2.6	0.3	86	1.8	2.6	4.9	0.0	1.09	0.49	5
3331B	48	45	7	0.055	2.6	2.5	0.4	84	1.7	3.5	5.8	0.0	1.19	0.48	6
3331C	48	44	7	0.057	2.8	2.5	0.4	84	1.7	2.8	6.0	0.0	0.92	0.61	6
3331E	46	50	4	0.042	1.9	2.1	0.2	80	1.3	2.5	12	0.0	1.26	0.43	12
3331F	46	49	4	0.046	2.1	2.3	0.2	81	2.2	4.0	8.5	0.0	1.24	0.53	8
3344A	60	27	13	0.051	3.0	1.4	0.7	85	1.3	2.1	6.5	0.0	1.23	0.52	7
3344B	56	30	14	0.048	2.7	1.4	0.7	82	1.7	2.6	8.7	0.0	1.25	0.49	9
3344C	60	25	15	0.041	2.4	1.0	0.6	85	1.6	3.1	5.8	0.0	1.13	0.58	6
3344D	50	37	13	0.064	3.2	2.4	0.9	80	1.2	3.6	8.3	0.0	1.12	0.56	8
3344E	53	31	15	0.046	2.5	1.4	0.7	88	0.0	1.6	3.4	2.1	1.08	0.54	5
3344F	55	31	14	0.053	2.9	1.6	0.7	81	2.7	2.2	8.7	0.0	1.16	0.54	9
3344G	49	36	15	0.041	2.0	1.4	0.6	83	2.8	3.1	6.9	0.0	1.21	0.56	7
3344H	49	36	14	0.059	2.9	2.1	0.9	83	2.6	2.7	5.6	0.0	1.12	0.56	6
3344I	46	45	9	0.044	2.0	2.0	0.4	76	1.7	1.8	16	0.0	0.93	0.67	16
3344J	48	42	10	0.049	2.3	2.0	0.5	84	1.2	2.1	7.9	0.0	1.06	0.74	8
3344K	38	53	9	0.074	2.8	3.9	0.7	68	0.8	1.3	22	0.0	1.01	0.74	22
3344L	41	47	12	0.040	1.6	1.9	0.5	84	1.7	2.3	8	0.0	1.46	0.79	8
3344M	44	40	16	0.106	4.7	4.2	1.7	70	1.2	1.5	17	0.0	1.47	1.17	17
3344N	42	58	1	0.061	2.5	3.5	0.0	2.9	0.0	0.0	91	0.0	2.78	0.20	91
3344P	51	48	1	0.084	4.3	4.0	0.1	3.4	0.0	0.0	72	16	4.85	0.23	88
Ave	48	42	10	0.054	2.6	2.3	0.5	75	1.4	2.6	15	0.7	1.42	0.54	15

8. Aux Vases, Storms Consolidated Field

3434A	55	40	6	0.080	nm	nm	nm	54	2.4	1.5	33	0	nm	nm	nm
3434B	43	19	38	0.085	3.6	1.6	3.3	71	4.0	2.9	13	0.0	2.03	1.29	13
3434C	61	12	28	0.087	5.3	1.0	2.4	74	3.8	2.2	12	0.0	1.70	1.63	12
3434D	42	30	29	0.070	2.9	2.1	2.0	82	2.6	1.7	7.0	0.0	1.58	1.36	7
3434E	57	18	25	0.048	2.7	0.9	1.2	77	3.6	3.4	11	0.0	2.03	1.38	11
3434F	55	18	28	0.044	2.4	0.8	1.2	72	3.3	2.0	19	0.0	1.63	1.71	19
3434G	60	35	5	0.150	9.0	5.3	0.8	58	4.1	2.8	20	0.0	nm	nm	20
3434H	60	38	2	0.680	41	26	1.4	23	2.3	1.2	5	0.0	nm	nm	5
3434I	86	10	4	0.005	0.4	0.1	0.0	2	0.0	0.0	98	0.0	nm	nm	98
3456	27	25	48	0.068	1.8	1.7	3.3	81	4.3	1.9	6.2	0.0	1.56	1.85	6
3457A	66	19	15	0.058	3.9	1.1	0.8	79	4.2	2.3	8.8	0.0	1.68	1.12	9

Mineralogical Data for All Aux Vases Fields* *continued*

Sample, API no.	%I	%I/S	%C	% Cl	% Iblk	% I/Sblk	% Cblk	%Q	% Kf	% Pf	% Cc	%D	W3/ W4	A4/ A3	Cc +D
3457B	41	33	26	0.068	2.8	2.2	1.8	73	6.0	2.8	11	0.5	1.83	1.84	12
Ave	54	25	21	0.120	6.9	3.9	1.6	62	3.4	2.1	20	0.0	1.75	1.52	19
All Aux Vases Fields															
Ave	50	28	33	0.036	1.5	1.1	1.0	78	1.5	2.6	14	0.9	1.41	1.49	14
Std dev	12	15	21	0.026	1.4	1.1	0.8	20.8	1.1	1.5	21	4.7	0.46	1.00	22

Mineralogical Data for Cypress Fields*

Sample, API no.	%I	% I/S	% C	% K	% Cl	% Iblk	% I/Sblk	% Cblk	% Kb	% Q	% Kf	% Pf	% Cc	%D	W3/ W4	A4/ A3	Cc +D
1. Cypress/ Tamaroa Field																	
3198A	3	2	22	73	0.020	0.1	0.0	0.4	1.5	94	0.0	3.0	1.5	0.0	2.12	4.62	1.5
3198B	5	3	28	63	0.114	0.6	0.4	3.2	7.2	68	0.0	20	0.3	0.0	2.28	4.71	0.3
3198C	7	10	39	45	0.121	0.8	1.2	4.7	5.5	42	0.0	34	12	0.0	2.14	4.88	12
3198D	1	1	34	64	0.018	0.0	0.0	0.6	1.1	87	0.0	10	0.9	0.0	1.93	7.16	0.9
Ave	4	4	31	61	0.068	0.4	0.4	2.2	3.8	73	0.0	17	3.6	0.0	2.12	5.34	3.6
2. Cypress/ Bartelso Field																	
3213A	16	0	11	73	0.010	0.2	0.0	0.1	0.7	67	0.6	31	0.2	0.0	1.35	4.33	0.2
3213B	24	8	11	57	0.027	0.7	0.2	0.3	1.5	91	1.2	4.0	1.1	0.0	1.42	4.25	1.1
3213C	21	12	14	53	0.053	1.1	0.6	0.7	2.8	91	1.0	1.6	0.9	0.2	1.37	4.42	1.1
3213D	24	14	11	52	0.025	0.6	0.4	0.3	1.3	91	1.2	4.1	1.0	0.1	1.38	4.20	1.1
3214A	14	4	3	78	0.019	0.3	0.1	0.1	1.5	95	1.6	0.8	0.5	0.0	1.55	6.79	0.5
3214B	23	14	17	46	0.049	1.1	0.7	0.8	2.2	75	1.3	6.8	0.0	0.5	2.19	4.24	0.5
3214C	19	12	13	56	0.035	0.7	0.4	0.5	2.0	84	0.1	12	0.1	0.3	2.08	3.79	0.5
3214D	12	11	54	22	0.027	0.3	0.3	1.5	0.6	88	2.3	6.5	0.2	0.1	2.62	4.14	0.3
Ave	19	10	17	54	0.031	0.6	0.3	0.5	1.6	85	2.7	8.3	0.5	0.2	1.75	4.52	0.7
3. Cypress/ Xenia East Field																	
3260A	36	11	7	46	0.012	0.4	0.1	0.1	0.6	93	1.6	3.4	0.0	0.4	nm	nm	0.5
3260B	31	16	35	18	0.026	0.8	0.4	0.9	0.5	92	1.2	3.8	0.1	0.0	nm	nm	0.1
3260C	39	15	26	21	0.015	0.6	0.2	0.4	0.3	97	0.4	0.6	0.0	0.0	nm	nm	0.0
3260D	0	0	21	79	0.002	0.0	0.0	0.0	0.2	98	0.1	0.8	0.0	0.8	nm	nm	0.8
3260E	21	16	23	40	0	0.0	0.0	0.0	0.0	93	1.7	5.0	0.1	0.0	nm	nm	0.1
3260F	29	15	13	43	0	0.0	0.0	0.0	0.0	96	1.0	2.8	0.0	0.0	nm	nm	0.0
3260G	28	7	62	3	0.018	0.5	0.1	1.1	0.0	97	0.4	0.3	0.2	0.0	nm	nm	0.2
3260H	35	10	51	4	0.016	0.5	0.2	0.8	0.1	95	0.5	2.8	0.0	0.0	nm	nm	0.0
Ave	27	11	30	32	0.031	0.4	0.1	0.4	0.2	95	0.9	2.4	0.1	0.2	nm	nm	0.2
4. Cypress/ Mattoon Field																	
3280A	17	5	0	78	0.041	0.7	0.2	0.0	3.2	93	0.0	2.4	0.6	0.0	nm	nm	0.6
3280B	15	7	0	78	0.036	0.5	0.2	0.0	2.8	82	0.0	1.7	12	0.0	nm	nm	12
3280C	12	4	0	84	0.010	0.1	0.0	0.0	0.8	96	0.0	2.1	0.8	0.0	nm	nm	0.8
3280D	34	31	16	19	0.073	2.5	2.2	1.2	1.4	87	0.0	5.0	0.4	0.0	2.20	2.08	0.4

Mineralogical Data for Cypress Fields* continued

Sample, API no.	% I	% I/S	% C	% K	% Cl	% IbIk	% I/SbIk	% CbIk	% Kb	% Q	% Kf	% Pf	% Cc	% D	W3/ W4	A4/ A3	Cc +D
3280E	37	21	12	30	0.075	2.8	1.6	0.9	2.2	89	0.0	3.0	0.6	0.0	2.86	1.5	10
3280F	21	18	18	43	0.036	0.7	0.6	0.6	1.5	92	0.0	4.1	0.8	0.0	2.01	2.33	0.8
3281A	16	7	0	76	0.054	0.9	0.4	0.0	4.1	89	0.0	2.1	2.8	0.5	2.10	3.06	3.4
3281B	18	3	7	72	0.040	0.7	0.1	0.3	2.9	89	0.0	2.9	3.9	0.0	2.83	1.83	3.9
3281C	12	7	8	72	0.042	0.5	0.3	0.4	3.0	88	0.0	1.7	6.0	0.0	2.47	2.96	6.0
282A	30	17	17	36	0.072	2.2	1.3	1.2	2.6	87	0.0	5.8	0.0	0.0	2.59	2.00	0.0
3282B	50	29	3	18	0.061	3.0	1.8	0.2	1.1	91	0.0	3.0	0.0	0.0	1.43	7.09	0.0
3282C	35	18	19	29	0.087	3.0	1.5	1.6	2.5	87	0.0	3.9	0.4	0.0	2.20	2.62	0.4
3282D	39	21	14	27	0.070	2.7	1.5	1.0	1.9	88	0.0	4.4	0.9	0.0	1.92	2.38	0.9
3286A	28	17	17	39	0.122	3.4	2.1	2.0	4.7	85	0.1	3.2	0.0	0.0	1.39	7.73	0.0
3287A	45	41	14	0	0.097	4.4	4.0	1.3	0.0	82	1.9	0.7	5.5	0.0	0.75	1.09	5.5
3287B	66	6	28	0	0.111	7.3	0.7	3.1	0.0	80	1.7	0.5	6.9	0.0	0.74	1.39	6.9
3288A	21	13	19	47	0.092	1.9	1.2	1.8	4.4	89	0.0	2.1	0.0	0.0	2.03	2.45	0.0
3288B	39	23	19	18	0.125	4.9	2.9	2.3	2.3	85	0.0	2.5	0.2	0.0	3.50	1.49	0.2
3289A	18	10	0	72	0.057	1.0	0.6	0.0	4.1	93	0.0	1.2	0.0	0.0	nm	nm	0.0
3289B	27	19	0	53	0.063	1.7	1.2	0.0	3.4	91	0.0	1.5	1.6	0.0	nm	nm	1.6
3289C	20	14	0	67	0.079	1.6	1.1	0.0	5.3	91	0.0	0.8	0.8	0.0	nm	nm	0.8
3290B	38	55	7	0	0.119	4.5	6.6	0.8	0.0	76	0.1	0.8	11	0.0	1.50	0.54	11
Ave	29	18	10	44	0.071	2.3	1.5	0.8	2.5	88	0.2	2.5	2.5	0.0	2.03	2.66	28
5. Cypress/ Lawrence Consolidated Field																	
3435	10	38	46	6	0.053	0.5	2.0	2.4	0.3	64	0.1	3.1	28	0.1	4.39	2.48	28
3436	12	47	1	40	0.073	0.9	3.4	0.1	2.9	65	0.8	2.3	24	0.1	3.43	0.89	24
3437	10	35	14	41	0.058	0.6	2.0	0.8	2.4	90	0.7	1.9	1.2	0.1	3.16	3.30	1.3
3438	2	10	14	73	0.024	0.1	0.2	0.3	1.8	74	0.2	2.1	22	0.1	2.01	2.89	22
3439	2	11	6	82	0.036	0.1	0.4	0.2	2.9	83	1.5	2.4	8.6	0.8	4.82	0.48	9.4
3440A	7	39	11	43	0.020	0.1	0.8	0.2	0.9	91	0.1	2.7	4.1	0.1	2.46	2.80	4.2
3440B	10	47	8	34	0.039	0.4	1.8	0.3	1.3	64	0.3	0.3	31	0.1	2.27	1.41	31
3441	11	44	6	39	0.020	0.2	0.9	0.1	0.8	92	0.8	3.4	1.0	0.9	2.17	2.45	1.9
3442	10	41	12	37	0.069	0.7	2.8	0.8	2.6	87	2.1	2.9	0.8	0.1	2.30	3.03	0.9
3443	9	28	55	8	0.033	0.3	0.9	1.8	0.2	94	0.1	2.0	0.1	0.1	2.66	2.55	0.1
3444	11	28	54	7	0.072	0.8	2.0	3.9	0.5	89	0.7	2.7	0.1	0.1	2.45	4.24	0.2
Ave	9	33	21	37	0.045	0.4	1.6	1.0	1.5	81	0.7	2.3	11	0.2	2.92	2.41	11
6. Aux Vases, Cypress, Storms Consolidated Field																	
3454C	56	12	13	19	0.142	7.9		1.9	2.6	79	0.0	6.6	0.0	0.0	2.80	3.35	0.0
3455	39	30	29	5	0.069	2.7	2.1	1.8	0.4	84	0.7	6.8	1.3	0.0	2.17	4.80	1.3
3459A	55	233	4	18	0.129	7.1	3.0	0.5	2.3	63	1.33	3.2	20	0.0	1.13	1.31	20
3459B	10	7	12	72	0.074	0.7	0.5	0.9	5.3	87	0.5	2.8	0.4	1.4	2.78	1.85	1.8
3459C	37	25	16	21	0.067	2.5	1.7	1.1	1.4	85	0.9	3.2	0.6	3.8	2.49	3.61	4.4
Ave	39	20	14	27	0.096	4.2	1.8	1.2	2.4	80	0.7	4.5	4.5	1.0	2.27	2.99	5.5
All Cypress Fields																	
Ave	23	20	17	40	0.063	1.8	1.3	1.1	2.1	83	0.8	5.2	4.6	0.2	2.24	3.22	4.8
Std dev	16	14	14	24	0.036	2.0	1.3	1.1	1.6	11	2.0	7.0	8.0	0.6	0.82	1.76	8.0

* See footnote on p. 353.

**APPENDIX XII-A. IDENTIFICATION OF CORE SAMPLES
WITH MINERALOGICAL DATA**

Sample, API no.	Well name	Field name	Formation	Average depth (ft)
01120	Mattoon no. 1	Mattoon	Aux Vases	1902.0
00312	Bates no. 1	Mattoon	Aux Vases	1882.0
23465	Morgan Coal no. 2	Energy	Aux Vases	2391.4
23491	Burr Oak no. 3	Energy	Aux Vases	2406.3
23456	McCreery no. 1	Dale Consol.	Aux Vases	3204.9
23744	Mack no. 1 (020*4)	Zeigler	Aux Vases	2623.0
23750	Mack no. 2	Zeigler	Aux Vases	2617.3
23753	Mack no. 3	Zeigler	Aux Vases	2642.5
23768	Mack no. 5	Zeigler	Aux Vases	2623.4
23769	Mack no. 6	Zeigler	Aux Vases	2625.6
	Misc. Mack Sample	Zeigler	Aux Vases	2626.0
01070	Novak no. 4	Oakdale	Aux Vases	2880.0
01543	Horrell no. 3	Oakdale	Aux Vases	2915.0
23499	Breeze no. 1	Oakdale	Aux Vases	2880.6
00078	G. D. Chaffee no. 1	Stewardson	Aux Vases	1954.0
01862	Chaffee no. 8	Stewardson	Aux Vases	1970.0
01972	Price no. 1	Boyd	Aux Vases	2133.0
01950	Sanders no. 7	Boyd	Aux Vases	2148.0
01935	F. High no. 2	Boyd	Aux Vases	2130.0
00496	B. W. Hale	King	Aux Vases	2740.0
00488	Ford no. 1	King	Aux Vases	2738.0
00490	L. Wallace no. 1	King	Aux Vases	2732.0
00090	I. W. Mace no. 1	King	Aux Vases	2752.0
00459	St. Game Farm no. 1	King	Aux Vases	2748.5
01301	Eugene Tnan no. 1	Mattoon	Cypress	1803.0
01131	Anna Strong no. 8	Mattoon	Cypress	1778.0
00795	Ruth Uphoff no. 6	Mattoon	Cypress	1821.0
01319	Strong-Seamen no. 1	Mattoon	Cypress	1831.0
01169	Kuelene Mfg. no. 1	Mattoon	Cypress	1813.0
00291	Joshua Akers no. 1	Mattoon	Cypress	1860.0
01330	Elizabeth Strong no. 7	Mattoon	Cypress	1872.0
00788	N. D. Rick no. 9	Mattoon	Cypress	1866.0
00325	A. G. Carmine no. 1	Mattoon	Cypress	1736.0
02187	Stockton Lease no. 1	Tamaroa	Cypress	1160.5
00551	Kampwerth no. 1	Bartelso	Cypress	1002.0
01266	Hempen no. 1	Bartelso	Cypress	1063.0
01812	Droege Unit no. 2	Richview	Cypress	1498.5
01165	Campbell Lease no. 3	Xenia East	Cypress	2538.0

APPENDIX XII B-Q. GEOCHEMICAL MODELING DATA

Appendix XII-B Saturation indices (SI) of minerals with potential for formation damage in five Aux Vases and five Cypress Sandstone water samples (SI>0, supersaturated; SI=0, equilibrium; SI<0, undersaturated). See Table 1 for detailed information on the samples and text for computation of reservoir temperature and pressure.

