A Method for Developing 3D Hydrocarbon Saturation Distributions in Old and New Reservoirs

Michael J. Heymans, Consultant
590 Prairie Ridge Road
Highlands Ranch, CO 80126-2036

ABSTRACT

In order to estimate the remaining recoverable hydrocarbons, or proved reserves in a reservoir, it is useful to have, as accurately as possible, an estimate of the original hydrocarbons in place, OHIP, and a quantitative model of the 3D hydrocarbon saturation distribution. Commonly used methods of estimating the OHIP, such as material balance, decline curve analysis, and simple volumetrics assume a tank model. These methods do not provide the overall dimensions or hydrocarbon saturation values for any location within a reservoir. However, the dimensions and 3D hydrocarbon saturation distributions are easily obtainable for more rigorous volumetrics. Comprehensive volumetrics in conjunction with numerical simulation production history matches can be used for determining the amount and locations of reserves within a reservoir.

The focus of this paper concerns one factor in more rigorous volumetrics and that is determining the average variations in hydrocarbon saturation throughout a reservoir. The methodology relates both laboratory and field derived data consisting of porosity, absolute permeability, drill stem test results, and capillary pressure core test measurements to average variations in 3D hydrocarbon saturation distributions throughout a reservoir. The methodology is applicable to reservoirs where the elevation of the free water level at discovery is not known. The technique is applied late in the life of a complex reservoir in the Big Horn Basin.

Particular attention concerns the determination of the top and base of transition zones because transition zones are encompassed in material balance and decline curve analysis calculations of OHIP. Including the respective transition zones into the case history example resulted in more than a 30% increase of the OHIP from previous simple volumetric calculations. The improved volumetrics were within 2% of concurrent material balance calculations of OHIP.

The remaining oil in place was obtained by subtracting the OHIP from the amount of hydrocarbons produced. The large remainder influenced the field operator’s decision to engage in the expense of 3D seismic for an improved reservoir description. The improved reservoir description helped to optimize reservoir management operations and significantly reduced the decline in secondary oil recovery.

INTRODUCTION

For improved reservoir management, an increasing number of companies are using numerical reservoir simulation to estimate the amount and the spatial distribution of oil and gas reserves throughout a reservoir. In order to accomplish those objectives it is necessary to have, as accurately as possible, an estimate of the original hydrocarbons in place, OHIP with a quantitative model of the 3D hydrocarbon saturation distribution. Commonly used methods of estimating the OHIP include material balance, decline curve analysis, and simple volumetrics.

In principle, material balance involves measurements of the volume of fluids produced from a reservoir as a function of the drop in reservoir pressure. With this data it is possible to calculate the OHIP without a direct measurement of the reservoir’s physical dimensions.

The reader is referred to Arps 1964 for a description of material balance equations.

Decline curve analysis consists of measuring production rate of reservoir fluids (in units of stock tank barrels per day for oil) plotted on a graph of time in months or years. As a trend of production rate is established it allows an extrapolation into the future of ultimate hydrocarbon recovery. Additional considerations that factor into this type of reserves estimate are the economic cutoffs for the operations being used to recover the remaining hydrocarbons. As with material balance, this method does not require nor can it provide the physical dimensions for a reservoir.

Simple volumetrics is the product of an average porosity for an entire reservoir, times the average thickness of net pay, times an arbitrary reservoir area, times an average hydrocarbon saturation value for an entire reservoir. Although a comprehensive discussion of determining net pay is beyond the scope of this paper it can be summarized as follows. Net pay is the thickness in a productive interval in which hydrocarbons can be produced economically. It is often times determined by a cut-off porosity, which is the porosity below which hydrocarbons can not be economically produced from the gross reservoir interval. The reservoir area term in simple volumetrics is arbitrary because it depends on which "oil-water" contact that is used to define the reservoir limits. There are at least four oil-water contacts that can be chosen for a water-wet reservoir. Only one of them is appropriate for volumetric OHIP calculations. For an expanded discussion of oil-water contacts, please refer to Heymans (1997). Although physical dimensions are used in simple volumetrics, those dimensions are not appropriate for delineating reservoir boundaries.

More rigorous volumetrics use dimensions that delineate the reservoir boundaries and a 3D hydrocarbon saturation distribution. More detailed volumetrics integrate variations in porosity, times variations in net pay thickness, times the reservoir area defined by the free water level (for water-wet reservoirs), times the variation in hydrocarbon saturation distributions. If the data from all of these sources is correct, there should be an acceptable agreement between material balance and volumetric calculations of OHIP.

The focus of this paper concerns one of the factors in more rigorous volumetrics, i.e. the determination of variations in average hydrocarbon saturation distributions throughout a reservoir. Presented is a methodology for developing a suite of hydrocarbon saturation curves and their distributions in a reservoir as a function of those properties that affect storage capacity and fluid flow.

