# TITLE: IMPROVED OIL RECOVERY IN MISSISSIPPIAN CARBONATE RESERVOIRS OF KANSAS -- NEAR TERM -- CLASS 2

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## FOREWORD

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## ABSTRACT

This annual report describes progress during the third year of the project entitled “Improved Oil Recovery in Mississippian Carbonate Reservoirs in Kansas”. This project funded under the Department of Energy’s Class 2 program targets improving the reservoir performance of mature oil fields located in shallow shelf carbonate reservoirs. The focus of this project is development and demonstration of cost-effective reservoir description and management technologies to extend the economic life of mature reservoirs in Kansas and the mid-continent. The project introduced a number of potentially useful technologies, and demonstrated these technologies in actual oil field operations. Advanced technology was tailored specifically to the scale appropriate to the operations of Kansas producers. An extensive technology transfer effort is ongoing. Traditional technology transfer methods (e.g., publications and workshops) are supplemented with a public domain relational database and an online package of project results that is available through the Internet. The goal is to provide the independent complete access to project data, project results and project technology on their desktop.

Included in this report is a summary of significant project results at the demonstration site (Schaben Field, Ness County, Kansas). The value of cost-effective techniques for reservoir characterization and simulation at Schaben Field were demonstrated to independent operators. All major operators at Schaben have used results of the reservoir management strategy to locate and drill additional infill locations. At the Schaben Demonstration Site, the additional locations resulted in incremental production increases of 200 BOPD from a smaller number of wells.

## EXECUTIVE SUMMARY

The majority of Kansas production is operated by the small independent oil and gas producer (90% of the 3,000 Kansas producers have less than 20 employees). The independent producer does not have the extensive resources and the ready access to a research lab to develop and test advanced technologies. For the Kansas oil and gas industry, access to new technology remains critical to sustained production and increased economic viability. A major emphasis of the Kansas project was collaboration of University of Kansas scientists and engineers with Kansas independent producers and service companies. The goal was to develop and modify cost-effective new technologies and to accelerate adaptation and evaluation of these technologies.

The demonstration project was conducted in cooperation with Ritchie Exploration, Inc. of Wichita, which operates leases that were the focus of the demonstration. However, a number of major operators in the Schaben Field contributed data to the project, and tested and adopted project results. Schaben Field (1963 discovery) is located in Ness County on the western flank of the Central Kansas uplift, and is typical of Mississippian production in Kansas. Prior to project initiation, cumulative field production was 9.1 million barrels of oil, and daily production was 326 BOPD from 51 wells prior. In Kansas, the majority of Mississippian production occurs at or near the top just below a regional unconformity. Production from Mississippian reservoirs accounts for approximately 43% of total annual production, and cumulative production exceeds 1 billion barrels. Today, independent producers, operating many of these reservoirs and production units, deal with high water cuts and low recovery factors that place continued operations at or near economic limits.

Common problems in Kansas reservoirs that affect producibility include; old and missing data, inadequate reservoir characterization, drilling and completion design problems, and non-optimal primary recovery. The value of cost-effective techniques for reservoir characterization and simulation at Schaben Field were demonstrated to independent operators. All major operators at Schaben have used results of the reservoir management strategy to locate and drill additional infill locations. At the Schaben Demonstration Site, the additional locations resulted in incremental production increases of 200 BOPD from a smaller number of wells.

Integrated geologic reservoir characterization provided the basis for development of a quantitative reservoir model. Descriptive reservoir characterization entailed integration and creative application of existing vintage data, drilling and coring three new wells. Core analysis (including NMR), petrophysical analysis, calibration of logs and core data integrated with existing data into a computerized 3D visualization. Procedures and computer code were developed to load and display available well logs using workstations for improved 3D visualization. Geologic, engineering and production data were brought into a common set of relational databases, and is available on-line at reservoir, lease and well levels.

One aspect of the project involved development of a low-cost PC-based petrophysical analysis package (PfEFFER) that works as part of a spreadsheet, and is a practical tool for the real-time, interactive log analysis. The US DOE Boast 3 Reservoir Simulation Package was modified to work at the full-field scale with commonly available, spreadsheet programs as pre- and post-processors. The result was a full field reservoir simulation model and management tool that the independent producer can run on a desktop PC using freeware and a spreadsheet.

Project design, methodologies, data, and results are disseminated to independent operators through focused technology transfer activities. These activities include development of cost-effective technologies, traditional publication; workshops and seminars; and public access

through the Internet. In addition to traditional workshops, electronic courses covering important technologies are available. All technologies used have been adapted to be cost-effective for independent operators of mature fields. Technologies include petrophysical analysis (PfEFFER), visualization (Pseudoseismic), core analysis using NMR, numerical simulation on a PC, and Internet technology transfer. The value of these technologies for independent operators has been demonstrated. All major operators at Schaben have adopted the results of the reservoir management strategy developed as part of the study, and have located and drilled approximately 20 infill locations. Overall results of the incremental wells are very favorable. The procedures continued to be transferred to other independent operators through publication, presentations, hands-on computer workshops and Internet access.

# 1.0 INTRODUCTION

The Kansas Class 2 project is an effort to introduce Kansas producers to useful technologies and to demonstrate these technologies in actual oil field operations. In addition, all technologies used as part of the project were adapted to be cost-effective for independent operators of mature fields. The majority of Kansas production is operated by small independent producers that do not have resources to develop and test advanced technologies (90% of the 3,000 Kansas producers have less than 20 employees). For Kansas producer's, access to new technology is important for sustaining production and increasing viability. A major emphasis of the project is collaboration of university scientists and engineers with the independent producers and service companies operating in Kansas to accelerate adaptation and evaluation of new technologies. An extensive technology transfer effort is ongoing. Traditional technology transfer methods (e.g., publications and workshops) are supplemented with a public domain relational database and an online package of project results that is available through the Internet. The goal is to provide the independent complete access to project data, project results and project technology on their desktop.

Project design, methodologies, data, and results are disseminated through focused technology transfer activities. Technology transfer activities include: development of cost-effective technologies and software (e.g. PfEFFER, “Pseudoseismic, Modification of BOAST 3); open-file reports; publication in trade professional, and technical publications; workshops and seminars; and the establishment of public access through the Internet. The target audience includes other operators in the demonstration area, operators of other Mississippian sub-unconformity dolomite reservoirs in Kansas, operators of analogous shallow shelf carbonate reservoirs in the Mid-continent, and technical personnel involved in reservoir development and management.

## 1.1 Objectives and Significance

The majority of Mississippian production in Kansas occurs at or near the top of the Mississippian section just below the regional sub-Pennsylvanian unconformity. These reservoirs are a major source of Kansas oil production and account for approximately 43% (21 million barrels in 1994) of total annual production (Carr et al., 1995a, Figure 1.1). Cumulative production from Mississippian reservoirs in Kansas exceeds 1 billion barrels. Today, independent producers, operating many of these reservoirs and production units, deal with high water cuts and low recovery factors that place continued operations at or near economic limits.

This project addressed producibility problems in the numerous Kansas fields such as the Schaben field in Ness County that produce from Meramecian and Osagian dolomites beneath the sub-Pennsylvanian unconformity. Producibility problems in these reservoirs include inadequate reservoir characterization, drilling and completion design problems, and non-optimal primary recovery. Tools and techniques developed as part of the project facilitate integrated, multi-disciplinary reservoir characterization. All technologies used have been adapted to be cost-effective for independent operators of mature fields. Technologies include petrophysical analysis (PfEFFER), visualization (Pseudoseismic), core analysis using NMR, numerical simulation on a PC, and Internet technology transfer. The value of these technologies for independent operators has been demonstrated. All major operators at Schaben have adopted the results of the reservoir management strategy developed as part of the study, and have located and drilled approximately 20 infill locations. Overall results of the incremental wells are very favorable. At the Schaben Demonstration Site, the additional locations resulted in incremental production increases of 200 BOPD from a smaller number of wells.

Equally important is innovative dissemination of the data, methodologies, and results to foster wider application of demonstrated technologies by the numerous operators of similar fields throughout the northern Mid-continent and US.

## 1.2 Site Description

The Schaben demonstration site consists of 1,720 contiguous acres within Schaben field, located in Township 19 South--Range 21 West, Township 20 South--Range 21 West, and Township 19 South--Range 22 West, Ness County, Kansas (Figure 1.2). The leases comprising the demonstration sites are highlighted in Figure 1.2. This site is located in the upper shelf of the Hugoton Embayment of the Anadarko Basin and produces oil from dolostones and limestones of the lower Meramecian Warsaw Limestone and Osagian Keokuk Limestone (Mississippian) at depths of 4,350-4,410 feet. The site is located on the western flank of the Central Kansas uplift at the western edge of the Mississippian Osagian subcrop beneath the sub-Pennsylvanian unconformity (figures 1.3 - 1.5), and is typical of numerous other Mississippian fields in Kansas.

Schaben field, discovered in 1963, consists of 78 completed oil wells spaced primarily on 40-acre locations (Figure 1.3). Cumulative field production as of October 1998 was 9.3 million barrels of oil (BO), and daily field production was 502 BOPD from 47 wells (Figure 1.2). Compared to production prior to infill drilling average daily production has increased approximately 200 BOPD from a smaller number of producing wells (during 1995 average production was 311 BOPD from 59 wells). From late 1996 through 1998, a total of twenty-two infill locations were drilled or recompleted at the Schaben Demonstration Site (Table 1). The locations were selected based on the results of the reservoir management strategy developed in Budget Period 1. All three major field operators (Ritchie Exploration, Pickrell Drilling and American Warrior) used the Schaben reservoir simulation to evaluate multiple locations and select optimum locations. The In addition to production from the Mississippian, one well produces oil from the Cherokee Group and the Fort Scott Limestone, however, the relative volume of oil produced from these secondary zones is small.

## 1.3 Participating Organizations

University of Kansas Center for Research Inc., the University of Kansas Energy Research Center, the Kansas Geological Survey, and the Tertiary Oil Recovery Project of Lawrence Kansas, and Ritchie Exploration Inc. of Wichita, Kansas are participating in the project. Total cost sharing in the project is 50 percent.

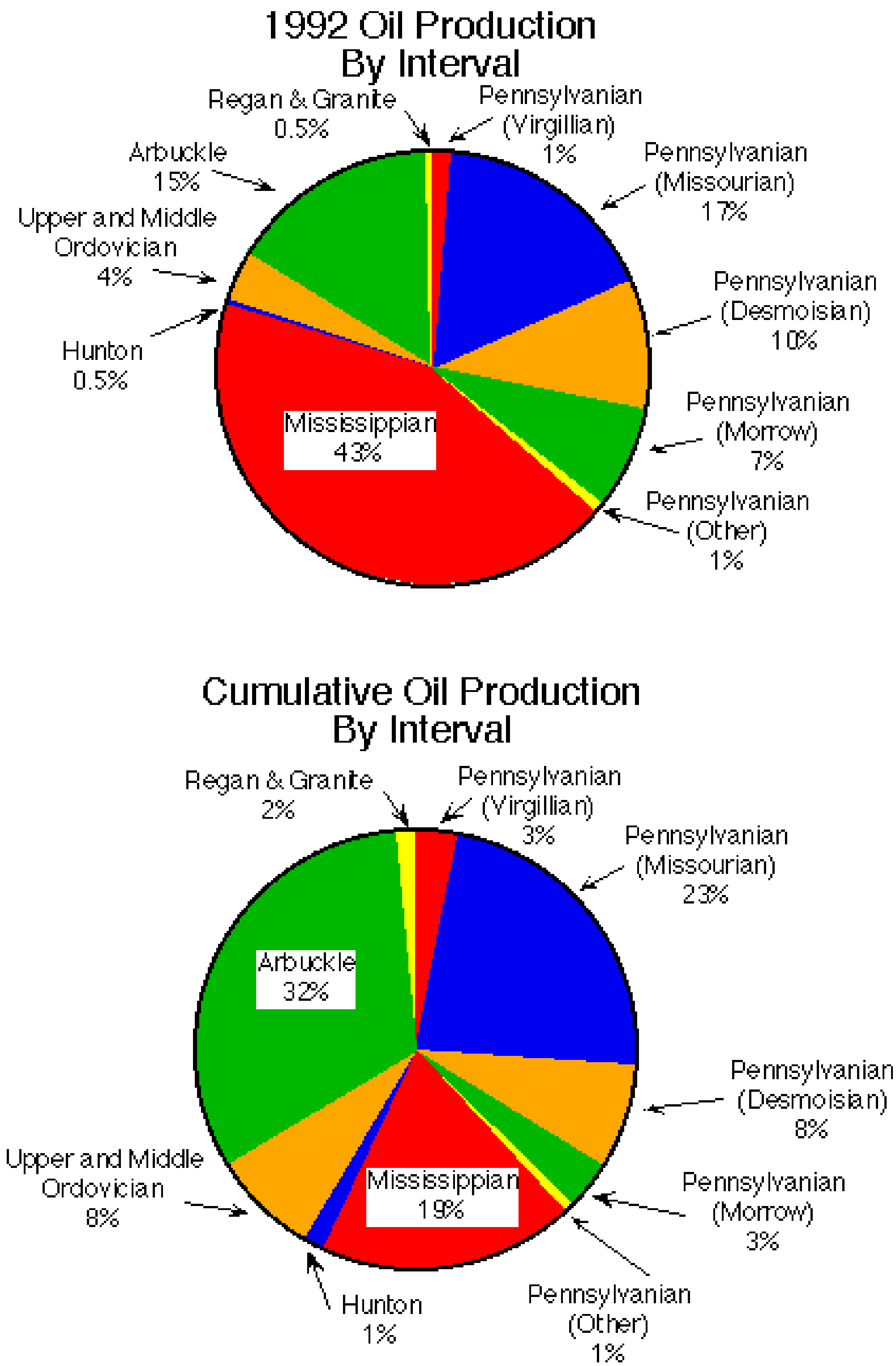



**FIGURE 1.1**. Kansas annual and cumulative oil production from Carr et al. 1995a. Mississippian reservoirs comprise one of the largest producing intervals in the state. Also available on-line through the Internet (http://www.kgs.ukans.edu/PRS/publication/OFR95_42/tim1.html).

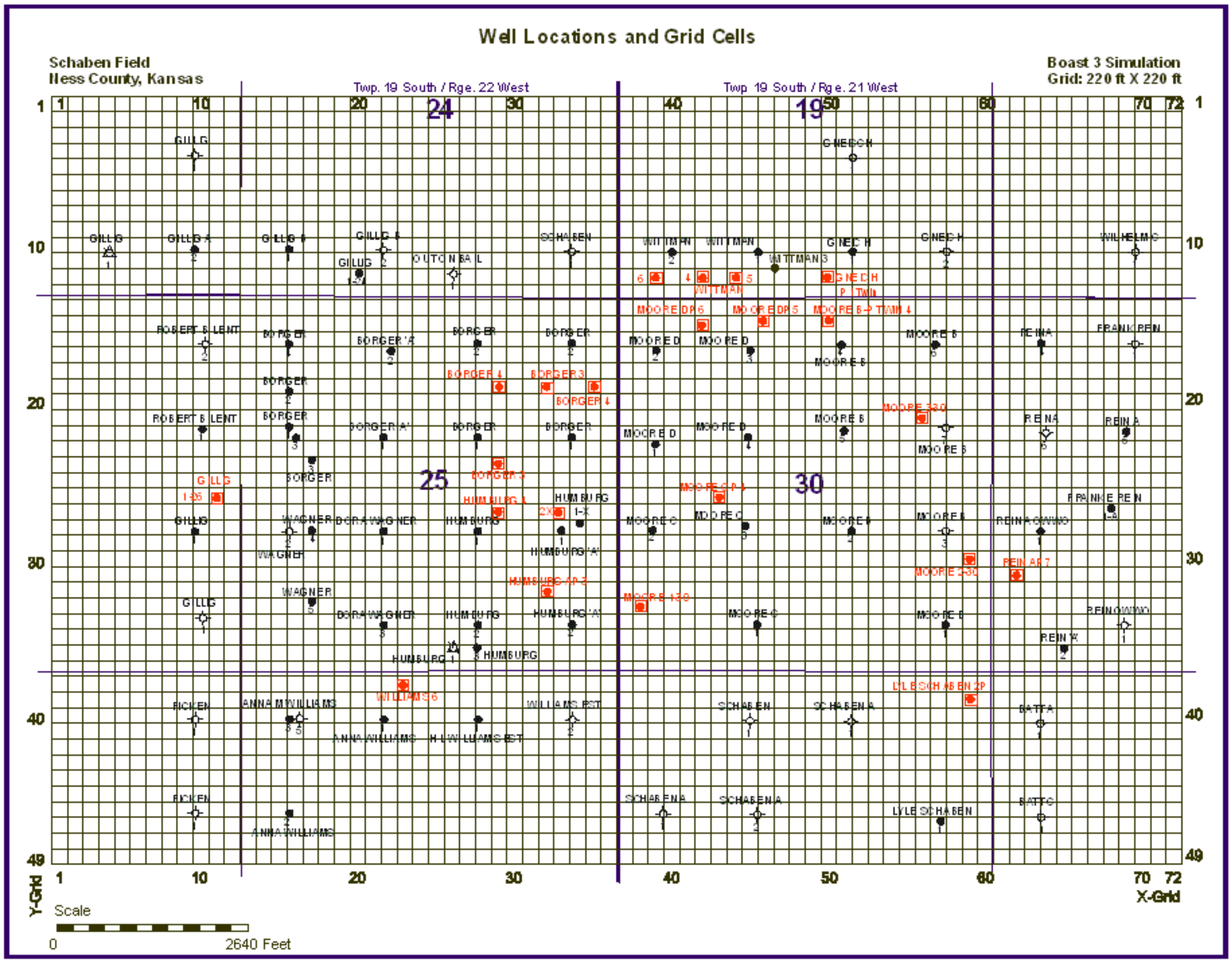



**FIGURE 1.2.** Schaben Field demonstration site with overlay of grid used in simulation. Locations of the wells located and drilled or recompleted, as a result of the demonstration project, are also indicated (red squares).

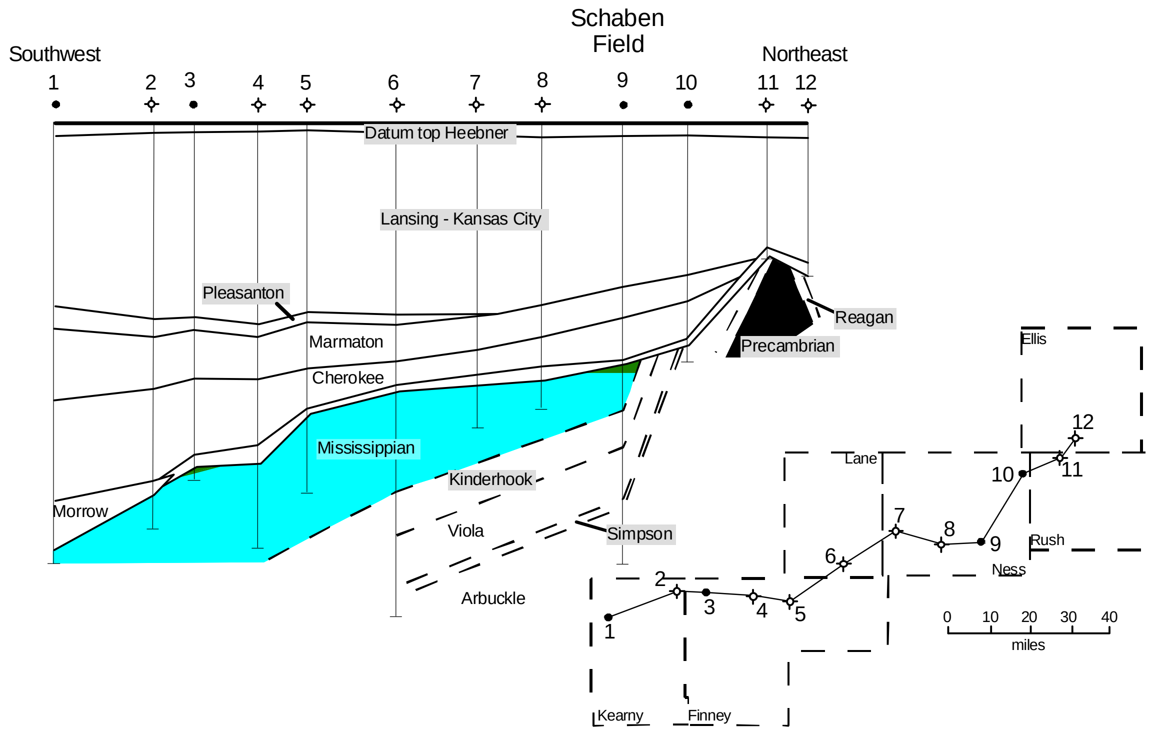



**FIGURE 1.3.** Regional southwest-northeast cross-section showing relation of Mississippian and older rocks to the pre-Pennsylvanian unconformity. The shaded area at the top of the Mississippian at well 9 indicates location of the Schaben Field demonstration site. Modified from Goebel and Merriam (1957).