Sample	Formation	Field	Saturation Indices				Fe-sulfide ¹
			Calcite	Gypsum	Celestite	Barite	
EOR-B17	Cypress	Bartelso	0.4	-3.3	-2.8	0.8	2.1, 2.2, 11.0
EOR-B36		Mattoon	0.3	-0.5	-0.5	0.2	2.1, 2.2, 11.5
EOR-B52		Clay City	0.8	-0.3	-0.4	0.0	2.5, 2.6, 11.1
EOR-B73		New Harmony	-0.7	-1.8	-1.5	1.3	2.0, 2.1, 11.4
EOR-B101		Dale Cons.	-0.5	-0.3	-0.3	0.0	2.5, 2.7, 12.1
EOR-B9	Aux Vases	King	0.3	-0.4	-0.3	0.3	1.5, 1.6, 10.6
EOR-B35		Mattoon	0.5	-2.0	-1.6	0.4	2.2, 2.3, 10.7
EOR-B70		Carmi North	-1.0	-0.7	-0.5	0.3	2.0, 2.1, 11.5
EOR-B93		Clay City	0.1	-0.2	-0.3	0.5	2.1, 2.2, 11.3
EOR-B99		Eldorado	0.1	-0.7	-0.3	0.1	2.5, 2.6, 11.7

¹ First, second, and third numbers belong to pyrothite, troilite, and pyrite, respectively.

Appendix XII-C Mineralogical composition and porosity of the producing sandstone zone in the Morgan Coal No. 2 Well, Energy Field.

Depth (ft)	Minerals (wt. %, except the last row) ¹								Porosity (%)
	I	I/S	Cl	Q	KF	PF	C	Other	
-2387.6	1.6	0.9	2.4	81	0.0	8.2	6.0	4.7	21.3
-2388.4	1.2	1.1	1.9	57	0.2	8.2	31.0	5.7	21.7
-2390.1	1.4	0.7	2.5	85	0.6	2.6	6.7	0.6	23.6
-2392.7	0.8	0.3	1.7	73	0.2	7.8	17.0	0.4	23.3
-2394.7	1.0	0.5	3.0	76	0.4	6.3	13.0	0.0	20.6
-2395.2	1.6	0.9	4.1	63	0.0	2.5	27.0	tr	13.6
Average(wt.%)	1.3	0.7	2.6	73	0.2	5.9	16.8	1.9	-
Average(vol%)	1.3	0.8	2.3	71	0.3	6.0	16.1	1.8	22.0 ²

¹ Abbreviations: I=illite; I/S=illite/smectite; Cl=chlorite; Q=quartz;

KF=K-feldspar; PF=plagioclase; C=calcite

² 22.1 was rounded to 22 in geochemical modeling computations.

Appendix XII-D Mineral volume corresponding to each 1 kg (917 cm³) of pore water (at 50% water saturation) or 1834 cm³ total pore volume, before and after treatment of a producing well with 15% HCl MCA in Energy Field.

Mineral	Original volume (cm ³)		Final volume (cm ³)	
	Measured	Predicted	(predicted)	Net change ¹
ZONE 2				
Quartz	4703	4703	4703	0
Albite	393	393	393	0
Calcite	1060	1057	147	-913
Chlorite	154	123	0	-154
Illite	112	68	0	-112
Smectite	26	67	0	-26
K-feldspar	17	17	0	-17
Kaolinite	0	49	161	+161
Mordenite-K	0	0	115	+115
Pyrite	0	tr	0.1	+0.1
Siderite	0	0	83	+83
Net change in total mineral volume			-863	
% change in total pore volume ²				+47.1
Final porosity (%) ³				32.4
ZONE 3				
Quartz	4703	4703	4703	0
Albite	393	393	393	0
Calcite	1060	1057	239	-821
Chlorite	154	123	0	-154
Illite	112	68	0	-112
Smectite	26	67	0	-26
K-feldspar	17	17	0	-17
Kaolinite	0	49	161	+161
Mordenite-K	0	0	115	+115
Pyrite	0	tr	0.2	+0.2
Siderite	0	0	84	+84
Net change in total mineral volume			-770	
% change in total pore volume ²				+42
Final porosity (%) ³				31.2
ZONE 4				
Quartz	4703	4703	4703	0
Albite	393	393	393	0
Calcite	1060	1057	1053	-7
Chlorite	154	123	102	-52
Illite	112	68	92.(muscovite) ⁴	-20
Smectite	26	67	90	+64
K-feldspar	17	17	0	-17
Kaolinite	0	49	39	+39
Pyrite	0	tr	0.2	+0.2
Siderite	0	0	2	+2
Strontianite	0	0.3	0.3	+0.3
Net change in total mineral volume				+9.5
% change in total pore volume ²				-0.5
Final porosity (%) ³				21.9

¹ Difference between original measured values and values after reaction path ended.

² (Net change in total mineral volume/original total pore volume) × 100

³ (1 + (% change in total pore volume/100)) × (original porosity)

⁴ Model assumes muscovite is a proxy for Illite.

Appendix XII-E Mineral volume corresponding to each 1 kg (917 cm³) of pore water (at 50% water saturation) or 1834 cm³ total pore volume, before and after treatment of a production well with 7.5% HCl MCA in Energy Field.

Mineral	Original volume (cm ³)		Final volume (cm ³)	
	Measured	Predicted	(predicted)	Net change ¹
ZONE 2				
Quartz	4703	4703	4703	0
Albite	393	393	393	0
Calcite	1060	1057	699	-361
Chlorite	154	123	0	-154
Illite	112	68	0	-112
Smectite	26	67	29	+3
K-feldspar	17	17	0	-17
Kaolinite	0	49	165	+165
Mordenite-K	0	0	86	+86
Siderite	0	0	80	+80
Net change in total mineral volume				-310
% change in total pore volume ²				+16.9
Final porosity (%) ³				25.7
ZONE 3				
Quartz	4703	4703	4703	0
Albite	393	393	393	0
Calcite	1060	1057	735	-325
Chlorite	154	123	0	-154
Illite	112	68	0	-112
Smectite	26	67	29	+3
K-feldspar	17	17	0	-17
Kaolinite	0	0	161	+161
Mordenite-K	0	0	115	+115
Pyrite	0	tr	0.2	+0.2
Siderite	0	0	90	+90
Net change in total mineral volume				-239
% change in total pore volume ²				+13
Final porosity (%) ³				24.9
ZONE 4				
Quartz	4703	4703	4703	0
Albite	393	393	393	0
Calcite	1060	1057	1056	-4
Chlorite	154	123	109	-45
Illite	112	68	90.(muscovite) ⁴	-21
Smectite	26	67	87	+61
K-feldspar	17	17	0	-17
Pyrite	0	tr	0.2	+0.2
Kaolinite	0	0	37	+37
Strontianite	0	0.3	0.3	+0.3
Net change in total mineral volume				+11.5
% change in total pore volume ²				-0.6
Final porosity (%) ³				21.9

¹ Difference between original measured values and values after reaction path ended

² (Net change in total mineral volume/original total pore volume) x100

³ (1+ (% change in total pore volume/100)) x (original porosity)

⁴ Model assumes muscovite is a proxy for illite.

Appendix XII-F Predicted pH, CO₂ gas, and dissolved iron species generated in response to MCA-treatment of a production well in Energy Field.

	ZONE-2	ZONE-3	ZONE-4
15% HCl MCA			
CO ₂ gas fugacity	10 ^{1.9}	10 ^{1.8}	10 ^{1.9}
pH	4.21	4.29	6.51
Fe ⁺⁺ (molar)	0.0072	0.0066	0.0012
FeCl ₂ (molar)	0.0114	0.0100	0.0010
FeCl ⁺ (molar)	0.0161	0.0144	0.0020
Total Fe (molar)	0.0340	0.0310	0.0042
7.5% HCl-MCA			
CO ₂ gas fugacity	10 ^{1.5}	10 ^{1.3}	10 ^{2.0}
pH	4.50	4.65	6.59
Fe ⁺⁺ (molar)	0.0047	0.0041	0.0008
FeCl ₂ (molar)	0.0015	0.0015	0.0006
FeCl ⁺ (molar)	0.0049	0.0046	0.0012
Total Fe (molar)	0.0110	0.0100	0.0026

Appendix XII-G Mineralogical composition and average porosity of the producing sandstone interval in McCreary No. 1 Well in Dale Consolidated Field.

Depth (ft)	Minerals (wt. %, except the last row) ¹							Porosity (%)
	I	I/S	Cl	Q	KF	PF	C	
-3190.5	3.2	1.4	0.7	84.5	1.3	2.5	6.4	20.4
-3191.5	2.8	1.5	0.7	81.6	1.7	3.2	8.6	23.4
-3192.7	2.5	1.1	0.6	84.9	1.5	3.7	5.6	25.6
-3194.0	3.4	2.5	0.9	79.5	1.2	4.3	8.1	23.6
-3196.7	2.6	1.5	0.7	88	1.9	3.2	2.0	19.8
-3197.9	3.1	1.7	0.8	80.7	2.6	2.6	8.5	24.8
-3199.4	2.1	1.5	0.6	82.5	2.7	3.7	6.8	24.3
-3201.0	3.1	2.3	0.9	82.3	2.6	3.3	5.5	21.4
-3203.0	2.1	2.1	0.4	77.8	1.5	1.9	14.2	18.6
-3205.8	2.4	2.1	0.5	83.7	1.2	2.4	7.6	21.4
-3207.1	3.1	4.2	0.7	67.8	0.8	1.5	21.8	14.5
-3208.4	1.7	1.9	0.5	82.9	1.7	2.8	8.4	13.1
-3209.9	5.2	4.7	1.9	68.4	1.2	1.8	16.8	11.5
Average(wt.%)	2.9	2.2	0.8	80.4	1.5	2.7	9.3	-
Average(vol.%)	2.9	2.1	0.8	80.8	1.6	2.7	9.1	20.0 ²

¹ Abbreviations: I=illite; I/S=illite/smectite; Cl=chlorite; Q=quartz; KF=K-feldspar; PF=plagioclase; C=calcite

² 20.2 was rounded to 20 in geochemical modeling computations.

Appendix XII-H Mineral volume for each 1 kg (917 cm³) of pore water (at a 50% water saturation), or 1834 cm³ total pore volume, before and after the flushing of the pore volume ten times with the injection water in Dale Consolidated Field.

Minerals	Original mineral volume(cm ³)		Predicted mineral volume (cm ³) after reaction path	Net change ¹
	Measured	Predicted by model		
Quartz	5853	5894	5937	+84
Albite	193	193	167	-26
Calcite	657	657	656	-1
Chlorite	58	22.(daphnite)	0	-58
Illite	290	176.(muscovite) ²	331.(muscovite) ²	+41
Smectite	77	71.(nontronite + saponite)	111.(nontronite +saponite)	+34
K-feldspar	116	116	0	-113
Kaolinite	0	131	38	38
Pyrite	0	tr	1	+1
Strontianite	0	0.1	1	+1
Witherite	0	tr	tr	
Net change in total mineral volume				-1
% change in total pore volume ³				+0.1
Final porosity (%) ⁴				20.0

¹ Difference between original measured values and values after reaction path ended

² Model assumes muscovite is a proxy for illite.

³ (Net change in total mineral volume/original total pore volume) × 100

⁴ (1 + (% change in total pore volume/100)) × (original porosity)

Appendix XII-H Mineral volume for each 1 kg (917 cm³) of pore water (at a 50% water saturation) or 1834 cm³ total pore volume, before and after the injection and formation waters were mixed at a 1:1 ratio in Dale Consolidated Field.

Mineral	Original mineral volume (cm ³)		Predicted mineral volume (cm ³) after reaction path	Net change ¹
	Measured	Predicted by model		
Quartz	5853	5894	5948	+95
Albite	193	193	184	-9
Calcite	657	657	657	0
Chlorite	58	22.(daphnite)	26	-32
Illite	290	176.(muscovite) ²	327.(muscovite) ²	+37
Smectite	77	71.(nontronite +saponite)	65.(saponite)	-12
K-feldspar	116	116	0	-116
Kaolinite	0	131	28	28
Pyrite	0	tr	0.4	+0.4
Strontianite	0	0.1	0.2	+0.2
Witherite	0	tr	tr	
Net change in total mineral volume				-20.4
% change in total pore volume ³				+1.1
Final porosity (%) ⁴				20.2

¹ Difference between original measured values and values after reaction path ended

² Model assumes muscovite is a proxy for illite.

³ (Net change in total mineral volume/original total pore volume) × 100

⁴ (1 + (% change in total pore volume/100)) × (original porosity)

Appendix XII-J Mineralogical composition and porosity of producing sandstone interval in Stockton No. 1 well, Tamaroa Field.

Depth (ft)	Minerals (wt. %, except the last row) ¹							Porosity (%)
	I	I/S	Cl	Q	KF	PF	C	
-1155.5	tr	tr	0.6	0.2	98	0.5	0.4	21.5
-1160.5	0.3	0.2	3.5	1.6	90	4.1	0.1	20.7
-1163.5	0.5	0.8	3.7	3.1	77	9.8	4.6	15.8
-1165.5	tr	tr	0.5	0.3	97	1.8	0.2	19.3
Ave (wt.%)	0.2	0.3	2.9	1.3	90.5	4.1	1.3	-
Ave (vol.%)	0.3	0.3	2.9	1.1	90	4.2	1.3	19.0 ²

¹ Abbreviations: I=illite; I/S=illite/smectite; K=kaolinite Cl=chlorite; Q=quartz; PF=plagioclase; C=calcite

² 19.3 was rounded to 19 in geochemical modeling computations.

Appendix XII-K Mineral volume corresponding to each 1 kg (943 cm³) of pore water (at a 40% water saturation) or a total pore volume of 2358 cm³, before and after the flushing of the pore volume ten times with the injection water in Tamaroa Field.

Mineral	Original mineral volume (cm ³)		Predicted mineral volume (cm ³) after reaction path	Net change ¹
	Measured	Predicted by model		
Quartz	9045	9017	9018	-27
Albite	423	423	338	-85
Calcite	132	131	127	-5
Chlorite	106	40.(daphnite)	0	+ 86
Kaolinite	291	334	379	-272
Illite	39	24.(muscovite) ²	28.(muscovite) ²	-11
Smectite	13	86.(nontronite +saponite)	175.(nontronite +saponite)	+162
Pyrite	0	tr	0.3	+0.3
Strontianite	0	0.1	1	+1
Witherite	0	tr	tr	
Net change in total mineral volume				+17.3
% change in total pore volume ³				+0.7
Final porosity (%) ⁴				18.9

¹ Difference between original measured values and values after reaction path ended

² Model assumes muscovite is a proxy for illite.

³ (Net change in total mineral volume/original total pore volume) × 100

⁴ (1 + (% change in total pore volume/100)) × (original porosity)

Appendix XII-L Mineral volume for each 1 kg (943 cm³) of pore water (at a 40% water saturation) or a total pore volume of 2358 cm³, before and the injection and formation waters were mixed at a 1:1 ratio in Tamaroa Field.

Mineral	Original mineral volume (cm ³) Measured	Predicted by model	Predicted mineral volume (cm ³) after reaction path	Net change ¹
Quartz	9045	9017	9030	-15
Albite	423	423	404	-19
Calcite	132	131	132	- 0
Chlorite	106	40.(daphnite)	44.(daphnite)	-62
Kaolinite	291	334	341	+50
Illite	39	24.(muscovite) ²	24.(muscovite) ²	-15
Smectite	13	86.(nontronite +saponite)	74.(nontronite +saponite)	+61
Pyrite	0	tr	0.2	+0.2
Strontianite	0	tr	0.2	+0.2
Witherite	0	tr	tr	
Net change in total mineral volume				+0.4
% change in total pore volume ³				+<0.1
Final porosity (%) ⁴				19.0

¹ Difference between original measured values and values after reaction path ended

² $(1 + (\% \text{ change in total pore volume}/100)) \times (\text{original porosity})$

³ Model assumes muscovite is a proxy for illite.

⁴ $(\text{Net change in total mineral volume}/\text{original total pore volume}) \times 100$

Appendix XII-M Mineral volume for each 1 kg (943 cm³) of pore water (at a 40% water saturation) or a total pore volume of 2358 cm³, before and after the reaction of 1 mol CO₂ gas with the Cypress reservoir in Tamaroa Field.

Mineral	Original mineral volume (cm ³) Measured	Predicted by model	Predicted mineral volume (cm ³) after reaction path	Net change ¹
Quartz	9045	9045	9045	0
Albite	423	423	423	0
Calcite	132	132	133	+1
Chlorite ²	103	47.(daphnite)	4.(daphnite)	-99
Kaolinite	291	273	303	+12
Illite ²	22	13.(muscovite) ³	13.(muscovite) ³	-9
Smectite ²	9	67.(nontronite +saponite)	64.(saponite +saponite)	+55
Gibbsite	0	33	23	+23
Dawsonite	0	0	5	+5
Siderite	0	0	26	+26
Pyrite	0	tr	0.2	+0.2
Strontianite	0	0.1	0.1	+0.1
Witherite	0	tr	tr	
Net change in total mineral volume				+15.3
% change in total pore volume ⁴				-0.6
Final porosity (%) ⁵				18.9

¹ Difference between original measured values and values after reaction path ended

² Original measured volumes of these minerals were adjusted somewhat to make the simulation runs converge (compare the first and second columns of this table to those of Appendix 12).

