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Interdisciplinary Study of
Reservoir Compartments and Heterogeneity

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By
C. Van Kirk

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Robert Lemmon, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
Colorado School of Mines
1500 Illinois Street
Golden, CO 80401

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ABSTRACT

A case study approach using Terry Sandstone production from the Aristocrat-Hambert Field, Weld County, Colorado is being used to document the process of integration. One specific project goal is to demonstrate how a multidisciplinary approach can be used to detect reservoir compartmentalization. Teamwork is the norm for the petroleum industry. Teams of geologists, geophysicists, and petroleum engineers work together to improve profits through a better understanding of reservoir size, compartmentalization, and orientation as well as reservoir flow characteristics. In this manner, integration of data narrows the uncertainty in reserve estimates and enhances reservoir management decisions. The process of integration has proven to be an iterative process. Integration has helped identify reservoir compartmentalization and reduce the uncertainty in the reserve estimates. The goal during the final phase of the project will be to quantify the value of integration and provide a template for making decisions.

EXECUTIVE SUMMARY

The project goal is to demonstrate how a multidisciplinary approach can be used to detect reservoir compartmentalization and to improve the reservoir description. The process of characterizing the reservoir has been an iterative process. Initial geologic mapping was done on a regional level. Qualitative core descriptions and initial producing GOR's were used to augment the mapping process and helped to identify reservoir compartments. The qualitative descriptions of the core were then linked to quantitative core descriptions including minipermeameter measurements. The petrophysical analysis, core descriptions, and minipermeameter results were then integrated to develop a correlation to estimate permeability from log derived data. The incorporation of the minipermeameter work resulted in the use of moved hydrocarbons to discriminate pay. As a result, revisions in the traditional cutoffs used in the petrophysical analysis were made to incorporate the moved hydrocarbon model. Further adjustments were made in the petrophysical analysis when the results of the production type curve matches were considered. Finally, detailed analysis of the production history in conjunction with the petrophysical data and cross sections has helped narrow the uncertainty in estimating the fluid distribution in the individual reservoir compartments.

Integration has reduced the uncertainty in the reserve estimates and helped define compartmentalization. The goal during the final phase of the project will be to quantify the value of integration and provide a template for making decisions.

INTRODUCTION

The integrated study of the Aristocrat-Hambert Field area has focused on the integration of geology, geophysics, and petroleum engineering as tools to describe and quantify reservoir compartmentalization. During the course of the project, data from each of the disciplines were gathered and form the basis for the integration. Experimental work was also performed and has been a valuable component in the integration.

Three major areas are addressed in the report: 1. Experimental Rock Property Measurements, 2. Reservoir Characterization, and 3. Reservoir Simulation. The discussion of these topics is intended to document the important concepts used by the team and support the statement that the process of integration is an iterative process. Each level of detail in the integration provides an added dimension, and possibly a change in thinking.

EXPERIMENTAL ROCK PROPERTY MEASUREMENTS

Rock properties and flow characteristics were measured on Terry Sandstone core in the Aristocrat-Hambert area. The measured rock properties were coupled with descriptive geologic interpretations of core sections and subsequently linked with log derived values to develop a correlation for permeability estimates. This integration of data permits estimates of permeability on a field wide basis. Relative permeability and compressibility (used in reservoir simulation), shear and compressional velocities (used in calibrating seismic data), Poisson's ratio and Young's modulus (used in hydraulic fracturing) were also measured.

Reservoir core samples of the Machi Ross #1 (Sec. 4N 65W), Vern Marshall #1 (NW SW 32 4N 65W), and Eckhardt # (Sec 15 4N 66W) wells were available and are located in a south-east to north-west trend in the Aristocrat-Hambert Field area (Figure 1).

A permeability-depth profile for each core was obtained with the Pressure Decay Profile Permeameter®. The Terry sandstone is a low permeability rock with permeability in the 0.015 to 9.0 md range. Permeability-depth profile measurements of the whole cores showed a good correlation to both the qualitative facies description and the log calculated values (Figure 2-4).

