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IMPROVED OIL RECOVERY IN MISSISSIPPIAN CARBONATE RESERVOIRS OF KANSAS – NEAR TERM – CLASS II

Final Report
September 16, 1994-April 30, 2001

By:
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Don W. Green
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Abstract

This final report describes progress during the final 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 the project was 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. As part of the project, tools and techniques for reservoir description and management were developed, modified and demonstrated, including PfEFFER spreadsheet log analysis software. The world-wide-web was used to provide rapid and flexible dissemination of the project results through the Internet.

A summary of demonstration phase at the Schaben and Ness City North sites demonstrates the effectiveness of the proposed reservoir management strategies and technologies. At the Schaben Field, a total of 22 additional locations were evaluated based on the reservoir characterization and simulation studies and resulted in a significant incremental production increase. At Ness City North Field, a horizontal infill well (Mull Ummel #4H) was planned and drilled based on the results of reservoir characterization and simulation studies to optimize the location and length. The well produced excellent and predicted oil rates for the first two months. Unexpected presence of vertical shale intervals in the lateral resulted in loss of the hole. While the horizontal well was not economically successful, the technology was demonstrated to have potential to recover significant additional reserves in Kansas and the Mid-continent. Several low-cost approaches were developed to evaluate candidate reservoirs for potential horizontal well applications at the field scale, lease level, and well level, and enable the small independent producer to identify efficiently candidate reservoirs and also to predict the performance of horizontal well applications.

Executive Summary

The Kansas Class 2 project was a demonstration project in an Osagian and Meramecian (Mississippian) shallow shelf carbonate reservoir in west central Kansas. Cumulative production from Mississippian carbonate reservoirs located beneath a regional sub-Pennsylvanian unconformity and karst surface is over 1 billion barrels distributed over a large number of small to medium size reservoirs. Small independent producers operate many of these reservoirs. Extremely high water cuts and low recovery factors place continued operations at or near their economic limits. This report concentrates on the results of the demonstration activities.

Application of cost-effective reservoir description and management strategies can significantly extend the economic life of these mature peritidal carbonate fields and recover incremental reserves. 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. Producibility problems in Kansas Meramecian and Osagian dolomite reservoirs include inadequate reservoir characterization, drilling and completion design problems, and non-optimal primary recovery.

The project entailed integration of and creative approaches to the often-inadequate existing data characteristic of small mature reservoirs operated by independent producers. At the Schaben and Ness City North demonstration sites, integrated reservoir characterization provided the basis for development of a descriptive reservoir model and the framework for simulation. The study results were used to evaluate and target infill vertical and horizontal wells, and contributed to a document increase in production.

As part of the Kansas Class 2 project a number of cost-effective tools and techniques for reservoir description were developed, modified and demonstrated. These include widely used low-cost spreadsheet log analysis software (PfEFFER).

The most significant Kansas Class 2 project results include: 1) identification of potential incremental reserves that can be accessed through targeted infill and possible horizontal drilling: 2) development of regional databases for evaluation of targeted infill drilling in similar Mississippian reservoirs of Kansas; and 3) new models for innovative cost-effective approaches to reservoir characterization and simulation using less existing less than optimal data.

1.0 Introduction

The Kansas Class 2 project was an effort to introduce Kansas producers to potentially useful technologies and to demonstrate these technologies in actual oil field operations. In addition, advanced technology was tailored specifically to the scale appropriate to the operations of Kansas producers. 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 sustained production and increased viability. A major emphasis of the project was 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 was, and continues to be, undertaken to inform other operators of the project results. In addition to traditional technology transfer methods (for example, reports; trade, professional, and technical publications; workshops; and seminars), a public domain relational database and computerized display package are available through the Internet. The goal is figuratively to provide access to necessary data and technology to independent producers in their office.

Project design, methodologies, data, and results were disseminated through focused technology transfer activities (Appendices 1, 2). These activities include development of new cost-effective technologies and software (e.g. PfEFFER, “Pseudoseismic”), demonstration of modified technologies that better fit the requirements and limitations of small independent producers operating small mature reservoirs (e.g., reservoir characterization and simulation and horizontal drilling). Technology was transferred through both widely disseminated technical publications and formal presentations (appendix 1) and a significant number of workshops and seminars (Appendix 2). In additional, personnel interactions and public access through the Internet to the results within a relational database and computerized display package were established. The target audience included 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 of independent producers involved in reservoir development and management.

Objectives and Significance

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

This project addresses reports on the use of reservoir characterization, reservoir simulation and the application of targeted infill drilling using horizontal wells to address producibility problems in the numerous Kansas fields that produce from Meramecian and Osagian dolomites beneath the sub-Pennsylvanian unconformity such as the Schaben and Ness City North fields in Ness County. 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 this project facilitated integrated, multi-disciplinary reservoir characterization. Application of cost-effective reservoir description and management strategies has the potential to significantly extend the economic life of these mature peritidal carbonate fields and recover significant incremental reserves. 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.

Site Descriptions

*Schaben Field.-*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). 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 Schaben Field demonstration 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 - 1.4).

Schaben field, discovered in 1963, consists of 78 completed oil wells spaced primarily on 40-acre locations. Production is primarily from the Mississippian. However, one well produces very small quantities of oil from the Cherokee Group and the Fort Scott Limestone Cumulative field production as of February 2001 was 9.3 million barrels of oil (BO), and daily field production was just less than 400 BOPD from 62 wells (Figures 1.5, 1.6). As part of the demonstration a reservoir characterization and reservoir simulation provided excellent full-field and good individual history matches for all existing wells. The simulation provided an estimate of additional incremental oil resulting from targeted infill drilling, and indicated that infill vertical and horizontal drilling could be a viable strategy to recover additional reserves. From late 1996 through early 1998, a total of twenty-two (22) infill locations were drilled or recompleted at the Schaben Demonstration Site (Table 1.1). Locations were selected using the results of the reservoir management strategy developed as part of this project. All three major field operators (Ritchie Exploration, Pickrell Drilling and American Warrior) have used results of the reservoir simulation and management strategy to evaluate multiple locations and select optimum locations (Figure 1.7). At the Schaben Demonstration Site, the additional locations resulting from the demonstration project resulted in an incremental production increase of 100 BOPD over the last five years (Figure 1.6).

_Ness City North Field.-_The Ness City North demonstration site is located just northwest of Schaben Field in Ness County, Kansas (sections 23, 24 and 25 of T18S-R24W: Figure 1.2). The producing horizon is Mississippian carbonate similar to that studied at nearby Schaben Field. Ness City North Field is a typical small Mississippian reservoir (i.e., buried positive erosional feature beneath the Pennsylvanian unconformity). The field was discovered in 1963 and a total of nine wells were drilled into the reservoir (Figure 1.2). Current average production is approximately 3.25 BO/D from 6 wells (1999 data from Kansas Geological Survey; http://www.kgs.ukans.edu/PRS/County/nop/ness.html). Operating and abandoned wells included in the reservoir characterization study are: Ummel #1 (Mull Drilling), Ummel #2 (Mull Drilling), Ummel #3 (Mull Drilling), Ummel #4 (Mull Drilling), Ummel #1-24 (Mull Drilling), Pfannenstiel #2 (Sun Oil Co.), Pfannenstiel #1 (Associate Oil & Gas), Pfannenstiel #1 (Sun Oil Co.), A Pember #5 (Mineral Exploration), Ummel #1 (Hembree) and Pfannenstiel #1 (Sun Oil Co.). The focus of the demonstration project at Ness City North Field was evaluation of the field for an infill horizontal well with emphasis on evaluating the potential of reentering the Mull Ummel #4 well (Figure 1.2).

Other Technology Transfer Products

The technology and information developed, as part of the Class 2 project includes modification and adaptation of existing technology (e.g., BOAST,). However, PfEFFER is a new technology product that provides addin software to existing spreadsheet software (i.e., Microsoft Excel) that provides log and core evaluation tools and preprocessing capabilities for reservoir simulators. We have reported on PfEFFER numerous times (e.g., Doveton and others, 1996; Watney and others 1999, Carr and others, 1999). As of the end of last year, approximately 140 entities (companies, institutions and individual consultants) from across the US and overseas have acquired PfEFFER (Figure 1.9). Some of these entities have multiple copies.

Participating Organizations

Organizations participating from the University of Kansas include the 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. Operators directly involved in the project include Ritchie Exploration Inc., Wichita, Kansas (Schaben Demonstration Site), and Mull Drilling, Inc., Wichita, Kansas, (Ness City North Demonstration Site). A large number of other operators in the area also provided data and other information. Total cost sharing in the project is 50 percent.

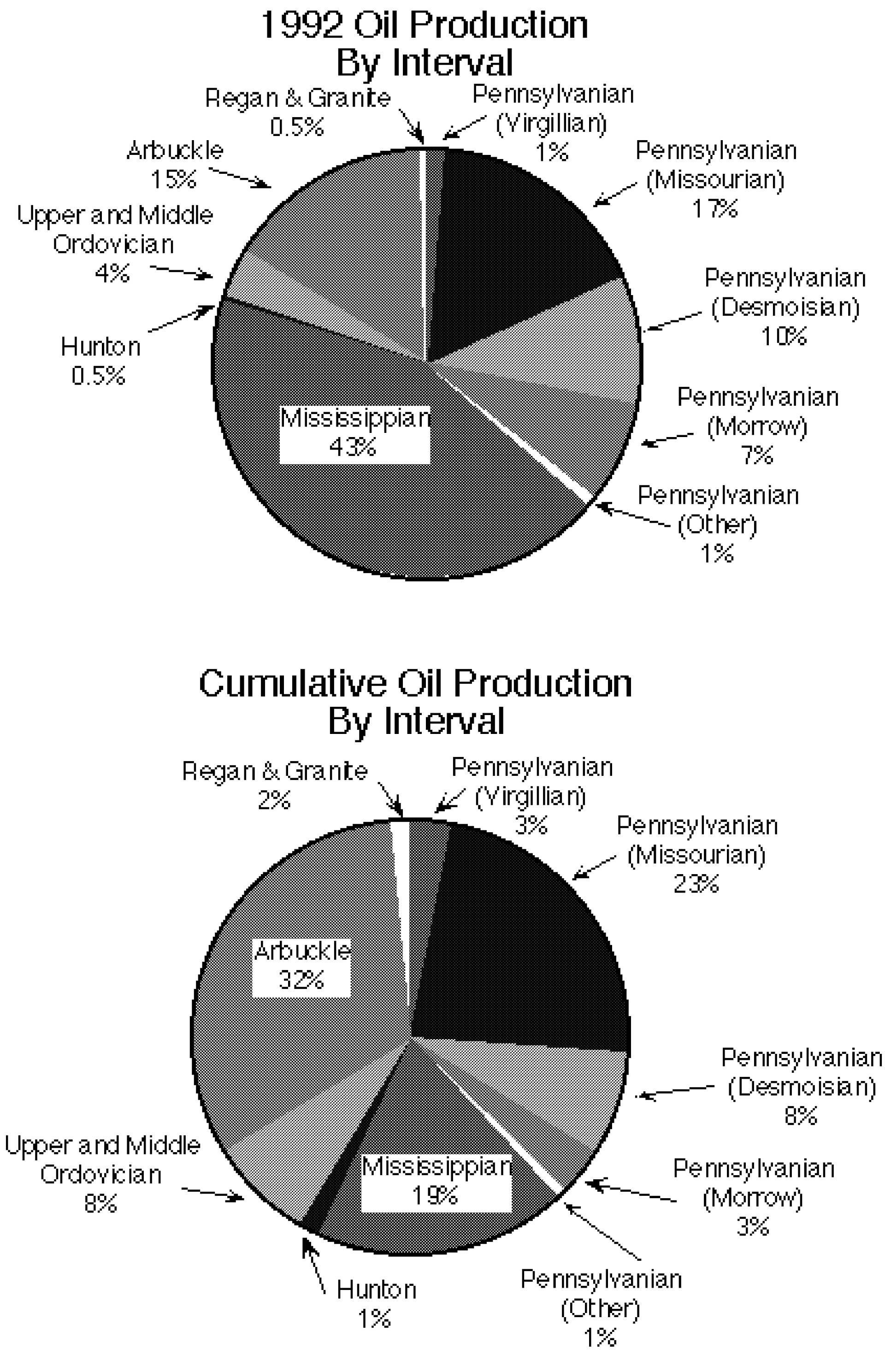


Figure 1.1 - Kansas annual and cumulative oil production from Carr et al. 1995a. Mississippian reservoirs comprise one of the largest producing intervals in the state. Also available on-line through the Internet (http://www.kgs.ukans.edu/PRS/publication/OFR95_42/tim1.html).

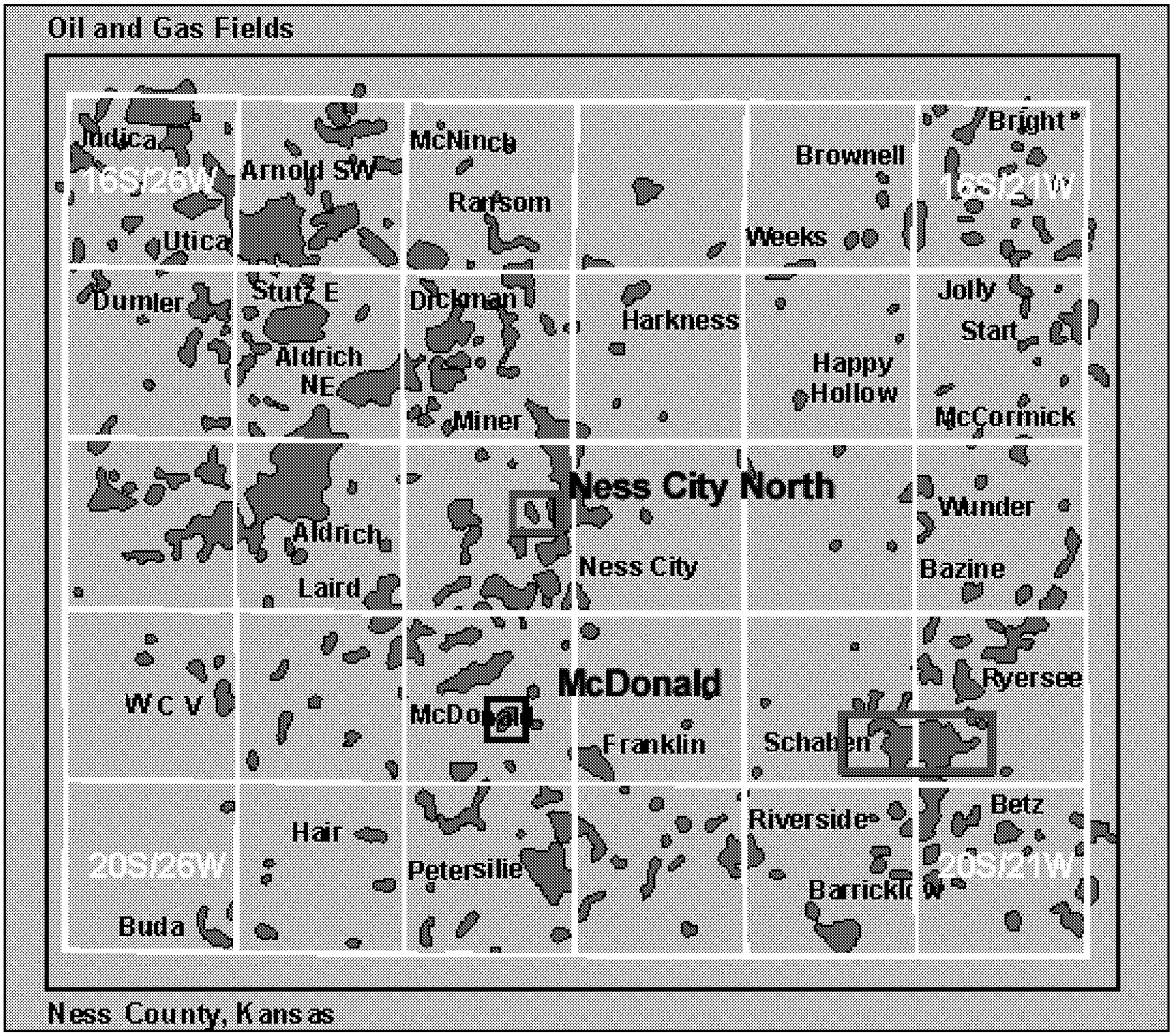


Figure 1.2 - Map for Ness County, Kansas showing townships, producing oil fields and the location of the Schaben, Ness City North and McDonald fields. The demonstration areas at Schaben and Ness City North fields (highlighted in red) produce from similar Mississippian reservoirs and are separated by approximately 12 to 15 miles.

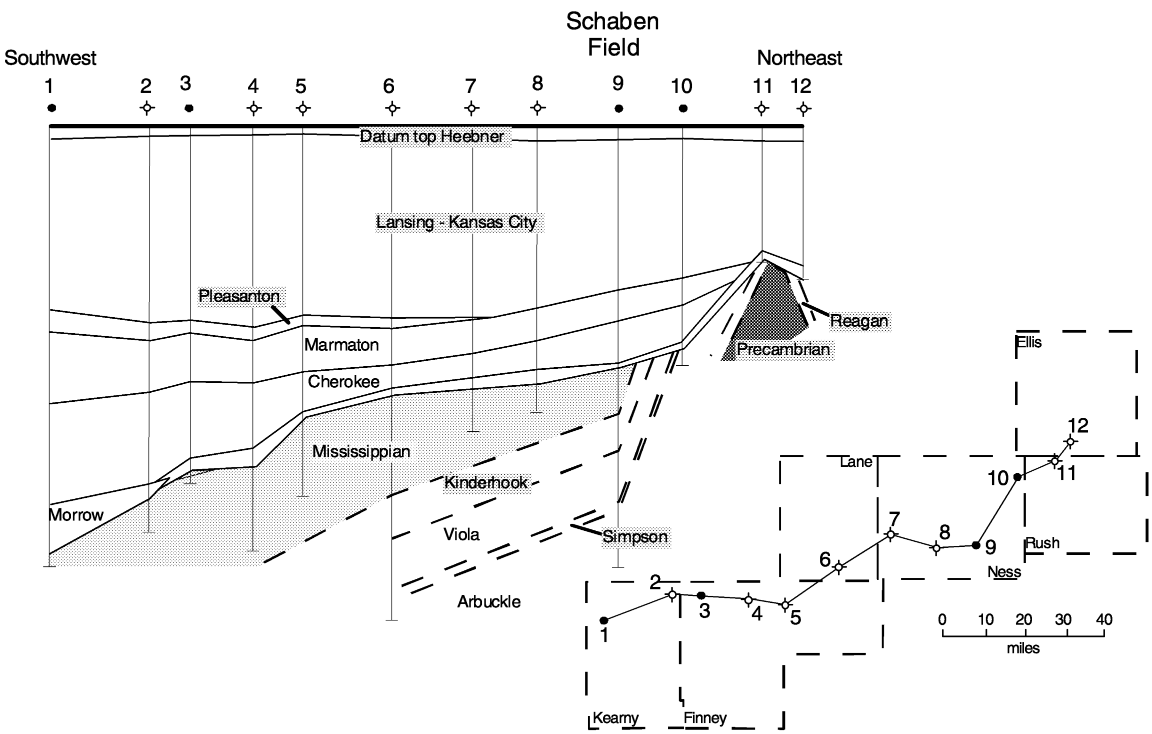


Figure 1.3 - Regional southwest-northeast cross-section showing relation of Mississippian and older rocks to the pre-Pennsylvanian unconformity. Location of the Schaben Field demonstration site is indicated by the shaded area at the top of the Mississippian at well 9. Modified from Goebel and Merriam (1957).

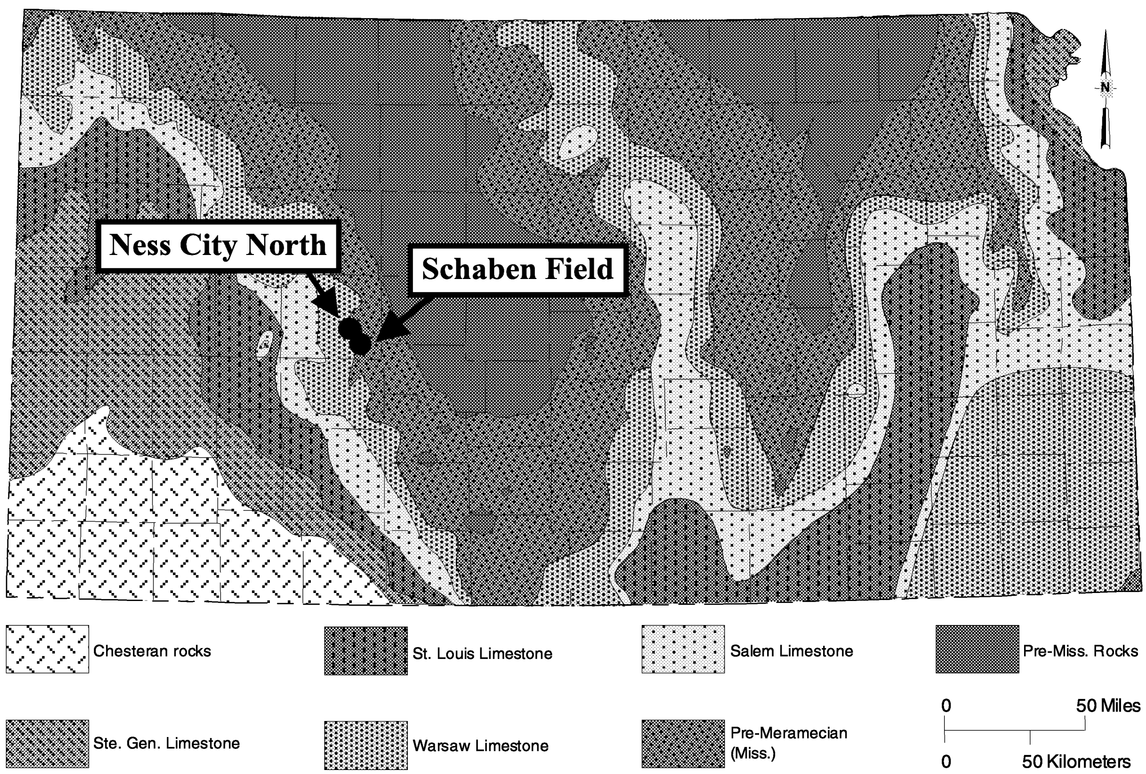


Figure 1.4 - Mississippian subcrop map beneath the Pennsylvanian unconformity showing location of Schaben Field. Mississippian units beneath the unconformity become progressively older and are absent on the Central Kansas uplift.

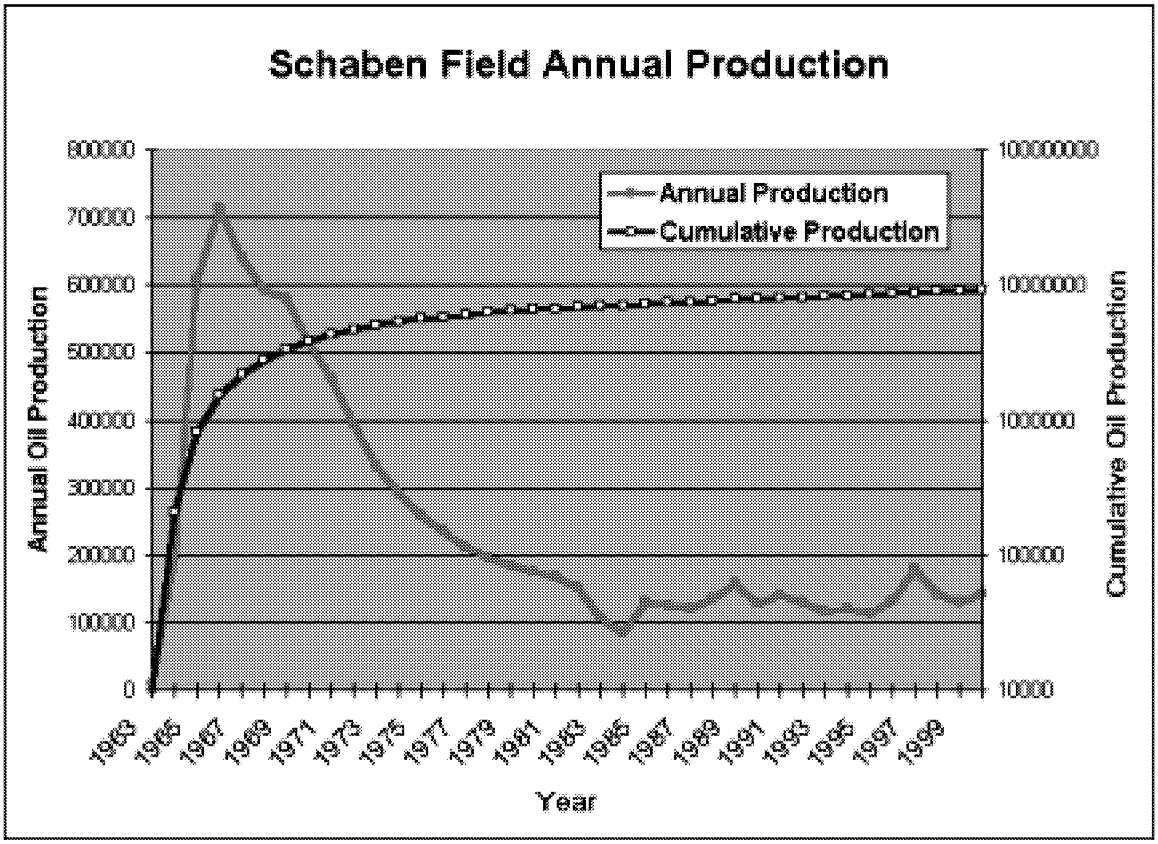


Figure 1.5 - Annual and cumulative field production for the Schaben Field Ness County, Kansas.

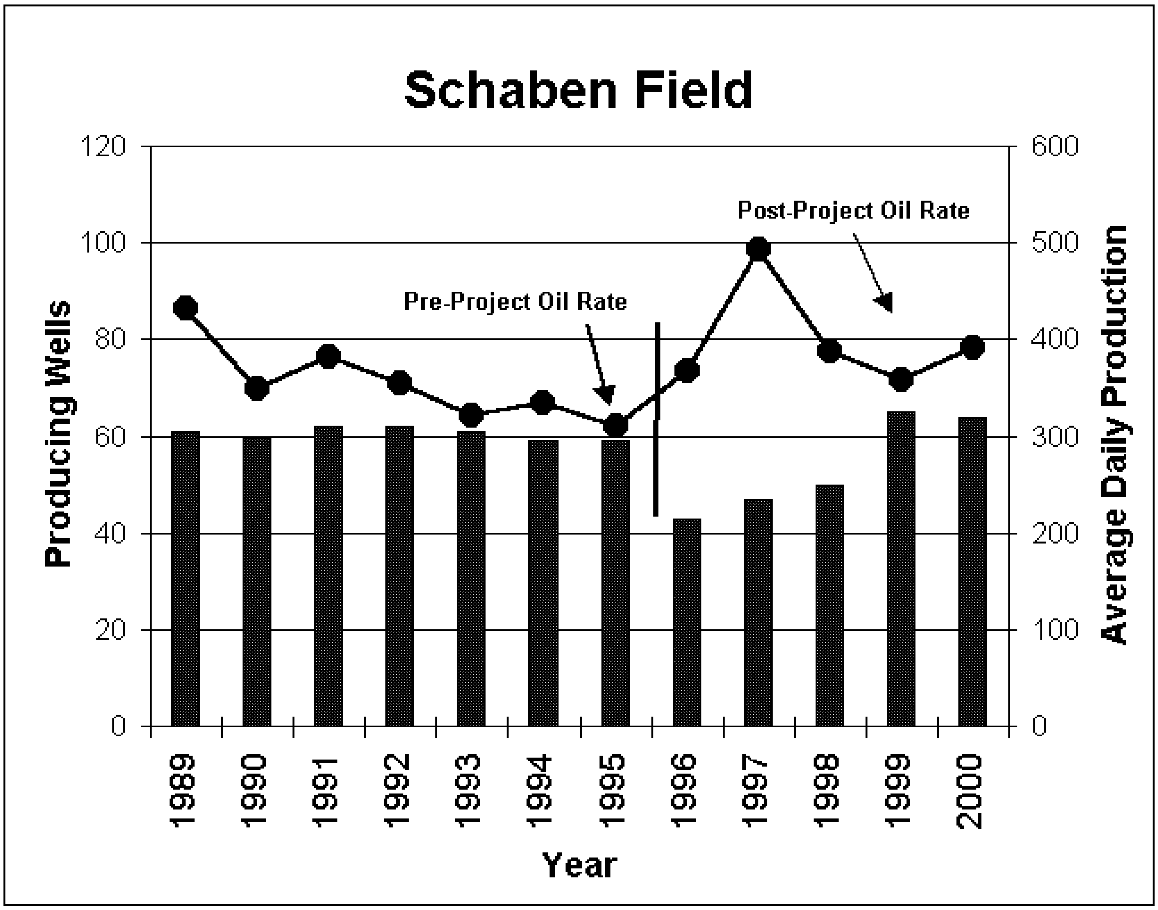


Figure 1.6 – Average daily production from the Schaben Field demonstration site showing the direct impact of the additional targeted vertical infill wells. A steady decline was arrested and approximately 100 BOPD were added to production.

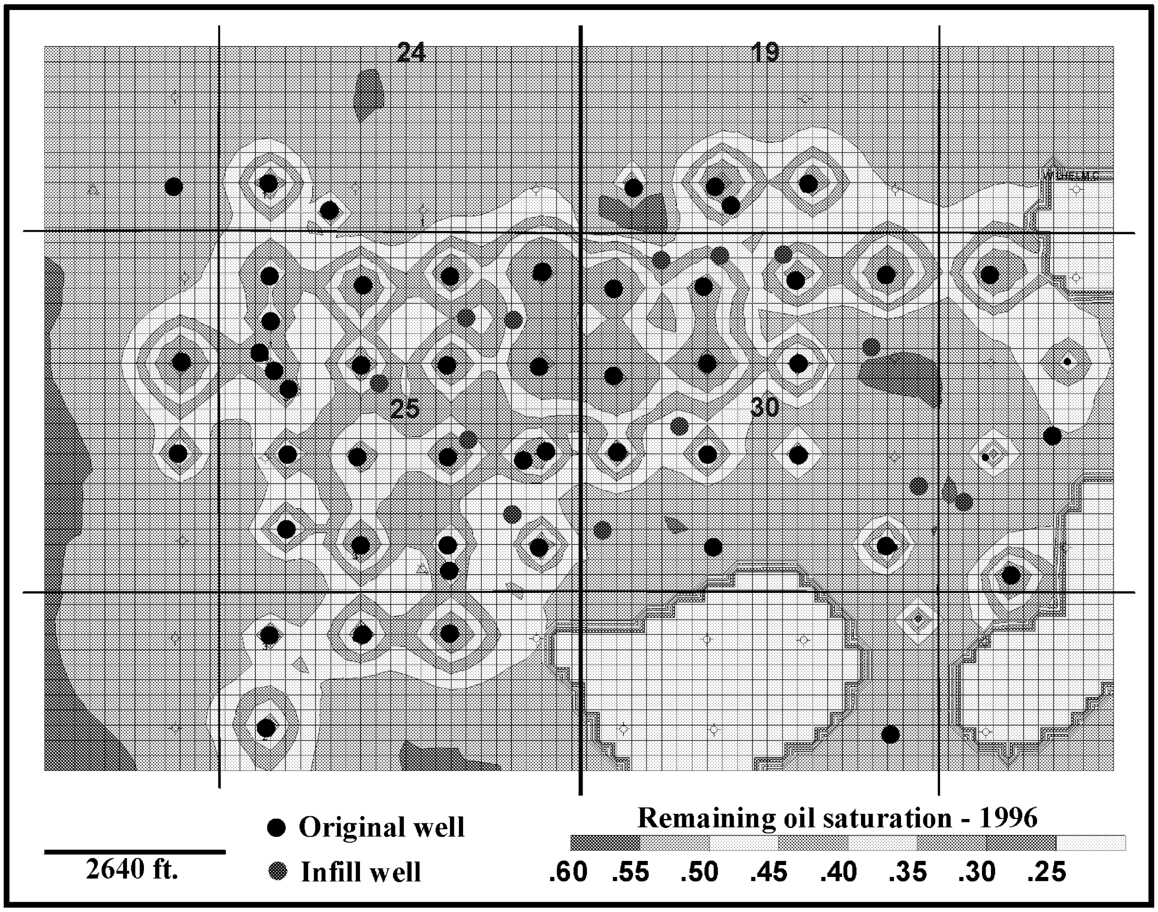


Figure 1.7 - Map showing remaining oil-saturation (as of December 1996) in Schaben field, Ness County, Kansas, and developed from the simulation results of BOAST4. Infill wells drilled by a single operator after the conclusion of this study are shown red dots whereas the black dots represent the location of the original wells in the field.

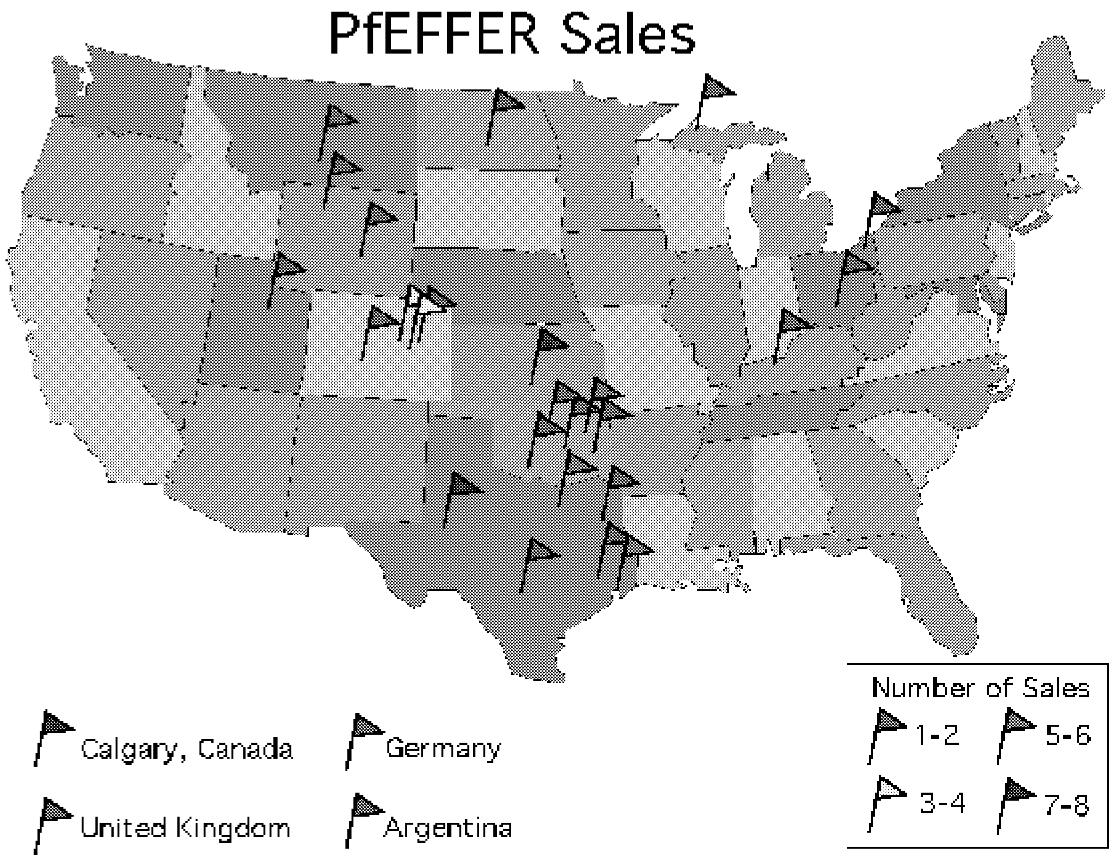


Figure 1.8 - Map showing distribution of approximately 140 entities that have one or more copies of PfEFFER. PfEFFER was initiated as a part of the Class 2 project and continues to draw interest as a low cost but high technology tool for reservoir characterization and evaluation.

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 from the Schaben Study.

2.0 Ness City North Field - Reservoir Characterization

Section based in part on Bhattacharya and others, 1999b and Gerlach and others, 2000.

Using tools and approaches developed at Schaben Field a reservoir characterization was undertaken as part of a demonstration project at the Ness City North Field. The limited log, core, petrophysical, drill stem test, and production data used to develop a reservoir geomodel are characteristic of a small mature oil field operated by an independent. The goal of the reservoir characterization was to provide input to a simulation study and to optimize the location and length of an infill horizontal well. Predicted performance for the horizontal well was compared to production results from the horizontal well to validate and fine-tune the assumptions incorporated in the reservoir model.

Wells included in the reservoir characterization are: Ummel #1 (Mull Drilling), Ummel #2 (Mull Drilling), Ummel #3 (Mull Drilling), Ummel #4 (Mull Drilling), Ummel #1-24 (Mull Drilling), Pfannenstiel #2 (Sun Oil Co.), Pfannenstiel #1-24 (Associate Oil & Gas), Pfannenstiel #1 (Sun Oil Co.), A Pember #5 (Mineral Exploration), Ummel #1 (Hembree), Pfannenstiel #1 (Sun Oil Co.) and Maier #1 (Walters Drilling Co.).

An immediate result of the reservoir characterization at Ness City North Field was the identification of a successful recompletion opportunity in the Pfannenstiel #1-24.

Geologic-Petrophysical Model

Tops of significant geologic and reservoir units were identified using well logs and mapped using a PC-based program. The Meramecian and Osagian dolomite reservoirs beneath the sub-Pennsylvanian unconformity show the erosional nature of the Mississippian surface. The structure of the Ness City North Field is typical of other small Mississippian reservoirs surround the immediate vicinity of the demonstration site (Figure 2.1, 2.2). Flow unit geometry (structure and thickness) was mapped and simple cross-sections constructed using available well logs and other well data (Figures 2.1 to 2.9). Based on the constraints of available data and the requirements of the operator, a five-layer reservoir model was constructed for the demonstration area at Ness City North (Figure 2.4). From the top, the five flow units were labeled LP1, LP2, LP3, HP1 and HP2.

In the study area, forty-one core plugs were available from four wells (Sun Ummel #1, Sun Pfannenstiel #1 and #2, and Walters Drilling Maier #1). Standard laboratory measurements carried out on the core plugs included routine helium porosity and air permeability measurements, in situ and effective Klinkenberg permeability determination, irreducible water saturation measurements, and identification of the dominant lithofacies (Table 2.1).

Optimal information about the porosity or permeability in the reservoir flow units is unavailable for most wells in the study-area. The only available porosity log in the study area is from the Mull Ummel #1-24. As a result, the approach to estimate porosity was to combine the very limited petrophysical logs with core studies at the well level. An average porosity value for each reservoir flow unit was obtained by correlation among the wells (Table 2.2). Using the core data, a permeability-porosity correlation for each individual lithofacies, and a histogram of the laboratory measured permeability values were generated (Figures 2.10, 2.11). Frequency peaks occur in the low permeability range at 8 md, in the medium permeability range at 25 md, and in the high permeability range at 40 and 60 md.

The reservoir geomodel assigns uniform porosity and permeability values for the flow units. Core studies indicate that moldic packstone-wackestone is the dominant facies in flow units LP1, LP2 and LP3, while moldic packstone dominates lithofacies in flow units HP1 and HP2. A uniform porosity value for each flow unit was determined as the lower value of the value calculated from the permeability-porosity correlation or the highest measured porosity (from standard core analysis on plugs) for the dominant lithofacies for each flow unit (Table 2.2). Permeability for LP1, LP2, and LP3 (i.e., 8 md, 25 md, and 8 md, respectively) correspond to the frequency peaks observed at the low permeability and medium permeability ranges of the permeability histogram (Figure 2.11). Layers HP1 and HP2 were assigned permeability corresponding to the frequency peaks in the high permeability range (i.e., of 60 md and 40 md, respectively.

Capillary pressure measurements were carried out on core plug samples representative of the five reservoir flow units (Figure 2.12). Estimates of water saturation (S_w) predictions based on capillary pressure analysis and log analysis tied to position above mapped oil-water contact (-2035 feet subsea) and lithofacies provide are comparable (Figure 2.13). Relative permeability curves were generated for each flow unit using the correlations of Honarpour (1986). The equation for intermediately wet limestone-dolomite was used to calculate the relative permeability of water. The relative permeability curve for oil was generated with the equation for limestone-dolomite of any wettability (Figure 2.14). Irreducible water saturation (S_{wi}) for core plugs was measured at 150 feet above the free water level, and was used in the calculation of the relative permeability (Figure 2.15). The irreducible oil saturations (S_{orw}) were measured on selected core plugs from the reservoir units at Ness City North (Figure 2.16). The irreducible oil saturations (S_{orw}) show two loose clusters, representing S_{orw} values for porosities less than 20% and the other representing porosities above 20%. An average S_{orw} value from each cluster was used to calculate relative permeability.

Sufficient log data were available for only two wells (Mull Pfannenstiel #1-24, and Mull Ummel #4) in the study area to undertake Super-Pickett plot analysis (Figures 2.17-2.19). A salinity of around 34000 ppm (NaCl) was considered for the calculation of Rw (= 0.13 ohm-m) at a reservoir temperature of 115°F. The Super-Pickett plot of Pfannenstiel #1-24 indicates irreducible bulk value water (BVW_i) of 0.066 (Figure 2.17). The Rhomaa-Umaa plot for the Mull Pfannenstiel #1-24 indicates that the Mississippian reservoir flow units are composed dominantly of dolomite with some quartz and calcite (Figure 2.18). Based on the log analysis of the Pfannenstiel #1-24, average porosities that were calculated for layers LP1, LP2, LP3, and HP1 are 0.144, 0.184, 0.163, and 0.178, respectively (Figure 2.17). In the Mull Ummel #4, the average porosity values that were calculated for layers LP1, LP2, and LP3 are 0.169, 0.176, and 0.174, respectively (Figure 2.19). These calculated porosity values from log data compare closely with the average porosity values determined from core analysis.

The very limited suite of available well logs hindered determination of initial water saturation (Sw) values and the oil-water-contact (OWC) for wells in the study area. Analysis of sample reports, DST data and production tests enabled mapping of a flat oil-water-contact (OWC) across the study area at subsea –2035 feet (Figure 2.2). The depth of the OWC was supported by the available log data in Pfannenstiel #1-24 (Mull Petroleum) well. Saturation values for each layer were calculated from the flow-units representative capillary curve and the average height of the unit above the field OWC.

Pressure and Production Data Analysis

Drill stem test (DST) data was available from five wells (Table 2.3). Calculated static reservoir pressure (P_i) based on the limited DST data indicated that reservoir pressure declined by 450 psi over a period of 17 years (Figure 2.19). The relatively small decrease in reservoir pressure supports the existence of an active bottom water drive in the reservoir, and is similar to the bottom water drive documented in the Mississippian reservoir at Schaben Field.

Production data for the Mull Ummel #1, Mull Ummel #2, and Mull Ummel #1, included the monthly sales record for the Ummel lease and results of periodic 24-hour barrel-tests at individual wells. The barrel test results included the oil and water production over a 24-hour period and were carried out periodically over the productive life of each well. Results of barrel tests were used to allocate monthly lease production of oil (actually volumes of oil sales) to individual wells on the Ummel lease. The calculated monthly oil production for each well was used in conjunction with the corresponding water-oil ratio (WOR), obtained from the barrel test, to derive the monthly water production. The monthly oil and water production for the three Ummel wells were averaged over three-month periods (Figure 2.21). Data was also plotted as WOR versus cumulative oil production along with the equations of the best fitting lines (Figure 2.17).

Production data available for the other wells in the study area included the monthly volumes of oil sales from corresponding leases. The wells include the Pfannenstiel #1 (Associates Oil & Gas), Pfannenstiel #1-24 (Mull Petroleum), Pember #A5 (Mineral Management), Pfannenstiel #2 (Sun Oil Co.), and Ummel #1 (Hembree). These wells are single well leases and lease sales can be allocated to individual wells. The monthly oil production for each well was obtained by averaging the lease sales volumes over a three-month period. A cumulative production profile was generated for each well in the Ness City North Field (Figure 2.22). The Mull Ummel #1 is the best performing well in the field having cumulative oil production exceeding 100,000 barrels. The remaining wells in the field show similar cumulative production patterns that are far behind that of Ummel #1 (Mull Petroleum) well (Figure 2.22).

The sparse and incomplete production data from the Ness City North Field is typical of the small fields in the area. In absence of water production data for wells outside the Ummel lease, water production values were estimated by using the plot of WOR versus cumulative oil production for Ummel #2 (Figure 2.23). In terms of WOR ratio, the Mull Ummel #2 well is a medium performer on the Ummel lease. The resulting monthly oil and water production data for the producing wells in the Ness City North field is only a best estimate based on available information (Figure 2.23). The production data along with the reservoir geomodel formed the input to the subsequent reservoir simulation.

Recompletion Opportunity

An immediate result of the reservoir characterization at Ness City North Field was the identification of a successful recompletion opportunity in the Pfannenstiel #1-24. A cross section between Ummel #4 and the Pfannenstiel #1-24 showed that the Pfannenstiel was completed only in the LP1 flow unit (Figure 2.24). Based on the reservoir characterization, it appeared that perforations in the Pfannenstiel #1-24 should be added to flow unit LP2. With the addition of new perforations in flow unit LP2 the operator increased production in the Pfannenstiel #1-24 from 2 BOPD and 20 BWPD (91% water) to 23 BOPD and 125 BWPD (84% water).