³ Model assumes muscovite is a proxy for illite: ⁴ $(\text{net change in total mineral volume}/\text{original total pore volume}) \times 100$; ⁵ $(1 + (\% \text{ change in total pore volume}/100)) \times (\text{original porosity})$

Appendix XII-N Mineral volume for each 1 kg (943 cm³) of pore water (at 40% water saturation) or a total pore volume of 2358 cm³, before and after the reaction of 5 mol CO₂ gas with the Cypress reservoir in Tamaroa Field.

Mineral	Original mineral volume (cm ³)		Predicted mineral volume (cm ³) after reaction path	Net change ¹
	Measured	Predicted by model		
Quartz	9045	9045	9045	0
Albite	423	423	423	0
Calcite	132	132	121	-11
Chlorite ²	103	47.(daphnite)	0	+2
Kaolinite	291	273	293	-59
Illite ²	22	13.(muscovite) ³	0	-22
Smectite ²	9	67.(nontronite +saponite)	0	-9
Gibbsite	0	33	0	
Clinopikolite	0	0	76	+76
Dawsonite	0	0	61	+61
Siderite	0	0	28	+28
Magnesite	0	0	30	+30
Mordenite	0	0	20	+20
Pyrite	0	tr	0.2	+0.2
Strontianite	0	0.1	0.1	+0.1
Witherite	0	tr	tr	
Net change in total mineral volume				+72.3
% change in total pore volume ⁴				-3.1
Final porosity (%) ⁵				18.4

¹ Difference between original measured values and values after reaction path ended

² Original measured volumes of these minerals were adjusted somewhat to make the simulation runs converge (compare the first and second columns of this table to those of Appendix 12).

³ Model assumes muscovite is a proxy for illite.

⁴ (Net change in total mineral volume/original total pore volume) x 100

⁵ (1 + (% change in total pore volume/100)) x (original porosity)

Appendix XII-O Mineral volume for each 1 kg (943 cm³) of pore water (at 40% water saturation) or a total pore volume of 2358 cm³, before and after the reaction of 0.5 mol NaOH solution with the Cypress reservoir in Tamaroa Field.

Mineral	Original mineral volume (cm ³)		Predicted mineral volume (cm ³) after reaction path	Net change ¹
	Measured	Predicted by model		
Quartz	9045	9045	9045	0
Albite	423	423	423	0
Calcite	132	132	104	-28
Chlorite ²	103	47.(claphnite)	93.(claphnite +ripidolite)	-10
Kaolinite	291	273	0	-291
Illite ²	22	13.(muscovite) ³	0	-22
Smectite ²	9	67.(nontronite +saponite)	0	-9
Prehnite	0	0	53	+53
Analcime	0	0	261	+261
Phlogopite	0	0	14	+14
Gibbsite	0	33	82	+82
Pyrite	0	tr	0	0
Strontianite	0	0.1	0.1	+0.1
Witherite	0	tr	tr	0
Net change in total mineral volume				+50.1
% change in total pore volume ⁴				-2.1
Final porosity (%) ⁵				18.6

¹ Difference between original measured values and values after reaction path ended

² Original measured volumes of these minerals were adjusted somewhat to make the simulation runs converge (compare the first and second columns of this table to those of Appendix XII-L).

³ Model assumes muscovite is a proxy for illite.

⁴ (Net change in total mineral volume/original total pore volume) × 100

⁵ (1 + (% change in total pore volume/100)) × (original porosity)

Appendix XI-P Mineral volume for each 1 kg (943 cm³) of pore water (at 40% water saturation) or a total pore volume of 2358 cm³, before and after the reaction of 0.25 mol Na₂SiO₃ solution with the Cypress reservoir in Tamaroa Field.

Mineral	Original mineral volume (cm ³)		Predicted mineral volume (cm ³) after reaction path	Net change ¹
	Measured	Predicted by model		
Quartz	9045	9045	9045	0
Albite	423	423	423	0
Calcite	132	132	123	-9
Chlorite ²	103	47.(daphnite)	93.(Ripidolite +clinoclare)	-10
Kaolinite	291	273	0	-291
Illite ²	22	13.(muscovite) ³	0	-22
Smectite ²	9	67.(nontronite +saponite)	0	-9
Analcime	0	0	421	+421
Prehnite	0	0	17	+17
Phlogopite	0	0	14	+14
Gibbsite	0	33	54	+54
Pyrite	0	tr	0.2	+0.2
Strontianite	0	0.1	0.1	+0.1
Witherite	0	tr	tr	
Net change in total mineral volume				+165.3
% change in total pore volume ⁴				-7.0
Final porosity (%) ⁵				17.7

¹ Difference between original measured values and values after reaction path ended

² Original measured volumes of these minerals were adjusted somewhat to make the simulation runs converge (compare the first and second columns of this table to those of Appendix XI-L).

³ Model assumes muscovite is a proxy for illite.

⁴ (Net change in total mineral volume/original total pore volume) x 100

⁵ (1 + (% change in total pore volume/100)) x (original porosity)

Appendix XI-Q Mineral volume for each 1 kg (943 cm³) of pore water (at 40% water saturation) or a total pore volume of 2358 cm³, before and after the reaction of 0.25 mol Na₂CO₃ solution with the Cypress reservoir in Tamaroa Field.

Mineral	Original mineral volume (cm ³)		Predicted mineral volume (cm ³) after reaction path	Net change ¹
	Measured	Predicted by model		
Quartz	9045	9045	9045	0
Albite	423	423	423	0
Calcite	132	132	134	+2
Chlorite ²	103	47.(claphnite)	47.(claphnite)	-56
Kaolinite	291	273	38	-253
Illite ²	2	13.(muscovite) ³	13	-9
Smectite ²	9	67.(nontronite +saponite)	69.(saponite)	+60
Dawsonite	0	0	130	+130
Analcime	0	0	226	+226
Gibbsite	0	33	39	+39
Rhodochrosite	0	0	tr	tr
Pyrite	0	tr	0.2	+0.2
Strontianite	0	0.1	0.1	+0.1
Witherite	0	tr	tr	tr
Net change in total mineral volume				+139.3
% change in total pore volume ⁴				-5.9
Final porosity (%) ⁵				17.9

¹ Difference between original measured values and values after reaction path ended

² Original measured volumes of these minerals were adjusted somewhat to make the simulation runs converge (compare the first and second columns of this table to those of Appendix XI-L).

³ Model assumes muscovite is a proxy for illite.

⁴ (Net change in total mineral volume/original total pore volume) × 100

⁵ (1 + (% change in total pore volume/100)) × (original porosity)

APPENDIX XIII. ENR/ DOE PROJECT DATA FILE

Tests and analyses of samples from project reservoirs and outcrops in Illinois are recorded on this form. The document serves as a master list of data generated for the Improved Oil Recovery Project conducted by the Illinois State Geological Survey and supported by the U.S. Department of Energy.

- L Left
- R Right
- M Middle
- X 1 sample
- 2X 1 sample and 1 repeat; 3X= 1 sample and 2 repeats; etc.
- * NOTE In this column, a number represents samples analyzed
 - a Micronizer tests
 - b Sample preparation procedure tests
 - c Chlorite type investigation
- ST Sample type:
 - DCP Drill Core Plug
 - CUT Cuttings from a boring
 - DCC Drill core (continuous)
 - DCB Drill core (biscuits)
 - OC Outcrop Samples

Engineering Data Symbols

- ϕ_h $\phi(He)$ = porosity by expansion
- ϕ_s $\phi(Sat)$ = porosity by saturation
- CF Core flow tests
- Ka $k(Air)$ = air permeability
- kl $k(Liq)$ = liquid permeability
- K kl and ka = both permeability tests were run in lab
- CP Capillary pressure
- SEM Samples catalogued according to date and a three-letter reference; these data may include SEM photomicrographs (P) and corresponding energy dispersive x-ray analyses (EDX).

A number before the P indicates the number of available photos: 2P means 2 photomicrographs are available. EDX analyses are numerous, variable in scope, and not enumerated.

Field Abbreviations Used for SEM Samples

- BAR Bartleso Oil Field
- BYD Boyd Oil Field
- ENG Energy Oil Field
- KNG King Oil Field
- LAW Lawrence Oil Field
- MAT Mattoon Oil Field
- MCA Stepped mud cleaning acid (MCA) studies
- OKD Oakdale Oil Field
- OCS I-57 engineering and outcrop studies
- PAR Parkersburg Oil Field
- RCV Richview Oil Field
- SCN Storms Consolidated Oil Field
- STW Stewardson Oil Field
- SWD Southwest Dale Consolidated Oil Field
- TAM Tamaroa Oil Field
- XNE Xenia East Oil Field
- ZGL Zeigler Oil Field

Project Data File

Well name	API no.	Depth (ft)	Field	Form-ation	TS	Bulk	Clay	Other	SEH	Petro no.	Engr data	ST
Stockett Lee no.1	1214502187	1155.5'	Tamaroa	CYP	X	X	X	c				
" "	" "	1156.5'	" "	" "					TAM; 5P; 1990	3198A	phi, ka	DCP
" "	" "	1159.5'	" "	" "					TAM; 1P; 1990		phi, ka	"
" "	" "	1160.5'	" "	" "	X	X	X	c		3198B	phi, ka	"
" "	" "	1163.5'	" "	" "	X	X	X	c	TAM; 2P; 1990	3198C	phi, ka	"
" "	" "	1165.5'	" "	" "	X	X	X	c		3198D	phi, ka	"
E.W. Hale no.1	1208100496	2736.0'	King	AuxVas	X	X	2	c		3199A		DCB
" "	" "	2739.0'	" "	" "	X	X	X	c		3199B		"
" "	" "	2744.0'	" "	" "	X	2X	X	c		3199C		"
Ford no.1	1208100488	2725.0'	King	AuxVas	X	X	X	c		3200A		DCB
" "	" "	2732.0'	" "	" "	X	2X	X	c		3200B		"
" "	" "	2738.0'	" "	" "	X	X	X	c		3200C		"
" "	" "	2745.0'	" "	" "	X	4X	X	c	KING; 3P; 4/12/90	3200D		"
" "	" "	2746.0'A	" "	" "	X	2X	X	c		3200E		"
" "	" "	2746.0'B	" "	" "	X							"
" "	" "	2748.0'	" "	" "	X	X	X	c		3200F		"
" "	" "	2750.0'	" "	" "	X	X	X	c	KING; 1P; 3/28/90	3200G		"
Lydia Wallace no.1	1208100490	2732.0'	King	AuxVas	X	X	X	c		3201		DCB
I.W. Nace no.1	1208100090	2722.0 to	King	AuxVas	X	X	X	c		3202A		DCB
" "	" "	2727.0'	" "	" "								
" "	" "	2747.0 to	" "	" "	X	X	X	c		3202B		DCB
" "	" "	2748.0'	" "	" "								
" "	" "	2772.0 to	" "	" "	X	X	X			3202C		DCB
" "	" "	2781.0'	" "	" "								
State Game												
Farm no.1-B	1208100459	2735.0'	King	AuxVas	X	X	X	c		3203		DCB
State Game												
Farm no.1	1208100374	2747.0'	King	AuxVas	X	X	X	c		3204A		DCB
" "	" "	2750.0'	" "	" "	X	X	2X	c		3204B		"
Nancy Adams no.4	1208101427	2735.0'	King	AuxVas	X						phi, ka	"
" "	" "	2736.0'	" "	" "	X						phi, ka	"
Neck no.1	1205523746	2613.0'	Zeigler	AuxVas	X	2X	X	c		3205A		DCB
" "	" "	2614.0'	" "	" "	X				ZGL; 4P; 3/24/93			"
" "	" "	2616.0'	" "	" "	X							"
" "	" "	2618.0'	" "	" "	X							"
" "	" "	2620.0'	" "	" "	X							"
" "	" "	2621.0'	" "	" "	X	2X	2X			3205B		"
" "	" "	2624.0'	" "	" "	X							"
" "	" "	2627.0'	" "	" "	X	3X	3X	c		3205C		"
" "	" "	2629.0'	" "	" "	X							"
" "	" "	2631.0'	" "	" "	X							"
" "	" "	2632.0'	" "	" "	X	X	X			3205D	phi, ka	"
" "	" "	2633.0'	" "	" "	X	X	X	c		3205E		"
" "	" "	2636.0'	" "	" "	X							"
Neck no.2	1205523750	2605.5'	Zeigler	AuxVas	X	X	X			3206A		DCB
" "	" "	2606.5'	" "	" "	X	2X	X		MCA; 5P; 3/19/93	3206B	X, CF, phi	"
" "	" "	2608.5'	" "	" "	X	X	X			3206C	X, CF, phi	"
" "	" "	2610.5'	" "	" "	X	X	X	c		3206D		"
" "	" "	2611.0'	" "	" "							X, CF, phi	"
" "	" "	2611.5'	" "	" "	X	X	X			3206E		"

Project Data File *continued*

Well name	API no.	Depth (ft)	Field	Formation	TS	Bulk	Clay	Other	SEN	Petro no.	Engr data	ST
" "	" "	2612.5'	" "	" "	X	X	X	c		3206F	k, CF, ϕ	"
" "	" "	2614.5'	" "	" "	X	X	X			3206G	k, CF, ϕ	"
" "	" "	2617.5'	" "	" "	X	X	X			3206H		"
" "	" "	2618.5'	" "	" "	X	X	X	c		3206I		"
" "	" "	2620.5'	" "	" "	X	X	X	c		3206J		"
" "	" "	2621.5'	" "	" "	X	X	X			3206K		"
" "	" "	2623.7'	" "	" "	X	X	X	c		3206L		"
" "	" "	2623.8'	" "	" "	X	X	X			3206M		"
" "	" "	2625.5'	" "	" "	X	X	X	c		3206N		"
" "	" "	2629.0'	" "	" "	X	X	X			3206O		"
Hack no.3	1205523753	2634.5'	Zeigler	AuxVas	X	2X	2X	c		3207A		DCC
" "	" "	2636.5'	" "	" "	X	X	X			3207B		"
" "	" "	2639.0'	" "	" "	X	X	X	c		3207C		"
" "	" "	2640.0'	" "	" "	X	X	X			3207D		"
" "	" "	2642.5'	" "	" "	X	X	X	c		3207E		"
" "	" "	2645.5'	" "	" "	X	X	X			3207F		"
" "	" "	2646.5'	" "	" "	X	X	X	c		3207G		"
" "	" "	2647.1'	" "	" "	X	X	X			3207H		"
" "	" "	2648.9'	" "	" "	X	X	X	c		3207I		"
" "	" "	2650.5'	" "	" "	X	X	X			3207J		"
Hack no.5	1205523768	2611.8'	Zeigler	AuxVas	X	X	2X	16a		3208A		DCC
" "	" "	2614.0'	" "	" "	X	2X	2X	c		3208B		"
" "	" "	2623.4'	" "	" "	X	X	X			3208C		"
" "	" "	2624.7'	" "	" "	X	X	X	c		3208D		"
" "	" "	2626.0'	" "	" "	X	X	X			3208E		DCC
" "	" "	2627.5'	" "	" "	X	X	X	c		3208F		"
" "	" "	2631.0'	" "	" "	X	X	X			3208G		"
" "	" "	2633.0'	" "	" "	X	X	X	c		3208H		"
" "	" "	2634.0'	" "	" "	X	X	X	Ba		3208I		"
" "	" "	2635.0'	" "	" "	X	X	X			3208J		"
Hack no.6	1205523769	2615.7'	Zeigler	AuxVas	X	X	2X			3209A		DCC
" "	" "	2617.0'	" "	" "	X	2X	2X	c		3209B		"
" "	" "	2619.8'	" "	" "	X	2X	2X			3209C		"
" "	" "	2621.0'	" "	" "	X	X	X	c		3209D		"
" "	" "	2624.9'	" "	" "	X	X	X			3209E		"
" "	" "	2628.0'	" "	" "	X	X	X	c		3209F		"
" "	" "	2631.0'	" "	" "	X	2X	2X			3209G		"
" "	" "	2633.8'	" "	" "	X	X	X	c		3209H		"
" "	" "	2635.5'A	" "	" "	X	X	X			3209I		"
" "	" "	2635.5'B	" "	" "	X	X	X			3209K		"
" "	" "	2636.0'	" "	" "	X	X	X	c		3209J		"
Alex no.2	12055	2631.0'	Zeigler	AuxVas					ZGL; 5P; 12/5/91			DCC
Kempwarth no.1	1202700551	997.0'	Bartelso	CYP	X	X	X	c		3213A		DCB
" "	" "	1000.0'	" "	" "	X	X	X	c	BAR; 1P; 4/4/90	3213B		"
" "	" "	1003.0'	" "	" "	X	X	X	c	BAR; 1P; 4/4/90	3213C		"
" "	" "	1006.0'	" "	" "	X	X	X	c	BAR; 6P; 4/12/90	3213D		"
Hempen no.1	1202701266	1060.5'	Bartelso	CYP	X	X	X	c		3214A		DCB
" "	" "	1061.5'	" "	" "	X	X	X	c		3214B		"
" "	" "	1062.5'	" "	" "	X	X	X	c		3214C		"
" "	" "	1065.5'	" "	" "	X	X	X	c		3214D		"