The Percent-Sand versus depth profile for the Vern Marshall #1 is shown as Figure 5. Core plugs were taken from the Vern Marshall #1 for further analysis. The core plugs (17 horizontal and 4 vertical) were cut based on the permeability profile results and variations in the depositional sequences. Porosity and permeability as a function of the net confining stress were determined. The permeability and porosity measurements were performed using the CMS-300 equipment under confining stress conditions of 500, 1000, 2000, 3000, 4000 and 4500 psig. The porosity was found to be in the 12% to 16% range under ambient conditions. Under the maximum applied confining stress of 4500 psig the porosity was reduced on the order of 1% porosity unit (Figures 6 to 8). The horizontal permeability was found to be in the order of 0.05 to 1.8 md under ambient conditions. Under the maximum applied confining stress of 4500 psig these values were reduced by 40% (Figures 9 to 12). The vertical permeability measured in four core plugs (adjacent to the horizontal plugs, see Table 1) ranged from 0.01 to 0.2 md. Under the maximum confining stress of 4500 psig, these values were reduced by 75% to 95%. The contrast between vertical and horizontal permeability is related to the shale laminae present in the Terry Sandstone. The vertical to horizontal permeability ratios under ambient conditions varied from 0.11 to 0.15. The vertical to horizontal permeability ratios under the maximum confining stress conditions of 4500 psig ranged from 0.017 to 0.063 (Table 1).

The experimentally determined porosity and permeability data under several confining stress conditions were curve fit to represent how these properties change with increasing stress (Figures 6 to 12). The empirical relations are given by the equations of the form:

$$\phi = A + Bp + Cp^2$$

and

$$k = A + Bp + Cp^2$$

where:

- ϕ = porosity (decimal)
- k = absolute permeability (md)
- p = confining stress condition (psig)
- A, B, C = regression constants.

The regression constants for the above equations are presented in Table 2 .

Compressional (P) and shear (S) wave-propagation velocities were measured in the horizontal and vertical core plugs under effective stress of 500, 1000, 2000, 3000, 4000 and 4500 psig. These measurements were made under gas (dry) and liquid saturated conditions (Figures 13 and 14). For the dry samples, no correlation between the seismic velocities and lithology was found. For the saturated measurements, a V_p/V_s ratio of approximately 1.7 indicates a "cleaner" sandstone (higher reservoir quality) and a ratio of 1.8 indicates a "shalier" sandstone (lower reservoir quality) (Figures 15 and 16). Samples were grouped as "good" reservoir quality (sample 5, 6, 14, and 17) and "poor" reservoir quality rock (sample 16, 19, and 20). When saturated, the good reservoir quality rocks (high porosity and permeability values) have higher V_s and lower V_p/V_s ratio than the poorer reservoir quality rocks (Figures 17 to 19). The elastic rock properties (shear modulus, Young's modulus, bulk compressibility and Poisson's ratio) were determined for the selected core plugs.

The following relationship between velocity (V) and effective stress (p) was found to fit the data :

$$V = A + B p^{1/3} + C p^{2/3}$$

- V = velocity (ft/sec)
- p = confining stress condition (psig)
- A, B, C = regression constants.

The regression constants for the above equations are presented in Tables 3 and 4.

The elastic properties, shear modulus ($m = G$), Young's modulus (E), Poisson's ratio (ν) and bulk compressibility (Cb), calculated under 3100 psia and 3600 psia for dry

measurements and saturated measurements and for "sand" and "shale" are presented in Table 5. There is no significant change in Young's modulus and the shear modulus for dry to saturated conditions. The bulk compressibility and Poisson's ratio, however, are dependent on whether the samples are dry or saturated.

Description of the whole core and clay content determinations were complemented with petrographic (epoxy-impregnation thin section analysis) and scanning electron microscope analysis on the Vern Marshall #1 (NW SW 32 4N 65W), Moser #1 (SE NW 34 4N 65W), Kinsman #1 (SE SW 18 4N 65W), Moser #1 (SE NW 34 4N 65 W), and Prima Oil Burke 24-3S (SE SE 24 4N 65W). The sandstones examined from all four wells are generally fine-grained, predominantly feldspathic, with variable amounts of carbonate cement mainly calcite. Laminae with almost no carbonate or clay often exhibit extensive quartz cementation. Stylolites are common in the Terry Sandstone in the study area. Clay laminae exhibit incipient stylolites that can inhibit vertical movement of reservoir fluids.

The stylolites, however, are typically discontinuous over long lateral distances. Petrographic analysis suggests presence of microporosity. Equivalent pore entry radius calculated from mercury-air capillary pressure experiment indicate abundance of less than 2 microns equivalent pore entry radius. Analysis of the scanning electron microscope indicate most pores in the sandstones are on the order of a few microns in diameter (microporosity), and that there are few large (>0.01 mm) pores.