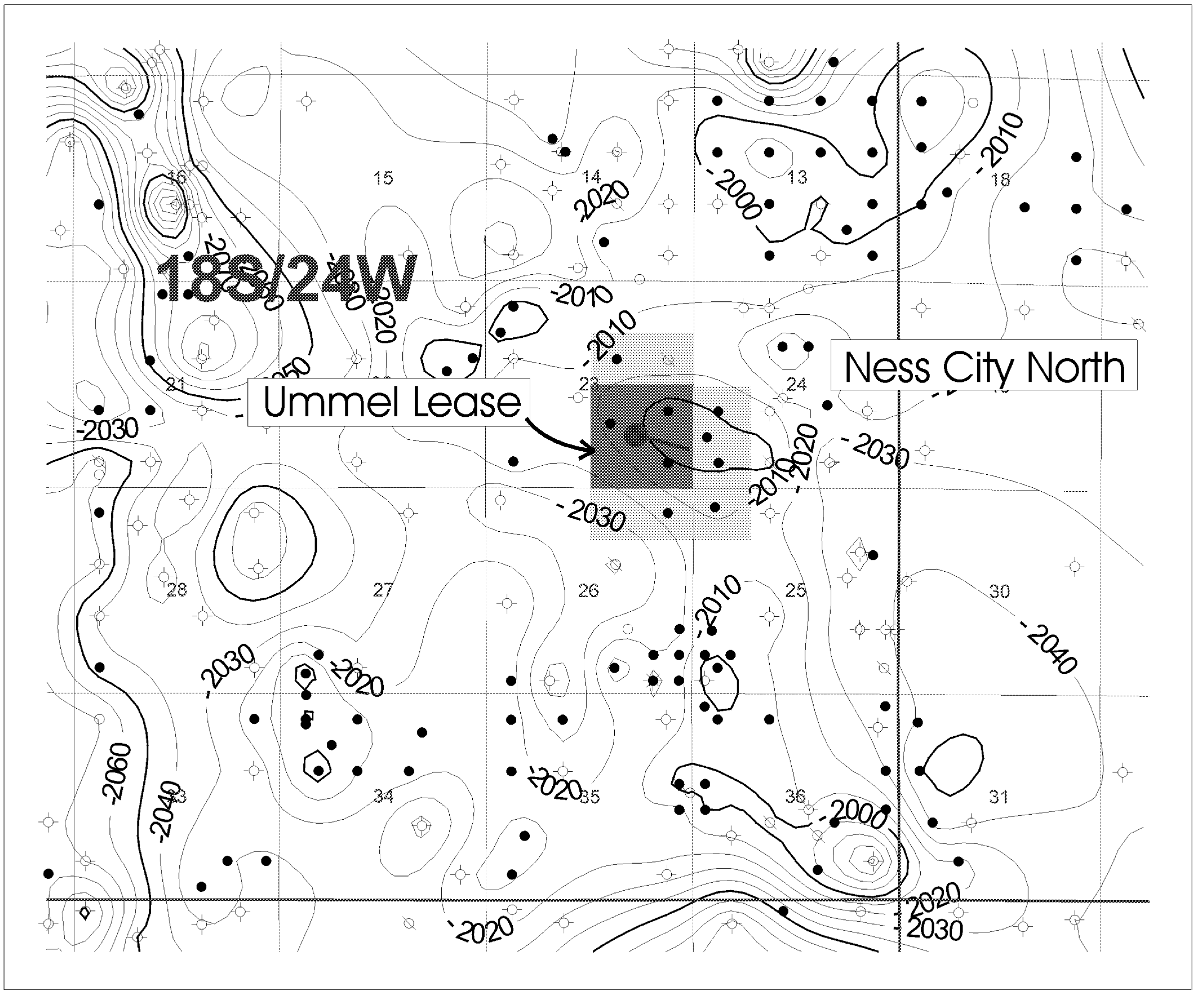
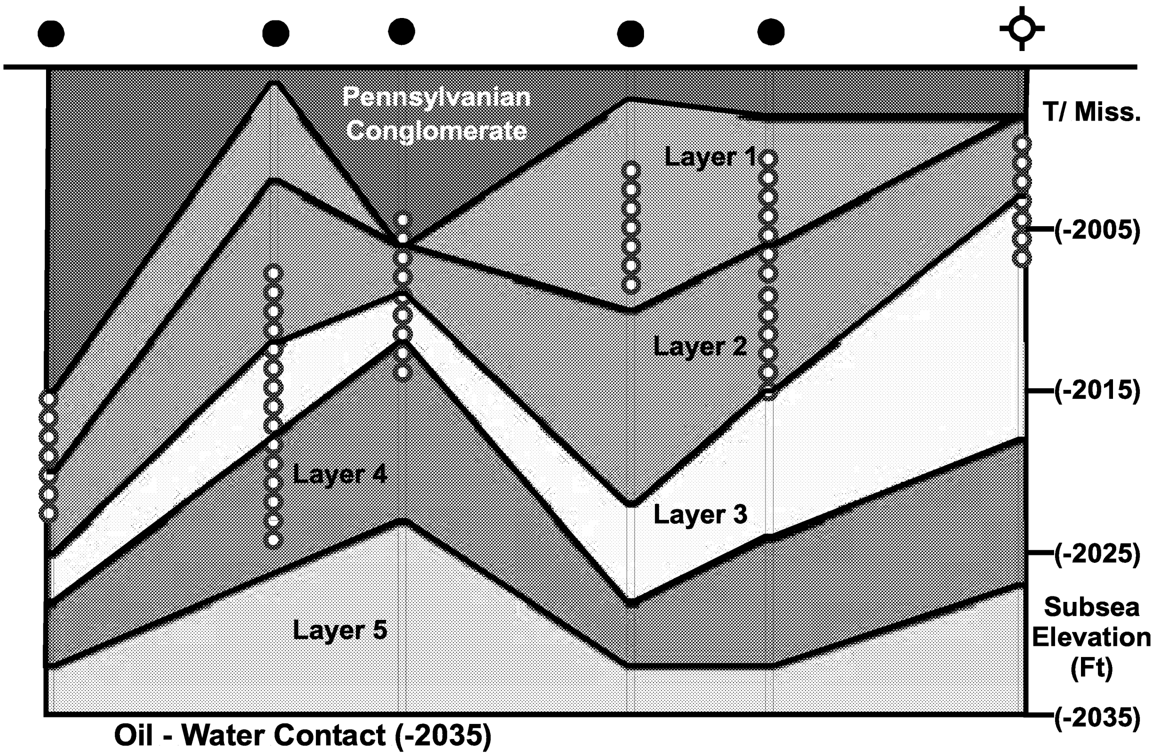


Figure 2.1 - Structure map on top of Mississippian reservoir unit showing field outline, leases and wells in the Ness City North Field which comprises the demonstration area for the horizontal infill well. The Ummel lease and Mull Ummel #4 well are highlighted. The Ummel #4 is completed, but is not producing. The Ummel #4 was evaluated as a candidate to reenter and drill a horizontal lateral toward the center of the field (possible well path is shown schematically). Numerous other Mississippian reservoirs surround the immediate vicinity of the proposed demonstration site.



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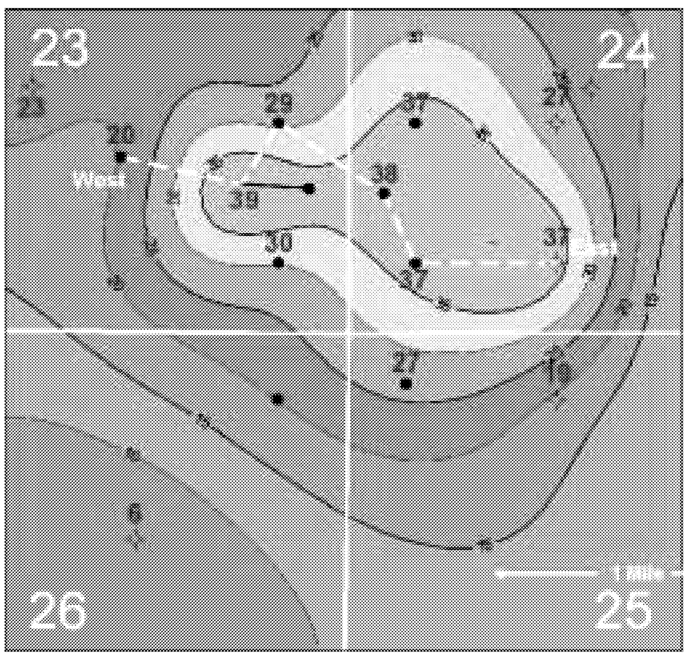


B

Figure 2.2 – **A)** Sample stick structural cross section across Ness City North Field showing geologic horizons (layers) developed in the reservoir characterization and used to develop grids input into the reservoir simulation. Oil water contact is at subsea –2035feet. The vertical exaggeration is 57 times. **B)** Isopach of gross oil column across Ness City North Field showing location of cross-section.

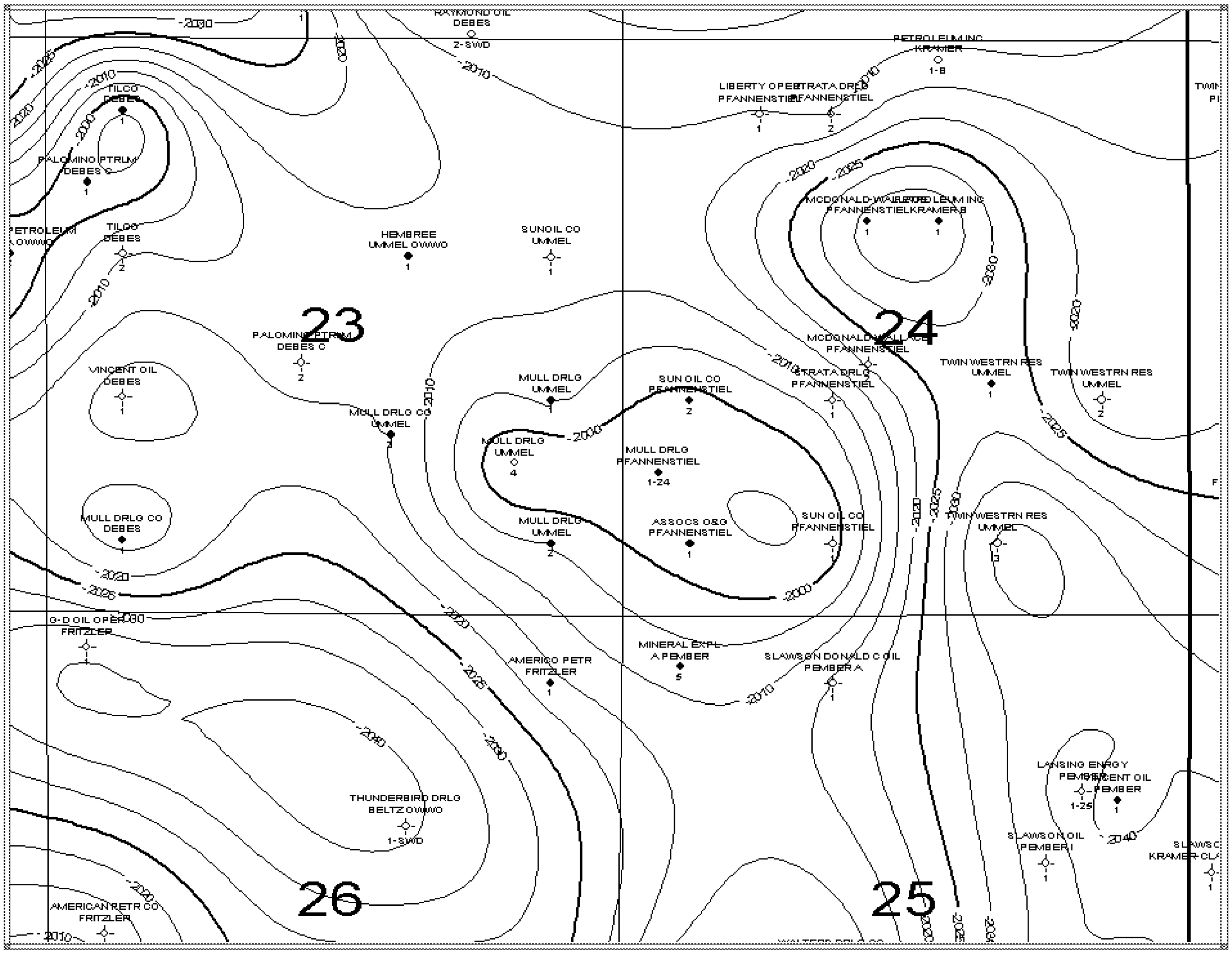


Figure 2.3 - Detailed structure map on top of Mississippian reservoir at Ness City North showing the nature of the erosional surface (i.e., small-buried positive features). Contour interval is five feet.

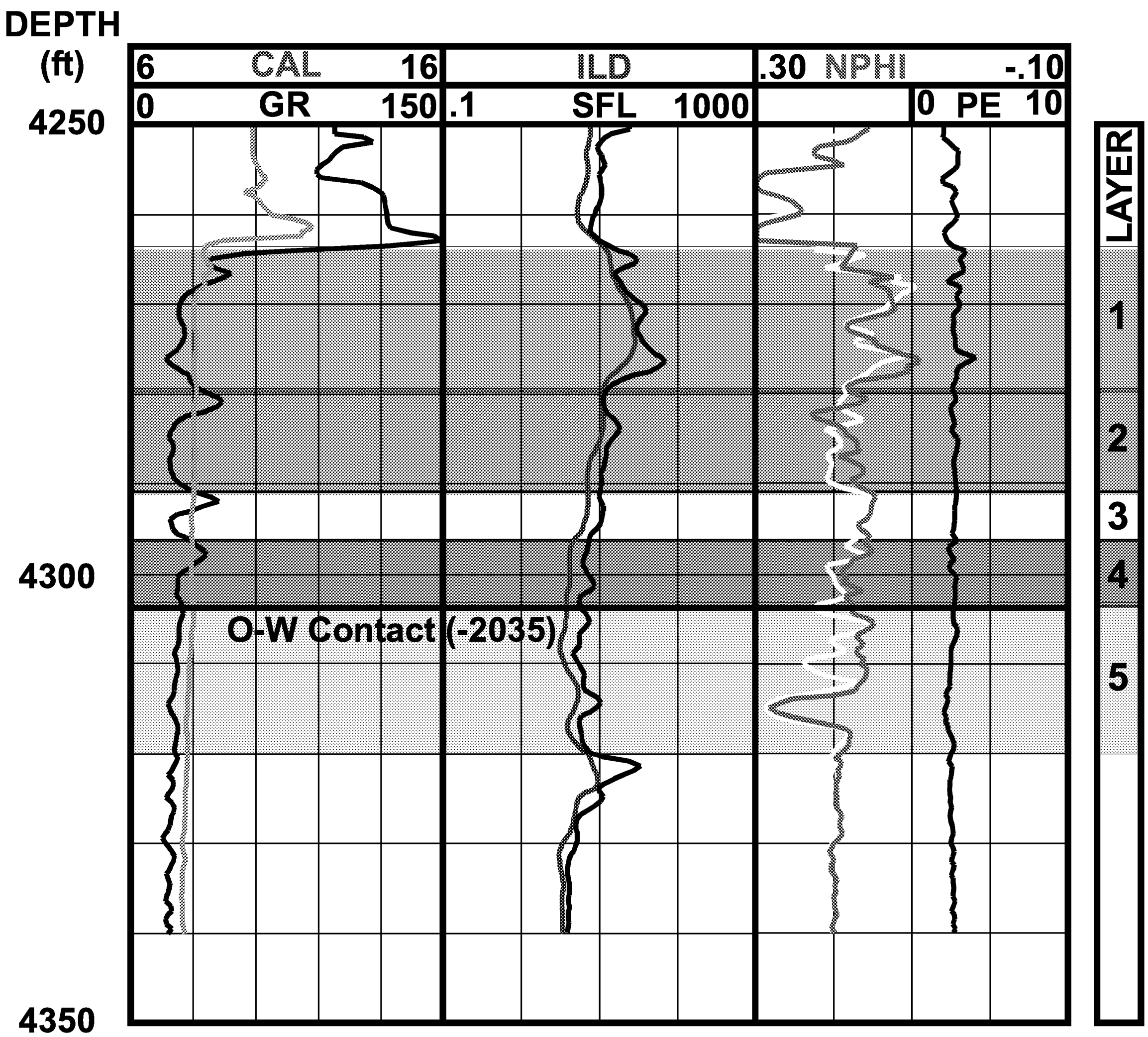


Figure 2.4 - Type log for the reservoir interval (Mull Drilling Company Pfannenstiel 1-24) showing the five flow units at Ness City North Field. The five flow units have 3 dominant lithofacies. Layers 1 and 3 (LP1, LP3) consist of dolomitic moldic packstone-wackestone. Layer 2 is dominated by dolomitic wackestone. Layers 4 and 5 (HP4, HP5) consist of dolomitic packstone.

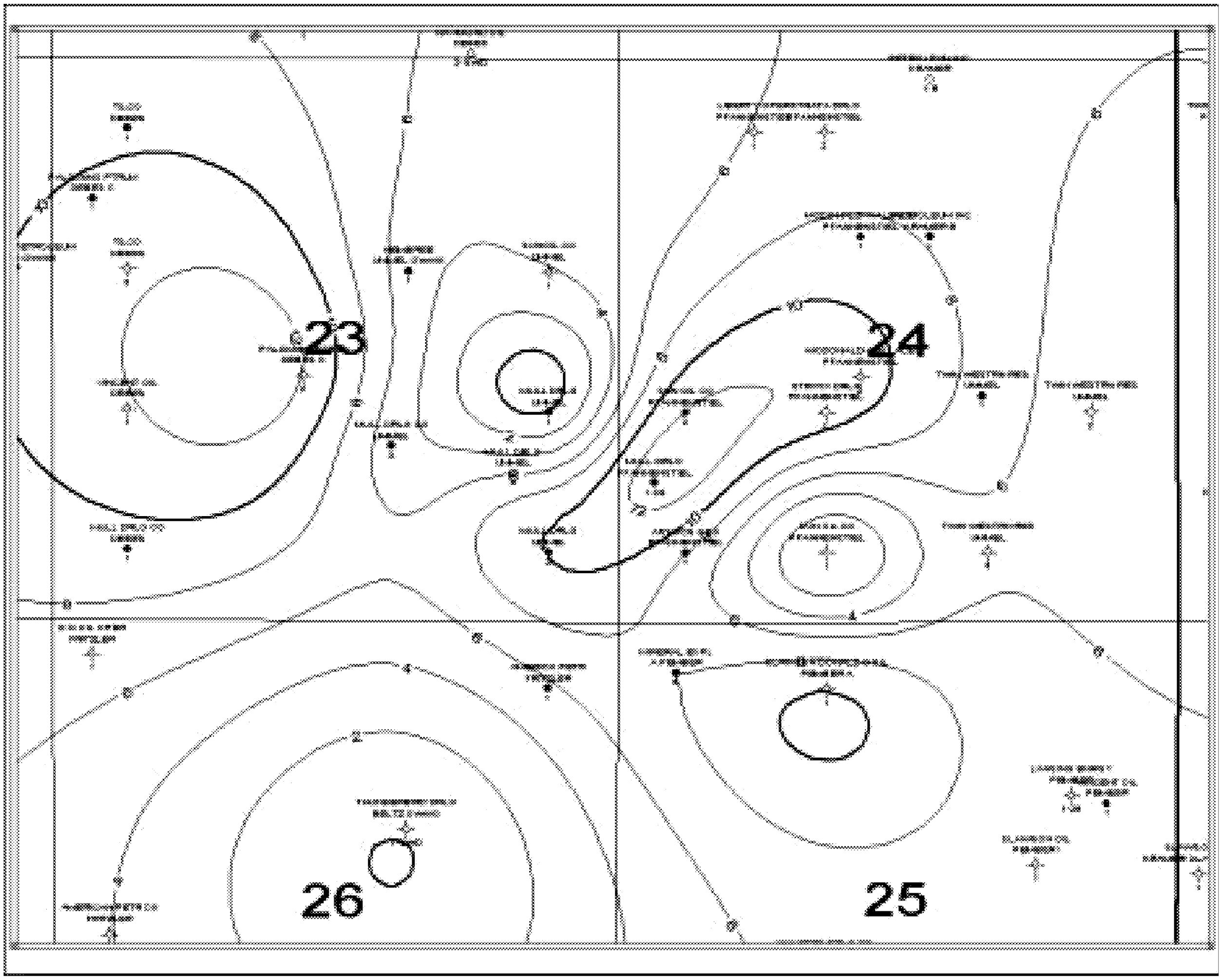


Figure 2.5 - Example of detailed isopach map for Layer 1 of the flow units comprising the Ness City North reservoir (LP1).

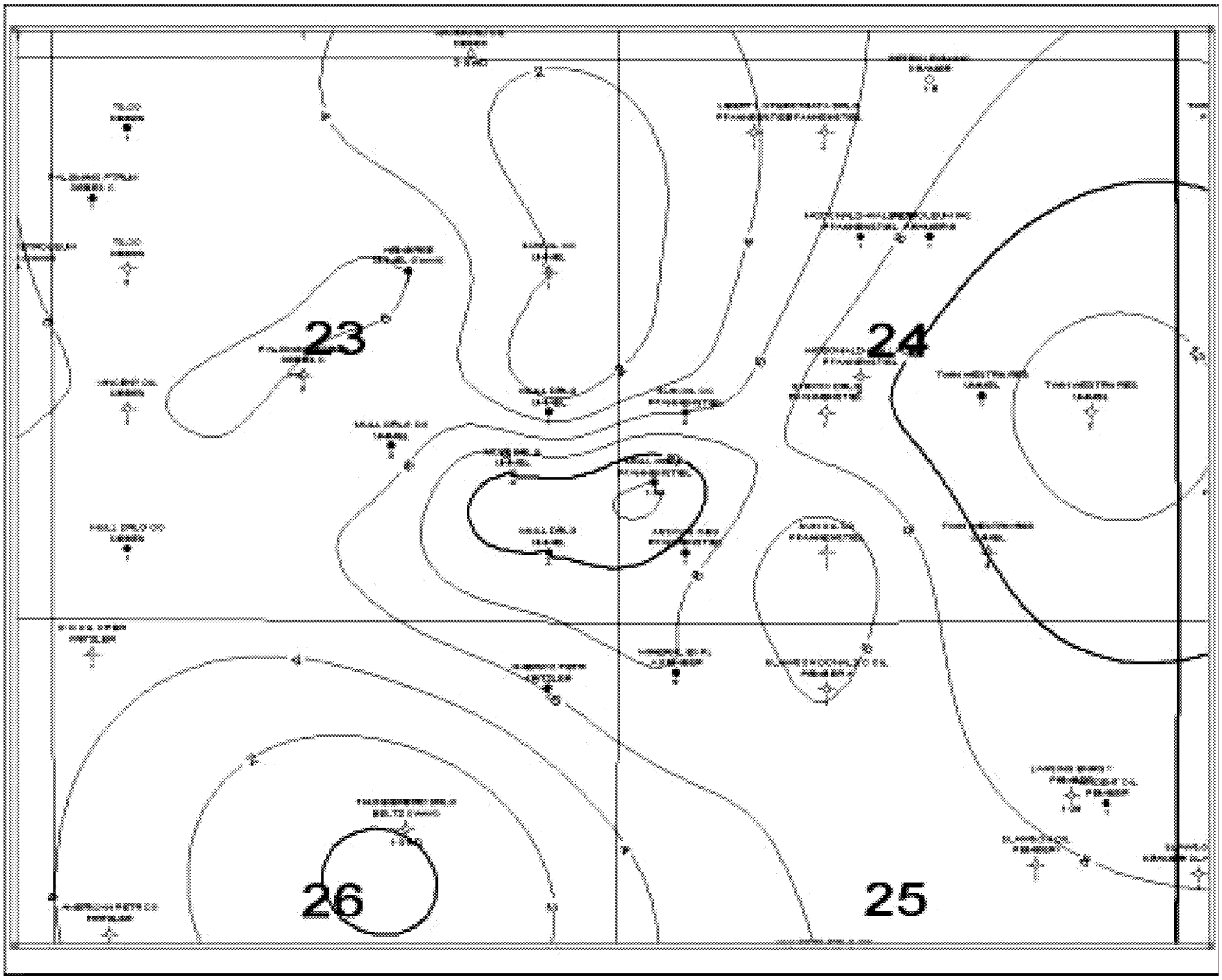


Figure 2.6 - Example of detailed isopach map for Layer 2 of the flow units comprising the Ness City North reservoir (LP2).

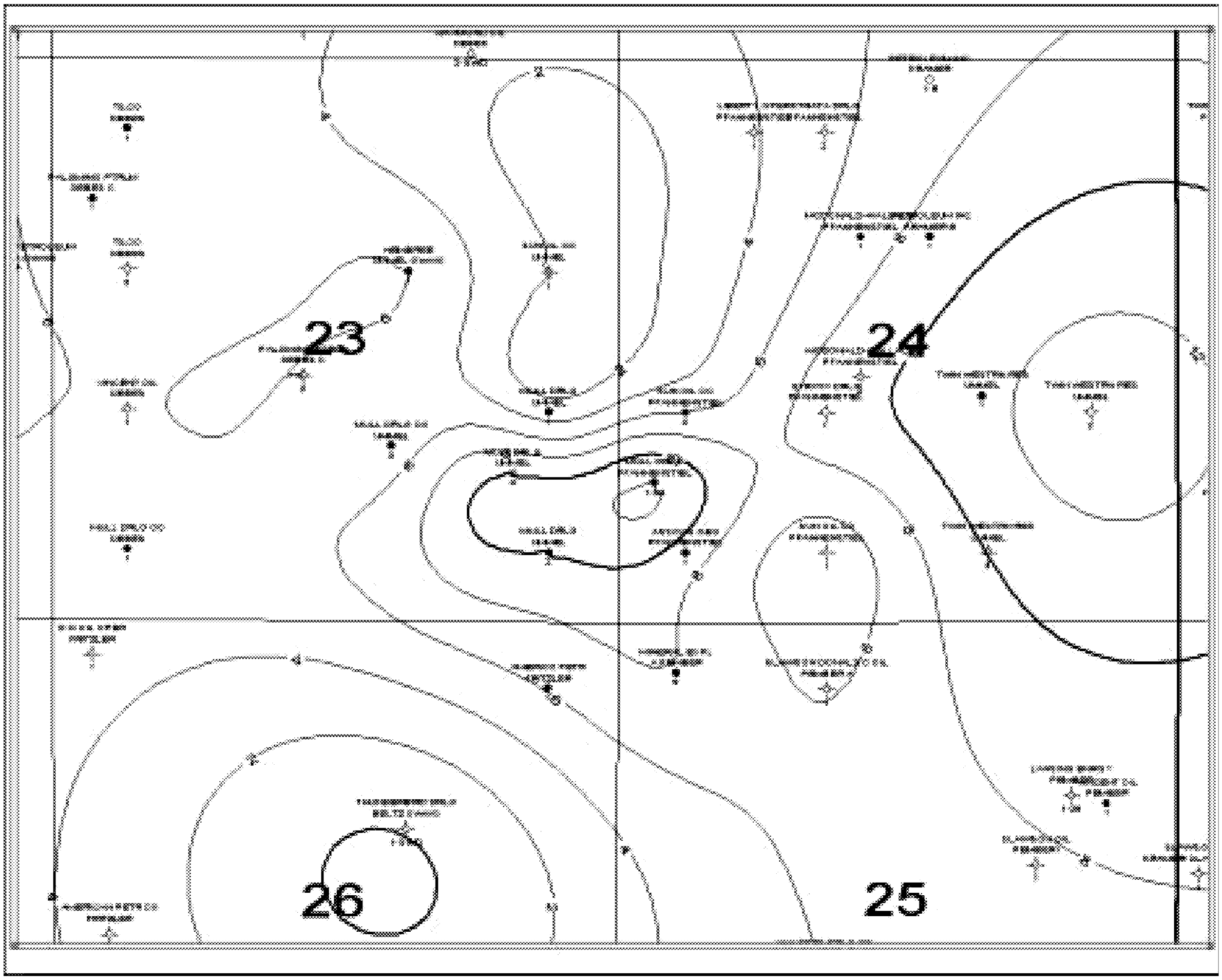


Figure 2.7 - Example of detailed isopach map for Layer 3 of the flow units comprising the Ness City North reservoir (LP3).

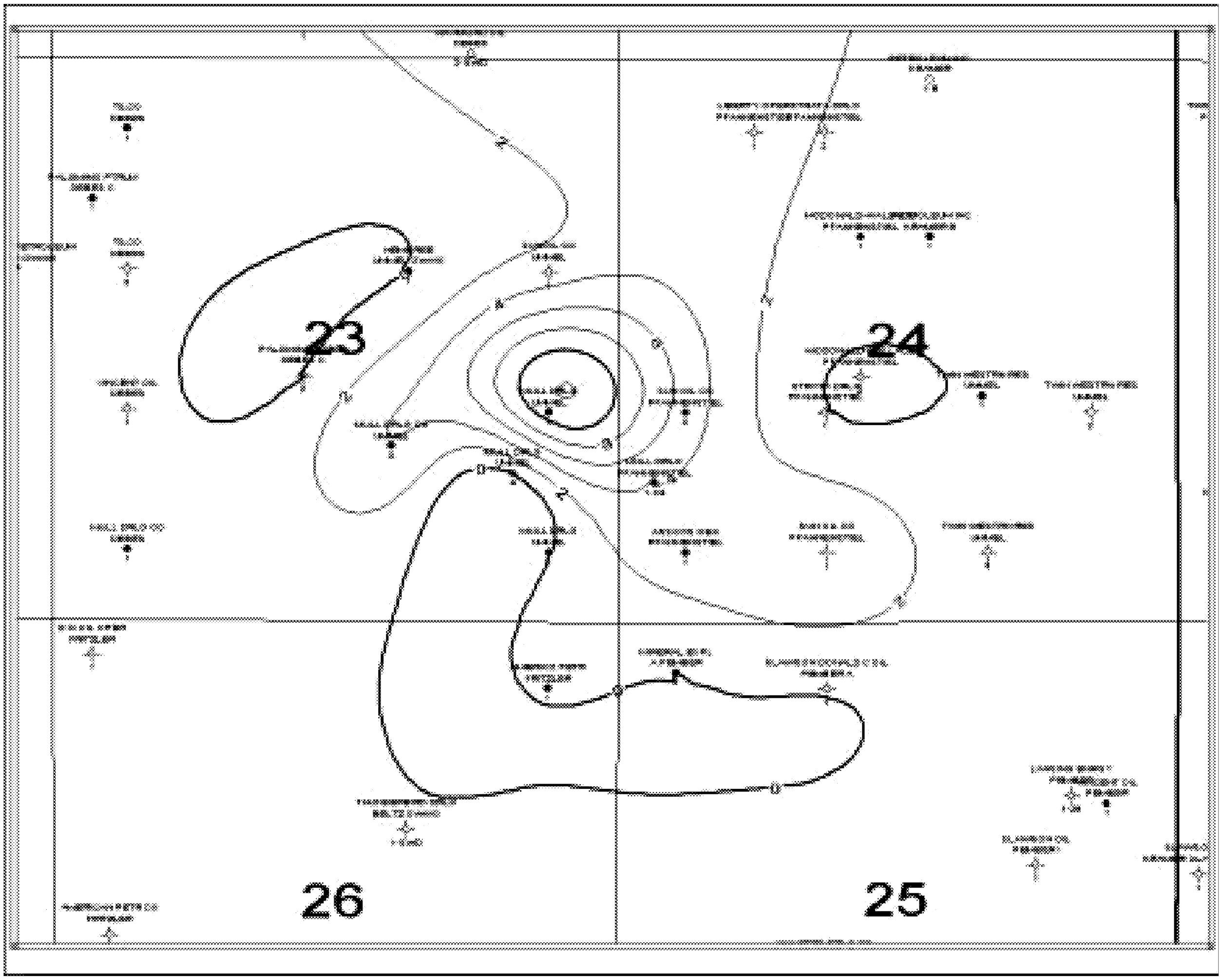


Figure 2.8 - Example of detailed isopach map for Layer 4 of the flow units comprising the Ness City North reservoir (HP1).

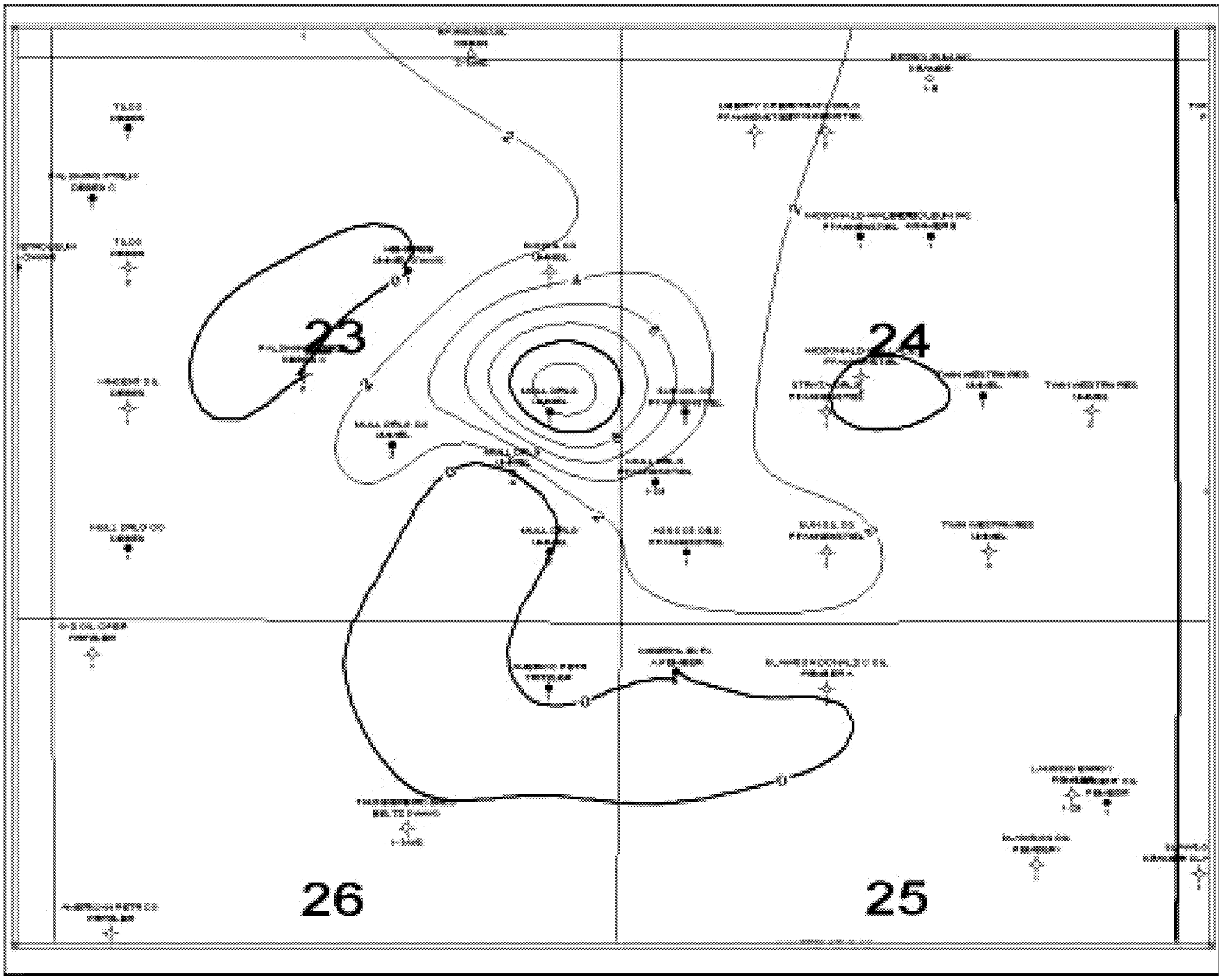


Figure 2.9 - Example of detailed isopach map for Layer 5 of the flow units of the Ness City North reservoir (HP2).

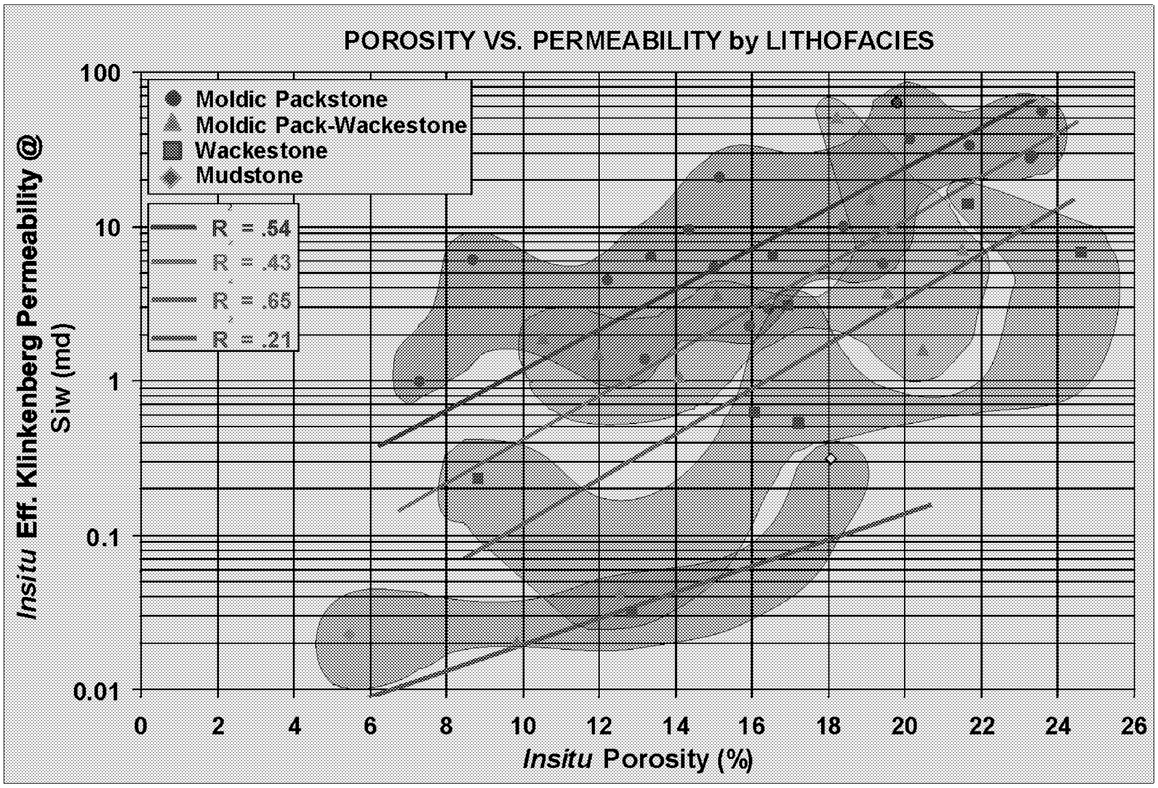


Figure 2.10 - Plot of core permeability and porosity for the different lithofacies that comprise the reservoir flow units at Ness City North Field.

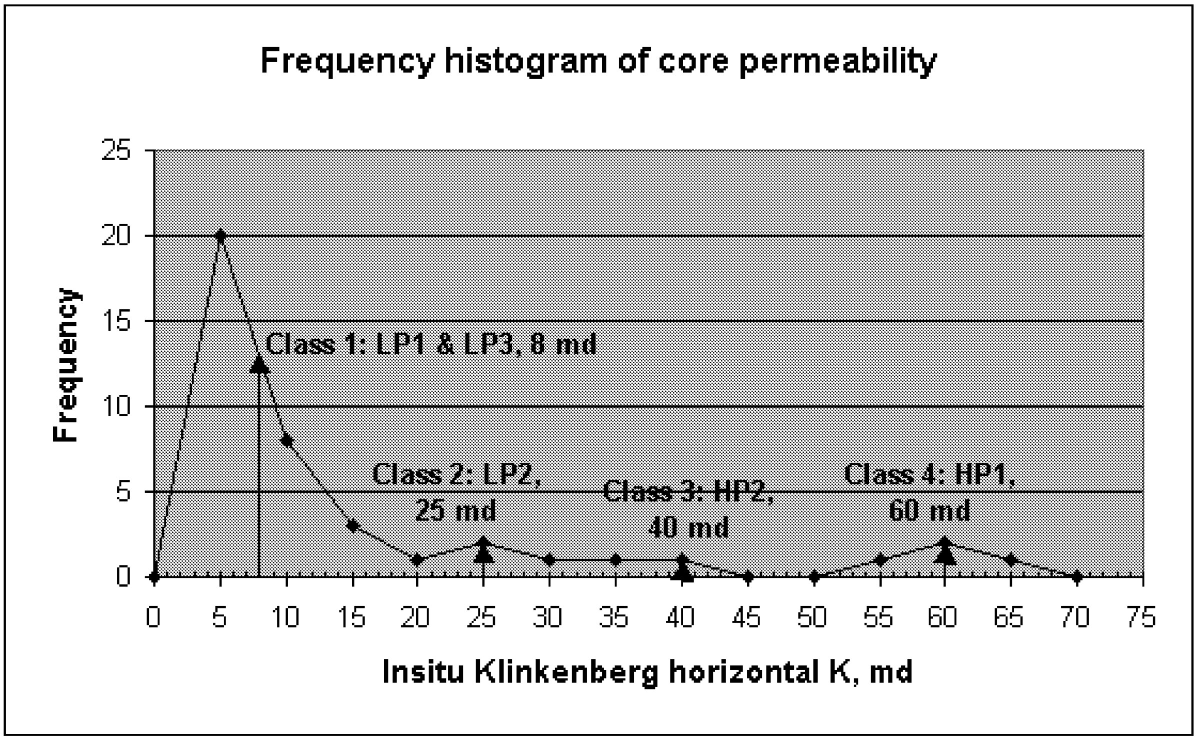


Figure 2.11 - Initial reservoir model was built assuming uniform permeability values that correspond to the frequency peaks observed in a histogram of core permeability values.

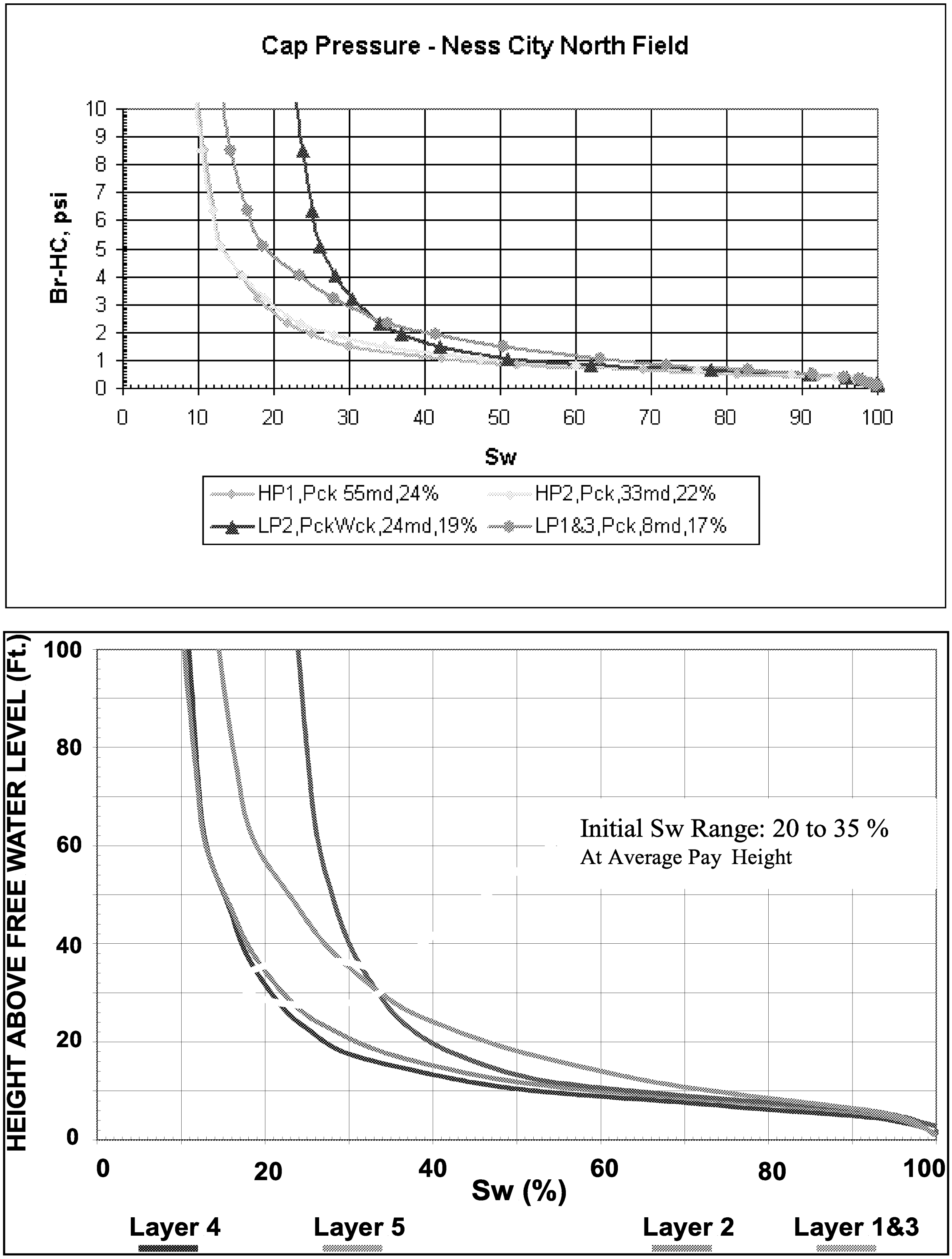


Figure 2.12 – **A)** Capillary pressure measurements carried out on core plug samples that represent each of the Mississippian flow units in the Mississippian reservoir at Ness City North Field. **B)** Due to the absence of log data from wells, initial Sw estimated from capillary pressure curves for flow units converted to height above free water table and average pay height.

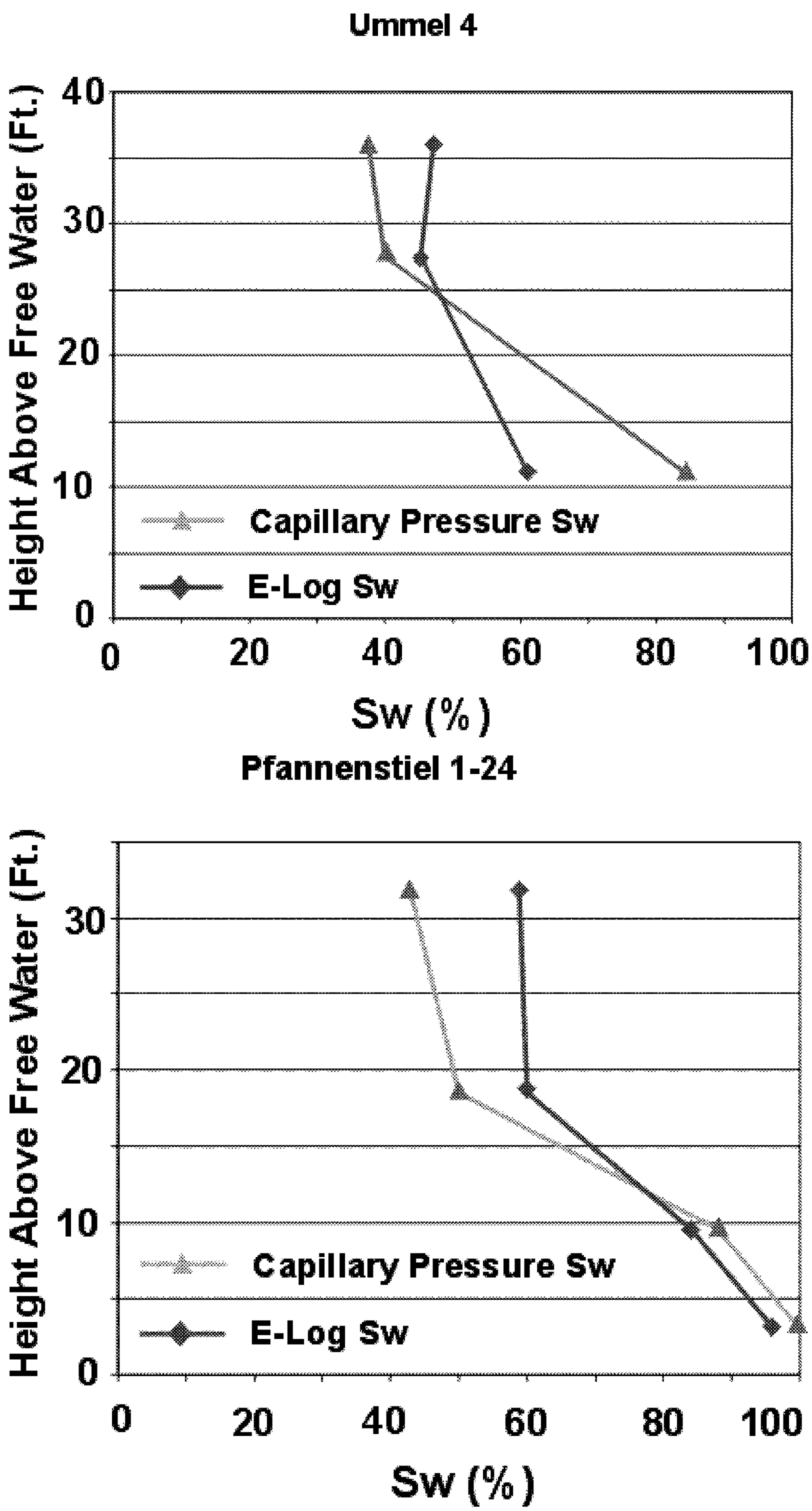


Figure 2.13 – Comparison of capillary pressure derived water saturation and water saturation derived from well logs and position above mapped oil-water contact for the only two wells in the Ness City North Field with adequate log suites.