Project Data File *continued*

Well name	API no	Depth (ft)	Field	Form- ation	TS	Bulk	Clay	Other	SEM	Petro no	Engr data	ST
Rincker no 1	1217300076	1925 0 to 1945 0'	Stewardson	AuxVas	X							CVT
" "	" "	1945 0 to 1965 0	" "	" "	X							"
Rincker no 1-B	1217300434	1945 0 to 1950 0'	Stewardson	AuxVas	X							"
Scheer Heirs no 1	1217300436	1935 0 to 1953 5'	Stewardson	AuxVas	X							"
Grge Chaffee no 1B	1217301076	1960 0 to 1974 0'	Stewardson	AuxVas	X							"
Morgan Coal no 2	1218923465	2387 5'	Energy	AuxVas					ENG, 6P, 2/23/90			DCC
" "	" "	2387 6'	" "	" "	X	X	X	C		3217A	φs, ka, CP	"
" "	" "	2388 3'	" "	" "					NCA, 2hr, 10P, 2/92			"
" "	" "	2388 4'	" "	" "	X	X	X	C		3217B	φs, ka, CP	"
" "	" "	2389 0'	" "	" "					ENG, 1P, 2/13/90			"
" "	" "	2390 1'	" "	" "	X	X	X	C		3217C	φs, ka, CP	"
" "	" "	2392 1'	" "	" "							φs, ka, CP	"
" "	" "	2392 7'	" "	" "	X	X	X	C		3217D		"
" "	" "	2392 8'	" "	" "					NCA, untreated, 2P			"
" "	" "	2392 8'	" "	" "					NCA, 0 5hr, 2P, 7/92			"
" "	" "	2392 8'	" "	" "					NCA, 1 5hr, 3P, 7/92			"
" "	" "	2392 8'	" "	" "					NCA, 4 5hr, 4P, 7/92			"
" "	" "	2392 8'	" "	" "					NCA, 5 5hr, 1P, 7/92			"
" "	" "	2392 8'	" "	" "					NCA 6 5hr, 4P, 7/92			"
" "	" "	2393 0'	" "	" "							φs, ka, CP	"
" "	" "	2393 0'	" "	" "					NCA, 0 5hr, 10P, 2/92			"
" "	" "	2393 0'	" "	" "					NCA, 1hr, 9P, 2/92			"
" "	" "	2393 0'	" "	" "					NCA, 2hr, 12P, 3/92			"
" "	" "	2393 0'	" "	" "					NCA, 3hr, 4P, 3/92			"
" "	" "	2393 0'	" "	" "					NCA, 4hr, 2P, 3/92			"
" "	" "	2393 0'	" "	" "					NCA, 5hr, 1P, 4/92			"
" "	" "	2393 0'	" "	" "					NCA, 6hr, 10P, 2/92			"
" "	" "	2393 0'	" "	" "					NCA, 7hr, 6P, 4/92			"
" "	" "	2394 7'	" "	" "	X	X	X	C		3217E		"
" "	" "	2395 2'	" "	" "	X	X	X	C		3217F		"
SE Hazel A/C1												
SE no 15	1210129518	1552 2'	Lawrence	AuxVas	12b					3190A		DCC
" "	" "	1554 0'	" "	" "	12b					3190B		"
Neck no 3	1205523753	2616 0'	Zeigler	AuxVas	16b					3191		DCC
Neck no 5	1205523768	2626 0	Zeigler	AuxVas	16b					3192		DCC
Judge no 3-A	1204724183	2906 6 & 2913 0'	Parkcrabg	CYP	36b					3157A&B		DCC
" "	" "	2920 4 & 2923 8'	" "	" "	30b					3157C&D		"
Judge no 3-A	1204724183	2900 5	Parkcrabg	CYP	X							DCC
" "	" "	2905 2'	" "	" "	X							"
" "	" "	2906 0'	" "	" "	X	X	X	C		3157A		"
" "	" "	2912 0'	" "	" "	X							"
" "	" "	2918 5'	" "	" "					PAR, 11P, 1989			"
" "	" "	2921 5'	" "	" "	X	X	X	C		3157C		"

Project Data File *continued*

Well name	API no.	Depth (ft)	Field	Form- ation	TS	Bulk	Clay	Other	SEM	Petro no.	Engr data	ST
" "	" "	2923.0'	" "	" "	X	X	X	c		3157D		"
" "	" "	2926.0'	" "	" "	X							"
A.Bierhaus no.1	1204700001	2850.0 to 2854.0'	Parkrsbg	CYP	X							CUT
" "	" "	2854.0 to 2856.0'	" "	" "	2X							"
" "	" "	2856.0 to 2860.0'	" "	" "	X							"
" "	" "	2863.0 to 2875.0'	" "	" "	X							"
Gadsu no.1	1204700030	2854.0 to 2859.0'	Parkrsbg	CYP	X							CUT
Wabash R.R. R.O.W. no.1	1217300079	1947.0 to 1952.0'	Stewrdn	AuxVas								CUT
" "	" "	1951.0 to 1959.0'	" "	" "	X							"
" "	" "	1959.0 to 1966.0'	" "	" "	X							"
Noran no.1-A	1217301330	1950.0 to 1960.0'	Stewrdn	AuxVas								CUT
" "	" "	1960.0 to 1980.0'	" "	" "	X							"
" "	" "	1980.0 to 2030.0'	" "	" "	X							"
G.Chaffee no.1-B	1217301076	1970.0 to 1980.0'	Stewrdn	AuxVas								CUT
" "	" "	1990.0 to 2010.0'	" "	" "	X							"
Grge D.Chaffee no.1	1217300078	1946.0 to 1947.0'	Stewrdn	AuxVas	X	X		c		3278A		DCB
" "	" "	1948.0 to 1949.0'	" "	" "	X	X		c		3278B		"
" "	" "	1950.0 to 1951.0'	" "	" "	X	X		c	STW; 6P; 1/25/91	3278C		"
" "	" "	1952.0 to 1953.0'	" "	" "	X	X	X	c	STW; 8P; 1/25/91	3278D		"
" "	" "	1954.0 to 1955.0'	" "	" "	X	X	X	c		3278E		"
" "	" "	1960.0 to 1961.0'	" "	" "	X	X	X	c		3278F		"
Chaffee no.6	1217301062	1925.0 to 1985.0'	Stewrdn	AuxVas								CUT
Chaffee no.8	1217301062	1955.0 to 1960.0'	Stewrdn	AuxVas	X	X		c		3279A		CUT
" "	" "	1960.0 to 1965.0'	" "	" "	X	X		c		3279B		"
" "	" "	1975.0 to 1980.0'	" "	" "	X	X		c		3279C		"
" "	" "	1980.0 to 1985.0'	" "	" "	X	X		c		3279D		"

Project Data File continued

Well name	API no.	Depth (ft)	Field	Form- ation	TS	Gulk	Clay	Other	SEN	Petro no.	Engr data	ST
Price no.1	1208101972	2129.0'	Boyd	AuxVas	X	X	X	c		3271A		DCB
" "	" "	2131.0'	" "	" "	X	X	X	c		3271B		"
" "	" "	2133.0'	" "	" "	X	X	X	c		3271C		"
" "	" "	2134.0'	" "	" "	X	X	X	c		3271D		"
" "	" "	2135.0'	" "	" "	X	X	X	c		3271E		"
Sanders no.7	1208101950	2141.0'	Boyd	AuxVas	X	X	X	c		3272A		DCB
" "	" "	2144.0'	" "	" "	X	X	X	c		3272B		"
" "	" "	2151.0'	" "	" "	X	X	X	c	BYD: 1P; 9/8/91	3272C		"
" "	" "	2155.0'	" "	" "	X	X	X	c		3272D		"
Novak no.4	1208101070	2869.5'	Oakdale	AuxVas	X	X	X	c		3258A		DCP
" "	" "	2872.5'	" "	" "	X	X	X	c		3258B		"
" "	" "	2878.5'	" "	" "	X	X	X	c		3258C		"
" "	" "	2881.5'	" "	" "	X	X	X	c		3258D		"
" "	" "	2883.5'	" "	" "	X	X	X	c		3258E		"
" "	" "	2885.5'	" "	" "	X	X	X	c		3258F		"
" "	" "	2889.5'	" "	" "	X	X	X	c		3258G		"
" "	" "	2890.5'	" "	" "	X	X	X	c		3258H		"
Horrell no.3	1208101543	2903.5'	Oakdale	AuxVas	X	X	X	c		3259A		DCP
" "	" "	2913.5'	" "	" "	X	X	X	c		3259B		"
" "	" "	2918.5'	" "	" "	X	X	X	c		3259C		"
" "	" "	2920.5'	" "	" "	X	X	X	c		3259D		"
" "	" "	2924.5'	" "	" "	X	X	X	c		3259E		"
" "	" "	2926.5'	" "	" "	X	X	X	c		3259F		"
Breeze no.1	1208124399	2870.1'	Oakdale	AuxVas	X	X	X	c		3261A		DOC
" "	" "	2870.9'	" "	" "	X	X	X	c		3261B		"
" "	" "	2871.5'	" "	" "					OKD: 6P; 5/3/91			"
" "	" "	2872.5'	" "	" "					OKD: 6P; 9/22/91			"
" "	" "	2872.9'	" "	" "	X	X	X	c		3261C		"
" "	" "	2875.2'	" "	" "	X	X	X	c		3261D		"
" "	" "	2875.9'	" "	" "	X	X	X	c		3261E		"
" "	" "	2877.0'	" "	" "					OKD: 1P; 2/23/90			"
" "	" "	2878.9'	" "	" "	X	X	X	c		3261F		"
" "	" "	2879.9'	" "	" "	X	X	X	c		3261G		"
" "	" "	2880.5'	" "	" "	X	X	X	c	OKD: 9P; 9/14/91	3261H		"
" "	" "	2880.5'	" "	" "					OKD: 3P; 12/29/92			"
" "	" "	2880.5'	" "	" "					OKD: 3P; 1/21/93			"
" "	" "	2880.5'	" "	" "					OKD: 2P; 1/23/93			"
" "	" "	2882.0'	" "	" "	X	X	X	c		3261I		"
" "	" "	2883.1'	" "	" "	X	X	X	c		3261J		"
" "	" "	2884.9'	" "	" "	X	X	X	c		3261K		"
" "	" "	2885.0'	" "	" "							φB, ka	"
" "	" "	2885.6'	" "	" "	X	X	X	c		3261L		"
" "	" "	2886.8'	" "	" "	X	X	X	c		3261M		"
" "	" "	2887.5'	" "	" "	X	X	X	c	OKD: 4P; 9/26/91	3261N		"
" "	" "	2888.0'	" "	" "	X	X	X	c		3261O		"
" "	" "	2888.1'	" "	" "	X	X	X	c		3261P		"
" "	" "	2889.4'	" "	" "	X	X	X	c		3261Q		"
" "	" "	2890.0'	" "	" "							φB, ka	"
" "	" "	2890.9'	" "	" "	X	X	X	c		3261R		"
" "	" "	2891.0'	" "	" "							φB, ka	"

Project Data File *continued*

Well name	API no.	Depth (ft)	Field	Formation	TS	Bulk	Clay	Other	SEM	Petro no.	Engr data	ST
" "	" "	2891.1'	" "	" "	X	X	X	c		32618	"	"
Campbell Lease no.3	1202501165	2526.5'	Xenia B	CYP	X	X	X	c		3260A		DCP
" "	" "	2528.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2529.5'	" "	" "	X	X	X	c		3260B		"
" "	" "	2530.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2531.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2532.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2533.5'	" "	" "	X	X	X	c		3260C		"
" "	" "	2534.5'	" "	" "	"	"	"	"	XME; 5P; 6/3/91			"
" "	" "	2535.5'	" "	" "	X	X	X	c		3260D		"
" "	" "	2537.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2538.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2539.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2536.5'	" "	" "	"	"	"	"	XME; 11P; 6/3/91			"
" "	" "	2540.5'	" "	" "	X	X	X	c		3260E		"
" "	" "	2541.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2542.5'	" "	" "	X	X	X	c		3260F		"
" "	" "	2543.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2544.5'	" "	" "	X	X	X	c		3260G		"
" "	" "	2545.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2546.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2547.5'	" "	" "	"	"	"	"			ps, sh	"
" "	" "	2548.5'	" "	" "	X	X	X	c		3260H		"
Anna Strong no.8	1202901131	1774.0'	Mattoon	CYP	X							DCB
" "	" "	1776.0'	" "	" "	X	X	X	c		3281A	ka, sh	"
" "	" "	1778.0'	" "	" "	X	X	X	c		3281B	ka, sh	"
" "	" "	1780.0'	" "	" "	X	X	X	c		3281C	ka, sh	"
" "	" "	1781.0'	" "	" "	X							"
Bryana Tynan no.1	1202901301	1776.0'	Mattoon	CYP	X				MAT; 7P; 7/91			DCB
" "	" "	1778.0'	" "	" "	X	X	X	c	MAT; 11P; 7/25/91	3280A	ka, ps, sh	"
" "	" "	1787.0'	" "	" "	X	X	X	c		3280B		"
E. Tynan no.1 conc	" "	1790.0'	" "	" "	X	X	X	c	MAT; 1P; 7/17/91	3280C	ka, sh	"
" "	" "	1793.0'	" "	" "	X							"
" "	" "	1801.0'	" "	" "	X	X	X	c		3280D	ka, ps, sh	"
" "	" "	1805.0'	" "	" "	X	X	X	c		3280E		"
" "	" "	1813.0'	" "	" "	X	X	X	c		3280F	ka, sh	"
" "	" "	1816.0'	" "	" "	X							"
" "	" "	1817.0'	" "	" "	X							"
" "	" "	1820.0'	" "	" "	X							"
" "	" "	1823.0'	" "	" "	X							"
" "	" "	1827.0'	" "	" "	X	X	X	c		3280G	ka, sh	"
" "	" "	1829.0'	" "	" "	X							"
Ruth Schoff no.6	1202900795	1808.0'	Mattoon	CYP	X	X	X	c		3282A	ka	DCB
" "	" "	1810.0'	" "	" "	X							"
" "	" "	1812.0'	" "	" "	X							"
" "	" "	1814.0'	" "	" "	X	X	X	c		3282B		"
" "	" "	1816.0'	" "	" "	X							"
" "	" "	1820.0'	" "	" "	X							"
" "	" "	1821.0'	" "	" "	X							"
" "	" "	1830.0'	" "	" "	X	X	X	c		3282C		"

Project Data File *continued*

Well name	API no.	Depth (ft)	Field	Formation	TS	Bulk	Clay	Other	SEN	Petro no.	Engr data	ST
" "	" "	1833.0'	" "	" "	X	X	X	c		3282D	ka, ϕ s, ϕ h	"
" "	" "	1837.0'	" "	" "	X							"
" "	" "	1838.0'	" "	" "	X							"
Strong-Seaman no.1	1202901319	1826.0'	Mattoon	CYP	X	X	X	c		3283A	ka, ϕ h	DCB
" "	" "	1832.0'	" "	" "	X	X	X	c		3283B	ka, ϕ h	"
" "	" "	1835.0'	" "	" "	X	X	X	c		3283C	ka	"
" "	" "	1842.0'	" "	" "	X							"
Kuehne Mfg. no.1	1202901169	1813.0'	Mattoon	CYP	X	X	X	c		3284A	ka, ϕ h	DCB
" "	" "	1816.0'	" "	" "	X	X	X	c		3284B	ka, ϕ h	"
" "	" "	1817.0'	" "	" "	X							"
" "	" "	1818.0'	" "	" "	X							"
Joshua Akers no.1	1202900291	1842.0	Mattoon	CYP	X							"
" "	" "	1845.0'	" "	" "	X							"
" "	" "	1845.0 to 1848.0'	" "	" "	X	X	X	c		3285A	ka, ϕ s, ϕ h	"
" "	" "	1851.0 to 1858.0'	" "	" "	X							"
" "	" "	1874.0'	" "	" "	X	X	X	c		3285B		DCB
" "	" "	1884.0'	" "	" "	X							"
Elizabeth Strong no.7	1202901330	1846.0'	Mattoon	CYP	X							DCB
" "	" "	1851.0'	" "	" "	X							"
" "	" "	1852.0'	" "	" "	X	X	X	c		3286A	ka, ϕ h	"
" "	" "	1854.0'	" "	" "	X							"
" "	" "	1856.0'	" "	" "	X							"
" "	" "	1858.0'	" "	" "	X							"
" "	" "	1867.0'	" "	" "	X							"
" "	" "	1869.0'	" "	" "	X	X	X	c		3286B	ka, ϕ s, ϕ h	"
" "	" "	1872.0'	" "	" "	X							"
" "	" "	1879.0'	" "	" "	X	X	X	c		3286C	ka, ϕ h	"
" "	" "	1886.0'	" "	" "	X							"
" "	" "	1892.0'	" "	" "	X	X	X	c	MAT; ZP; 3/11/53	3286D	ka, ϕ h	"
E. Strong no.7 cont	" "	1901.5'	" "	" "	X							"
Mattoon no.1	1202901120	1893.0'	Mattoon	ARKVas	X							DCB
" "	" "	1896.0'	" "	" "	X	X	X	c		3287A	ka, ϕ s, ϕ h	"
" "	" "	1900.0'	" "	" "	X							"
" "	" "	1908.0'	" "	" "	X	X	X	c		3287B	ka, ϕ h	"
N.D.Rick no.9	1202900788	1857.0'	Mattoon	CYP	X	X	X	c		3288A	ka, ϕ s, ϕ h	DCB
" "	" "	1859.0'	" "	" "	X							"
" "	" "	1873.0'	" "	" "	X							"
" "	" "	1874.0'	" "	" "	X	X	X	c		3288B	ka, ϕ h	"
" "	" "	1876.0'	" "	" "	X							"
" "	" "	1880.0'	" "	" "	X							"
A.G.Carmine no.1	1202900325	1718.0'	Mattoon	CYP	X	X	X	c		3289A		DCB
" "	" "	1720.0'	" "	" "	X							"
" "	" "	1722.0'	" "	" "	X							"
" "	" "	1724.0'	" "	" "	X							"
" "	" "	1726.0'	" "	" "	X							"
" "	" "	1729.0'	" "	" "	X							"
" "	" "	1744.0 to	" "	" "	X							"

