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

Cooperative Agreement No.:	DE-FC22-94BC14987
Contractor Name and Address:	The University of Kansas Center for Research Inc.
Date of Report:	June 1, 1999
Award Date:	September 16, 1994
DOE Cost of Project:	$ 3,169,252 (Budget Period 2 05/16/97 -- 07/30/99)
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Project Manager:	Daniel J. Ferguson, NPTO Tulsa, Oklahoma
Reporting Period:	January 1, 1999 -- March 31,1999

OBJECTIVES

The objective of Kansas Class 2 project is to demonstrate incremental reserves from Osagian and Meramecian (Mississippian) dolomite reservoirs in western Kansas through application of reservoir characterization to identify areas of unrecovered mobile oil. The project addresses producibility problems in two fields: Specific reservoirs target the Schaben Field in Ness County, Kansas, and the Bindley Field in Hodgeman County, Kansas. The producibility problems to be addressed include inadequate reservoir characterization, drilling and completion design problems, non-optimum recovery efficiency. The results of this project will be disseminated through various technology transfer activities.

At the Schaben demonstration site, the Kansas team will conduct a field project to demonstrate better approaches to identify bypassed oil within and between reservoir units. The approach will include:

- Advanced integrated reservoir description and characterization, including integration of existing data, and drilling, logging, coring and testing three new wells through the reservoir intervals. Advanced reservoir techniques will include high-resolution core description, petrophysical analysis of pore system attributes, and geostatistical analysis and 3D visualization of interwell heterogeneity.
- Computer applications will be used to manage, map, and describe the reservoir. Computer simulations will be used to design better recovery processes, and identify potential incremental reserves.
- Comparison of the reservoir geology and field performance of the Schaben Field with the previously described by slightly younger Bindley Field in adjacent Hodgeman, County.
- Drilling of new wells between older wells (infill drilling) to contact missed zones;

- Demonstration of improved reservoir management techniques, and of incremental recovery through potential deepening and recompletion of existing wells and targeted infill drilling.

SUMMARY OF TECHNICAL PROGRESS BUDGET PERIOD 2

Progress is reported for the period from 1 January 1999 to 31 March 1999. Work in this quarter concentrated on demonstrating the incremental recovery of additional mobile oil through targeted infill drilling (Task 2.1) and the potential of horizontal drilling. The completed full-field reservoir simulation was demonstrated with the addition of eighteen infill wells. We continue to monitor those wells and to improve our understanding of the reservoir at Schaben.

This quarterly report will concentrate on a brief summary of the relationships developed among critical petrophysical properties including porosity, routine air and Klinkenberg permeability, air-brine and air-mercury capillary pressure, NMR T2, and electrical formation resistivity factor (Archie cementation exponent, m). This petrophysical data is summarized in Guy and others (Appendix A). A comprehensive report is in preparation that will provide online access to detailed tables and figures for the complete suite of advanced rock property analyses performed on the three cores recovered as part of the Schaben Demonstration Project (i.e., Ritchie Exploration #1 Foos, #2 Lyle, and #4 Moore).

Petrophysical measurements were performed as a function of confining stress and include; porosity, pore volume compressibility, bulk volume compressibility, routine air permeability, calculated Klinkenberg permeability, and formation resistivity factor. In addition, porous plate and centrifuge air-brine capillary pressure analyses were preformed. Addition measurements for include *in situ* effective gas permeability at partial water saturation and resistivity index (Archie saturation exponent, n), air-mercury capillary pressure and pore-throat size distribution analysis, and NMR T1 and T2 analysis.

Appropriate relationships among variables were graphed, statistically analyzed, and equations developed. Relationships between lithofacies and petrophysical properties are also examined and used to improve the parameters used in the full-field reservoir simulation and to provide the foundation of an online digital catalog for use by Kansas oil operators in other Mississippian fields.

A revised simulation model with added reservoir complexity incorporates the results of the infill wells and improved reservoir characterization. The new simulation model provides new insight into the performance of Mississippian reservoirs such as the Schaben demonstration site.

Task 2.1 DEMONSTRATION OF RESERVOIR MANAGEMENT STRATEGY

From late 1996 through early 1998, a total of twenty-two (22) infill locations were drilled or recompleted at the Schaben Demonstration Site. Locations were selected using the results of the reservoir management strategy developed in Budget Period 1 (see Quarterly Report 10/1/98 - 12/31/98 for locations). All three major field operators (Ritchie Exploration, Pickrell Drilling and American Warrior) have used results of the reservoir simulation and management strategy to locate and drill additional infill locations. At the Schaben Demonstration Site, the additional locations resulted in an incremental production increase of 200 BOPD from a significantly smaller number of wells (Figure 1).