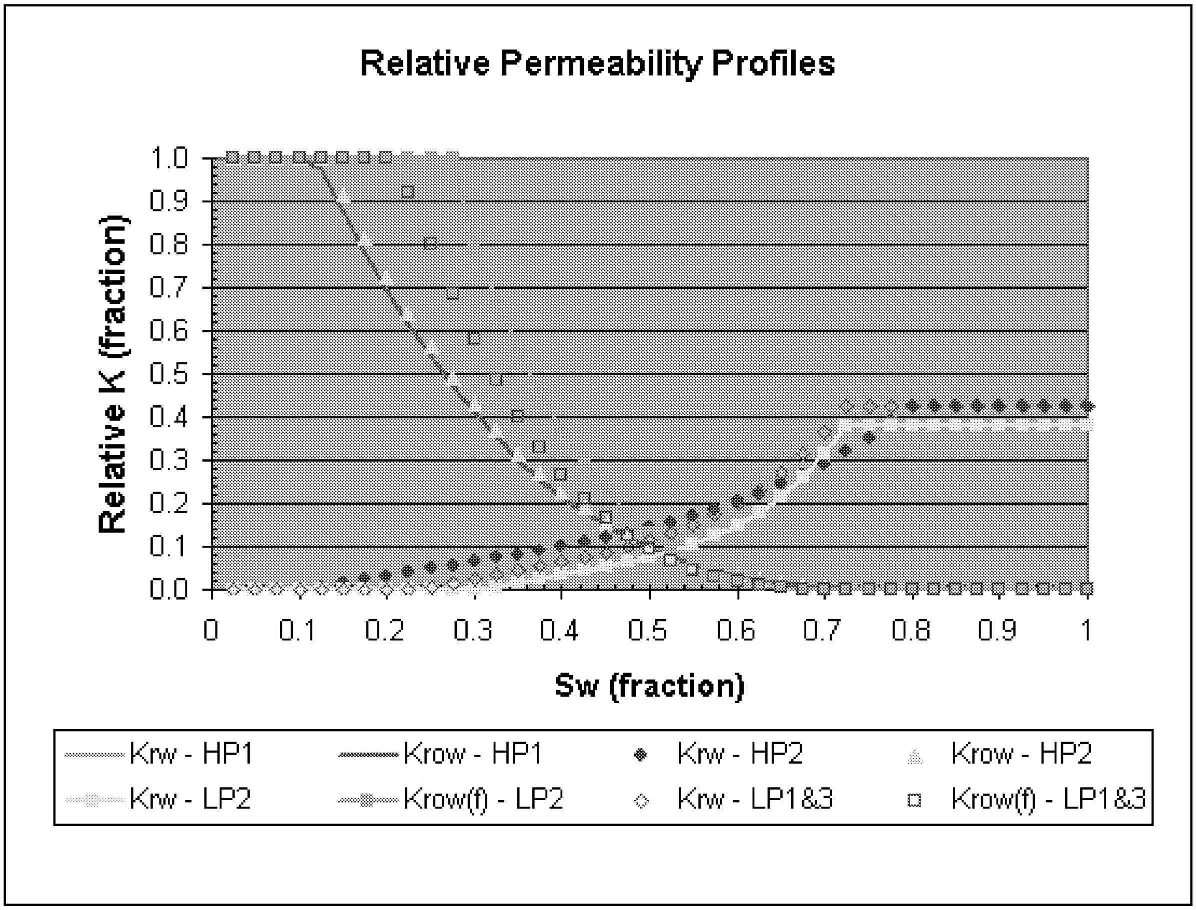


Figure 2.14 - Relative permeability curves generated for each flow unit of the Mississippian reservoir at Ness City North Field. The equation corresponding to intermediate-wet limestone/dolomite was used to estimate relative permeability of water. The equation referring to limestone/dolomite of any wettability was used to generate the relative permeability curve for oil.

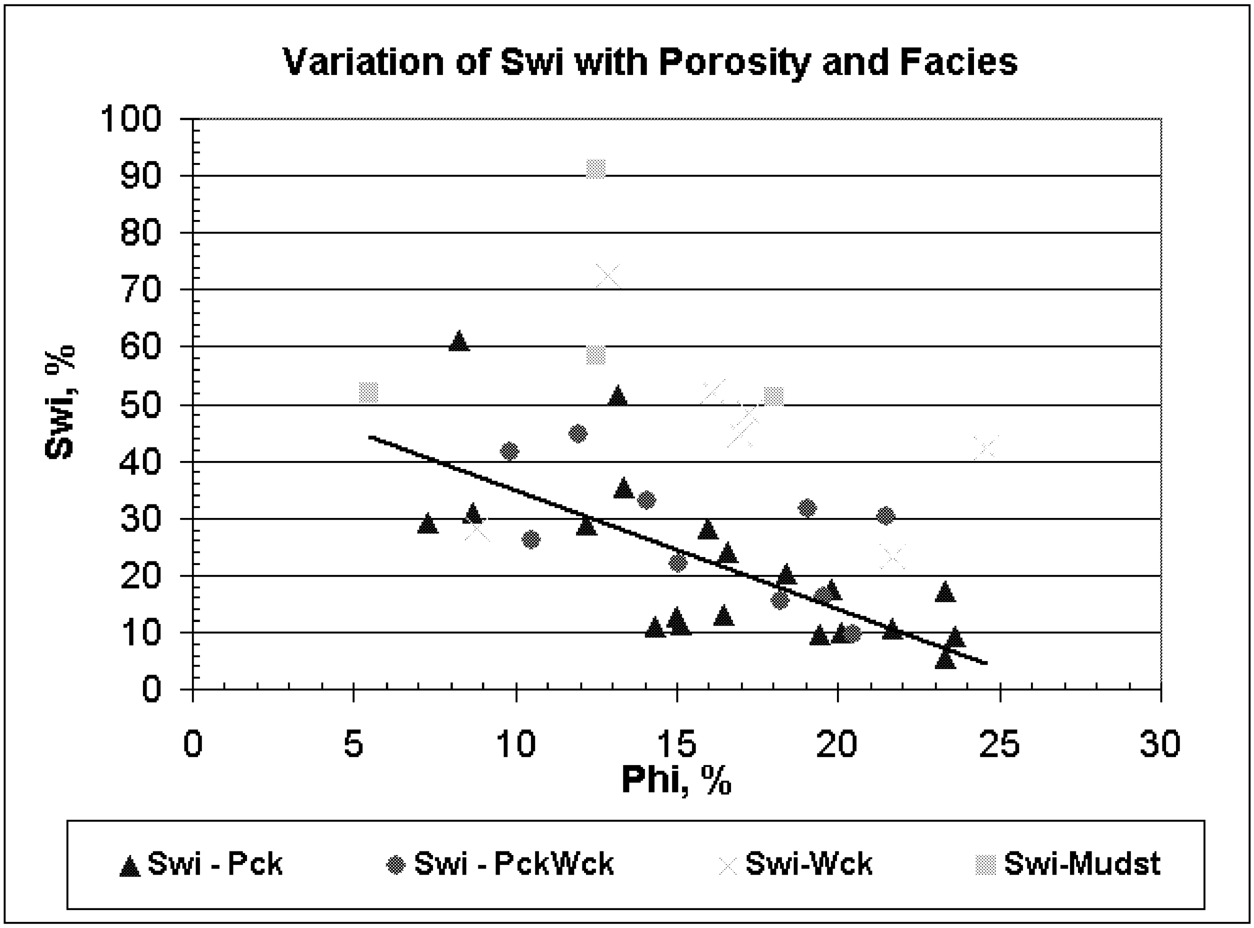


Figure 2.15 – Measured irreducible water saturation (S_{wi}) for core plugs at 150 feet above the free water level. The measured S_{wi} for dominant facies was used in the calculation of the relative permeability for each flow unit at Ness City North.

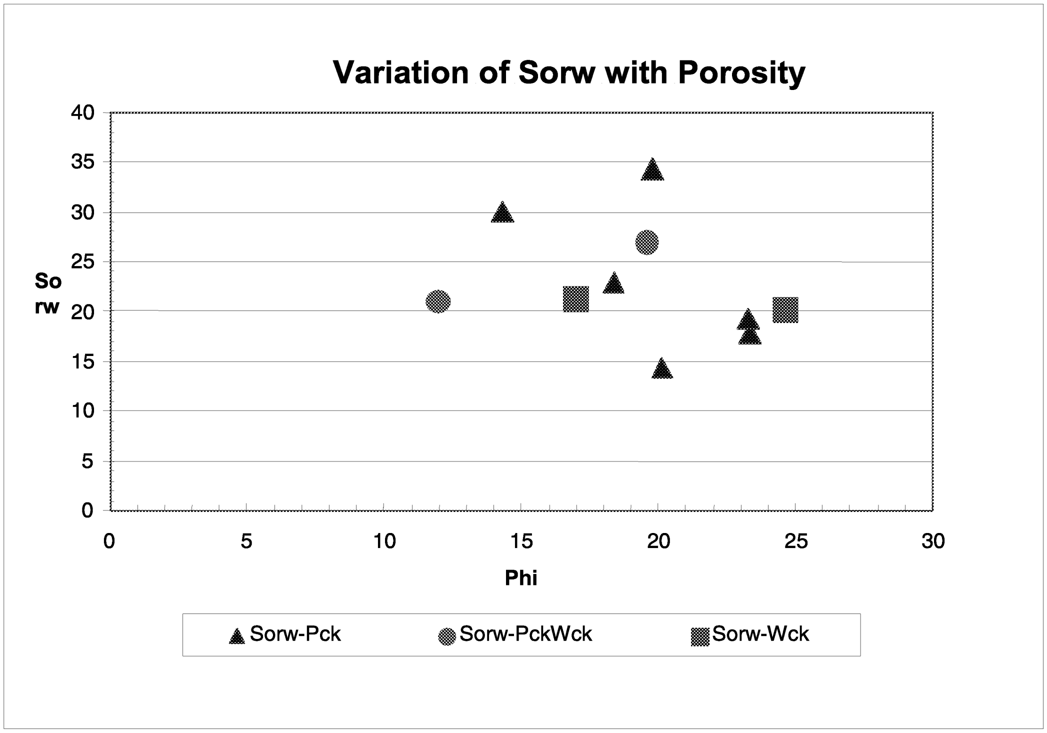


Figure 2.16 - Irreducible oil saturations (S_{orw}) measured on selected core plugs from the reservoir flow units at Ness City North. The irreducible oil saturations (S_{orw}) show two loose clusters, representing S_{orw} values for porosities less than 20% and the other representing porosities above 20%.

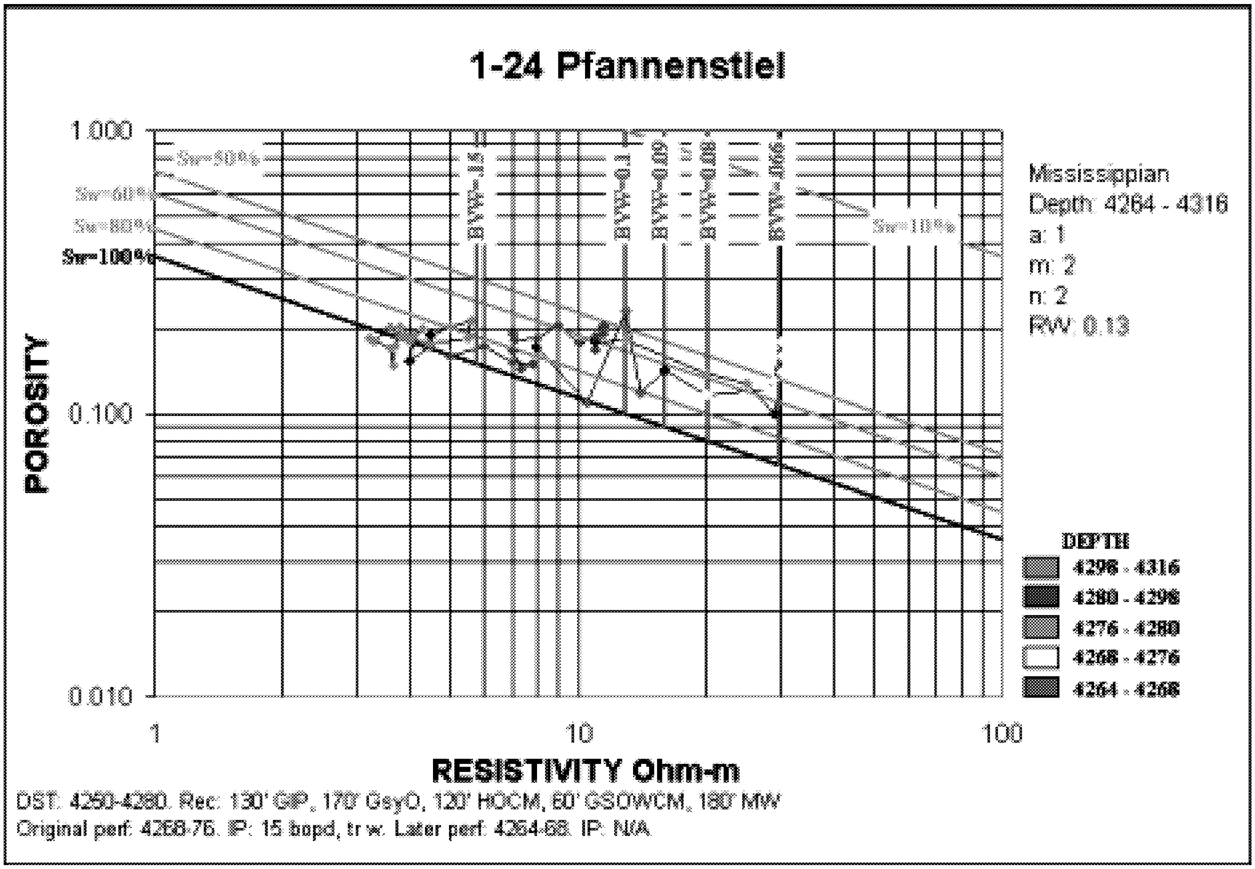
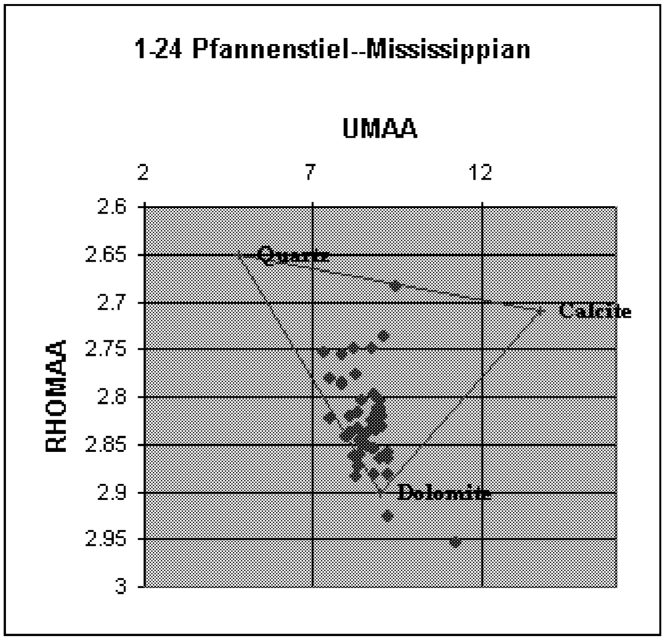


Figure 2.17 - Super-Pickett plot analysis for the Mull Pfannenstiel #1-24 showing irreducible bulk value water (BVW_i) of 0.066. Based on the log analysis of the Pfannenstiel #1-24, average porosities that were calculated for layers LP1, LP2, LP3, and HP1 are 0.144, 0.184, 0.163, and 0.178, respectively. Calculated porosity values from log data compare closely with the average porosity values determined from core analysis.



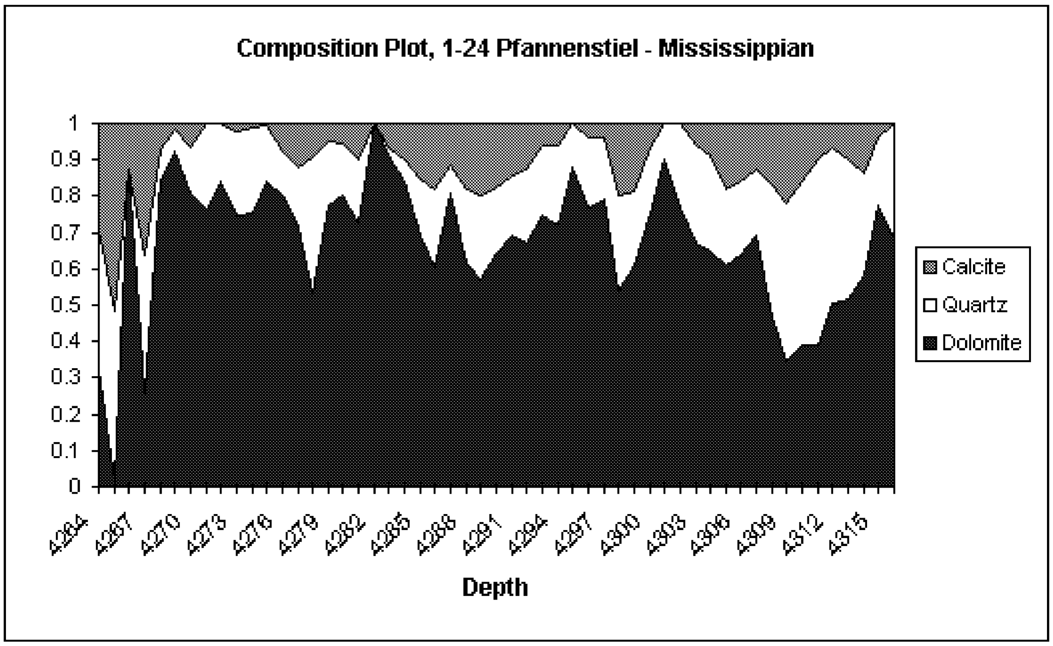


Figure 2.18 - Rhomaa-Umaa plots for the Mull Pfannenstiel #1-24 indicating that the Mississippian reservoir flow units at Ness City North Field are composed dominantly of dolomite with some quartz and calcite.

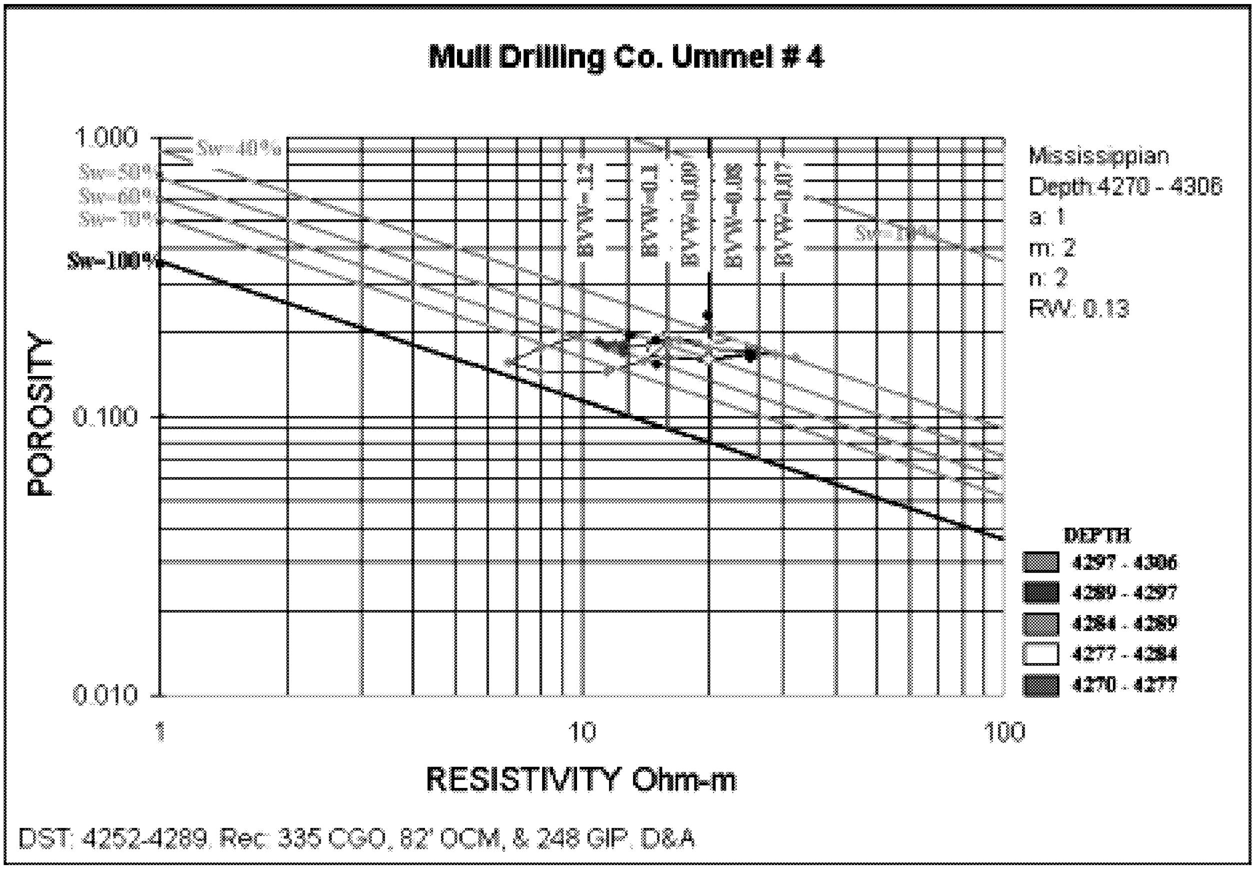


Figure 2.19 - Super-Pickett plot analysis for the Mull Ummel #4, the average porosity values that were calculated for layers LP1, LP2, and LP3 are 0.169, 0.176, and 0.174, respectively. Calculated porosity values from log data compare closely with the average porosity values determined from core analysis.

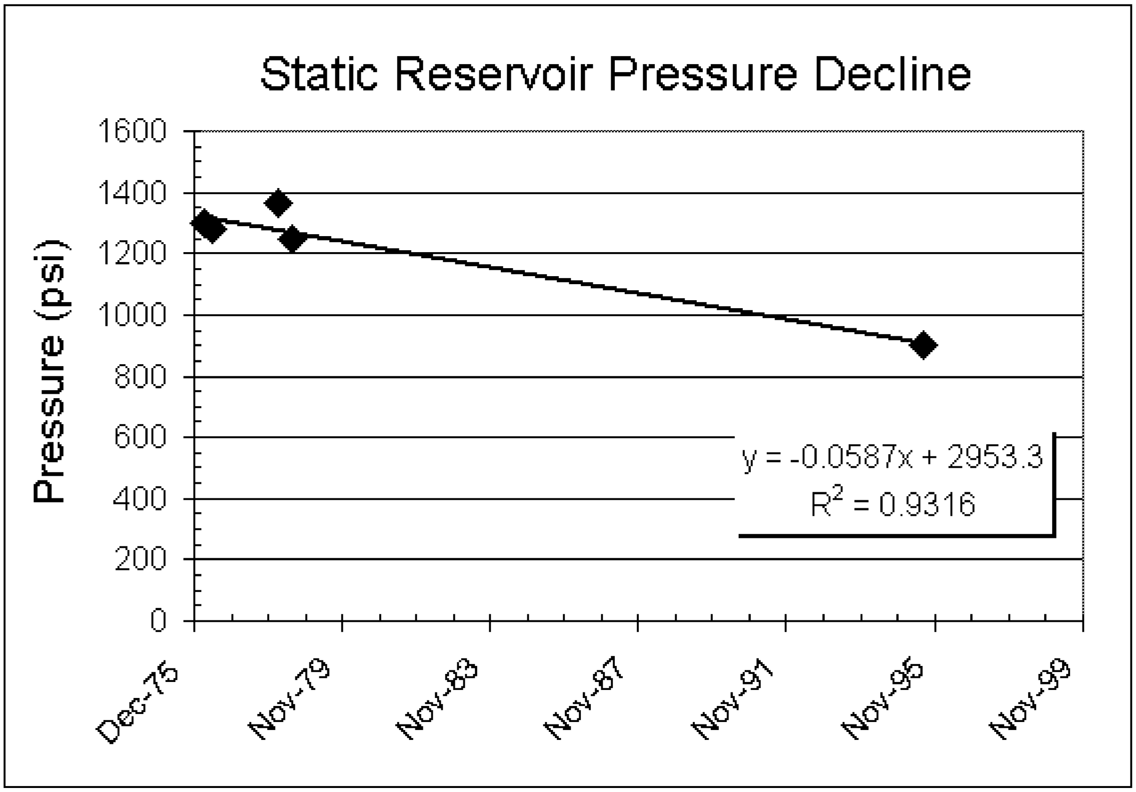
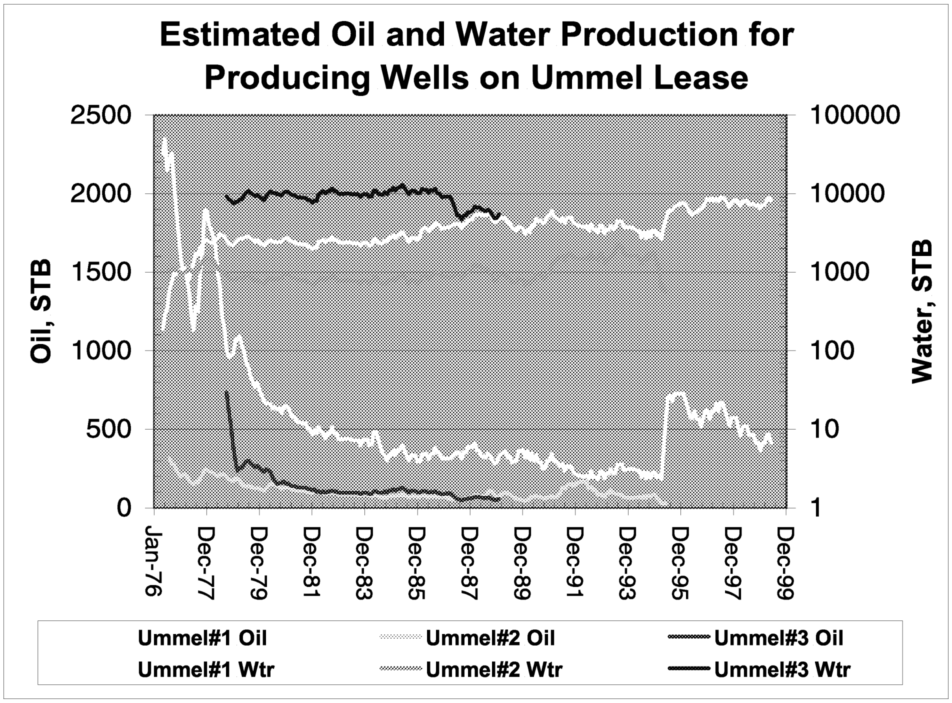


Figure 2.20 - Drill stem test data indicate that static reservoir pressure at the Ness City North Field declined only 450 psi over a period of 17 years and supports the existence of an active bottom water drive for the reservoir. Available DST data is summarized in Table 2.3.



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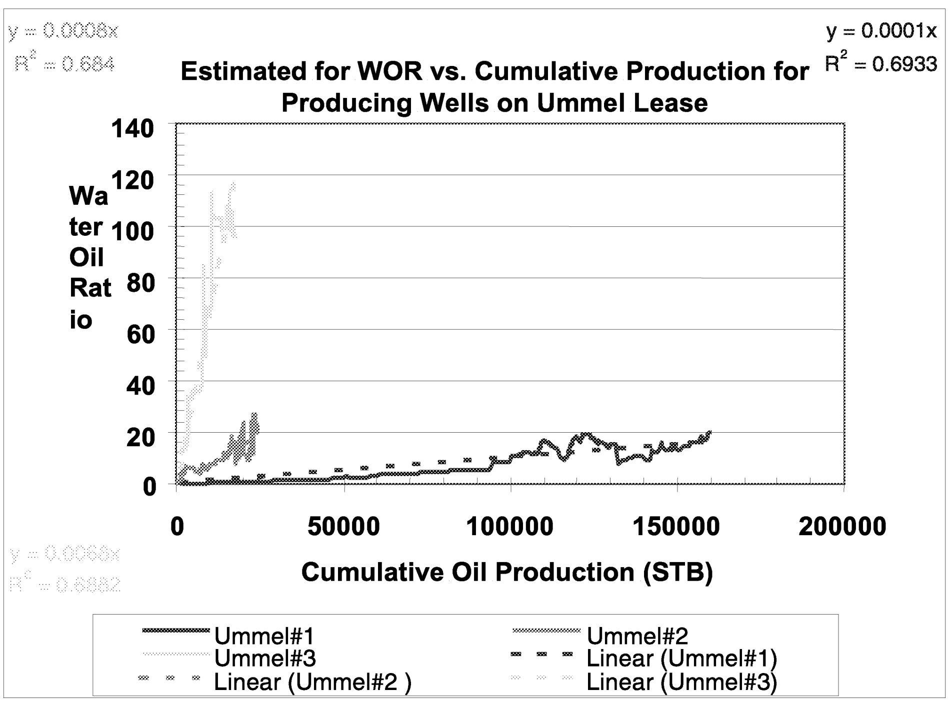

B

Figure 2.21 - A) Estimated monthly oil and water production averaged over a three-month periods for three producing wells on the Ummel lease. **B)** Estimated monthly oil and water production averaged over a three-month periods for three producing wells on the Ummel lease plotted as WOR versus cumulative oil production. Oil and water production was estimated from lease sales data and periodic production tests.

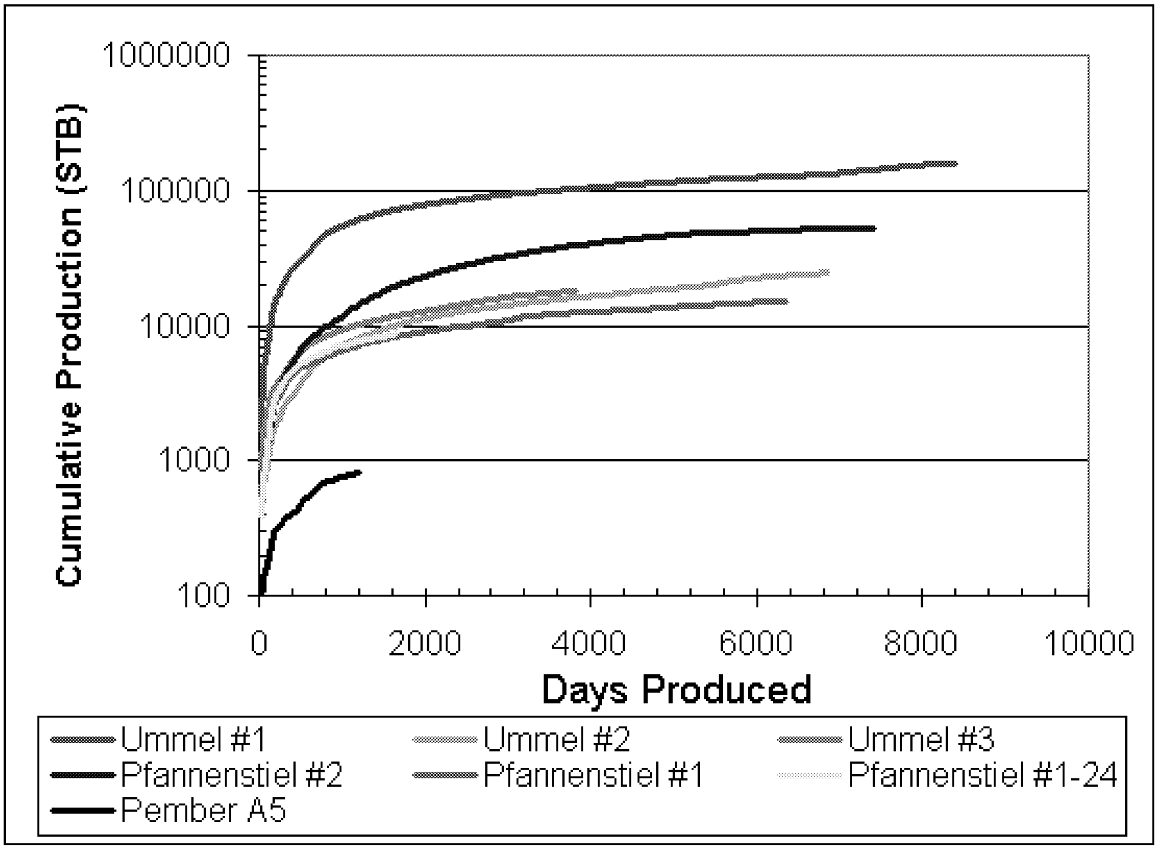

Figure 2.22 - Estimated cumulative oil production for producing wells in the Ness City Field. The Mull Ummel #1 is the best well in the field having cumulative oil production exceeding 100,000 barrels. The remaining wells in the field show similar cumulative production patterns, but far behind the cumulative of Ummel #1 (Mull Petroleum) well.

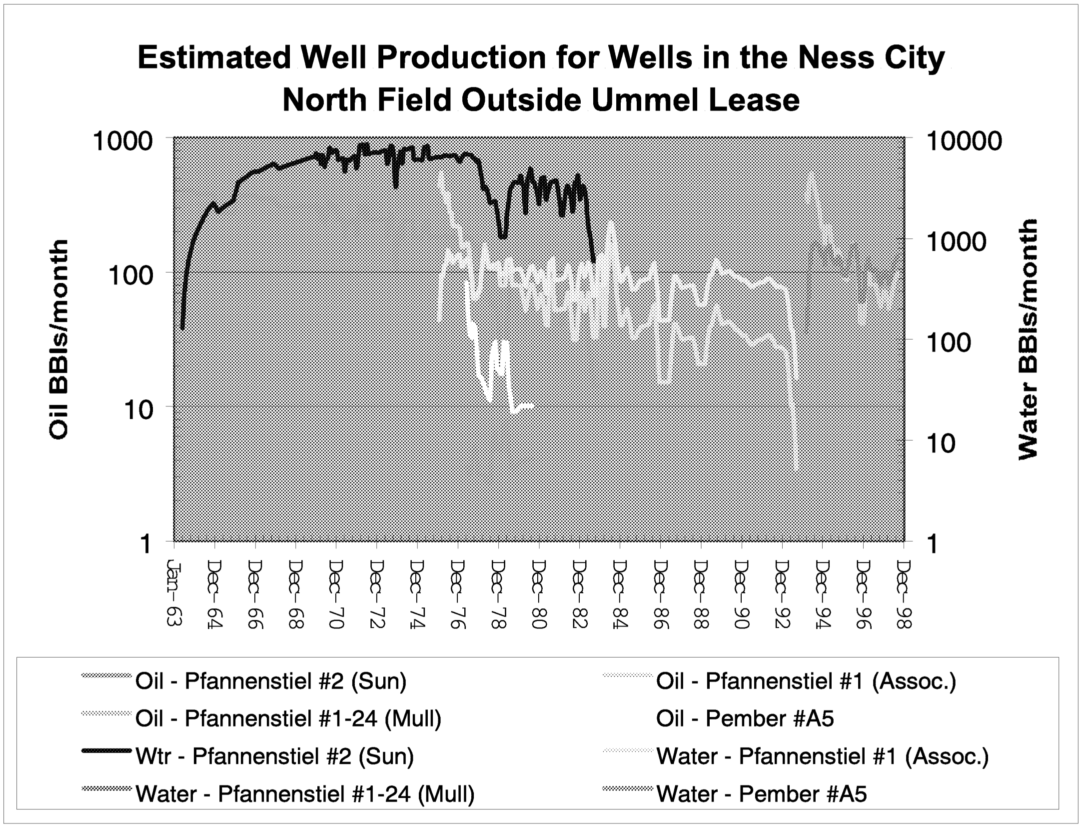

Figure 2.23 - Estimated monthly oil and water production averaged over a three-month periods for producing wells in the Ness City Field outside of the Ummel lease. Water production for all wells was estimated from the WOR profile derived from the Ummel #2 production tests.

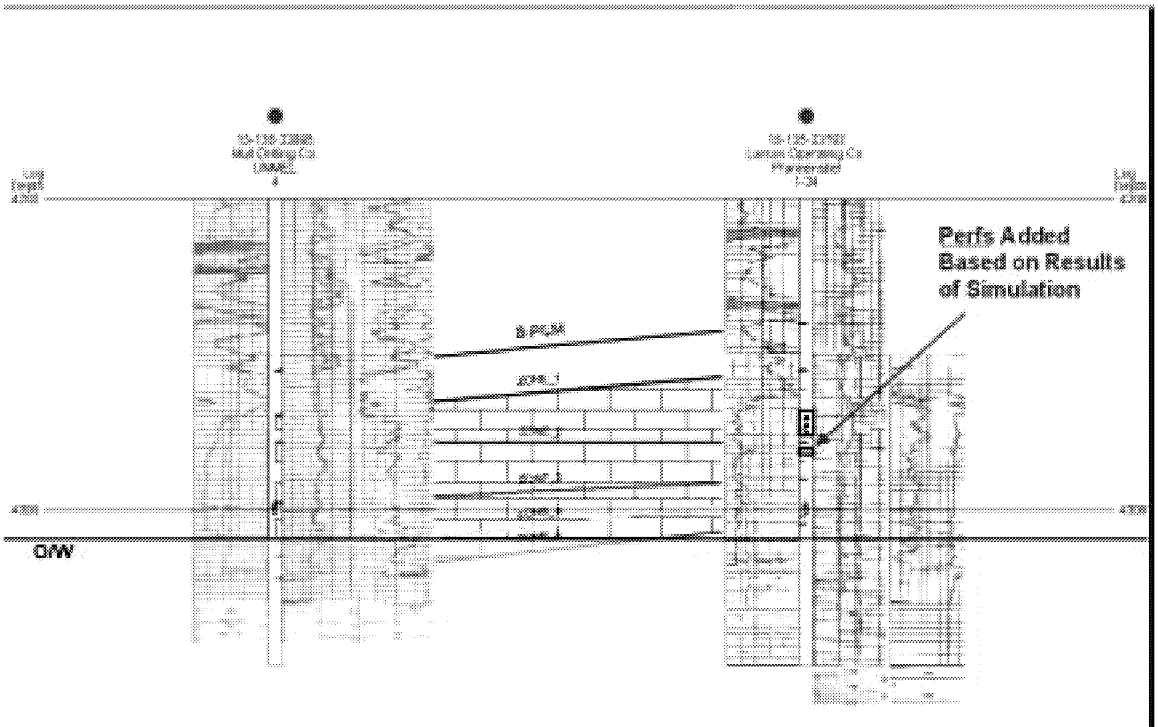

Figure 2.24 – Cross section between Ummel #4 and the Pfannenstiel #1-24 showing that the Pfannenstiel was originally completed only in the LP1 flow unit. Based on the reservoir characterization it appeared that perforations in the Pfannenstiel should be added to flow unit LP2. Addition of new perforation in flow unit LP2 increased production from 2 BOPD and 20 BWPD (91% water) to 23 BOPD and 125 BWPD (84% water

Well Name	Depth (ft)	ID #	Helium Porosity (%)	Routine Air Perm. (md)	Insitu Klinkenberg Perm. (md)	keo @ Siw Effective Klinkenberg Perm .(md)	"Irreducible" Water Saturation (h=150',%)	Grain Density (g/cc)	Litho-facies
Walters 1 Maier	4256		18.2	67.33	53.86	49.60	28.9	2.85	pack-wck
Walters 1 Maier	4261		19.1	30.18	23.86	15.05	31.4	2.85	pack-wck
Walters 1 Maier	4263.9		19.6	24.51	18.78	3.78	35.4	2.85	pack-wck
Walters 1 Maier	4263.1		20.5	11.66	9.02	1.59	26.6	2.86	pack-wck
Sun 2 Pfannenstiel	4266	1	8.3	0.14	0.04	0.01	61.1	2.83	packstone
Sun 2 Pfannenstiel	4267	2	15.0	7.58	5.69	5.44	20.7	2.85	packstone
Sun 2 Pfannenstiel	4268	3	13.4	8.79	6.32	6.32	50.5	2.85	packstone
Sun 2 Pfannenstiel	4270	5	8.7	9.65	6.07	6.07	44.5	2.86	packstone
Sun 2 Pfannenstiel	4271	6	7.3	1.66	1.16	0.98	42.4	2.85	packstone
Sun 2 Pfannenstiel	4272	7	16.6	10.31	7.64	6.44	27.7	2.87	packstone
Sun 2 Pfannenstiel	4277	8	9.8	0.62	0.22	0.02	41.7	2.83	pack-wck
Sun 2 Pfannenstiel	4278	9	8.8	0.57	0.39	0.23	28.3	2.85	wckstone
Sun 2 Pfannenstiel	4279	10	23.6	67.71	55.19	55.19	9.2	2.84	packstone
Sun 2 Pfannenstiel	4280	11	21.5	10.79	8.25	7.15	30.4	2.82	pack-wck
Sun 2 Pfannenstiel	4281	12	19.8	77.34	63.25	63.25	17.6	2.81	packstone
Sun 2 Pfannenstiel	4282	13	19.4	8.73	6.65	5.70	9.6	2.86	packstone
Sun 2 Pfannenstiel	4283	14	20.1	45.29	36.41	36.41	9.9	2.83	packstone
Sun 2 Pfannenstiel	4284	15	18.4	13.10	10.16	9.87	20.3	2.83	packstone
Sun 2 Pfannenstiel	4285	16	10.5	2.70	2.02	1.88	26.1	2.83	pack-wck
Sun 2 Pfannenstiel	4286	17	15.9	3.55	2.52	2.26	34.5	2.83	packstone
Sun 2 Pfannenstiel	4287	18	23.3	70.42	57.52	27.63	5.4	2.83	packstone
Sun 2 Pfannenstiel	4288	19	13.2	2.36	1.77	1.38	51.6	2.83	packstone
Sun 2 Pfannenstiel	4289	20	15.1	5.09	3.81	3.56	22.1	2.81	pack-wck
Sun 1 Pfannenstiel	4265	1	23.3	35.27	28.27	28.27	17.2	2.83	packstone
Sun 1 Pfannenstiel	4266	2	12.2	6.55	4.99	4.49	28.8	2.70	packstone
Sun 1 Pfannenstiel	4267	3	12.0	2.36	1.75	1.48	44.7	2.82	pack-wck
Sun 1 Pfannenstiel	4272	4	24.6	10.80	8.34	6.77	73.9	2.40	wckstone
Sun 1 Pfannenstiel	4276	5	17.2	1.35	0.98	0.53	48.5	2.81	wckstone
Sun 1 Pfannenstiel	4277	6	17.0	4.96	3.69	3.04	44.5	2.82	wckstone
Sun 1 Pfannenstiel	4279	7	14.1	1.67	1.20	1.07	32.9	2.85	pack-wck
Sun 1 Pfannenstiel	4280	8	21.7	17.76	13.75	13.26	23.3	2.81	wckstone
Sun 1 Pfannenstiel	4281	9	12.5	0.14	0.04	0.00	91.2	2.79	mudstone
Sun 1 Pfannenstiel	4282	10	18.1	1.99	1.02	0.31	51.1	2.81	mudstone
Sun 1 Pfannenstiel	4283	11	12.5	0.60	0.36	0.04	58.4	2.81	mudstone
Sum 1 Ummel	4290	1	5.5	0.05	0.02	0.02	53.0	2.84	mudstone
Sum 1 Ummel	4291	2	16.4	3.81	2.91	2.91	19.5	2.85	packstone
Sum 1 Ummel	4292	3	14.3	13.54	10.55	9.43	15.4	2.85	packstone
Sum 1 Ummel	4293	4	15.1	28.77	21.78	20.65	11.3	2.83	packstone
Sum 1 Ummel	4294	5	21.7	42.62	33.41	33.41	10.8	2.85	packstone
Sum 1 Ummel	4295	6	12.9	0.35	0.19	0.03	72.3	2.81	wckstone
Sum 1 Ummel	4296	7	16.1	1.86	1.19	0.62	52.1	2.83	wckstone

Table 2.1 Summary of core plug data from cores in the vicinity of Ness City North Field.

Reservoir Unit	Porosity %	Permeability (md)
LP1	15	8
LP2	21.5	25
LP3	15	8
HP1	23.6	60
HP2	22.2	40

Table 2.2 Porosity and permeability values used for each flow unit of the Mississippian reservoir at the Ness City North Field.

Well	Test Date	FFP, psi	FSIP, psi	Pi, psi	IP - oil, B/D	IP - wtr, B/D	DST K, md	Layer	DST Recovery	Eff. flow, B/d
Ummel 1	***3-76***	1125	1272	1300	115	nw	167.9	LP2 & HP1	2570' CO, 400' MO, 180' GIP	208.7
Ummel 2	***6-76***	62	1129	1280	15	45	0.8	LP1	30' M with oil spots	8.7
Ummel 3	***8-78***	103	1113	1250	30	120	0.4	LP2	3' CO, 117' SOCM	2.3
Ummel 4	***8-95***	186	671	900	D&A	D&A	7.3	LP2	335 CGO, 82' OCM, 248' GIP	21.5
Debes 1	***3-78***	197	1338	1362	26	80	9.9		380' GFMO	11.4

Table 2.3 Summary of Drill Stem Test (DST) information for flow units of the Mississippian reservoir at the Ness City North Field.

3.0 Ness City North Field - Reservoir Simulation

Section based in part on Bhattacharya and others, 2000 and Gerlach and others, 2000.