Water-oil displacement experiments were used to determine relative permeabilities and capillary pressures. An experimental apparatus capable of working under lab and under confining stress conditions of up to 5,000 psig and at a reservoir temperature of 140°F was fabricated. Experiments were performed with 50,000 ppm (NaCl and KCl) brine and kerosene. Berea core plugs were used for preliminary work to test the apparatus and establish a standard reference. For relative permeability experiments, the core plug number 4 from the Vern Marshall #1 was selected based on its homogeneity and relatively high permeability. Core measurements were taken under lab and in-situ conditions. Under the maximum net applied confining stress of 3500 psig and a reservoir temperature of 140°F, the relative permeability curves were found to shift slightly to the right while maintaining their characteristic shape (Figures 20 and 21). The end points exhibited a minor or no shift. Figure 22 shows the simulated relative permeability curves for the imbibition process. Mercury-air capillary pressures were determined and the transformation to water-oil capillary pressure was found to be in excellent agreement with the experimental water-oil displacement (Figure 23).

A numerical simulation of the experimental water-oil displacement experiments was also performed (Figures 24 and 25). The simulation results were in good agreement with the laboratory observed pressures and production (Figures 24 and 25) (Ramakrishnan and Cappiello, 1991). The use of the numerical simulation technique to simulate the experimental displacement experiments is highly recommended to obtain the relative permeability curves because it provides smooth results and also provides information before the breakthrough (Johnson et al., 1959; Ramakrishnan and Cappiello, 1991). However, due to the tedious or lengthy process of the trial and error change of the relative permeability curves during the

matching process, it is recommended to generate a program to augment the automatic history matching process.

No general equation was found to transform the relative permeabilities obtained from measurements under lab conditions to the relative permeabilities under the reservoir conditions. The experimental results have been integrated with the other tasks. Experimental porosity and permeability estimates were compared to log derived estimates. A relationship between log derived values and permeability permits estimates of the permeability in other wells that have logs but no core samples. Also, these properties are related to the V_s and the V_s/V_p ratio. The results of the analysis of compressional and shear wave-propagation velocities from core plug samples are used to calibrate the tools used in the geophysical 3-D seismic interpretation.

RESERVOIR CHARACTERIZATION

The process of integration started with a regional structural and stratigraphic analysis. The analysis was further refined in the study area. This refinement was augmented by an analysis of initial producing gas-oil ratio's and seismic data. Additional refinement was obtained with the integration of core and production data. A production type curve analysis resulted in adjustments to the traditional well log cutoffs for porosity, water saturation, and shale content. These adjustments resulted in an increase in net pay relative to the original estimates. These examples of integration are described in the following paragraphs.

Geologic Mapping, Seismic Data, and Production Data

Figure 26 is the current structural interpretation. The fault mapping from well log correlation's compared favorably with fault mapping based on 3D horizon slice mapping. However, smaller faults appear to be more readily mappable from log correlations, coupled with initial GOR well data, than from seismic data.

The petrophysical parameters coupled with the geologic and geophysical fault interpretations and production data supports the interpretation of sealing faults. Tom Davis (1985) postulated the faulting to be associated with diagenetic events which damage the reservoir quality of the rocks. The petrophysical data from the HSR Salisbury 6-29 (very low porosity) supports this theory. This well appears to be in a down-dropped fault block. It is postulated that this block has experienced diagenetic cementing which has almost completely diminished the primary porosity. Producing GOR's also confirm the compartmentalized nature of the reservoir with faults being a major factor to the compartmentalization.

Core and Log Derived Data

The petrophysical analysis, core descriptions, and minipermeameter results were integrated to develop a correlation to estimate permeability from log derived data. The incorporation of the minipermeameter work resulted in the use of moved hydrocarbons to

discriminate pay. Moved hydrocarbon is estimated from the difference between BVW and BVZ. BVW is the bulk volume water (water saturation times the porosity) calculated for the uninvaded zone. BVZ is the bulk volume water for the mixed zone near the wellbore. The water in this zone is considered to be a mixture of the formation water and the water from the drilling fluid. R_z is defined as the resistivity of the water in the flushed zone that is a mixture of R_{mf} (resistivity of mud filtrate) and R_w (resistivity of formation water). Tixier's work (1949) in the Rocky Mountain area was used to estimate R_z .

The use of BVZ is crucial in the calculations of bulk volume water near the well bore. Since the Terry Sandstone is a low permeability formation, the invasion process is one of slow diffusion of fresh drilling mud filtrate into the formation. The clays contain formation waters near their surfaces and are diluted somewhat by the mud filtrate leaving a mixture of waters in the flushed zone. The common invasion profile for an induction log in a hydrocarbon formation is (from high to low resistivity) Shallow tool (SN or SFL), Medium tool (IML), and the Deep tool (ILD or 6FF40). The shallow reading device will read a higher resistivity than R_t because of the waters in the flushed zone. Common logging convention uses R_{mf} as the resistivity of the water in the flushed zone. Because of the invasion process specific to the Terry Sandstone, R_z describes the water present in the flushed zone.