Task 2.2 TECHNOLOGY TRANSFER

Technology transfer is an ongoing process that includes access to information through the Internet, almost daily inquires and formal presentations. A presentation at the Tertiary Oil Recovery Project Oil Recovery Conference in Wichita, Kansas (Willhite, G. P., March 17-18) focused on application of a commercial simulator and the role of fracture porosity to a portion of the Schaben Field. A workshop on log analysis application of PfEFFER software in the Michigan Basin was presented in Mt. Pleasant, Michigan (Guy, W., and Watney, W.L., February 19). A presentation on the results of the project with emphasis on PfEFFER was presented at the SIPES National Meeting

(Watney, W.L., March 3, Wichita). 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).

We continue to work with a number of Kansas's operators on application of the technologies developed as part of the Class 2 project. We are providing access to the digital data and results from the project through an on-line (Internet) accessible format (see Schaben homepage at http://www.kgs.ukans.edu/Class2/index.html).

REFERENCES CITED

1998, Guy, W.J., Byrnes, A.P., Doveton, J.H., and Franseen, E.K., submitted, 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.

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

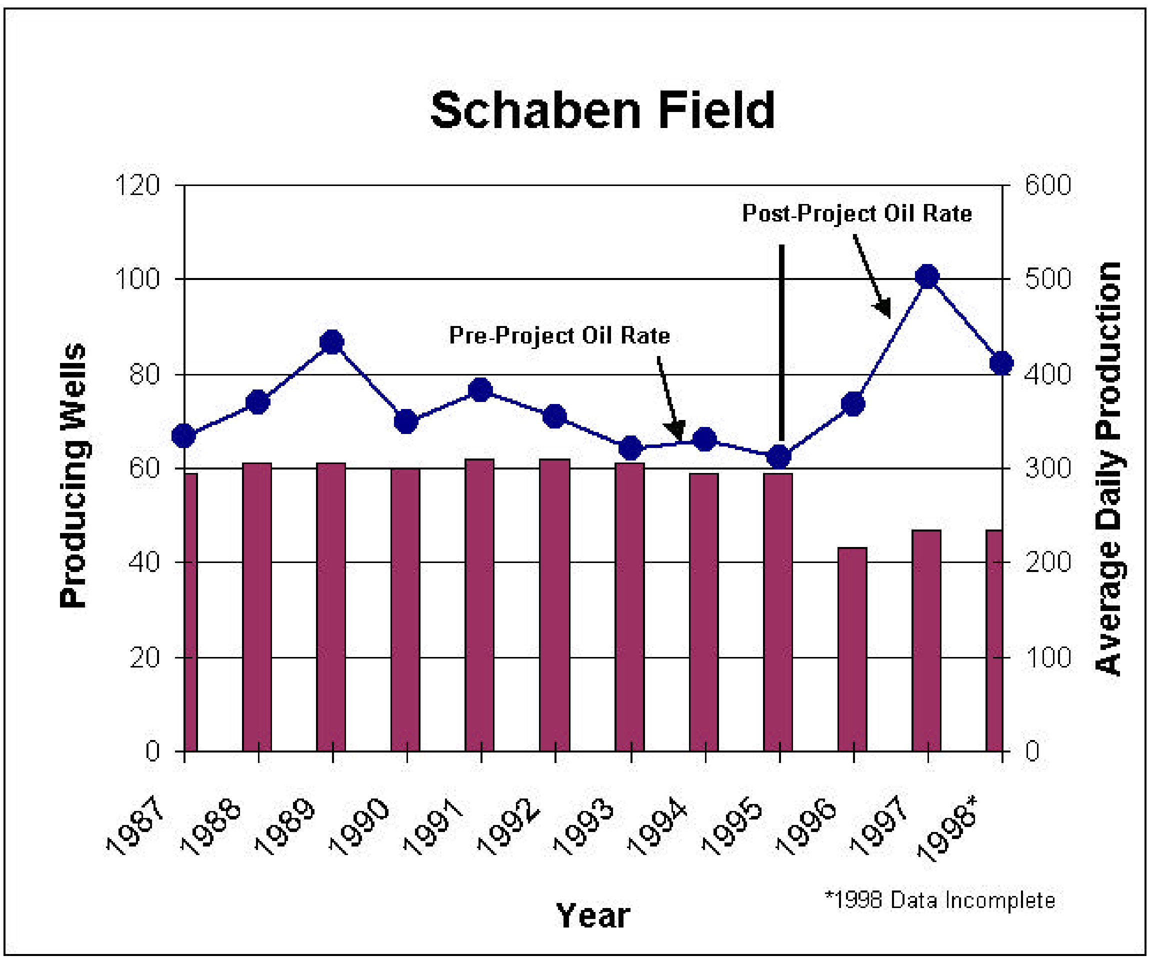

Figure 1. Average daily oil production rates for the Schaben Field Demonstration Site, Ness County Kansas. Producing rate from well has increased significantly has a result of targeted infill wells and recompletions.

APPENDIX A

Modified from: 1998, Guy, W.J., Byrnes, A.P., Doveton, J.H., and Franseen, E.K., submitted, 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 A1). 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. A portion of this work was funded as part of the DOE and industry supported Class 2 project (Cooperative agreement DE-FC22-93BC14987).