Project Data File continued

Well name	API no.	Depth (ft)	Field	Form- ation	TS	Bulk	Clay	Other	SEM	Petro no.	Engr data	ST
" "	" "	1750.0 to 1753.0'	" "	" "	X	X	X	c		3269B		"
" "	" "	1754.0'	" "	" "	X	X	X	c		3269C	ka, ph, sh	"
" "	" "	1756.0'	" "	" "	X							"
Bates no.1	12022900312	1879.0 to 1884.0'	Natatoon	AuxVan	X	X	X	c		3290	ka, ph	DCB
E.E. Osborne no.2	1202901019	1740.0 to 1741.0'	Natatoon	CYP	X							DCB
" "	" "	1743.0'	" "	" "					WAT: 1P; 3/11/93			"
" "	" "	1747.0 to	" "	" "	X							"
B. Finsley no.1	1202901134	1756.0'	Natatoon	CYP	X							DCB
Gray no.1	1202901353	1847.0'	Natatoon	CYP	X							DCB
" "	" "	1848.0'	" "	" "	X							"
" "	" "	1849.0'	" "	" "					WAT: 11P; 3/19/93			"
" "	" "	1856.0'	" "	" "	X							"
Sanders no.3	1202901285	1808.0'	Natatoon	CYP	X							DCB
Elizabeth Strong no.2	1202901326	1830.0'	Natatoon	CYP	X							DCB
" "	" "	1836.0'	" "	" "	X							"
L.E. Arterburn no.1	1202900326	1865.0'	Natatoon	AuxVan	X							DCB
" "	" "	1867.0'	" "	" "	X							"
" "	" "	1870.0'	" "	" "	X							"
J.M. Seaman no.3	1202901308	1754.0'	Natatoon	CYP	X							DCB
" "	" "	1755.0'	" "	" "	X							"
" "	" "	1758.0'	" "	" "	X							"
" "	" "	1759.0'	" "	" "	X							"
" "	" "	1760.0'	" "	" "	X							"
M.D. Rick no.2	1202900869	1820.0'	Natatoon	CYP	X							DCB
" "	" "	1831.0'	" "	" "	X							"
" "	" "	1833.0'	" "	" "	X							"
" "	" "	1835.0'	" "	" "	X							"
Zmudzinski, Aug no.1	1214502708	1133.0'	Tamazoa	CYP	X							CUT
Ben Newborn no.1	1214502722	1115.0 to 1195.0'	" "	" "	X							CUT
Prosser, W.O. no.1	1215901269	2790.0 to 2800.0'	Parkrsbg	CYP	X							CUT
Noods, Emma no.1	1215901273	2720.0 to 2729.0'	Parkrsbg	CYP	X							CUT
Koertge et al Comm no.1	1204702648	2680.0 to 2690.0'	Parkrsbg	CYP	X							CUT
" "	" "	2650.0 to 2670.0'	" "	" "	X							"
" "	" "	2750.0 to 2820.0'	" "	" "	X							"
" "	" "	2730.0 to 2750.0'	" "	" "	X							"
" "	" "	2825.0 to 2835.0'	" "	" "	X							"
" "	" "	2670.0 to 2680.0'	" "	" "	X							"

Project Data File *continued*

Well name	API no.	Depth (ft)	Field	Form- ation	TS	Bulk	Clay	Other	SGM	Petro no.	Engr data	ST
Allen, Jas. W. no.1	1204701298	2765.0 to 2795.0'	Parkrsby	CYP	X							CUT
" "	" "	2695.0 to 2720.0'	" "	" "	X							"
" "	" "	2750.0 to 2760.0'	" "	" "	X							"
" "	" "	2859.0'	" "	" "	X							"
" "	" "	2815.0 to 2850.0'	" "	" "	X							"
" "	" "	2764.0'	" "	" "	X							"
" "	" "	2864.0'	" "	" "	X							"
Hedrick-Schmidt no.1	1204722527	2710.0 to 2715.0'	Parkrsby	CYP	X							CUT
" "	" "	2715.0 to 2725.0'	" "	" "	X							"
" "	" "	2745.0 to 2755.0'	" "	" "	X							"
" "	" "	2775.0 to 2780.0'	" "	" "	X							"
" "	" "	2782.0'	" "	" "	X							"
" "	" "	2790.0 to 2800.0'	" "	" "	X							"
" "	" "	2830.0 to 2840.0'	" "	" "	X							"
" "	" "	2840.0 to 2865.0'	" "	" "	X							"
" "	" "	2870.0 to 2880.0'	" "	" "	X							"
Bierhaus, A. no.1	1204700001	2885.0 to 2890.0'	Parkrsby	CYP	X							CUT
Anderson, V.G. no.1	1204700912	2745.0 to 2750.0'	Parkrsby	CYP	X							CUT
" "	" "	2750.0 to 2760.0'	" "	" "	X							"
" "	" "	2760.0 to 2765.0'	" "	" "	X							"
" "	" "	2768.0 to 2825.0'	" "	" "	X							"
" "	" "	2820.0 to 2830.0'	" "	" "	X							"
" "	" "	2860.0 to 2880.0'	" "	" "	X							"
" "	" "	2895.0 to 2905.0'	" "	" "	X							"
Clodfelter, B. et al no.1	1204701974	2620.0 to 2625.0'	Parkrsby	CYP	X							CUT
" "	" "	2658.0'	" "	" "	X							"
" "	" "	2660.0 to 2717.0'	" "	" "	X							"

Project Data File *continued*

Well name	API no.	Depth (ft)	Field	Form- ation	TS	Bulk	Clay	Other	SEM	Petro no	Engr data	ST
" "	" "	2705.0 to 2740.0'	" "	" "	X							"
" "	" "	2783.0 to 2800.0'	" "	" "	X							"
Kent no.1	1204700038	2810.0 to 2820.0'	Parkrsbg	CYP	X							CUT
" "	" "	2820.0 to 2880.0'	" "	" "	X							"
Koertge, G. P. no.1	1215901247	2810.0 to 2845.0'	Parkrsbg	CYP	X							CUT
" "	" "	2820.0 to 2830.0'	" "	" "	X							"
" "	" "	2845.0 to 2865.0'	" "	" "	X							"
" "	" "	2875.0 to 2880.0'	" "	" "	X							"
" "	" "	2880.0 to 2910.0'	" "	" "	X							"
Capan no.1	1215923926	2800.0 to 2820.0'	Parkrsbg	CYP	X							CUT
" "	" "	2820.0 to 2825.0'	" "	" "	X							"
" "	" "	2845.0 to 2890.0'	" "	" "	X							"
" "	" "	2900.0 to 2910.0'	" "	" "	X							"
Koertge, H. no.MI-1	1215900044	2765.0 to 2913.0'	Parkrsbg	CYP	X							CUT
" "	" "	2858.0 to 2859.0'	" "	" "	X	X	X	c		3334A		DCB
" "	" "	2859.0 to 2860.0'	" "	" "	X							"
" "	" "	2863.0 to 2864.0'	" "	" "	X	X	X	c		3334B		"
Rothrock, C. L. no.1	1204700028	2856.0'	Parkrsbg	CYP	X							DCB
" "	" "	2857.0'	" "	" "	X							"
" "	" "	2859.0'	" "	" "	X							"
" "	" "	2862.0'	" "	" "	X	X	X	c		3335		"
Brake, C. C. no.2	1204701345	2885.0 to 2890.0'	Parkrsbg	CYP	X							CUT
Ridgeley, Tim et al no.1	1215924532	2860.0 to 2875.0'	Parkrsbg	CYP	X							CUT
" "	" "	2880.0 to 2885.0'	" "	" "	X							"
" "	" "	2885.0 to 2995.0'	" "	" "	X							"
Hundley, J. no.3	1215901270	2790.0 to 2800.0'	Parkrsbg	CYP	X							CUT

Project Data File continued

Well name	API no.	Depth (ft)	Field	Form- ation	TS	Shale	Clay	Other	SRK	Petro no.	Engt data	ST
Clodfelter, C.												
no. WI-2	1215900051	2645.0 to 2675.0'	Parkrbg	CYP	X							CUT
Ross, Wendell no.1	1215901099	2930.0 to 3040.0'	Parkrbg	CYP	X							CUT
Rosette, K.O. no.1	1204700027	2740.0 to 2833.0'	Parkrbg	CYP	X							CUT
-	-	2870.0 to 2912.0'	-	-	X							-
-	-	2912.0'	-	-								-
-	-	2912.0 to 2930.0'	-	-	X							-
Abnormalty,												
Ploessie no.1	1204701045	2730.0 to 2755.0'	Parkrbg	CYP	X							CUT
Deegee fault no.2												
-	1218901812	1484.5'	Richview	CYP	X	X	X	C		3332A		DCP
-	-	1486.5'	-	-	X							-
-	-	1502.5'	-	-	X							-
-	-	1504.5'	-	-	X	X	X	C		3332B		-
-	-	1505.5'	-	-	X	X	X	C	RCV, 5P; 5/7/93	3332C		-
-	-	1507.5'	-	-	X	X	X	C		3332D		-
-	-	1508.5'	-	-	X							-
-	-	1510.5'	-	-	X	X		C	RCV, 4P; 5/7/93	3332E		-
-	-	1512.5'	-	-	X	X	X	C		3332F		-
Rumro, R. no.5	120503164	3116.5'	SW Dale	AuxVas	X	X	X	C	SMD, 15P; 9/24/91	3330A		DCP
-	-	3118.5'	-	-	X							-
-	-	3121.5'	-	-	X	X	X	C		3330B		-
-	-	3122.5'	-	-	X							-
-	-	3124.5'	-	-	X	X	X	C	SMD, 10P; 9/29/91	3330C		-
-	-	3127.5'	-	-	X							-
-	-	3130.5'	-	-	X	X	X	C		3330D		-
Rumro, R. no.5 cont	-	3132.5'	-	-	X							-
-	-	3134.5'	-	-	X	X	X	C		3330E		-
Droit, Reno no.5-C												
-	120503162	3021.5'	SW Dale	AuxVas	X	X	X	C		3331A		DCP
-	-	3023.5'	-	-	X							-
-	-	3025.5'	-	-	X	X	X	C	SMD, 1P; 9/24/91	3331B		-
-	-	3026.5'	-	-	X							-
-	-	3028.5'	-	-	X	X	X	C		3331C		-
-	-	3030.5'	-	-	X							-
-	-	3033.5'	-	-	X	X	X	C		3331D		-
-	-	3036.5'	-	-	X	X	X	C		3331E		-
-	-	3038.5'	-	-	X							-
-	-	3040.5'	-	-	X	X	X	C		3331F		-
-	-	3042.5'	-	-	X							-
McCreary no.1												
-	1205523456	3189.5'	SW Dale	AuxVas						Ka, %s, %h		DCP
-	-	3190.5'	-	-	X	X	X	C		3344A		-
-	-	3191.5'	-	-	X	X	X	C		3344B		-
-	-	3192.7'	-	-	X	X	X	C		3344C		-
-	-	3194.0'	-	-	X	X	X	C		3344D		-
-	-	3195.7'	-	-	X	X	X	C		3344E		-
-	-	3197.8'	-	-	X	X	X	C		3344F		-

Project Data File continued

Well name	API no.	Depth (ft)	Field	Form- action	TS	Bulk	Clay	Other	SEM	Refract no.	Drift data	ST
MCA; 11P; 2/10/92												
"	"	3188.7'	"	"	"	"	"	"	"	3344G	"	"
"	"	3189.4'	"	"	"	X	X	X	"		"	"
"	"	3200.6'	"	"	"	"	"	"	"	3344H	K, φn, φh, CP	"
"	"	3201.0'	"	"	"	X	X	X	"	3344I	"	"
"	"	3203.3'	"	"	"	X	X	X	"	3344J	"	"
"	"	3205.8'	"	"	"	"	"	"	"	3344J	"	"
"	"	3205.9'	"	"	"	X	X	X	"		"	"
"	"	3207.1'	"	"	"	"	"	"	"	3344K	Kn, φn, φh	"
"	"	3208.4'	"	"	"	X	X	X	"	3344L	"	"
"	"	3209.9'	"	"	"	X	X	X	"	3344M	"	"
"	"	3212.7'	"	"	"	X	X	X	"	3344N	"	"
"	"	3216.7'	"	"	"	X	X	X	"	3344O	"	"
"	"	3219.2'	"	"	"	X	X	X	"	3344P	"	"
King, Perry												
a/c1 no. NM-1	1210107173	1515.0'	Lawrence	CYP	X							DCC
"	"	1519.0'	"	"	"	X						"
"	"	1526.0'	"	"	"	X						"
"	"	1544.0'	"	"	"	X						"
Leighley, W. P.												
no. IV-6	1210107399	1622.4'	Lawrence	CYP	X							DCC
"	"	1635.2'	"	"	"	X						"
Cooper, William no. 8	1210107078	1558.2'	Lawrence	CYP	X							DCC
"	"	1565.8'	"	"	"	X						"
Boone, E. no. NM-13	1210105885	1319.8'	Lawrence	CYP	X							DCC
"	"	1349.1'	"	"	"	X						"
"	"	1358.2'	"	"	"	X						"
"	"	1374.1'	"	"	"	X						"
"	"	1380.7'	"	"	"	X						"
"	"	1392.2'	"	"	"	X						"
Balsall, O. no. NT-2	1210127134	1277.0'	Lawrence	CYP	X							DCC
"	"	1388.1'	"	"	"	X						"
"	"	1416.7'	"	"	"	X						"
"	"	1423.3'	"	"	"	X	X	X	"	3433	"	"
Balsall, O. no. OS-35	1210127623	1287.7'	Lawrence	CYP	X		X	X	"	3436	"	DCC
"	"	1290.7'	"	"	"	X		X	"			"
"	"	1309.3'	"	"	"	X						"
"	"	1317.0'	"	"	"	X						"
"	"	1326.8'	"	"	"	X						"
Boyd, I (NB) no. NT-10	1210128362	1305.9'	Lawrence	CYP	X	X	X	X	"	3437	"	DCC
"	"	1330.0'	"	"	"	X						"
"	"	1353.5'	"	"	"	X						"
Boyd, I (NB) no. NT-11	1210128363	1308.5'	Lawrence	CYP	X		X	X	"	3438	"	DCC
"	"	1311.0'	"	"	"	X						"
"	"	1345.9'	"	"	"	X						"
Boyd, I (NB) no. NT-12	1210128364	1312.0'	Lawrence	CYP	X						Xn	DCC
"	"	1314.5'	"	"	"	X						"
"	"	1329.1'	"	"	"	X						"
"	"	1330.0'	"	"	"						Kn, φn, φh	"
"	"	1334.0'	"	"	"						Kn, φn, φh	"
"	"	1343.9'	"	"	"	X						"

Project Data File continued

Well name	API no.	Depth (ft)	Field	Formation	TS	Bulk	Clay	Ochar	SEN	Petro no.	Engr data	ST
-	-	1344.0'	-	-	-	-	-	-	-	-	Ka	-
-	-	1348.8'	-	-	X	-	-	-	-	-	-	-
-	-	1352.7' L	-	-	-	-	-	-	-	-	K, ϕ s, ϕ h, CF	-
-	-	1352.7' R	-	-	-	-	-	-	-	-	K, ϕ s, ϕ h, CF	-
Boyd, I (BB) no. MI-16	1210128928	1291.6'	Lawrence	CYP	X	X	X	c	-	3439	-	DCC
-	-	1324.0'	-	-	X	-	-	-	LAW; SP; 9/3/92	-	-	-
-	-	1327.0'	-	-	-	-	-	-	-	-	K, ϕ s, ϕ h, CF	-
-	-	1342.3'	-	-	X	-	-	-	-	-	-	-
Boyd, I (BB) no. MI-17	1210128929	1305.3'	Lawrence	CYP	X	X	X	c	-	3440A	-	DCC
-	-	1315.0'	-	-	X	X	X	c	-	3440B	-	-
-	-	1345.0'	-	-	X	-	-	-	-	-	-	-
Structure Tests												
Boyd, I (BB) no. MI-18	1210129103	1302.5'	Lawrence	CYP	X	X	X	c	-	3441	-	DCC
-	-	1329.0'	-	-	X	-	-	-	-	-	-	-
-	-	1355.3'	-	-	X	-	-	-	-	-	-	-
Boyd, I (BB) no. MI-19	1210129104	1309.0'	Lawrence	CYP	-	-	-	-	-	-	ϕ s	DCC
-	-	1312.0'	-	-	X	-	-	-	-	-	-	-
-	-	1314.0'	-	-	-	-	-	-	-	-	ϕ s	-
-	-	1317.0'	-	-	-	-	-	-	-	-	ϕ s	-
-	-	1320.0'	-	-	-	-	-	-	-	-	ϕ s	-
-	-	1321.0'	-	-	-	-	-	-	-	-	ϕ s	-
-	-	1327.5'	-	-	X	-	-	-	-	-	-	-
-	-	1332.1'	-	-	X	-	-	-	-	-	-	-
-	-	1347.9'	-	-	X	X	X	c	-	3442	-	-
-	-	1370.0'	-	-	-	-	-	-	-	-	ϕ s	-
Boyd, I (BB) no. MI-20	1210129105	1313.6'	Lawrence	CYP	X	-	-	-	-	-	-	DCC
-	-	1326.0'	-	-	X	-	-	-	-	-	-	-
-	-	1345.9'	-	-	X	-	-	-	-	-	-	-
Cooper, Geo W. no. 28												
-	-	1343.3'	Lawrence	CYP	X	-	-	-	-	-	-	DCC
-	-	1345.4'	-	-	X	-	-	-	-	-	-	-
-	-	1345.5'	-	-	X	-	-	-	-	-	-	-
-	-	1349.6'	-	-	X	-	-	-	-	-	-	-
-	-	1353.8'	-	-	X	-	-	-	-	-	-	-
-	-	1359.6'	-	-	X	X	X	c	-	3443	-	-
-	-	1360.1'	-	-	-	-	-	-	-	-	ϕ s	-
-	-	1360.8'	-	-	-	-	-	-	-	-	ϕ s	-
-	-	1367.5'	-	-	-	-	-	-	-	-	ϕ s	-
-	-	1370.0'	-	-	-	-	-	-	-	-	ϕ s	-
-	-	1371.1'	-	-	-	-	-	-	-	-	ϕ s	-
-	-	1372.7'	-	-	-	-	-	-	-	-	ϕ s	-
-	-	1373.0'	-	-	X	-	-	-	-	-	ϕ s	-
-	-	1393.0'	-	-	X	-	-	-	-	-	-	-
Baltzell, Olvr no. 33	1210127608	1307.7'	Lawrence	CYP	X	-	-	-	-	-	-	DCC
-	-	1309.0'	-	-	X	-	-	-	-	-	-	-
-	-	1310.5'	-	-	X	-	-	-	-	-	-	-
-	-	1312.1'	-	-	-	-	-	-	-	-	ϕ s	-