The impact of using R_z instead of R_{mf} for the invaded zone is a reduction in the resistivity reading for the Shallow tool. Before the shift, the shallow tool almost always reads a higher resistivity than the deep investigation tool in the pay zone. After the shift, the shallow device will still have a higher resistivity reading in the pay zones (indicating invasion) than the deep device. However, in the non pay zones (no invasion), the opposite resistivity profile will occur where the shallow reading tool will have a lower resistivity reading than the deep reading tool.

The BVW processing using R_z enhances the ability to discriminate pay in tight laminated sandstone reservoirs. The technique does not enhance the vertical resolution of the logging tool, but does enhance the ability to detect invasion. The integration of the core descriptions with the minipermeameter results and the resulting correlation to estimate permeability from log derived data was a key to this analysis.

Although we have found the method to be useful in the discrimination of pay zones, the amount of the flushing and how it relates to permeability may not be a good consistent inference tool. This is because the quality of the digital data can make a big difference in the results of the inferred permeability.

Log Derived and Production Data

The production data was analyzed using an Infinite Conductivity Fracture Production Type Curve (Cox, 1995). Estimates of drainage area, fracture length, and permeability were made from the type curve match using estimates for net pay and porosity from log derived data. When the resulting fracture lengths and drainage areas

were plotted to scale at individual well locations to visually check the drainage patterns across the reservoir, further refinements in the petrophysical analysis were warranted. An iterative procedure was used to adjust the log derived values for net pay to better reflect the production performance. The integration of the production data shows that the traditional type of cutoffs (porosity, water saturation, and shale volume) were pessimistic when compared to the ultimate recoveries and reasonable recovery efficiencies. Table 6 presents a comparison of the petrophysical cutoff values used in the initial volumetric calculations and the revised values after the production data analysis.

TABLE 6

Comparison of Petrophysical Cutoff Values
Initial Volumetric Calculations and
Revised Values After Production Data Analysis

Parameter	Initial (%)	Revised(%)
Porosity	3	8
Water Saturation	55	65
Shale Volume	40	45

Pressure Testing

Pressure data from two wells were analyzed, the Jack C. Noel #1 and the Warren McMillen #1. These wells, completed in the 1970's, were hydraulically fracture stimulated. The wells were not tested prior to hydraulic stimulation. Well test analysis goals include estimating effective reservoir permeability and fracture half-length. The analysis results indicate permeability is 0.02 md and the fracture half-length is 700 feet. On the Jack C. Noel, the permeability and half-length were used along with a set of production rate type curves for Infinite Conductivity Vertical Fracture (Cox, 1995) to estimate the drained reservoir volume. The relatively short duration of the Warren McMillen test makes the interpretation more subjective. A high permeability streak, 0.6 md., appears to dominate the test. The results and reservoir parameters used in the analysis are summarized in Tables 7 and 8.

Table 7

Well Name	Permeability md	Fracture Half-Length feet	Drainage Area acres
Jack C. Noel #1	0.016	730	82
Warren McMillen #1	<0.6	~ 700	Estimate not possible

Table 8

Well Name	Porosity Fraction	Net Pay feet	Sw fraction	Ct x 10 ⁶ psi ⁻¹	Temperature F
Jack C. Noel #1	0.1	34	.50	450	170
Warren McMillen #1	0.12	54	.50	450	170

The layered nature and low permeability of the Terry Sandstone formation makes the well tests difficult to analyze. The variable production rate prior to the build-up adds complexity to the pressure signal, but multi-rate analysis can compensate for this problem if the rate data are available. The relatively short test duration and lack of rate data for the Warren McMillen #1 adds uncertainty to the analysis. The long build-up on the Jack C. Noel #1 lends more confidence to the analysis, but the lack of rate history prior to the test detracts from the certainty of the analysis. Regardless of the data problems, a reasonable estimate for the effective permeability is 0.01 to 0.02 md in the area around the well tests. The fracture treatments are yielding fracture half-lengths of approximately 700 feet.

RESERVOIR SIMULATION

A reservoir simulation model is being set up based on the integrated reservoir description. Reservoir simulation is another level of integration which will provide a dynamic test of our current interpretation. It is expected that the process of simulation will further narrow the uncertainty in our reserve estimates. Reservoir simulation of the study area provides the opportunity to test alternative methods of field development and the basis for economic comparison of the alternatives. In this study, the following variables are uncertain: initial reservoir pressure, bubble point-pressure, and fluid composition. Substantial effort was dedicated to the understanding of the reservoir fluid distribution. These issues are discussed in the following paragraphs.