The reservoir 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.

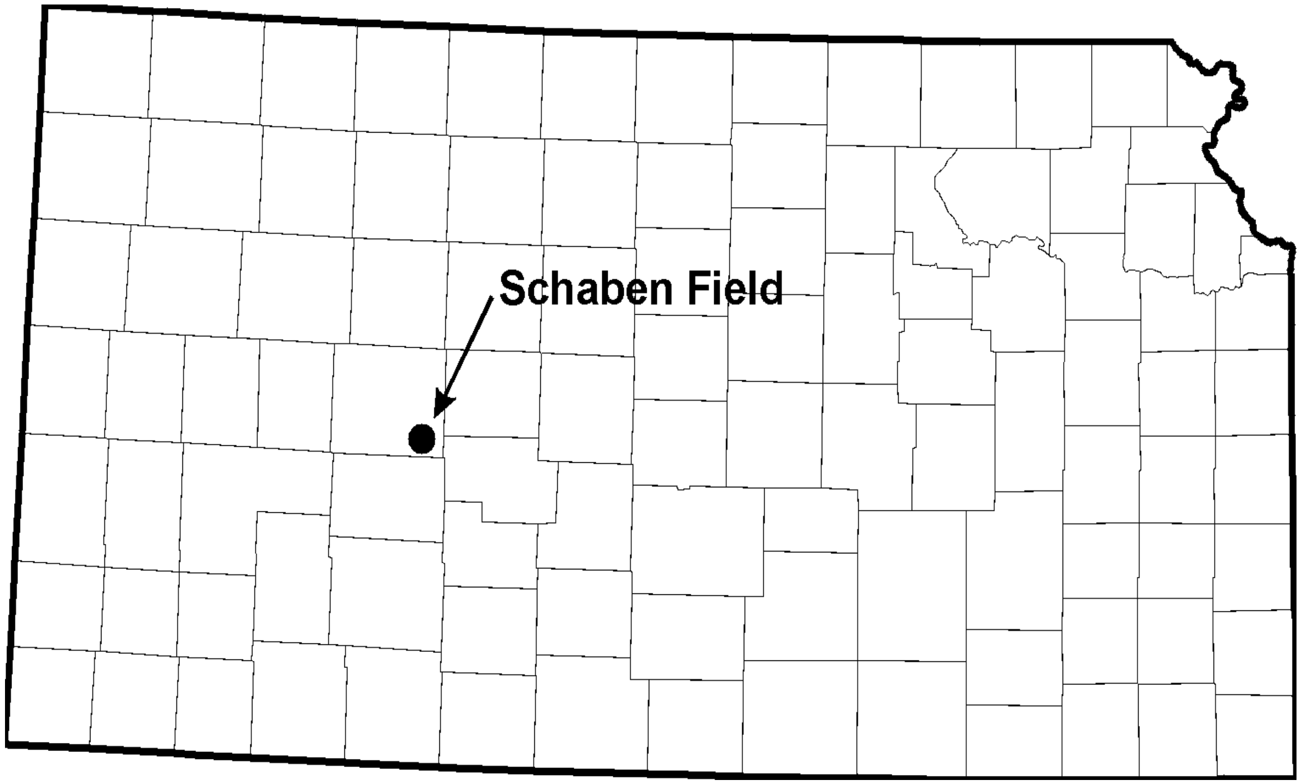

Figure A1. Location of Schaben Field in Kansas

INTRODUCTION

Over 40% of the oil production in Kansas is obtained from the Mississippian section immediately underlying the regional sub-Pennsylvanian unconformity. Cumulative production from these reservoirs exceeds 1 billion barrels. Many of these 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 USDOE 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. The Schaben field is located in T19S-R21W, T20S-R21W, and T19S-R22W, Ness County, Kansas (Figure 1). This site is located on the upper shelf of the Hugoton Embayment of the Anadarko Basin. Cumulative field production as of September, 1996 was 9.1 million barrels produced from the Meramecian Warsaw Limestone and Osagian Keokuk Limestone at depth of 4,350 to 4,410 feet. The Schaben field, and many similar fields, 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.

GEOLOGIC SETTING

The Mississippian reservoir at Schaben field is interpreted to have been deposited on a shallow southwestward dipping ramp that underwent a relative sea level drop through Mississippian time. An abundance of echinoderm-rich facies in the basal portions of the cores studied suggests deposition in a normal to restricted marine environments. The abundance of mudstone, wackestone, spicule-rich facies, and evaporites in the upper portions of the cores studied suggests deposition in a restricted, evaporative ramp or lagoonal environment. Each core exhibits a shoaling upward trend terminated by the sub-Pennsylvanian unconformity representing a regional subaerial exposure event.
Six major facies are present in this reservoir system: (1) dolomite or lime mudstone-wackestone, (2) sponge spicule-rich dolomitic or lime wackestone-packstone, (3) echinoderm-rich dolomitic or lime wackestone-packstone-grainstone, (4) chert/chalcedony, (5) sandstone/siltstone/shale, and (6) brecciated or fractured facies. The first three facies represent over 80% of the cored intervals and are described below.