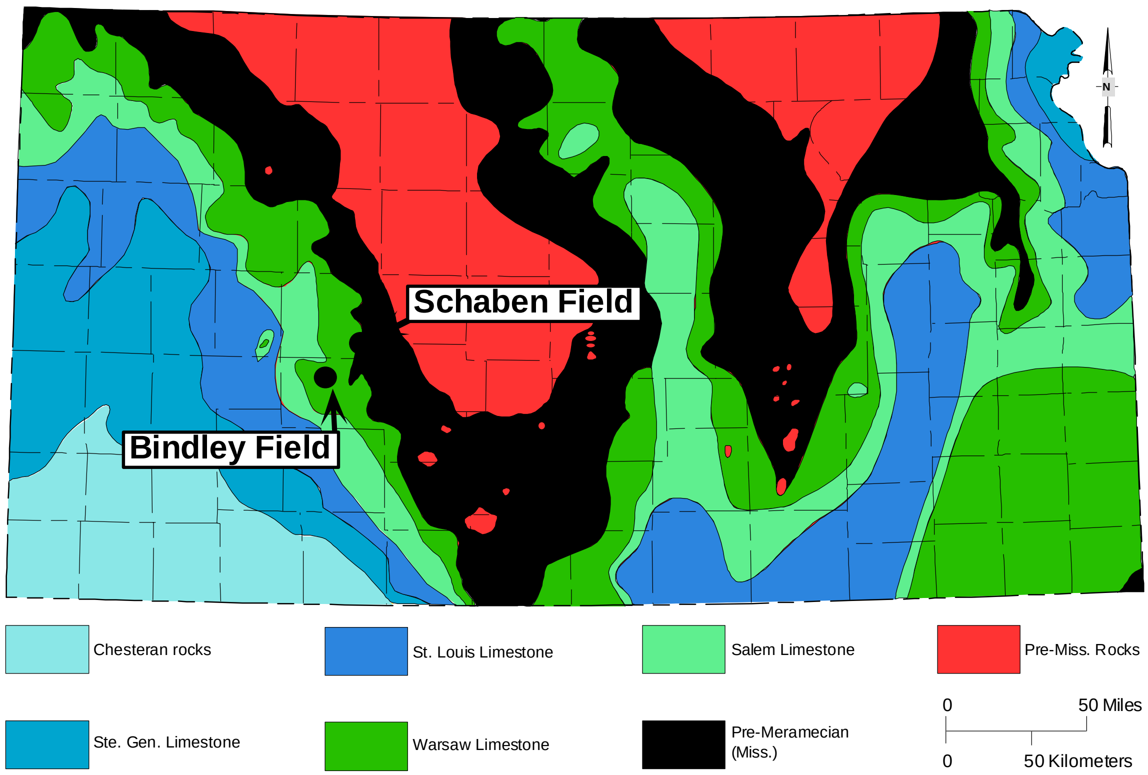



**FIGURE 1.4.** Mississippian subcrop map beneath the Pennsylvanian unconformity showing location of Schaben Field. Mississippian units beneath the unconformity become progressively older and are absent on the Central Kansas uplift.

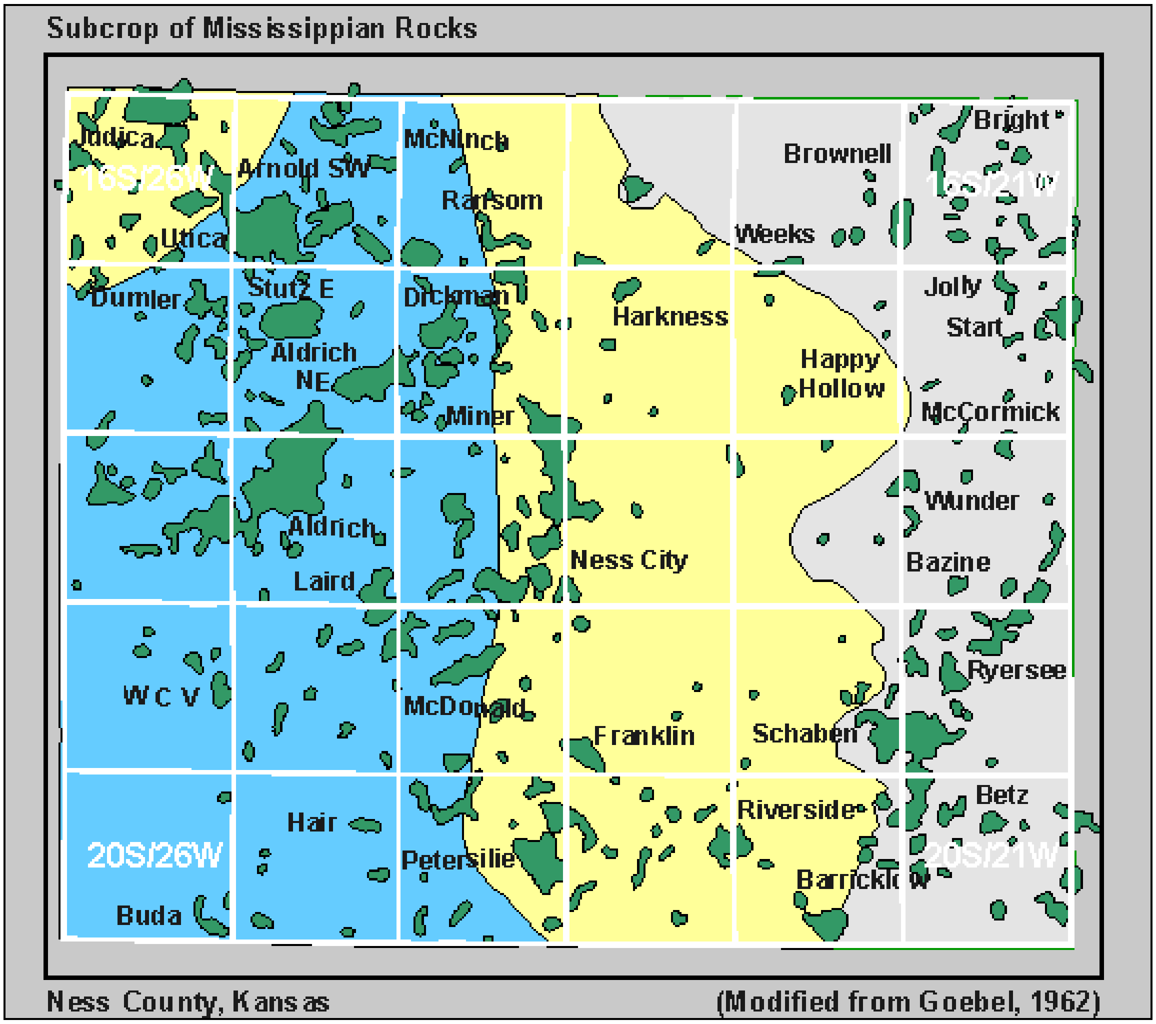



**FIGURE 1.5.** Mississippian subcrop map and structure on top of the Mississippian for Ness County Kansas. Field outlines for Mississippian production are shown. Schaben Field is located in the southeast corner of the county. Map available on-line through the Internet (http://www.kgs.ukans.edu/DPA/County/ness.html).

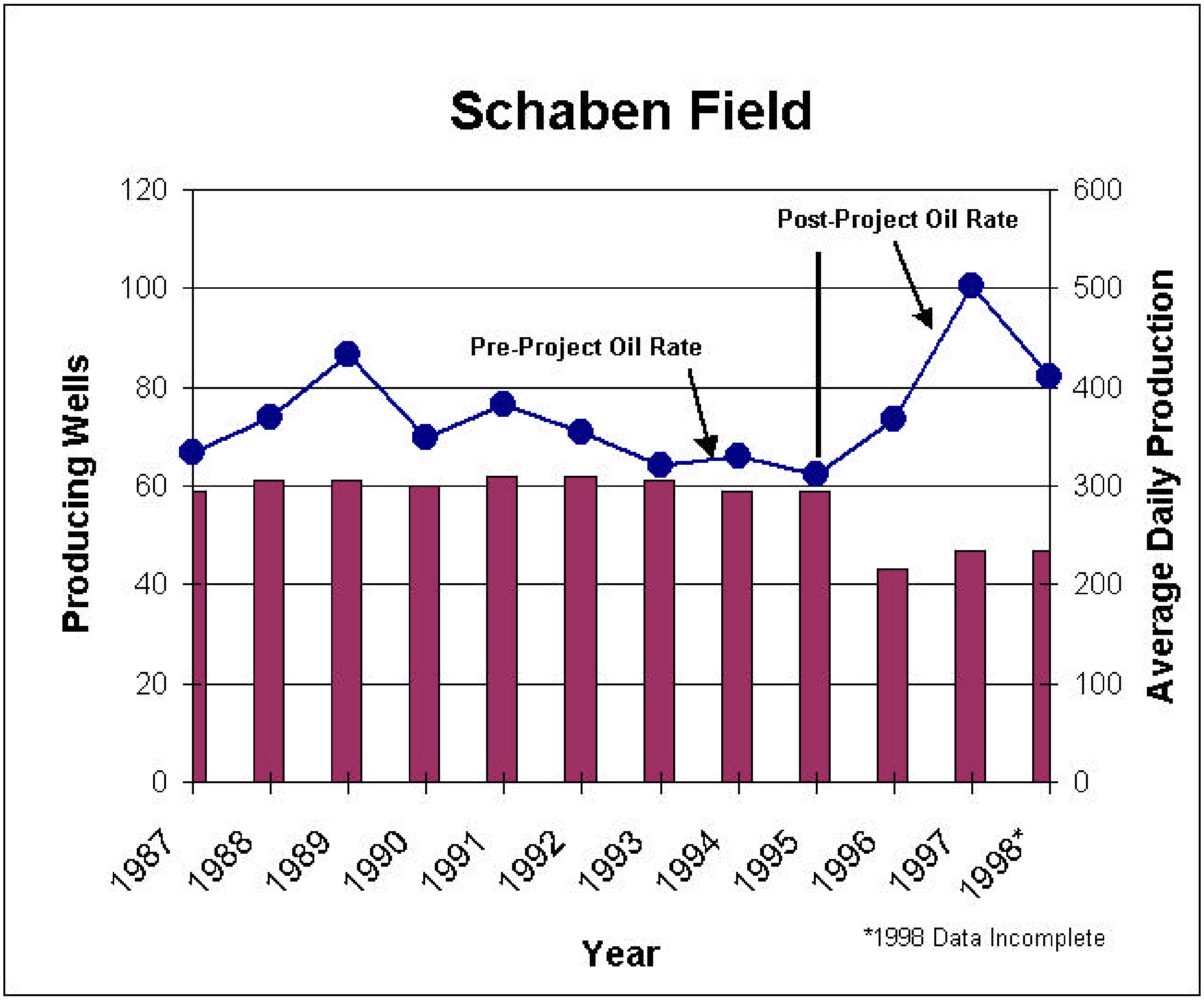



**FIGURE 1.6.** Annual field production and number of producing wells for the Schaben Field Ness County, Kansas.

| Well Name/Year | Operator | API Number | Status Rates Per Day | Location |
|---|---|---|---|---|
| 4 BP Twin / 1996 | Ritchie Exploration | 15-135-23864 | 15 BO, 283 BW | 30-19S-21W, NW-NW-NE |
| 2 P Lyle Schaben / 1996 | Ritchie Exploration | 15-135-23925 | 53 BO, 97 BW | 31-19S-21W, NE-NE-NE |
| 1 Gneich P Twin / 1996 | Ritchie Exploration | 15-135-23933 | 13 BO 72 BW | 19-19S-21W, SW-SW-SE |
| 2-30 Moore / 1997 | American Warrior | 15-135-23800 | 37 BO 0 BW | 30-19S-21W, SE-NE-SE |
| 6 DP Moore / 1997 | Ritchie Exploration | 15-135-24006 | 60 BOPD, 100 BW, 241' FOP | 30-19S-21W, NE-NW-NW |
| 3 AP Humburg / 1997 | Ritchie Exploration | 15-135-24013 | 70 BOPD, 130 BW, 33' FOP | 25-19S-22W, NW-SE-SE |
| 4 Humburg / 1997 | Pickrell Drilling | 15-135-24010 | 70 BOPD, 130 BW, 1347' FOP | 25-19S-22W, NE-NW-SE |
| 3 Borger / 1997 | Pickrell Drilling | 15-135-23998 | 66 BOPD, 66 BW, 1426' FOP | 25-19S-22W, SW-NE-NE |
| 4 Wittman/ 1997 | American Warrior | 15-135-23958 | 108 BO. ? BW | 19-19S-21W, SE-SW-SW |
| 5 Wittman / 1997 | American Warrior | 15-135-23966 | 108 BO. ? BW | 19-19S-21W, SW-SW-SW |
| 7 Rein AP / 1997 | Ritchie Exploration | 15-135-24031 | 70 BOPD, 80 BW, 530' FOP | 29-19S-21W, SW-NW-SW |
| 5 DP Moore / 1997 | Ritchie Exploration | 15-135-23973 | ? | 30-19S-21W, NE-NE-NW |
| 4 CP Moore / 1997 | Ritchie Exploration | 15-135-24030 | ? | 30-19S-21W, NW-NE-SW |
| 4 Borger / 1997 | American Warrior | 15-135-24007 | 20 BO, 30 BW | 25-19S-22W, SE-NW-NE |
| 3-30 Moore / 1997 | American Warrior | 15-135-23801 | 25 BO, Little Water | 30-19S-21W, NW-SE-NE |
| 1-30 Moore / 1997 | American Warrior | 15-135-23799 | 13 BO, 21 BW | 30-19S-21W, NW-SW-SW |
| 3 Borger / 1997 | American Warrior | 15-135-23969 | 250' FOP | 25-19S-22W, SE-SW-NE |
| 2X Humburg | Mid Cont R | 15-135-24015 | 12 BO, 60 BW | 25-19S-22W, NW-NE-SE |
| 4 Borger | Pickrell Drilling | 15-135-24048 | 40 BO, 9 BW | 25-19S-22W, NE-SE-NE |
| 1-26 Gillig | American Warrior | 15-135-24052 | 15 BO, 110 BW | 26-19S-22W, NE-NE-SE |
| 6 Williams | American Warrior | 15-135-24053 | 15 BO, 150 BW | 36-19S-22W, NE-NE-NW |
| 6 Wittman | American Warrior | 15-135-23958 | 20 BO, 30 BW | 19-19S-22W, SE-SW-SW |

**TABLE 1.1.** List of infill locations drilled or recompleted in the Schaben demonstration area from late 1996 through 1998. The majority of locations were selected based on the reservoir description and simulation results resulting from the project.

## 2.0 DISCUSSION

The general goal of the project is the application of existing cost-effective recovery technologies to extend the economic life of selected fields producing from shallow shelf carbonate reservoirs, and the innovative dissemination of the data, methodologies, and results for the purpose of fostering wider application of demonstrated technologies to other fields. The specific goal is to identify areas of unrecovered mobile oil in Osagian and Meramecian (Mississippian) dolostone reservoirs in western Kansas through integrated, multi-disciplinary reservoir characterization, and the demonstration of incremental primary recovery at the Schaben Field Demonstration Site.

At the Schaben site, integrated, descriptive reservoir characterization provided the basis for development of a reservoir model. Descriptive reservoir characterization entailed integration and creative application of existing data, drilling and coring three new wells through the reservoir interval. Descriptive core analysis, petrophysical and petrographic analysis, calibration of logs and core data, and integration of existing well data into a computerized three dimensional visualization/simulation were used to develop a descriptive reservoir model for the Osagian and Meramecian rocks at the Schaben site.

Acquisition and consolidation of geologic, digital log, and production data are complete and all data have been entered into a database management and analysis system. Digital data used in constructing geologic maps and cross-sections and reservoir analysis is available through the Internet (http://www.kgs.ukans.edu/Class2/index.html and http://www.kgs.ukans.edu/DPA/Schaben/schabenMain.html). Log analyses, core analyses and descriptions were completed to better understand the pore geometry of the carbonate reservoir in the Schaben Field. All of the complexities existing in an evaluation of an extremely heterogeneous reservoir, are present in the producing reservoir in the Schaben Field. Satisfactory determinations of pore size, throat size, irreducible water saturation, permeability, effective porosity, and movable oil are possible with the techniques being used in the Schaben Field project.

### 2.1 Field Activities

From late 1996 through 1998, a total of twenty-two infill locations were drilled or recompleted at the Schaben Demonstration Site (Table 1). The locations were selected based on the results of the reservoir management strategy developed in Budget Period 1. All three major field operators (Ritchie Exploration, Pickrell Drilling and American Warrior) used the Schaben reservoir simulation to evaluate multiple locations and select optimum locations. The history of each well is being evaluated and incorporated into a final revised full-field simulation. The current reservoir simulation has provided excellent full-field and good individual history matches for all existing wells. The simulation also provides an estimate of additional incremental oil as a result of targeted infill drilling (Figure 2.1).

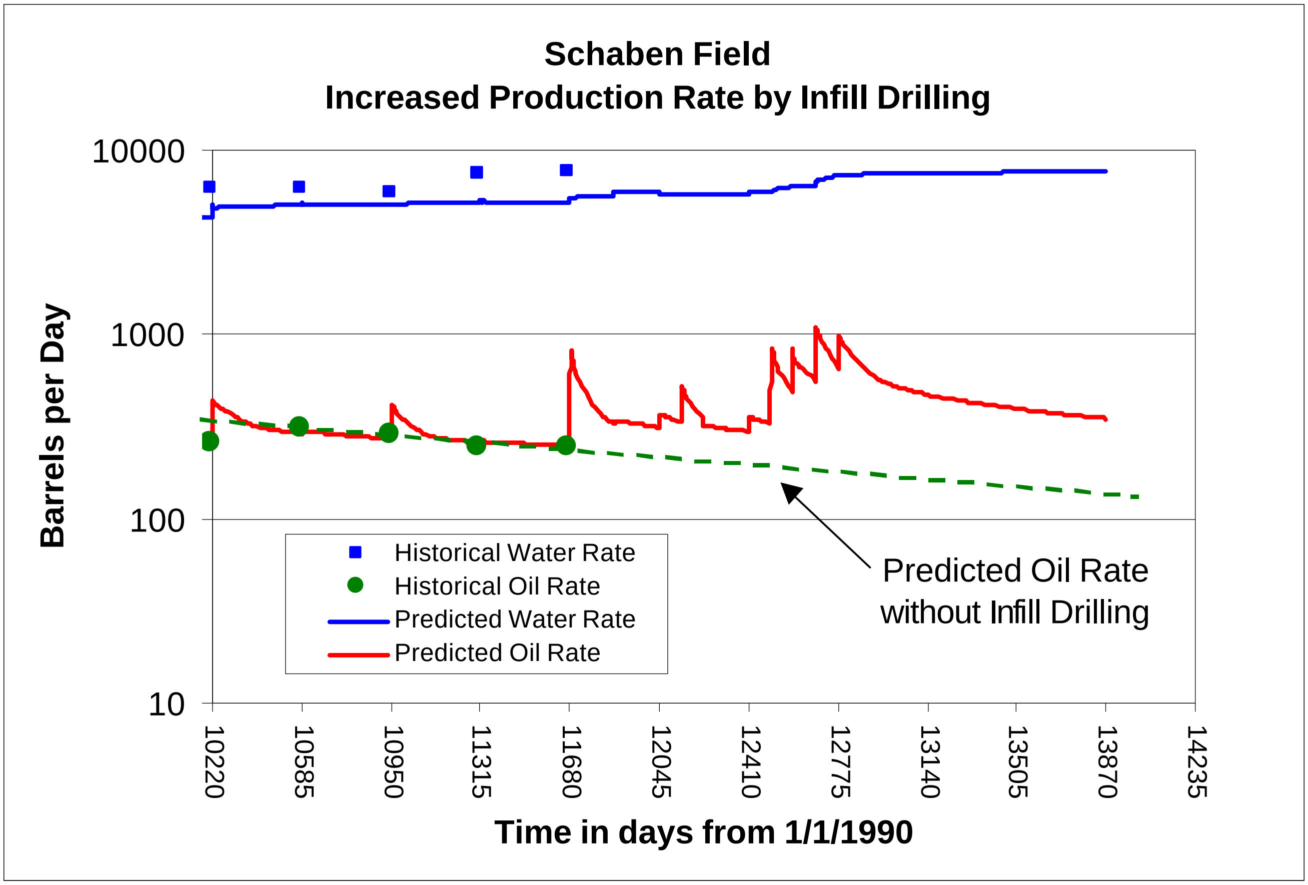



**FIGURE 2.1.** Predicted and historical oil and water rates for the Schaben Field Demonstration Site through the end of Budget Period 1. The predicted effect of infill wells and recompletions is shown. The observed effect of infill wells on production is shown in Figure 1.6. The over prediction in BOPD is due in part to reduced number of operating wells. Older low-rate wells are being replaced by new infill wells.