The reservoir characterization developed for the Ness City North Field was used to generate data necessary to simulate the field and the planned horizontal infill well. The simulation used a commercial PC-based a black-oil reservoir simulator (CMG-IMEX). The results of the simulation study were used to optimize the location and length of an infill horizontal well planned as part of the demonstration project. Predicted performance for the horizontal well was compared to observed production results from the horizontal well to validate and fine-tune the assumptions implicit in the reservoir model.

Reservoir Simulation Construction

The simulation was based on the reservoir geomodel developed by integrating the limited log, core, petrophysical, and production data, characteristic of a small mature oil field operated by an independent. Five wells in the Ness City North Field were included in the simulation (Table 3.1). Oil and water production was available for only three of the wells. In the absence of production data for the Pfannenstiel wells and for Mull Ummel #1-24, oil production was assumed to be equal to the volume of oil sold from their respective leases (Each lease contains only a single well). Water production was estimated using the water-oil ratio (WOR) profile against cumulative production of the mediocre performer in the Ness City North Field (i.e., Mull Ummel #2).

Well Name	Oil Production	Water Production
Mull Ummel #1	**Available**	**Available**
Mull Ummel #2	**Available**	**Available**
Mull Ummel #3	**Available**	**Available**
Mull Ummel #1-24	**Sales Volumes**	**Calculated**
Associate Pfannenstiel #1	**Sales Volumes**	**Calculated**
Sun Pfannenstiel #2	**Sales Volumes**	**Calculated**

Table 3.1 – Wells used in the simulation study showing the source of oil and water production.

A five-layer reservoir model was used to construct the simulation model for the demonstration area at Ness City North. From the top, the five flow units were labeled LP1, LP2, LP3, HP1 and HP2. The only available porosity log for any of the wells in the study area was from the Mull Ummel #1-24. As a result the initial reservoir model assumed constant porosity and permeability values for each of the 5 flow units across the reservoir (Table 3.2). Flow unit geometry (structure and thickness) was mapped from available well logs at each individual well (Figure 3.1). Based on the reservoir characterization, layer porosities were used to compute storativity (product of porosity and thickness) distribution in the each of the five flow units (Figure 3.2). The product of layer permeabilities and thickness were used to compute the distribution of flow unit permeability-feet (Kxy) for each flow unit (Figure 3.3).

In the wells within the simulation area, the bottom two layers (HP1 and HP2) were located just above the oil-water contact (OWC) and had a combined thickness of less than 10 feet. The corresponding capillary pressure curves for these layers show that at 10 feet above the OWC hydrocarbons saturation was negligible (i.e., in these layers only one fluid, water, flows through the reservoir). However, the simulator uses the product of relative permeability of the fluid and total matrix permeability to calculate the effective permeability for mass transfer of that fluid. At heights less than 10 feet above the OWC, water is the only fluid that flows and thus the concept of relative permeability does not apply. Initially, the matrix permeability of HP1 and HP2 were assumed to be 60 md and 40 md while the K_{rw} at S_{oir} for these layers was calculated to be close to 0.35. For the simulator to employ an effective permeability of 60 md to water-flow, matrix permeability was set between 160 to 170 md (e.g., 165.0*0.35 = 58 md). During the process of history matching, it was observed that for wells where the thickness of HP1 and HP2 layers was less than 10 feet, setting the matrix permeability close to 180 md improved the match between the simulation output and the well production history.

The simulator output was fine-tuned to match the available production and pressure histories, at each well in the study area. The history matches obtained in the six wells were judged to be acceptable given the limited reservoir and production data (Figures

3.4-3.5). Also, evaluating the effectiveness of history matching for wells without water production records is a difficult task. The simulation output was used to construct maps of residual oil saturation and oil saturation feet (S_o-feet), as of December 1999, in each flow unit. The main focus was on remaining reserves in flow unit LP2 that was determined to be the primary layer contributing to production (Figures 3.6 and 3.7).

Flow Unit Designation	Porosity Percent	Permeability (md)
LP1	15	8
LP2	21.5	25
LP3	15	8
HP1	23.6	60
HP2	22.2	40

Table 3.2 – Flow units and rock properties used in the reservoir simulation study at the Ness City North Field. Due the paucity of data, rock properties were assumed to be constant for each of the 5 flow units across the reservoir.

Horizontal Infill Well – performance prediction

The horizontal well was located on the boundary of drainage areas of two adjacent wells, (i.e., Mull Ummel #1 and Mull Ummel #2.). Mull Ummel #1 is the best producer in the field and no other well comes even close to its production output. It is the only well that was in operation at the time of the infill drilling. Two different scenarios were simulated. In once case the drainage area of the horizontal well was attributed with flow-properties similar to the Mull Ummel #1 and this was termed as the "best case" scenario. In the second set of simulation runs, the flow-properties assigned to the horizontal infill well were assigned values prevalent around Mull Ummel #2 and this was called the "expected case".

The total length of the horizontal well (Mull Ummel #4-H) drilled within the Mississippian formation is 533 feet. Streaks of shale are evident along the lateral length of the well from the gamma log and it effectively reduces the productive (clean) length to about 440 feet. Average fluid levels recorded in the well over a period of one-month show an average bottom hole pressure (P_{wf}) of about 650 psi. The simulation output summarized was based on an effective horizontal well length of 400 feet, a uniform skin of 4.5 across the producing length, and a P_{wf} of 675 psi (Figure 3.8). The continuous and broken lines define production-envelopes, of oil and water, and these highlight the expected and the best-case simulation outputs respectively (Figure 3.8). The average monthly oil and water production recorded at the horizontal well over the first 2 months is also shown (by red symbols) and it appears on the lower boundary of both the oil and water envelops. The expected cumulative oil and water production from the horizontal infill well during the first 10 years was estimated from the simulation (Figure 3.9, Table 3.3).

Year	Cumulative Oil (Barrels)		Cumulative Water (Barrels)	
	Expected Case	Best Case	Expected Case	Best Case
1	18,240	34,320	36,720	14,568
2	44,749	65,700	123,735	71,066
3	58,437	76,103	196,005	125,341
4	70,409	85,556	271,195	182,099
5	81,322	94,316	348,210	240,499
6	91,542	102,602	426,320	299,994
7	101,324	110,486	505,525	360,584
8	110,705	118,041	585,460	421,904
9	119,757	125,305	666,125	483,954
10	128,480	132,276	747,155	546,734

Table 3.3 – Predicted production performance for expected-case and best-case cumulative oil and water production in barrels for the first ten years of the reservoir simulation study at the Ness City North Field. Plot of same production performance prediction is shown in Figure 3.9.

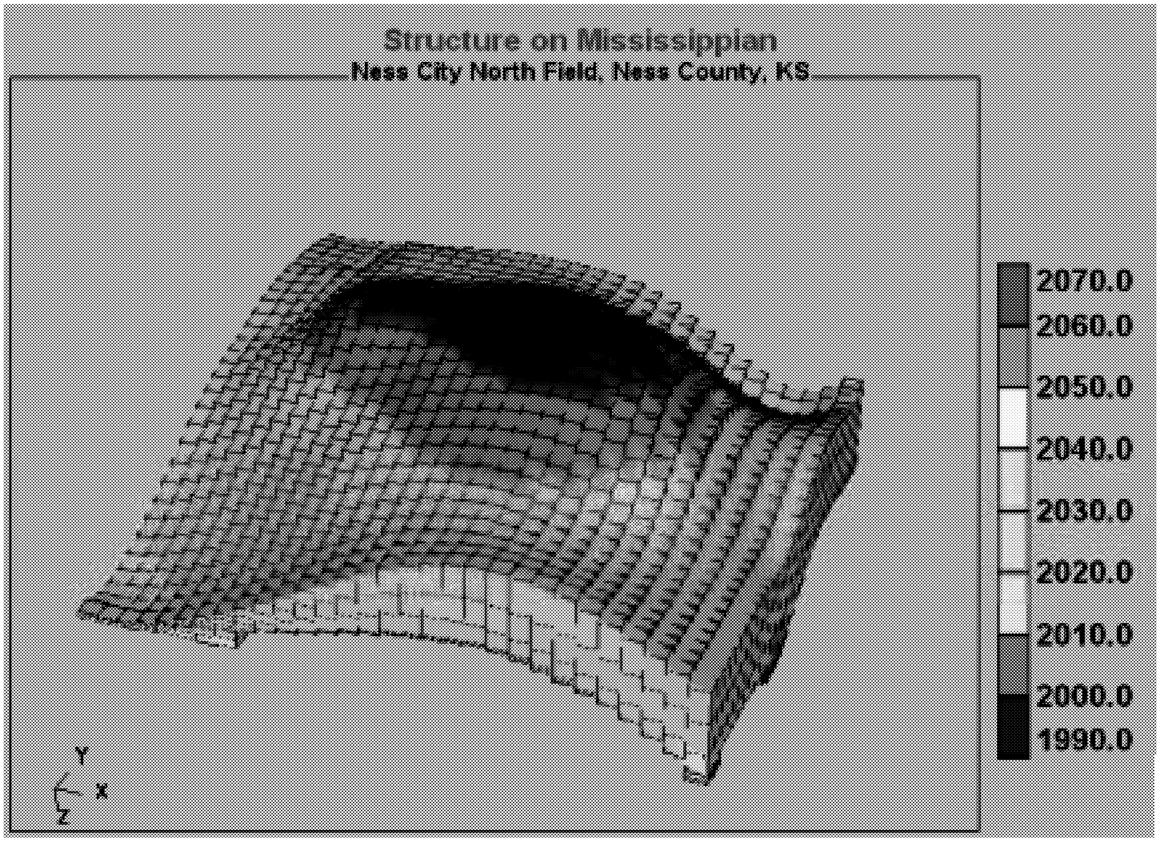

Figure 3.1 – Three-dimensional image of the structure of the simulation area at Ness City North Field. Cell size and geometry of the flow units is shown.

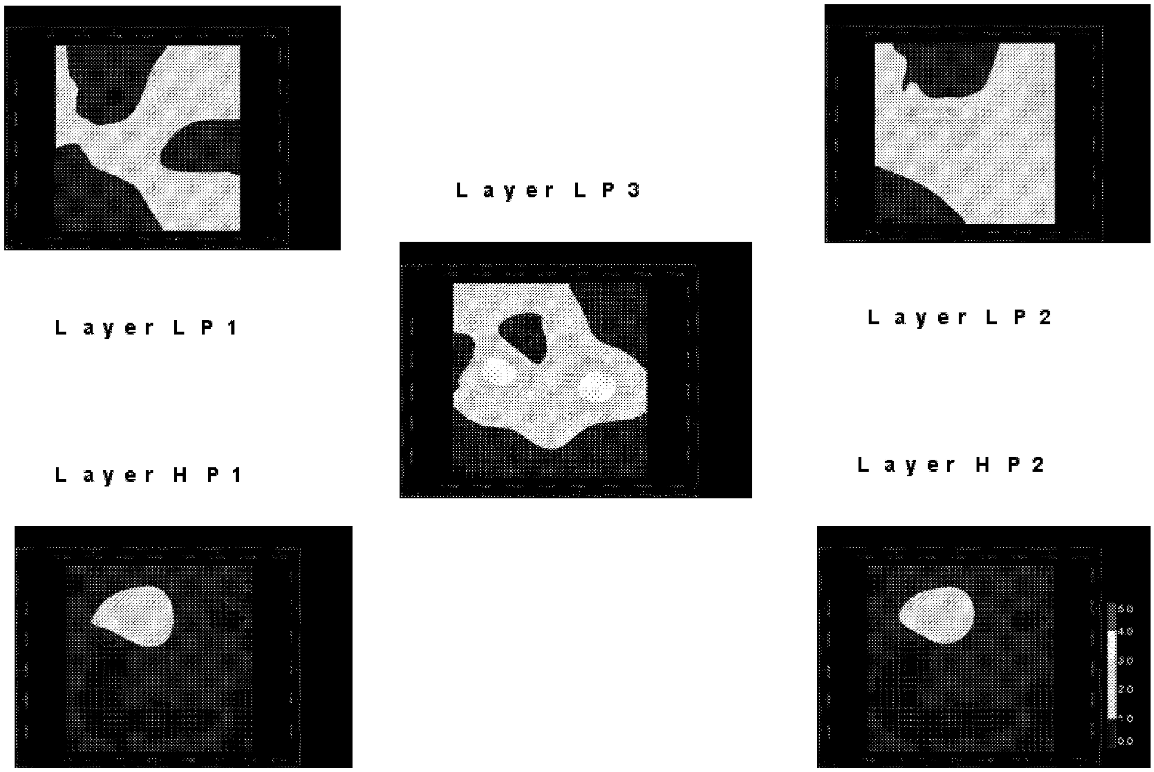

Figure 3.2 – Map distribution of computed flow unit storativity computed as the product of porosity and thickness for each of the five units.

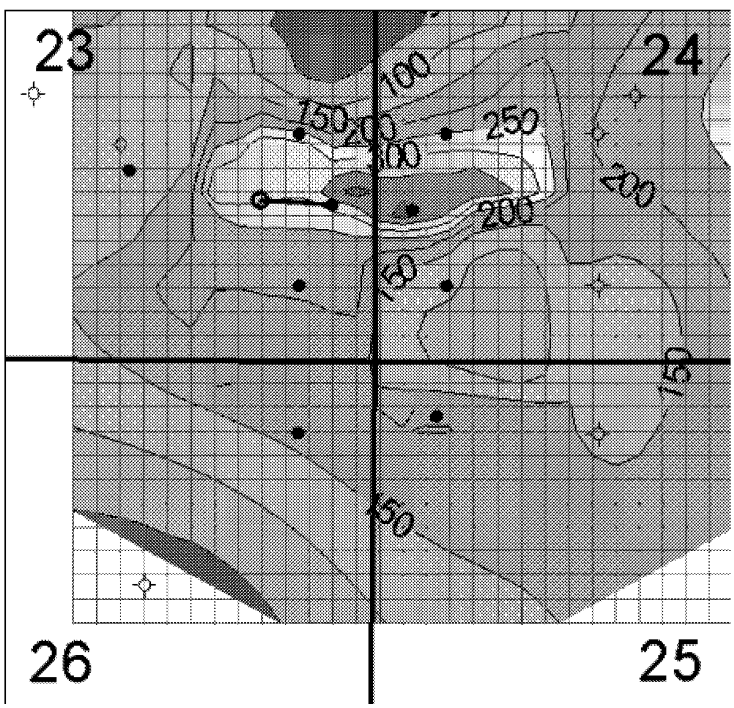

Figure 3.3 – Map showing distribution of flow unit permeability-feet (Kxy) computed as the product of permeability and thickness for Layer 2 (flow unit LP2).

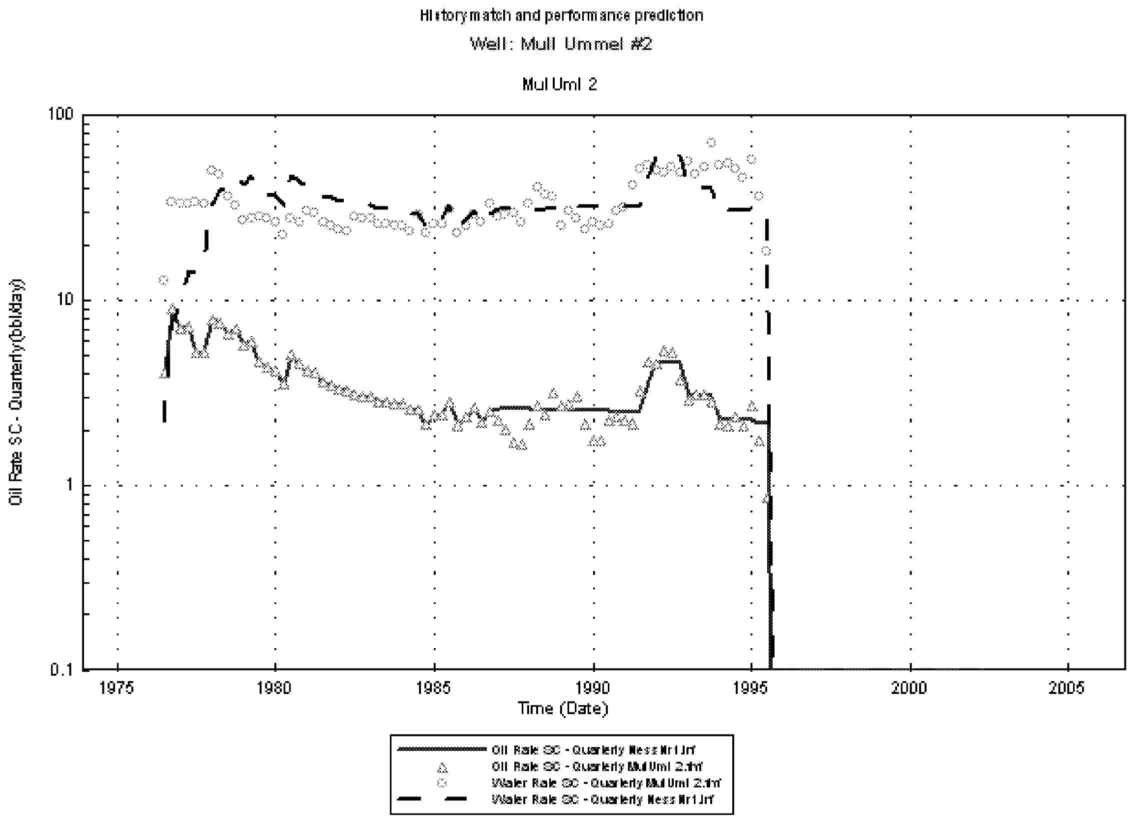

Figure 3.4 – Example of acceptable history match and performance prediction for the Mull Ummel #2.

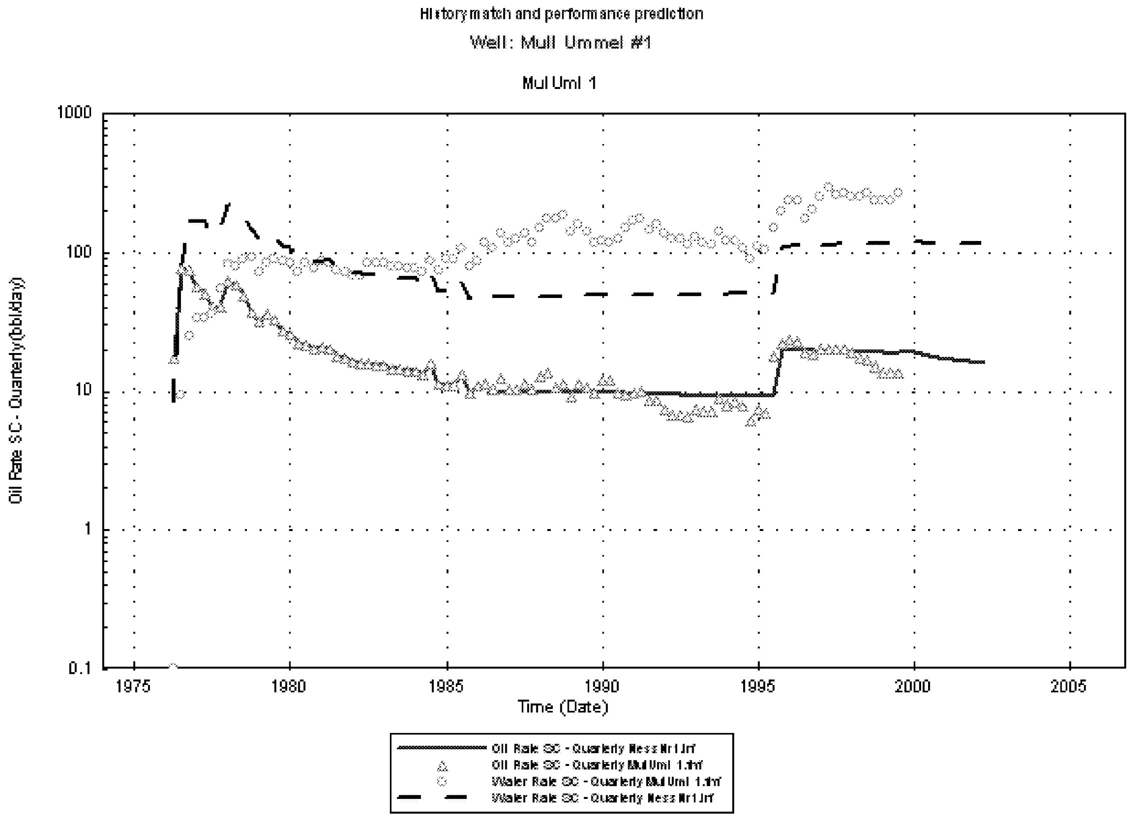

Figure 3.5 – Example of history match and performance prediction for the Mull Ummel #1. Water production was not available for the Ummel #2. Water production history was estimated by using the WOR observed at the Mull Ummel #1, and may account for the poor water match.

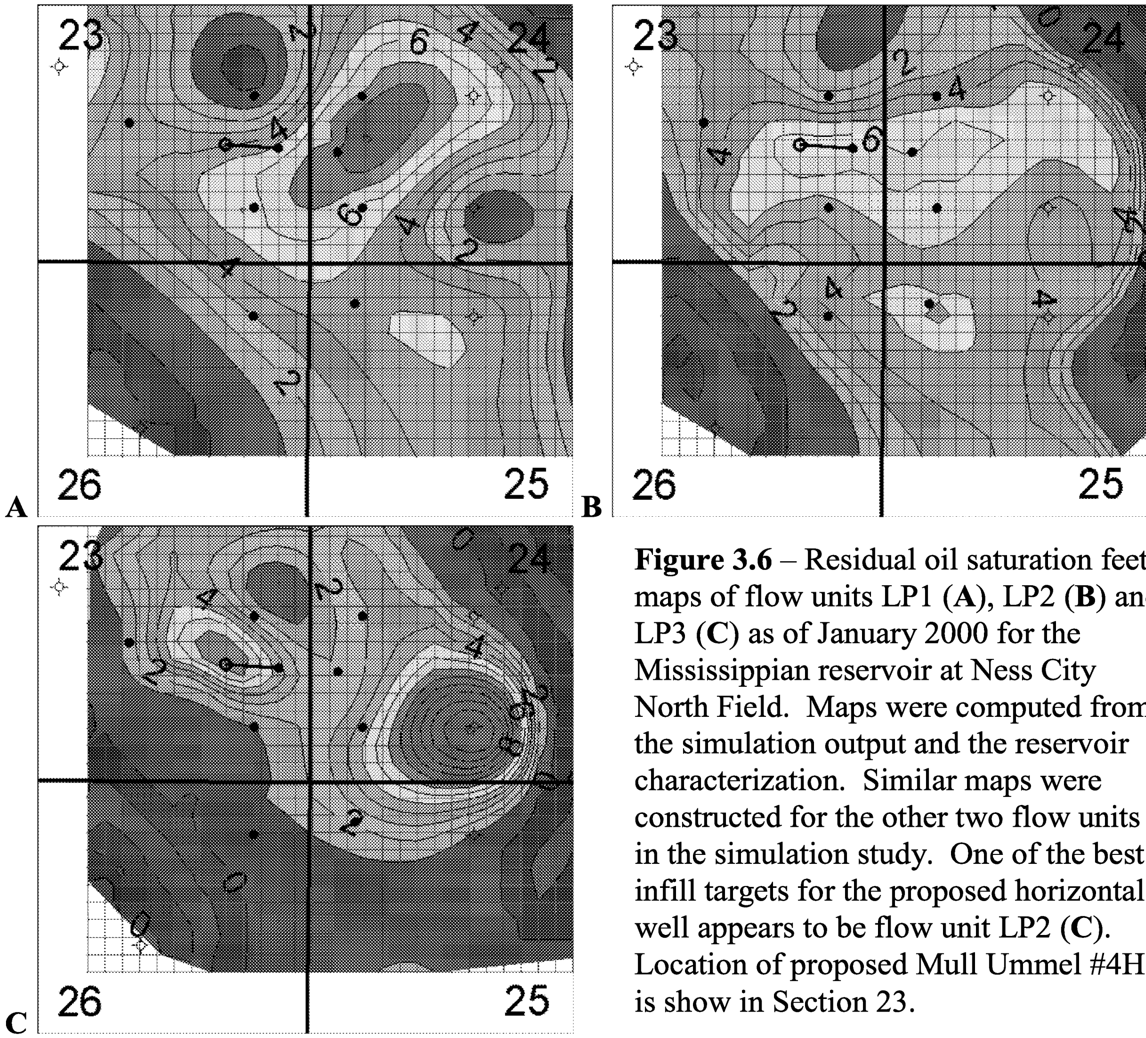

Figure 3.6 – Residual oil saturation feet maps of flow units LP1 (**A**), LP2 (**B**) and LP3 (**C**) as of January 2000 for the Mississippian reservoir at Ness City North Field. Maps were computed from the simulation output and the reservoir characterization. Similar maps were constructed for the other two flow units in the simulation study. One of the best infill targets for the proposed horizontal well appears to be flow unit LP2 (**C**). Location of proposed Mull Ummel #4H is show in Section 23.

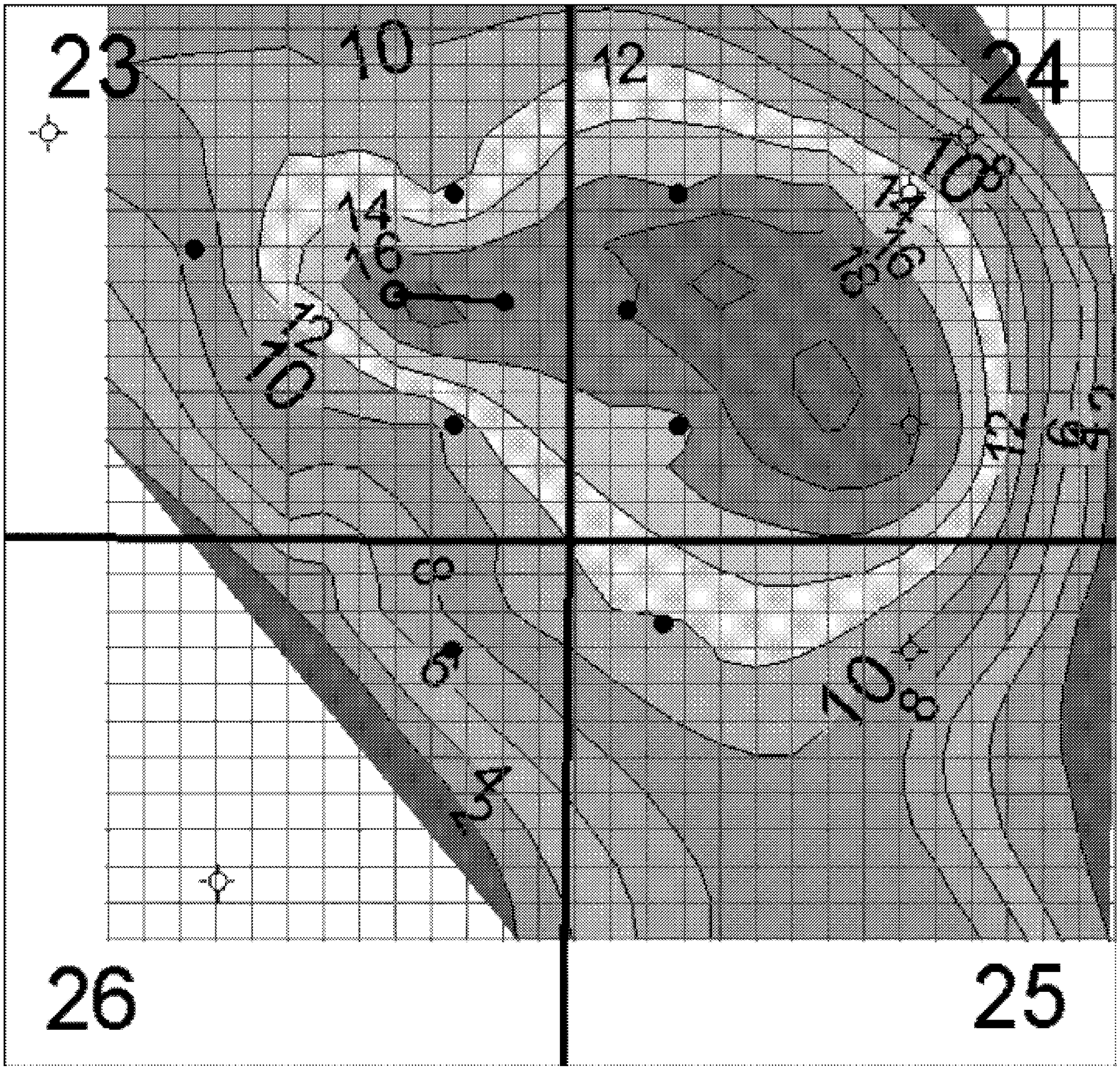

Figure 3.7 – Map of residual oil saturation feet (S_o-feet) for all flow units in the Mississippian reservoir at Ness City North Field as of January 2000. Maps were computed from the simulation output and the reservoir characterization. Location of proposed Mull Ummel #4H is show in Section 23.

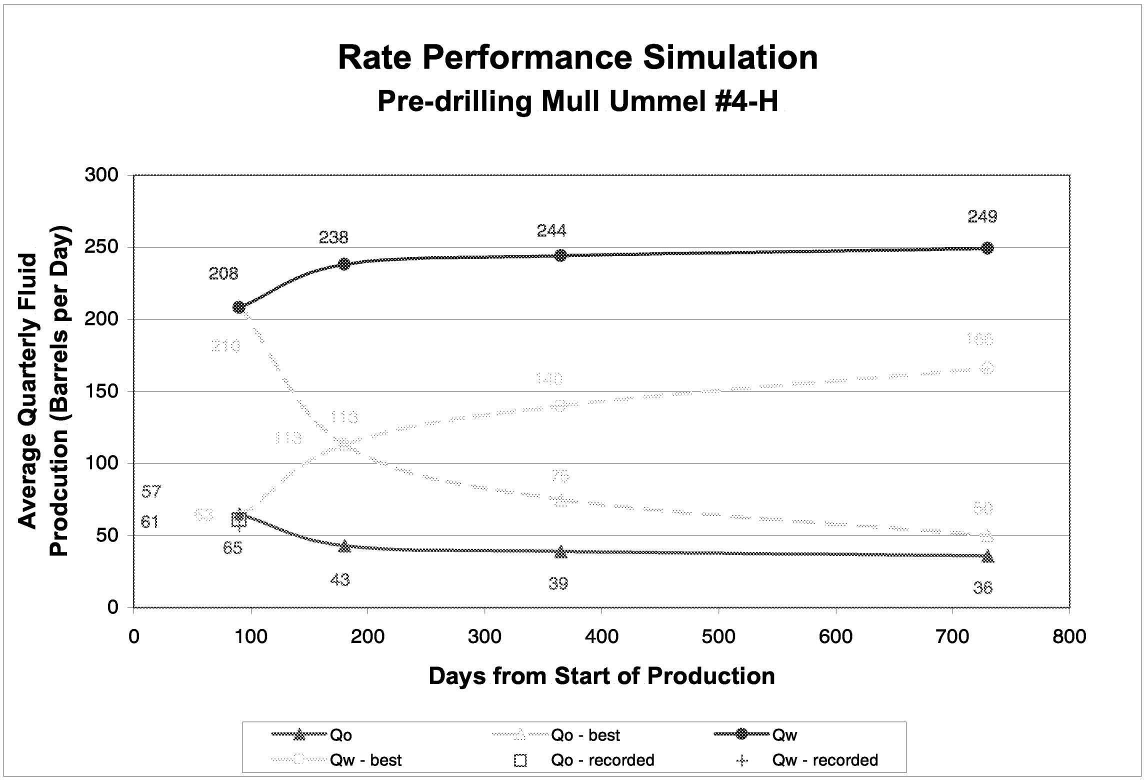

Figure 3.8 – Pre-drill simulation output for Mull Ummel #4H showing production rates for oil and water. Simulation was for a horizontal well with an effective horizontal well length of 400 feet, a uniform skin of 4.5 across the producing length, and a P_{wf} of 675 psi. Fluid production rates are plotted for the expected (Q_o, Q_w) and the best-case (Q_o-best, Q_w-best) simulations. Average production rates observed in the first month are shown (Q_o-recorded, Q_w-recorded).

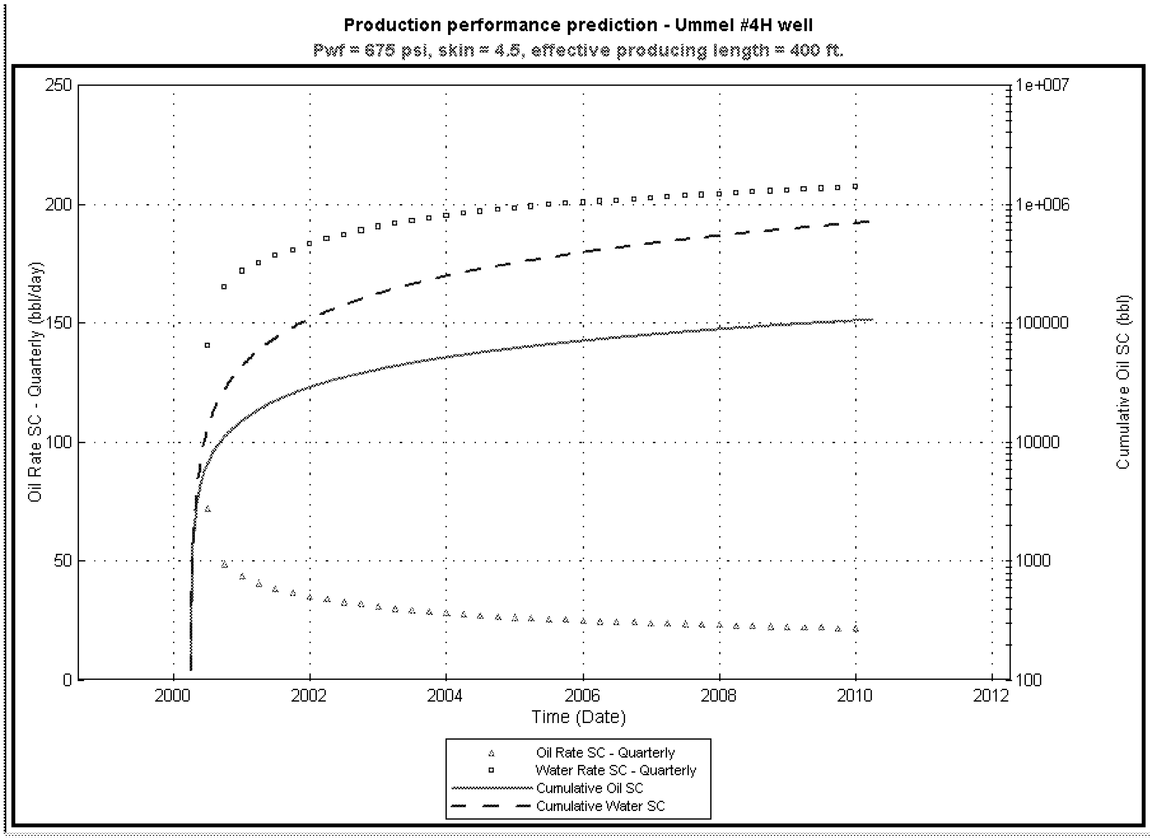

Figure 3.9 – Production performance prediction for Mull Ummel #4H based on the pre-drill simulation output showing expected and best case cumulative production for oil and water over ten years. Values for the first ten years of production performance prediction are listed in Table 3.3.

4.0 Cost-Effective Techniques for the Independent Producer to Identify Candidate Reservoirs for Horizontal Drilling in Mature Oil and Gas Fields

Section based on manuscript by Saibal Bhattacharya, Paul M. Gerlach, and Timothy R. Carr in press in AAPG Memoir entitled ***Horizontal Wells – Focus on the Reservoir,*** Timothy R. Carr, Erik P. Mason and Charles T. Feazel (editors). Expected publication date is 2nd quarter 2002. Paper was also presented at AAPG International Hedberg Conference October 10-13, 1999 in Houston, Texas. Information in this section concerns the transfer of technologies applied at the Schaben and Ness City North demonstration sites to the independent producer (e.g., cost effective reservoir characterization and simulation). The focus is on providing tools to the independent producer to identify candidate reservoirs in mature oil and gas fields for horizontal drilling.

Abstract

Horizontal wells have exploited successfully the remaining oil potential in mature reservoirs around the world. Because typical horizontal well costs between 1.3 to 4 times that of a vertical well, it needs to produce significantly greater volumes of oil to be considered an economic success. Previous studies have concluded that poor selection of target reservoirs has been the principle cause of failure of horizontal wells. Many mature fields in the Midcontinent of the United States have significant volumes of residual reserves, and vertical wells have proven uneconomic to produce these unswept assets. Small independent producers with limited financial and technological resources operate most of these fields. In Kansas, few horizontal infill wells have been drilled to date, and results have been mixed. Operator concerns for an appropriate economic return and the difficulty in cost-effectively identifying candidate reservoirs have been the principal factors restricting application of horizontal drilling technology in many mature production areas of the Midcontinent.

Recent declines in cost factors have brought horizontal drilling technology within the economic reach of small independent producers. Lack of inexpensive tools to screen and evaluate candidate reservoirs has constrained independent producers with limited resources from taking full advantage of this modern technology. The remaining barrier to wider use of horizontal technology by independent operators includes the demonstration of low-cost tools and methodology to screen, evaluate, and target a horizontal well to produce incremental reserves in mature areas.

We present several low-cost approaches that can be used to evaluate candidate reservoirs for potential horizontal well applications. These cost-effective screening techniques apply at the field scale, lease level, and well level, and enable the small independent producer to identify efficiently candidate reservoirs and also to predict the performance of horizontal well applications. Field examples have been used to demonstrate the application of each technique. The demonstrated tools use easily available and standard spreadsheet and mapping packages to analyze production data, map geologic data, integrate and compare geologic and production data, conduct detailed petrophysical analyses, carry out field- and lease-level volumetric analyses, and conduct material-balance calculations. The methodology that the independent operator may follow to identify prospective areas, within a production region/field, can include any combination of these tools. This paper describes the use of PC-based freeware simulators to history match well and field production, map residual reserves on a field scale, and predict performance of targeted horizontal infill wells in candidate reservoirs/leases. This process of identifying candidate reservoirs or leases and evaluating their productive potential to horizontal infill drilling will enable independent producers to study the viability of horizontal applications before drilling and thereby help them to select targets appropriately.

Introduction

Horizontal well technology has been applied successfully to exploit different types of reservoirs throughout the world. The 1980s proved to be the developing years for horizontal drilling, with the technology maturing and gaining acceptance through the

1990s. Many mature fields with significant volumes of remaining reserves are present in the Continental United States. Mature fields, thanks to their history of development and production, may have a bank of geophysical, petrophysical log and core data, and production history and test results. These data are invaluable in developing reservoir models, which can be used to simulate the viability of horizontal well application. Independent producers, with limited financial and technical resources, operate many of these older oil and gas fields. Advances in drilling technology have made horizontal well applications economical for independent producers. However, one of the principal causes of failure for horizontal wells has been poor evaluation and selection of targets (Coffin, 1993; Joshi and Ding, 1996). Typically, a horizontal well costs 1.4 to 3 times that of a vertical well (Joshi, 1991). Lacy et al. (1992) suggest that as a rule of thumb for a horizontal well to be an economic success, it should recover volumes between two to three times that of a vertical well. This makes identification of reservoirs that are viable candidates for horizontal drilling to be of crucial importance, especially for an independent producer with limited resources.

This paper highlights some cost-effective tools that can be employed to select prospects for horizontal drilling. Prospective areas are selected by applying one or a combination of different tools such as: a) production data analysis, b) geologic mapping, c) integration of geologic and production data, d) field-level and lease-level volumetric calculations, e) detailed lease-level petrophysical analyses, and f) reservoir simulation. These screening tools enable the user to focus on a small area from investigations at a regional scale. Each method is described with a field example from Kansas, a mature oil and gas province, where the majority of the operators are independent producers.

Background

Proper application of horizontal drilling can revive the productive potential of mature fields by mobilizing reserves that are not be drained economically by vertical wells. The volume and scale of residual hydrocarbons left in mature basins is illustrated by the Welch-Bornholdt-Wherry fields (Figure 4.1) in Rice County, Kansas. These fields were discovered in 1964 and they produce from a stratigraphic trap (Osagian, Mississippian). The total number of vertical wells drilled in this area is about 1200, and the cumulative production as of 1997 was about 60 MMbbl of oil. A type-well was selected to represent each quarter section of the field. Average values of porosity, thickness, and fluid saturation for the producing zone were obtained from the petrophysical logs of the type-well in each quarter section. These values were used to map the initial oil in place on a quarter section basis. Lease production data were used to calculate the total volume of oil produced per quarter section, and thereby map the remaining volume of oil in these fields on a quarter section basis. Figure 4.1 reveals areas with significant volumes, about 7 MMbbl per quarter section, of residual oil. The limited drainage potential of vertical wells coupled with reservoir heterogeneity results in areas with substantial unswept hydrocarbons in mature basins.

The Oppy South Field, located in Hodgeman County, Kansas, was discovered in 1962, and developed with 12 vertical wells. Cumulative production, up to 1997, was 800 Mbbl oil, and daily rates had declined to 300 bbl of oil per day. A horizontal infill well was drilled in 1997 to rejuvenate the field (Figure 4.2). The economic impact of this horizontal well was dramatic (Figure 4.3). The advantage of a horizontal well is that it can drain a large reservoir contact area if optimally directed. This results in minimizing the number of infill wells (horizontal) required to effectively redevelop a mature area. Also, the ability of horizontal well to produce large fluid volumes under controlled drawdown enables it to accelerate production. Thus, horizontal wells not only produce at a higher rate than vertical wells but also enhance the producible reserve volume by their extended reach. It is for this reason that the independent producer should consider applying horizontal well technology to rejuvenate production from mature fields.

Horizontal wells have been applied successfully to exploit thin bedded and compartmentalized reservoirs, to produce attic oil, in fractured reservoir systems, to produce from reservoirs with water or gas coning problems, and in low permeability gas reservoirs. They also are used for EOR (enhanced oil recovery) operations as injectors and producers and in SAGD (steam assisted gravity drainage) thermal recovery operations. Figure 4.4 highlights different producing zones in Kansas where horizontal technology can be applied. Figure 4.5 shows the current status of horizontal drilling activity in Kansas. As of 1999, only 16 horizontal wells have been drilled in Kansas with the majority of them being drilled in the Mississippian Osagian units of Ness and Hodgeman Counties.

Small independent oil and gas producers operate the majority of producing wells in Kansas. Almost 90% of these independent producers employ fewer than 20 employees (Carr et al., 1998). The independent producer generally does not have access to advanced commercial technologies suitable for screening production areas to identify candidate locations and for studying the viability of infill horizontal wells. This inability, to identify appropriate applications of horizontal wells, coupled with the higher drilling costs have been two of the major reasons why the horizontal drilling potential of Kansas has not been exploited. It therefore is the intent of this paper to present a list of cost-effective techniques that independent producers can use to identify candidates for horizontal well applications within their assets.

Cost-Effective Tools to Identify Candidate Reservoirs for Horizontal Drilling

Production Data Analysis - Fields in a mature production area such as Kansas have a long history of production, and one of the commonly available data is that of production volumes. High vertical permeability in aquifer-driven reservoirs may cause a rapid decline in oil-cut and hence results in poor sweep efficiency. Plotting the production data of a well such as Ritchie No 1B Moore, Schaben field, Ness County, Kansas (Figure 4.6) clearly shows a steep decline in oil-cut. The operator attempted to contain the water cut by squeeze-cementing the bottom of the perforations. After a temporary surge in the oil rate the oil-cut declined again. Well production profiles, such as these, can be used to identify areas with inefficient horizontal sweeps. Such areas may have significant unswept reserves and can be considered for a horizontal well application.

Another technique (Figure 4.7) of using production data to identify areas with residual reserves is to compare the distribution of initial production (IP) rates in a field with the cumulative production map. Production commenced in the Welch-Bornholdt-Wherry field, Rice County, Kansas, in 1924, and Figure 4.7 maps the cumulative lease production as of 1996. The well locations shown on the cumulative lease production map are those of the first wells that were drilled in each lease. High IP-rates are the result of pay thickness as much as 80 ft. A comparison of the two maps reveals that the IP peaks coincide with that of cumulative production highs only in certain pockets of the field. The cumulative production in areas, such as that circled "A" on Figure 4.7, is not proportionate to the high IP rate. Such comparisons may highlight areas where vertical wells have been ineffective in draining reserves, and therefore indicative of significant remaining reserves. Additional discussion on this area will be carried out in a later section.

The ability of a horizontal well to drain a significantly larger reservoir volume makes it an ideal application to recover the remaining reserves left because of excessive well spacing in a field. Figure 4.8 is a structure map of the producing Mississippian zone in the Aldrich field, Ness County, Kansas. This field was discovered in 1929, and by 1973 had produced 1044 Mbbl from 15 producing wells. By 1973, the field production had declined to less than 400 bbl of oil per month, and 8 vertical wells were drilled as a part of the infill-drilling program. Figure 4.9 shows the effect of the infill wells on the monthly field production. By mid 1997, the field production was increased to 900 bbl oil per month, and an additional 553 Mbbl of oil had been recovered from the field since the onset of infill drilling. Clearly, the original well spacing was insufficient to drain the field and this resulted in incremental infill recovery. The Aldrich field is a typical example of a mature field having significant recoverable reserves left because of inadequate drainage. Such fields can be more efficiently drained with far fewer wells if horizontal wells are drilled instead of vertical wells. This strategy could prove economic for the independent producer because the same area will be drained faster by fewer wells. An effective method, to identify fields that are candidates for horizontal infill drilling, is by comparing field production before and after infill drilling in analogous reservoirs with similar well spacing.

Mapping Geologic Data - The structure map (Figure 4.10) on the Mississippian zone in an area of the Welch-Bornholdt-Wherry fields, Rice County, Kansas, does not emphasize the subdued features. The first derivative of the structure map highlights the change in the local dip of the formation and this helps to determine the location of folds and faults in the subsurface. Area "B", in Figure 4.10, delineates the axis of the fold. Structural folding may create an associated fracture network, which can enhance the flow permeability. Such phenomenon may be the cause for the high cumulative production volumes (as shown in Figure 4.7) for area "B" of Figure 4.10. The first derivative map also shows that the axis of the structural folding stops short of area "A" (Figure 4.10). Absence of fold induced fractures may have resulted in significantly lower cumulative production volumes in area "A". Areas such "A" can be spotted on first derivative structure maps, and can be analyzed along with the production history, particularly for mature production areas, to evaluate potential of reserves left unswept by vertical wells. A horizontal well, with its extended drainage, may be well suited for these candidates.