Mudstone-wackestone: The mudstone-wackestones facies is generally laminated or wavy to wispy laminated with mottling, interpreted to result from burrowing, locally common. Fenestral fabric, indicating early subaerial exposure, is also developed locally. This facies generally exhibits low porosity and permeability except locally where fenestral porosity is well developed.

Spicule-rich wackestone-packstone: This facies occurs in the upper portion of all three cores and is commonly oil stained. Mottled wispy and wavy horizontal laminated textures are common. Monaxon sponge spicules and their molds are the dominant grain type. Porosity is primarily moldic, intercrystalline, and vuggy more locally. Massive and microporous chert replaces evaporite crystals, matrix, and grains.

Echinoderm-rich wackestone-packstone-grainstone: This facies is present in the basal portion of all three cores. It is characterized by echinoderm fragments but also contains sponge spicules, bryozoan fragments and numerous other skeletal debris. Wispy lamination and mottling is common and interbedded coarse and fine grained layers result in porous and tight layering.

PETROPHYSICAL MEASUREMENTS

Total Porosity

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 A2).

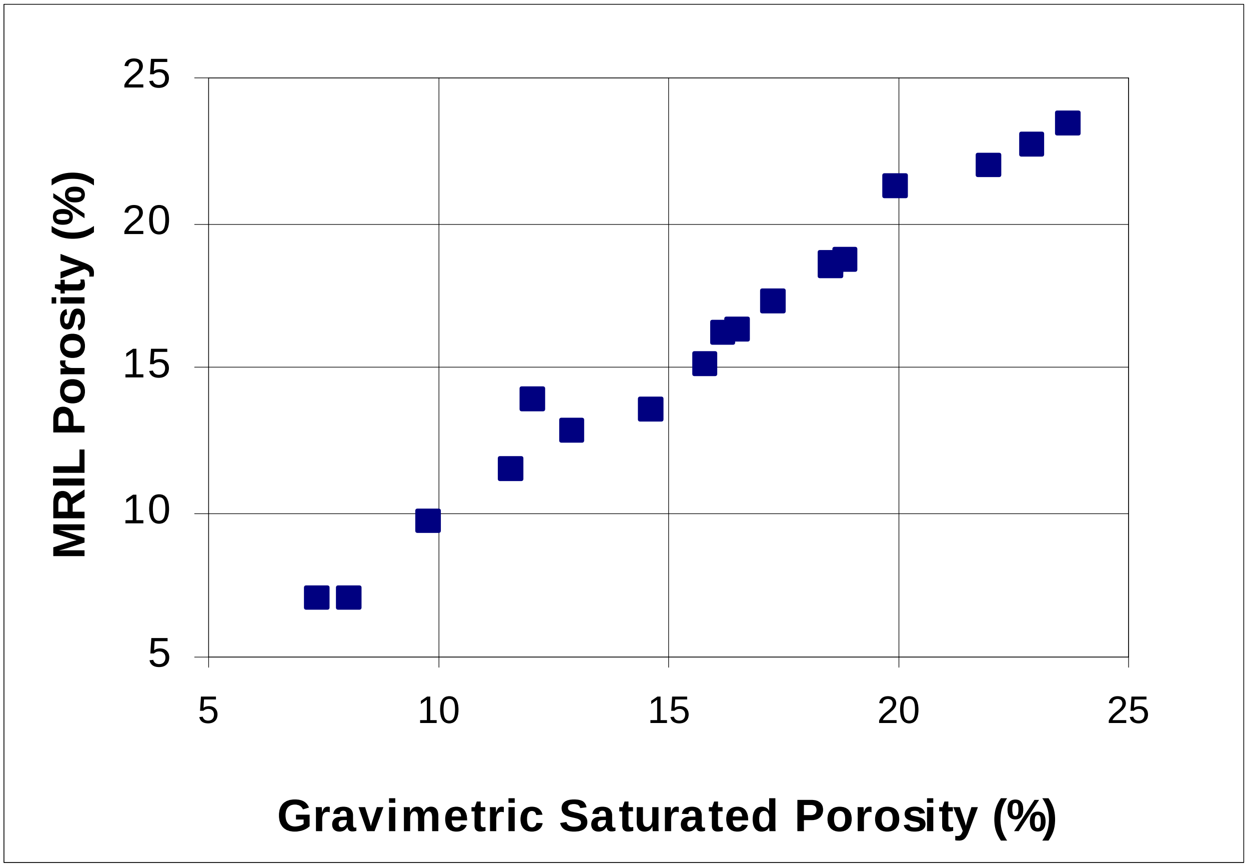

Figure A2. Cross-plot of NMR total porosity versus gravimetric total porosity illustrating high degree of correlation.

"Irreducible Water" Saturation

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 A3).

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.