CASE HISTORY BACKGROUND

A project was initiated to model the performance of all of the wells in a Wyoming oil reservoir through numerical simulation. After the simulator could reproduce the performance history of the field, it would be used to forecast reservoir performance depending on various hypothetical field operations. These results would be used to justify the economics for infill development and the other operational practices. Simple volumetrics had been used in previous estimates of OHIP. More rigorous volumetrics of the OHIP needed to be developed for the level of detail incorporated into the numerical simulator.

For the example reservoir the elevation of the top of the transition zone, or base of the oil column, described as the "productive limit" was known but the FWL was not known. The "productive limit" was based on the lowest elevation at which dry oil was found from drill stem tests. This datum elevation, which excluded transition zone oil, was used to define the areal reservoir limits for simple volumetric calculations. A methodology, presented in this paper, was developed that incorporated the missing transition zone oil into the reservoir description for improved volumetrics of OHIP.

RESERVOIR FLUID DISTRIBUTION DESCRIPTIONS

At discovery, prior to hydrocarbon withdrawal, oil saturation distributions in a reservoir are controlled by such factors as: the density difference between water and the hydrocarbons, the thickness of the hydrocarbon column, pore entry size and distribution from the scale of particles to the largest pore types (i.e. including fractures, vugs, and caves), rock/fluid interaction (i.e. interfacial tension and wettability), and the presence of a hydrodynamic gradient. This distribution can be mathematically modeled for 3D visualization with combinations of field and well performance data, geologic models of structural and facies distributions, and statistically representative core samples used in capillary pressure core test measurements.

In a reservoir, fluids in general are commonly divided into three divisions of the fluid column, i.e. a hydrocarbon column, transition zone, and water leg. The uppermost division, the hydrocarbon column, is characterized as producing only hydrocarbons. Problems arise in determining the base of a hydrocarbon column when the terms oil-water-contact are used. There isn't a universally accepted definition for the expression among various disciplines involved in reservoir characterization.

Because of differences in defining an oil-water-contact (Heymans, 1997), a transition zone could be completely excluded, partially included, or included in its entirety in volumetric calculations of the OHIP. Another problem is the amount of hydrocarbons recoverable from a transition zone is not well understood. One reason is because there isn't a universally accepted definition of what constitutes the top and bottom of a transition zone. Another reason is the inappropriate conventional understanding and use of the relationship between a drainage saturation distribution curve and a pair of forced imbibition relative permeability curves to model oil recovery from waterflooding. Through a combination of laboratory core test measurements (Christiansen, et al 1999), graphical analysis (as discussed in this paper), and selection of the appropriate options in a modern numerical simulator (Fanchi et al 1999), the amount of hydrocarbons recoverable in a hydrocarbon oil column and transition zone can be determined.

Transition zones are present in nearly all hydrocarbon reservoirs. The literature reveals that oil-water transition zones vary in thickness from a few feet to several thousand feet (Bradley, 1992). Like the concept of an oil-water-contact there doesn't appear to be a universally accepted definition of a transition zone. In this paper, a transition zone is defined, for volumetric calculations of OHIP, as the hydrocarbon and water distribution below a hydrocarbon column of potential water-free hydrocarbon production and immediately above a zero buoyant pressure level, i.e. the FWL.

CORRELATING FLUID CONTACTS

For newly discovered and older reservoirs, it is possible to apply a technique published by Schowalter and Hess (1982) to estimate the position of a FWL. The technique uses water or oil saturation data from as limited a source as a single well, a local or regional structure map, and capillary pressure core test measurements.

A new method of determining an unknown FWL, that is an extension of Schowalter's work (1979, 1982), involves a combination of field data and a graphical method based on work published by Swanson (1981). Swanson (1981), used a graphical method for estimating absolute permeability from air/mercury capillary pressure core test measurements. He found, through porosimetry, that as soon as an effective saturation of the non-wetting phase, i.e. mercury or hydrocarbon, is attained, fluid flow is dominated by that fluid. The effective saturation, as acquired from air/mercury capillary pressure core test measurements and plotted on Swanson's nomograph, can be correlated to the top of a transition zone in a reservoir. By converting the laboratory air/mercury capillary pressure core test measurements to reservoir fluids at reservoir conditions, a hydrocarbon saturation distribution as a function of height in a reservoir can be constructed. From this curve it is possible to extrapolate to the elevation of the FWL in a reservoir. The extrapolation is accomplished by tying the effective saturation point on this curve to the known elevation of the top of the transition zone in a reservoir.

METHODOLOGY

A single drainage curve used to describe the hydrocarbon saturation distribution in a reservoir provides more detail than a single average saturation value used in simple volumetrics. However, a single curve provides a change in hydrocarbon saturation in a vertical plane but no variation in a horizontal plane (assuming there isn't a hydrodynamic gradient).