One of the important applications of horizontal drilling has been to recover attic reserves. Figure 4.11 compares the structure map on the Simpson sand in Hollow-Nikkel field, Harvey County, Kansas, with the first derivative map of the same structure. The attic axis is clearly defined (area "A") on the first derivative map, and serves as location for an exploratory horizontal well to confirm the presence of the attic. Depending on the results of the exploratory horizontal well, the same wellbore can be used to drill a second lateral in the southwestern direction to delineate the extent of the attic axis.

Murray (1965) postulated that the maximum fracture intensity could be predicted by mapping the rate of change of dip or the radius of curvature of a structure. Clay model and analytical studies demonstrate that fracture porosity and permeability is highest where the curvature of the fold is highest. However because of structural complexity, first derivative maps are unable (Stright and Robertson, 1993) to delineate fold axis in formations such as the Niobrara shale. Stright and Robertson suggest using the maximum second derivative values to determine the curvature of structural surfaces in complex situations like the Niobrara structures in northwestern Colorado. Cumulative production can be overlaid on the second derivative structure map to establish the minimum amount of curvature needed to generate reservoir quality fractures. These workers have determined that fractured reservoirs of the Niobrara, in northwestern Colorado, have a recoverable potential ranging between 1200 to 1400 bbl of oil per acre if the value of the second derivative of the structural surface exceeds $10^{-4.5}$ ft^{-1}. Structural discontinuities, such as faults, will also show on second derivative maps, and will help to understand the fault-generated fracture system. Detailed mapping procedures to evaluate fractured-enhanced production along with field applications have been discussed in the previously mentioned reference. Candidate reservoirs with a productive fracture system can be exploited with horizontal drilling because horizontal wells have a higher probability of intersecting a fracture network than vertical wells.

Mapping Production and Geologic Data - It may be difficult to exploit thin pay zones with vertical wells because of limited sweep efficiency. Horizontal wells are effective tools to drain reserves trapped in thin pays. The Welch-Bornholdt-Wherry field, Rice County, Kansas, is an updip stratigraphic trap. On the northwestern side the reservoir layer subcrops against the overlying Pennsylvanian sediments, whereas the oil-water contact truncates the trap on the southern side. Figure 4.12 overlays the cumulative oil production per quarter section, as of 1997, over the pay isopach of the field. The thick black contour lines show the boundaries of 100 Mbbl of cumulative oil production. The red contour lines mark the border of pay greater than 30 ft. Vertical wells in this field have pay cut-off of 30 ft, and they are considered economic if they produce more than 100 Mbbl of oil. In the southern part of the field, the 30-ft pay contour closely follows that of economic production limit, whereas the northwestern part the cut-off contours of pay and production are significantly apart. The separation between the pay and production contours indicates that vertical wells in certain areas have proved uneconomic even when the pay thickness is greater than 30 ft. Reservoir compartmentalization along with solution-gas drive have contributed to poor sweep in the northwestern part of the field. Horizontal wells have been known to drain compartmentalized reservoirs, and they produce at economic rates under lower drawdown than vertical wells. Areas such as the northwestern part of the Welch-Bornholdt-Wherry field are candidates for horizontal well application.

Mapping Field Level Volumetrics - In Canada, horizontal drilling has been applied in conventional reservoirs to accelerate recovery and to increase reserves (Faquharson et al., 1992). In the Williston Basin of southeastern Saskatchewan, horizontal drilling has been successful in naturally fractured and stratified Mississippian age carbonate reservoirs. Horizontal permeabilities in the limestone reservoirs of the Mississippian Midale and Frobisher are low, and solution of deeper Devonian Prairie salt beds have resulted in fractures caused by collapse. Vertical wells have proven uneconomic in these reservoirs. Drilling results in this area have shown that horizontal well bores reach vertical fractures in proportion to the length of the well. The Mississippian carbonate (Meramecian Facies) reservoirs in south-central Kansas also are naturally fractured and stratified, and application of proper screening methods will help to locate prospective candidates for horizontal drilling. Field level volumetric calculations are a quick and effective way to start the screening process. The first step is to calculate the original volume of reserves in place. Parameters such as pay thickness, average porosity, and initial saturations are obtained from petrophysical logs that were run in the well during drilling. Welch-Bornholdt-Wherry field produces from the Mississippian Osage reservoir and extends over 30 sections and averages about 40 wells per section. The size of the field and the number of wells may make this task of log interpretation daunting. A huge area can be effectively screened to isolate pockets with significant remaining potential by selecting a type-well in each quarter section and obtaining the necessary volumetric parameters from the petrophysical logs of the type-wells. Figure 4.13 shows the original oil in place per quarter section (using a formation volume factor of 1.04 reservoir barrels per stock tank barrel) in the Welch-Bornholdt-Wherry field. Figure 4.14 shows the distribution of recovery efficiency in the field, and it helps to focus attention on areas with low recoveries. Areas showing low recovery efficiencies need to be followed up with a more detailed analysis to study the viability of horizontal well application.

Detailed Petrophysical Analyses for Lease Level Volumetrics - Application of one or a combination of the tools described here results in the identification of areas with significant remaining potential. These prospective target-areas may extend across leases, and need to be subjected to a more detailed analysis to evaluate the prospects of reserve recovery by horizontal drilling. Cost-effective tools that can be used in lease-level analysis include the Super-Pickett crossplot, and the use of pore-size distribution (from capillary pressure data) and NMR data to determine effective macro porosity and mobile water saturations.

Doveton (1994) and Doveton et al. (1996) have described the fundamentals of Super-Pickett crossplot in detail. Applications of Super-Pickett analysis for integrated petrophysical analysis have been studied by several authors (Watney et al., 1999; Guy et al., 1996; Guy et al., 1997; Bhattacharya, et al., 1999). The Super-Pickett crossplot uses equations of Archie to plot data from resistivity and porosity logs on log-log axes. All the plotting and calculations are carried out in a PC-based environment. Pattern recognition techniques are used to integrate information about pore character and lithology with porosity, saturation, BVW (bulk-volume-water) and BVW_i (bound-volume-water). Permeability contours, based on empirical correlations between porosity and permeability such as Timur's equation, can be drawn on the Super-Pickett plot to analyze sandstone reservoirs. Various cut-off criteria, such as shaliness, fluid saturation, porosity, and permeability, can be included on the Super-Pickett analysis to identify "pay". The depth of the FWL (free-water-level) can be used to generate synthetic capillary pressure curves for different porosity intervals. The Super-Pickett template can be used to compare these synthetic capillary curves with laboratory measured capillary pressure data, obtained from rock samples with comparable porosity and taken from the same interval, to identify petrofacies. NMR data also can be integrated into the Super Pickett analysis to highlight zones that will produce water-free, that is zones where the porosity values are significantly higher than the BVW value, and the BVW and BVW_i values are approximately equal.

Figure 4.15 is a Super Pickett crossplot of the log data from Ritchie No 2P Lyle Schaben well located in Schaben field, Ness County, Kansas. This well produces from a Mississippian carbonate reservoir and the crossplot shows a clear transition to 100% water saturation. A detailed petrophysical analysis was carried out on the Schaben field wells (Carr et al., 1998; Bhattacharya, et al., 2000) to build a reservoir model for the producing horizon. Results from Super-Pickett analysis revealed that the BVW_i value ranged between 0.09 to 0.11. High BVW_i values, such as those observed in Schaben field, are caused by the presence of micro-porosity. Initial water saturation values in most wells, in this field, are near 60%, and yet most of them have produced water-free for the initial year or two. One possible explanation for this dichotomy is that a significant portion of the water in the reservoir rock is held immobile in the micro pores.

A frequency distribution of pore throat sizes can be generated from capillary pressure measurements. A qualitative estimate of micro porosity and thus its effect on fluid-flow can be obtained from this pore-size frequency distribution. As a part of the reservoir characterization study of Schaben field, three new wells were drilled and cored. Capillary pressure measurements were obtained from core plugs taken from the producing horizon of these wells. Figure 4.16 shows the distribution of micro (pore throat size equal or less than 5 micron) and macro (pore throat size greater than 5 micron) pores in core plugs taken from the Ritchie Exploration No 2P Lyle-Schaben well in Schaben field. The pore size distribution indicates that there is a significant presence of micro porosity in the reservoir rock.

Simulation results were unable to match the initial water-free production phase at many Schaben wells when distributions of log-derived total water saturation were used. Petrophysical logs measure the total volume of water present in the reservoir rock. However, in a reservoir such as the Schaben field, a significant portion of the water is held immobile within the capillary pore spaces (micro porosity). NMR measurements provide a quantitative estimate of micro porosity and effective macro porosity. A plot, Figure 4.17, of effective macro-porosity against total (core) porosity was generated from NMR measurements on core plugs taken from three wells in Schaben field. In this study, it was assumed that the micropores are totally saturated with immobile water, whereas the macropores contained mobile water and hydrocarbons. The effective macro-porosity represents the pore volume (i.e., the macro pore volume) within which fluid-flow occurs under reservoir conditions. In the absence of free gas in the reservoir, the oil volume, obtained from petrophysical logs, was used to calculate the mobile (free) water saturation (Rezaee and Lemon, 1996; Hedges and Moothart, 1996) in the effective macro-porosity. Use of effective macro-porosity and mobile fluid saturation distributions (Bhattacharya et al., 2000) enabled the simulation output to match the initial water-free production period in Schaben field wells. NMR data is a cost-effective measure of macro-porosity and mobile fluid saturation. It relates the total water saturation, derived from petrophysical logs, to the productive potential of a horizon. This detail about pore character and its effects on reservoir fluid-flow is essential to characterization studies to screen candidate reservoirs for horizontal drilling.

The petrophysical tools described in this section were used to make a detailed lease level volumetric analysis on the Wieland and Wieland West fields in Hodgeman County, Kansas. These fields (Figure 4.18) were discovered in 1956 and produce from a structural Mississippian Osagian trap. Lease level volumetric calculations when compared with the cumulative lease production (until 1997) revealed that adjacent leases displayed differing (Figure 4.19) recovery efficiencies. The operator of Wieland West field drilled a commercial (Figure 4.20) horizontal well, No 1 Antrium-Cossman, in between the Cossman and Antrium leases. This well was able give a significant boost to the monthly field production of this mature area, and is a good illustration of how detailed lease level petrophysical studies can result in proper selection of horizontal well candidates. The success of the horizontal infill well in the Wieland West field, where primary recovery efficiencies ranged between 13 to 15%, indicates that the Wieland field leases have potential for horizontal infill applications because of lower primary recovery efficiencies (varying between 6 to 14%).

Cost-effective Reservoir Simulation - Marginal fields may be exploited efficiently when field management plans are based on reservoir characterization and simulation studies. In the past, simulation studies required expensive hardware and software and were restricted to core assets of major companies. With the advent of powerful PCs and PC-based software, full-field integrated studies have come within the resource reach of independent producers. Also, PC-based simulation tools such as BOAST4 and BOAST-VHS have been developed by the U.S. Department of Energy, and have been released as freeware. These simulators have proved versatile for full field studies (Carr et al., 1998; Bhattacharya, et al., 2000; Montgomery, et al., 2000), and are cost-effective tools to map residual reserves in mature fields and can be used to predict the performance of a horizontal infill well in a candidate reservoir.

The techniques described so far help to identify leases/areas with geology and recoverable reserve potential suitable for horizontal infill application. Geologic mapping and petrophysical analyses results in the construction of geomodel, which forms the base for any simulation study. It therefore is prudent to use material-balance calculations to crosscheck the robustness of the geomodel before starting reservoir simulation. This makes the exercise of simulation a two-step process consisting of material-balance calculations followed by field simulation.

Spreadsheet-Based Material-Balance Calculations - Material-balance calculations corroborate the OHIP (original hydrocarbons in place), calculated volumetrically from the geomodel, with the initial reserve potential calculated by a geology independent technique. The input required for these calculations include the production and pressure histories and PVT parameters of hydrocarbons and water. Material-balance calculates the effective OHIP. The difference between the volumetric OHIP and the effective OHIP is the measure of the reservoir heterogeneity effecting production performance in the reservoir. Also, the material-balance calculation helps to identify the reservoir drive mechanism. For water-driven reservoirs it helps to define the average aquifer properties and to estimate the volume of influxed water. For reservoirs with gas caps this technique helps to quantify the volume of the initial gas cap. When pressure and production data are recorded through the life of the field, advanced material-balance calculations can be employed in versatile ways. Such endeavors result in the generation of full field pseudo relative permeability curves and, for gas cap driven reservoirs, in the determination of critical gas saturation and recovery efficiencies at specified abandonment pressures. Dake (1994) has noted that reservoir simulation can not provide additional clarity when the material-balance calculations show a mismatch with volumetrics. In case of a mismatch, it is prudent to revise the geomodel and its associated petrophysics rather than proceed with the simulation study. The principles of material-balance are versatile to model different reservoir scenarios, and can be accomplished effectively in a spread-sheet environment (Dake, 1994).

Material-balance calculations were carried out on Schaben field, Ness County, Kansas. Regular recording of reservoir pressure at each well is necessary for mass-balance calculations. However, pressure data through the production life of wells may be unavailable in fields, such as Schaben, that are operated by independent producers. An estimate of the initial reservoir pressure and current operating fluid levels at most producing wells however were available for the Schaben field study. In absence of a field pressure history, material balance calculations can not be used to confirm the volumetric OHIP. However by assuming that the volumetric OHIP is valid, the technique can be utilized to confirm the current average reservoir pressure and the reservoir drive mechanism. Identification of reservoir drive mechanism is important because it helps to define the aquifer and also to estimate the size of the initial gas cap. Well production patterns and current fluid levels in the producing wells of Schaben field indicate that the reservoir is supported by strong bottom water drive. As in most fields, direct measured data of different aquifer parameters such as porosity, permeability, thickness, and rock and fluid compressibilities were not available for Schaben field, and they were inferred initially from reservoir properties.

Spread-sheet based material-balance calculations are suitable for aquifer fitting through a process of trial and error, and was used for the Schaben field (Carr et al. 1999). Based on the reservoir geomodel, the volumetric estimate of OOIP (original oil in place) for the Schaben field was 37.8 MMSTB. The field has been in production since 1963. DST analysis of available data approximated the initial reservoir pressure (P_i) about 1370 psi.

Standard correlations were used to generate PVT profiles for the reservoir fluids, and the bubble point pressure calculated as 225 psi. The Carter-Tracy formulation was used to calculate the water influx (W_e) from an infinite aquifer. In a spread-sheet environment, it is easy to change the aquifer properties (within geologic and engineering limits) for different average reservoir-pressure distributions until the plot of F/E versus W_e/E appears as a straightline with unit slope (Figure 4.21). F denotes the underground withdrawal of fluids from the reservoir, and W_e stands for the reservoir volume of water that influxed from the aquifer. E represents the sum of the change in volume of the oil and the dissolved gas and the change in volume due to expansion of connate water and reduction in pore volume. The aquifer properties and reservoir pressure distribution over time were adjusted until the straightline correlation between F/E and W_e/E produced an intercept that translated to an OOIP value that was lower but close (within 10%) to that calculated from volumetrics. The average reservoir pressure distribution through the production life of the field, obtained under the stated conditions, is shown in Figure 4.22, and it indicates that the current average field pressure is near 800 psi. Available fluid level data indicate that the majority of the wells in the field currently produce against bottomhole pressures that range between 400 to 1100 psi.

Material-balance study in Schaben field confirmed that the volumetric description of the reservoir-aquifer system together with the natural bottom-water drive mechanism is able to support the reported fluid production history of the field. This example also demonstrates that the calculated average reservoir pressure lies within the range of current operating fluid level data. The process of "aquifer-fitting" fine-tuned aquifer parameters such as its height, porosity, permeability, and effective compressibility, and also the reservoir radius. These parameters along with the reservoir drive mechanism form essential components of the input file for any reservoir simulation study.

PC-based Reservoir Simulation - Reservoir simulation is the final step in the selection process of a candidate reservoir. This exercise models fluid flow through the reservoir during its producing life, and predicts the performance of horizontal wells under different operating scenarios. The results of a simulation study, however are only as good as the geomodel on which it is based. A combination of cost-effective reservoir simulators, such as the U.S. DOE's BOAST4 and BOAST-VHS have been applied successfully to carry out full field studies (Carr et al., 1998; Bhattacharya et al., 2000, Carr et al., 1999). These studies have mapped residual reserves and predicted horizontal infill performance in a mature area such as the Schaben field, Ness County, Kansas. These studies also have demonstrated that the limitations of the pre- and post-processing tools of these simulators are overcome easily by using commercially available inexpensive and user-friendly spreadsheet programs, relational databases, and gridding and mapping packages.

The Schaben field produces from Meramecian and Osagean age (Mississippian) cherty dolostones that lie below the sub-Pennsylvanian unconformity on the western flank of the Central Kansas Uplift. The field has been developed on a 40-acre spacing and has been producing since 1963. Data such as core, log, and production history and test results were integrated to develop a 3D reservoir-geomodel. Material-balance calculations were then used to confirm the drive mechanism and to refine aquifer description and properties. Initial simulation of the field was completed on BOAST4 (reference 21). BOAST4 is a 3D, three-phase, isothermal black-oil simulator that uses IMPES solutions to simulate the performance of vertical wells. This tool can be used to simulate a wide variety of field applications such as primary depletion (with option to include an aquifer in the model), pressure maintenance by water/gas injection, and performance of waterfloods. Well production history of the first eleven years was entered into the simulator and the permeability distribution was fine-tuned to match the production profile for the next 23 years. The oil saturation map (Figure 4.23) after 34 years of production shows areas of remaining reserves. A saturation-feet map (Figure 4.24) of the remaining reserves, using a pay thickness cut-off of 20 feet and an oil saturation cut-off of 40%, was used to design the infill drilling strategy. The boxed area, on the saturation-feet map, named as "Area A" was selected to compare the potentials of horizontal and vertical infill wells.

BOAST-VHS (Chang et al., 1992) is a PC-based 3D, three phase, finite difference black oil simulator that uses IMPES solution technique to simulate the performance of vertical, slant, or horizontal wells. This tool is recommended for studying problems such as primary depletion, pressure maintenance, and waterflooding. However because of memory limitations, BOAST-VHS can not handle more than 810 grid blocks. Thus, in the Schaben simulation project, the entire field was simulated until 1996 in BOAST4. Area A in Figure 4.25 highlights the portion of the Schaben field that was simulated in BOAST-VHS. Locations of the wells drilled in this area before the onset of the field-study are shown by black dots, while the red dots denote the locations of the three infill wells drilled by the operator based on the remaining reserves map generated from the results of simulation study. Of the six original wells, American Warrior No 2 Witman and Ritchie No 2D Moore had ceased production by 1996. Remaining fluid saturation and reservoir pressure distribution data as of January 1997, for area A, were obtained from the BOAST4 output and used as input to BOAST-VHS study. The VHS tool does not have the option to model an aquifer below the reservoir. A bottom-water drive was simulated in the study area by modeling 12 horizontal water injector wells, placed uniformly apart, in a layer below the reservoir layer. Each of these water injection wells was required to inject sufficient volumes such that pressure in the injection layer remained constant, thereby incorporating the effects of a strong bottom water drive in the reservoir model. Area "A" was simulated for 5 years (starting from 1997) in BOAST-VHS to obtain the cumulative production from its operating vertical wells. Cumulative production for area 'A" and during the same interval of time was also obtained from BOAST4, and the results compared closely with the output from BOAST-VHS. This similarity in production profiles demonstrated that the use of 12 horizontal injectors operating in the layer below the production zone was able to mimic the effects of a bottom aquifer.

BOAST-VHS was used to simulate, for 5 years (beginning 1997), two different infill development scenarios: a) area A with 3 vertical infill wells along with the existing producing wells and b) area A with one horizontal infill well along with the producing wells. The results of the simulation study are summarized in Figure 4.26, and it shows that at the end of the first year, the three vertical infill wells recovered an additional 53 MSTB while one horizontal infill well recovered 137 MSTB. Thus in the first year, the horizontal infill well is expected to produce 250% more than 3 vertical infill wells whereas moving an additional 395 MSTB of water. This study also predicts that during a 5-year period, the fluid-production from one horizontal infill well exceeds the cumulative production from three vertical infill wells by 103 MSTB of oil and by about 2.7 MMSTB of water. In the first year of production, the horizontal infill well appears to deliver half the volume that it will finally recover during 5 years. Such a performance suggests that the operator may be better off to produce the horizontal well for just one year and thus restrict the volume of produced water to 0.6 MMSTB.

In the Schaben field study, various scenarios were simulated in BOAST-VHS to study the effect of well orientation, producing bottomhole pressures, and skin factors on the infill production potential. Cost-effective simulation studies are able to reveal information that is critical to evaluate the performance of horizontal drilling at a selected site and also in designing efficient production strategies. Production estimates from a horizontal well in a candidate reservoir serves as an important input to the management to outline a strategy to exploit remaining reserves in mature areas.

Conclusions

Horizontal drilling has been applied effectively all over the world to exploit reserves under different geologic settings. Though the technology of horizontal drilling has come of age, major reasons why many such wells remain a technical success and not an economic one are poor evaluation and selection of target reservoirs. Mature areas, such as the Mid-Continent in the United States, have significant volumes of unswept hydrocarbons. Independent producers, with limited technical and economic resources, operate a significant portion of the oil and gas fields in these mature areas. This study outlines many cost-effective techniques, which can be used to screen reservoirs in a producing area to identify potential candidates for horizontal drilling, and illustrates their applications through field examples from Kansas.

Mature areas, because of their long production history, may carry an extensive database of geological and geophysical data, production history, and pressure test results.

Production data, such as water-cut, IP, and cumulative production volumes can be mapped over a field to identify areas with inefficient sweep. Analyses of productivity from vertical infill-wells reveal if excessive well spacing is the cause of the inefficient sweep. Comparison of structure map with its first derivative may result in highlighting the attic-axis or the axis of the fold. Vertical wells have proven ineffective in draining attic-oil, and identified attic-axes may be taken up for detailed lease level analyses to consider their potential for horizontal drilling. Folds may be associated with regional fracture networks, which can be used advantageously to drain hydrocarbons from the reservoir to the horizontal wellbore. This paper shows a field example where poor sweep, by vertical wells, in the thin pays of updip stratigraphic traps can be identified by overlaying cumulative production distribution on the payzone isopachous map. Cumulative production volumes when mapped over second derivative maps of structure surfaces also have proven successful in delineating "fracture-fairways" and references to select field studies have been provided. Using a type-well per quarter section, regional volumetric calculations can be completed and mapped to highlight areas with low recovery efficiency. A combination of these techniques quickly shifts the focus of investigation from a large producing basin or region to prospective leases (or small fields).

Application of a cost-effective and state-of-the-art tool, the Super-Pickett crossplot, for petrophysical analyses at well and lease level has been described. This crossplotting technique provides a common platform to integrate petrophysical-log data, lithologic information, pore-size distribution, and capillary pressure and NMR data to identify petrofacies and to predict the productive potential of pay zones. Frequency distribution of pore sizes, derived from capillary pressure data, have been used to obtain a qualitative measure of micro-porosity whereas NMR data from core plugs is shown to quantify effective macro porosity and mobile (free) water saturation. Constituent well models, which are constructed from detailed petrophysical analyses, are integrated to build a reservoir geo-model. Spreadsheet based material balance calculations are shown to verify the geo-model against production, PVT, and pressure history of the reservoir. Finally, field-scale applications of cost-effective simulators, such as BOAST4 and BOAST-VHS, to map residual reserves, and to compare recovery efficiencies of vertical and horizontal infill wells have been demonstrated. An independent producer can use any combination of these tools to select candidate reservoirs and also to predict the performance of horizontal infill wells.

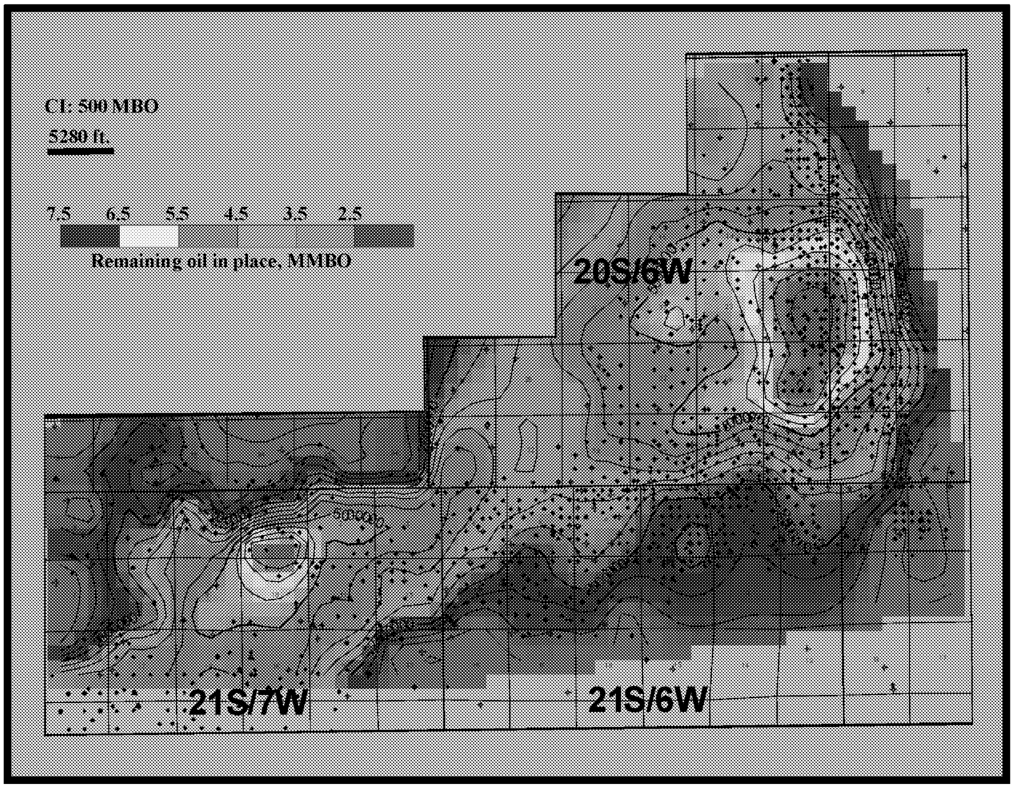

Figure 4.1 - Map showing the remaining oil in place, as of 1997 and calculated per quarter section, in the Welch-Bornholdt-Wherry fields, Rice County, Kansas.

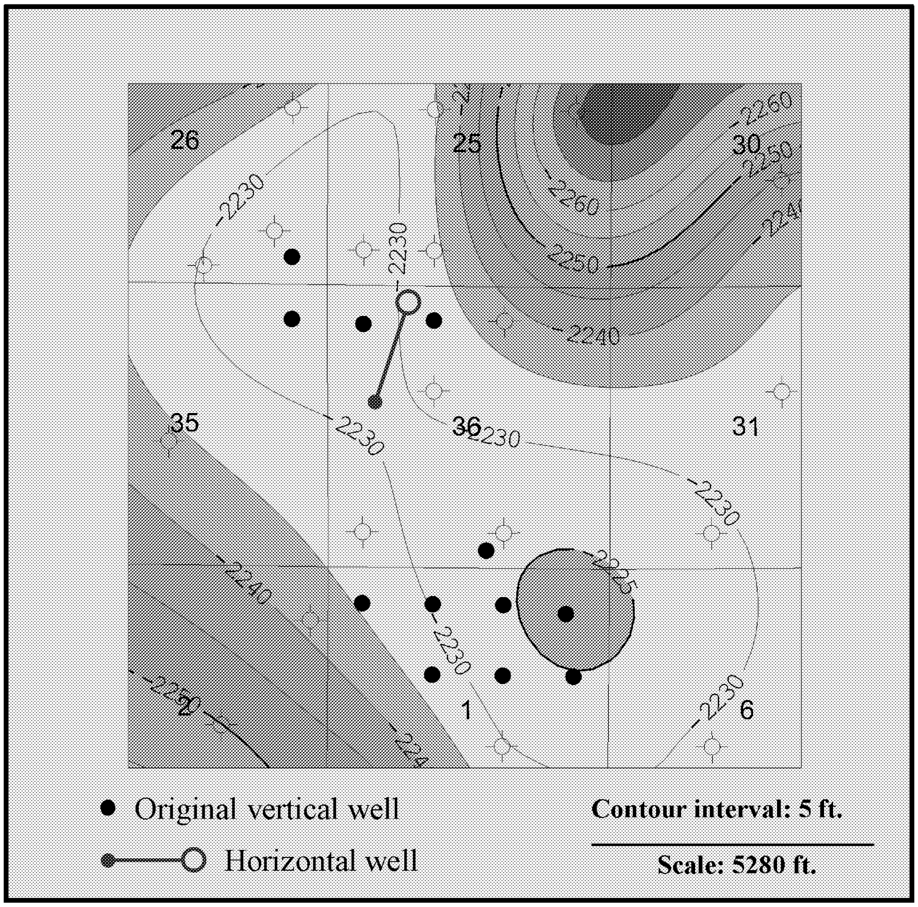

Figure 4.2 - Map showing the structure on the Mississippian horizon in Oppy South field, Hodgeman County, Kansas, along with the location of the horizontal well.

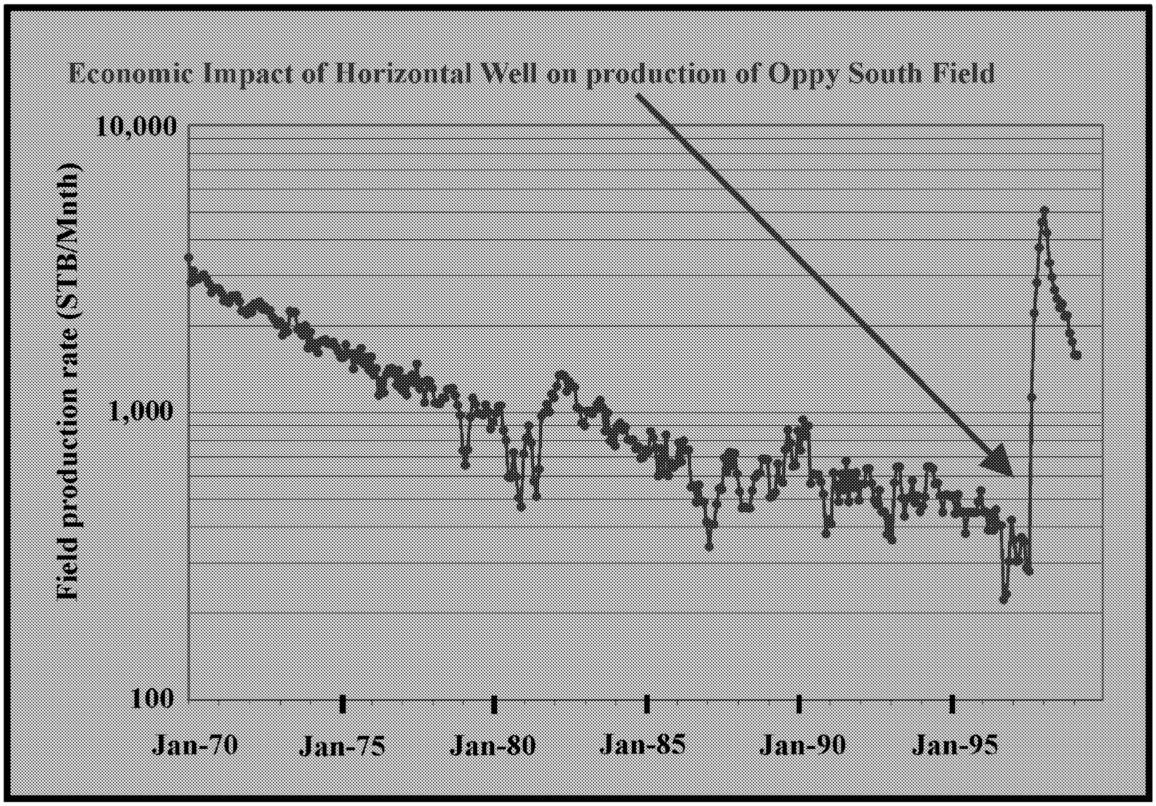

Figure 4.3 - Impact of the horizontal well on the production of the Oppy South field, Hodgeman County, Kansas.

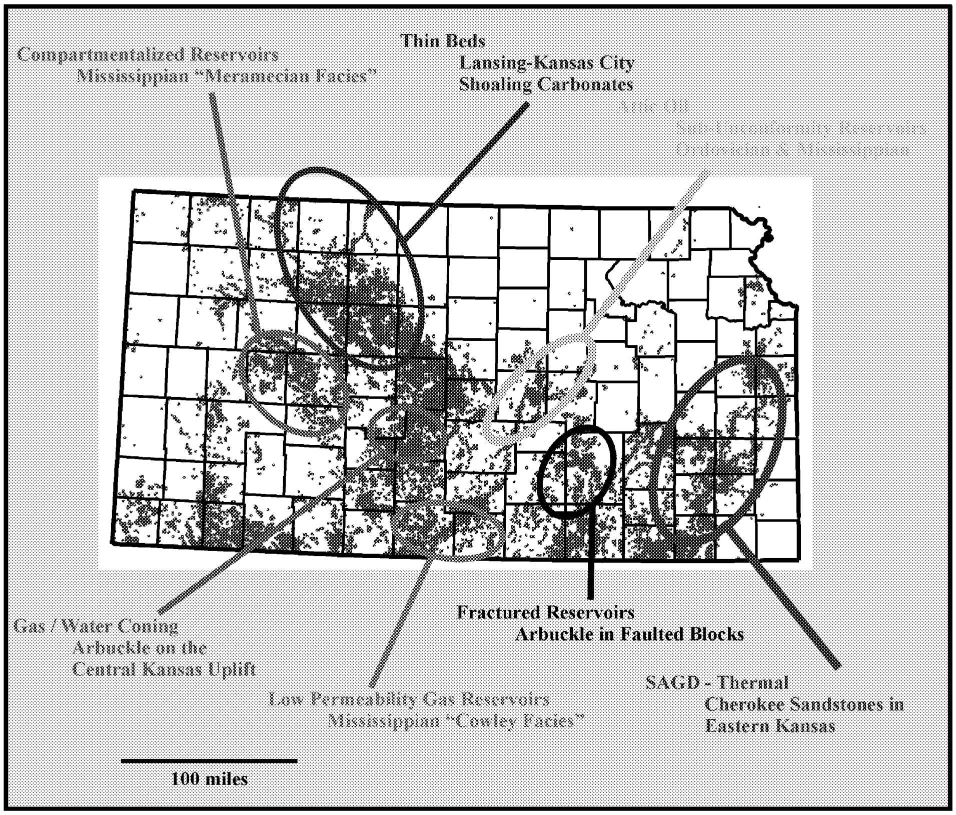

Figure 4.4 - Map showing the location of fields, in Kansas, producing from zones that have the potential for horizontal well applications.

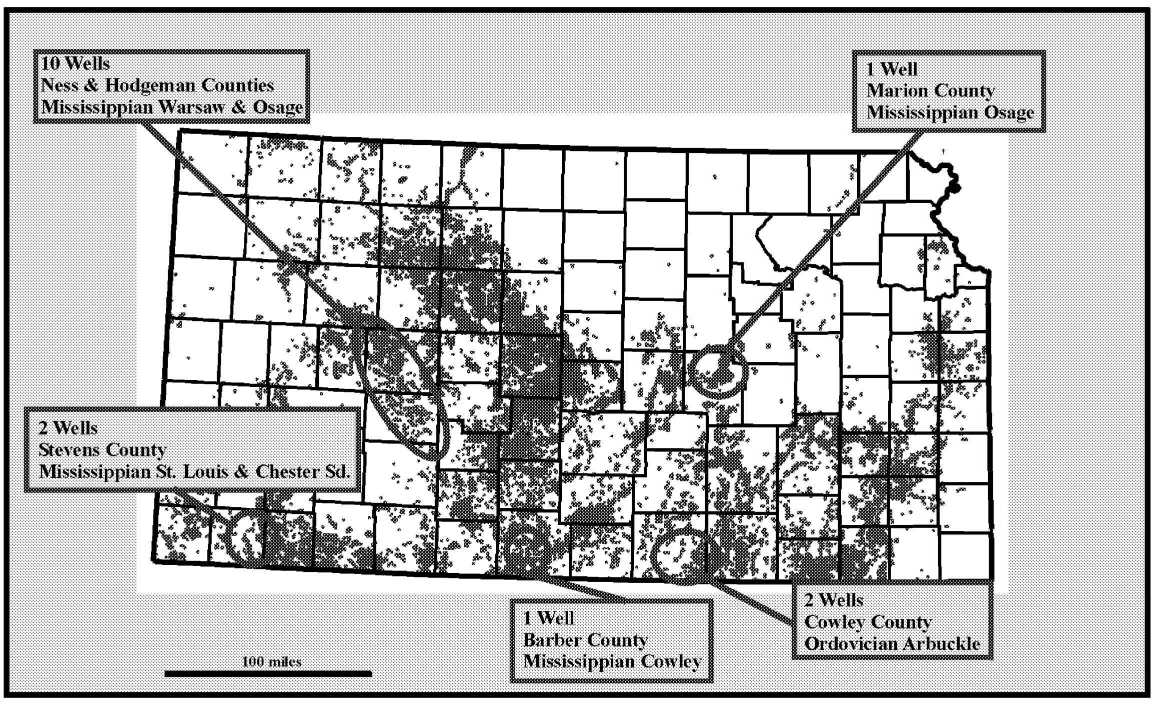

Figure 4.5 - Current status (as of 1999) of horizontal drilling activity in Kansas.

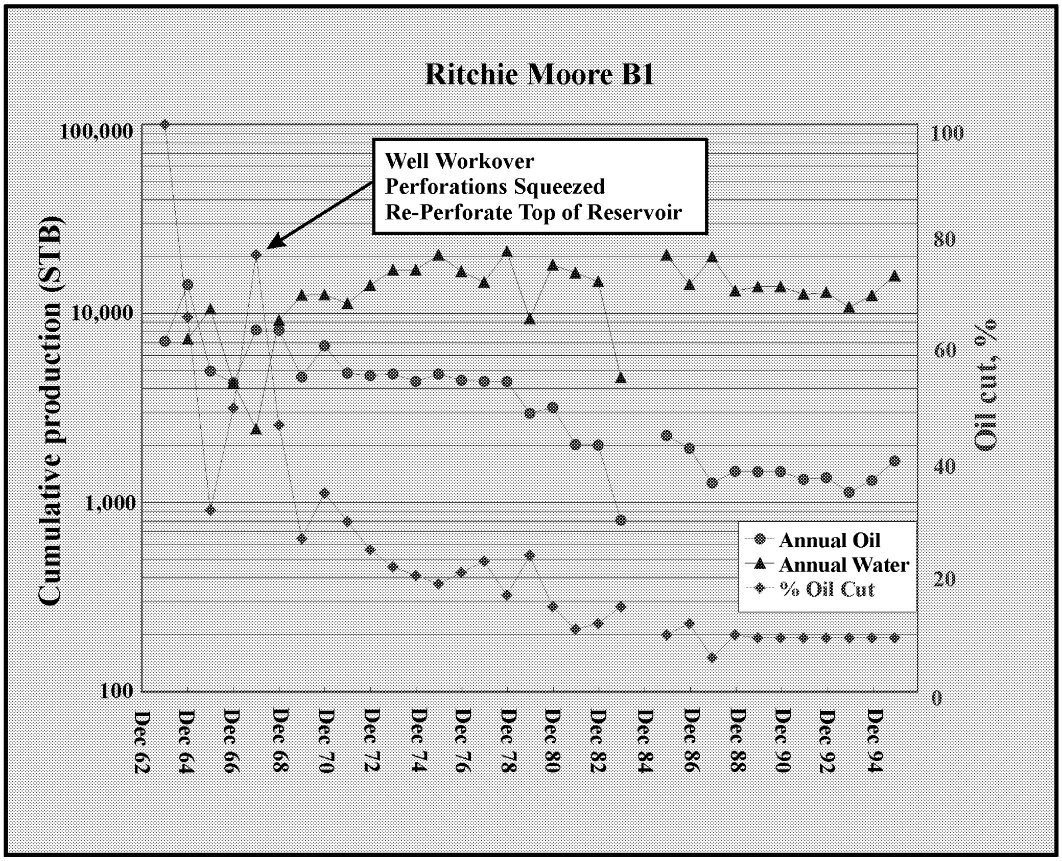

Figure 4.6 - Production profile of Ritchie Exploration No 1B Moore (located in T19S-R21W-Section 30) in Schaben field, Ness County, Kansas.

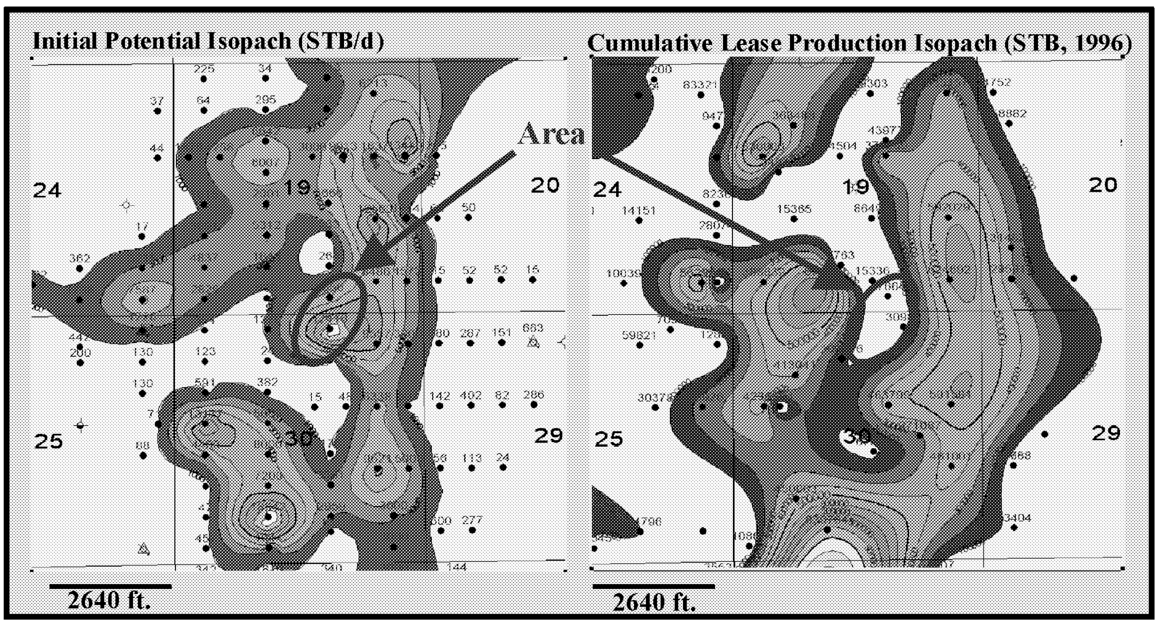

Figure 4.7 - Isopach maps of initial production and cumulative lease production (as of 1996) in an area of the Welch-Bornholdt-Wherry field, Rice County, Kansas.

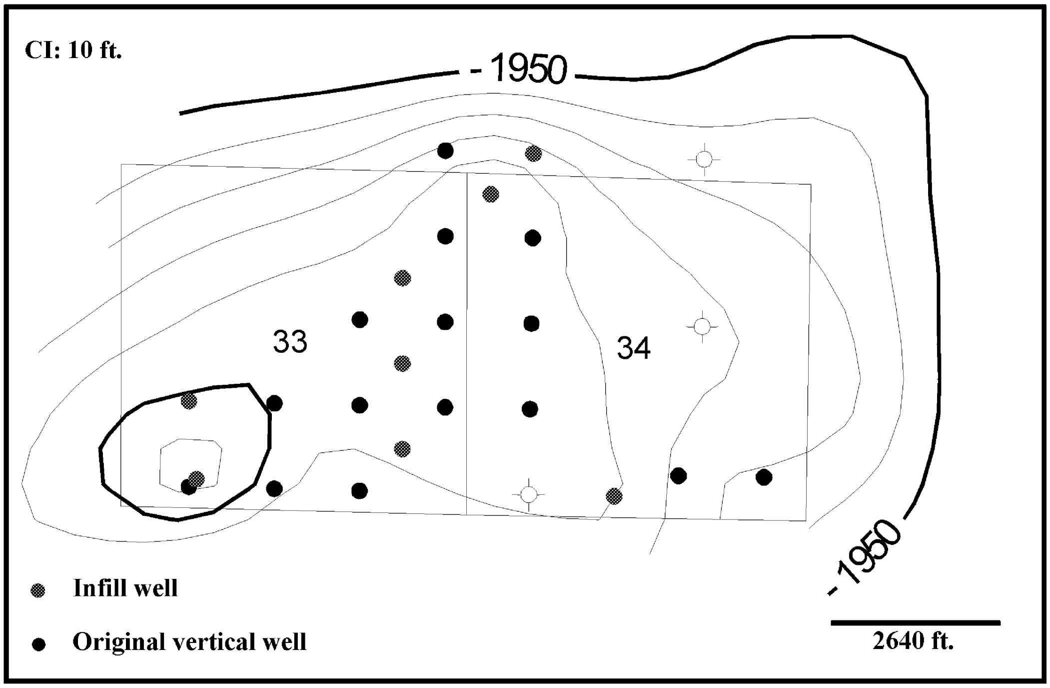

Figure 4.8 - Structure map of Mississippian top and well locations in the Aldrich field, Ness County, Kansas.