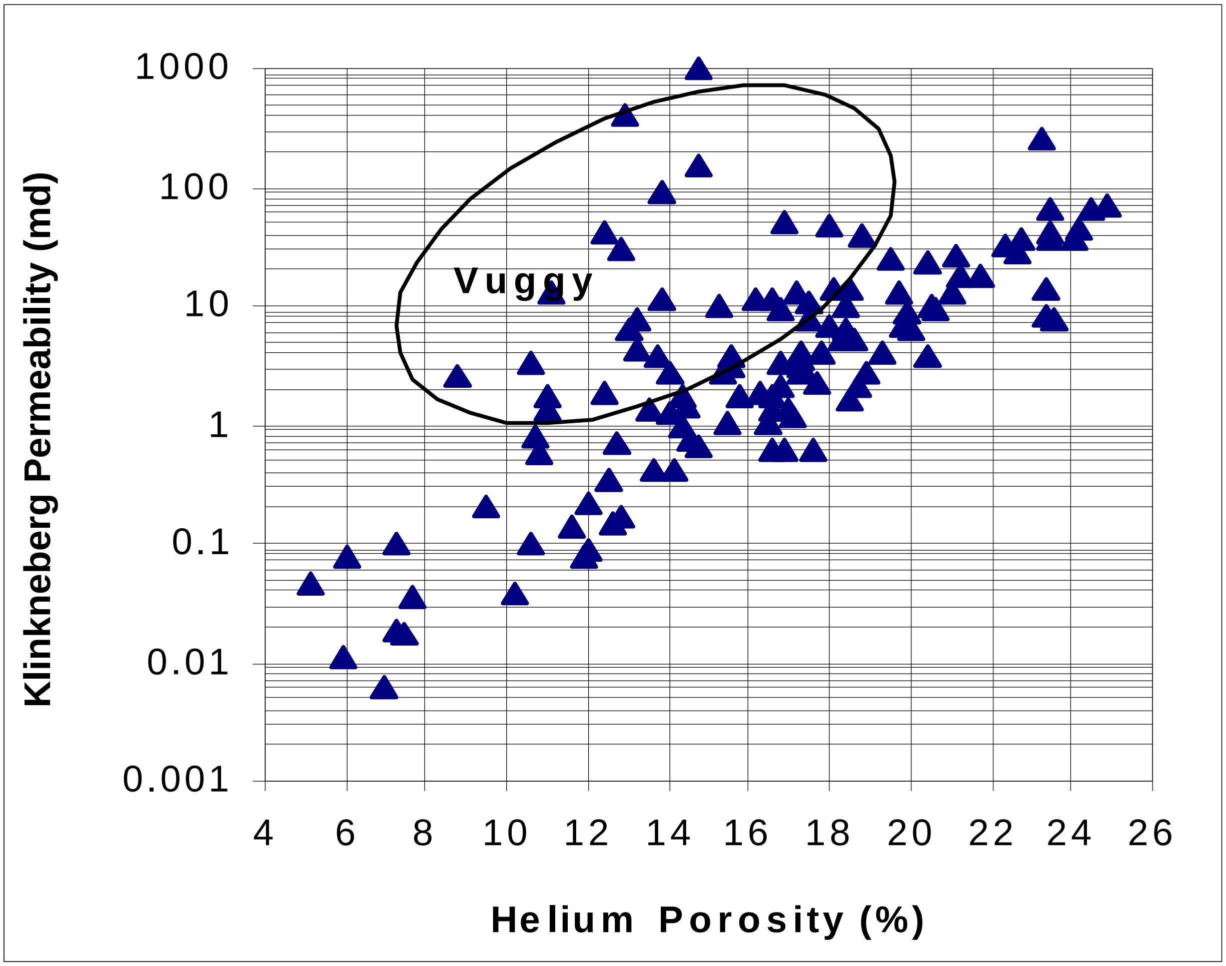

Figure A3. Cross-plot of water saturation at 20 psi air-brine capillary pressure, corresponding to ~50ft of oil column, to *in situ* Klinkenberg permeability.

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 A4). 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.