A further improvement over using a single oil saturation curve as a function of height can be made by using a suite of curves that are tied to rock properties that can be mapped throughout a reservoir. It is well known that as the distribution of porosity and permeability change in a reservoir, hydrocarbon saturations will also change laterally and vertically. The following details the elements used to characterize the lateral and vertical oil saturation distribution.

The approximate elevation of the top of the transition zone was determined in the example field from drill stem test (DST) data to be the deepest elevation where dry oil could be measured. The next set of steps elaborate on the laboratory core test measurements that were correlated to this DST datum. The respective porosities and absolute permeabilities for three core plugs, on which air/mercury capillary pressure tests had been performed, were compared to the porosity/permeability plot derived for the formation within the field (Fig. 1). One of the core test samples came closest to the dashed best fit regression curve line. The sample had a porosity of 13.4% with an absolute permeability of 49md. On the plot in Figure 1, an ideal statistically representative sample with a 13.4% porosity would have a corresponding absolute permeability of about 60md. The arithmetic average porosity was 13.8% and average absolute permeability 68md for all of the cored wells in the example reservoir. The core test sample mentioned earlier was interpreted to be statistically representative of the pore types that control the reservoir rock matrix storage and fluid flow. Ordinarily it is best to select statistically representative samples prior to core testing. However, in the example reservoir, attempts were made to use the existing data and evaluate whether it could be used instead of gathering more data. Personal experience has shown that core test samples with porosity and permeability values that deviate significantly from a best fit regression curve on a porosity/permeability plot have anomalous fluid flow characteristics.

The use of a graphical presentation of porosity versus permeability is not meant to imply that porosity is the best or only predictor of absolute permeability. The scatter and range of absolute permeability values for given porosity values shown in Figure 1 provides an indication of that. Absolute permeability is related to porosity because permeability doesn't exist without porosity, but it is one of three variables that control absolute permeability. The other two most influential variables are stream area and surface area. Stream area is the cross sectional area for flowing fluids and not the total area term used in Darcy's Law. Surface area is the area that would be contacted by liquids flowing through a pore network. All three of these variables are elements of a geologic model which could be comprised of grain size distributions, stratigraphic facies distributions, and/or diagenetic overprints that can be modeled throughout a reservoir. A porosity versus absolute permeability correlation is more useful when tied to those elements of a geologic model that influence storage and fluid flow.

The air/mercury capillary pressure curve for the sample deemed statistically representative (Figure 2) was then plotted on Swanson's (1981) nomograph which uses the percent of bulk volume of mercury saturation on the horizontal log scale versus capillary pressure on the vertical log scale (Fig. 3). The measured absolute permeability of the core plug sample and that predicted graphically by the tangent of the hyperbolic curve to a diagonal line, i.e. absolute permeability on a log scale on the nomograph, should be in close agreement. An agreement indicates that the pore entry size distribution characteristics that influence fluid flow are represented by the capillary pressure curve. For this core plug sample the absolute permeability measured was 49 md and the nomograph estimate is 50 md.

This hyperbolic curve (Fig. 3) was then used as a template to develop a suite of paralleling hyperbolic curves on the nomograph (Fig. 4). Each hyperbolic curve was constructed such that the tangent of each curve on the nomograph matched the absolute permeability value for each whole number porosity value from the porosity/permeability relationship in Figure 1. Those values are listed in Table 1. The range of porosity values, from 8-19%, come from the range of average porosity values from well log data for the formation in the example reservoir. There was also close agreement between core porosities and well log porosities. The tangent of each hyperbolic curve (Fig. 4), i.e. an absolute permeability value, was spotted on a perpendicular line to the tangent from the model hyperbolic curve (Fig. 3). The location of the perpendicular line to the absolute permeability diagonal lines is dependent on the pore geometry characteristics as dictated by the first representative sample plotted, from Figure 3. Constructing all of the hyperbolic curves approximately parallel to this representative sample is an attempt to preserve the fundamental similarities in pore geometry characteristics that affect hydrocarbon storage, capillary pressure, and fluid flow.

The hyperbolic curves (Fig. 4), although nearly parallel, are also constrained in two other ways. Given a certain buoyancy pressure, which is directly proportional to the height of an oil column, a more porous and permeable reservoir rock will have a lower initial water saturation than a less porous and permeable reservoir rock. For the example reservoir, the height of the oil column, i.e. from the FWL to the highest structural elevation in the reservoir, corresponds to the equivalent of 370 psi mercury capillary pressure. It was also known that the initial water saturations at the top of this oil column ranged from 5 to 20% of a pore volume. The initial water saturations were obtained from Dean-Stark extractions from oil cut core taken at or near the crest of the reservoir prior to the influx of water.