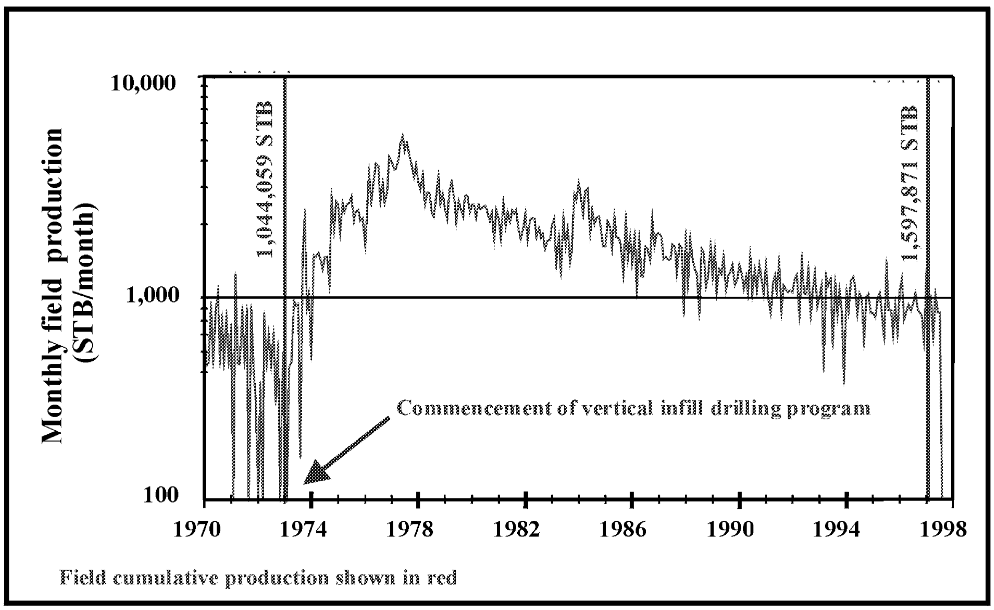

Figure 4.9 - Effect of infill drilling on monthly field production in Aldrich field, Ness County, Kansas

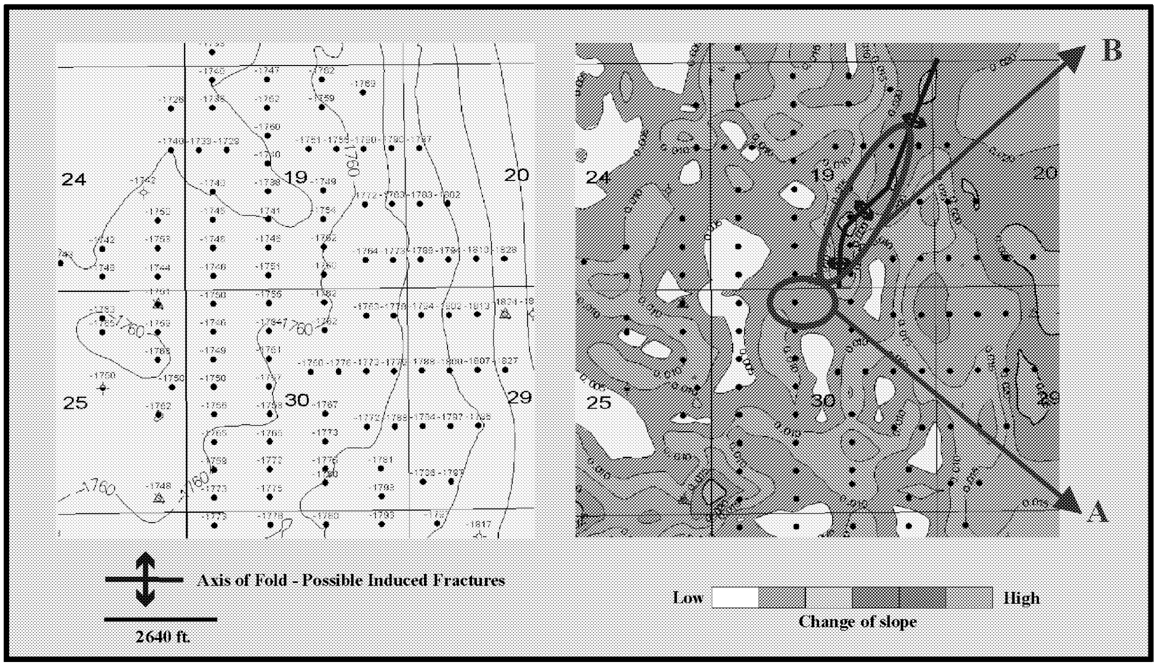

Figure 4.10 - Comparison of the structure map on Mississippian zone with the first derivative map of the structure, in the Welch-Bornholdt-Wherry field, to identify fold axis.

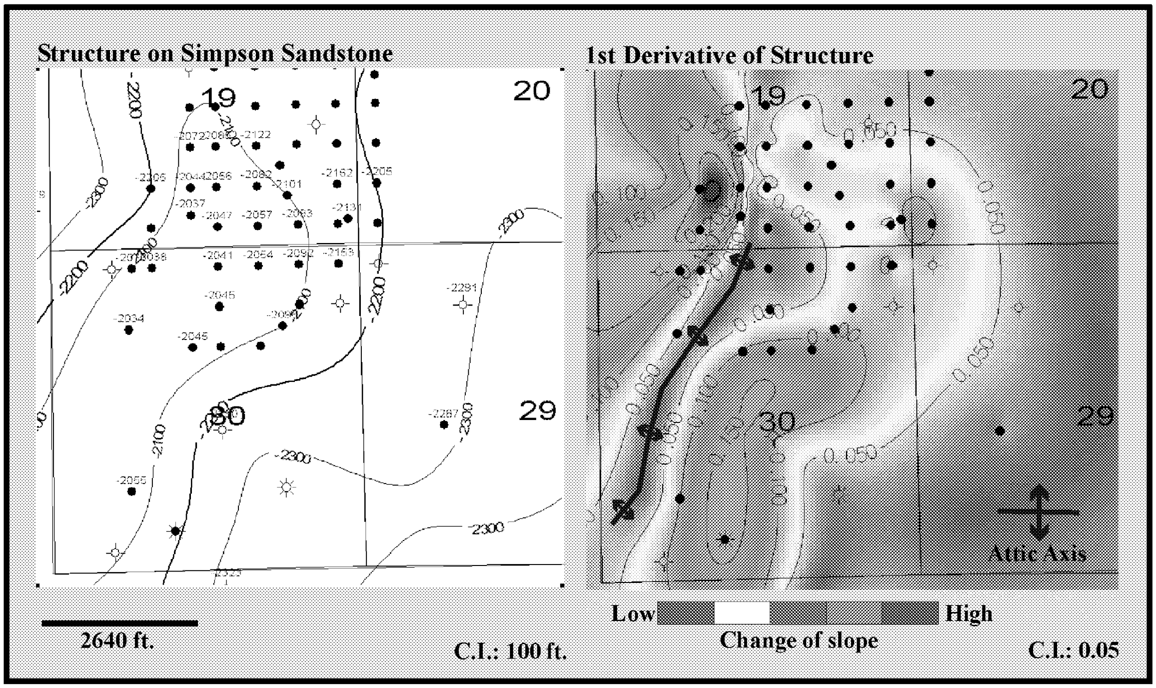

Figure 4.11 - Comparison of the structure map and the map of first derivative of the structure of Simpson sand in the Hollow-Nickel field, Harvey County, Kansas, to identify attic axis.

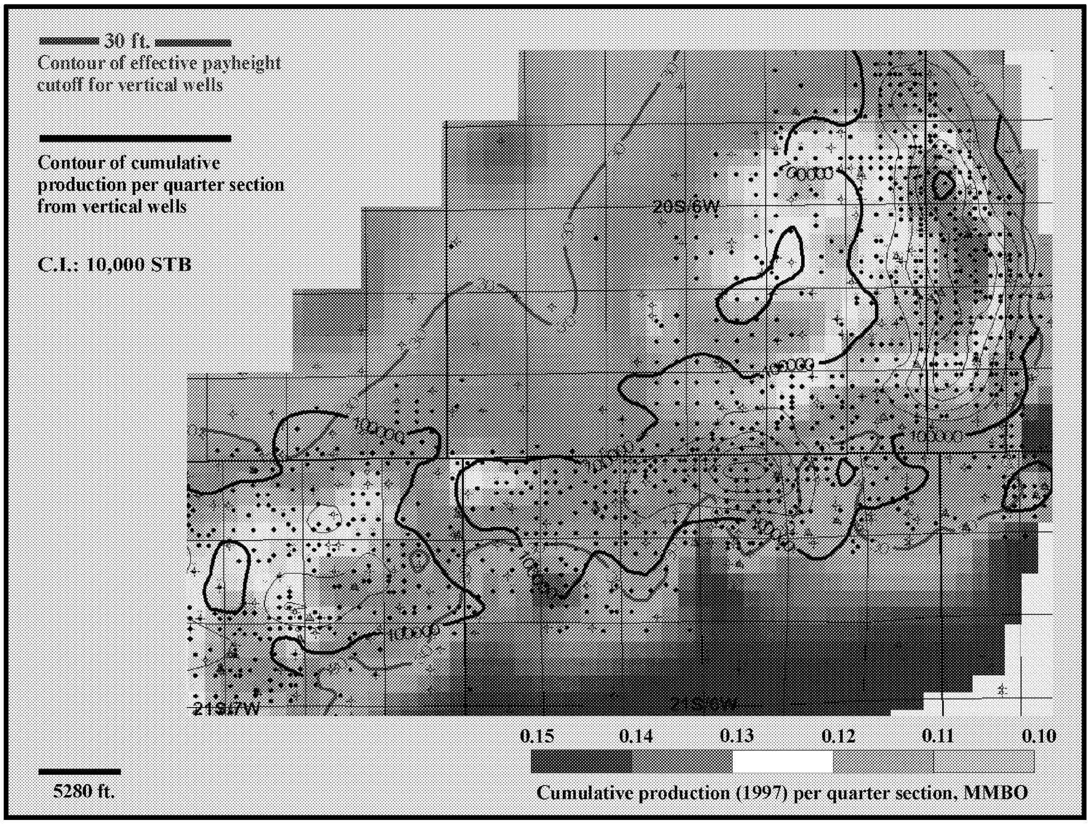

Figure 4.12 - Map showing cumulative production of oil, as of 1997 and calculated per quarter section, in the Welch-Bornholdt-Wherry field, Rice County, Kansas. The black contour lines represent the cumulative production per quarter section while the red contours delineate the borders of the pay cutoff (30 feet) in the producing region of the field.

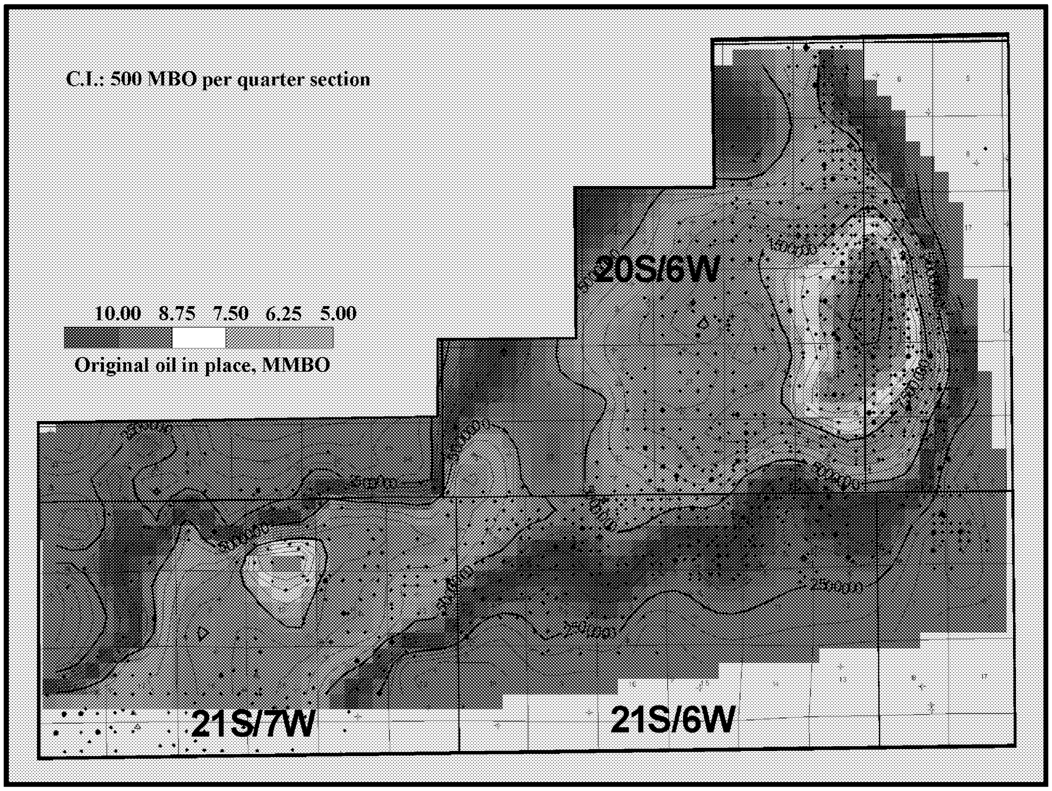

Figure 4.13 - Map showing the distribution of original oil in place in the Welch-Bornholdt-Wherry field, Rice County, Kansas. Volumetric calculations were carried out using a type-well to represent a quarter section.

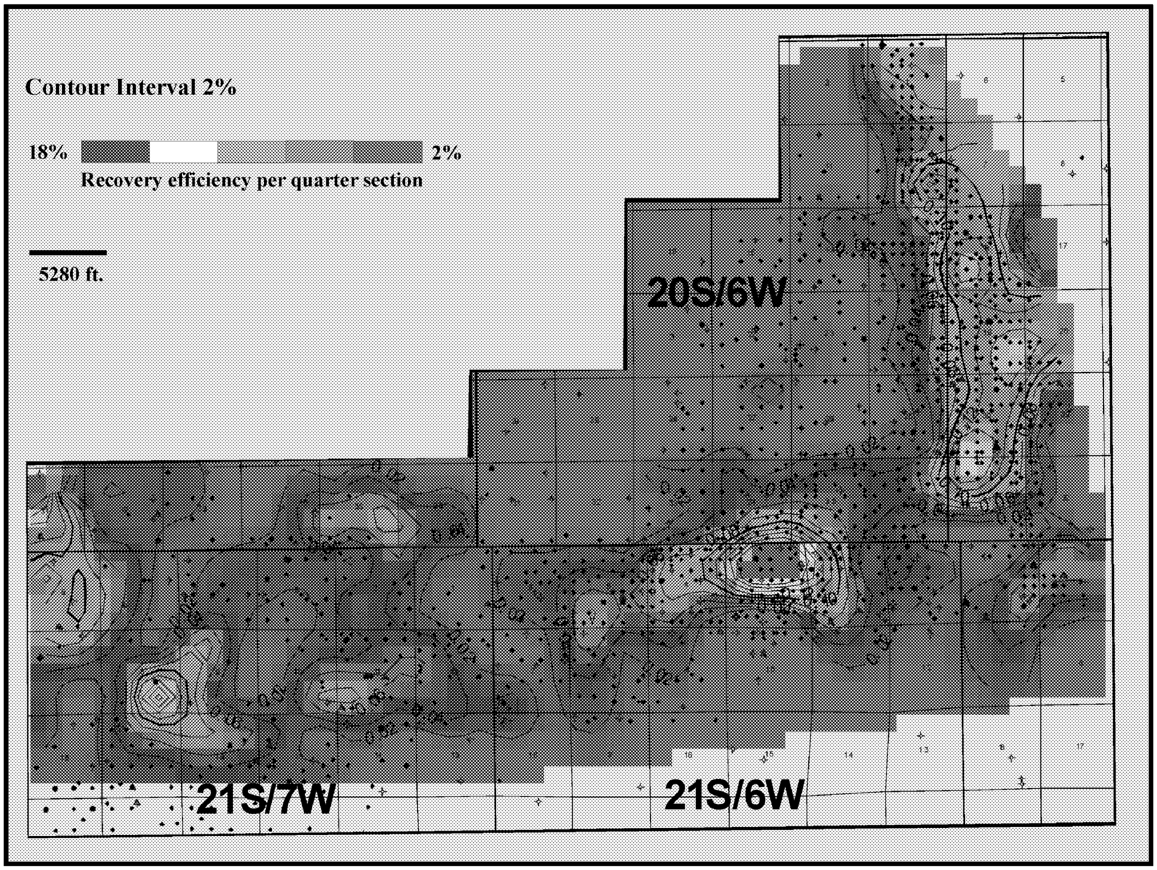

Figure 4.14 - Map of recovery efficiency, as of 1997 and calculated per quarter section, in the Welch-Bornholdt-Wherry field, Rice County, Kansas.

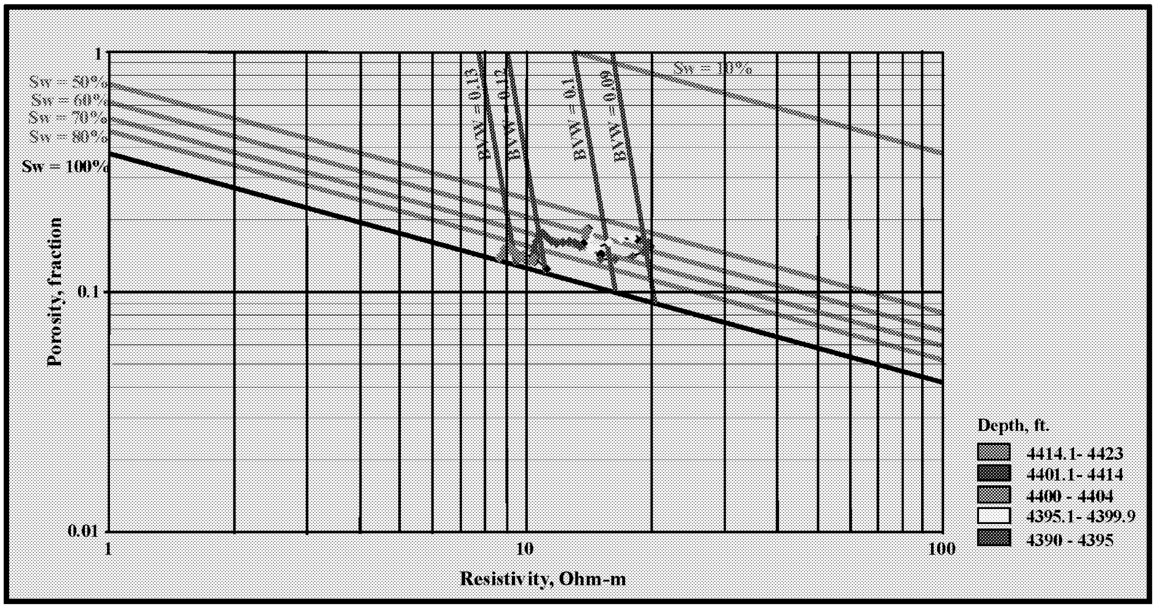

Figure 4.15 - Super Pickett crossplot of Mississippian zone in Ritchie Exploration No 2P Lyle-Schaben well located in Schaben field, Ness County, Kansas. The Archie constants used are a = 1, m = 2.1, n = 2 and R_w = 0.13. The perforated interval is 4400 to 4404 ft. and the initial production recorded from this zone was 85 BOPD and 132 BWPD.

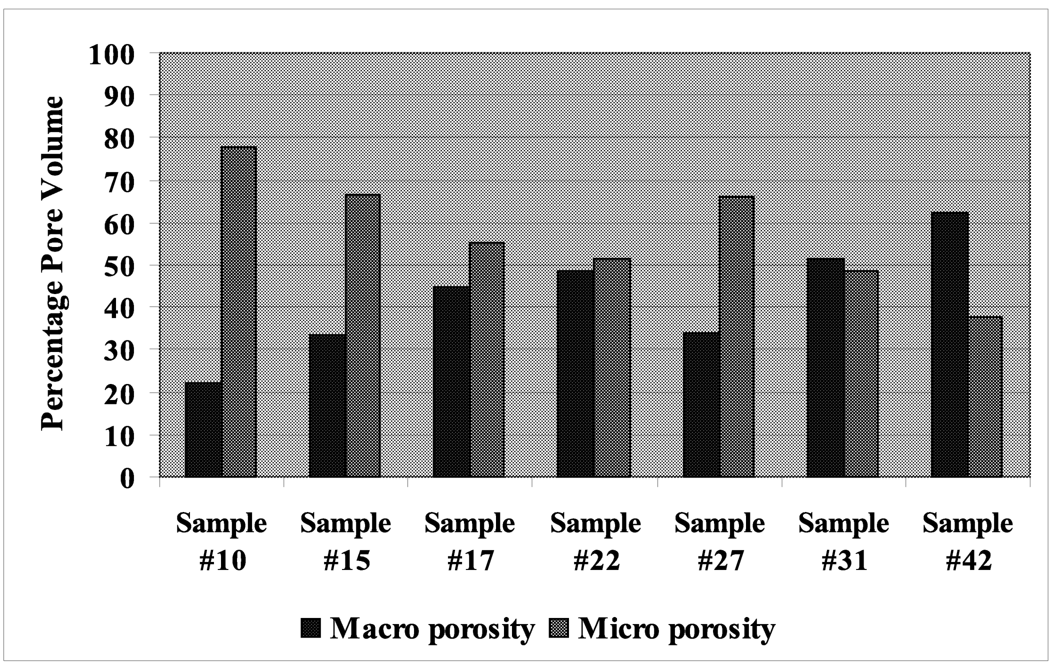

Figure 4.16 - Plot comparing percentage pore volume occupied by micro (pore throat size equal or less than 5 micron) and macro pores (pore throat size greater than 5 microns) in core plugs obtained from Ritchie Exploration No 2P Lyle-Schaben well located in Schaben field, Ness County, Kansas. The pore size distribution was generated from capillary pressure data.

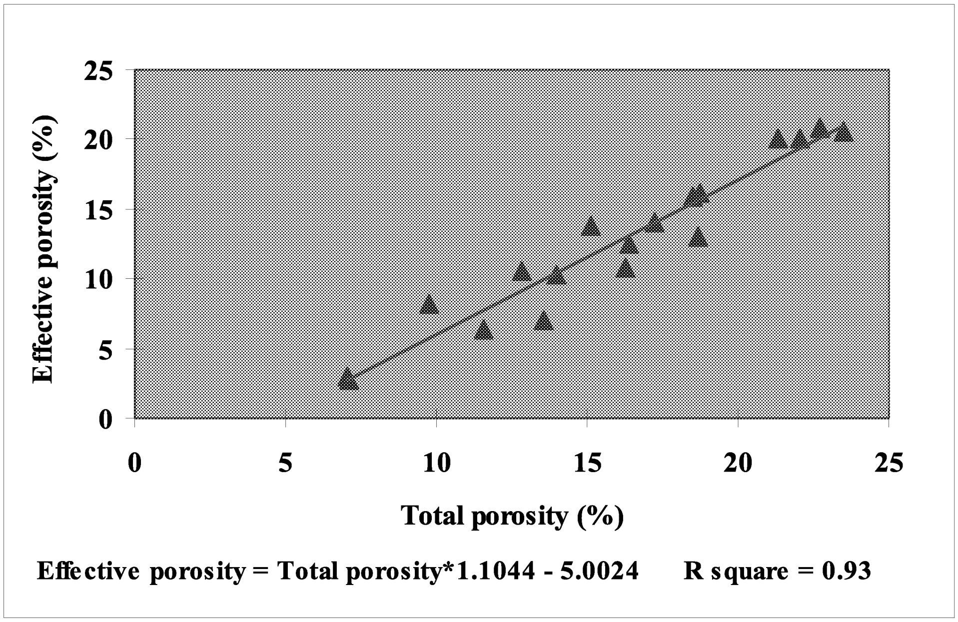

Figure 4.17 - Plot of effective versus total porosity constructed from NMR measurements on core plugs obtained from wells in Schaben field, Ness County, Kansas.

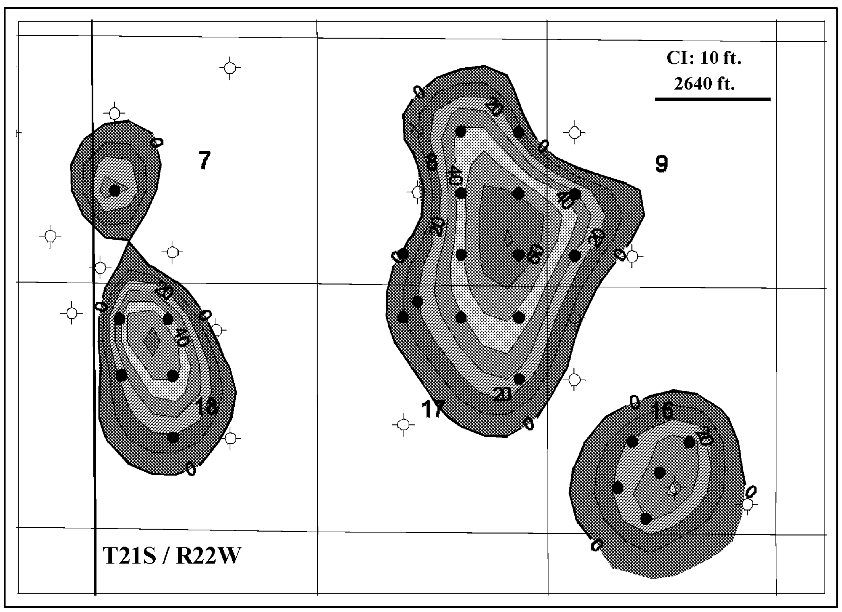

Figure 4.18 - Payzone isopach maps of Wieland and Wieland West fields, Hodgeman County, Kansas.

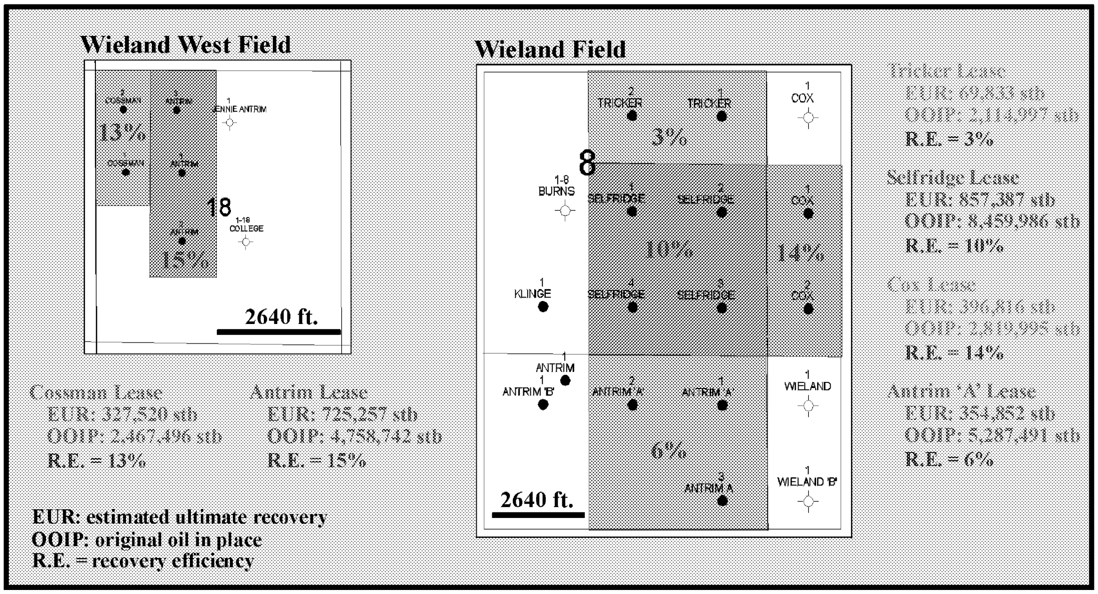

Figure 4.19 - Comparison of recovery efficiency (R.E.) between adjacent leases in Wieland and Wieland West fields, Hodgeman County, Kansas.

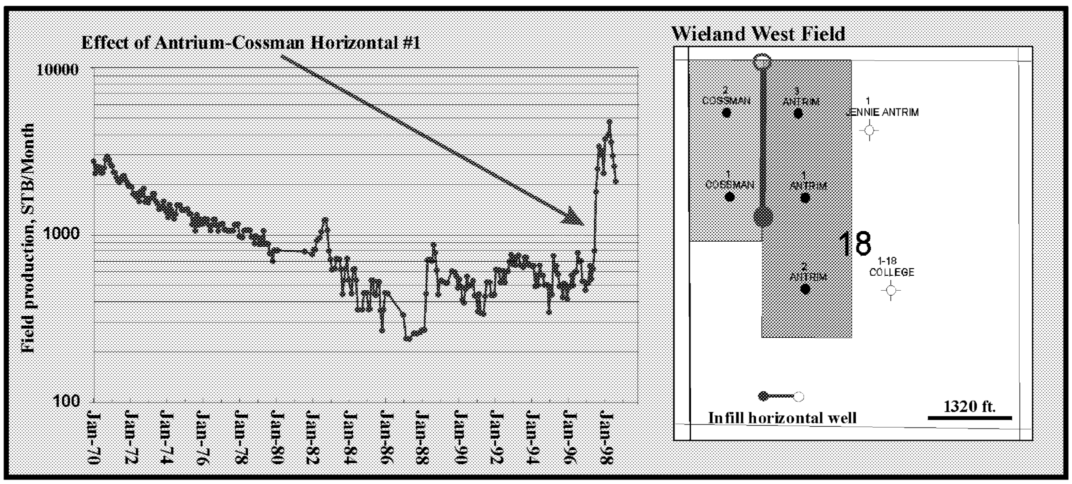

Figure 4.20 - Effect of horizontal infill well on the production of Wieland West field, Hodgeman County, Kansas. Also, the location of the infill well is shown relative to the original vertical wells.

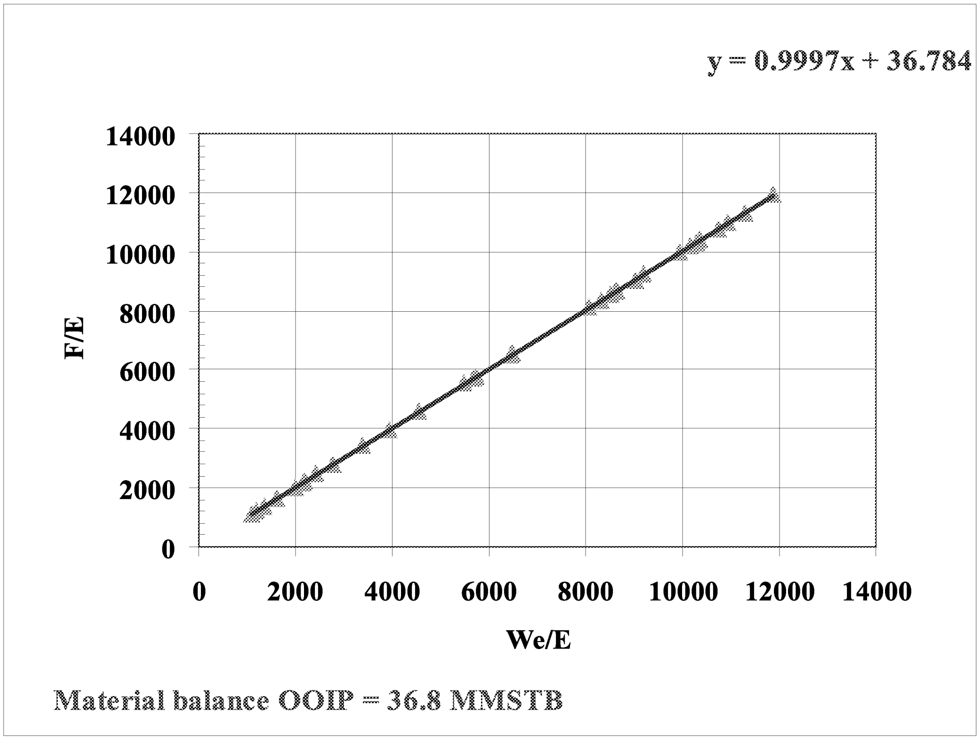

Figure 4.21 - Results of material-balance calculation showing the plot of F/E versus W_e/E for Schaben field, Ness County, Kansas. F denotes the underground withdrawal of fluids from the reservoir, and W_e stands for the reservoir volume of water that influxes from the aquifer. E represents the sum of the change in volume of the oil and the dissolved gas and the change in volume due to expansion of connate water and reduction in pore volume.

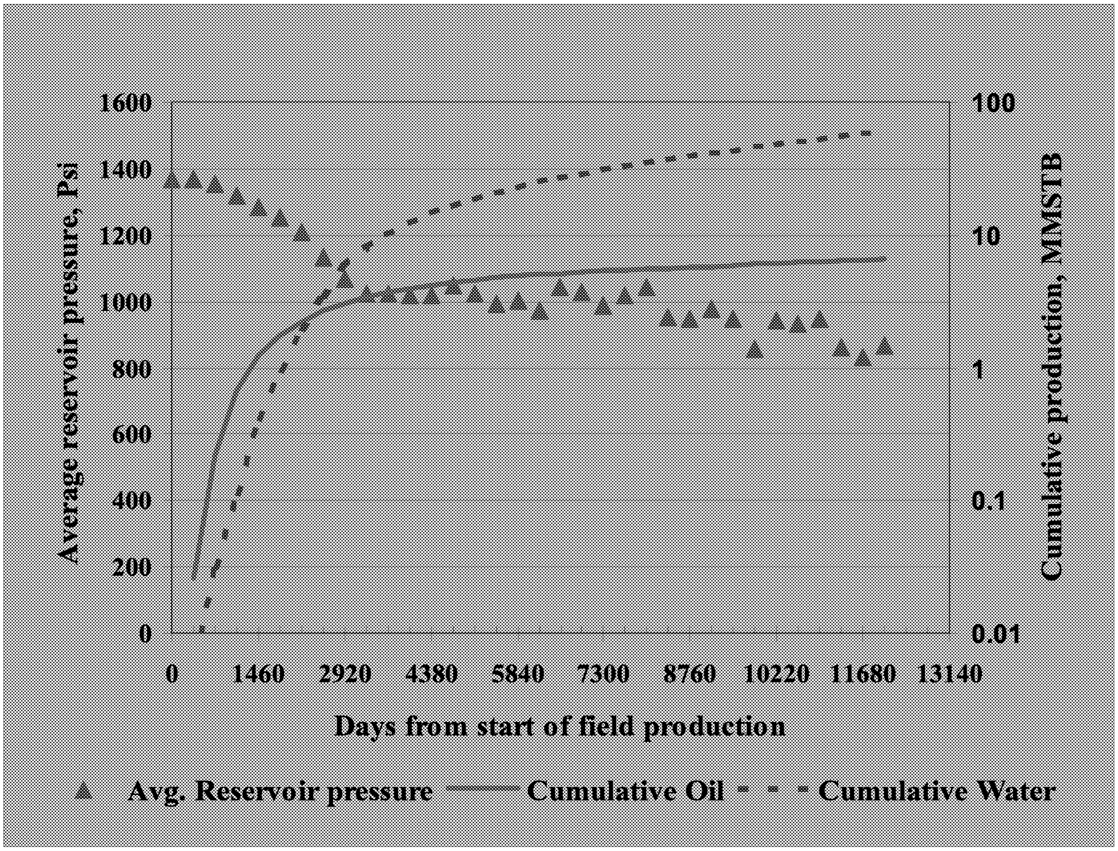

Figure 4.22 - Average reservoir pressure profile, obtained from material-balance calculations, over the producing life of Schaben field, Ness County, Kansas.

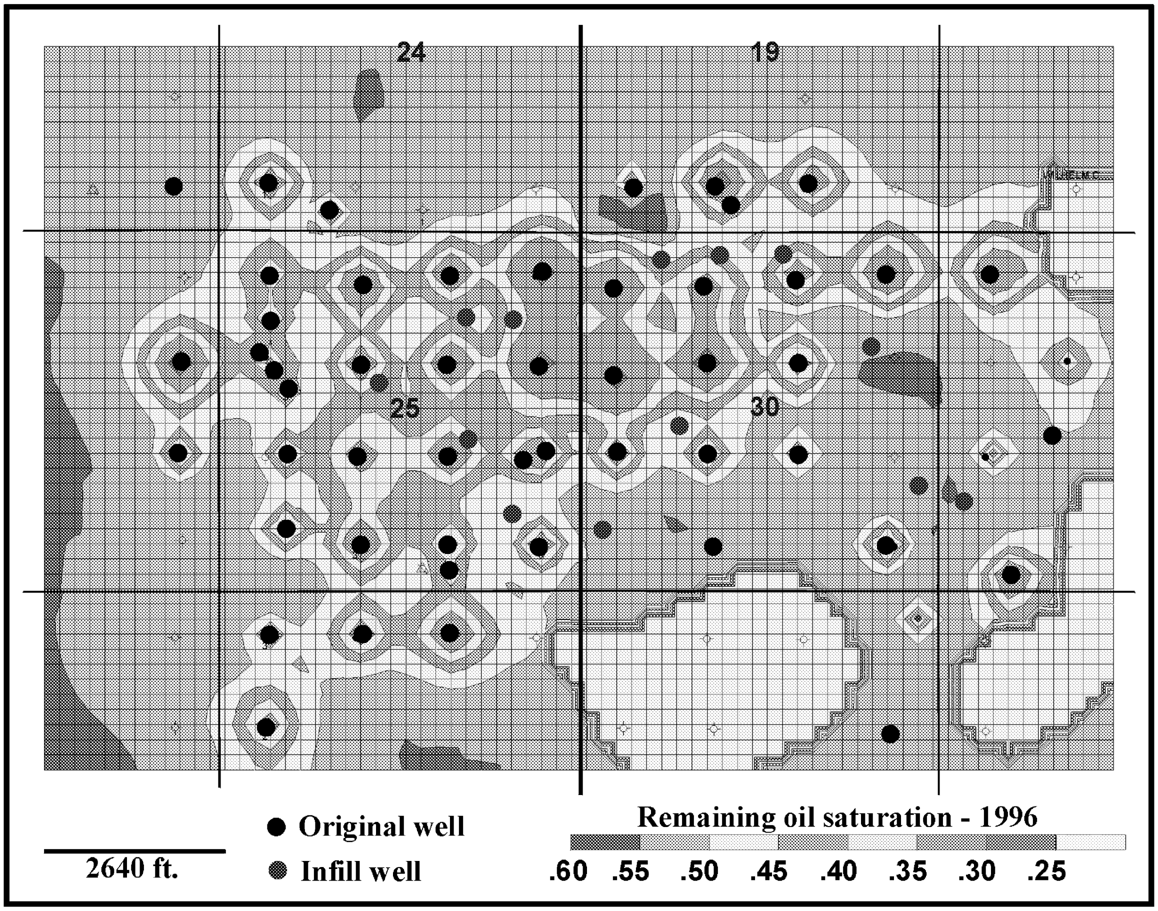

Figure 4.23 - Map showing remaining oil-saturation (as of December 1996) in Schaben field, Ness County, Kansas, and developed from the simulation results of BOAST4. Infill wells drilled by the operator after the conclusion of this study are shown red dots whereas the black dots represent the location of the original wells in the field.

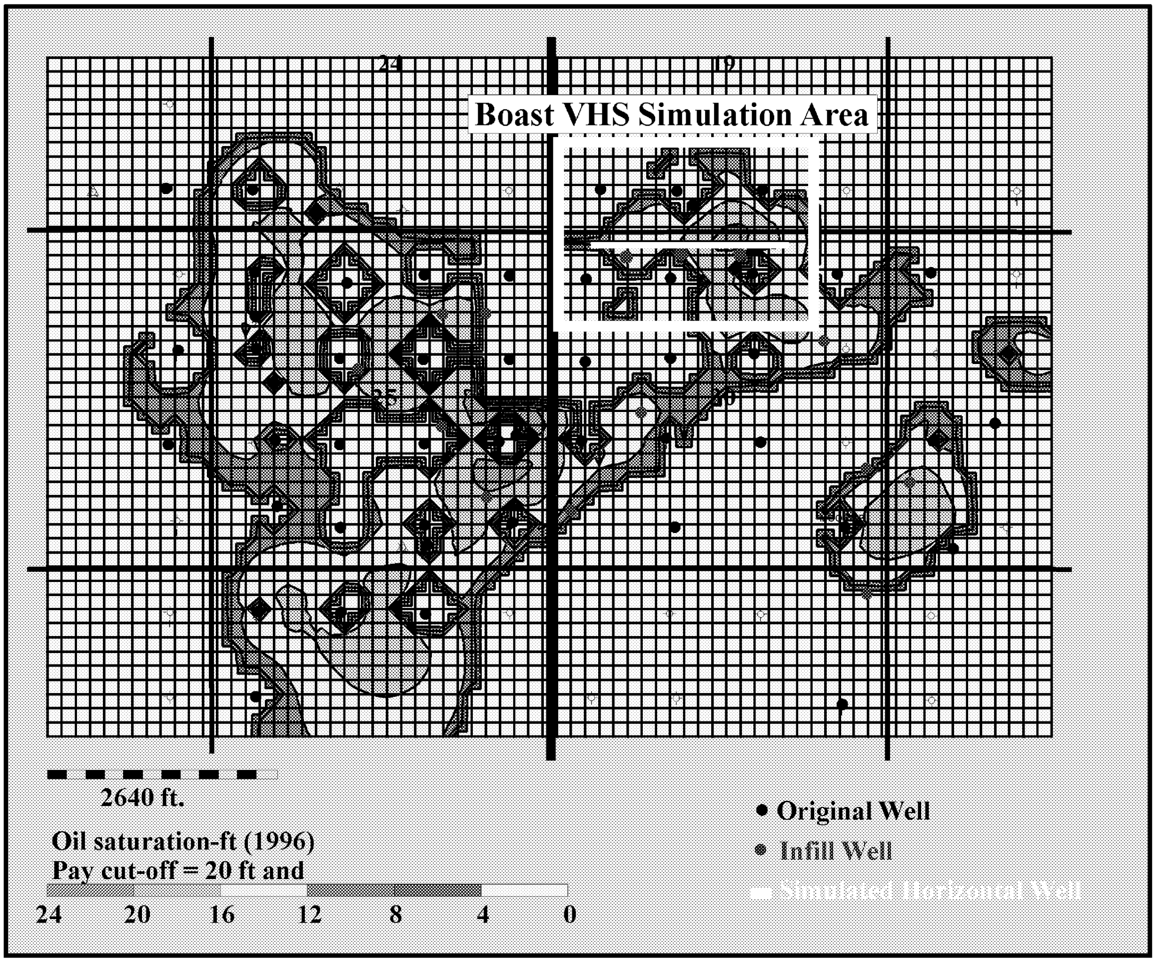

Figure 4.24 - Saturation-feet map of Schaben field, December 1996, developed from results of BOAST4 simulation and using pay cut-off of 20 feet and an oil saturation cut-off of 40%. The boxed area was further studied in BOAST-VHS to compare recoveries from vertical and horizontal infill wells.

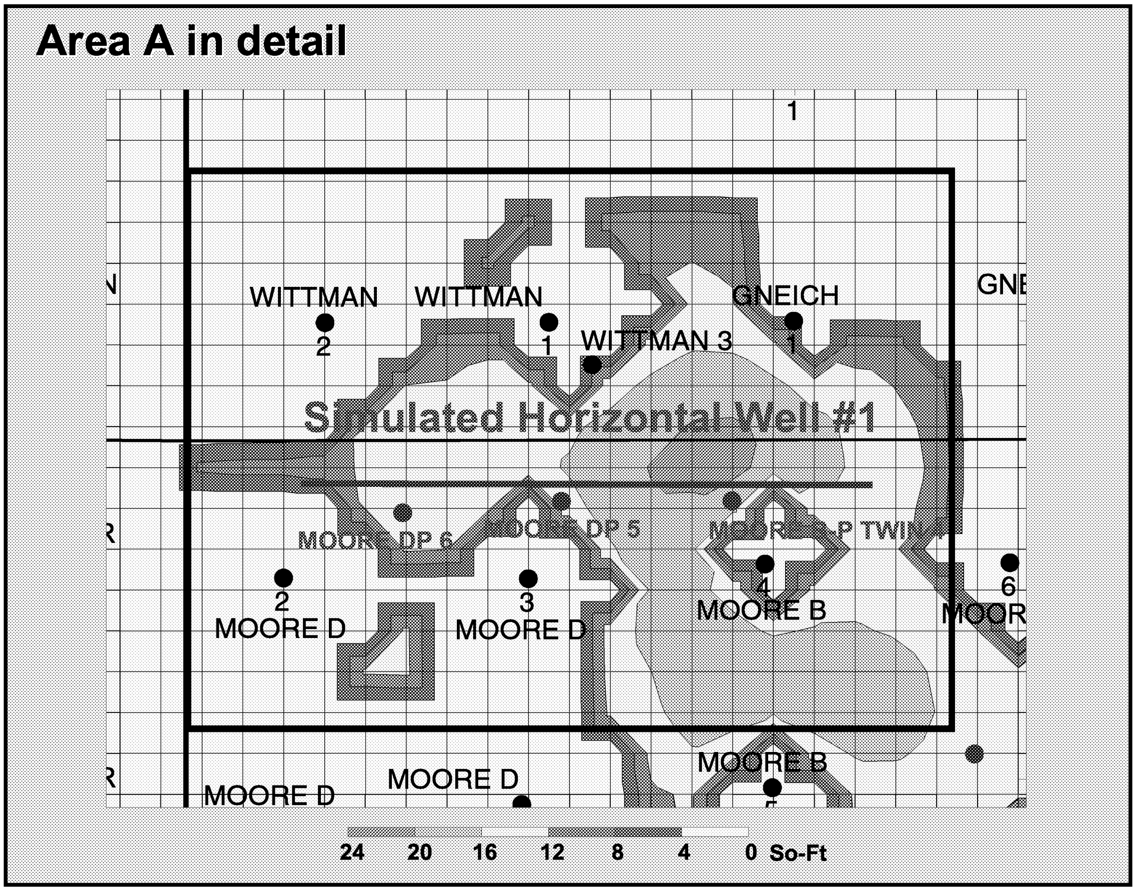

Figure 4.25 - Detail map of well locations in Area A (Figure 4.23) of Schaben field, Ness County, Kansas. The red line well shows the location of the simulated horizontal infill well, whereas the red dots show the location of the 3 vertical infill wells. The black dots show the location of the original wells in this study area.

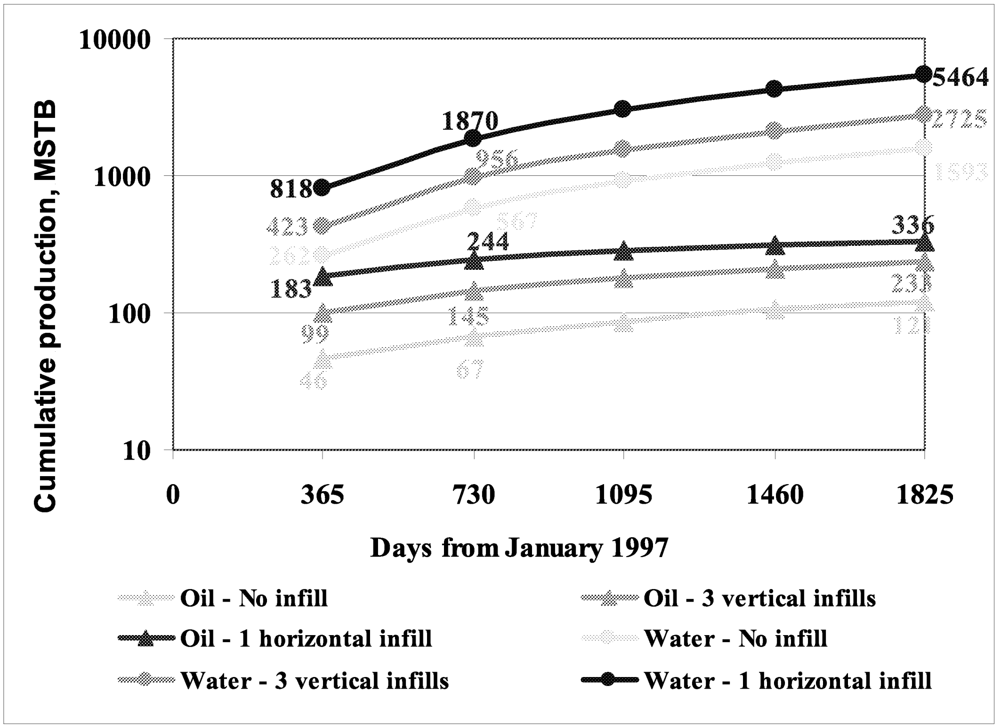

Figure 4.26 - Plot of BOAST-VHS results comparing the cumulative performance of 3 vertical infill wells with one horizontal infill well in Area A of Schaben field, Ness County, Kansas. The infill wells were simulated to start production from January 1997 and produced for 5 years.