Project Data File continued

Well name	API no.	Depth (ft)	Field	Form- ation	TS	Bulk	Clay	Other	SEN	Petro no.	Engr data	ST
-	-	1312.9'	-	-	-	-	-	-	-	-	qs	-
-	-	1316.0'	-	-	X	-	-	-	-	-	-	-
-	-	1316.3'	-	-	-	-	-	-	LAW; 6P; 9/3/92	-	-	-
-	-	1317.0'L	-	-	-	-	-	-	-	-	-	-
-	-	1317.0'S	-	-	-	-	-	-	-	-	-	-
-	-	1319.0'	-	-	-	-	-	-	-	-	-	-
-	-	1321.0'	-	-	-	-	-	-	-	-	-	-
-	-	1337.6'	-	-	X	X	X	c	-	3444	-	-
-	-	1359.6'	-	-	X	-	-	-	-	-	-	-
-	-	1361.0'	-	-	X	-	-	-	-	-	-	-
-	-	1361.1'	-	-	X	-	-	-	-	-	-	-
-	-	1376.0'	-	-	-	-	-	-	-	-	qs	-
Campbell no.1	1202500534	2555.0 to 2575.0'	Xenia E	CYP	X	-	-	-	-	-	-	CUT
Woomer, Ira W. no.1	1202502029	2570.0 to 2585.0'	Xenia E	CYP	X	-	-	-	-	-	-	CUT
-	-	2585.0 to 2665.0'	-	-	X	-	-	-	-	-	-	-
Joplin, Stella no.1	1202501727	2560.0 to 2580.0'	Xenia E	CYP	X	-	-	-	-	-	-	CUT
Shocks-Woomer no.1	1202501454	2535.0 to 2550.0'	Xenia E	CYP	X	-	-	-	-	-	-	CUT
-	-	2560.0 to 2660.0'	-	-	X	-	-	-	-	-	-	-
-	-	2650.0 to 2660.0'	-	-	-	-	-	-	XMB; 5P; 6/4/91	-	-	-
Woomer-Campbell no.1	1202501447	2550.0 to 2570.0'	Xenia E	CYP	X	-	-	-	-	-	-	CUT
Bryan, Schel no.3	1202501315	2545.0 to 2560.0'	Xenia E	CYP	X	-	-	-	-	-	-	-
-	-	27900.0 to 2845.0'	-	-	X	-	-	-	-	-	-	-
Bailey, Edgar no.1	1202501214	2555.0 to 2570.0'	Xenia E	CYP	X	-	-	-	-	-	-	CUT
Songer, Ira no.1	1202500562	2585.0 to 2605.0'	Xenia E	CYP	X	-	-	-	-	-	-	CUT
Remugh, Mary no.1	1202500561	2560.0 to 2580.0'	Xenia E	CYP	X	-	-	-	-	-	-	CUT
Hazz Oak no.3	1219921491	2392.5'	Energy	AndVag	X	X	X	c	-	3396A	-	DCC
-	-	2393.4'	-	-	-	-	-	-	-	-	Ka, qs, qh	-
-	-	2393.5'	-	-	-	-	-	-	ENG; 12P; 2/28/92	-	-	-
-	-	2394.0'	-	-	X	X	X	c	-	3396B	-	-
-	-	2395.5'	-	-	X	X	X	c	-	3396C	-	-
-	-	2396.0'	-	-	X	X	X	c	-	3396D	-	-
-	-	2397.0'U	-	-	X	X	X	c	-	3396E	-	-
-	-	2397.0'L	-	-	X	X	X	c	-	3396F	-	-
-	-	2398.0'	-	-	X	X	X	c	-	3396G	Ka, qs, qh	-
-	-	2399.3'	-	-	-	-	-	-	-	-	Ka, qs, qh	-
-	-	2400.0'	-	-	-	-	-	-	ENG; 10P; 2/17/92	-	-	-
-	-	2402.5'	-	-	X	X	X	c	-	3396H	-	-

Project Data File *continued*

Well name	API no.	Depth (ft)	Field	Form- ation	TS	Bulk	Clay	Other	SEM	Petro no.	Engr data	ST
" "	" "	2403.8'	" "	" "							Ka, ϕ s, ϕ h	"
" "	" "	2405.7'	" "	" "							Ka, ϕ s, ϕ h	"
" "	" "	2405.2'	" "	" "					ENG; 12P; 2/5/92			"
" "	" "	2405.2'	" "	" "					ENG; 14P; 2/7/92			"
" "	" "	2412.0'	" "	" "	X	X	X	c		33951		"
" "	" "	2414.5'	" "	" "	X	X	X	c		3396J		"
" "	" "	2417.8'	" "	" "	X	X	X	c		3396K		"
" "	" "	2419.5'	" "	" "	X	X	X	c		3396L		"
" "	" "	2419.7'	" "	" "	X	X	X	c		3396M		"
" "	" "	2420.0'	" "	" "	X	X	X	c		3396N		"
Wesley Found no.1	1206503090	3202.0 to 3212.0'	SW Dale	AuxVas	X							CUT
Osburn no.1	1206503116	3177.0 to 3184.0'	SW Dale	AuxVas	X	X	X	c		3405A	Ka, ϕ h	DCB
" "	" "	3184.5'	" "	" "	X	X	X	c		3405B		"
" "	" "	3184.5 to 3187.0'	" "	" "	X	X	X	c		3405C		"
Rudolph cr. 11A no.26	1219331131	2926.2'	Storvas	AuxVas	X	X	X	c		3434A		DCB
" "	" "	2930.0'	" "	" "					SCN; 1P; 12/29/92			"
" "	" "	2930.5'	" "	" "	X	X	X	c		3434B		"
" "	" "	2931.0'	" "	" "					SCN; 1P; 12/29/92			"
" "	" "	2937.9'	" "	" "	X	X	X	c		3434C		"
" "	" "	2942.1'	" "	" "	X	X	X	c	SCN; 3P; 12/16/92	3434D		"
" "	" "	2942.6'	" "	" "	X	X	X	c		3434E		"
" "	" "	2945.1'	" "	" "	X	X	X	c		3434F		"
" "	" "	2950.0'	" "	" "	X	X	X	c		3434G		"
" "	" "	2950.1'	" "	" "		X	X	c		3434H		"
" "	" "	2950.6'	" "	" "	X	X	X	c		3434I		"
Garrison, H.S. et al no.2	1219306226	2619.0 to 2620.0'	Storvas	CYP	X	X	X	c	SCN; 2P; 12/16/92	3454C		DCB
McCarty, Emil no.2	1219303173	2954.5'	Storvas	AuxVas	X						Ka, ϕ h	DCP
" "	" "	2966.5'	" "	" "	X	X	X	c		3456	Ka, ϕ h	"
" "	" "	2971.5'	" "	" "	X						Ka, ϕ h	"
McCarty, Emil no.1	1219303359	2969.5'	Storvas	AuxVas	X	X	X	c	SCN; 1P; 12/16/92	3457A	Ka, ϕ h	DCP
" "	" "	2973.5'	" "	" "	X	X	X	c		3457B	Ka, ϕ h	"
" "	" "	2987.5'	" "	" "	X						Ka, ϕ h	"
Wright, L.B., et al no.1	1219302727	2735.0 to 2636.0'	Storvas	CYP	X						Ka, ϕ h	DCP
" "	" "	2737.0 to 2738.0'	" "	" "	X	X	X	c		3458	Ka, ϕ h	"
Sanders, R. A. no.9	1208102628	2163.0'	Boyd	AuxVas							X, ϕ s, ϕ h, CP LCC	
" "	" "	2165.0'	" "	" "							Ka, ϕ h	"
" "	" "	2165.9'	" "	" "								"
" "	" "	2166.0'	" "	" "							Ka, ϕ h	"
" "	" "	2167.0'	" "	" "							Ka, ϕ h	"
" "	" "	2168.0'A	" "	" "							Ka, ϕ h	"
" "	" "	2168.0'B	" "	" "							Ka, ϕ h	"

Project Data File continued

Well name	API no.	Depth (ft)	Field	Form- ation	TS	Bulk	Clay	Other	SEM	Petro no.	Engt data	ST
Sanders, R. no. 9 cont	"	2169.0'	"	"	"						Ka, ph	"
"	"	2170.1'	"	"	"						Ka, ph	"
"	"	2171.8'	"	"	"						Ka, ph	"
"	"	2174.0'	"	"	"						Ka, ph	"
"	"	2176.8'	"	"	"	X						"
"	"	2177.0'	"	"	"						Ka, ph	"
"	"	2180.0'	"	"	"	X						"
"	"	2181.1'	"	"	"	X						"
"	"	2184.3'	"	"	"	X						"
"	"	2184.4'	"	"	"						Ka, ph	"

Outcrop Samples from Engineering Studies

Outcrop name	Location, Qtr, S-T-R	Sample/ft	Formation	TS	Bulk	Clay	Other	SEM	Petro#	Engdata	ST
I-57 roadcuts	NW/4 SW/4 + SW/4 NW/4 31-T13B-R1B; Anna Quadrangle										
Southbound lane-east side		SE2A/ 1.0'	CYP							ph, Ka	UCP
"	"	SE2A/15.0'	"	"						ph, Ka	"
"	"	SE3A/13.0'	"	"						ph, Ka	"
"	"	SE3 / 4.0'	"	"	X					ph, Ka	"
"	"	SE4 / 6.0'	"	"						ph, Ka	"
"	"	SE4 / 2.5'	"	"						ph, Ka	"
"	"	SE4A/ 1.5'	"	"						ph, Ka	"
"	"	SE5 / 3.5'	"	"						ph, Ka	"
"	"	SE5 / 9.0'	"	"	X					ph, Ka	"
"	"	SE5 /15.5'	"	"						ph, Ka	"
"	"	SE5A/ 2.0'	"	"						ph, Ka	"
"	"	SE5A/14.0'	"	"						ph, Ka	"
"	"	SE6 / 4.0'	"	"						ph, Ka	"
"	"	SE6 /16.0'	"	"						ph, Ka	"
"	"	SE6A/14.5'	"	"						ph, Ka	"
"	"	SE7 / 3.5'	"	"						ph, Ka	"
"	"	SE7 /13.0'	"	"						ph, Ka	"
"	"	SE7A/ 3.0'	"	"						ph, Ka	"
"	"	SE7A/ 4.7'	"	"						ph, Ka	"
"	"	SE8 / 2.5'	"	"						ph, Ka	"
"	"	SE8 / 6.5'±	"	"						ph, Ka	"
"	"	SE8 / 6.5'±	"	"						ph, Ka	"
Southbound lane-west side		SW1 / 6.0'	"	"						ph, Ka	UCP
"	"	SW2A/ 3.5'A	"	"						ph, Ka	"
"	"	SW2A/ 3.5'B	"	"						ph, Ka	"
"	"	SW2 /10.5'A	"	"						ph, Ka	"
"	"	SW2 /10.5'B	"	"						ph, Ka	"
"	"	SW2A/ 3.5'	"	"						ph, Ka	"
"	"	SW3 / 6.0'A	"	"						ph, Ka	"
"	"	SW3 / 6.0'B	"	"						ph, Ka	"
"	"	SW3A/ 2.5'	"	"						ph, Ka	"

Project Data File *continued*

Outcrop Samples from Engineering Studies

[illegible]

Project Data File continued

Outcrop Samples from Engineering Studies

[illegible]

Output to Subsurface Studies

Outcrop name	Location, Qtr, S-T-R	Sample/ft	Formation	TS	Bulk Clay	Other	SEN	Petro#	Engdata	ST
I-57 roadcuts	NW/4 SW/4 + SW/4 NW/4, 11-T15-R1E; Anna Quadrangle									
Northbound lane	" "	CY57-1	CYP	X						OC
" " "	" "	CY57-2	" "	X						"
Southbound lane	" "	CY57-3	CTP	X						OC
" " "	" "	CY57-4	" "	X						"
Golconda; Ohio	NE/4 SE/4 NW/4, 30-T138-R7E, Riv bluff									
" " "	Golconda Quadrangle	GOCY-1	CYP	X						OC
" " "	" "	CY90-04	Hidenhower	X						"
Golconda South; Ohio Riv bluff	NW/4 NE/4 NW/4, 11-T138-R7E, Golconda Quadrangle	SGOCY-2	CTP	X						OC
Repars Landing; Ohio Riv bluff	SE/4 NE/4 NE/4, 14-T145-R6E NW/4 NW/4 NW/4, 13-T145-R6E; Brownfield Quadrangle	CYRL-1	CTP	X						OC
" " "	" "	CYRL-2	" "	X						"
" " "	" "	RLCY-1	" "	X						"
" " "	" "	RLCY-2	" "	X						"
" " "	" "	RLCY-3	" "	X						"
" " "	" "	CYRL-4	" "	X						"
" " "	" "	CYRL-5	" "	X						"
" " "	" "	CYRL-6	" "	X						"
Bay City, roadcut in bluff	SW/4 NW/4 NE/4, 1-T155-R6E, Smithland Quad	CYBC-1	CYP	X						OC
" " "	" "	CYBC-2	" "	X						"
Dog Creek Section, near Bay City	SW/4 SW/4 SW/4, 8-T155-R7E Smithland Quad	CTDC-1	CTP	X						OC
Rainking Hill, Ill Cent RR cut	SE/4 SE/4 NE/4, 23-T145-R4E, Reevesville Quad	CYR23-1	CYP	X						OC
" " "	" "	CYR23-2	" "	X						"
Cagle bluff, facing SE	SE/4 NW/4 SE/4, 10-T145-R4E, Hermat Quad	CYCB-1	CYP	X						OC
" " "	" "	CYCB-2	" "	X						"

Project Data File *continued*

Outcrop to Subsurface Studies

Outcrop name	Location, Qtr, S-T-R	Sample/ft	Formation	TS	Bulk Clay	Other	SEM	Petrol	Engdata	ST
Roadcut along I-24	NE/4 NE/4 SW/4, 10-T14S-R4E, Herkert Quad	CY24-2	CYP	X						OC
" " "	" " "	CY24-3	" "	X						"
" " "	" " "	CY24-4	" "	X						"
" " "	" " "	CY24-5A	" "	X						"
" " "	" " "	CY24-6	" "	X						"
" " "	" " "	CY24-7	" "	X						"
New Columbia bluff	W/2 SE/4 NW/4, 15-T14S-R4E, roadcut west of New Columbia Rd	CY24B-TOP	CYP	X						OC
" " "	" " "	CY24C-1	" "	X						"
" " "	" " "	CY24C-2	" "	X						"
" " "	" " "	CY24C-3	" "	X						"
" " "	" " "	CY24C-4	" "	X						"
" " "	" " "	CY24C-5	" "	X						"
Travis Farm, west-	NE/4 SW/4 SE/4, 7-T14S-R4E, trading ravine, measured sect 2	CY24F-1	CYP	X						OC
" " "	" " "	CY24F-2	" "	X						"
Bunkerin' Ditch	E/2 SE/4 NE/4, 1-T14S-R3W, natural exp & ditch cuts north side county rd	CY24D-1	CYP	X						OC
" " "	" " "	CY24D-3	" "	X						"
Indian Point, RR cut		S/2 SE/4, 32-T13S-R3E and and S-facing bluff	S/2 SW/4, 33-T13S-R3E,		CY24F-1	CYP	X			OC
" " "	Raznak Quad									
" " "	" " "	CY24F-5	" "	X						"
" " "	" " "	CY24F-6B	" "	X						"
Bethany Chrch. meas-	W/2 SE/4 NE/4, 24-T13S-R1E,				CY24B-2	CYP	X			OC
ured sections	Cypress Quad									
along SW-facing bluff										
" " "	" " "	CY24B-3	" "	X						"
" " "	" " "	CY24B-4	" "	X						"
" " "	" " "	CY24B-5	" "	X						"
" " "	" " "	CY24B-6	" "	X						"
Measured sect near	SW/4 NW/4 NE/4, 20-T13S-R2E, Cypress, Ill	CY24C-1	CYP	X						OC
" " "	Cypress Quad									
Measured sect near	W/2 NE/4 NE/4, 20-T13S-R2E, Cypress, Ill	CY24C-2	CYP	X						OC
" " "	Cypress Quad									
Cypress Creek bluffs		E/2 SW/4, 30-T12S-R1E,			CY24S7-1	CYP	X			OC
east of I-57	Anna Quadrangle									
" " "	" " "	CY24S7-2	" "	X						"
Seminary Fork River	NW/4 SE/4 SE/4, 16-T11S-R2W, bluffs	CY24S7-1	CYP	X						OC
" " "	Cobden Quadrangle									
Measured sect at	NW/4 NE/4 NW/4, 33-T13S-R2E, Turner's Bluff	CY24B-1	CYP	X						OC
" " "	SW/4 SE/4 SW/4, 28-T13S-R2E, Karnak Quadrangle									
Cypress sections	SW/4 NW/4 SW/4, 9-T12S-R1N, N of Anna, Ill	CY24A1	CYP	X						OC
" " "	Anna Quadrangle									
" " "	" " "	CY24A2	" "	X						"