Initial Pressure and Bubble-Point Pressure

The maximum known pressure of 1,768 psig was recorded in April 1976 at a depth of 4,422 feet. This pressure was recorded before fracture stimulation with the completion fluid still in the well. It was noted that the well was on a vacuum. A second pressure of 1,572 psig was recorded after fracture stimulation and well clean up. Based on this information, the initial reservoir pressure is estimated to be between 1,600 - 1,750 psia and equal to the bubble-point pressure. The initial pressure will be different for each fault block because the Gas/Oil Contacts (GOC's) are at different depths. The uncertainty of the estimates may narrow during history matching.

Fluid Types

The average oil gravity was 51° API from the predominately oil area and 60° API from the gas area. The gas gravity averaged 0.8 for the whole focus area. Based on the fluid analysis from production reports, one set of Pressure-Volume-Temperature (PVT) properties will adequately model the reservoir fluid in the different compartments. Using

correlations, an oil API of 51, and a gas gravity of 0.8, the gas in solution is approximately 757 Standard Cubic Feet/Barrel (SCF/BBL). This agrees with the observed initial producing GOR's in the oil zone.

Regions

The focus area was split into three regions. Currently, the relative permeability curves and PVT properties are considered constant throughout the focus area, and did not influence the determination of the regions. These regions were incorporated into the model to account for the different gas-oil contact depths in different fault blocks, which correlate to either a predominately oil area, gas area, or an area with intermediate GOR values. The highly compartmentalized nature of the Hambert Field is the result of extensive faulting. The transmissibility of the faults (whether they are sealing or not) will be refined during history matching.

Figure 27 is an example well log where the shale corrected density and neutron logs indicates a gas-oil contact. The relative amount of neutron-density separation was used to support gas-oil contact selection. Many of the wells with neutron and density logs do not have a clear separation of these two curves. Cross sections were prepared for different parts of the field. An example is shown in Figure 28. The cross section A-A¹ is shown on the area map, Figure 26. Cross sections were made to augment the determination of gas-oil contacts for the compartments on a depth basis. Perforated zone, GOR, and neutron density data were integrated with the structural data to estimate the gas-oil contact. For example, the higher the GOR the more the perforated zone was assumed to be saturated with gas and less with oil. The cross sections indicate that the gas is in the upper layers and the oil is predominately in lower zones within any fault block having a gas-oil contact.

Many of the wells that had an initially low GOR (predominately oil zone) are still producing oil at reasonably low GOR values. For wells that started with an intermediate GOR value, the gas invasion is minimal and the gas-oil contact is within the perforated interval. The wells producing with high initial GOR's are in a block or region which is predominately gas, with small or no oil present. In these cases the GOR is constant at a value greater than 50,000 SCF/BBL.

Simulation Model Layers

The geologic description and the petrophysical analyses have identified nine layers, as shown in Table 9. The top and bottom layers were eliminated because they were shale. The identified geologic layers were combined into five layers for the reservoir simulation model. The layers for the simulation are summarized in Table 9

TABLE 9
Comparison of Geologic and Simulation Models

<u>Geologic Model</u>	<u>Descriptions</u>	<u>Simulation Model</u>
Layer 0-1	Top shale layer	Not used
Layer 1-2	Top sand body	Layer 1
Layer 2-3	Shale layer	Layer 2
Layer 3-4	Sand body	Layer 2
Layer 4-5	Shale layer	Layer 3
Layer 5-6	Sand body	Layer 3
Layer 6-7	Shaly sand body	Layer 4
Layer 7-8	Sand body	Layer 5
Layer 8-9	Shale layer	Not used

Most of the wells are perforated in simulation model layers 3, 4 and 5.

Gross and Net Thickness

Manual mapping of layers 5-6 and 7-8 were performed considering the northwest to southeast depositional trend. Computer maps were generated using petrophysical derived net thickness, kriging software, and the assumed depositional trend. Comparisons of the computer maps with the manual mapping of layers 5-6 and 7-8 show good agreement. The perimeter wells in the buffer area have recently been analyzed and are now ready to be incorporated into the final maps.

Porosity and Water Saturation

The porosity and water saturation values obtained by the petrophysical analysis are being processed in a manner similar to net thickness.

Permeability

The permeabilities were estimated from two sources. The permeabilities estimated from the production-frac type curves compare favorably with the permeability map developed using the correlation derived from log data and the minipermeameter analysis. Individual permeability distributions for the selected layers were prepared from the log

transforms. Maps were prepared using the kriging software and imported into the simulator.