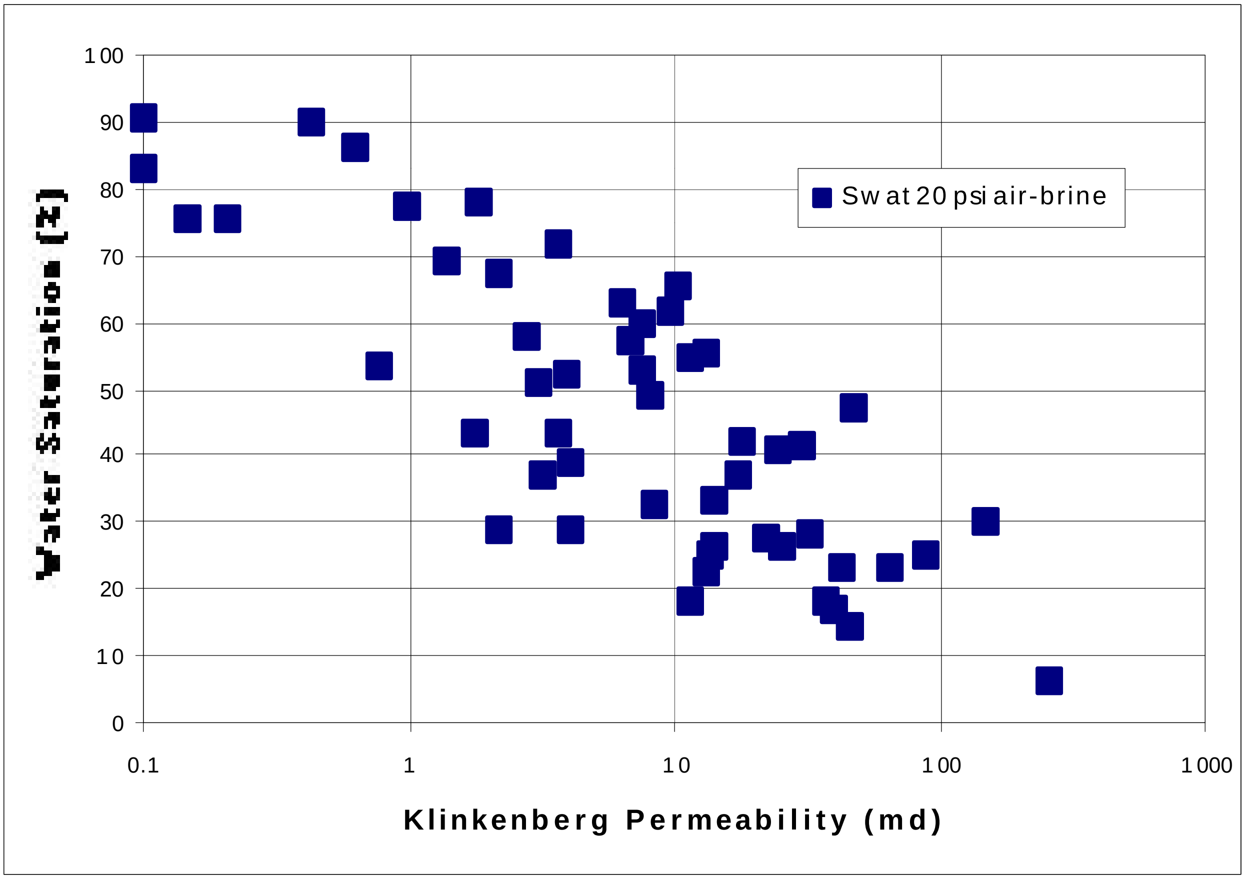

Figure A4. Cross-plot of permeability versus porosity.

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 5).

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 A6). 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 6 illustrates the difference in correlations between T2 and permeability between pore geometries that are predominantly intergranular and those that are vuggy.