APPENDIX XIV-A. POROSITY AND PERMEABILITY

AUX VASES SANDSTONE

Depth	K (md)	ϕ (%)	Depth	K (md)	ϕ (%)
ZEIGLER FIELD, Mack no.1			ZEIGLER FIELD, Mack no.2 <i>continued</i>		
2613	2.4	19.0	2614.5	35.6	23.6
2614	15.5	20.7	2615.5	66.0	24.8
2615	9.7	19.6	2616.5	41.7	23.3
2616	12.7	22.4	2617.5	89.5	24.5
2617	10.2	21.0	2618.5	47.8	24.8
2618	385	27.2	2619.5	68.6	23.8
2619	277	19.4	2620.5	47.8	23.5
2620	279	24.0	2621.5	56.0	23.8
2621	131	23.8	2622.5	15.5	22.6
2622	213	22.3	2624.5	1.0	15.5
2623	517	25.3	ZEIGLER FIELD, Mack no.6		
2624	638	26.3	2615.5	7.1	17.8
2625	517	25.9	2616.5	14.7	17.2
2627	750	25.3	2617.5	35.6	18.7
2628	750	25.7	2618.5	15.5	18.9
2629	750	26.4	2619.5	7.6	17.8
2630	584	25.7	2620.5	20.6	20.5
2631	178	22.1	2621.5	1.4	18.9
2632	62.2	21.9	2622.5	37.6	20.6
2632.*	1.08	16.0	2623.3	56.0	19.9
2633	11.9	20.4	2624.5	10.9	19.5
2634	10.2	17.7	2625.5	8.3	19.3
2636	1.1	16.4	2626.5	10.2	18.7
ZEIGLER FIELD, Mack no.2			2627.5	2.7	15.8
2606.4V*	91.0	23.5	2628.5	2.4	17.0
2606.5*	182.4	24.3	2629.5	1.6	16.7
2606.5*	6.34	8.9	ENERGY FIELD, Burr Oak no.3		
2606.8*	142.2	23.4	2393.4*	16.8	18.7
2608.5*	46.3	21.6	2398.0*	307	24.2
2608.8*	46.3	22.1	2399.3*	131	24.2
2609.2*	67.3	22.3	2403.8*	129	20.7
2610.0*	31.9	23.1	2405.7*	63.6	23.1
2610.5*	142.0	27.5	2392.5	20.0	21.3
2611.*	114.0	25.5	2393.5	18.0	18.9
2611.*	112.0	26.6	2394.5	1.3	15.1
2611.5*	95.5	21.3	2395.5	0.0	6.4
2612.5*	74.0	21.4	2396.5	0.0	7.8
2615.0*	26.9	21.6	2397.5	40	14.4
2605.5	24.9	14.4	2398.5	257	23.9
2606.5	216	25.1	2399.5	168	19.2
2607.5	244	26.3	2400.5	85	22.7
2608.5	49.5	22.1	2401.5	108	22.3
2609.5	58.0	23.1	2402.5	60	21.6
2610.5	64.0	22.1	2403.5	67	23.2
2611.5	124.0	24.1	2404.5	149	22.3
2612.5	152.0	25.5	2405.5	108	22.1
2613.5	178.0	26.1			

Depth	K (md)	ϕ (%)
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ENERGY FIELD, Burr oak no.3 *continued*

2406.5	49	23.9
2407.5	67	23.7
2408.5	97	22.8
2409.5	82	24.1
2410.5	19	23.0
2411.5	38	21.7
2412.5	56	22.0
2413.5	49	21.3
2414.5	35	20.1
2415.5	48	21.0
2416.5	25	19.5
2417.5	26	22.1

ENERGY FIELD, Morgan Coal no.2

2387.5	184	21.3
2388.0*	249	20.9
2388.1*	388	21.9
2388.3*	156	22.2
2388.3*	154	19.2
2388.4*	187	19.0
2388.4*	206	20.1
2388.5	246	21.7
2389.0*	130	21.7
2389.0*	88.5	19.9
2389.2*	142	17.7
2389.5	161	23.2
2390.0*	79.3	18.8
2390.0*	194	21.2
2390.5	69	23.6
2391.5	92	21.1
2391.9*	82.7	22.1
2392.0*	215	23.0
2392.1*	170	23.5
2392.1*	220	20.9
2392.5	85	23.3
2392.8*	100	22.1
2392.9*	307	20.0
2392.9*	205	22.4
2393.0*	53	20.4
2393.0*	143	22.5
2393.5	88	22.3
2394.5	69	20.6
2395.5	4.3	13.6

ENERGY FIELD, Eigenrauch-Armstrong no.1

2350.5	223	20.2
2351.5	431	23.7
2352.5	350	22.5
2353.5	380	21.2
2354.5	350	22.3

Depth	K (md)	ϕ (%)
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ENERGY FIELD, Eigenrauch-Armstrong no.1
continued

2355.5	210	22.7
2356.5	75	21.0
2357.5	135	20.0
2358.5	187	19.9

STORMS FIELD, McCarty, E. no.1

2969.5	78.9	18.9
2973.5	9.5	13.5
2987.5	0.6	14.5

STORMS FIELD, Wright L.B. et al. no.1

2735.4	10	16.3
2737.4	36	16.4

STORMS FIELD, N.H. McQueen no.1

2912.5	0.0	15.1
2913.5	4.5	15.5
2914.5	2.9	17.0
2915.5	2.9	24.8
2916.5	4.6	21.7

STORMS FIELD, McCarty, E. no.2

2954.5	172	19.4
2966.5	33.7	18.0
2971.5	0.3	11.1

STORMS FIELD, Peterson, V. no.1

2928.5	0	4.1
2943.5	57	13.7
2948.5	3.8	13.1

SOUTHWEST DALE CONSOLIDATED,
McCreery no.1

3204.7	19.4	17.5
3200.6	195.1	24.6
3205.9	29.6	15.3
3189.8	112.0	25.0
3198.7	89.5	22.9
3189.9	133.1	21.6
3194.9	135.7	23.3
3205.8	8.4	18.2
3196.5	35.5	22.7
3196.4	31.9	21.6
3196.7	43.3	22.8
3189.8	112	25.0
3204.7	10.1	17.5
3205.9	18.6	15.3

Depth	K (md)	ϕ (%)
SOUTHWEST DALE CONSOLIDATED, R. Hunro no.5		
3115.5	110	23.4
3116.5	370	23.1
3117.5	61	19.3
3118.5	62	23.3
3119.5	71	19.4
3120.5	104	25.0
3121.5	263	22.4
3122.5	319	26.1
3123.5	71	21.2
3124.5	80	21.1
3125.5	77	21.9
3126.5	258	18.8
3127.5	218	23.3
3128.5	258	23
3129.5	98	23
3130.5	258	23.3
3131.5	104	21.8
3132.5	129	23.1
3133.5	98	22.4
3134.5	129	21.2
3135.5	39	13.7
3136.5	37	19.3

OAKDALE FIELD, Breeze no.1

2870.5	68.6	19.6
2871.5	517	24.5
2872.5	330	22.4
2873.5	157	20.2
2874.5	455	24.0
2875.5	180	21.7
2876.5	62.2	20.5
2877.5	162	24.0
2878.5	208	23.3
2879.5	15.5	21.4
2880.5	292	25.1
2881.5	71	20.5
2882.5	73.6	22.9
2883.5	20.6	15.6
2884.5	155	23.9
2885.5	167	23.9
2886.5	64.0	21.9
2887.5	96.5	22.2
2888.5	584	26.3
2889.5	109	23.5
2890.5	455	25.9
2885.0*	138	23.1
2890.0*	400	23.7
2891.0*	378	26.8

Depth	K (md)	ϕ (%)
OAKDALE FIELD, Novak no. 4		
2869.5	56	20.1
2870.5	212	20.9
2871.5	9.3	20.8
2872.5	40	20.5
2873.5	11	20.3
2874.5	43	21.5
2875.5	37	22.5
2876.5	57	20.8
2877.5	46	23.4
2878.5	7.3	20.4
2879.5	29	21.9
2880.5	3.2	22.3
2881.5	34	20.9
2882.5	14	23.2
2883.5	1.5	14.3
2884.5	11	16.7
2885.5	51	21.1
2886.5	0.39	19.1
2887.5	32	20.3
2888.5	30	17.7
2889.5	0.88	13.7
2890.5	0	11.2

OAKDALE FIELD, Horrel, B.E. no. 3

2902.5	766	15.9
2903.5	788	14.9
2912.5	850	24.3
2913.5	427	22.6
2914.5	293	22.4
2915.5	487	24.5
2916.5	569	21.9
2917.5	521	23.7
2918.5	546	25.2
2919.5	341	23.7
2920.5	104	19.9
2921.5	17	13.0
2922.5	0.17	12.9
2923.5	5.1	17.1
2924.5	10	17.1
2925.5	0.2	9.6
2926.5	0	7.1

BOYD FIELD, Sanders no. 9

2165*	221	19.8
2166*	353	24.4
2167*	149	23.0
2168*	28.9	23.2
2168*	172	23.5
2169*	22.8	22.8
2170*	341	23.7

Depth	K (md)	ϕ (%)
BOYD FIELD, Sanders no.9 <i>continued</i>		
2172*	176	24.1
2174*	166	22.5
2177*	2.6	14.2
2184*	9.3	13.8
BOYD FIELD, Payne H. no.1		
2154	55.5	18.1
	0	15.1
	0	11.2
	105.0	14.6
	115.0	18.6
	0	11.4
	103.0	14.8
	33.0	13.2
	270.0	17.9
2165	76.7	16.6
BOYD FIELD, Payne H. no.2		
2149	0	15.7
	21.3	17.8
	63.0	21.0
	92.0	17.5
	0	11.8
2165	48.5	16.5
BOYD FIELD, Sanders no. 3		
2161	222.0	18.2
	145.0	18.1
	39.0	16.6
	115.0	16.6
	1.0	14.2
	0	12.8
	0	13.9
	39.0	16.1
2171	66.0	20.2
BOYD FIELD, Sanders no. 4		
2155	1.3	15.0
	100.0	15.3
	0	7.9
	115.0	18.5
	112.0	18.2
	80.0	17.6
2162		0 5.7
BOYD FIELD, Dawson HF no. 1		
2160	142.0	18.9
	0	12.1
2167	0	7.2

Depth	K (md)	ϕ (%)
BOYD FIELD, Friedrich no. 8		
2140	3.7	13.0
	0	3.5
	10.7	13.4
	58.4	17.4
	486.0	23.3
	77.8	20.6
	13.0	15.3
	17.4	18.7
	24.5	15.9
	10.3	18.2
	0	10.8
	10.8	17.2
2166	0	15.8
BOYD FIELD, Friedrich no. 9		
2145	9.5	18.4
	6.7	15.7
	55.0	19.5
	134.0	20.9
	158.0	21.1
	409.0	19.6
	102.0	20.1
	58.0	17.0
	130.0	18.4
	197.0	20.6
2165	92.0	19.9
BOYD FIELD, Friedrich no. 12		
2129	0	11.9
	0	12.4
	3.2	13.4
	9.0	13.9
	3.2	15.0
	0	8.8
	6.4	16.2
	8.0	15.3
2164	157.0	19.2
BOYD FIELD, Schallert C no.1		
2160	145.0	22.2
	396.0	24.8
	95.8	21.0
	408.0	23.0
	266.0	21.5
	83.0	21.2
	41.5	19.3
	0	9.9
	15.7	15.6
	112.0	18.0
	120.0	17.6

Depth	K (md)	ϕ (%)
BOYD FIELD, Schallert C no.1 <i>continued</i>		
	303.0	19.0
	17.0	14.9
	0	14.2
	1.6	15.1
	19.8	15.8
	13.3	14.3
	0	13.7
	8.3	18.5
	46.4	21.6
	60.5	17.3
	9.8	15.4
	126.5	21.6
	28.0	14.5
	7.8	16.3
	0	19.7
	26.0	17.0
	6.8	16.0
	35.0	17.0
	33.0	17.3
2200	2.0	15.6

BOYD FIELD, Schallert C no.2		
2140	5.7	18.2
	7.2	14.7
	0	16.7
	130.0	21.4
	95.8	24.8
	785.0	32.0
	510.0	29.1
	116.0	19.5
	387.0	22.7
	358.0	24.1
	448.0	25.4
	313.0	24.2
	345.0	24.2
	368.0	23.4
	324.0	23.7
	103.0	20.2
	324.0	23.9
	120.0	22.5
	12.0	18.4
	0	12.4
	6.9	18.6
2165	100.0	24.0

BOYD FIELD, Schallert C no.3		
2148	0	17.7
	21.5	20.6
	6.3	16.5
2163	0	13.7

Depth	K (md)	ϕ (%)
BOYD FIELD, Fannon MJ no.1		
2134	0	6.4
	0	6.5
	10.2	16.4
	0	16.1
	52.2	19.9
	113.0	22.0
	101.5	21.8
2149	170.0	23.7

BOYD FIELD, Fannon MJ no. 2		
2114	6.0	16.3
	3.0	16.4
	0	8.1
	0	9.8
	149.0	24.4
	106.0	22.0
	70.0	22.4
	92.0	22.8
	0	6.5
	325.0	22.9
	140.0	31.0
	600.0	28.6
	868.0	23.0
	600.0	25.3
	723.0	27.0
	812.0	27.6
2149	885.0	25.6

BOYD FIELD, Fannon MJ no. 3		
2123.5	0	14.5
2124.5	0	13.5
2125.5	10.0	14.8
2126.5	10.0	16.7
2128.5	0	5.8
2129.5	2.2	11.3
2138.5	647.0	27.3
2139.5	700.0	30.1
2140.5	555.0	28.5
2141.5	845.0	30.9
2142.5	1220.0	32.3
2143.5	905.0	28.6
2144.5	605.5	29.7
2145.3	1190.0	31.3

BOYD FIELD, Friedrich CH no.4		
2123	4.30	14.3
	51.0	15.8
	71.5	19.0
	37.0	13.2
	24.5	16.0

Depth	K (md)	ϕ (%)
BOYD FIELD, Friedrich CH no.4 <i>continued</i>		
	4.0	17.2
	17.0	17.0
	0	15.4
	0	16.5
	24.0	16.1
	22.2	18.3
	122.0	16.7
	98.0	16.5
	185.0	18.6
	345.0	17.3
	0	12.2
2157	0	12.7
BOYD FIELD, Friedrich CH no. 5		
2131	1.6	14.2
	0	12.1
	7.2	14.4
	21.3	16.1
	27.5	14.7
	73.0	16.9
2150	13.0	14.4
BOYD FIELD, Friedrich C no.6		
2135.5	38.0	15.8
2136.5	67.0	17.5
2137.5	112.0	16.5
2138.5	26.0	16.7
2139.5	11.4	11.4
2146.5	1.3	15.8
2147.5	1.8	16.4
2148.5	0	16.1
2149.5	5.0	15.4
2150.5	6.9	15.1
2151.5	0	9.1
2158.5	75.0	17.8
2160.5	20.0	19.6
2161.5	22.0	20.9
2162.5	81.0	22.8
2163.5	49.0	21.3
2164.5	149.0	23.1
2165.5	53.0	22.6
2166.5	37.0	20.2
2167.5	70.0	21.3
2168.5	68.0	18.3
2169.5	19.0	18.6
2170.5	5.7	18.3
2171.5	3.6	17.3

Depth	K (md)	ϕ (%)
BOYD FIELD, Friedrich CH no.7		
2140	10.8	15.1
0	11.8	
95.7	16.7	
82.8	20.4	
2155	153.0	16.8
BOYD FIELD, Friedrich CH no.10		
2137	0	9.4
	3.2	11.1
	0	10.0
	5.7	14.2
	138.0	24.0
	240.0	26.6
	358.0	27.5
	314.0	26.8
	92.0	13.1
	664.0	24.0
BOYD FIELD, Friedrich CH no.14		
2130	10.8	12.4
	0	14.2
2141	0.5	16.3
BOYD FIELD, Friedrich CH no.15		
2134	0	10.3
	0	9.6
	14.3	13.8
	66.0	13.8
	39.0	13.5
	5.0	13.9
	39.0	20.4
	3.2	23.6
	0	7.4
	0	7.4
	0	12.4
	0	6.8
	4.3	16.5
	24.5	17.8
	0	14.6
	0	7.4
	0	16.8
	0	10.5
	7.2	18.5
	0	19.6
	0	17.8
	23.0	18.6
	0	14.8
	10.8	19.6
	9.0	19.6
2174	0	18.9

Depth	K (md)	ϕ (%)
BOYD FIELD, Friedrich CH no.17		
2131	46.0	14.1
	55.5	14.8
	100.0	16.1
	33.0	17.7
	0	16.2
	0	12.1
	0	18.7
2146	0	5.2
BOYD FIELD, Friedrich CH no.18		
2129	5.7	14.8
	0	3.6
	21.3	18.5
	0	16.0
	0	10.0
	0	6.5
	0	6.1
	0	11.8
	0	5.8
	1.6	15.6
2143	58.0	17.0
BOYD FIELD, Garren no. 1		
2136.5	7.9	14.5
2137.5	0	9.6
2138.5	0	8.1
2139.5	0	9.4
2140.5	74.0	17.3
2141.5	204.0	19.1
2142.5	4.0	13.8
2143.5	387.0	20.3
2144.5	13.0	17.3
2145.5	40.0	18.3
2146.5	19.0	18.0
2147.5	16.0	17.8
2148.5	26.0	19.6
2149.5	48.0	17.1
2150.5	21.0	16.2
2151.5	102.0	17.0
2152.5	0	8.0
2155.5	0	13.8
2156.5	8.2	16.0
2157.5	83.0	15.3
2158.5	10.0	12.7
2159.5	71.0	18.3
2160.5	37.0	19.7
2161.5	23.0	17.1
2162.5	21.0	15.3
2163.5	4.0	15.4
2164.5	22.0	16.8

Depth	K (md)	ϕ (%)
BOYD FIELD, Garren no.1		
2165.5	2.1	10.9
2166.5	4.8	13.7
2190.5	42.0	15.8
2191.3	98.0	16.0
2191.8	109.0	15.8
2192.5	126.0	16.0
2193.5	88.0	17.1
2194.5	45.0	10.0
2195.5	45.0	19.0
2196.5	13.0	14.0
2197.5	3.3	14.8
BOYD FIELD, High F et al. no.5		
2134	71.5	15.6
	24.5	10.3
	27.5	12.2
	5.7	8.1
	0	6.2
	0	14.9
	0	4.7
	3.5	14.6
	55.5	15.6
	0	7.1
	105.0	21.4
	83.0	20.2
	134.0	20.8
	108.0	21.6
2149	132.0	21.0
BOYD FIELD, High F et al. no.6		
2127	53.0	15.4
	49.0	16.3
	19.7	14.2
	12.6	12.0
	36.0	16.0
2144	232.0	15.2
BOYD FIELD, Pasco Price no.5		
2120	0	12.6
	0	6.0
	0	12.5
	0	10.2
	0	13.4
	0	13.6
	0	15.1
	683.0	27.8
2139	880.0	31.2