5.0 Ness City North Field -Horizontal Well

Based on the results of the reservoir characterization and simulation, the Mull Ummel #4-H horizontal well was drilled within the Mississippian reservoir at the Ness City North Field. The well has a horizontal displacement of 628 feet and a lateral length of 533 feet within the reservoir interval. The gamma ray logging while drilling (LWD) tool shows numerous near vertical shale intervals along the lateral length of the well. These vertical shale intervals reduced effective productive length and would lead to significant stability problems within the openhole-completed lateral. Effective productive (clean) length in the lateral is approximately 440 feet.

The vertical shale intervals appear to be solution enhanced fractures extending down from the karst erosional surface that marks the top of the Mississippian reservoir. Based on cuttings and MWD gamma ray log, the vertical shale intervals are filled with lithologies similar to the overlying Pennsylvanian Cherokee Shale. The vertical shale intervals vary in width from a few inches to more than 6 feet. It is believe that the in addition to stability problems within the openhole-completed lateral, the vertical shale intervals could form vertical barriers to fluid flow. These barriers may be an explanation to the strong reservoir heterogeneity and low well recovery efficiencies observed in Mississippian reservoirs of Kansas.

Daily production fluid rates for the Mull Ummel #4-H horizontal well during the first month averaged 54 barrels oil and 50 barrels of water (Figure 5.2). Fluid levels recorded in the well averaged over a period of one month show a bottom hole pressure (P_{wf}) of about 650 psi. The average oil and water production rates recorded at the well for the first month were within the predicted ranges and were significantly higher than traditional vertical infill wells in similar Mississippian reservoirs. After two months of stable fluid production, well rates rapidly decreased to near zero (1 BOPD, 3BWPD). It appeared and was confirmed during subsequent remedial workover operations that the vertical shale intervals were unstable and collapsed into the lateral. The remedial coiled tubing operations on the Ummel #4H were unsuccessful in cleaning out the lateral and restoring production. The initial production rates and the lessons learned in reentry, and drilling of a horizontal lateral in the Mississippian reservoir at Ness City North hold significant promise for similar applications by independent producers in Kansas and the Midcontinent.

Well Operations

The original vertical well, the Mull Drilling Co. Ummel #4, was drilled as an infill well in the Ness City North Field during July 1995. The well was plugged and abandoned in April 1996 after extensive testing. The well produced non-economic quantities of oil with large quantities of water. The original perforations in the vertical well were located from 4,278 to 4,300 feet (subsea -2,201 to -2023 feet), approximately 12 feet above the mapped oil-water contact in the reservoir (Figure 5.3).

Reentry operations for the Mull Drilling Co. Ummel #4H began in April 2000 (Appendix 3 contains the daily drilling report, and Appendix 4 the daily completion report). Operations required 348.5 hours of rig time at a total cost was $248,200 (Table 5.1). The reentry operations are outlined below:

1) Cement plugs were drilled out and a cast iron bridge plug had been set at 4,136 feet (Figure 5.4). With 2,925 feet of cement in the wellbore, operations required significantly longer time than expected (82 hours) and resulted in a cost of $26,400.
2) A window was milled in the 5-1/2 inch casing from 4,115 to 4,129 feet, and set an oriented whipstock at 4,117 to 4,132 feet (Figure 5.5). Milling of the casing and setting of the whipstock required 84 hours and resulted in incremental costs of $24,200. The major problem encountered at this stage of operations was setting and confirming the orientation of the whipstock. A drilling gyroscope was used to confirm orientation of whipstock.
3) Drilling a 4-3/4" diameter wellbore through the build section required 120 hours of rig time and 28 hours of drilling time (Figure 5.6). A problem arose when

switching from the drilling gyroscope to the standard measurement while drilling package (MWD), plus gamma ray LWD. The mud pumps were upgraded to triplex pumps to successfully transmit MWD and LWD data to the surface. Also as the inclination increased in the overlying Cherokee Shale wellbore problems developed (e.g., caving and tight spots), which required that the mud weight to be increased. The incremental costs for drilling the curve were $135,100. The build rate for the curve was 42.5° per 100 feet and the wellbore was landed five feet below the top of the reservoir interval at 75.0 ° and building to 90 °.

4) In comparison with the build section, the lateral section of the wellbore was drilled with little or no problems (Figure 5.7). Operations in the lateral section required 52 hours of rig time and 33 hours of drilling time. The incremental costs for drilling the lateral were $44,300. The lateral had an azimuth of approximately west to east (N94.6 ° S) and an inclination of approximately 90 °. At the end of the lateral section inclination was increased slightly downward (86.8 °). The lateral section has a horizontal displacement of 628 feet and a lateral length of 533 feet within the reservoir interval. The gamma ray LWD tool shows numerous near vertical shale intervals along the lateral length of the well. Effective productive (clean) length is approximately 440 feet.
5) A 3-1/2", flush joint liner was run through the curve from 4073 to 4400 total feet measured length (Figure 5.8). The lateral was completed open hole from 4400-4828 feet total measured length. No stimulation work was performed on the lateral. Running the liner required 10 hours and resulted in incremental costs of $10,200. Running the liner was delayed by having trouble working the liner through the curve section (3.25 hours).
6) A 2-1/2 inches x 2 inches x 16 feet RWB pump was run and anchored at 4003 (Figure 5.9). The pumping unit was run at 4.5 strokes per minute with a 74-inch stroke length.

Work Performed	Rig Hours	%	Costs	%
Drilling out Cement & Setting CIBP	82.0	23.5	$26.4 M	10.6
Setting Whipstock & Milling Casing	84.5	24.2	$24.2 M	9.8
Drilling Curve & Horizontal Section	172.0	49.4	$178.0 M	71.7
(Time & Cost in Active Drilling)	(61)	(17.5)	($116.5 M)	(46.9)
Setting Liner Through the Curve	10.0	2.9	$19.6 M	7.9
Totals	348.5	100	$ 248.2 M	100

Table 5.1 – Summary of operations and costs for reentry operations for the Mull Drilling Co. Ummel #4H

The total cost for the Mull Drilling Co. Ummel #4H were higher than expected because of problems inherent to re-entering an existing wellbore (i.e., drilling out the cement, setting and orienting the whipstock, and some the hole problems). Drilling a new well and setting casing through the curve might minimize borehole problems. For future horizontal drilling work, an operator should compare the cost and risks of drilling a new well to the cost of re-entering an existing well. The reentry costs for the Ummel #4H were increased for the following general and specific reasons:

1. Shortage and inexperience of rig hands. On a number of occasions work had to wait on hands.
2. Took longer to drill out old cement than expected.
3. A bad joint of drill collar in which the ID was too narrow for the gyro tool to get through resulted in an extra round trip.
4. Did not know if the whipstock was set resulted in two extra round trips to verify that the whipstock was set and oriented correctly.
5. Could not get the gyro tool through the Kelly required cutting the wireline and re-heading
6. Rig pumps created too much interference noise to read MWD required renting a triplex pump. This activity resulted in several hours of lost time to transport and set up pump. In future, directional company should be more specific about pump requirements for MWD.
7. Problems in stability of the build section as the curve was initially drilled with produced water. Eventually the operator had to mud up and condition the hole.

8. Had difficulty running the liner through the curve section.

The well was placed on pump operating at 4.5 to 4.75 strokes per minute. Daily production fluid rates for the Mull Ummel #4-H horizontal well during the first month averaged 54 barrels oil and 50 barrels of water (Figure 5.2, Appendix 4). Fluid levels recorded in the well averaged over a period of one month show a bottom hole pressure (P_{wf}) of approximately 650 psi. After two months fluid rates for both oil and water began to rapidly decrease. It appeared and was confirmed during subsequent remedial workover operations that the vertical shale intervals were unstable and began to collapse into the lateral resulting in partial blockage after two months of production (Figure 5.10). By December 2000 fluid rates had decreased to near zero (1 BOPD, 3BWPD). It appeared that the vertical shale intervals had collapsed completely blocked the lateral (Figure 5.11).

In January 2001, coiled tubing and a jet nozzle with foam unit were used to attempt to cleanout blockages in the openhole lateral (Appendix 5, Figure 5.12). Blockages of shale were encountered where MWD gamma ray log indicated vertical shale intervals. Shale continued to collapse after jetting. In a more aggressive attempt to clean out the hole a mud motor and bit were lost in the lateral at 4600 feet measured depth. An attempt was made to run a 2-3/8 inch liner into the lateral. The liner could be run only to 4,230 feet measured depth before blockages in the lateral were encountered (Figure 5.13). The remedial coiled tubing operations on the Ummel #4H were unsuccessful in cleaning out the lateral and economic production rates.

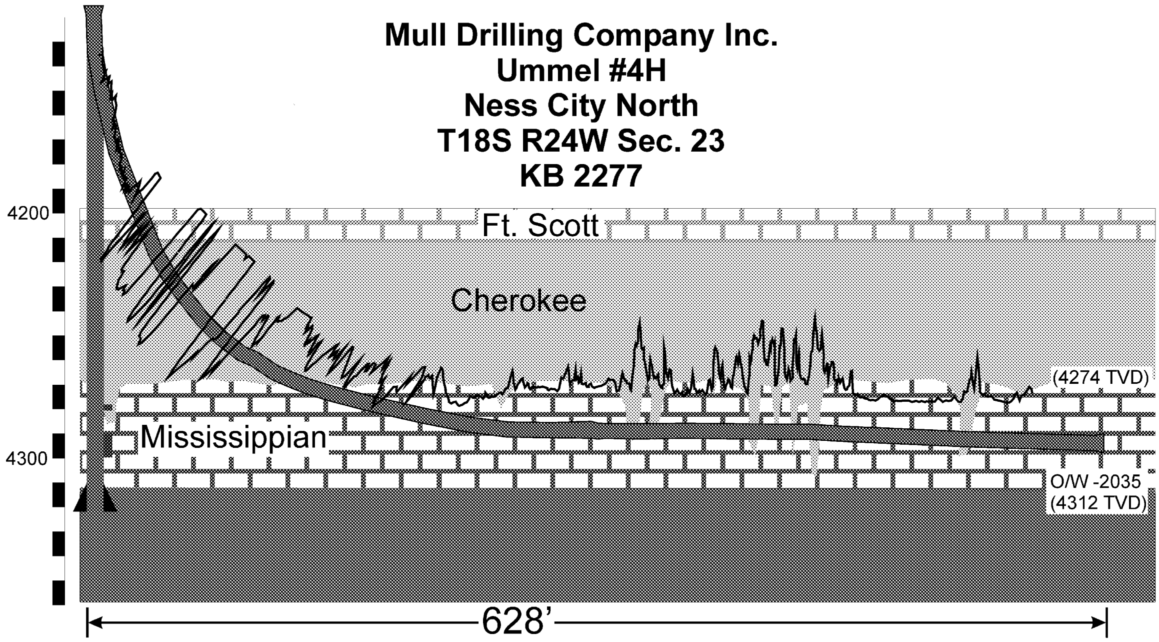

Figure 5.1 – Lateral well plan for the Mull Ummel #4-H horizontal well drilled within the Mississippian formation at the Ness City North Field. The well has a horizontal displacement of 628 feet and a lateral length of 533 feet within the reservoir interval. Based on the gamma ray LWD log, shale intervals are evident along the lateral length of the well.

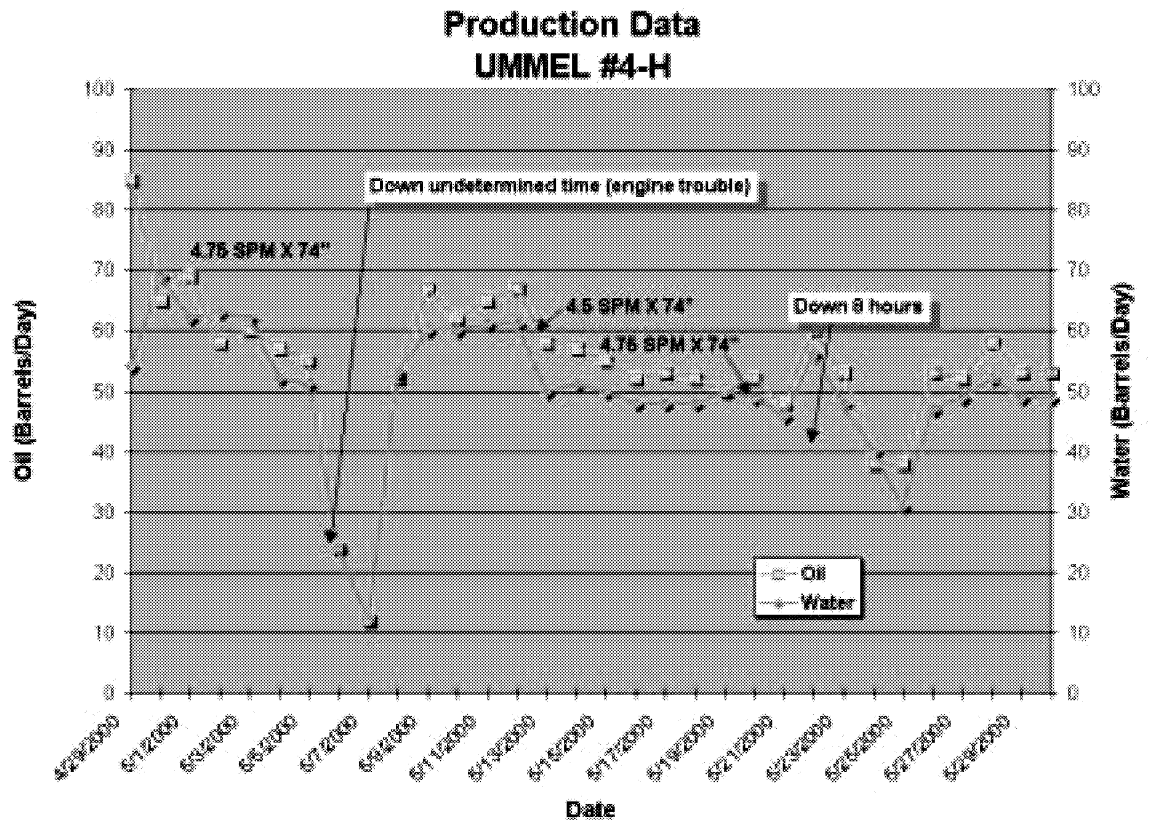

Figure 5.2 –Daily production fluid rates for the Mull Ummel #4-H horizontal well during the first month. Average daily production was 54 barrels oil and 50 barrels of water. Fluid levels recorded in the well averaged over a period of one month show a bottom hole pressure (P_{wf}) of about 650 psi. The average oil and water production rates recorded at the well for the first month were within the predicted ranges and were significantly higher than traditional vertical infill wells in similar Mississippian reservoirs.

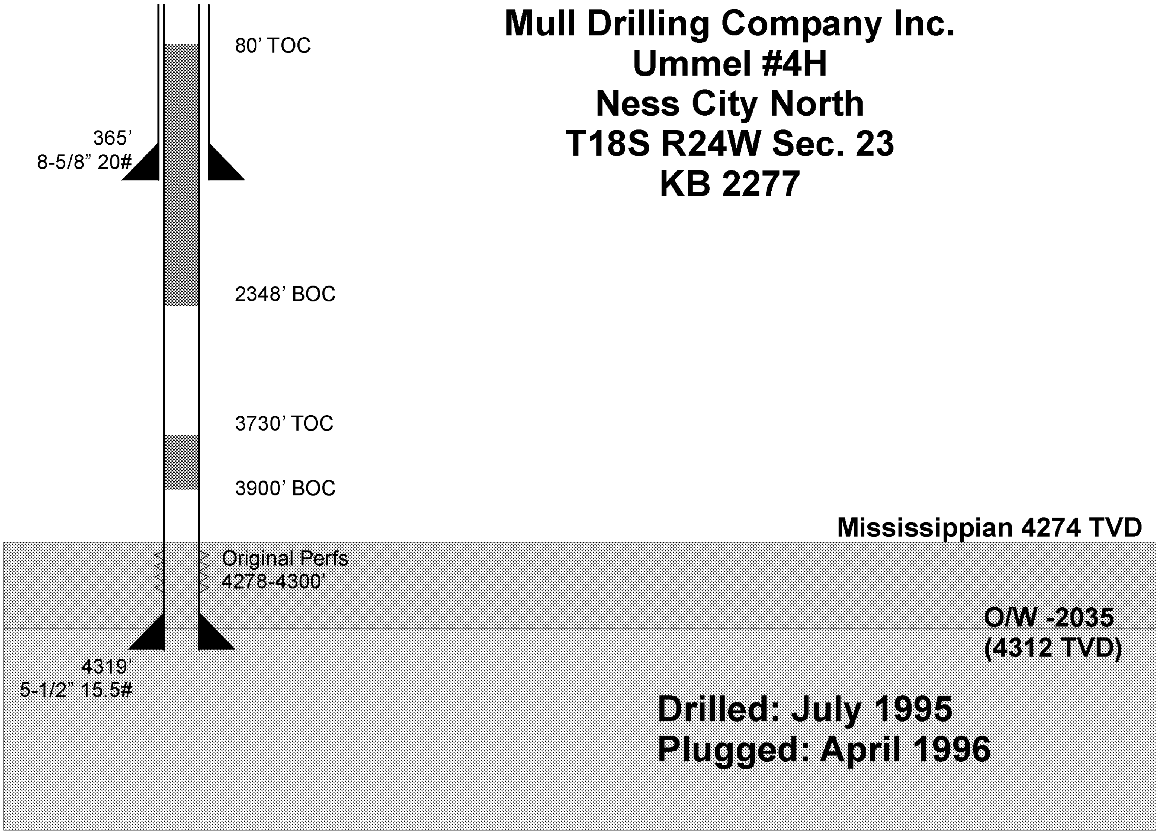

Figure 5.3 – Well bore schematic showing condition of the Mull Ummel #4 when reentry operations for the Mull Ummel #4H commenced in April 2000. The original vertical well was drilled as an infill well in the Ness City North Field during July 1995. The well was plugged and abandoned in April 1996 after extensive testing as producing non-economic quantities of oil with large quantities of water. The original perforations in the vertical well were located from 4,278 to 4,300 feet (subsea -2,201 to -2023 feet), approximately 12 feet above the mapped oil water contact in the reservoir.

Figure 5.4 – Well bore schematic showing the Mull Ummel #4H after cement plugs had been drilled out and a cast iron bridge plug had been set at 4,136 feet. Operations to drill out the cement plugs took significantly longer than expected (82 hours) and resulted in a cost of $26,400.

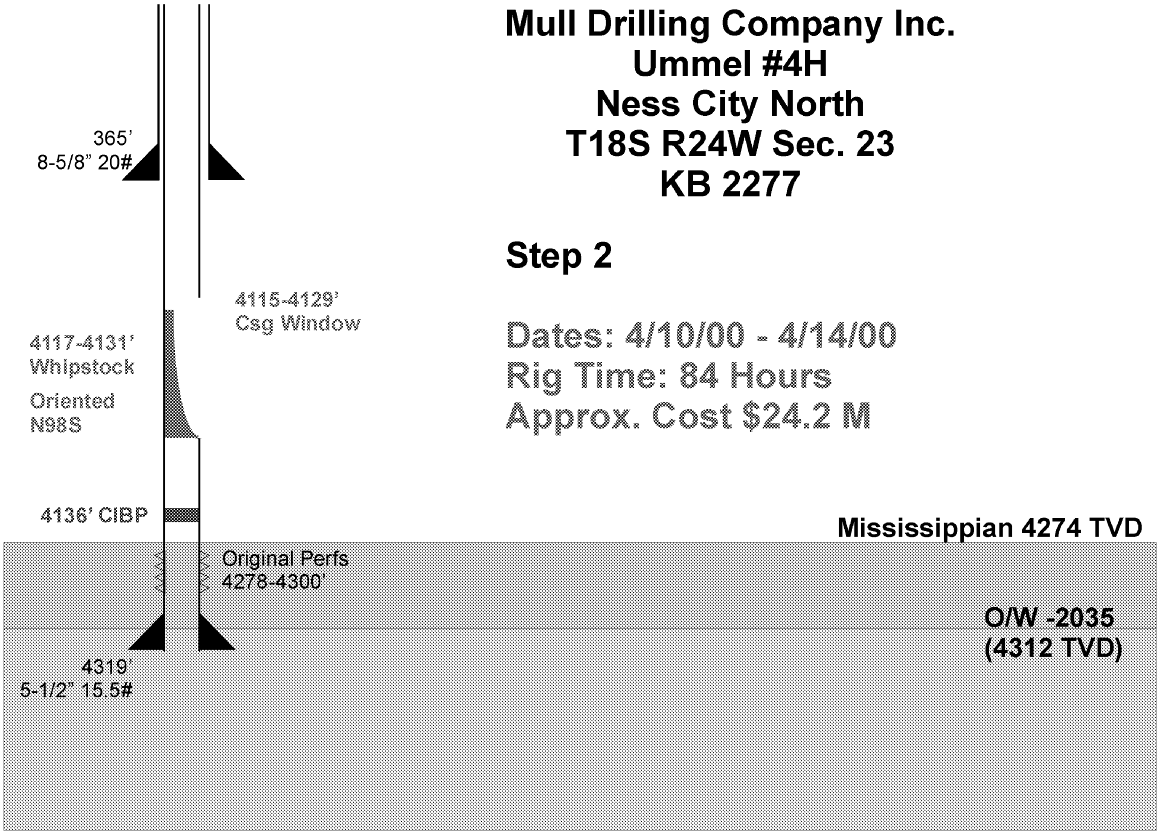

Figure 5.5 – Well bore schematic showing the Mull Ummel #4H after milling window in casing from 4,115 to 4,129 feet, and setting an oriented whipstock at 4,117 to 4,132 feet. Operations to required 84 hours and resulted in incremental costs of $24,200. Setting the oriented whipstock required several attempts to confirm orientation using a drilling gyroscope.

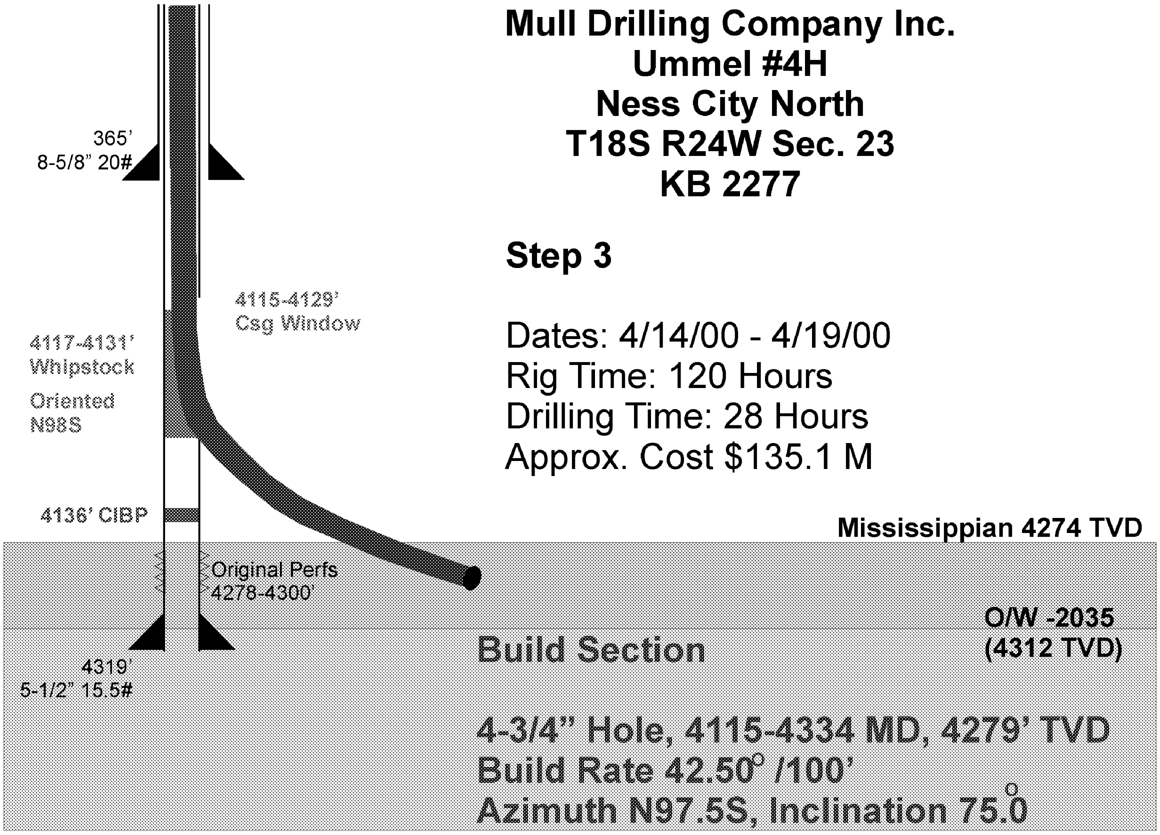

Figure 5.6 – Well bore schematic showing the Mull Ummel #4H after drilling a 4-3/4" diameter wellbore through the build section. Operations to drill the curve required 120 hours of rig time and 28 hours of drilling time. The incremental costs for drilling the curve were $135,100. The build rate for the curve was 42.5° per 100 feet and the wellbore was landed five feet below the top of the reservoir interval at 75.0° and building to 90°.

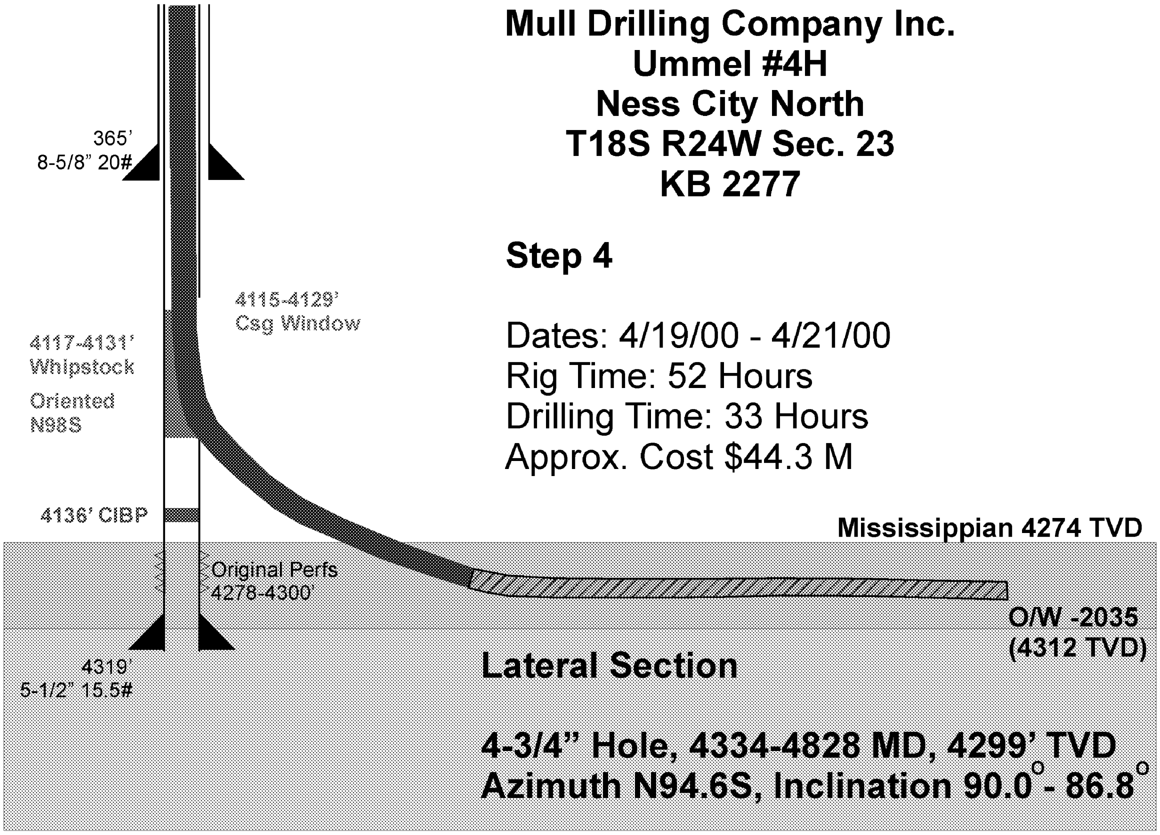

Figure 5.7 – Well bore schematic showing the Mull Ummel #4H after drilling a 4-3/4" diameter lateral section of the wellbore. Operations to required 52 hours of rig time and 33 hours of drilling time. The incremental costs for drilling the lateral were $44,300. The lateral had an azimuth of approximately west to east (N94.6 ° S) and an inclination of approximately 90 °. At the end of the lateral section inclination was increased slightly downward (86.8 °).

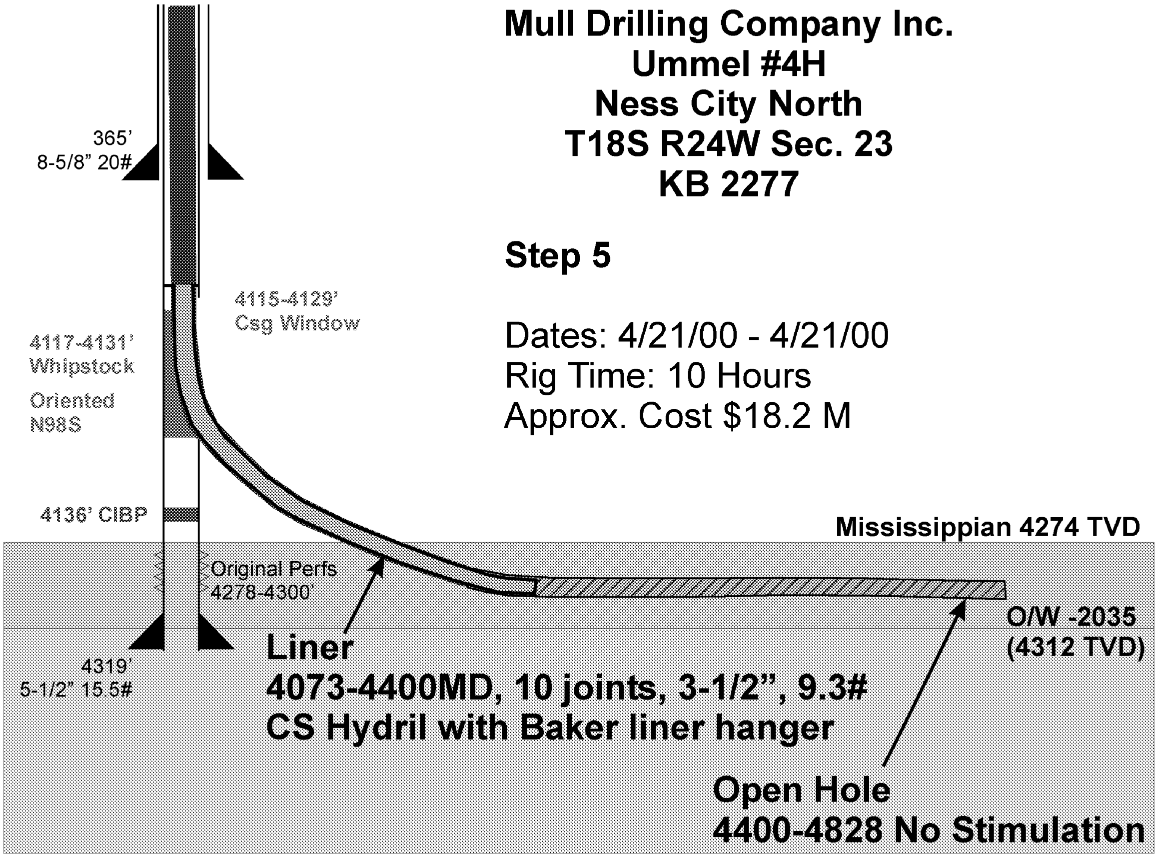

Figure 5.8 – Well bore schematic showing the Mull Ummel #4H after running a 3-1/2", flush joint liner through the curve from 4073 to 4400 feet total measured length. The well was completed open hole from 4400-4828 feet total measured length. No stimulation work was performed on the wellbore.

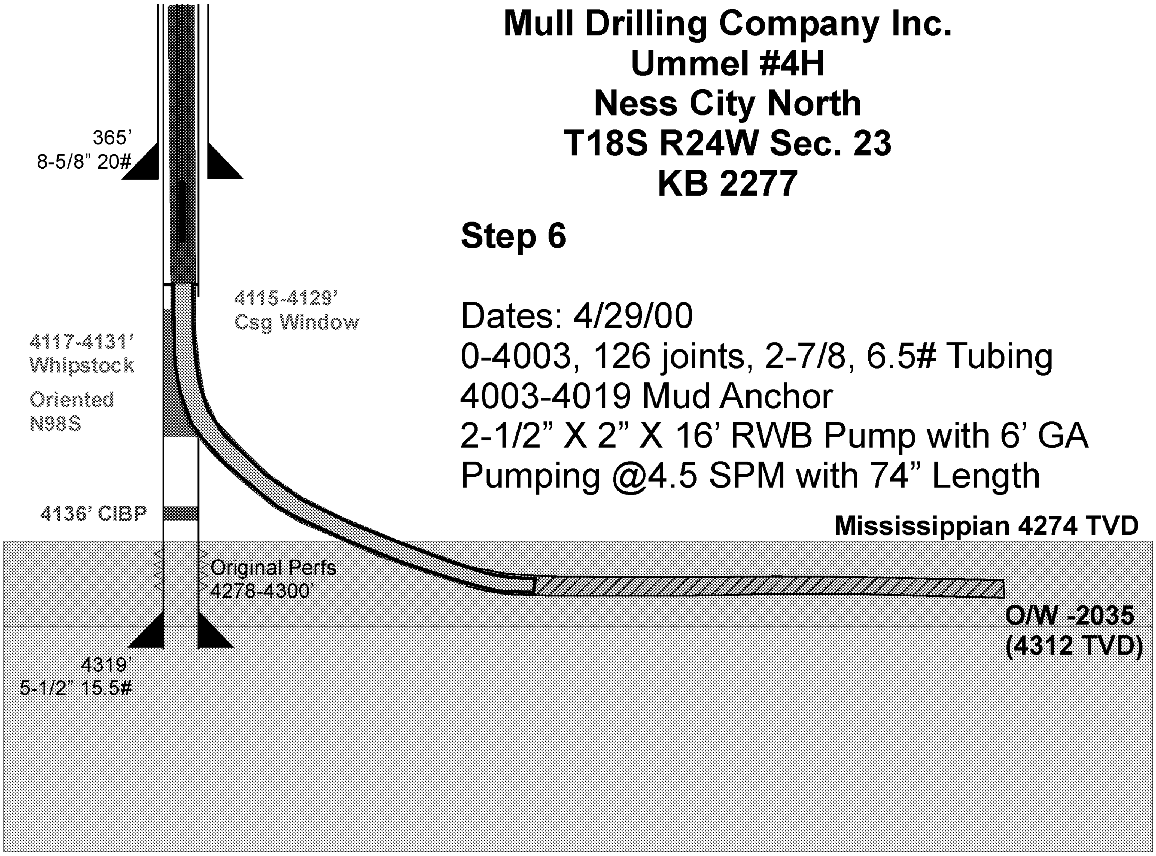

Figure 5.9 – Well bore schematic showing the Mull Ummel #4H after running a 2-1/2"x 2"x16' RWB pump to 4003. The pumping unit has been running at 4.5 SPM with a 74" stroke length.

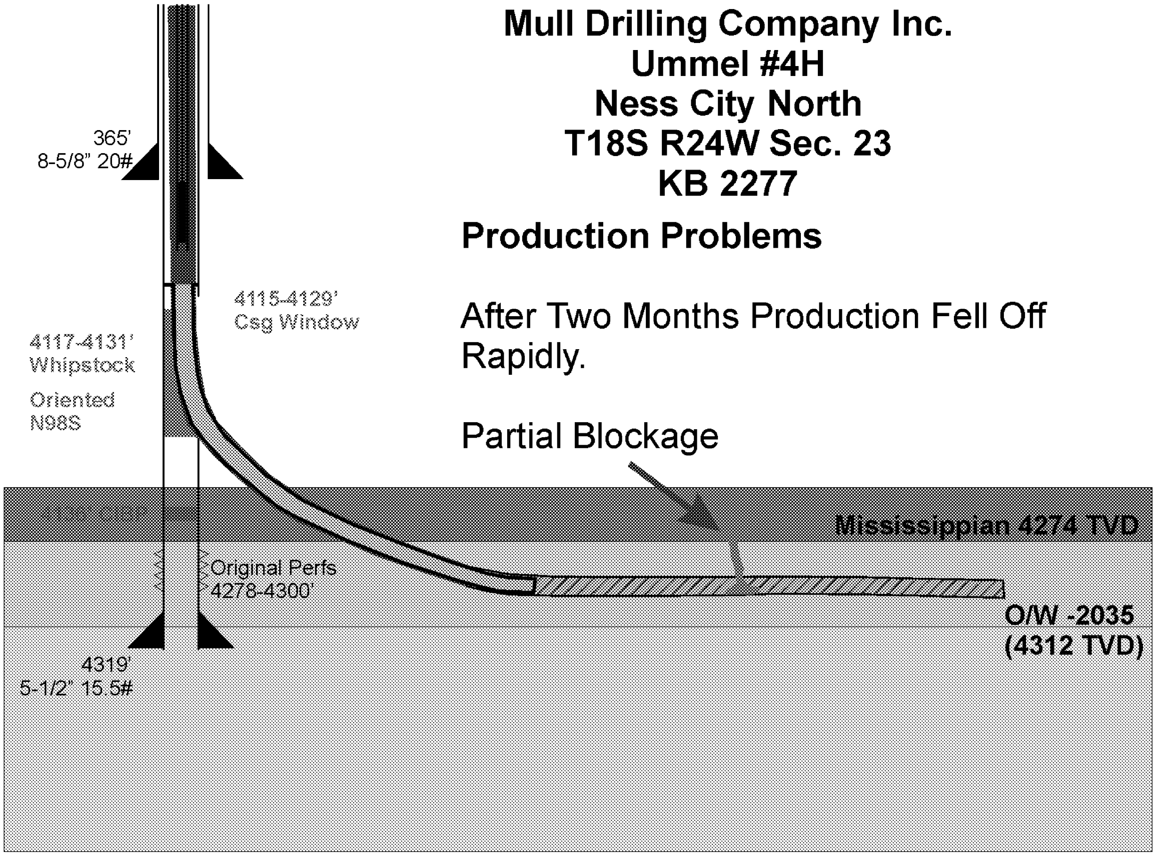

Figure 5.10 – For the first two months daily fluid production was stable at 54 barrels oil and 50 barrels of water. After two months fluid rates for both oil and water began to rapidly decrease. It appeared and was confirmed during subsequent remedial workover operations that the vertical shale intervals were unstable and began to collapse into the lateral resulting in partial blockage after two months of production.

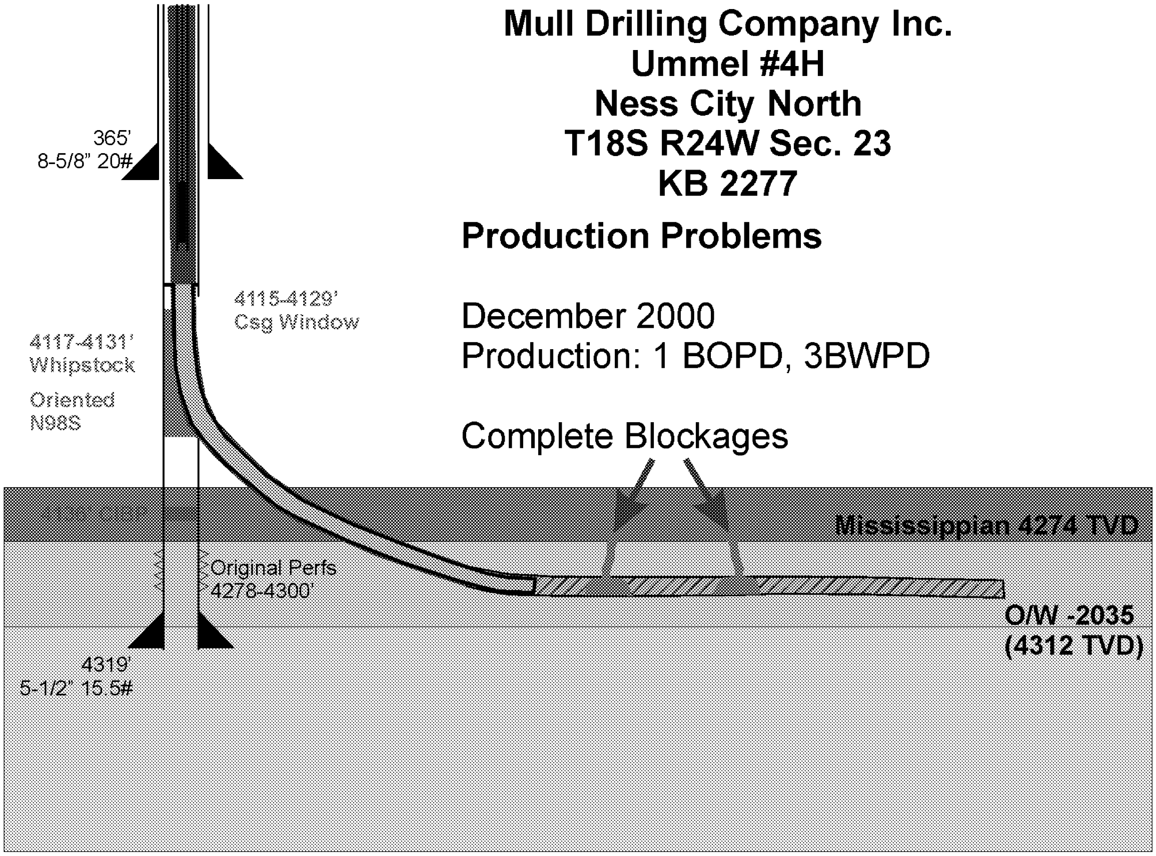

Figure 5.11 – By December fluid rates had decreased to near zero (1 BOPD, 3BWPD). It appeared that the vertical shale intervals had collapsed completely blocked the lateral.

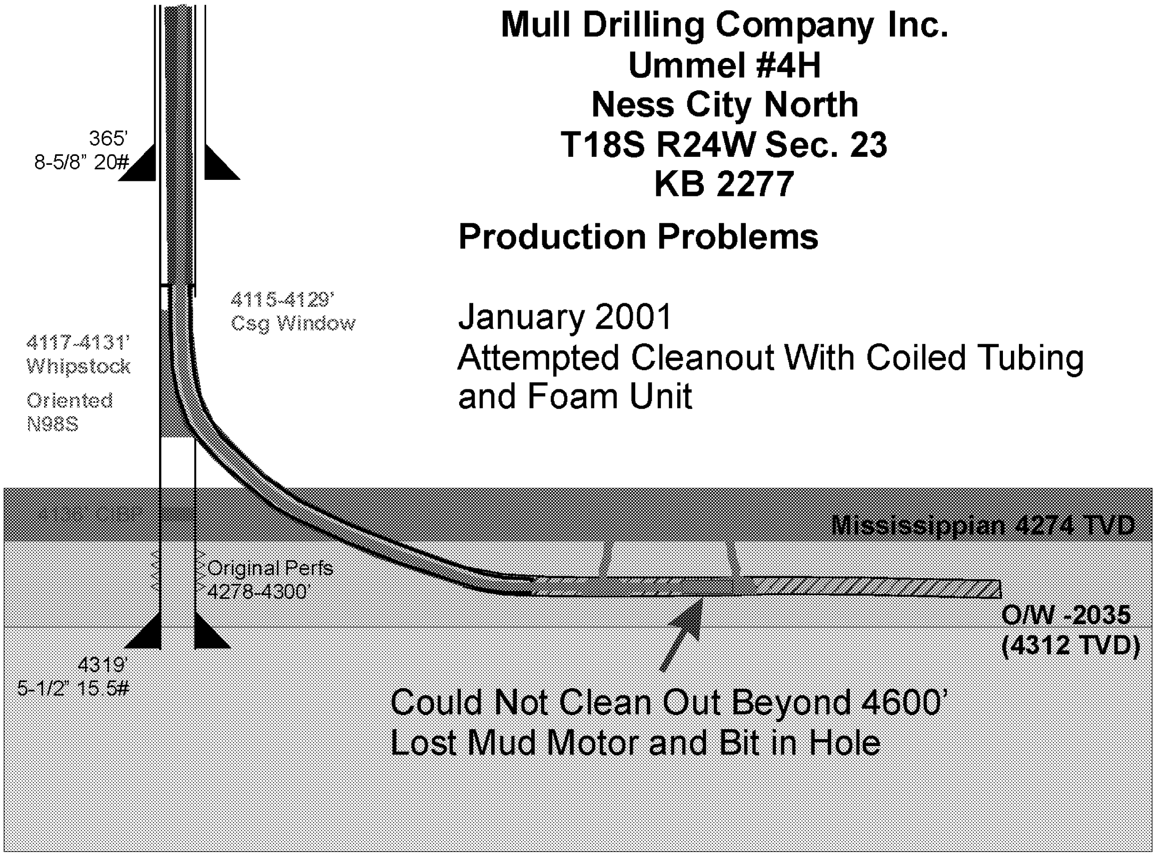

Figure 5.12 – In January 2001, coiled tubing and a jet nozzle with foam unit was used to attempt to cleanout blockages in the openhole lateral. Blockages of shale were encountered where MWD gamma ray log indicated vertical shale intervals. Shale continued to collapse after jetting. In a more aggressive attempt to clean out the hole a mud motor and bit were lost in the lateral at 4600 feet measured depth.