## 2.2 Summary of Reservoir Geology

*Modified form 1998, Evan K. Franseen, Timothy R. Carr, Willard J. Guy and D. Scott Beaty, Significance of Depositional and Early Diagenetic Controls on Architecture of a Karstic-Overprinted Mississippian (Osagian) Reservoir, Schaben Field, Ness County, Kansas: 1998 AAPG Meeting, Salt Lake City, Utah*

A sedimentologic and diagenetic study of Mississippian (Osagian) cores from the demonstration site was undertaken to discern the interplay of original depositional facies and early to late diagenetic events in producing the complex architecture of this dominantly cherty dolomite reservoir (Summarize in Franseen and others, 1998). The strata represent deposition on a ramp. Basal strata (M0 unit) consist of normal to somewhat restricted marine strata characterized by an abundance of echinoderm-rich facies commonly containing a diverse fauna. Upper strata (M1 unit and above) are dominated by sponge spicule-rich facies and silicified original evaporite minerals indicating restricted evaporitive ramp, lagoon or supratidal environments. An internal unconformity, apparently a subaerial exposure event, separates upper and lower strata (M1 surface). The post-Mississippian unconformity caps the entire sequence.

Macroscopic, microscopic, well-log, petrophysical and minipermeameter data, and oil shows, indicate that depositional facies and early diagenetic events were dominant controls for reservoir characteristics. The best reservoir is the sponge spicule-rich wackestone/packstone facies (SWP) with replaced evaporites. Echinoderm-rich wacke-packstones (EWPG) are also locally important reservoir facies. Burrow mottling was important in creating localized networks for early diagenetic fluids. Early dissolution of grains and dolomitization created the moldic, intercrystalline and vuggy porosity important for favorable reservoir conditions. Abundant early silica cementation and replacement (chert, megaquartz, chalcedony) created complex heterogeneity. Silica replacement and cementation in EWPG facies typically results in impermeable areas whereas silica cementation and replacement in SWP and mudstone-wackestone (MW) facies results in variably tight or porous (tripolitic) areas containing vuggy, moldic, and intercrystalline porosity. Coarse calcite cementation and poikilotopic calcite replacement associated with the M1 surface significantly occluded much of the porosity in underlying M0 strata. Fracturing and brecciation from the post-Mississippian karst, burial and structural events variously enhanced or destroyed reservoir characteristics. Ramp strata were differentially eroded at the post-Mississippian unconformity resulting in complex buried paleotopography.

The most favorable areas for successful production appear to be where SWP facies containing abundant evaporites (M1 unit and above) intersect the post-Mississippian unconformity and form topographic highs. Our data suggest the EWPG facies to be locally favorable reservoirs. However EWPG facies that are dominant in the M0 unit are not likely to be favorable reservoirs because processes associated with the M1 surface significantly occluded much of the porosity. This prediction is confirmed to the northeast of our study area where M0 strata intersect the unconformity and are not productive. Our methods and results provide predictive capability, indicate the potential for deeper stratigraphic traps, and suggest alternate production strategies such as horizontal drilling or targeted infill drilling may be warranted.

The results presented here come from three recently cored wells from the Schaben field located in Ness County of west central Kansas (Figure 2.2). This area is located on the upper shelf of the Hugoton Embayment of the Anadarko Basin, on the southwest flank of the Central Kansas Uplift. This area produces oil from Mississippian (lower Meramecian Warsaw Limestone and Osagian Keokuk Limestone) dolomites and limestones. The three cores of this study are from the Osagian interval. The strata represent deposition on a ramp, the dip of which has been accentuated by post-depositional regional uplift. The ramp strata were differentially eroded at the post-Mississippian unconformity resulting in paleotopographic highs (buried hogbacks, Figures1.3-1.5, 2.3). Previously, these strata have been understood using a karst reservoir model based on the truncation of these strata by the post-Mississippian subaerial unconformity (Figure 2.3). The data of this study indicate that original depositional facies and relatively early diagenetic events have a significant influence on present reservoir characteristics and that later fracturing and dissolution from karst and/or structural influences are locally important but may not be the primary control on favorable reservoir conditions. The results presented here are providing predictive capabilities to better characterize the many existing subunconformity fields in Kansas.

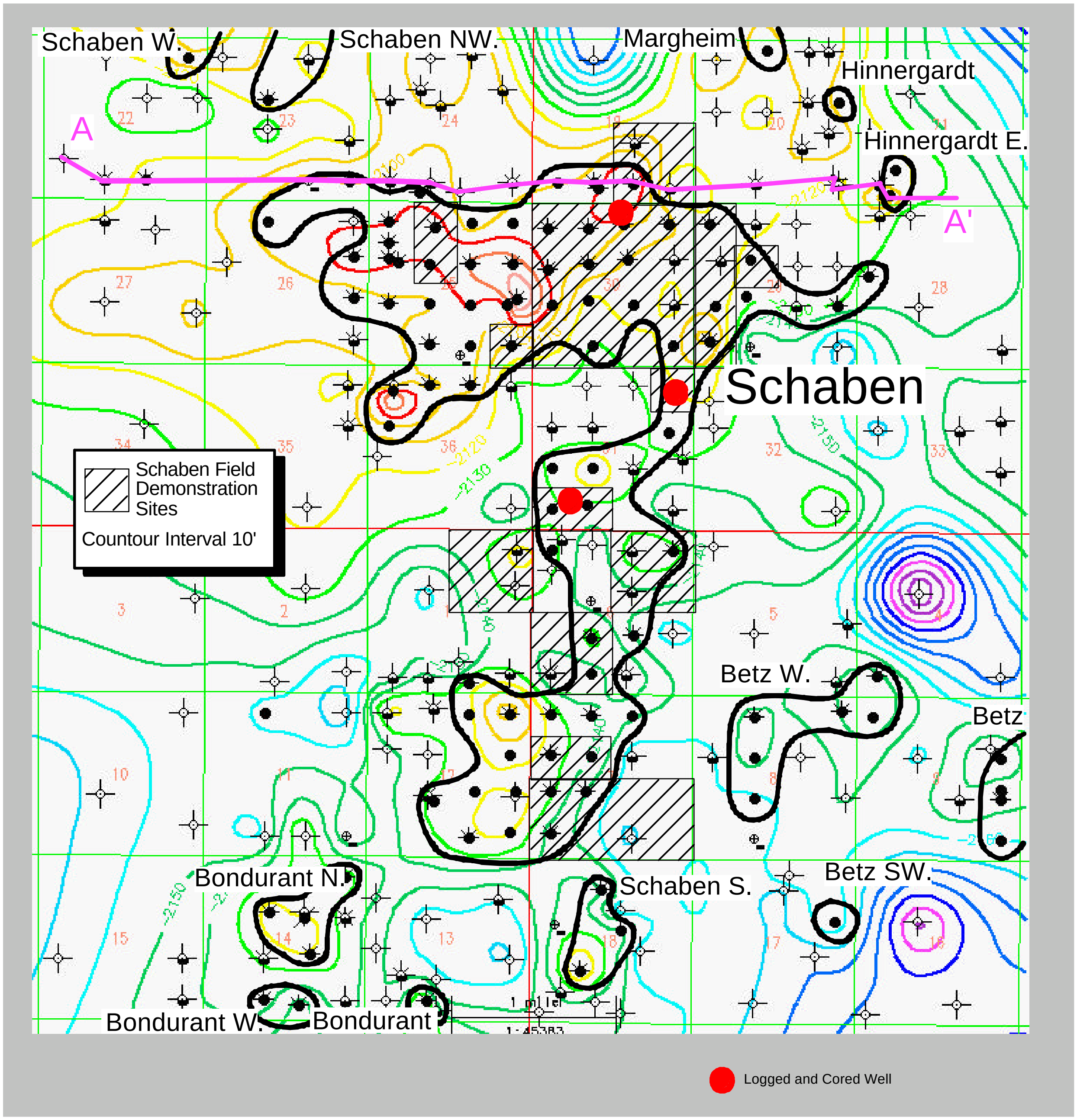



**FIGURE 2.2.** Schaben Field demonstration site with structure on top of the Mississippian Limestone. The Schaben Field outline and location of leases involved in demonstration are indicated. Locations of the three cored wells used for litofacies and petrophysical analysis are indicated.

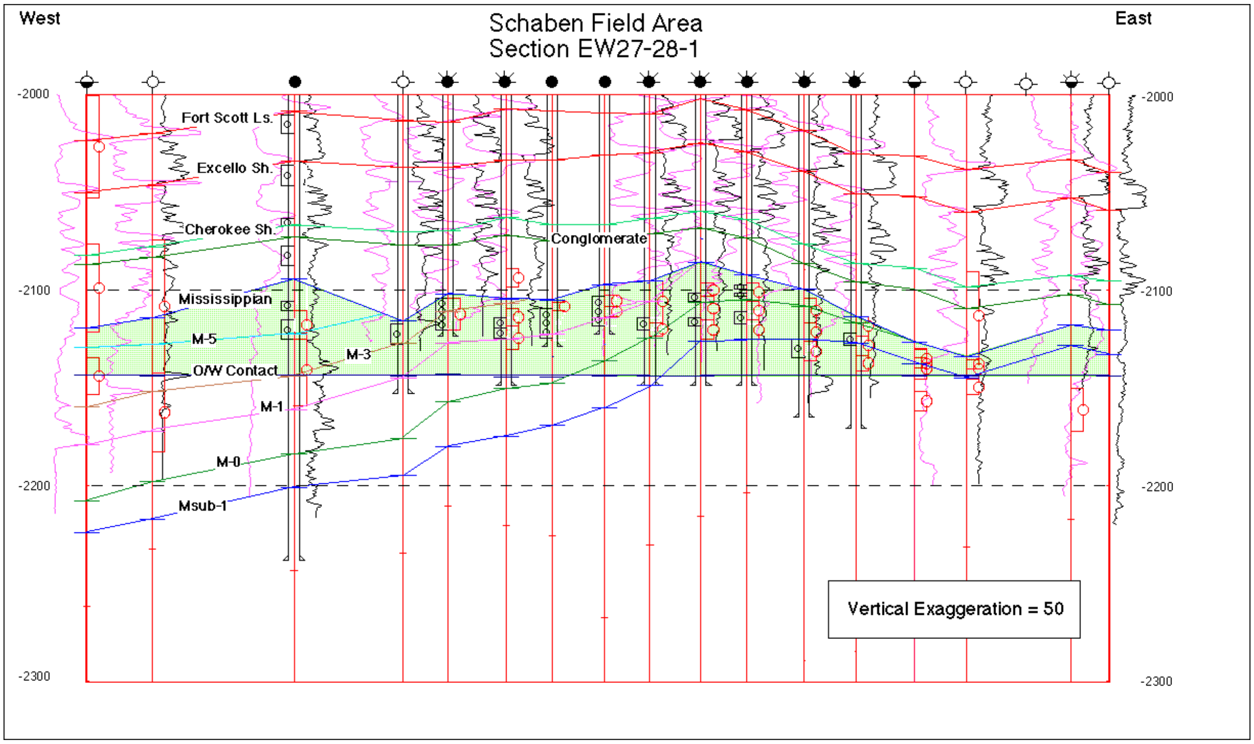



**FIGURE 2.3.** A selected east-west cross-section across the Schaben Field demonstration area (Cross-section EW27-26-1). Cross-section shows the erosional Mississippian surface, geologic tops, original oil-water contact and other well data (e.g., perforations, DST's, casing). This is an example of one of many cross-sections available from the Internet (http://www.kgs.ukans.edu/DPA/Schaben/CrossSect/EW27281.html).

The following depositional facies were recognized in the cores.

1) Sponge Spicule-rich Wacke-Packstone (SWP): SWP facies are especially abundant in the upper portions of the cores and form an important reservoir facies. This facies, dark to light gray, olive green, tan, or brown in color, is characteristically mottled from burrowing, or wispy to wavy horizontal laminated. Sponge spicules (mostly monaxon) and their molds are the dominant, and commonly exclusive, grain type. Echinoderm, bryozoan, gastropod, and peloid grains occur more rarely. The sponge spicules are locally concentrated in layers or in "pockets" as a function of depositional processes (currents) and reworking by burrowing organisms. Moldic, intercrystalline, and vuggy porosity are locally abundant, and fenestral porosity occurs more rarely. Some primary porosity is solution enlarged forming vugs. The mottling texture and concentration of grains in layers locally results in variable tight and porous areas at a thin section scale. This facies has been extensively dolomitized. Dolomite occurs as very finely crystalline to aphanocrystalline (~20 µm to <100 µm), subhedral to anhedral crystals; where developed, euhedral crystals contain more intercrystalline porosity. The SWP facies commonly contains silica replaced evaporite crystals, nodules or coalesced nodules that form layers. Silica variably replaces matrix and grains. Brecciation is common, likely from dissolution and collapse of evaporites and early differential compaction between brittle chert and soft dolomitic matrix.
2) Mudstone-Wackestone (MW): MW facies occurs throughout the cores but is most abundant in upper portions of the cores. It is very similar to SWP facies except that identifiable skeletal grains or their molds are rare in MW facies and MW facies is typically tight or has minor moldic, intercrystalline, and vuggy porosity only locally developed.
3) Echinoderm Wacke-Pack-Grainstone (EWPG): EWPG facies is most abundant in the lower parts of the cores. Echinoderm fragments are typically dominant but abundant sponge spicules, bryozoan fragments, brachiopods, coral fragments, gastropods, ostracods, ooids, peloids, grapestone, calcispheres, oncolites, and other unidentifiable skeletal debris also variably occur. This facies has been extensively dolomitized. Where dolomitic, grains in this facies are typically preserved as molds. Horizontal laminations and low-angle cross laminations are locally preserved. Some intervals show sorting of grains into finer-grained layers and coarser-grained layers. Other intervals show normal grading of grains. Evidence for abundant early compaction is rare. However, locally, grains in this facies show compromise boundaries, overly-close packing, grain breakage and flat, horizontal alignment of skeletal fragments. EWPG facies is characteristically tan to dark brown in color and typically has a wispy laminated or mottled texture; locally it has a massive texture. Locally, interbedded skeletal rich layers (more porous) and skeletal poor layers (tighter) result in an alternating porous and tight layering within this facies. Moldic, intercrystalline, and vuggy porosity in this facies can exceed 35% (visual estimate). Dolomite is typically very finely crystalline (~50 µm or less) but locally exceeds 150 µm. Crystals are typically subhedral to euhedral. Some of the crystals are zoned with a clear to turbid (locally calcian) center and clear dolomite rim. Partial or pervasive replacement and cementation by chert, clear megaquartz and chalcedony is common. Where this facies has been silicified, grains have either been replaced with textures preserved or their molds are filled with silica or calcite cement; an isopachous chalcedony cement coats grains and locally lines primary pores. Abundant microcrystalline porosity occurs within tripolitic chert areas and both tripolitic and porcelaneous chert typically contains micro- and mega- fracture porosity Vugs developed within chert areas are partially or fully filled with silica cement. Fenestrae occur locally and are partially or fully filled with silica cement.

A general upward facies pattern from bottom to tops of cores is discernible in all three cores. Echinoderm facies predominates in the bases of all the cores (M0 unit, Figure 2.3). Although a variety of facies occur, importantly, evidence of evaporites is generally lacking. The upper portions of all cores (M1 unit and above) are dominated by sponge spicule-rich and mudstone/wackestone facies and contain abundant evidence of evaporites. Correlations of facies in cores and well-logs indicate deposition on a ramp. The abundance of echinoderm-rich facies with other diverse fauna, abundance of burrowing organisms and only rare occurrence of evaporites in M0 suggest deposition in relatively normal to somewhat restricted marine environments. In contrast, the abundance of mudstone, wackestone and spicule-rich facies, relative rarity of echinoderm-rich facies, and abundance of evaporites in M1 and above suggest deposition in restricted, evaporitive ramp, lagoon or supratidal environments. However, the abundance of burrow mottling indicates conditions sufficient to support organisms that reworked the sediment. Evaporite characteristics (radiating blades, isolated to coalesced nodules, and coalesced vertically elongate nodule layers) indicate formation in a supratidal to shallow subaqueous setting at or just below the sediment/water interface. Local fenestral fabric indicates at least intermittent subaerial exposure.

EWPG facies are mostly characteristic of a shallow subtidal ramp setting. Horizontal lamination, cross-lamination, normal grading, packing of grains, grain breakage, and scoured contacts evidence at least intermittent high energy. In the M0 unit, this facies likely represents deposition from storm and turbidity currents or from migration of subtidal shoals or banks. Local fenestral fabrics in the echinoderm facies, especially in the M1 unit, indicate at least local subaerial exposure. Local echinoderm-rich layers in the M1 unit may represent shelfward migration of subtidal shoals or shelfward deposition from storm currents.

SWP and MW facies are more indicative of a low energy and restricted setting. Although sponge spicule facies are commonly thought to represent deeper water basinal sections, their association with evaporites and local evidence of subaerial exposure evidence shallow water environments. As demonstrated by studies in other areas, sponges thrived and likely formed sponge mats, gardens or mounds in this environment. Local wispy and wavy horizontal lamination, horizontal planar lamination and interbeds of grainstone in mudstone to packstone indicate transport and reworking of sediment by currents likely generated from tides or storms. The change between the normal to restricted marine ramp (M0 unit) and the evaporitic ramp to lagoon (M1 unit and above) is marked by a sharp contact (termed the M1 surface). This surface and the strata immediately below for several meters show significant alteration. A coarse calcite cement and replacive poikilotopic calcite is associated with the M1 surface and occurs variably throughout strata below this surface to the bottom of the cores. This cement is very important for occluding porosity in strata below the surface. A similar calcite cement and calcite replacement in the upper five feet of the cores is presumably a separate event related to post-Mississippian subaerial exposure. The interpretation of two separate events is supported by:

1) the absence of calcite in strata lying between the M1 surface and the occurrence of calcite in the upper five feet,
2) fractures that were filled with coarse calcite cement below the M1 surface are cross cut by fractures filled with sediment from facies overlying the M1 surface, and
3) brecciated areas just below the M1 surface that contain clasts of the poikilotopic calcite-replaced facies in dolomitic matrix.

These features are not observed in strata above the M1 surface. The strata immediately below the M1 surface contain local fenestral fabric, fractures, breccia, autobreccia, clay-rich horizons with abundant horizontal fenestrae interlaminated with fine- to coarse-grained detrital quartz, locally abundant glauconite, oblong altered areas with abundant fenestrae and local branching, downward tapering microfractures (roots?). In combination, these features and crosscutting relationships strongly support a subaerial exposure event at the M1 surface.

Petrographic, minipermeameter, and nuclear magnetic remanence (NMR) data indicate SWP facies with abundant original evaporites are the most favorable reservoirs. EWPG facies are also locally favorable reservoir facies. Burrow mottling was very important in creating networks for later diagenetic fluids that resulted in variable porous and tight areas on macroscopic and microscopic scales. Very finely crystalline (<10-50 μm) dolomite is characteristic of early reflux or mixing zone dolomitization. The predominance of original evaporites in M1 strata is supportive of a reflux mechanism. Early dissolution of grains and dolomitization created moldic, intercrystalline and vuggy porosity important for favorable reservoir conditions.

Silica cementation and replacement of original lithologies is abundant throughout all three cores and replaces all facies types. The abundance of silica replacement is at least partially due to the abundance of sponge spicules. Early silica cementation and replacement is evidenced by silicified areas closely following burrow networks, displacive growth of silica nodules, brittle fracturing of silica areas and soft-sediment deformation of surrounding dolomite sediment and fractures in silica filled with dolomitic sediment. In addition, preservation of radiating bladed evaporite crystal and nodule textures without much breakage or compaction is supportive of early silica replacement. Silica replacement and cementation tend to result in relatively tight and pervasive replacement in EWPG facies whereas in SWP and MW facies, silica replacement is variable, especially where evaporites were replaced and contain more moldic and vuggy porosity. Brittle fracturing results in local micro- and macro-fracture porosity The silicified areas in EWPG are typically tight and form impermeable layers. However, some silicified areas contain abundant microcrystalline, vuggy and moldic porosity (tripolitic chert). In SWP and MW facies, silica replacement may partially or totally replace matrix and grains or replace the dolomite matrix and leave spicules as molds.