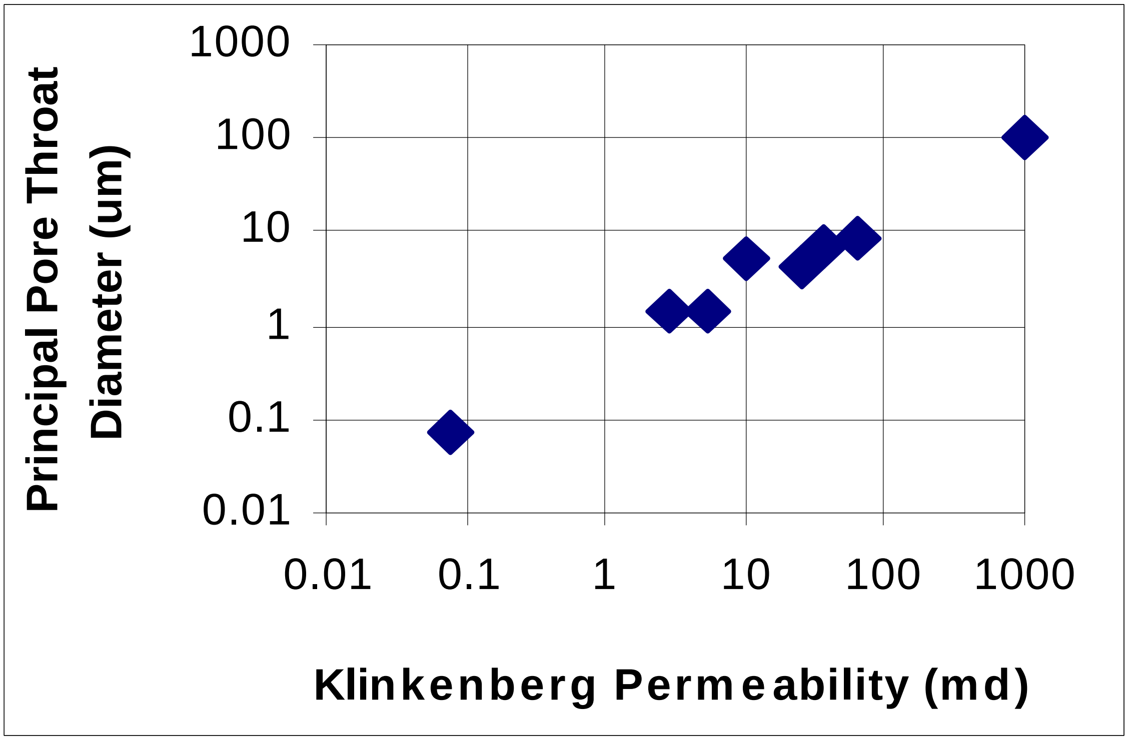

Figure A5. Cross-plot of Klinkenberg permeability versus principal pore throat diameter.

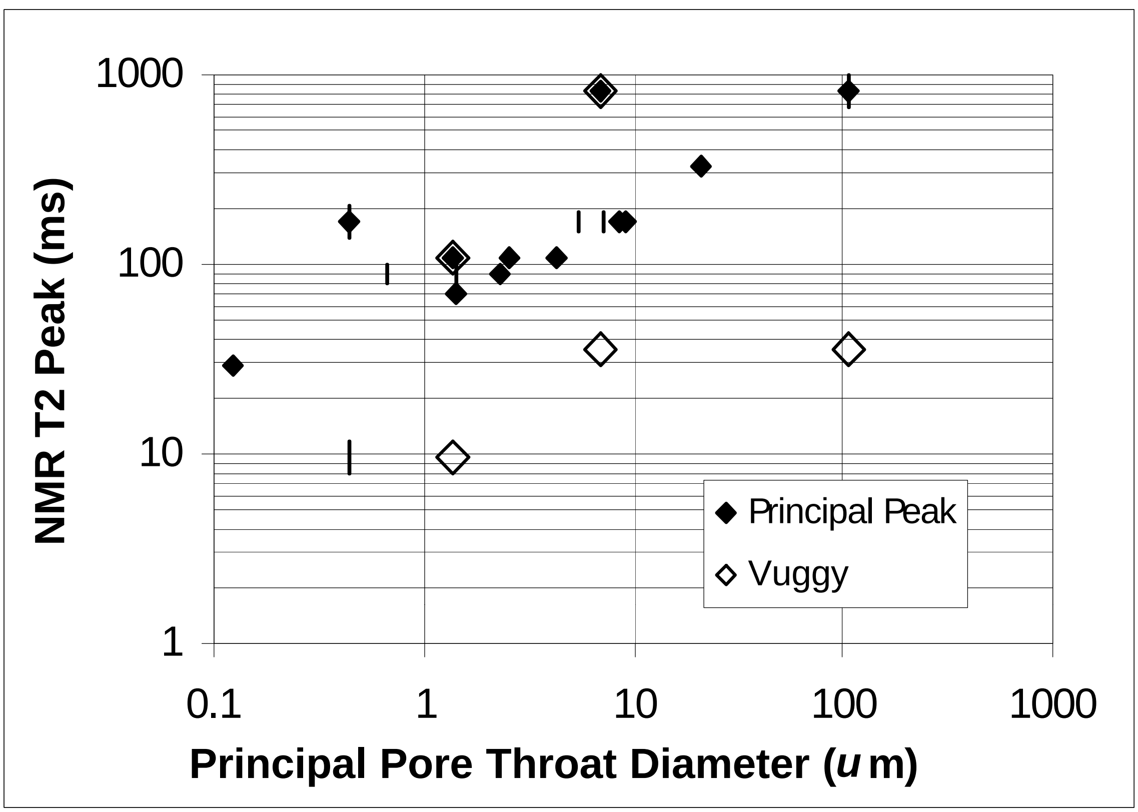

Figure A6. Cross-plot between NMR measured T2 peak position and the principal pore throat diameter as measured by air-mercury capillary pressure.

T2 Cutoff

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 A7). Rocks with vuggy porosity exhibit significantly greater cutoff values for a given permeability than rocks with intergranular porosity.

Electrical Resistivity

Electrical resistivity measurements for samples with predominantly intergranular porosity exhibit an average Archie cementation exponent of 1.97 ± 0.09 (Figure A8). Vuggy samples exhibit higher cementation exponents ranging from 2.2 to 2.5.

Conclusions

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.