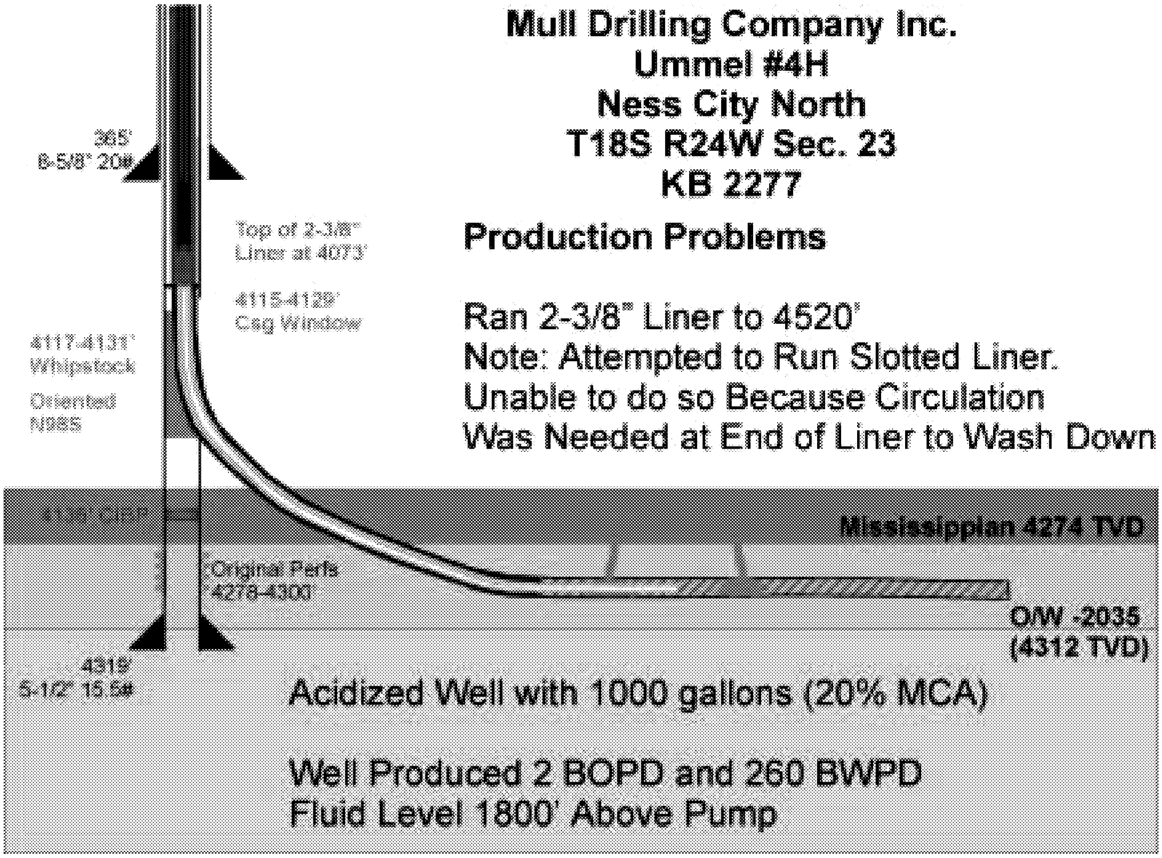

Figure 5.13 – An attempt was made to run a 2-3/8 inch liner into the lateral. The liner could be run only to 4,230 feet measured depth before blockages in the lateral were encountered. The remedial coiled tubing operations on the Ummel #4H were unsuccessful in cleaning out the lateral and restoring economic production rates.

APPENDICES

Appendix 1

Publications Related to Project Results

Does not include informal presentations to local societies and publications in newsletters.

Published Abstracts

1996, Carr, T. R., 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.

1996, Carr, T. R., H. R. Feldman, W. J. Guy, A new look at the reservoir geology of the Mississippian Schaben Field, Ness County, Kansas; Oklahoma Geological Survey Workshop on “Platform Carbonates in the Southern Midcontinent” Abstracts, p. 8.

1996, Carr, T. R., W. R. Guy, E. K. Franseen, and S. Bhattacharya, Enhanced Carbonate reservoir model for an old reservoir utilizing new techniques: The Schaben Field (Mississippian), Ness County, Kansas; American Association of Petroleum Geologists, Annual Meeting Abstracts, p. A23-A24.

1996, Guy, W. R., J. H. Doveton, W. L. Watney, T. R. Carr, and S. Bhattacharya, Reservoir characterization utilizing a low cost resistivity-porosity crossplot and an interactive spreadsheet; American Association of Petroleum Geologists, Annual Meeting Abstracts, p. A58.

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1996, Carr, T. R., Technology transfer for the independent; Society of Independent Professional Earth Scientists National Convention Abstracts, p. 10.

1997, Guy, W. J., T. R. Carr, E. K. Franseen, S. Bhattacharya, and S. Beaty, Combination of magnetic resonance and classic petrophysical techniques to determine pore geometry and characterization of a complex heterogeneous carbonate reservoir: American Association of Petroleum Geologists Annual Meeting Abstracts, Dallas.

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.

1998, Gerlach, P.M., S. Bhattacharya, and T.R. Carr, Application of Cost-Effective PC-Based Reservoir Simulation and Management--Schaben Field (Mississippian), Ness County, Kansas: Proceedings 1998 AAPG Presentations, Salt Lake City

1998, Franseen, E.K., T.R. Carr, W.J. Guy, and S.C. Beaty, Significance of Depositional and Early Diagenetic Controls on Architecture of a Karstic-Overprinted Mississippian (Osagian) Reservoir, Schaben Field, Ness County, Kansas: Proceedings 1998 AAPG Presentations, Salt Lake City.

1999, Carr, T. R., Bhattacharya, S., Byrnes, A., Franseen, E. K., Gerlach, P. M., Guy, W. J., and Watney W. L., Cost-effective techniques for improved carbonate reservoirs of Kansas – Near Term – Class 2: DOE and PTTC 1999 Oil and Gas Conference: Technology Options for Producers’ Survival, June 28-30, 1999, Dallas, Texas.

1999 Bhattacharya, Saibal, Watney, W.L., Guy, W., and Gerlach, P., From geomodels to engineering models - Opportunities for spreadsheet computing: for Nineteenth Annual Research Conference, Advanced Reservoir Characterization for the Twenty-First Century, Gulf Coast Section SEPM Foundation. (Meeting December 5-8, 1999).

1999, Guy, Willard J. Alan P. Byrnes, John H. Doveton, and Evan K. Franseen, The Prediction of Effective Porosity and Permeability in Mississippian Carbonates, Kansas; Proceedings AAPG Mid-Continent Section Meeting in conjunction with KIOGA Convention 1999 Annual Meeting (August 29 - 31), Wichita, Kansas (http://www.kgs.ukans.edu/midcont99/findex.html).

1999, Gerlach, Paul M., Saibal Bhattacharya, and Timothy R. Carr, Cost Effective Techniques for the Independent Producer to Evaluate Horizontal Drilling Candidates in Mature Areas; AAPG/SPWLA Hedberg Research Symposium "Horizontal Wells -- Focus on the Reservoir" October 10-13, 1999, Woodlands, Texas (http://www.kgs.ukans.edu/PRS/AAPG/papers/gerlach.html).

1999, Gerlach, Paul M., Saibal Bhattacharya, and Timothy R. Carr, Cost Effective Techniques for the Independent Producer to Evaluate Horizontal Drilling Candidates in Mature Areas; AAPG/SPWLA Hedberg Research Symposium "Horizontal Wells -- Focus on the Reservoir" October 10-13, 1999, Woodlands, Texas (Invited Presentation).

2000, Gerlach, Paul M., S. Bhattacharya, A. P. Byrnes, and T. R. Carr, 2000, Demonstration of Cost-Effective Tools for Integrated Reservoir Characterization and Simulation to Predict Performance of Horizontal Infill Well, Ness City North Field, Ness County, Kansas, Proceedings 1998 AAPG Annual Meeting, Denver Colorado.

2000, Willhite, G. P., A presentation at the Tertiary Oil Recovery Project Oil Recovery Conference in Wichita, Kansas (March 17-18) focused on application of a commercial simulator and the role of fracture porosity to a portion of the Schaben Field.

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1995, Carr, T. R., J. Hopkins, H. Feldman, A. Feltz, J. Doveton, and D. Collins, Color 2-D and 3-D Pseudo-Seismic Transforms of Wireline Logs: A Seismic Approach To Petrophysical Sequence Stratigraphy; Landmark Computer Graphics UserNet, 6p.

1996, Carr, T. R., Adkins-Heljeson, D.M., Beaty, S.D., Bhattachary, S., Franseen, E.K., Gerlach, P.M., Guy, W.J. and Watney, W.L., 1996, Improved Oil Recovery in Mississippian Carbonate Reservoirs of Kansas-Near Term-Class 2: Annual Report: Kansas Geological Survey Open File Report 96-7, 55 p.

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1996, Hopkins, J. F., T. R. Carr, H. R. Feldman, Pseudoseismic Transforms of Wireline Logs: A Seismic Approach to Petrophysical Sequence Stratigraphy, in J. A. Pacht, R. E. Sheriff and B. F. Perkins, eds., Stratigraphic Analysis Utilizing Advanced Geophysical, Wireline and Borehole Technology for Petroleum Exploration and Production: Gulf Coast SEPM Seventeenth Annual Research Conference, p. 133-144.

1996, Carr, T. R., W. R. Guy, E. K. Franseen, and S. Bhattacharya, Enhanced carbonate reservoir model for an old reservoir utilizing new techniques: The Schaben Field (Mississippian), Ness County, Kansas; Kansas Geological Survey Open-File Report 96-30.

1997, Watney, W. L., W. J. Guy, J. H. Doveton, S. Bhattacharya, P. M. Gerlach, G. C. Bohling, and T. R. Carr, Petrofacies Analysis -- The petrophysical tool for geologic/engineering

reservoir characterization; in Proceedings of the USDOE 4th International Reservoir Characterization Technical Conference (Houston, Texas), p. 95-114.
1997, Bhattacharya, Saibal, Paul Gerlach, Tim Carr, Willard Guy, Scott Beaty, Evan Franseen, Cost-effective PC-based reservoir simulation and management -- The Schaben Field (Mississippian) Ness County, Kansas; Proceedings Twelfth Tertiary Oil Recovery Conference, Wichita, Kansas, p.39-58.
1997, Gerlach, P, and S. Bhattacharya, Simulation of primary and alternate locations for five infill wells, Schaben Field, Ness County, Kansas: Kansas Geological Survey Open File Report 97-46.

1997, Carr, T. R., S. Bhattacharya, E. K. Franseen, P. M. Gerlach, W. J. Guy, J. Doveton, W. L. Watney, D. Adkins-Heljeson, J. Hopkins, S. Beaty, R. R. Reynolds, S. Vossoughi, G. P. Willhite, Improved Oil Recovery in Missippian Carbonate Reservoirs of Kansas – Near Term – Class 2: Kansas Geological Survey Open-File Report 97-24.

1998, Watney, W. L. and Bohling, G., PfEFFER Demo, in Mark, Sandra, compiler, PTTC's Petroleum E&P Software Sampler, CD-ROM v. 1.0, PTTC, Washington.

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1999, Watney, W. L., W. J. Guy, J. H. Doveton,S., Bhattacharya, P., Gerlach, G. C., Bohling, T. R., Carr, Petrofacies analysis - The petrophysical tool for coherent reservoir characterization and management: 4th International Reservoir Characterization Conference, Houston, March, 1997, in R. Schatzinger and J. Jordan, eds., Reservoir Characterization - Recent Advances, AAPG Memoir 71, p. 73-90.
1999, Carr, T. R., Bhattacharya, S., Byrnes, A., Franseen, E. K., Gerlach, P. M., Guy, W. J., and Watney W. L., Cost-effective techniques for improved carbonate reservoirs of Kansas – Near Term – Class 2: DOE and PTTC 1999 Oil and Gas Conference: Technology Options for Producers' Survival, June 28-30, 1999, Dallas, Texas, Conference Proceedings from the National Energy Technology Laboratory Paper 2A.5 [PDF-2458KB] http://www.fetc.doe.gov/publications/proceedings/99/99oil&gas/ng2a-5.pdf .
1999, Bhattacharya, Saibal, Watney, W.L., Doveton, J.H., Guy, W.J., Bohling, G., From geomodels to engineering models - Opportunities for spreadsheet computing: Gulf Coast Section Society SEPM, Advanced Reservoir Characterization for the Twenty-First Century, Nineteenth Annual Bob F. Perkins Research Conference, Gulf Coast Section, SEPM Foundation, Houston, TX., p. 179-193.
1999, Bhattacharya, Saibal, P.M. Gerlach, Byrnes, and Evan K. Franseeen, Reservoir Characterization of Ness City North Field, Ness County, Kansas, for horizontal well application, Kansas Geological Survey Open-File Report 99-58, 30p.
2000, Montgomery, S. L., Franseen, E.K., Bhattacharya, S., Gerlach, P., Guy, W., Byrnes, A.P., and Carr, T.R., Schaben Field, Kansas: Improving Performance in a Mississippian Shallow-Shelf Carbonate: American Association of Petroleum Geologists Bulletin, v. 84, p. 1069-1086.
2000, Bhattacharya, Saibal, Paul Gerlach, Results of 3 Layer Reservoir Simulation Study – Schaben Field, Ness Count, Kansas: Kansas Geological Survey Open-File Report 2000-78, 63p.
2000, Bhattacharya, Saibal, DST Analysis, Super-Pickett Analysis to determine pay cut offs, integration of capillary pressure data with petrophysical log data, and material balance

calculations to validate reservoir pressure history and drive mechanism – Schaben Field, Ness County, Kansas, Kansas Geological Survey Open File Report 2000-79, 72p.

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(In Press), Bhattacharya, Saibal, Paul M. Gerlach, and Timothy R. Carr, Cost Effective Techniques for the Independent Producer to Evaluate Horizontal Drilling Candidates in Mature Areas, in Horizontal Wells -- Focus on the Reservoir, Timothy R. Carr, Erik P. Mason and Charles T. Feazel (editors). Expected publication date is 2nd quarter 2002.

(In Press), Timothy R. Carr, Charles T. Feazel, and Erik P. Mason, Horizontal Wells: Focus on the Reservoir - Introduction , in Horizontal Wells -- Focus on the Reservoir, Timothy R. Carr, Erik P. Mason and Charles T. Feazel (editors). Expected publication date is 2nd quarter 2002.

Appendix 2

Short Courses and Workshops Related to Project Results

The number of short courses of ½ day or more related to the DOE project totaled 22.

The short courses fall into the following areas:

1) Well evaluation using PfEFFER
2) Reservoir characterization and simulation using low-cost tools
3) Accessing the project data and other information through the Internet
4) Horizontal drilling technology

Major personnel involved indicated in parentheses.

April 1, 1997 - Workshop on PfEFFER at Phillips Exploration and Production Seminar Bartlesville, Okla., (John Doveton, Bill Guy, Geoff Bohling).

June 24, 1997 – Internet for the Petroleum Professional. One-day short course (part of three day series), using materials and results derived from the Class 2 project presented in Lawrence, KS (Tim Carr).

June 25, 1997 – PfEFFER Speadsheet Program. One-day short course (part of three day series), using materials and results derived from the Class 2 project presented in Lawrence, KS (John Doveton).

June 27, 1997 – Reservoir Simulation on a PC using USDOE Boast 3 and Computer Mapping Packages. One-day short course (part of three day series), using materials and results derived from the Class 2 project presented in Lawrence, KS (Saibal Bhattacharya and Paul Gerlach).

November 7, 1997 – Internet for the Petroleum Professional. One-day short course (part of three day series), using materials and results derived from the Class 2 project presented in Wichita, KS (Tim Carr).

November 14, 1997 – PfEFFER Speadsheet Program. One-day short course (part of three day series), using materials and results derived from the Class 2 project presented in Wichita, KS (John Doveton).

November 21, 1997 – Reservoir Simulation on a PC using USDOE Boast 3 and Computer Mapping Packages. One-day short course (part of three day series), using materials and results derived from the Class 2 project presented in Wichita, KS. (Saibal Bhattacharya and Paul Gerlach).

November 13, 1997 - Contribution to BDM-DOE Workshop on "Advanced applications of wireline technologies" in Midland, Texas (John Doveton).

January 13,1998 - Contribution to BDM-DOE Workshop on "Advanced applications of wireline technologies" in Denver, Colorado (John Doveton). Repeat of November 13.

February 24, 1998 - Hands-on demonstrations and workshops focusing on PfEFFER in Tulsa, Oklahoma at DOE.

March 3-4, 1998 - Hands-on demonstrations and workshops focusing on PfEFFER in Odessa Texas by invitation of Phillips Petroleum Company (John Doveton and Lynn Watney).

June 16, 1998 – Presentations at PTTC Horizontal Drilling Workshop, Wichita, Kansas (Paul Gerlach, Saibal Bhattacharya and Tim Carr).

June 26, 1998 - PTTC Workshop on Internet for the Petroleum Professional in Tyler, Texas (Tim Carr and Dana Adkins-Helheson).

June 28, 1999 - PfEFFER course at the Software Workshop of the 1999 DOE Oil & Gas Conference, Dallas, Texas (John Doveton).

December 1999- A two day workshop, "Log Analysis Using PfEFFER" to Bureau Land Management in Casper, Wyoming. (Bill Guy).

1998 - Not a physical workshop, but a demo nevertheless - PfEFFER Demo, in Petroleum Software CD-ROM released by PTTC (Watney, W. L. and Bohling, G.).

August 28, 1998 - PTTC Workshop on Internet for the Petroleum Professional in Kalamazoo, Michigan (Tim Carr and Dana Adkins-Heljeson).

November 19, 1998 – PfEFFER hands-on demonstration (4 hours) presented at the North Midcontinent PTTC workshop in Wichita, Kansas (John Doveton and Lynn Watney).

August 29, 1999 PTTC Workshop on Internet for the Petroleum Professional attached to Kansas Independent Oil and Gas Association (KIOGA) Annual Meeting in Wichita, Kansas (Tim Carr and Dana Adkins-Heljeson).

February 19, 2000 - 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.).

May 25, 2000 - PTTC one day short course "Computer Databases and Mapping" at Wichita State University Downtown Campus, Wichita, Kansas (Tim Carr).

June 16, 2000 – Presentations at North Mid-continent PTTC Horizontal Drilling Workshop in Wichita Kansas (Paul Gerlach, Saibal Bhattacharya, Richard Pancake and Tim Carr).

August 29, 2000 - PTTC workshop on horizontal drilling in Kansas at the annual meeting of the Kansas Independent Oil and Gas Association (KIOGA) in Wichita, Kansas (Saibal Bhattacharya, Richard Pancake and Tim Carr).

May 9-10, 2001 – Organized and contributed (4 hours) to PTTC workshop "Optimized Exploitation and Horizontal Well Technologies for Independent Operators" in Wichita, Kansas (Saibal Bhattacharya, Richard Pancake and Tim Carr).

<u>Appendix 3</u>

DRILLING REPORT

Well Name: **UMMEL #4-H** **Operator:** **MULL DRLG CO INC**
Loc: **W/2 E/2 SE/4 24-18S-24W** **API #:** **15-135-23895-0101**
County/State: **NESS CO, KS** **Contractor:** **NORESEMAN RIG #4**

4/8/00 DRILLING CEMENT @ 210' (CUT 210')
7:30 am - 9:30 am (2 hrs) = Setting in Rat Hole
9:30 am - 11:00 am (1 1/2 hrs) = PU Scientific drilling top entry swivel. Re-set Rat Hole.
11:00 am - 3:00 pm (4 hrs) = Drilling cement. Tagged cement @ 80'. Cement drilling hard.
3:00 pm - 6:00 am (15 hrs) = Drilling cement. Cement very hard. Drilling rate picked up the last 3 hrs.
DWC = $5,474

4/9/00 DRILLING CEMENT @ 745' (CUT 535')
6 am - 2:15 pm (8 1/4 hrs) = Drilling
2:15 pm - 5:00 pm (2 3/4 hrs) = Drilling. Drilled off @ 320' to 390' drilled 2'/min.
Remainder is drilling 3-4'/min.
5:00 pm - 6:00 pm (1 hr) = Rig repair.
6:00 pm - 6:30 pm (1/2 hr) = Drilling
6:30 pm - 7:00 pm (1/2 hr) = Rig Repair. Work on pump, wood under valve.
7:00 pm - 6 am (11 hrs) = Drilling. Drilling about 3'/min.
15,000 BW 70 RPM
DWC = $4,965
CWC = $10,439

4/10/00 RUNNING DRILL PIPE @ 3670' (CUT 2925')
6:00 am - 8:30 am (2 1/2 hrs) = Drilling Cement.
8:30 am - 9:30 am (1 hr) = Began drilling off, rate increased to 1/2 min/ft.
9:30 am - 9:45 am (1/4 hrs) = Work on pump.
9:45 am - 3 pm (5 1/4 hrs) = Drill down to 1303'
3:00 pm - 3:30 pm (1/2 hr) = Clean suction on pump.
3:30 pm - 2:00 am (10 1/2 hrs) = Drill down to 2348', quit taking weight.
2:00 am - 6:00 am (4 hrs) = Run drill pipe.
DWC = $4,965
CWC = $15,404

4/11/00 RUNNING WHIPSTOCK @ 4144' (CUT 474')
6:00 am - 6:15 am (1/4 hr) Ran drill pipe to 3730' and tagged bottom
6:15 am - 8:00 am (1 3/4 hrs) Circulation. Run back to bottom. Circulate hole

8:00 am - 1:15 pm (5 1/4 hrs) Drill to cement to 3900'. Wash down to 4144'.
No cement and not taking any weight.
1:15 pm - 2:15 pm (1 hr) Circulate hole clean
2:15 pm - 5:00 pm (2 3/4 hrs) Pull out of hole
5:00 pm - 5:30 pm (1/2 hr) Rig up Log Tech and run cast iron bridge plug and set at 4136. Circulate to bond log.
5:30 pm - 8:30 pm (3 hrs) Pick up starter mill and water mellon mills and run in hole.
Tag bridge plug at 4139'.
8:30 pm - 2:30 am (6 hrs) Mix mud and circulate milling fluid around.
Had to clean lots of cement out of pits.
2:30 am - 5:00 am (2 1/2 hrs) Pull out of hole
5:00 am - 6:00 am (1 hr) Running whipstock
DWC = $10,994
CWC = $26,398

4/12/00 RUNNING WHIPSTOCK BACK IN HOLE @ 4140'
6:00 am - 9:30 am (3 1/2 hrs) Running whipstock.
9:30 am - 12:00 noon (2 1/2 hrs) - RU Scientific Drlg gyro and RIH. Could not sting into orienting sub w/mule shoe.
12:00 noon - 1:30 p.m. (1 1/2 hrs) - Pull gyro out of hole and inspect. Could not see anything wrong. Circ slowly down drill pipe.
1:30 pm - 6:00 p.m. (4 1/2 hrs) - Attempt to run gyro, could not get down w/gyro. Attempt to pump down drill pipe, could not pump due to thick mud. RU Cheyenne high-pressure truck and pump down drill pipe w/25 bbls. Pressure dropped to 400 psi.
6:00 pm - 7:00 pm (1 hr) - Attempt to run gyro, could not get gyro to seat in orienting sub.
7:00 p.m. - 8:30 pm (1 1/2 hrs) - WO evening tour.
8:30 pm - 1:30 am (5 hrs) - POOH w/whipstock, recover all of whipstock.
1:30 am - 2:30 am (1 hr) - Check all cross overs and connections above orienting sub to be sure that gyro passes through. Found tight spot in the bottom upset of the 2nd jt of heavy weight above whipstock.
2:30 am - 6:00 am (3 1/2 hrs) - PU whipstock and orient concave w/orienting sub.
Run whipstock.
DWC = $7,998
CWC = 34,396

4/13/00 MILLING W/STARTER MILL
6:00 - 8:00 am (2 hrs) - Run whipstock in hole
8:00 - 9:30 am (1 1/2 hrs) - Run gyro in hole and sting into orienting sub. Orient whipstock and attempt to set. Did not see bolt shear. Set full weight on whipstock.
9:30 am - 1:00 pm (3 1/2 hrs) Pull out of hole with starting mill.
1:00 pm - 2:00 pm (1 hr) Lay down starter mills and pick up whipstock retrieving tool.
2:00 pm - 5 pm (3 hrs) - Run in hole with retrieving tool.
5:00 pm - 6:00 pm (1 hr) - Latch into whipstock and pull up approx 10'. Could

not go down. Confirm that we are latched into whipstock retrieving slot.
6:00 pm - 7:00 pm (1 hr) - Run in with Scientific Drilling gyro and confirm whipstock orientation. Whipstock facing 98 degrees. Release from whipstock
7:00 pm - 10:30 pm (3 1/2 hrs) - Pull out of hole with retrieving tool.
10:30 pm - 11:30 pm (1 hr) - Hook up lines to roll mud pits and condition mud.
11:30 pm - 12:30 am (1 hr) - Pick up starting mill and run in hole.
Floor had got metal sliver in hand, took him to Ness to have it removed.
12:30 am - 2:30 am (2 hrs) - Wait on floor hand.
2:30 am - 5:30 am (3 hrs) Finish trip in hole. Set down on whipstock to confirm that it takes weight. Looks good.
5:30 am - 6:00 am (1/2 hr) - Mill starter hole in casing.
DWC = $6,304
CWC = 40,700

4/14/00 LD MILLS & CLEAN PITS. GETTING READY TO PU DIRECTIONAL TOOLS
6:00 am - 7:15 am (1 1/4 hrs) - Mill out starter hole
7:15 am - 9:00 am (1 3/4 hrs) - Mix up vis pill and pump around to clean up hole
9:00 am - 12:00 pm (3 hrs) - Pull out of hole with starter mill.
12:00 pm - 12:30 pm (1/2 hr) - Lay down starter mill and pick up bottom mill and water mellon mill.
12:30 pm - 2:30 pm (2 hrs) - Run in hole with mills.
2:30 pm - 1:00 am (10 1/2 hrs) - Mill out window.
1:00 am - 2:15 am (1 1/4 hrs) - Pump high vis pill and circulate hole clean.
2:15 am - 5:30 am (3 1/4 hrs) - Pull out of hole with windown mills.
5:30 am - 6:00 am (1/2 hr) - Lay down mills. Jet and clean pits.
Top of window 4115', bottom of window 4129'.
Top of Whipstock 4117.02', bottom at 4131.07'. Whipstock slot at 4119.89'.
DWC = $7,299
CWC = $47,999

4/15/00 DRILLING AHEAD @ 4181' (CUT 52')
6:00 am - 8:00 am (2 hrs) - Clean out steel pits and fill w/produced water.
8:00 am - 11:15 am (3 1/4 hrs) - PU motors and make up MWD tools, orient all tools w/Scientific Drilling gyro.
11:15 am - 3:45 pm (4 1/2 hrs) - RIH w/motors.
3:45 pm - 4:45 pm (1 hr) - Attempt to run gyro through kelly, kelly was too small.
4:45 pm - 5:45 (1 hr) - Run gyro down drill pipe and check whipstock face, oriented at 98°.
5:45 pm - 8:00 pm (2 1/4 hrs) - Cut logging line and run through kelly, rehead gyro and run in hole. Seat into mule shoe.
8:00 pm - 10:00 pm (2 hrs) - Drilling ahead to 4136'.
10:00 pm - 12:30 am (2 1/2 hrs) - Move wire line sheave up in derrick. Had trouble making connection.
12:30 am - 5:00 am (4 1/2 hrs) - Drilling ahead from 4137' to 4168'.
5:00 am - 6:00 am (1 hr) - Drilling ahead from 4168' to 4181'.

DWC = $52,711
CWC = $100,710
Note: Costs reflect all of whipstock and Sperry Sun mobilization and standby.

4/16/00 DRILLING AHEAD @ 4340' (CUT 159')
6:00 am - 7:45 am (1 3/4 hrs) - Work on pumps.
7:45 am - 8:30 am (3/4 hrs) - Drilling ahead.
8:30 am - 8:45 am (1/4 hr) - Work on pumps.
8:45 am - 9:30 am (1/2 hr) - Drilling ahead.
9:30 am - 10:30 am (1 hr) - Pull gyro out of hole and rig down Scientific Drilling.
10:30 am - 11:00 am (1/2 hr) - Attempt to get MWD to work w/rig pumps, pumps have too much interference noise for MWD.
11:00 am - 1:45 pm (2 3/4 hrs) - Order out Swift pump truck and rig up.
1:45 pm - 2:15 pm - (1/2 hr) - Re log gamma while making wiper trip.
2:15 pm - 12:00 am (9 3/4 hrs) - Drilling ahead. Slide drilling, building curve. Repair liners on standby pump.
12:00 am - 1:15 am (1 1/4 hrs) - Attempt to drill using stand by pump, liners still leaking.
1:15 am - 6:00 am (4 3/4 hrs) - Drilling ahead. Ordered out Weatherford rental triplex pump.
DWC = $45,980
CWC = $146,690
Tops:
Pawnee 4109' MD
Ft.Scott 4198' MD
Cke 4222' MD

4/17/00 RIH W/MOTORS
6:00 am - 7:00 am (1 hr) - Drill ahead to 4346' MD.
7:00 am - 9:15 am (2 1/4 hrs) - Set in Weatherford triplex pump and hook up. Bleed air and check pressures. Check MWD response.
9:15 am - 11:45 am (2 1/2 hrs) - Drill ahead, building curve, slide drilling from 4346' to 4373'.
11:45 am -12:15 pm (1/2 hr) - Pump mud sweep around and circulate bottoms up.
12:15 pm - 3:00 pm (2 3/4 hrs) - Pull out of hole, had approx 10 points of drag as pulling through curve.
3:00 pm - 4:00 pm (1 hr) - Adjust motor to 1.5 degree, change bit.
4:00 pm - 7:00 pm (3 hrs) - Run in hole with motor and bit in hole, fill at 37 stands.
7:00 pm - 11 pm (4 hrs) - Tagged up at 4240'. Attempt to wash down, MWD not working, pull up into pipe, MWD working, run to 4240' MWD not working, could get MWD to work in verticle but not curve, got good tool face and wash to 4315', could not maintain tool face. MWD working intermittently.
11:00 pm - 1:00 am (2 hrs) -Trip out.
1:00 am - 2:30 am (1 1/2 hrs) - Adjust motor to 3.06 degree and install kick pad. Change out MWD tools and test tools.
2:30 am - 4:00 am (1 1/2 hrs) - ?

4:00 - 6:00 am (2 hrs) - Run in hole with motors.
8.5 MW   29 Vis   1 PV   0 YP   7 pH   1/32 Cake   16,000 Chl
DWC = 14,222
CWC = $160,912

4/18/00 HOOK UP PULSATION DAMPENER @ 4373'
6:00 am - 6:30 am (1/2 hr) - Finish trip in to window.
6:30 am - 9:00 am (2 1/2 hrs) - Check out MWD and run to 4292, wash out bridge and slide to 4318, pick up to 4308 and became stuck.
9:00 am - 10:30 am (1 1/2 hrs) - Work pipe and circulate trying to free pipe.
10:30 am - 11:00 am (1/2 hr) - Pump 20 bbls oil from Ummel Tank Battery followed by 10 bbls water, stack 15 points on drill pipe.
11:00 am - 11:30 am (1/2 hr) - Let oil soak.
11:30 am - 12:30 pm (1 hr) - Work pipe and pump 2 bbls, let soak and work pipe, pump 2 bbls, work pipe and came free.
12:30 pm - 2:00 pm (1 1/2 hrs) - Work pipe to keep free and circ hole clean. Still getting cavings.
2:00 pm - 3:15 pm (1 1/4 hrs) - Pull motors up into pipe and circulate clean.
3:15 pm - 10:00 pm (6 3/4 hrs) - Clean pits, and mix mud using produced water.
10:00 pm-10:30 pm (1/2 hr) - Run in to 4293, pu kelly & check MWD, too much pump noise.
10:30 pm - 1:15 am (2 3/4 hrs) - Work on pump, go through valves, build pit volume, check suction hoses.
1:15 am - 5:30 am (4 1/4 hrs) - Wait on pulsation dampener from Weatherford.
5:30 am - 6:00 am (1/2 hr) - Hook up pulsation dampener.
8.6 MW   39 Vis   8 WL   13 PV   26 YP   10 pH   1/32 Cake   20,000 Chls
DWC = $16,676
CWC = $177,588

4/19/00 POOH TO RESET MOTOR @ 4373’
6:00 am - 6:30 am (1/2 hr) - Hook up mud pumps, tie triplex pump into premix to charge Weatherford pump.
6:30 am - 6:45 am (1/4 hr) - Check MWD.
6:45 am - 8:30 am (1 3/4 hr) - Run bit and motor to 4287 and wash down to 4300, working down 2' at a time at 4300 pulled tight, worked loose.
8:30 am - 10:30 am (2 hrs) - Work pipe from 4290 to 94 and circulate, getting lots of big pieces of shale and conglomerate.
10:30 am - 12:00 pm (1 1/2 hrs) - Wash back to 4313.
12:00 pm - 1:00 pm (1 hr) - Wash down from 4313 to 4314, hole continuing to slough.
1:00 pm - 2:30 pm (1 1/2 hrs) - Work on pumps.
2:30 pm - 4:00 pm (1 1/2 hrs) - Wash back from 4314 to 4318.
4:00 pm - 6:00 pm (2 hrs) - Wash to 4318, work on light plant, continue to work pipe, hole caved in, washed from 4312 to 4320.
6:00 pm - 11:45 pm (5 3/4 hrs) - Wash from 4320 to 4365
11:45 pm - 12:30 am (3/4 hrs) - Wash and ream from 4365 to 4373, hole is probably side tracked from 4320 to 4373.
12:30 am - 1:15 am (3/4 hrs) - Circulate bottoms up.
1:15am - 2:30 am (1 1/4 hrs) - Short trip to 4127 and wait 30 min.

2:30 am - 3:30 am (1 hr) - Circulate bottoms up.
3:30 am - 6:00 am (2 1/2 hrs) - Pull out of hole to reset motor from 3.06 degree to 1.05.
8.6 MW 43 Vis 6 WL 10 PV 24 YP 2/4 Gels 10 pH 18,000 Chls
DWC = $15,397
CWC = $192,985

4/20/00 DRILLING @ 4502' (CUT 129')
6:00 am - 8:00 am (2 hrs) - Continue out of hole.
8:00 am - 9:00 am (1 hr) - Reset motor to 1.69, had to change out flow tube. Connection appeared to be over torqued.
9:00 am - 10:30 am (1 1/2 hrs) - Locate oil pump for torque gauge and pump up torque gauge.
10:30 am - 11:30 am (1 hr) - Pick up change over from PH6 to AOH, PH6 threads appear to be several hundreths too big. Elected to run same BHA as before.
11:30 am - 1:30 pm (2 hrs) - Run in hole to 4285.
1:30 pm - 2:15 pm (3/4 hrs) - Test MWD tools.
2:15 pm - 5:30 pm (3 1/4 hrs) - Work through tight spots from 4285 to 4373.
5:30 pm - 9:15 pm (3 3/4 hrs) - Drilling ahead, slide drill from 4373 to 4388 (65R).
Slide from 4388 to 4408 (70R)
9:15 pm - 12:00 am (2 3/4 hrs) - Rotate from 4408 to 4420, Slide from 4420 to 4435 (45R)
12:00 am - 3:30 am (3 1/2 hrs) - Rotate from 4435 to 4452. Slide 4452 to 4457 (70R)
3:30 am - 6:00 am (2 1/2 hrs) - Rotate from 4457 to 4483. Slide 4483 to 4493 (85R)
Rotate from 4493 to 4502.
15,000 BW 8.3 MW 43 Vis 6.4 WL 7 PV 19 YP 1/2 Gels 10 pH 2/32 Cake 17,000 Chls
DWC = $15,136
CWC = $208,121

DEVIATION RECORD

DEPTH	INCL	AZM	TVD
4115	1.4	83.6	4114.88
4133	5.45	94.03	4132.84
4157	14	89.1	4156.48
4191	24.3	97.6	4188.56
4223	34.9	94.4	4216.34
4254	48.4	97.4	4239.83
4286	57.4	95.8	4259.64
4318	68.2	97	4274
4334	73.4	93.9	4279
4349	79.6	92.2	4282.91
4381	86.4	91	4286.81
4413	87.8	93	4288.43

4444	89	94.1	4289.29

SAMPLE TOPS

FORMATION	MD	TVD	.
Pawnee	4109	4109	- 1832
Ft Scott	4198	4194	- 1917
Cherokee	4222	4216	- 1939
B/Cherokee LS	4283	4258	- 1981
EROS Miss	4311	4271	- 1994
Miss WS	4317	4274	- 1997

Appendix 4
COMPLETION REPORT

Well Name: **UMMEL #4-H** **Operator:** **MULL DRLG CO INC**
Loc: **W/2 E/2 SE/4 24-18S-24W** **API #:** **15-135-23895-0101**
County/State: **NESS CO, KS** **Contractor:** **NORESEMAN RIG #4**

4/26/00 MIRU MDC DDPU. Found fluid 1400' FS with 100' oil on top. Fluid started kicking back 80' per pull @ 2200'. With 75 bbls swabbed back, had first show of muddy oil. Swabbed down to 3900' FS. Recovered 111 bbl. Last two pulls 5 bbl per pull 54% and 60% gassy emulsified oil. SDON. DCC = $2300

4/27/00 2500' ONFU, 1535' CGO oil on top (36.5 bbls oil - 61%). Swabbed down to 3500', recovered 66.5 bbls. One hr test - 2 pulls from 3450' - 12.25 bbl - 62% CGO. Ran 126 jts 2 7/8" tubing (12 new on bottom 114 used tested on top), SN depth - 4003', 15' perf mud anchor TD @ 4019', 2 1/2" x 5 1/2" anchor catcher set 2 jts above SN @ 3936. SDON.
DCC = $10,400
CCC = $12,700

4/28/00 Ran new 2 1/2 x 2 x 16' RWB pump w/6' GA, (6) 1 1/2" sinker bars, (5) 1" stabilizer bars, (150) used 7/8' rods, (2) 7/8" x 6' and (2) 7/8" x 4' rod subs. Moved rig off. Started well up at 6:30 p.m. with 5 SPM x 74" stroke.
12 hrs production: 12 BO 39 BW
DCC = $5,800

CCC = $18,500

4/29/00	85 BO	54 BW	Slowed to 4 3/4 SPM.
4/30/00	65 BO	69 BW	
5/1/00	69 BO	62 BW	
5/2/00	58 BO	63 BW	
5/3/00	60 BO	62 BW	
5/4/00	57 BO	52 BW	Shot fluid level, found 2415’ fluid from surface.
5/5/00	55 BO	51 BW	
5/6/00	24 BO	24 BW	Down 12 hrs (engine trouble)
5/7/00	12 BO		Down undetermined time (engine trouble)
5/8/00	52 BO	65 BW	
5/9/00	67 BO	60 BW	
5/10/00	62 BO	60 BW	
5/11/00	65 BO	61 BW	Producing fluid level: 1175’ FAP 4.5 SPM X 74”
5/12/00	67 BO	61 BW	
5/13/00	58 BO	50 BW	
5/14/00	57 BO	51 BW	
5/15/00	55 BO	50 BW	
5/16/00	52 BO	48 BW	
5/17/00	53 BO	48 BW	

5/18/00	52 BO	48 BW	Shot FL, found 1128' actual fluid above pump w/4 3/4 SPM x 74' stroke.
5/19/00	50 BO	50 BW	
5/20/00	52 BO	49 BW	
5/21/00	48 BO	46 BW	
5/22/00	60 BO	56 BW	
5/23/00	53 BO	48 BW	
5/24/00	38 BO	40 BW	Down 8 hrs for cleaning pumping unit Shot fluid level: 858' fluid above pump 74" stroke x 5.5 SPM
5/25/00	38 BO	31 BW	
5/26/00	53 BO	47 BW	
5/27/00	52 BO	49 BW	
5/28/00	58 BO	52 BW	
5/29/00	53 BO	49 BW	
5/30/00	53 BO	49 BW	

Appendix 5

MAINTENANCE REPORT

Well Name: **UMMEL #4-H** **Operator:** **MULL DRLG CO INC**
Loc: **W/2 E/2 SE/4 24-18S-24W** **API #:** **15-135-23895-0101**
County/State: **NESS CO, KS**

DAILY MAINTENANCE REPORT:

Date	Type	Cost	Remarks
6/7/2000	Fluid Level	$0.00	Shot fluid level. Found 572' FAP.
6/15/2000	Fluid Level	$0.00	Shot fluid level. Found 381' FAP
6/22/2000	Fluid Level	$0.00	Shot fluid level. Found 318' FAP.
			Speed from 5 1/2 SPM to 6 1/2 SPM.
6/30/2000	Fluid Level	$0.00	Shot fluid level. Found 0' FAP. 6 1/2 SPM @ 74" stroke.
7/20/2000	Production	$0.00	12 BO 29 BW
7/21/2000	Prod (C)	$0.00	13 BO 21 BW
7/22/2000	Prod (C)	$0.00	18 BO 22 BW
7/23/2000	Prod (C)	$0.00	18 BO 27 BW
7/24/2000	Prod (C)	$0.00	18 BO 32 BW
7/24/2000	Prod (C)	$0.00	18 BO 32 BW
7/26/2000	Prod (C)	$0.00	15 BO 19 BW
8/22/2000	Barrel Test	$0.00	3.25 BO 9.71 BW
11/17/2000	Pump Failure	$0.00	Shut well down for pump failure.
11/27/2000	Electrify	$0.00	Hooked up to electricity.
1/2/2001	Workover	$2,000.00	MIRU Plains Well Service. TOOH w/rods and tubing. SDON.

Date	Type	Cost	Remarks
1/3/2001	Workover (C)	$18,200.00	RU Haliburton. Ran 2.6" mill and mud motor on 1 1/2" coiled tubing. Milled out guide shoe @ 4400' MD, no returns. Pulled motor and mill, ran jetting nozzle on coiled tubing. Started pumping nitrogen and foamer. Tagged bridge @ 4465' MD, getting partial returns of shale and formation. Worked nozzle to 4490' MD, tubing dragging hard due to partial returns. Pulled up into build section and cleaned up. SDON. CC = $20,200
1/4/2001	Workover (C)	$19,000.00	Ran jet nozzle on coiled tubing, pumping gel and nitrogen. Hit bridge @ 4430' MD. Worked nozzle to 4477' MD. After 1 hr, no progress but getting good returns. TOOH. Ran 2.6" mill and mud motor. Drilled on guide shoe @ 4480' MD, getting good returns of formation and aluminum. Locked up mud motor. Cleaned up hole and TOOH. SDON. CC = $39,200
1/5/01	Workover (C)	$49,500.00	Ran in 2.75" bit and mud motor on coiled tubing, pumping nitrogen & gel. Worked bit through tight spots @ 4440 and 4463' MD. Worked bit to 4600', no progress for 2 1/2 hrs, pumped heavy gel sweep and pulled out of hole. Mud motor and bit left in hole. Suspect lost motor @ 4600' MD in last hour of drilling. Rigged down Halliburton. CC = $88,700
1/6/01	Workover (C)	$1,400.00	Ran casing swab and found fluid 2925' FS. Swabbed down to 3950', recovered 26 bbl on swab down. Began 1 hr tests: 1st hr .36 bbl 100% gel water 2nd hr .6 bbl trace oil 3rd hr .6 bbl 50% gel and 50% water w/show of oil 4th hr .6 bbl water w/bucket top of oil, no gel Total 28 bbl swabbed back. SDOWE.

Date	Type	Cost	Remarks
1/8/01	Workover (C)	$4,300.00	Ran 596' of 2 3/8" flush jt tubing w/guide shoe on 2 7/8" tubing. Hit tight spot in 3 ½" liner at 4225'. RU Swift and pumped 80 bbl lease oil down tubing. Casing loaded w/52 bbls pumped and shut in. Pumped 1 BPM @ 400# and continued working tubing to 4230'. TOOH/w tubing, guide shoe had 6" of drilling mud stuck in end. Found fluid 600' FS w/casing swab. Swabbed fluid down to 4000'. Swift pumped 1000 gal 15% MCA, displaced w/97 bbl 2% KcL. Casing loaded w/89 bbl pumped. AIR 2 BPM @ 475#; MP 475#; ISIP 450#, after 10 min 400#. Shut in casing. Total load 121 bbl. CC = $94,400
1/9/01	Workover (C)	$3,700.00	Fluid 20' FS. Swabbed down to 4000', recovered 97.7 bbl on swab down. Began 1 hr tests: 1st hr 2 pulls .65 bbl 95% oil 2nd hr 1 pull 1.67 bbl 94% gassy oil Total swabbed back 100 bbl, 21 bbl short of load. Ran 15 jts 2 3/8" flush jt tubing w/guide shoe (1 5/8" diameter hole on end), change over sub, FL overshot and seal nipple, 4 ½" centralizer, 2 3/8" x 2 7/8" change over, and 2 ½" SN. Total length of 451.3'. Ran 116 jts of 2 7/8" tubing and tagged up TD @ 4155'. RU Heat Waves and pumped 80 bbl oil while working tubing. Beat through tight spot. Tagged up mud @ 4170', started pumping 2 BPM @ 200# of 2% KcL, backside loaded (shut in); washed down to 4225' and became hard and guide shoe plugging off; washed down to 4235'. MP 1750# tubing and 1000# casing. Pulled up to 3950'. SDON. CC = $98,100
1/10/01	Workover (C)	$4,300.00	Tagged up @ 4230'. Hooked up Heat Waves, hole standing full of fluid. Pumped down tubing @ 3 BPM 1000-2000#, washed down guide shoe to 4520' MD, 4 ½" centralizer and 3 ½" liner hanger 4073', 2 ½" SN @ 4070'. Circulated clean w/260 bbl 2% KCL. Last 60 bbl, pressure dropped to 500# @ 2 BPM. Good fluid return and clean. Pumped 1000 gal 20% MCA. Displaced 250 gal acid out end of 2 3/8" liner and shut in backside. Pumped 8 bbl @ 1 BPM 250#, increased rate to 1 ½ BPM @ 350# for 10 bbl. MP=350# ISIP=200# Vac in 10 min. Total load=48 bbl. After 45 min – fluid 400' FS. Casing fluid going down while swabbing tubing. (Hole capacity 97 bbl.) Recovered 110 bbl on swab down. Fluid staying 3200' FS and swabbing from 4070'.

		1 hr test 28 bbl 5 pulls 2nd pull tested 18% oil 3rd & 5th pulls-swab stacked out @ 3800', pulled formation and some mud. SDON. CC = $102,400
1/11/01	Workover (C) $15,000	Found fluid 1850' FS, 2000' ONFU, 50' oil on top. RU Swift, mixed 15 gal packer fluid and 5 gal biocide in 5 bbl 2% KcL. Pumped down tubing and displaced w/40 bbl 2% KcL. Backside started blowing after 30 bbls pumped. AIR – 2 BPM MP – 275# Vac in 10 sec. Backside on vac. Released FL overshot from seal nipple. Pulled up 1 jt and set in slips, 127 jts 2 7/8", 2 ½" SN @ 4038', bottom of FL overshot @ 4040'. Ran rebuilt 2 ½" x 2" x 16' RWB w/6' GA and 3' x 1" stabilizer bar; (6) 1 ½" sinker bars; (153) 7/8" rods – top 2 rods inspected; and 1 ½" x 22' polish rod w/liner. Loaded and pressure tested tubing. BOP. CC -= $117,400
1/12/01		0 BO 150 BW
1/13/01		0 BO 147 BW
1/14/01		0 BO 259 BW
1/15/01		Shot FL, found 2164' FAP. Sped PU up from 5.5 SPM to 7.5 SPM. 2 BO 259 BW
1/16/01		2 BO 258 BW
1/17/01		2 BO 259 BW
1/18/01		1 BO 255 BW
1/19/01		1 BO 258 BW Shot FL, found 1814' FAP.
1/20/01		1 BO 259 BW
1/21/01		1 BO 256 BW
1/22/01		Shot FL, found 1814' FAP. Shut down for SWD room. Note: Production before workover: 0 BO 0 BW