Silicified areas, MW facies and local shale layers that tend to be tight impart a complex vertical heterogeneity in the cores. Minipermeameter data collected every 0.25 feet (0.08 meters) support macroscopic and petrographic observations and document this vertical heterogeneity at a detailed scale not revealed by whole-core and standard plug data.

The coarse calcite cement and replacement associated with the M1 surface was extremely important in occluding porosity in underlying strata. This is confirmed by low minipermeameter readings, NMR data, the relative lack of oil staining, and the lack of production even where the M0 interval intersects the post-Mississippian unconformity in favorable structurally high areas to the northeast of Schaben Field (Figures 2.2, 2.3).

Brecciation and fracturing are ubiquitous throughout the three cores on macroscopic and microscopic scales. Fracture fill and breccia matrix includes shale, subangular to rounded, silt- to coarse-grained size detrital quartz, chert, megaquartz, chalcedony grains, carbonate micrite, carbonate grains, and skeletal grains. Clasts (ranging from rounded to angular) include chert/chalcedony/megaquartz fragments, clasts of original carbonate facies, replacive poikilotopic calcite clasts, coarse calcite cement fragments, and rubble of red and greenish limy clay.

Brecciation and fracturing were caused by a variety of processes interacting at different times. Some areas reveal several generations of fracturing, brecciation, cementation and sediment fills resulting in complex fabrics. As discussed earlier, early differential compaction between silicified areas and surrounding matrix resulted in brittle fracturing and soft-sediment deformation of surrounding matrix which imparted a fracture and breccia fabric. Local fracturing and brecciation were caused by early subaerial exposure (M1 surface). Post-Mississippian subaerial exposure, burial compaction and structural uplift resulted in brittle fracturing and brecciation of all facies and previous diagenetic events. Early and late fracturing and brecciation variably enhanced or destroyed reservoir characteristics as indicated by minipermeameter and NMR data and oil stain patterns. Fracture and breccia matrix porosity that remained open results in vertical communication among the thin intervals with favorable reservoir characteristics controlled by depositional facies and early diagenesis.

Historically, topographic highs just underlying the post-Mississippian unconformity are viewed as the most favorable locations for petroleum exploration and production. This study indicates that structurally uplifted and tilted Mississippian ramp strata were differentially eroded at the post-Mississippian unconformity resulting in a complex buried paleotopography. Sedimentologic, stratigraphic, diagenetic, petrophysical and well log data indicate that the most favorable areas for successful production may be where SWP facies originally containing abundant evaporites intersect the post-Mississippian unconformity and form the topographic highs. In contrast, areas where EWPG facies intersect the unconformity and form topographic highs are more variable as to reservoir characteristics. Our results indicate that M0 strata are relatively tight due to calcite cementation and replacement associated with subaerial exposure at the M1 surface and, therefore, are not favorable reservoir intervals. The fact that M0 strata are not productive where the M0 interval intersects the post-Mississippian unconformity in structurally favorable positions to the NE of our study area confirms the above prediction and highlights the value of detailed sedimentologic and diagenetic studies for understanding the relative importance of controls on reservoirs and providing predictive capabilities.

Although drilling strategies have been based on a karst-controlled model, the complex vertical heterogeneity and significance of depositional facies and early diagenesis in controlling reservoir architecture demonstrated in this study indicate that other production strategies such as horizontal drilling or targeted infill drilling may be viable alternative strategies. Future studies should address whether or not fracture porosity is necessary for making the depositional and early diagenetic controlled reservoir facies productive intervals.

## 2.3 Overview of Petrophysical Analyses

*Modified from: 1998, Guy, W.J., Byrnes, A.P., Doveton, J.H., and Franseen, E.K., Influence of Lithology and Pore Geometry on NMR Prediction of Permeability and Effective Porosity in Mississippian Carbonates, Kansas: 1998 AAPG Meeting, Salt Lake City, Utah.*

Saturated and desaturated NMR response was integrated with air-brine and air-mercury capillary pressure analysis and with lithologic and other petrophysical analyses for cores from a carbonate reservoir in Kansas. This integration provides guidelines for selection of appropriate T2 cutoffs in these rocks and an understanding of lithologic controls on permeability prediction using NMR response. Three cores from the Mississippian reservoir, Schaben Field, Ness County, Kansas were studied (Figure 2.1). From these wells, 50 core plugs, representing a wide range in porosity, permeability, and lithology were selected for detailed investigation. Special core-analysis testing was performed on these samples including (for most samples): routine and in situ porosity and pore volume compressibility, routine air and in situ Klinkenberg permeability, air-brine capillary pressure analysis and determination of "irreducible" brine saturation, air-mercury capillary pressure on selected samples, effective and relative gas permeability, determination of the Archie cementation and saturation exponents, and saturated and desaturated NMR analysis for selected samples. Core lithologies were described and thin-sections of representative samples were examined.

The reservoir at Schaben Field is composed primarily of dolomite or lime mudstone-wackestone, sponge spicule-rich wackestone-packstone, and echinoderm-rich wackestone-packstone-grainstone. Porosity within these lithologies is generally intergranular, intercrystalline, or moldic but may also contain a significant portion of vugs. Grain or crystal sizes are fine to micrite size (<100um to <2um) resulting in very fine pores. Brecciation, fracturing, and carbonate replacement with microporous chert are common in all lithologies. Each lithology exhibits a generally unique range of porosity and permeability values, which together define a continuous porosity-permeability trend. Where fracturing and vugs are present, permeability is enhanced and the range in permeability for any given porosity is broadened. Mercury capillary pressure analysis shows that pore throat size for all lithologies is the dominant control on permeability and threshold entry pressures.

Oil columns in this region are generally less than 50 feet. Water saturations, corresponding to the capillary pressure generated by this column, correlate well with permeability for rocks with little or no vuggy porosity or microporous chert. Because of this correlation, permeability prediction using both porosity and T2 is improved over prediction using porosity alone. While a causal relationship exists between effective porosity (and pore body size), measured by T2, and permeability, the relative influence of effective porosity and pore body sizes appears to be small compared to the influence of pore throats. Based on the significant difference in the correlation between T2 and permeability for rocks with and without vugs, it is probable that this correlation is partially based on a correlation between pore body and pore throat size, which can differ between lithologies exhibiting different pore geometries. If this is correct, accurate permeability prediction using NMR will require "calibration" of the T2-permeability relationship for each lithology exhibiting a unique relationship between pore throats and pore bodies. These correlations and the constant or exponents obtained will therefore be lithology specific. However, relationships using T2 in addition to porosity should also provide a significant improvement over permeability prediction using porosity alone. Where vuggy porosity is present, T2 cutoffs appropriate for intergranular porosity do not provide good permeability prediction. Based on these observations appropriate T2 cutoffs for delineating effective intergranular porosity are range from 10 to 100 and increase with increasing permeability and pore throat and body size.

Many Mississippian reservoirs exhibit high water-cuts and low recovery efficiencies, which requires accurate reservoir characterization and assessment for effective reservoir management. Delineation of effective and ineffective porosity and accurate prediction of production potential plays an important role. Conventional logging tools provide significant data but do not generally allow definitive identification of productive and non-productive intervals. NMR logs provide information concerning effective porosity and pore size, both of which can aid significantly in reservoir characterization, but NMR response has not been evaluated against petrophysical properties in these carbonate reservoir systems. Of particular interest are issues concerning the selection of T2 cutoffs, permeability prediction, and the robustness of selected parameters for the wide range of lithologies present in these reservoirs. As part of the Class 2 project the Schaben field has been extensively studied to provide information for the hundreds of other small operators who manage fields with similar characteristics.

<u>Total Porosity.</u> Routine helium-porosity values, measured on core plugs, range from 4 to 26%. Petrographic analysis indicates that porosity is dominantly intergranular or intercrystalline or moldic where the rock is dolomitized. Locally, subaerial exposure and karstification resulted in the development of fenestral or vuggy porosity. Porosity values are generally highest in the grainstones and lowest in the mudstones. *In situ* porosity values, measured at a net confining stress of ~2,000 psi (13,800 kPa), are approximately 96$\pm$6% of ambient values (error represents 2 standard deviations). NMR total porosity values agreed with helium and gravimetric fluid-filled porosity values within the error of the various measurement methods ($\pm$0.1 porosity percent).for 75% of the samples and was off by approximately 1 p.u. for 25% of the samples (Figure 2.4).

<u>"Irreducible Water" Saturation</u>. Air-brine and air-mercury capillary pressure curves indicate that for many of the lithologies present in the Schaben field reservoir there is insufficient oil column to displace water to "irreducible" water saturation levels. Oil columns in the Schaben field range from approximately 35-50ft, corresponding to laboratory air-brine capillary pressures of 15-20 psi and pore entry throat diameters of 2-3 microns. At air-brine capillary pressures of 20 psi, water saturations ($Sw_{20}$) average 26$\pm$5% higher than those near "irreducible" brine saturation, as measured at 1,000 psi air-brine capillary pressure (Figure 2.5). When capillary pressures are insufficient to desaturate a rock to "irreducible" it is important to distinguish between effective porosity as measured by NMR, which represents the volume of the pores involved with total fluid flow, and effective hydrocarbon porosity, which represents the fraction of the effective porosity that is available for hydrocarbon flow. For the carbonates studied here, permeabilities predicted using the effective porosity must be modified to reflect the relative permeability of the actual sample saturations. This requires the development of a correlation between the effective hydrocarbon permeability at the appropriate water saturation and total or absolute permeability.

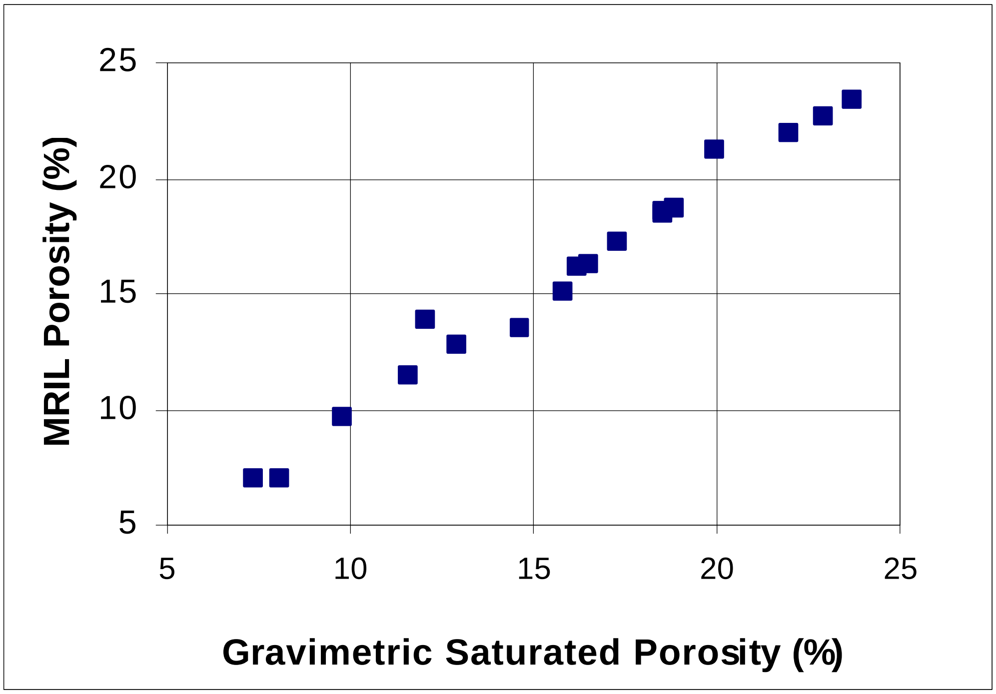



**FIGURE 2.4.** Cross-plot of NMR total porosity versus gravimetric total porosity illustrating high degree of correlation.

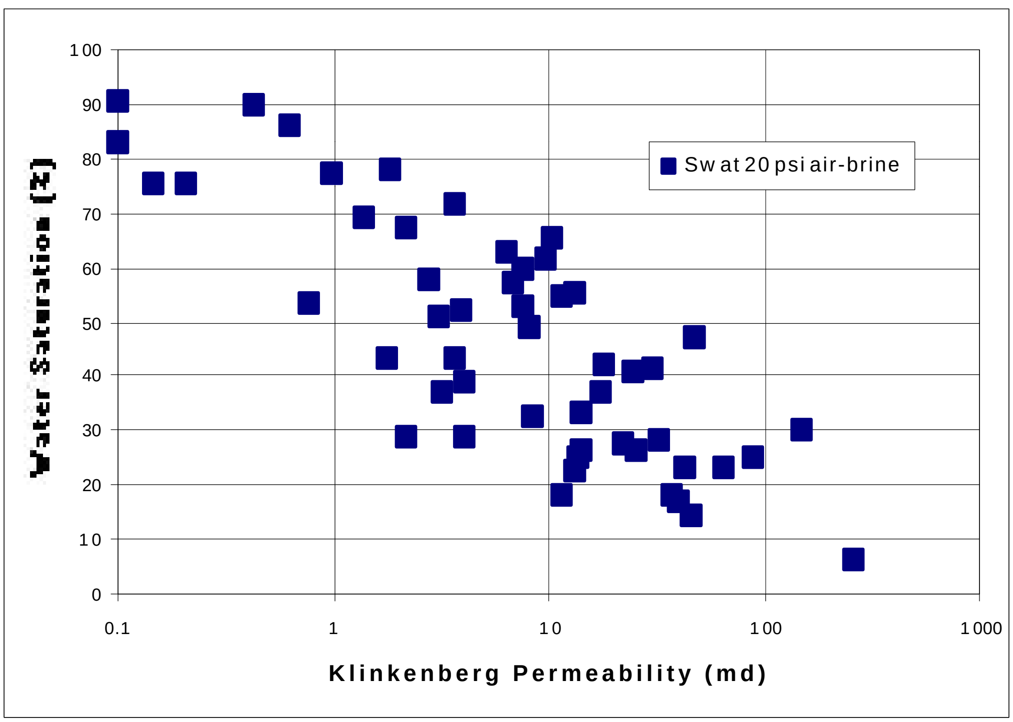



**FIGURE 2.5.** Cross-plot of water saturation at 20 psi air-brine capillary pressure, corresponding to ~50ft of oil column, to *in situ* Klinkenberg permeability.

Permeability. Permeability and other petrophysical properties at the core plug scale are generally controlled by matrix grain size and resulting pore throat diameters. Each grain size class (e.g. mudstone, wackestone, packstone, grainstone) exhibits a generally unique range of petrophysical properties modified by the presence of fractures, vuggy porosity, or grain size variations within the lithologic class. Facies comprising multiple lithologies of differing grain size exhibit different properties within those lithologies. Petrophysical properties for facies that are a composite of lithologies are scale-dependent and are a function of the proportions and architecture within the facies. All lithologies exhibit increasing permeability with increasing porosity and can be characterized as lying along the same general porosity-permeability trend (Figure 2.6). Variance in permeability for any given porosity in rocks that are not vuggy is approximately one order of magnitude and may be primarily attributed to the influence of such lithologic variables as the ratio and distribution of matrix and fenestral/vuggy porosity, grain size variations, and subtle mixing or interlamination of lithologies. Vuggy porosity appears to be isolated in mudstones but is better connected in wackestones.

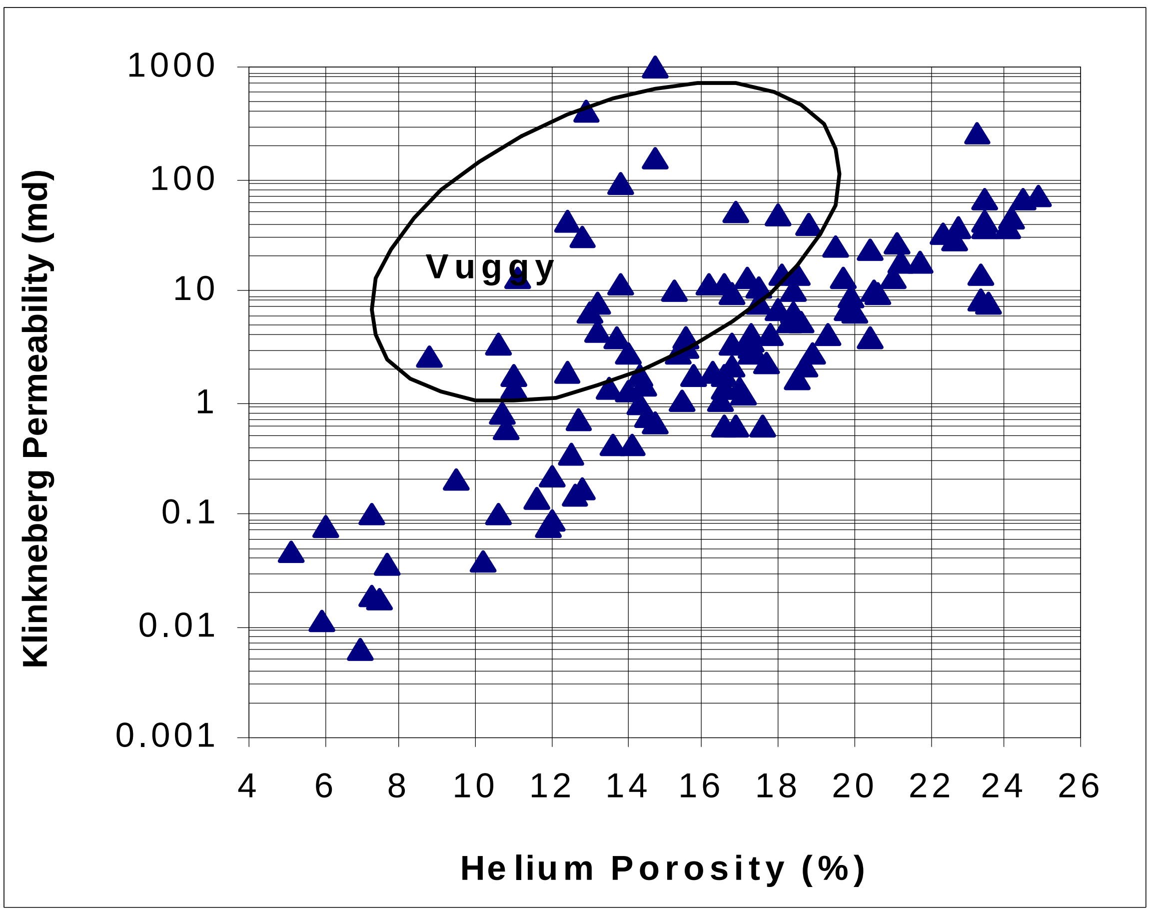



**FIGURE 2.6.** Cross-plot of permeability versus porosity.

Principal pore throat diameters, defined as the largest pores that provide access to the majority of the rock porosity as measured by air-mercury capillary pressure analysis, reveal a high degree of correlation between these variables for these rocks (Figure 2.7).

Recognizing that pore throats are a dominant control on permeability, raises the question as to why T2 provides such a good permeability predictor, or improves the prediction of permeability in conjunction with porosity, given that T2 predominantly measures pore body properties. Correlation of the T2 peak position with pore throat diameters, measured by air-mercury capillary pressure, indicates that pore body size is highly correlated with pore throat size (Figure 2.6). The accuracy of the T2-permeabilty correlation may therefore be based on the strong association between pore body and throat sizes. Within lithologies reflecting primarily just grain size change, but still consisting generally of packed spheres, this association could be anticipated to be uniform. This is consistent with the similar T2 exponents for T2-permeability relationships in sandstones. In lithologies exhibiting pore geometries that are not similar to the packed sphere geometry, the relationship between pore bodies and throats must be different. This should be reflected in a change in the T2 exponent in the T2-permeability equation. Figure 2.7 illustrates the difference in correlations between T2 and permeability between pore geometries that are predominantly intergranular and those that are vuggy.