Relative Permeability

Relative permeability data obtained from the Terry Sandstone core experimental work will be used as a starting point in the simulation model. These curves were obtained from the best of the three cores measured. The measured water relative permeability is very low (approximately 0.1 at S_{or}). This agrees with field performance where the water production is insignificant. Similarly, gas coning is not a problem which may be due to the low vertical permeability and the shale laminae of the sand bodies. Increasing GOR's are not a problem which supports a slow advance of the free gas in the reservoir.

Leases

There are a few cases where production was reported for a multi-well lease. In some cases the GOR history behaved opposite from what was normally expected, i.e. the GOR decreased instead of increasing. This behavior is probably due to the inclusion of a new oil well in a lease report. Individual production is not available in these cases and the history matching will be compared to lease production.

TECHNOLOGY TRANSFER

During the year several presentations were made.

1. Two abstracts were presented at the 1995 American Association of Petroleum Geologists (AAPG) annual meeting. The abstracts were *Structural and Stratigraphic Compartmentalization of the Terry Sandstone, and Effects on Reservoir Fluid Distributions, Latham Bar Trend, Denver Basin, Colorado* and *Structural and Stratigraphic Compartmentalization of the Terry Sandstone and Effects on Reservoir Fluid Distributions in Hambert-Aristocrat Fields, Denver Basin, Colorado*.
2. An integrated team presentation was made on August 9, 1995 at the Colorado Oil and Gas Conference held in Denver, Colorado. Most of the team members were able to participate in this one-half day workshop.
3. On September 27, 1995, two team members made presentations and conducted a workshop in Houston for a Petroleum Technology Transfer Council sponsored event.
4. On September 10-13, 1995, one member of the team presented the results of the study at the 1995 American Association of Petroleum Geologists (AAPG) International Conference and Exhibition in Nice, France.

The Aristocrat-Hambert data are being used in multidisciplinary courses at the Colorado School of Mines.

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Figure 1 Base Map - Hambert Field - Location of the Wells
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Well Vern Marshall #1

Figure 10 Permeability versus Confining Stress

Figure 11 Permeability versus Confining Stress

Well Vern Marshall #1

Figure 12 Permeability versus Confining Stress

Well Vern Marshall #1

Figure 13

Figure 14

Figure 15

Vp/Vs ratio vs Effective Stress o - dry sample • - saturated sample (brine)

Figure 16

Vp/Vs ratio vs Effective Stress ○ - dry sample ● - saturated sample (brine)

Figure 17

Porosity vs Vp and Vs at 3100 psia effective stress
 • - Sample 5, 6, 14 and 17 ○ - Sample 1, 16, 19 and 20

Figure 18

Air permeability for horizontal samples vs V_p and V_s at 3100 psia effective stress
 Air permeability was measured at 4500 psig confining pressure

Figure 19

Top: Porosity vs Vp/Vs • - Sample 5, 6, 14 and 17 ○ - Sample 1, 16, 19 and 20
 Bottom: Air permeability for horizontal samples vs Vp/Vs
 All velocity measurements at 3100 psia effective stress
 Permeability measured at 4500 psig confining pressure

Figure 20 Relative Permeability Curves First Drainage

Under Net Confining Stresses of 200 psig, $T = 70^\circ\text{F}$ and 3500 psig, $T = 140^\circ\text{F}$

Figure 21 Relative Permeability Curves Experiments 20 and 26, Second Drainage

Under Net Confining Stresses of 200 psig, $T=70^{\circ}\text{F}$ and 3500 psig, $T=140^{\circ}\text{F}$

Figure 22 Relative Permeability Curves First Imbibition

Core Plug VM4

Figure 23 Capillary Pressure from Oil Displacing Water
 Experiment 18, First Drainage , Core Plug VM4 - Net
 Confining Stress 200 psig, T = 70 °F and Air-Mercury
 Experiment

Figure 24 Oil Displacing Water Relative Permeability Experiment 18, First Drainage

Core Plug VM4 - Net Confining Stress 200 psig, $T = 70^{\circ}\text{F}$

Figure 25 Oil Displacing Water Relative Permeability Experiment 18, First Drainage

Core Plug VM4 - Net Confining Stress 200 psig, $T = 70^{\circ}\text{F}$

HambGOR/ :Layer 1/Structure Tops(Ft)

Cross Section

Fig. 26 Terry Structure Map with Cross Section A-A¹

SPOT LOCATION
11980FNL 1980 FEL 29 4N 65W

CSM/DOE - Sussex
Preliminary Work Product
Contract No. DE-AC22-93PC14891
Task 1.1.2