Depth	K (md)	ϕ (%)
BOYD FIELD, Sanders R et al. no.1		
2124	0	12.1
	4.3	13.6
	0	15.8
	8.0	15.5
2144	0	13.2
BOYD FIELD, Sanders R et al. no.2		
2144	37.0	18.5
	320.0	24.6
	290.0	25.1
	498.0	25.5
	740.0	24.9
	682.0	21.4
	89.0	11.0
	142.0	21.6
	0	7.9
	92.0	17.2
	351.0	18.3
	105.0	17.6
	250.0	18.4
	332.0	17.7
	163.0	15.5
2162	0	12.6
BOYD FIELD, Sanders R et al. no.7		
2141	42.0	21.6
	9.0	18.9
	444.5	26.6
	362.0	24.2
	198.0	21.6
	153.0	20.2
	417.0	27.8
	377.0	24.4
	340.0	17.5
	163.0	23.8
	140.0	21.5
	118.5	20.4
	156.5	22.6
	143.5	22.7
	58.0	19.5
	60.5	17.8
	0	12.3
	43.5	17.0
2161	63.0	17.7
BOYD FIELD, Wittenbrink E no.1		
2147	17.7	12.5
	104.5	14.4
	86.2	19.0
	0	15.1

Depth	K (md)	ϕ (%)
BOYD FIELD, Wittenbrink E no.1 <i>continued</i>		
	0	16.6
	39.2	20.4
2167	90.3	17.3
BOYD FIELD, Wittenbrink E no.2		
2154	55.5	13.8
2159	35.0	15.4
BOYD FIELD, Pasco Price no.1		
2128.5	0	7.3
	21.0	15.5
	22.0	17.5
	1.7	17.7
	2.5	17.5
	118.0	15.1
	81.0	11.4
	0	7.0
	3.7	17.0
	28.0	17.1
	6.3	14.9
	30.0	16.4
	26.0	14.0
2146.5	0	13.7

CYPRESS SANDSTONE

RICHVIEW, Droege Unit no.2		
1483.5	1.3	12.1
1484.5	47	12.4
1485.5	35	14.0
1486.5	4.4	15.9
1501.5	0	5.2
1502.5	0	7.5
1503.5	199	15.4
1504.5	737	22.5
1505.5	264	21.9
1506.5	304	22.3
1507.5	752	22.1
1508.5	280	18.3
1509.5	484	23.8
1510.5	510	22.5
1511.5	36	19.2
1512.5	31	18.7
1513.5	177	19.8
RICHVIEW, Grotti no.1		
1526.5	28	23.5
1528.5	11	19.7

Depth	K (md)	ϕ (%)
TAMAROA, Bagwell no. 1		
1164.5	129	17.7
TAMAROA, Malinski no.1		
1148.5	244	17.6
1149.5	10.7	15.7
1151.5	178	18.2
1152.5	35.9	16.4
1153.5	170	17.1
TAMAROA, Stockton-Gosper no.1		
1153.5	88	17.7
1154.5	167	17.9
1155.5	178	21.5
1156.5	173	20.9
1157.5	183	20.1
1158.5	123	22.1
1159.5	121	20.3
1160.5	138	20.7
1161.5	132	20.2
1162.5	113	20.4
1163.5	3.6	15.8
1164.5	132	22.7
1165.5	156	19.3
1166.5	128	17.7
MATTOON, Harris F no. 2		
1764	22.7	10.5
1767	0	11.0
1768	12.6	15.4
1769	19.1	17.2
1770	19.1	16.5
1771	14.9	16.4
1772	17.3	18.2
1773	18.2	17.7
1774	15.4	18.0
MATTOON, Rick ND no. 2		
1820	99	16.8
1822	20.3	17.1
1824	38.1	18.3
1826	30.3	16.9
1828	32.5	16.4
1830	11.3	14.1
1832	1.5	18.4
1835	0	15.4
MATTOON, Uphoff R no.6		
1808	4.2	19.7
1809	22.3	19.9
1810	11.6	20.4

Depth	K (md)	ϕ (%)
MATTOON, Uphoff R no.6 <i>continued</i>		
1811	36.2	20.9
1812	24.3	13.5
1813	49.3	18.7
1814	11.1	16.2
1815	19.3	19.1
1816	4.4	16.2
1830	23.0	20.2
1831	3.7	19.4
1832	13.6	21.7
1833*	1.3	13.0
1833	1.6	19.4
1834	12.4	18.0
1835	4.73	18.2
1836	2.36	18.9
MATTOON, Osborne EB no. 1		
1759.5	86	16.5
1760.5	43	20.1
1761.5	98	20.2
1762.5	71	20.2
1763.5	110	20.0
1764.5	114	16.6
1765.5	83	14.7
1766.5	73	19.9
1767.5	57	21.3
1768.5	45	20.2
1769.5	1.5	15.5
1802.5	10	17.5
1803.5	213	15.9
MATTOON, Osborne EB no. 3		
1729.5	11	18.3
1730.5	18	18.8
1731.5	67	17.9
1732.5	85	19.2
1733.5	34	19.7
1734.5	26	18.6
1735.5	20	20.1
1736.5	21	12.7
MATTOON, Mattoon no.3		
1752	13.5	11.1
MATTOON, Mattoon no. 7		
1704	0.2	2.9
1706	51.3	15
1707	5.7	14.9
1708	0.2	12.4
1733	1.1	17
1734	0.8	13.6

Depth	K (md)	ϕ (%)
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MATTOON, Mattoon no.7 *continued*

1735	4.6	14.2
1736	0.9	17.2
1737	0.5	16.3
1751	6.5	17.6
1752	15.6	16.3
1753	94.4	17.9
1754	15.4	17.1
1755	28.6	15.9
1756	25.5	14.4
1759	1.5	18.7
1760	10.5	20.8
1762	58.6	20.7
1763	98.6	21.5
1764	23.0	20.2
1765	66.2	20.7
1766	90.6	21.5
1767	68.3	20.1
1768	21.5	16.9
1769	80.3	20.8
1770	100	21
1771	109	19
1772	140.7	18.4

MATTOON, Tinsley B no.1

1755.5	4.1	17.6
1756.5	3	19.2
1783.5	1	11.1

MATTOON, Tinsley AB no.2

1767.5	0.2	11.3
1768.5	1	9.6
1769.5	5.5	12.9
1770.5	14	16.3

MATTOON, Tinsley AB no. 3

1732.5	1.5	11.5
1733.5	6.8	19.2

MATTOON, Tinsley B no. 4

1750.5	0.3	16.8
1752.3	0	6.8
1769.5	2.3	11.2
1773.5	0	9.0
1774.5	2.1	7.0
1775.5	8.3	9.4

MATTOON, Craig EC no.2

1718	37	21.1
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Depth	K (md)	ϕ (%)
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MATTOON, Craig EC no.7

1777.5	47	21.2
1778.5	89	20.0
1779.5	28	18.6
1780.5	126	17.4
1781.5	132	19.8
1782.5	125	19.1
1783.5	93	18.5
1784.5	74	19.8
1785.5	111	19.1

MATTOON, Carmine AG no.1

1718.5	101	16.3
1719.5	8	15.6
1720.5	50	16.0
1721.5	86	15.6
1723.5	87	15.1
1724.5	21	11.0
1725.5	3.3	8.0
1744.5	61	13.1
1745.5	131	19.1
1749.0	83	21.6
1753.5	312	18.2
1754*	119	16.4
1754.5	88	17.3

MATTOON, Lowe HF no.1

1721	0	17.8
1722	89	19.5
1723	5.8	21.9
1724	0	19.4
1725	47	18.8

MATTOON, Jefferies E no.3

1753.5	15	17.2
1755	14	17.6
1756	67	17.2
1757	53	16.9
1758	110	17.8
1759	35	17.8
1760	28	18.3
1761	15	15.3
1762	3.7	18.1
1763	70	18.4
1764	15	17.0
1765	51	17.6
1766	36	17.0
1767	14	17.8
1768	7.2	17.6
1769	10	18.8
1770	30	17.6

Depth	K (md)	ϕ (%)
MATTOON, Jefferies E no.3 <i>continued</i>		
1771	7.5	17.6
1771.5	7.2	18.4
MATTOON, Tynan E. no.1		
1776.5	99	19.6
1777.5	142	21.9
*1778h	67.8	17.3
*1778v	71.6	20.3
1778.5	74	21.2
1779.5	147	21.2
1780.5	62	22.2
1781.5	132	24.3
1782.5	71	22.6
1783.5	34	21.5
1784.5	140	21.5
1785.5	154	22.5
1786.5	100	23.1
1787.5	87	21.0
1788.5	84	21.9
1789.5	61	23.0
1790.5	75	19.5
1791.5	155	23.4
1792.5	118	24.1
1793.5	58	20.5
1799.5	0	19.2
1800.5	0	16.7
*1801	4.9	14.3
1801.5	0	16.4
1802.5	0	17.3
1803.5	0	18.4
1805.5	0	16.5
1806.5	0.6	15.2
1807.5	3.8	16.8
1808.5	0	11.4
1809.5	0	19.0
1811.5	0	13.4
1813*	27.5	13.3
1827*	0	11.2
MATTOON, Strong-Seaman no.1		
1820	19.1	19.1
1821	18.9	18.4
1822	6.9	14.8
1823	107	15.8
1824	83.9	18.9
1825	95.1	16.2
1826	47.7	18.9
1826*	143.4	15.0
1827	130	19.3
1828	28.4	18.8

Depth	K (md)	ϕ (%)
MATTOON, Strong-Seaman no.1 <i>continued</i>		
1829	74.9	20.3
1830	70	20.3
1831	55.7	15.8
1832*	76.8	12.1
1832	47.6	16.3
1833	62.6	17.4
1834	2.5	12.4
1835	2.5	8.6
MATTOON, Seaman JH no.5		
1798	21.0	22.6
1799	7.8	20.9
1800	15.1	18.7
1812	17.9	20.3
1814	19.5	18.9
1816	16.2	20.6
1818	15.4	18.8
1820	5.1	16.5
1822	5.6	13.6
1824	63.3	21.0
1826	83.2	20.1
1828	70.1	18.6
MATTOON, AOR/Seaman JH no.15		
1748.9	71	20.9
1750	73	19.6
1751	119	20.2
1752	73	20.7
1753	60	21.3
1754	28	19.5
1755	54	21.0
1756	11	13.5
1757	2.1	13.8
1777.8	17	20.9
1779	67	19.6
1780	41	19.9
1781	38	20.2
1782	33	21.4
1783	25	20.6
1784	12	20.5
1785	0.81	16.5
1786	2.4	16.9
1787	6	18.4
1788	0	13.3
1789	3.5	13.8
1790	0.4	12.6
1792	0.15	11.0
1793	0.79	11.1
1799.7	9.5	16.4
1801	7.4	16.4

Depth	K (md)	ϕ (%)
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MATTOON, AOR/Seaman JH no.15

continued

1802	15	17.4
1803	6.6	17.6
1804	9.1	17.2
1805	10	16.7
1806	25	17.4
1807	9.8	16.7
1808	9.7	17.1
1809	9.5	15.9
1810	4.9	15.0

MATTOON, Strong E no.2

1829	0.1	13.6
1830	1.9	15.8
1831	0.6	13.2
1832	66.3	15.5
1833	101	12.2
1834	30.2	19
1835	20.7	19.9
1836	24.7	18.4
1837	1.6	11.3
1839	0	9.9
1840	0.5	9.3

MATTOON, Uphoff H no.1

1795	12.0	18.2
1796	95.5	21.7
1797	136.0	21.8
1798	77.9	20.2
1799	141.0	19.6
1800	109.0	19.7
1801	84.9	19.5
1802	166.0	20.8
1803	106.0	20.4
1804	96.6	20.6
1805	78.7	20.9
1806	76.9	20.2
1807	213.0	23.0
1808	72.6	20.8
1809	82.3	22.5
1810	12.7	16.4
1811	15.0	15.9
1812	24.6	18.1
1813	3.2	16.5
1814	3.1	13.3
1815	2.2	13.9
1816	52.2	14.8
1817	7.3	15.2
1818	2.2	18.5
1819	1.7	15.1

Depth	K (md)	ϕ (%)
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MATTOON, Uphoff, H no.1

1821	7.6	17.3
1823	5.8	19.1
1825	7.0	15.1

MATTOON, Strong E no.8

1776*	64.3	14.6
1778*	31.5	14.5
1780h*	23.3	12.7
1780v*	1.8	12.8

MATTOON, Akers J no.1

1848*	14.5	15.6
1874*	189.1	16.1

MATTOON, Strong E no. 7

1852*	2.3	15.0
1869*	37.7	16.0
1879*	1.8	14.2
1892*	17.2	15.7

MATTOON, Rich ND no.7

1857*	6.6	14.7
1874*	7.0	13.7

HARCO EAST, Moore no.5

2601.5	73.1	12.9
2606.5	17.7	12.5

XENIA FIELD, Campbell no.3

2526.5	9.9	14.8
2527.5	11	15.8
2528.5	17	14.5
2529.5	4.4	13.5
2530.5	14	14.6
2531.5	9.7	14.3
2532.5	16	15.2
2533.5	68	15.2
2534.5	61	14.2
2535.5	88	15.4
2536.5	86	15.2
2537.5	69	14.2
2538.5	23	14.5
2539.5	64	16.2
2540.5	21	16.1
2541.5	21	16.5
2542.5	66	16.6
2543.5	12	16.6
2544.5	42	15.9
2545.5	20	15.4
2546.5	44	17.0

Depth	K (md)	ϕ (%)
XENIA FIELD, Campbell no.3		
2547.5	64	16.2
2548.5	21	14.6
I-57 OUTCROP*		
NW2 10.17'	0.8	14.2
NW3A 11.17'	1.1	14.9
SE3A 13'	1.8	17.0
SW1 6'	1.9	15.6
NW4A 15.5'	2.8	15.8
NW5 16.67'	4.5	15.8
NE2A 10'	5.8	16.1
NE3 16.5'	6.2	16.3
NE4 16.5'	6.5	15.8
NW5A 19.5'	8.5	15.8
NE3A 12.5'	9.1	16.0
NE1A 3'	10.3	15.9
SE2A 15'	10.3	18.1
NW3 4.75'	11.5	15.2
SE3 4'	12.1	16.9
NE4A 18'	12.7	14.9
SW2A 3.5A'	12.8	15.6
SW2A 10.5'	14.1	16.4
NW4 5'	20.0	15.0
SE5 15.5'	20.3	16.3
NE1A 4.25'	20.9	16.2
SW4A 10'	21.7	16.0
SW4A	23.0	16.2
NE6A 14.08'	24.9	15.9
SW2B	29.9	16.2
NW3A 1'	35.6	16.2
NE5A 23'	38.1	17.3
NW3 18'	38.1	20.1
SW4B	38.3	14.7
NW7 11.75'	38.6	14.5
SW5A 9'	46.2	17.3
NE4A 3.5'	47.1	15.7
SE6 15.92'	48.4	17.2
NE7 14'	52.5	16.0
NE3 3'	57.9	14.3
SE5 3.5'	58.7	14.9
SW2A 3.5'	58.9	16.0
NE4A 3.5'	59.3	15.5
NE2 3.5'	73.2	15.4
SE4 6'	75.5	17.3
SW3C	80.4	16.8
NE4 4'	83.5	15.0
NW4A 6.5'	87.8	16.2
SW3B	91.0	17.4
NW5 7'	96.6	15.9
SE4 2.5'	97.0	17.0

Depth	K (md)	ϕ (%)
I-57* OUTCROP <i>continued</i>		
SE2A 1'	102.0	18.3
SW4A 2'	104.0	17.1
SE5 9'	114.3	14.4
NW5A 9'	118.4	14.8
SE6A 14.5'	120.0	16.1
NE6 10'	121.8	15.2
NW6 10.42'	122.5	14.3
NE3A 2'	126.1	15.4
SW3A 2.5'	132.3	16.9
NE2A 1.92'	137.3	16.8
NE5A 3.5'	144.6	15.5
SE4A 1.5'	160.0	18.3
SE7A 4.67'	163.4	17.8
NW4 1.42'	188.6	15.5
NW6A 7.5'	193.3	16.0
NW2A 2.5'	204.4	17.8
SE5A 14'	218.0	15.3
SE5A 14'	218.0	15.3
NW6 3'	243.7	16.2
SE7 13'	249.0	15.7
NE6 2.5'	249.0	16.6
NW7A 8.75'	255.8	16.5
SE7A 3'	259.0	18.7
NE7A 3.08'	278.7	17.4
SE6 4'	318.7	18.6
NE6A 2.75'	320.8	17.0
SW7B 7.5'	324.0	18.7
SW6A 2.75'	325.5	18.2
NW7 3'	349.0	16.5
NE7 2'	350.9	17.6
SW5A	353.0	16.9
SW7A 5'	373.0	17.9
SW8 5'	384.6	19.4
NE7A 8'	391.0	16.5
SE7 3.5'	435.0	15.9
SE5A 2'	449.0	17.3
NW6A 2.25'	453.6	16.2
SW5A 2.6'	459.5	16.6
NE8 3'	511.5	18.1
SW7A 2'	587.0	17.9
SE8 6.5L'	615.3	18.3
SW7 2.5'	622.3	17.5
NE8 4'	635.0	18.6
SW6A	771.3	21.4
NW7A 2.67'	783.9	17.4
SE8 6.5S'	790.2	19.4
SE8 1.5'	794.0	18.0
SW8 2.5'	915.3	18.2

* core analysis by ISGS

APPENDIX XIV-B. POROSITY AND PERMEABILITY PLOTS

APPENDIX XIV-B. *continued*