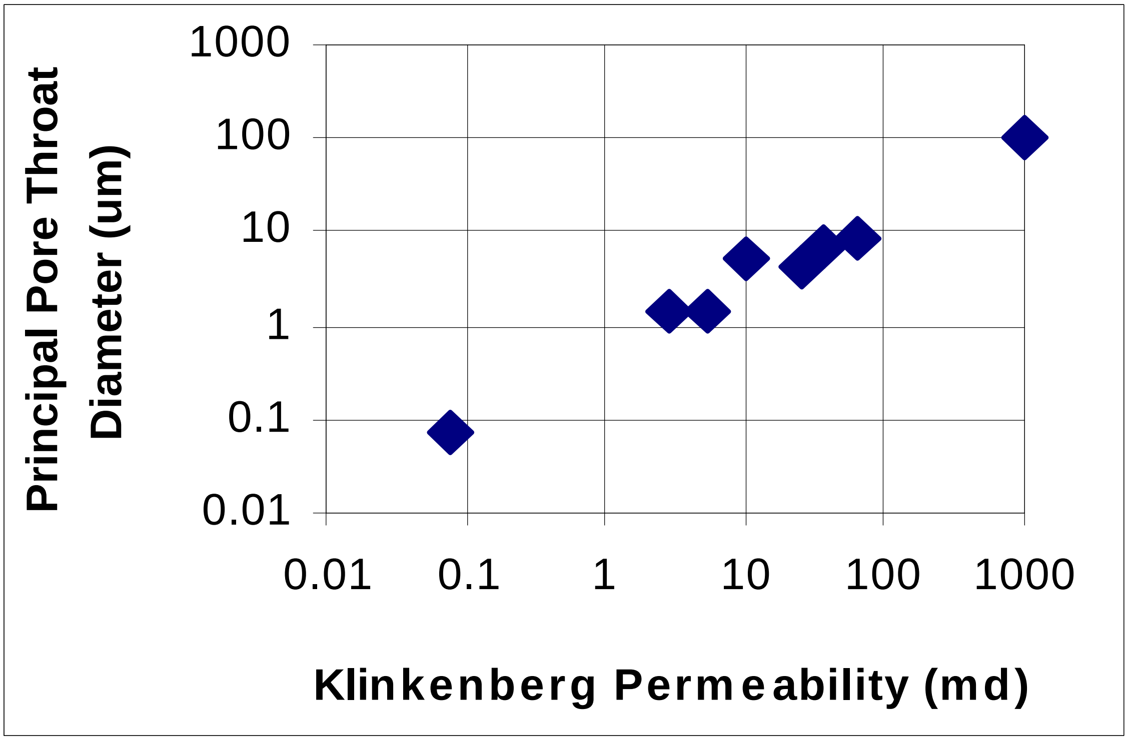



**FIGURE 2.7.** Cross-plot of Klinkenberg permeability versus principal pore throat diameter.

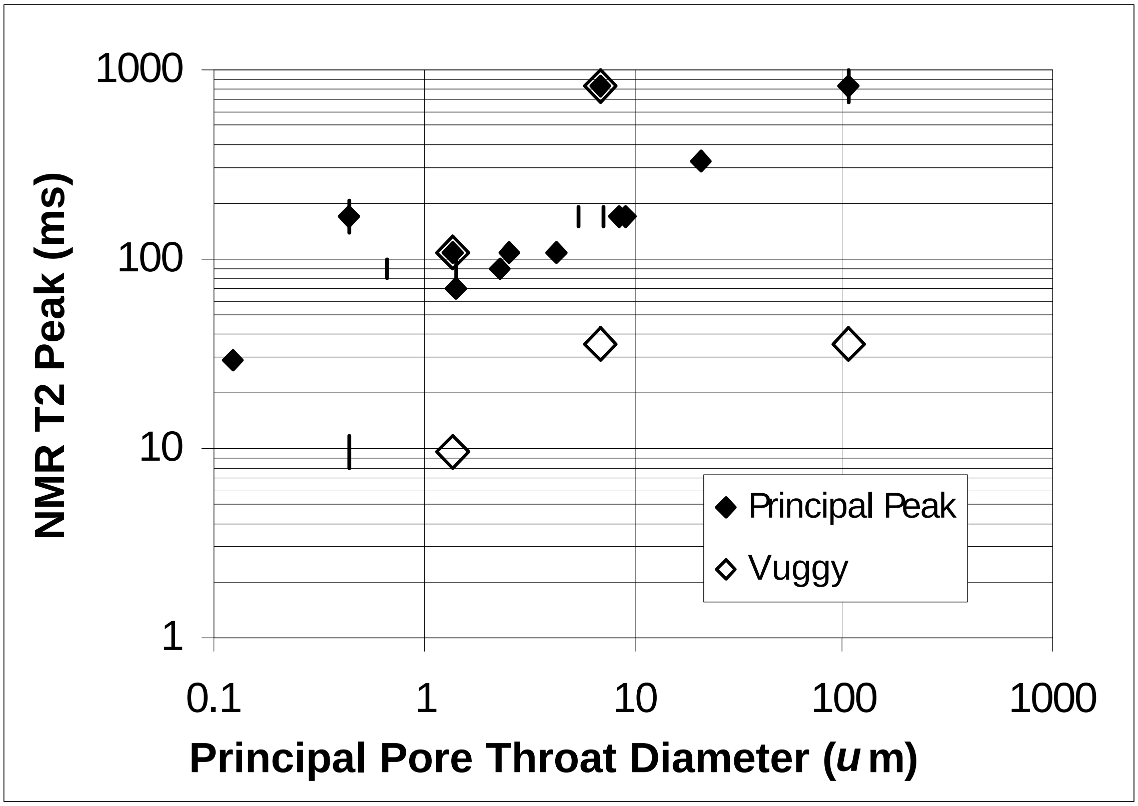



**FIGURE 2.8.** Cross-plot between NMR measured T2 peak position and the principal pore throat diameter as measured by air-mercury capillary pressure.

<u>T2 Cutoff.</u> The relaxation time cutoff for distinguishing between effective and ineffective pore sizes is often reported as 33ms for sandstones and has ranged from 20ms to 225ms for carbonates. For the samples analyzed in this study, to date, cutoff values, defined by the point of divergence of the saturated and desaturated cumulative porosity curves, increase with increasing permeability, and consequently increasing pore body and throat size (Figure 2.9). Rocks with vuggy porosity exhibit significantly greater cutoff values for a given permeability than rocks with intergranular porosity.

<u>Electrical Resistivity</u>. Electrical resistivity measurements for samples with predominantly intergranular porosity exhibit an average Archie cementation exponent of 1.97$\pm$0.09 (Figure 2.10). Vuggy samples exhibit higher cementation exponents ranging from 2.2 to 2.5.

Saturated and desaturated NMR response was integrated with air-brine and air-mercury capillary pressure analysis and with lithologic and other petrophysical analyses for cores from a carbonate reservoir in Kansas. This integration provides guidelines for selection of appropriate T2 cutoffs in these rocks and an understanding of lithologic controls on permeability prediction using NMR response.

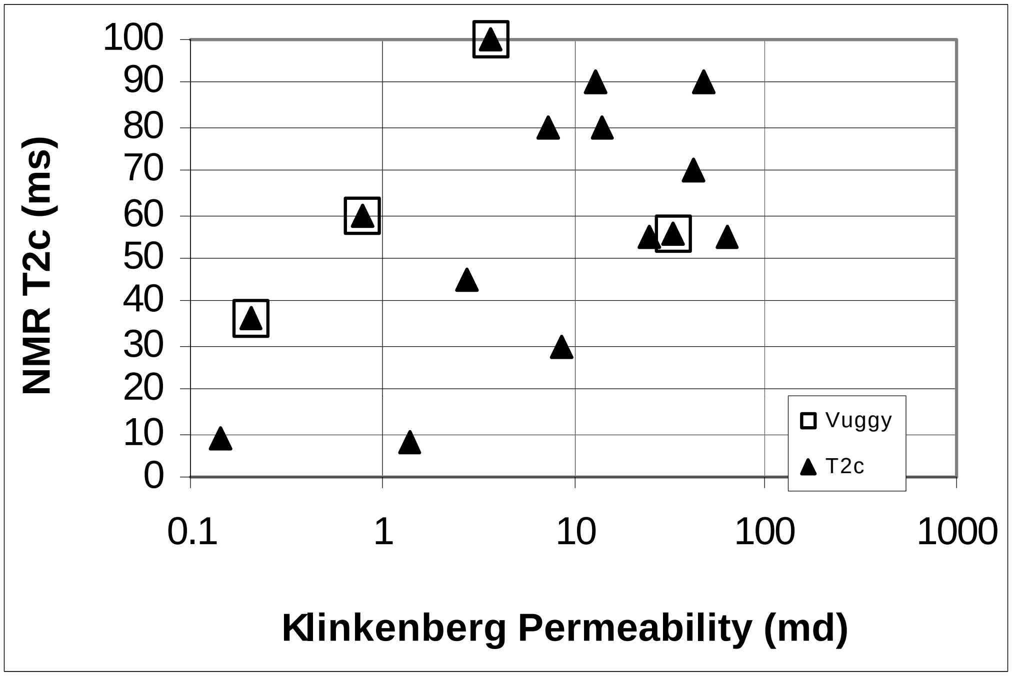



**FIGURE 2.9.** Cross-plot of NMR T2 cutoff and Klinkenberg permeability.

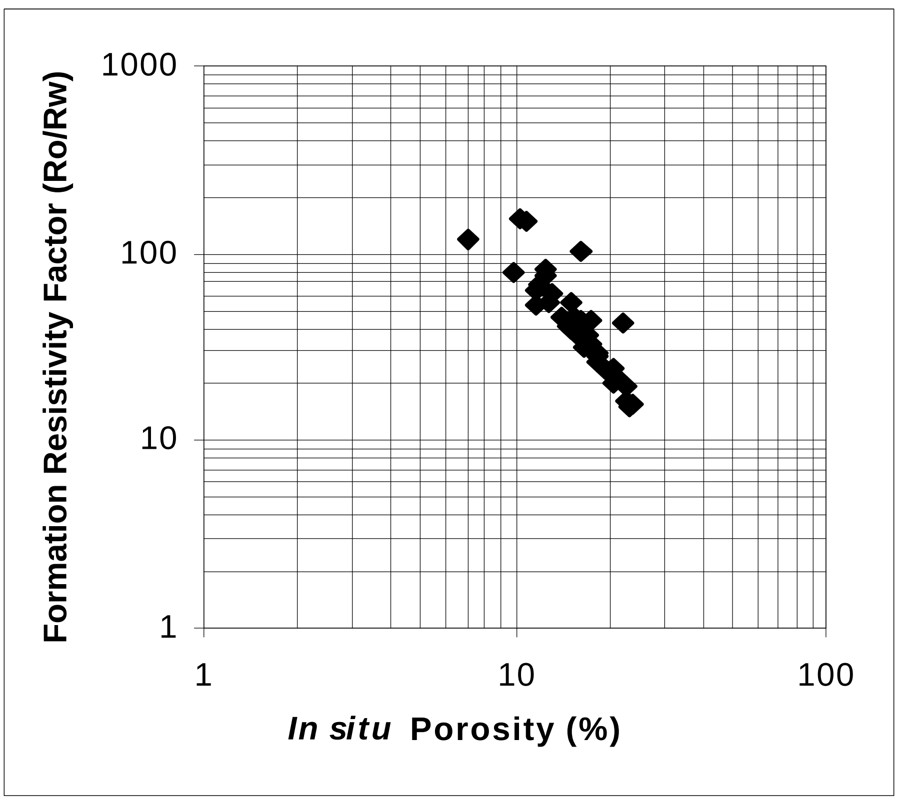



**FIGURE 2.10.** Cross-plot of *in situ* formation electrical resistivity factor versus *in situ* porosity.

## 2.4 Evaluation of Horizontal Drilling

*Modified from: in press, P.M. Gerlach, S. Bhattacharya, T.R. Carr, Cost Effective Techniques for the Independent Producer to Evaluate Horizontal Drilling Candidates in Mature Areas: AAPG Hedberg Conference, International Horizontal Well Symposium: Focus on the Reservoir, http://www.kgs.ukans.edu/PRS/AAPG/papers/gerlach.html.*

Horizontal wells are a cost efficient tool for reservoir management that has not been widely adopted by small independent operators of mature oil fields. Horizontal drilling has been extensively applied as an exploitation and exploration tool in relatively under-exploited reservoirs such as the Austin Chalk and in structurally complex reservoirs. In recent years horizontal technology has been extended to incremental oil recovery in the mature oil fields of southeast Saskatchewan. Though the technological needs in many mature onshore reservoirs are unique, the overall reservoir management objectives and requirements for commercial success are similar to those elsewhere.

Application of horizontal drilling in Kansas has been limited to 28 wells. In Kansas results have been mixed with a few significant successes (Figure 2.11). Operator concerns for appropriate economic return, and difficulty in identifying candidate reservoirs have been the principal factors restricting application of horizontal drilling technology. Recent declines in cost factors have brought horizontal drilling technology within the economic reach of small independent producers. The remaining barrier to wider application of horizontal technology by the small independent is cost-effective approaches to target a horizontal well. We present several low-cost approaches that can be used to evaluate a potential horizontal well. These cost-effective screening techniques apply at the field scale, the lease level, and the well level. The techniques discussed enable the small independent producer to quickly and efficiently evaluate reservoir candidates, and predict performance of horizontal well application.

Kansas is a mature petroleum producing province with many marginal oil and gas fields operated by over 3,000 independent oil producers. As a result of operational and depositional-diagenetic heterogeneities most of these fields have recovery efficiencies of less than 30% original oil in place (OOIP). This low recovery efficiency results in significant remaining oil in place (ROIP). Operators can use horizontal technology to add new reserves by exploiting the ROIP in their existing fields, and to more efficiently recover known oil and gas reserves.

Operational heterogeneities are inherent in field development practices and results in significant ROIP. Examples of operational heterogeneities include inadequate drainage due to excessive well spacing, openhole/partial completions, bypassed attic oil, thin pays, and water coning. Depositional-diagenetic reservoir heterogeneities due to vertical and lateral variability of petrophysical properties create compartments in the reservoir. These types of heterogeneities are a function of original depositional architecture and the subsequent diagenetic overprint. Examples include highly variable pore geometry of carbonate rocks, anisotropic permeability in fractured reservoirs, and stratified flow units.

Cost-effective screening tools. The primary screening tool for identifying candidate reservoirs is "quick-look volumetric" calculations. This method uses only one well per unit area (e.g., quarter section) to identify pay height, porosity, and saturation to compute OOIP. These reservoir properties can be estimated from public domain data and computed using simple log analysis programs. PfEFFER, a low cost integrated log analysis tool developed by the Kansas Geological Survey, is used to identify well flow units, associated petrophysical and reservoir properties, and potential for production. Cumulative production per quarter section is then divided by OOIP to calculate recovery efficiency. The mapping of recovery efficiency across the field identifies target areas for further study. Regions with low recovery efficiency are those most likely to yield additional or incremental hydrocarbon reserves.

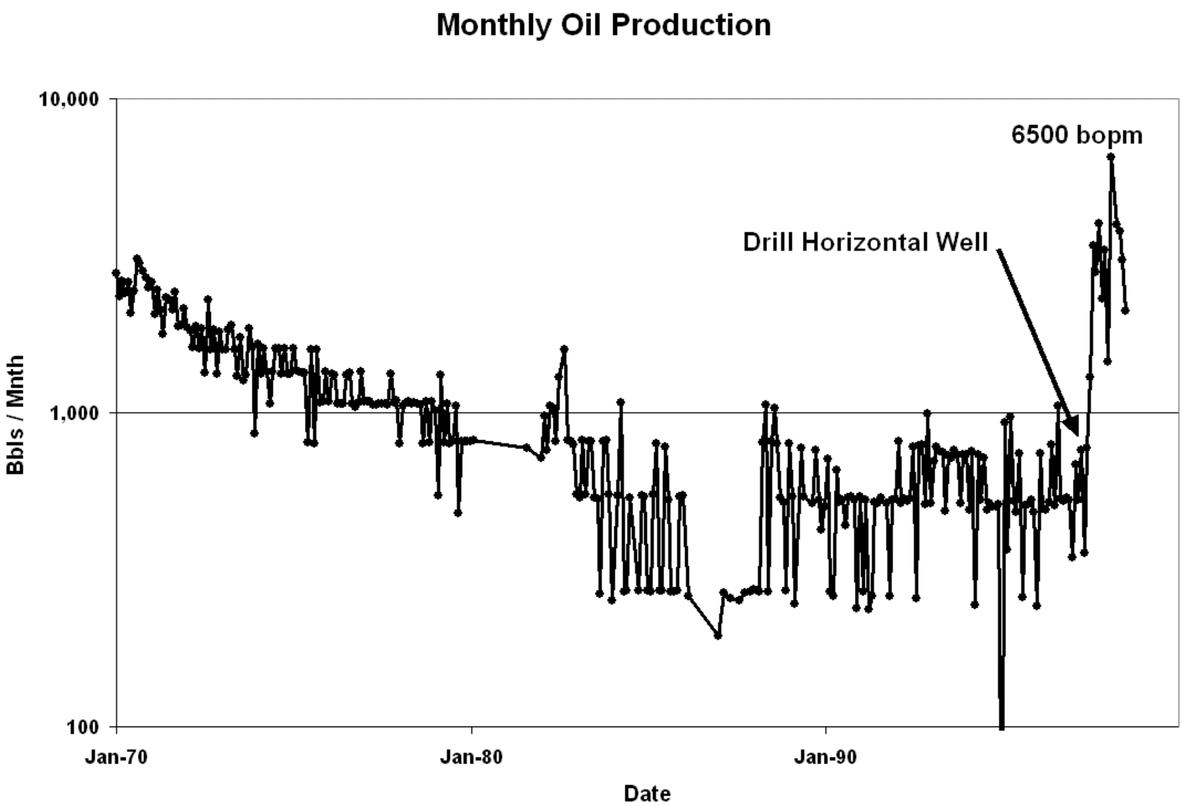



**FIGURE 2.11.** Effect of a horizontal well on oil production in the Wieland West Field, Hodgeman County Kansas.

Detailed volumetric calculations at the lease level can be used to further evaluate potential target areas. Information from all wells on a lease is used to calculate and compare recovery efficiency between adjacent leases and adjacent wells. Mapping well production, normalized by petrophysical parameters, can approximate sweep efficiency between wells. Well production is normalized by dividing cumulative production by the product of payheight, hydrocarbon saturation, porosity, and horizontal permeability. NMR measurements on selected core plugs in reservoirs with significant micro-porosity are used as a cost-effective approach to separate total porosity from effective porosity. Permeability data can be estimated from well tests or by using porosity-permeability crossplots developed from core plug studies. Areas with low normalized production values suggest high reservoir heterogeneity and less effective sweep.

Following volumetric screening, the next step in the candidate selection process is identifying of the cause of poor recovery efficiency. The causes can be many-fold, but in Kansas the most prevalent are stratified thin pays, attic oil, excessive well spacing, coning due to strong water drive, and fractured reservoirs. ROIP in stratified thin pays can be identified by comparing initial rates of production and cumulative production between wells with similar payzone properties but different completion procedures. Attic oil is a common result of well spacing or lease boundaries coinciding with the structural axis of a payzone. First derivative maps show the change in the structural dip and can be used to identify the attics of a structure with undrained reserves. A simple method to determine excessive well spacing is to compare estimated ultimate production between primary vertical wells and infill vertical wells in an analog field. Analysis of lease total fluid production through time is a quick and cost effective method to suggest water break-through as a result of coning.

The final step in the candidate selection process is reservoir simulation to accurately identify ROIP on a grid cell by grid cell basis. Boast4, a freeware black oil simulator, was used to history match the performance of the Schaben Field, (Ness County, Kansas). Remaining hydrocarbon saturation-feet map (Figure 2.12) from this simulation was used to select areas with greatest potential for infill drilling. Boast VHS (vertical-horizontal-slant) simulation was used to predict and compare the performance of infill vertical and horizontal wells.

The Kansas Geological Survey has been working to develop and transfer cost-effective technologies to evaluate a potential horizontal target. We believe that small independents can successfully apply horizontal drilling technology to recover additional oil and gas in mature areas. Our approach recommends low-cost techniques to understand reservoir heterogeneity, to evaluate recovery potential at the field, lease and well scales, and to characterize and simulate candidate reservoirs.