OPERATOR	Georgia Polytechnic College
WELL	NO. 1 Bentlener 32-28 (4
COUNTY	WILK
STATE	GA.
DATE	5-15-60 - 4830.0
DEPT	911/28
Drill Legged	0235
API Number	4830
PROCESS	Dist. 0
	5/27/1985 14:10

[illegible]

Fig. 27 Neutron - Density Curve Separation Used to Support Gas Oil Contact

Fig. 28 Northwest-Southeast Terry Sandstone Cross Section A-A¹

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**Table 1 Summary of Permeability and Porosity Measurements
Hambert Field - Well Vern Marshall #1**

Core Plug No					No Confining Stress				Net Confining Stress 4500 psig				Ratio of Values Stress/Ambient		
	Depth	Diameter	Length	Dry Weight	Permab	Porosity	Pore Vol	kv/kh	Permab	Porosity	Pore Vol	kv/kh	Permab	Porosity	Pore Vol
	ft	cm	cm	gr	md	%	cc		md	%	cc				
1	4672.04	2.51	7.51	86.68	0.121	12.52	4.636		0.021	11.3	4.210		0.174	0.903	0.908
2	4671.67	2.51	7.35	83.66	0.650	13.33	4.835		0.438	12.4	4.477		0.674	0.930	0.926
3	4669.67	2.50	7.51	84.05	1.167	14.13	5.221		1.170	13.2	4.872		1.003	0.934	0.933
4	4668.08	2.51	7.15	79.46	1.840	14.91	5.256		1.370	13.8	4.885		0.745	0.926	0.929
5	4665.96	2.51	7.50	83.61	1.500	14.36	5.329	0.125	0.925	13.5	4.989	0.017	0.617	0.940	0.936
6 Vert	4665.88	2.51	7.52	84.92	0.187	13.76	5.095		0.016	12.8	4.753		0.086	0.930	0.933
7 Vert	4664.92	2.50	7.51	84.44	0.180	14.91	5.525	0.155	0.048	14.2	5.235	0.053	0.267	0.952	0.948
8	4664.67	2.52	7.51	83.86	1.159	15.21	5.759		0.765	14.5	5.423		0.660	0.953	0.942
9	4662.88	2.50	7.54	83.14	1.837	16.16	6.041		1.480	15.4	5.755		0.806	0.953	0.953
10	4661.84	2.50	7.43	82.53	1.276	15.83	5.761		0.816	14.9	5.422		0.639	0.941	0.941
11 Vert	4658.34	2.51	2.45	28.03	0.016	14.85	1.791	0.111	0.001	11.7	1.395	0.028	0.063	0.788	0.779
12	4658.08	2.51	6.97	80.30	0.144	13.05	4.473		0.036	11.8	3.995		0.250	0.904	0.893
13	4656.08	2.49	6.93	77.62	1.020	14.30									
14	4650.92	2.50	7.00	77.76	0.390	16.85	3.435		0.228	15.6	3.171		0.585	0.926	0.923
15	4648.80	2.50	7.53	85.11	0.253	14.50	5.401		0.141	13.7	5.071		0.557	0.945	0.939
16	4645.40	2.50	6.92	79.83	0.129	11.94	4.069		0.014	11.2	3.803		0.109	0.938	0.935
17	4637.90	2.50	7.55	83.77	0.561	15.53	5.754		0.384	14.8	5.478		0.684	0.953	0.952
18	4633.25	2.50	7.59	86.91	0.149	14.31	5.315		0.066	12.8	4.770		0.443	0.894	0.897
19	4627.29	2.50	7.43	85.17	0.495	13.05	4.767	0.111	0.007	12.1	4.410	0.266	0.014	0.927	0.925
20 Vert	4627.12	2.50	6.21	71.75	0.055	11.80	3.553		0.002	11.2	3.420		0.036	0.949	0.963
21	4622.96	2.50	7.52	86.96	0.056	13.38	4.890		0.004	11	4.054		0.071	0.822	0.829

* Max stress 2000 psig

Table 2 Parameter Coefficients for Curve Fit

Porosity							
	Core Plug 5	Core Plug 6	Core Plug 9	Core Plug 17	Core Plug 19	Core Plug Berea 1	Core Plug Berea 2
A	14.3612	13.7592	16.1600	15.5334	13.0517	16.808	23.9597
B	-0.000371302	3.96E-08	-0.000280718	-0.000339687	-0.000274664	-0.000295293	-0.000369955
C	-0.0003858	4.02E-08	2.57E-08	3.97E-08	1.34E-08	2.63E-08	3.97E-08