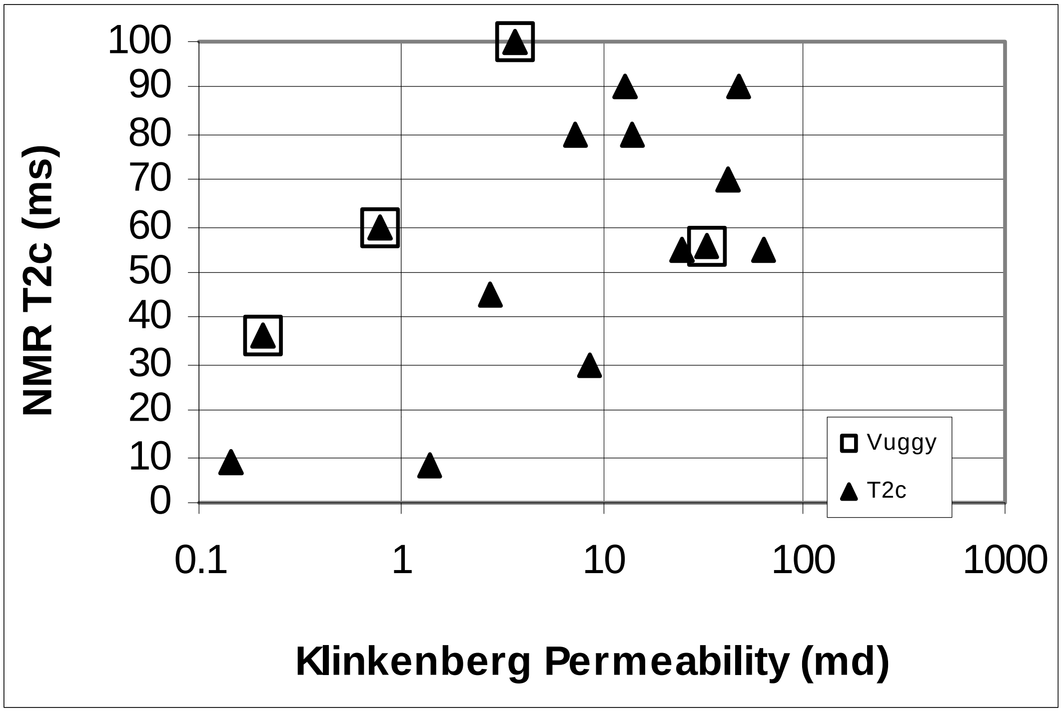

Figure A7. Cross-plot of NMR T2 cutoff and Klinkenberg permeability.

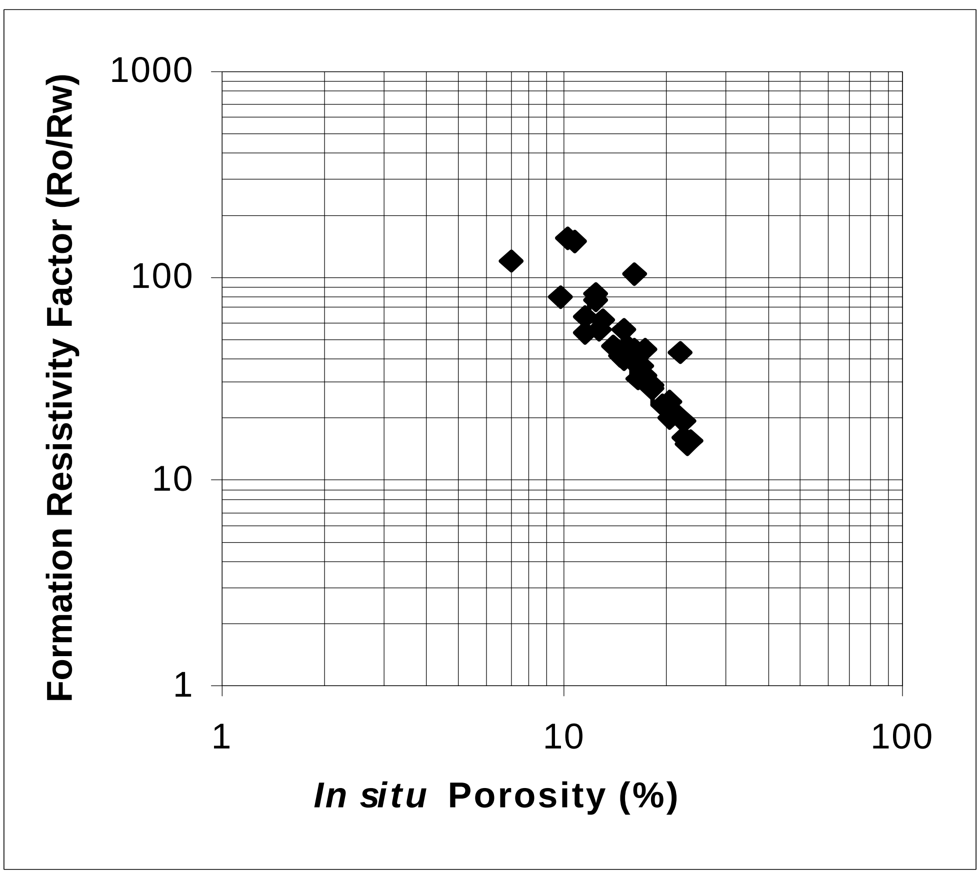

Figure A8. Cross-plot of *in situ* formation electrical resistivity factor versus *in situ* porosity.