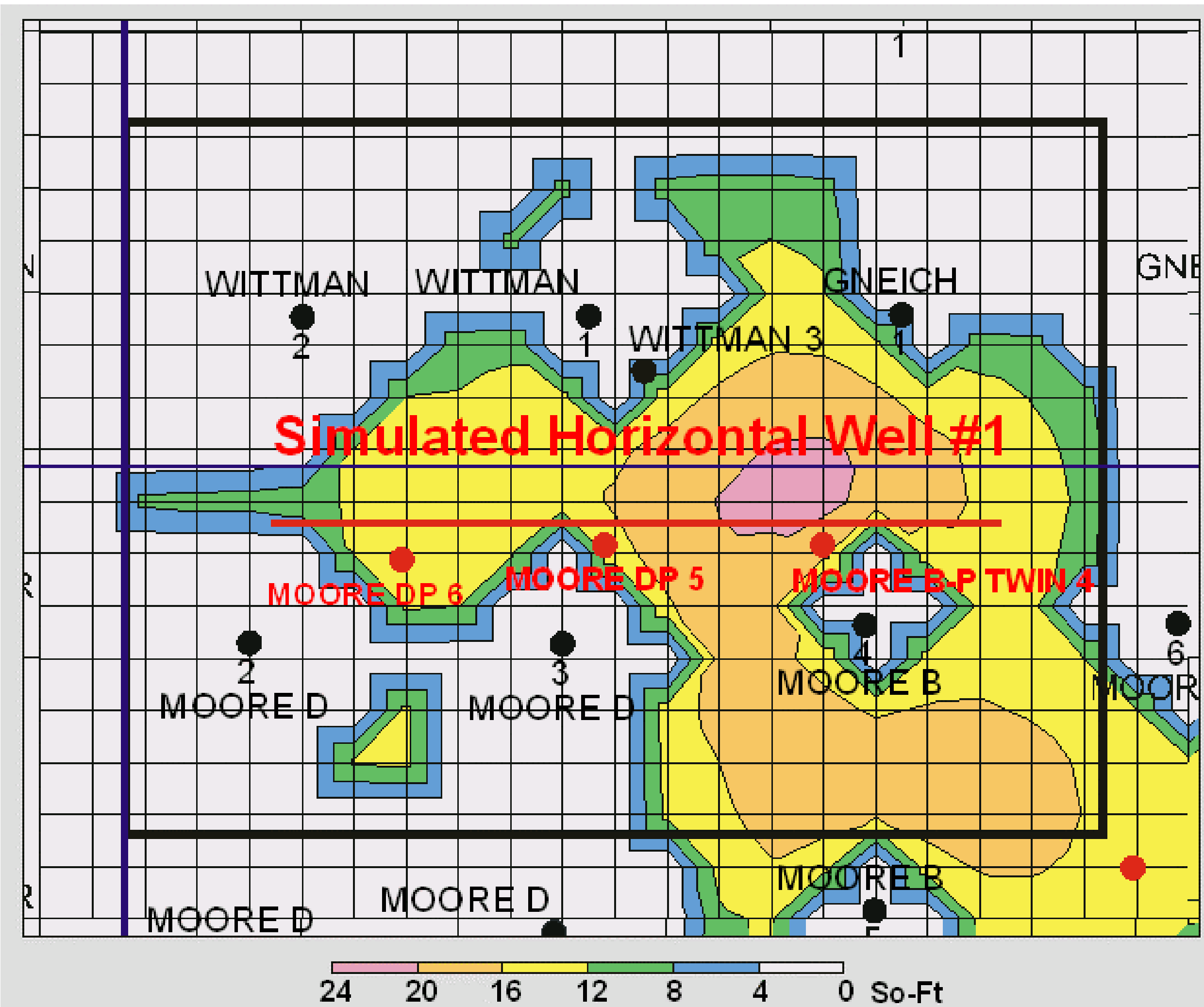



**FIGURE 2.12**. Remaining hydrocarbon saturation-feet map with possible vertical and horizontal infill locations base on the reservoir characterization and simulation at Schaben Field.

## 2.5 Synopsis of PfEFFER

The petrophysical analysis and reservoir evaluation computer package (PfEFFER) was enhanced in conjunction with the Class 2 project. PfEFFER version 2.0 and PfEFFER Pro were released in February 1998. Prototype software was tested and successfully applied in Schaben Field. PfEFFER stands for "Petrofacies Evaluation of Formations For Engineering Reservoirs" (Doveton and others, 1995).

The minimum log data required by the spreadsheet-based software are a porosity and resistivity log. Old logs are well suited to this analysis once they are digitized or simply typed into the spreadsheet. Toolbars and menus perform most operations through the utilization of nearly 8,000 lines of Visual Basic code. PfEFFER v. 1 reads standard LAS log data files such as those obtained from a logging truck or permits manual entry, organizes digital data by well and zone, and creates a "Super Pickett" crossplot, depth plots, and lithology solutions (if sufficient logs are available (Figure 2.13).

The software is focused on interpreting and analyzing reservoir pore type, permeability trends, and variations in mineral composition. PfEFFER provides procedures for optimal estimation of bulk volume water and water saturation (including irreducible values) to better evaluate potential production, reservoir quality, and heterogeneity. Also capillary pressure data can be incorporated to further calibrate well log data with pore size or to assess depth to the free water level. The program will assemble zonal information from well workbooks into a project workbook and can automatically generate map and 3-D visualizations of key parameters as defined by the user. "Hot links" are maintained in the project workbook to each well workbook to aid in data management (Figure 2.14).

All of the standard EXCEL features continue to be available to users for independent analysis and data exploration. The simplicity of hardware and software requirements means that PfEFFER is an attractive option for companies of all sizes. The range and versatility of module capabilities makes them powerful tools for the analysis of both old log suites and the latest generation of logging measurements.

In addition to revising the appearance of the spreadsheet and refining the modules as described above, PfEFFER v. 2.0 contains new modules. The new features in PfEFFER v. 2.0 are:

1) Vshale (shale proportion) can be calculated, based on either the gamma ray or the neutron and density porosity logs.

2) Porosity can be calculated using density, neutron, density/neutron, or sonic with and without correction for shale volume.

3) Shaly sand models are available for Sw calculation. Sw model menu permit selection of Archie water saturation model (the default) and two shaly sand models, the Simandoux model and the dual-water model.

4) Hough Transform is included. The Hough transform is used for simultaneous solution of Archie equation constants and formation water resistivity.

5) Secondary porosity is calculated as the difference between the total porosity (from density or neutron porosity) minus sonic porosity.

6) Moveable hydrocarbons can be determined (Figure 2.15). Based on the assumption that the zone near the well is permeated with mud filtrate, the Archie equation is used to compute Sxo, the filtrate saturation of this flushed zone. Sxo is used to compute moveable and residual hydrocarbon saturations. PfEFFER generates a moveable oil plot consisting of bulk volume water, bulk volume fluid, and porosity. Difference between BVF and BVW represents the moveable hydrocarbon saturation.

7) Lithological analysis now includes two options in PfEFFER v. 2.0, one based on the RHOMAA-UMAA plot and the other allowing a more general selection of logs and system components. The general option allows user to compute up to six components based on up to five logs. Any log can be employed and the component selection is at the discretion of the user.

8) Depth-constrained multivariate cluster analysis can be employed to segment the entire spreadsheet into subintervals based on user-specified set of logs. A hierarchical cluster (Ward's method) is used to produce subintervals that are as homogeneous as possible and distinct as possible from each other, in terms of their log characteristics. Option is useful in evaluating flow units and can be used as a blocking function.

9) Forward modeling module implements equations to predict values of rx, capillary pressure, and hydrocarbon column height for a range of water saturation values based on specific values of permeability and porosity.

10) Pay flag cuttoff can be activated to add color to cells of selected variables used to determine pay (porosity, BVW, Sw, and Vsh) and to color cells in the pay column according to pay and non-pay intervals.

Three additional modules (add-ins) are available as PfEFFER Pro. These modules include color cross section generation, map coordinate conversion (longitude-latitude to UTM x-y), and software to help build an input file for a reservoir simulator based on the petrophysical characterization. DOE's freeware reservoir simulation software, BOAST 3, was used in the development and testing.

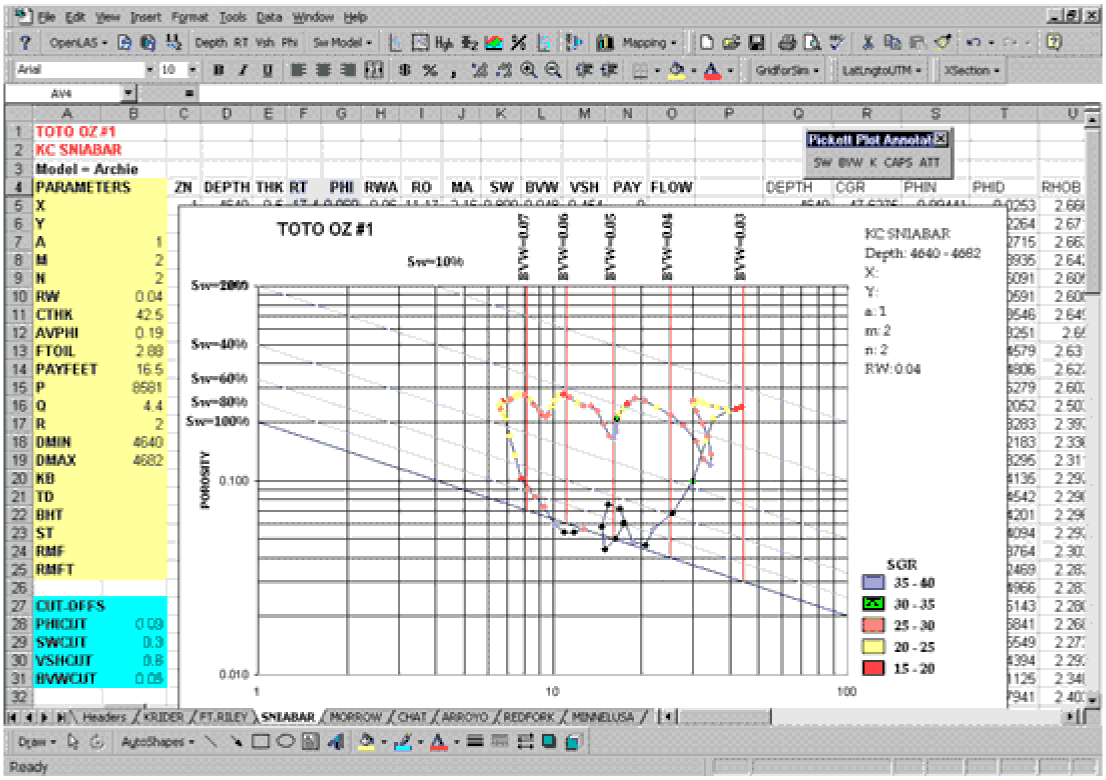


**FIGURE 2.13.** The "Super Pickett" crossplot is the focal point of the analytical routines and graphical displays are an extension of the standard log-log porosity/resistivity plot. The special features include tracking the pattern of data points by depth, and annotation of the crossplot with bulk volume water and permeability lines in addition to the standard water saturation lines.

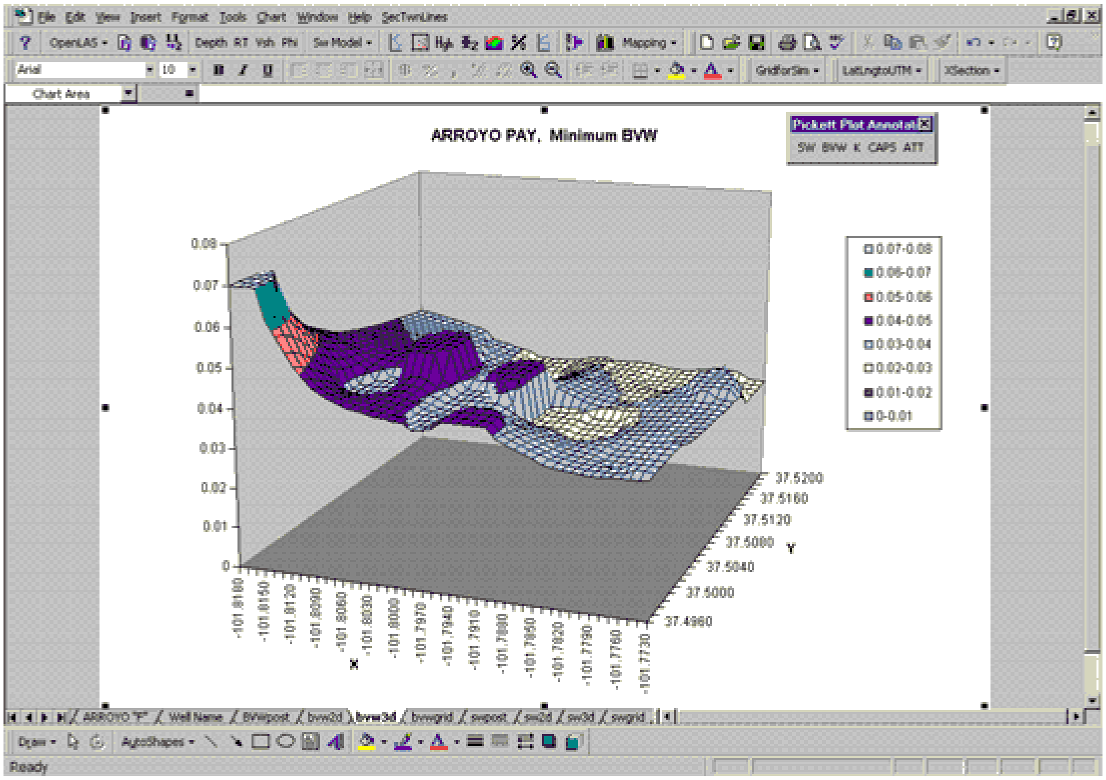



**FIGURE 2.14.** The PfEFFER 2.0 Mapping module produces a "first-look" map to examine spatial variability/continuity among wells, assess reservoir heterogeneity, and evaluate the consistency of the variables being mapped. The "mapping" or project workbook is electronically linked to "well" workbooks and associated "reservoir" worksheets. Information changed in a reservoir worksheet level is reflected in the mapping workbook. Griding, base map generation, 2-D and 3-D visualization of the parameters are accomplished automatically

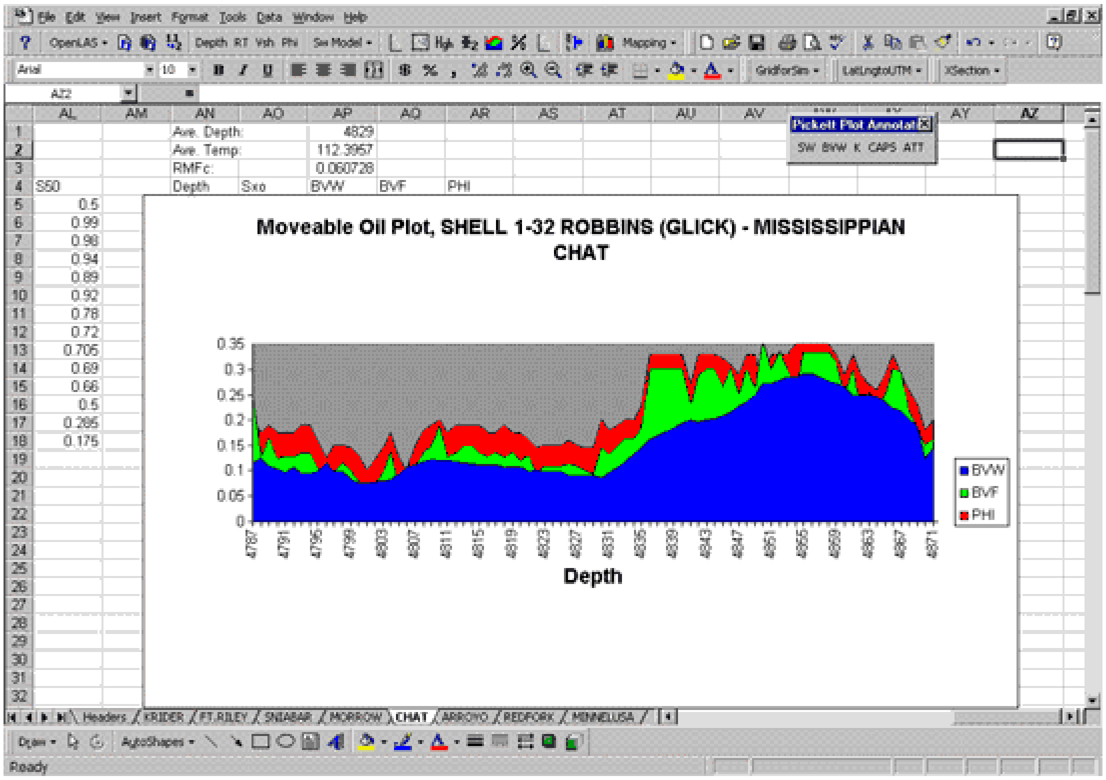



**FIGURE 2.15.** Based on the assumption that the zone near the well is permeated with mud filtrate, the Archie equation is used to compute Sxo, the filtrate saturation of this flushed zone. Sxo is used to compute moveable and residual hydrocarbon saturations. PfEFFER 2.0 generates a moveable oil plot consisting of bulk volume water, bulk volume fluid, and porosity. Difference between BVF and BVW represents the moveable hydrocarbons saturation.

## 2.6 Cost-Effective PC-based Reservoir Simulation and Management

*Modified from: 1998, Gerlach, P, and S. Bhattacharya, T. R. Carr, Application of Cost-Effective PC-based Reservoir Simulation and Management - Schaben Field (Mississippian), Ness County, Kansas: 1998 AAPG Meeting, Salt Lake City, Utah.*

In today's competitive economic climate, cost-effective production technology is required by producers of marginal petroleum reservoirs to continue to survive and prosper. Field management based on reservoir characterization and simulation studies can assist the producer in efficient exploitation of hydrocarbon reserves in marginal fields. In the past reservoir simulation and management was restricted to large oil companies and to producing fields considered "core assets". Today, PC-based reservoir simulation is economically and technically feasible for the small independent producer.

The objective of the Class 2 project was to characterize and simulate a typical oil field producing from a Mississippian reservoir by using tools that are modern and cost-effective for small independent producers operating mature fields. General application of PC-based simulators such as BOAST3 to large-scale or full-field simulation has been restricted by hardware and software limitations. Recent advances in the computational speed and memory capabilities have drastically reduced the simulation run time. The development of powerful and "user-friendly" spreadsheet, relational database, girding and mapping software have provided the front and back-end tools to efficiently assemble and manipulate simulation input data and generate useful maps and charts.

Integrated reservoir characterization forms the foundation for the development of a descriptive reservoir model and provides the framework for simulation. The descriptive reservoir model integrated existing and newly acquired well. Simulation input parameters were generated from the reservoir model and used to simulate the reservoir performance of the Schaben field from discovery to 1996. Analysis of the reservoir performance and the distribution of the remaining mobile oil in place led to the identification of regions with potential for incremental oil recovery. The simulator was used to predict the performance of potential infill wells drilled in these areas. It is hoped that this study will provide a model for improving field management of similar reservoirs in Kansas and in the mid-continent.

Reservoir Model and Volumetric Calculations**.** Descriptive reservoir characterization entailed integration and creative application of existing data and new data from three wells. New core and log data provided insight into fundamental reservoir parameters (e.g., core plug NMR analysis to determine effective porosity). Integrated analyses of welllogs, core data and field mapping provided a better understanding of the complexities of an extremely heterogeneity of the reservoir. Determination of pore and throat size, irreducible water saturation, permeability, effective porosity, and movable oil are part of an integrated reservoir characterization. The descriptive reservoir model developed for Schaben Field provided a major component of the input data for reservoir simulation. (Carr and others, 1996a, 1996b; Carr and others, 1997; Guy and others, 1996)

Prior to the start of reservoir simulation, a volumetric study of the Schaben simulation study area was completed on a grid-by-grid basis. The volumetric calculations were performed to check if the different reservoir parameters such as effective porosity, net pay thickness, and water saturation in the effective porosity were able to support the observed historic production volumes. The resultant oil saturation values in the grid cells of the reservoir layer indicate the combination of reservoir parameters can with the historical production figures for the Schaben field.

BOAST 3 Simulation. The major premise of this simulation study was to enter eleven years of historical data and have the simulator predict and match the next 23 years of known field production data. At the field level, a good match between simulated and observed was obtained for both oil and water production rates during the 34 years encompassed by the historical and predictive periods (Figure 2.16).

A good match was also obtained for the simulated and observed cumulative oil and water production for the field from 1963 to 1995. After matches were obtained within acceptable tolerances for both oil and water at a field scale, attention was focused on the performance of the individual wells. The mismatch of water production in some of the wells may be due to inaccurate description of the reservoir properties surrounding these wells. The vertical permeability in the reservoir and aquifer layers plays an important role in controlling the water production at each well. Several simulation runs were carried out with varied (decreased and increased) vertical permeabilities in the cells of the reservoir and aquifer layer surrounding wells with a poor history match. The results drastically improved the history match for water production. This process of local adjustment of the vertical permeability is now being applied on a well by well basis and should result in an acceptable individual well history match for the entire field.