Permeability							
	Core Plug 5	Core Plug 6	Core Plug 9	Core Plug 17	Core Plug 19	Core Plug Berea 1	Core Plug Berea 2
A	1.50047	0.187008	1.83713	0.560179	0.495264	41.3974	549.504
B	-0.000225574	-9.09E-05	-0.000150628	-8.08E-05	-0.000357719	-0.00114484	-0.0113162
C	2.20E-08	1.19E-08	1.60E-08	9.30E-09	6.02E-08	9.29E-08	6.94E-07

Pore Volume							
	Core Plug 5	Core Plug 6	Core Plug 9	Core Plug 17	Core Plug 19	Core Plug Berea 1	Core Plug Berea 2
A	5.32851	5.09452	6.04088	5.75371	4.76658	6.55295	8.38555
B	-0.000153417	-0.000142163	-0.000124292	-0.000113754	-0.000112054	-0.000142253	-0.000144657
C	1.76E-08	1.49E-08	1.37E-08	1.18E-08	7.24E-09	1.57E-08	1.61E-08

$$V=A+Bp_e^{1/3}+Cp_e^{2/3}$$

Table 3

Sample	<u>Dry V_p</u>			<u>Dry V_s</u>		
	A	B	C	A	B	C
1	7977.43	230.379	2.45164	5590.02	53.8949	5.80345
5	7600.98	345.589	-0.883505	5531.51	154.636	1.36246
6	7351.69	151.366	10.5353	4773.26	251.585	-1.83017
14	9185.39	91.548	7.75116	6290.25	53.5639	4.39532
16	9443.85	227.244	-1.37185	5983.98	151.994	-1.21266
17	10117.2	118.464	4.38886	6424.3	87.6907	2.40063
19	10172.4	56.5785	6.71888	7150.22	-28.716	6.22058
20	6603.63	209.355	4.49303	5679.24	107.938	1.59842

The constants A, B and C for the best fit equation $V=A+Bp_e^{1/3}+Cp_e^{2/3}$ where p_e is the effective stress and V is the seismic velocity

$$V=A+Bp_e^{1/3}+Cp_e^{2/3}$$

Table 4

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Sample	<u>Saturated Vp</u>			<u>Saturated Vs</u>		
	A	B	C	A	B	C
1	12377.4	-14.217	5.05396	5662.77	129.735	-0.41666
5	10488.2	262.404	-4.16033	4667.17	280.117	-4.33327
6	10757.9	225.719	-2.3265	4710.43	290.833	-4.77779
14	10885.6	185.194	-1.56252	5977.33	56.2924	3.68567
16	11237.2	125.41	0.04521	5064.07	125.269	0.83528
17	10478.0	340.681	-8.89301	4866.62	300.683	-6.33057
19	12299.2	-46.0168	7.2945	6045.13	27.6383	4.19486
20	10834.2	92.7883	-0.56432	5811.36	-22.593	5.29925

The constants A, B and C for the best fit equation $V=A+Bp_e^{1/3}+Cp_e^{2/3}$ where p_e is the effective stress and V is the seismic velocity

Table 5

Property	<u>Dry measurements</u>		<u>Saturated measurements</u>	
	$P_e=3100$ psia	$P_e=3600$ psia	$P_e=3100$ psia	$P_e=3600$ psia
μ_{sand} (psi)	2.000×10^6	2.064×10^6	1.973×10^6	2.023×10^6
μ_{shale} (psi)	1.948×10^6	2.007×10^6	1.770×10^6	1.819×10^6
μ_{ave} (psi)	1.980×10^6	2.043×10^6	1.872×10^6	1.921×10^6
E_{sand} (psi)	4.539×10^6	4.690×10^6	4.921×10^6	5.024×10^6
E_{shale} (psi)	4.475×10^6	4.608×10^6	4.524×10^6	4.635×10^6
E_{ave} (psi)	4.507×10^6	4.649×10^6	4.723×10^6	4.829×10^6
ν_{sand}	0.1346	0.1359	0.2470	0.2418
ν_{shale}	0.1489	0.1477	0.2784	0.2475
ν_{ave}	0.1418	0.1418	0.2627	0.2584
Cb_{sand} (1/psi)	4.831×10^{-7}	4.672×10^{-7}	3.085×10^{-7}	3.085×10^{-7}
Cb_{shale} (1/psi)	4.712×10^{-7}	4.600×10^{-7}	2.900×10^{-7}	2.855×10^{-7}
Cb_{ave} (1/psi)	4.771×10^{-7}	4.636×10^{-7}	3.011×10^{-7}	2.999×10^{-7}

Rock properties at 3100 psia and 3600 psia effective stress. Subscript "sand" refers to good reservoir quality rock and subscript "shale" refers to poor reservoir quality rock. Subscript "ave" refers to the average.