Cost-Effective Reservoir Management. Oil saturation maps from simulation output at the end of 1973 (field life of 10 years) show areas of low oil saturation (<40%) have developed around most wells. The poor areal sweep efficiency of the reservoir, due to its heterogeneity, is demonstrated by the area between wells which have high oil saturation (>60%). At the end of 1996 (field life of 33 years) the simulation shows oil saturation around most wells to just above the irreducible oil saturation (between 31%-35%). However, significant pockets of high oil saturation (>60%) are still left unswept in between the drainage areas of surrounding wells.

The choice of location for infill (increased density) wells for efficient oil recovery in accordance with a cost-effective reservoir management plan requires the consideration of current oil saturation and pay height in the reservoir layer. Due to the difficulty of producing oil from zones with low oil saturation (<40%) and thin pay height (<20 ft.), those areas of the field at low oil saturation and thin pay height can be eliminated from consideration for infill drilling. Those areas of the field with the highest predicted infill drilling potential can be identified with a saturation-feet map. All grid cells on the reservoir layer with an oil saturation less than 40% or with a net pay thickness less than 20 feet were set to zero. The oil saturation layer and the pay height layer were then multiplied in a grid to grid operation to produce a saturation-feet map showing those areas of the field with best infill potential.

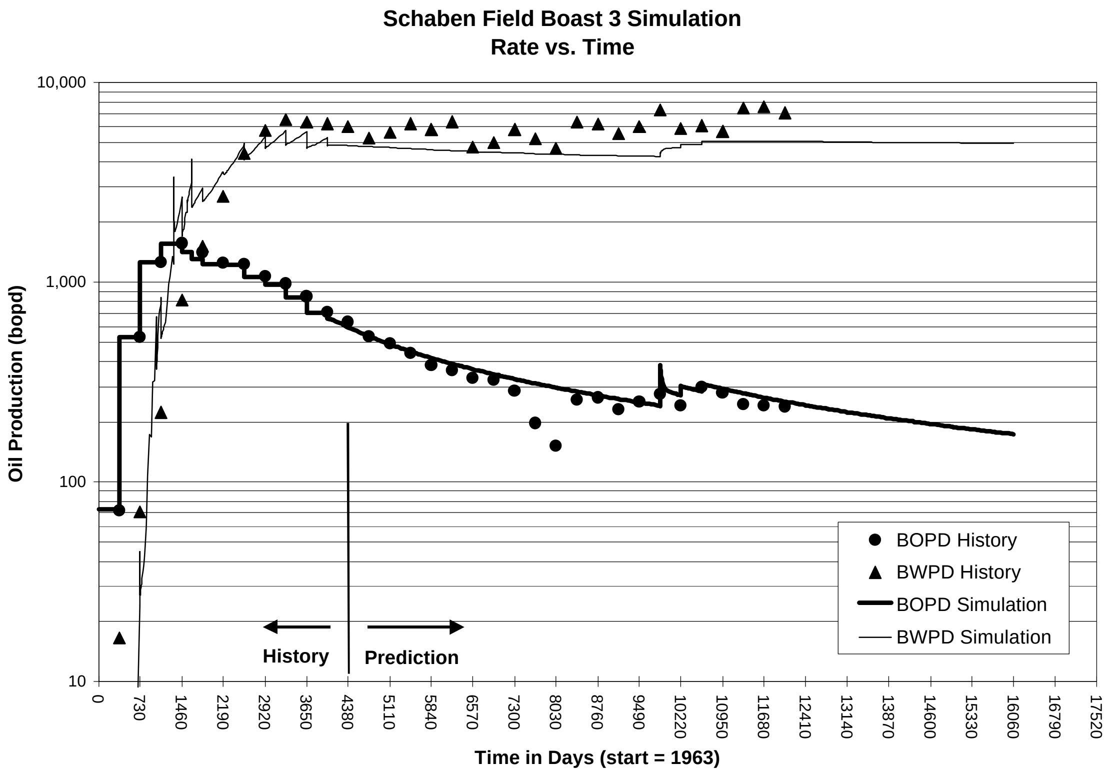



**FIGURE 2.16**. History match and performance prediction of Schaben field from Boast 3 simulation.

Based on the infill potential map and in consultation with Ritchie Exploration, operator of Schaben field, three infill-drilling sites were chosen. Subsequent simulation runs covering the ten year period of 1996 to 2006 were performed to predict the production rates for each of the three well locations and the effect on the oil saturation of the reservoir layer. The three new wells were simulated to produce with a flowing bottom hole pressure equal to that of the nearest well at the end of 1995. The daily production rate simulated for the Moore BCP #3 is calculated to produce a total of 47,200 bbls of oil and 227,600 bbls of water over a period of ten years (Figure 2.17). The simulator also predicts daily oil production above 10 bopd during the first 5 years. Predicted daily field production rate of oil and water with the addition of the three new wells indicates the addition of significant additional oil production.

The following conclusions were drawn based on the results of the Class 2 project:

1) Practical application of cost-effective technologies in reservoir simulation enables the small independent producer to map remaining hydrocarbon reserves in marginal fields.
2) Simulation results allow proper field management by targeting infill drilling in areas of best potential.
3) PC-based reservoir simulation is a practical reality for small independent producers with limited resources.
4) Procedures demonstrated in this study provide a guide for geologic modeling, simulating, and managing similar reservoirs in Kansas and in the mid-continent.

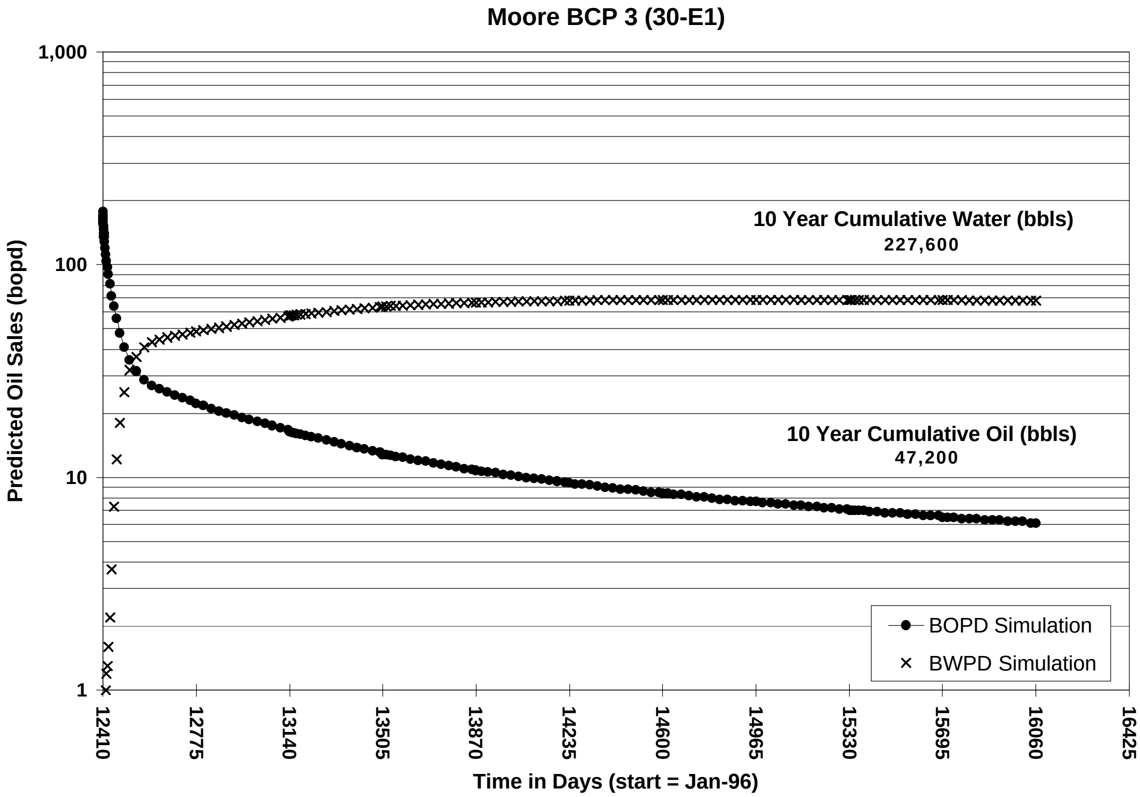



**FIGURE 2.17.** Performance prediction of Moore BCP #3 from Boast 3 simulation.

## 2.7 Material Balance Calculations

The volumetric estimate of original -oil-in-place (OOIP) for the Schaben Field was calculated to be 37.8 MMSTB (Carr and others, 1997). The reservoir at Schaben Demonstration Site has been in production since 1963. Initial reservoir pressure was approximated at 1370 psi by using the DST pressure recordings from the early wells (Carr and others, 1997). PVT properties were generated by using standard correlations. All wells in the Schaben Field produce under artificial lift. The current fluid columns in most wells indicate that the reservoir is producing significantly above the bubble point pressure (calculated at 225 psi). Reported gas production has been negligible and the reservoir is assumed to have no gas cap and or significant dissolved gas. The absence of gas is common in reservoirs of central Kansas (Walters, 1958). The main source of energy driving the production from the reservoir comes from the strong natural water drive.

For a reservoir with no gas cap and being driven by an aquifer, the generalized material balance equation gets simplified as:

$$\frac{F}{E} = N + \frac{W_e}{E}$$

where

$$E = E_o + E_{fw}$$

F denotes the underground withdrawal of fluids from the reservoir, $E_o$ represents the change in volume of the oil and the dissolved gas, $E_{fw}$ stands for the connate water expansion and the reduction in pore volume, and $W_e$ stands for the reservoir volume of water that influxes from the aquifer. The initial volume of oil in the reservoir is defined as N. This simplified material balance equation appears as a straight line, with a unit slope, when F/E is plotted against $W_e$/E and the Y-axis intercept (i.e. N) of this line estimate the OOIP (Figure 2.18). This estimate of the OOIP should be comparable to that obtained from volumetric calculations if assumptions about the drive mechanism and in the calculation of the aquifer water influx are reasonable. The material balance OOIP is considered to represent the oil volume that contributes to the production and pressure history of the field (Dake, 1994). This is often referred to as the "active" or "effective" initial oil in place in the reservoir. Because the OOIP determined by volumetric calculations includes immobile oil, it is generally higher than determined by material balance. A difference of less than 10% in calculated OOIP is regarded as an acceptable in the industry (Dake, 1994). If the OOIP is significantly different between volumetric and mass balance calculations one may need to reevaluate reservoir parameters (e.g., dimensions, petrophysical properties and cut-offs).

Aquifer Description. Water influx calculations are based on the geological and petrophysical parameters of the aquifer. Incorrect choices of aquifer parameters will result in deviation of the data from the straight line when F/E is plotted against $W_e$/E. Modifications of the aquifer parameters through a process of "aquifer fitting" can improve the match of observed pressure and production data with the reservoir characterization. Aquifer fitting assumes importance in situations where, as at Schaben Field, little is known about the aquifer geometry and petrophysics. At Schaben Field, very few wells are drilled into the aquifer.

Water influx from very small aquifers can be calculated by time-independent material balance equations. However, for large reservoirs the aquifer boundary takes a finite time to respond to reservoir pressure changes and thus time dependent models such as developed by Hurst and van Everdingen, Fetkovitch, Carter and Tracy, or Allerd and Chen are used to calculate the water influx, $W_e$ (Dake, 1994).

An aquifer model that can match reservoir pressure and production data is generally determined through a process of trial and error. However aquifer models are not unique and problems may persist despite all efforts at aquifer fitting because of incorrect identification of the reservoir drive mechanism. Initial assumptions about the reservoir drive mechanism are indirect, and are based on the pressure and production performance profiles of the reservoir. Identification of reservoir drive mechanism is important to determine aquifer description and definition and also estimate the size of the initial gas cap. Aquifer parameters were not available for Schaben field and were inferred from reservoir parameters (e.g., porosity, permeability, thickness, rock and fluid compressibility). The small numbers of available logs that penetrate the aquifer in the vicinity of Schaben Field were used to estimate the height of the aquifer. The reservoir radius at Schaben was calculated volumetrically and was found to be 7000 feet Carr and others, 1997). The Carter-Tracy method was used for water influx calculations because it is the time-dependent aquifer modeling option available within the reservoir simulator BOAST3.

OOIP. Material balance calculations require adequate field pressure and production profiles along with the PVT data of reservoir fluids. One method to determine the average field pressure is by volume weighting the shut-in pressures within the drainage area of each well. Regular recording of reservoir pressure at each well form the basis of material balance calculations. Unfortunately at Schaben Field, a recorded history of pressure measurements carried out at individual wells is not available. Only current operating water column heights are available for most of the wells. With limited pressure data, it is impossible to obtain the average reservoir pressure through the life of the field. Thus, the material balance calculations were used to generate the average reservoir pressure profile through the life of the field, and to check if the aquifer description and assumed drive mechanism was adequate to support the reported field performance data. As a result the OOIP determined from volumetric calculations was accepted as correct.

The first nine years of production data from Schaben Field were used to generate yearly oil ($N_p$) and water ($W_p$) production data along with the calculations for the underground volume withdrawal (F) of fluids. The Carter-Tracy formulation was used to calculate the water influx ($W_e$) from an infinite aquifer. Initial aquifer parameters were varied within geologic and engineering limits. The resulting plot between F/E versus $W_e$/E showed a straight line with unit slope and an intercept showing an OOIP value that is lower but within 10% volumetric OOIP (Figure 2.18). The average reservoir pressure (for the first 9 years) as a result of this match is plotted as the “base case” profile (Figure 2.19).

Sensitivity calculations were carried out by varying aquifer and reservoir parameters (e.g., aquifer height, reservoir radius, aquifer permeability, and aquifer porosity). In each case, the value of only one of the above parameters was changed. In each case the average reservoir pressure profile was generated, so that the resultant F/E versus $W_e$/E plot was a straight line with unit slope and its intercept read an OOIP value that was within acceptable tolerances. The plotted pressure profiles show the effects of varying different aquifer and reservoir parameters (Figure 2.19). Available fluid level data from the Schaben Demonstration Area indicate that the majority of the wells are currently producing against a backpressure of 400 to 1100 psi. The “Best case” scenario, incorporating knowledge of Schaben Field performance (e.g., strong water drive and a significant backpressure), was modified over a period of 34 years. Due to the rapid development of the field during the first 9 years, the average reservoir pressure profile shows a rapid decline from 1370 psi to 1000 psi (Figure 2.20). Subsequently, reservoir pressure stabilized near 1000 psi for the next 14 years and then gradually declined to 880 psi over the next 11 years. The plot of F/E versus $W_e$/E for the “best case” scenario remains a straight line with unit slope and the OOIP value at the intercept is within acceptable tolerances (Figure 2.21).

Summary.--The material balance study at the Schaben Demonstration Site confirms that the volumetric description of the reservoir-aquifer system together with the natural water drive mechanism is capable of supporting the reported fluid production history of the field. A process of “aquifer-fitting” was used to fine tune selected aquifer parameters (e.g., height, porosity, permeability, and effective compressibility). In addition a better understanding of the radius of the reservoir at Schaben was obtained.

As typical of older fields in the mid-continent the average reservoir pressure profile for the Schaben field is not available and the mass balance calculations can not be used to validate of the volumetric description of the reservoir. As a consequence the volumetric OOIP is assumed correct and used to calculate an average reservoir pressure profile. The reservoir pressure profile controls the PVT properties of the reservoir fluids and hence the mobility ratios operating during the production life of the field. Changes in average reservoir pressure are indicative of the amount of change occurring in the fluid viscosities.

The material balance calculations were used to check the consistency among different aspects of reservoir description. These calculations tie together the geologic reservoir characterization of the reservoir, the PVT data, production data and available pressure data. The material balance calculations were used to confirm the reservoir drive mechanism and aquifer parameters. The results of the material balance calculations confirm the initial reservoir characterization and refine important input parameters that can be used to revise the full-field reservoir simulation.

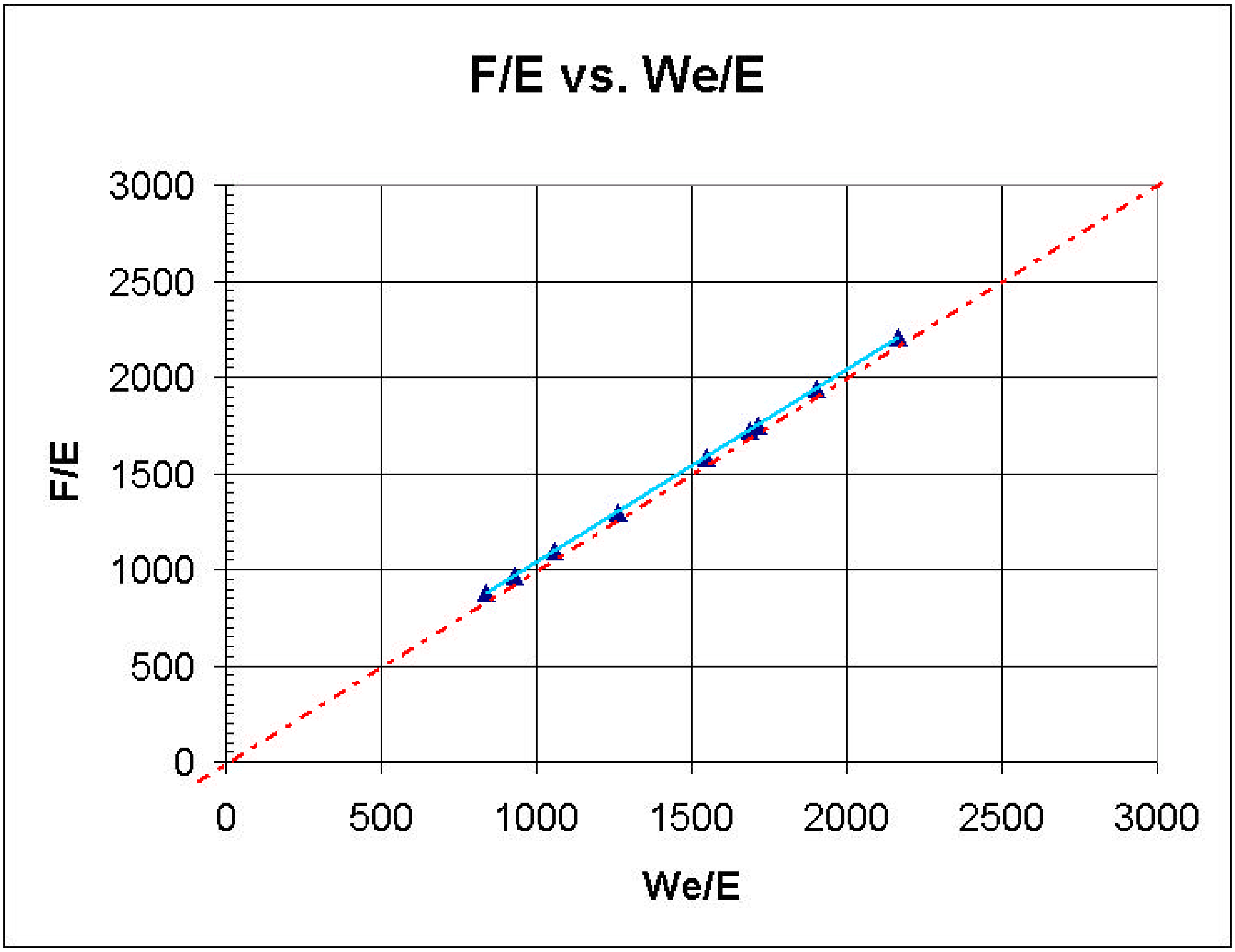



**FIGURE 2.18.** Plot of F/E versus $W_e$/E showing a straight line with unit slope and an intercept showing an OOIP value that is lower but within 10% of OOIP determined from volumetric calculations (37.8 MMSTB).

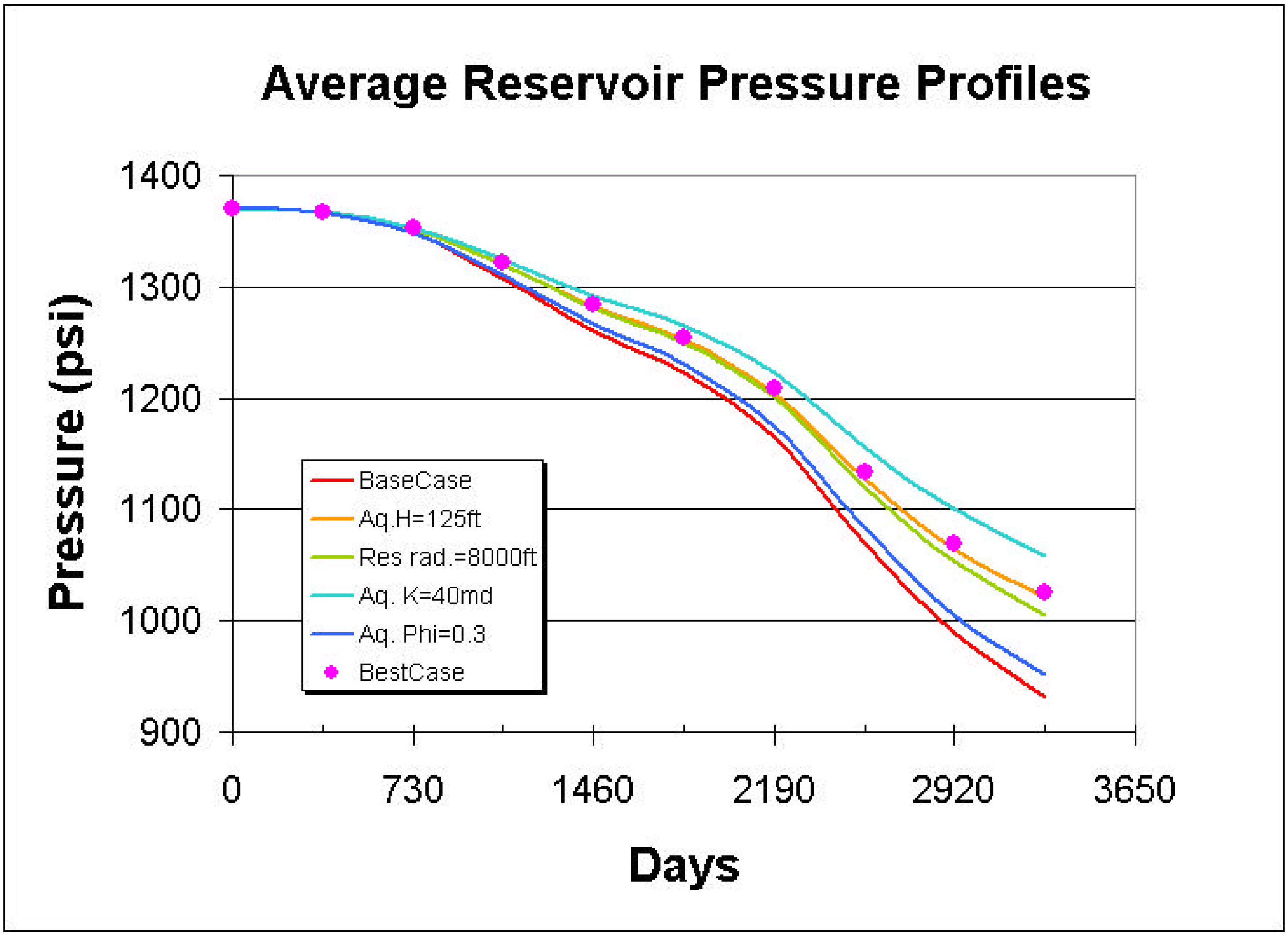



**Figure 2.19.** Plot of sensitivity calculations with varying aquifer and reservoir parameters (e.g., aquifer height, reservoir radius, aquifer permeability, and aquifer porosity). In each case, the value of only one parameter was changed. An average reservoir pressure profile was generated, so that the resultant F/E versus $W_e$/E plot was a straight line with unit slope and its OOIP value was within acceptable tolerances. The plotted pressure profiles show the effects of varying different aquifer and reservoir parameters.

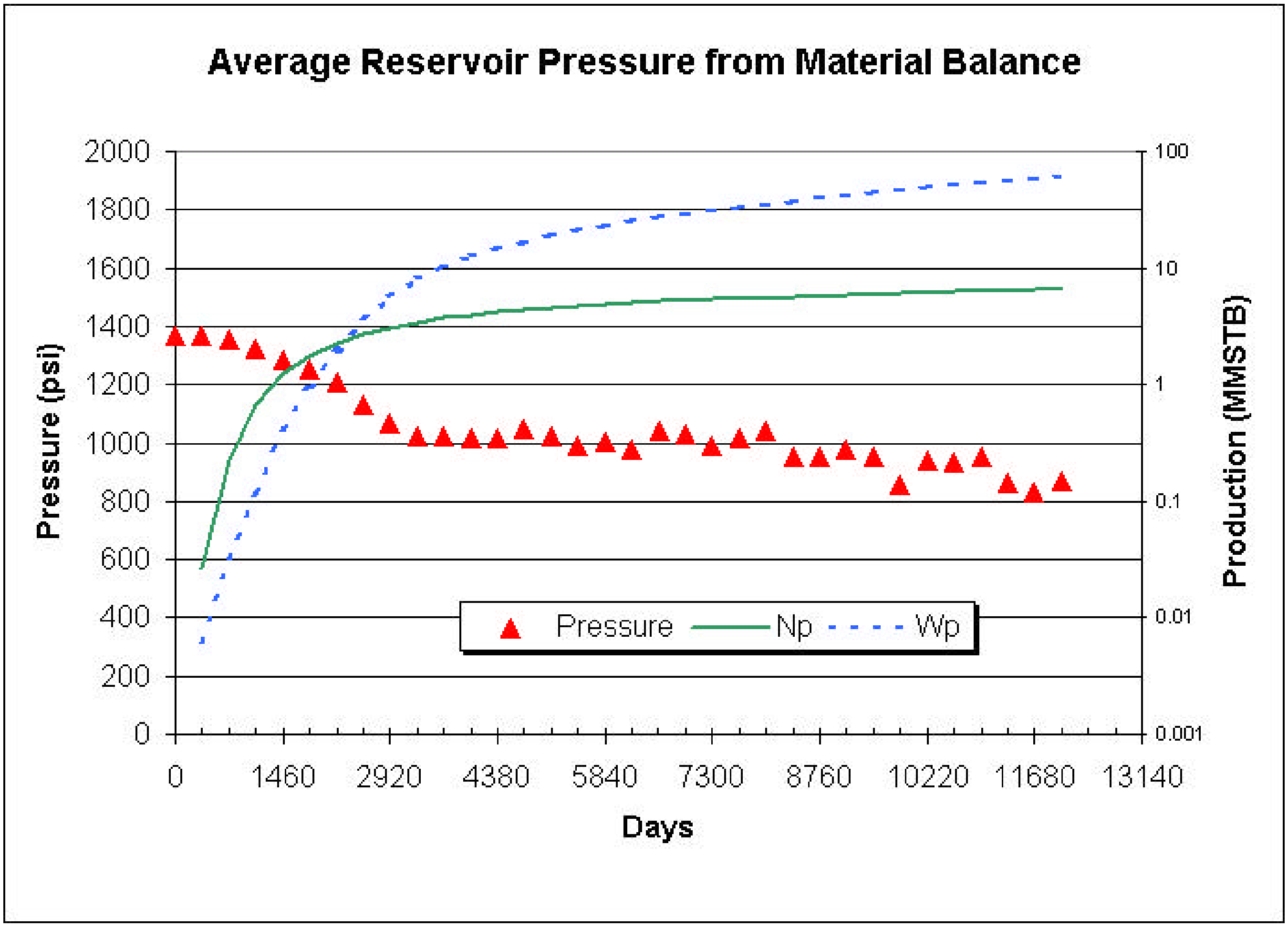



**Figure 2.20.** "Best case" scenario for Schaben Field generated over a period of 34 years. Due to the rapid development of the field during the first 9 years, the average reservoir pressure profile shows a rapid decline from 1370 psi to 1000 psi. Subsequent reservoir pressure stabilized near 1000 psi for the next 14 years and then gradually declined to 880 psi over the next 11 years.

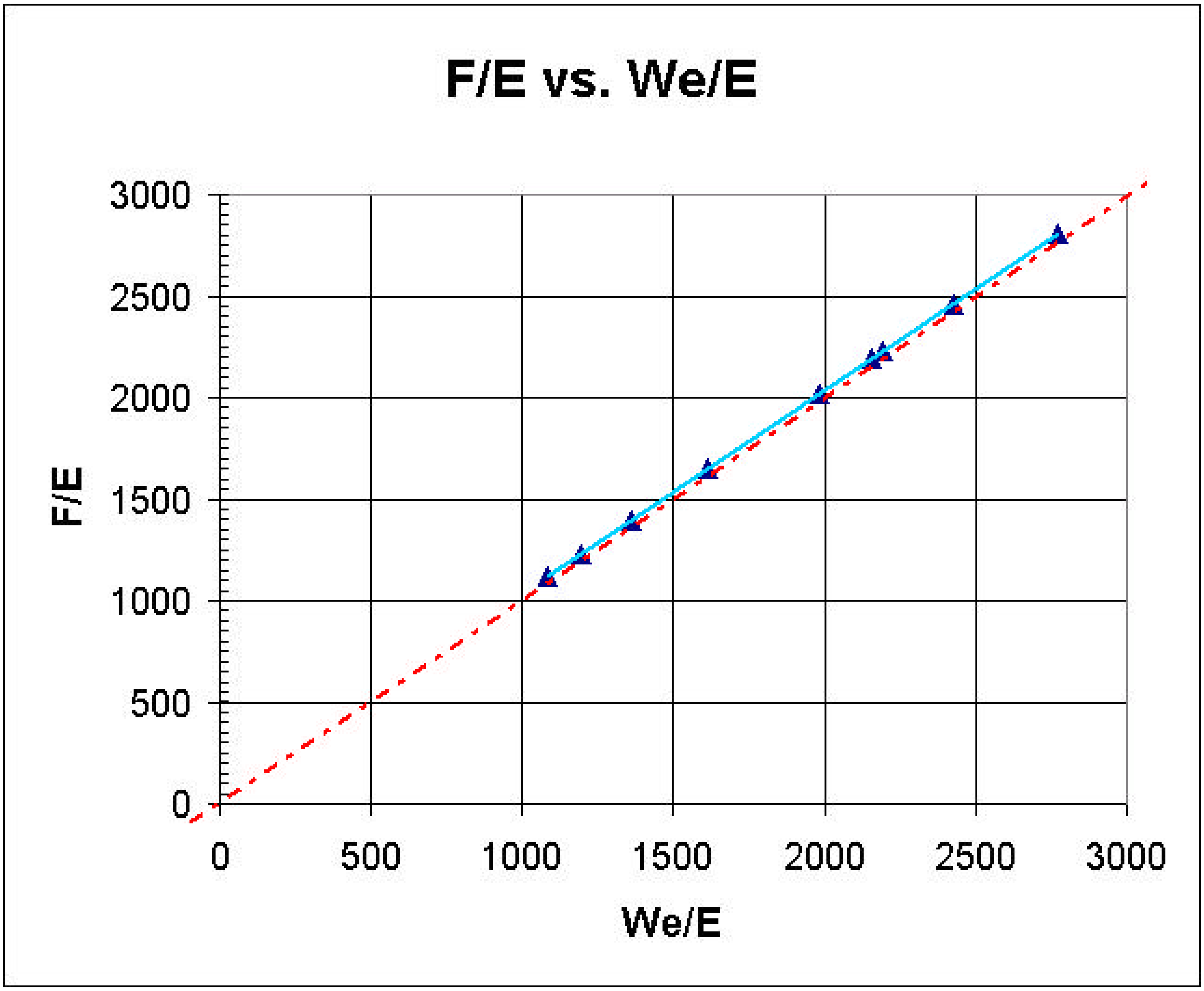



**Figure 2.21**. Plot of F/E versus $W_e$/E for the "best case" scenario remains a straight line with unit slope and its intercept within acceptable tolerances.

## 3.0 TECHNOLOGY TRANSFER ACTIVITIES

Technology transfer is an ongoing process that includes access to information through the Internet, almost daily inquires from operators and formal presentations. The data, results and technology developed as part of the project have been presented at numerous technical meetings and published in technical papers in local, regional and national publications (Appendix A).

PfEFFER, a software package using a widely available spreadsheet, continues to be improved, tested and demonstrated as part of the Class 2 project. PfEFFER Version 2.0/Pro was released in February 1998. PfEFFER Version 2.0/Pro is a popular and cost-effective tool for the independent oil and gas operator. Hands-on demonstrations and workshops focusing on PfEFFER were presented for the Michigan Oil and Gas Association (Mt. Pleasant, Michigan, February 19) at National Petroleum Technology Office (Tulsa, Oklahoma, February 24), at the SIPES National Meeting (Wichita, Kansas, March 3) and in Odessa Texas (Invitation of Phillips Petroleum Company, March 3-4). Also four hours of hands-on demonstrations and presentations using PfEFFER were presented at the North Midcontinent PTTC workshop in (Wichita, Kansas, November 19). The PTTC short course involved well log analysis techniques with an emphasis on modern logging technologies applicable to Kansas. Many of these new techniques were a direct development of the Class2 project.

The results of the evaluation of horizontal drilling technology in the Mississippian reservoirs of Kansas was presented at the North Midcontinent PTTC Horizontal Drilling Workshop (June 16, Wichita Kansas). This presentation emphasized cost-effective strategies for independents in selection of reservoir targets for horizontal drilling. The presentation has been invited and accepted for an AAPG Hedberg Conference entitled " International Horizontal Well Symposium: Focus on the Reservoir" (October 10-13, The Woodlands, Texas). Additional information on the conference and an online extended abstract (Gerlach and others, submitted) are available at http://www.kgs.ukans.edu/PRS/AAPG/horizon.html).

A presentation at the Tertiary Oil Recovery Project Oil Recovery Conference in (Wichita, KS, March 17-18) focused on application of a commercial simulator and the role of fracture porosity to a portion of the Schaben Field. Additional presentations are planned for the USDOE Oil and Gas Conference (Dallas, TX, June 29, 30), and at the joint meeting of the Midcontinent AAPG and Kansas Independent Oil and Gas Association (Wichita, KS, August 29-31). A paper has been accepted for the proceedings of a research conference on advanced reservoir characterization (Gulf Coast Section SEPM Nineteenth Annual Research Conference, December 5-8, Houston, Texas; Bhattacharya and others, accepted). Three extended abstracts covering a variety of topics were prepared for the 1998 AAPG Annual Meeting in Salt Lake City Utah (Franseen and others 1998; Guy and others, 1998 and Gerlach and others, 1998). We have worked to assure that the presentations provided complementary information and had similar formats. A manuscript covering the approach to geologic/engineering developed as part of the Class 2 project was completed (Watney and others, in press).

All data and results of the Schaben project are being added to a world-wide-web server. The Internet protocol provides independent operators with on-line access to digital information, digital databases, results of the field study, related regional geologic and production data, and purposeful transfer of technology. Access is through the Class 2 page (http://www.kgs.ukans.edu/Class2/index.html), and through the Schaben Field Page (Figure 2.22) of the Kansas Digital Petroleum Atlas (http://www.kgs.ukans.edu/DPA/dpaHome.html).

We continue to work on a daily basis with a number of Kansas's operators on application of the technologies developed as part of the Class 2 project.

DPA Home Page | Kansas DPA Home | Site Map | Help

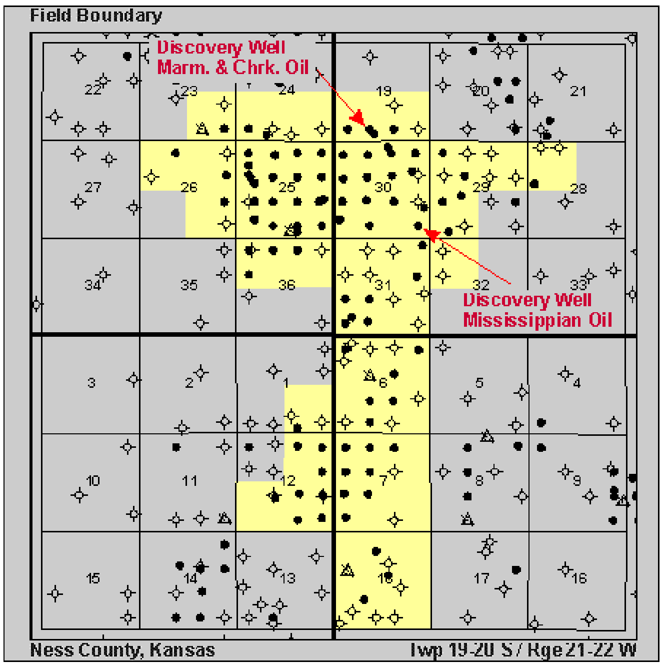
General
Geology
Geophysics
Reservoir
Wells

**Play:** Lower Mississippian
**Basin:** Anadarko
**County:** Ness County

Field Site Map

# Schaben Field

You can explore the Schaben Field by clicking on the blue topic buttons to the left.
Use the Schaben Site Map to learn what resources are available for the Schaben Field.




**Discovery Well**
Cities Service Oil Company, #1 Moore 'B'
SE SE 30-T19S-R21W
09/04/63, Mississippian Oil, 4494' RTD

American Warrior, #1 Wittman, 'OWWO'
Champlin Petroleum, #1 Wittman
SE SW, 19-T19S-R21W
06/20/91, Marmaton & Cherokee, 4407' RTD

**Field Size:** 8,880 acres
**Total Wells:** 90
**Productive Wells:** 65
**Abandoned Wells:** 25

**Cumulative Oil:** 10,416,796 bbls as of 7/1/96
**Cumulative Gas:** 112,395 mcf as of 7/1/96

Annual Field Production Data

Class 2 Project Page also has info on the Schaben field.

Kansas Geological Survey, Digital Petroleum Atlas
Send comments and/or suggestions to webadmin@kgs.ukans.edu
Updated Oct. 27, 1997
URL = http://crude2.kgs.ukans.edu/DPA/Schaben/schabenMain.html

**FIGURE 2.22.** Schaben homepage from the Kansas Digital Petroleum Atlas provides access to data generated as part of the Schaben Class 2 project (http://www.kgs.ukans.edu/Class2/index.html).

## 4.0 PROBLEMS ENCOUNTERED

The historically low oil prices of late 1998 and early 1999 have affected continued operations throughout Kansas including the Schaben Demonstration Area. However, the project has demonstrated the value of cost-effective technology and will be applied when oil prices justify resuming development activity. The project is well within budget and cost sharing is in excess of 50%.

## 5.0 RECOMMENDATIONS FOR REMAINDER OF BUDGET PERIOD 2

Tasks for Budget Period 2 as outlined in the original Continuation Proposal remain unchanged. Plans for the remainder of the Project, which concludes on July 30, 1999 include:

1) Develop Improved Boast 3 model that incorporates a refined reservoir description. The reservoir will be divided into two units M1 and M0 that better reflect the known reservoir geology.
2) Develop an online tutorial for using BOAST 3 at the full-field scale that uses commonly available spreadsheets as pre and post-processors.
3) Complete a full-field simulation using a commercial simulator (e.g., VIP).
4) Continue technology transfer activities (e.g., the Midcontinent AAPG and Kansas Independent Oil and Gas Association).
5) Complete manuscript entitled "Significance of Depositional and Early Diagenetic Controls on Architecture of a Karstic-Overprinted Mississippian (Osagian) Reservoir in Kansas" for AAPG Bulletin.
6) Develop an digital online petrophysical atlas that includes Mississippian reservoirs
7) Complete Final Report.

## 6.0 REFERENCES CITED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## 7.0 APPENDIX LIST OF PUBLICATIONS

A list of publications that are a result of the Class 2 Demonstration Project.


Bhattacharya, S, and P. M. Gerlach, 1997, Carbonate Reservoir characterization and field simulation using boast 3: The Schaben Field (Mississippian), Ness County , Kansas; Proceedings Twelfth Tertiary Oil Recovery Conference, Wichita, Kansas (March 19-20), p.39-58.

Bhattacharya, S., Watney, W.L., Guy, W., and Gerlach, P., accepted, Nineteenth Annual Research Conference, Advanced Reservoir Characterization for the Twenty-First Century, Gulf Coast Section SEPM Foundation. (Meeting December 5-8, 1999).

Carr, T. R., 1996, Improved oil recovery in Mississippian carbonate reservoirs of Kansas; US Department of Energy and BDM Oklahoma Workshop “Improving Production in Shallow Carbonate Reservoirs”, p. G1-G46.

Carr, T. R., 1996, Technology transfer for the independent; Society of Independent Professional Earth Scientists National Convention Abstracts, p. 10. Invited Talk/Panel Discussion at Society of Independent Petroleum Earth Scientists (SIPES) National Convention, March 20 -- 23, Dallas, TX**.**

Carr, T. R., J. Hopkins, H. Feldman, A. Feltz, J. Doveton, and D. Collins, 1994, Color Image Transforms of Wireline Logs: A Seismic Approach to Petrophysical Sequence Stratigraphy, Landmark Worldwide Technology Symposium, p. 36. Invited Talk at Landmark Worldwide Technology Forum, November, 29 - December 1, 1994, Houston, Texas.

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