The suite of hyperbolic curves, representing the range of oil saturation curves for the corresponding range of mapped porosity values, were replotted to linear scales of air/mercury saturation, as a percent pore volume, versus mercury capillary pressure. These linear scale curves were then converted from air/mercury data to reservoir fluids at reservoir conditions, i.e. oil saturation as a function of height above the FWL established earlier (Heymans et al, 1992).

Each oil saturation curve as a function of height corresponds to an average mapped porosity value. For each average whole number porosity value at a given elevation, i.e. height above the FWL in the reservoir, a certain hydrocarbon saturation value from the appropriate saturation curve can be assigned. A result of these correlations between mapped porosity elevation above a FWL, and capillary pressure core test measurements converted saturation distribution as a function of height, an average hydrocarbon saturation value can be determined for any location within a numeric reservoir model. That is, for each grid node in a numeric reservoir simulator, a unique hydrocarbon saturation value can be assigned depending on the porosity value for the node and the elevation above the FWL. For an expanded discussion comparing the results of this methodology to estimates of OHIP using simple volumetrics, a single saturation curve for each formation, and hydrocarbon saturations calculated from each well in the field, the reader is referred to Heymans et al, 1992.

UNCERTAINTIES

Uncertainties in the application of the methodology proposed in this paper would include the accuracies of the measurements performed in wells and on the core samples. However, discussions of the uncertainties associated with each of those measurements is beyond the scope of this paper. But, even if those measurements are accurate, there is the common uncertainty associated with interpolations of geologic and engineering data between wells. A large number of wells, e.g. 600 or more, and well spacing close enough to delineate influential geologic features affecting storage capacity and fluid flow, reduces statistical uncertainties for interpolations of mapped data between wells.

On a relative comparison, there are uncertainties associated with an average absolute permeability value determined for a given porosity value from a general ø/k relationship as shown in this paper. There can be a unique ø/k relationship for each facies/flow unit in a formation. For more than one flow unit there are uncertainties in determining the dimensions and locations of those units throughout a reservoir. Hence the need for the application of a geologic model to help determine the distributions of measurements from wells and cores. Assigning a permeability value to a mapped porosity value from well log measurements, is similar in uncertainty to assigning a capillary pressure saturation curve to a mapped porosity value. Both cases are dependent on representative statistical averages, distances between mapped control locations, and interpretations of a geologic model of the reservoir.

CONCLUDING REMARKS

A more detailed hydrocarbon saturation distribution model is more useful for numerical simulation of a reservoir than the more commonly used single saturation curve. Attempts at history matching individual well performances are more easily accomplished when the proper amount of oil and water are allocated to areas around each well. Closer history matches instill more confidence in reservoir performance forecasting results. These results are then used to assist in making more informed reservoir management decisions to help to improve the bottom line.

Including the respective transition zones for each formation into more rigorous volumetrics resulted in less than a 2% difference between material balance and volumetric calculations and more than a 30% increase of the OHIP from previous simple volumetric calculations. An improved estimate of the remaining oil in place influenced the operator of the example field to engage in the expense and use of 3D seismic for an improved reservoir description. The improved reservoir description contributed to optimizing reservoir management operations and significantly reduced the decline in secondary oil recovery.

CONCLUSIONS

(1) There are potentially four oil water contacts within the same well bore for water-wet reservoirs.
(2) The base of a transition zone for volumetrics of OHIP in a water-wet reservoir is the FWL.
(3) Using Swanson's graphical technique derived from laboratory core test measurements and a dry-oil elevation from DST data it is possible to determine the FWL.
(4) The top of a transition zone in a field is that elevation in an oil column where dry-oil is located from drill stem tests.
(5) The exclusion of transition zone oil in volumetrics can result in significant underestimates of OHIP.
(6) Comprehensive volumetrics of OHIP should include variations in hydrocarbon saturation values throughout a reservoir.

(7) There should be an agreement between material balance and volumetric calculations of OHIP.
(8) Comprehensive volumetrics used with numerical reservoir simulators can be used to determine the physical locations of reserves.
(9) Multiple drainage curves provide a 3D model of hydrocarbon saturation distributions in a reservoir.
(10) A graphical method for developing average hydrocarbon saturation distribution curves tied to porosity and absolute permeability is presented.
(11) A method for selecting statistically representative core plug samples for core test measurements is presented.
(12) Comprehensive volumetrics use dimensions that delineate reservoir boundaries and a 3D hydrocarbon saturation distribution.

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Table 1

Porosity %	Absolute Permeability md
8	**3**
9	**7**
10	**12**
11	**20**
12	**30**
13	**60**
14	**80**
15	**90**
16	**110**
17	**130**
18	**200**
19	**220**

The corresponding absolute permeability for a given porosity was estimated from the best fit curve on the porosity/permeability plot from Figure 1. These permeability values became the tangents for the hyperbolic curves that are created (Figure 4).

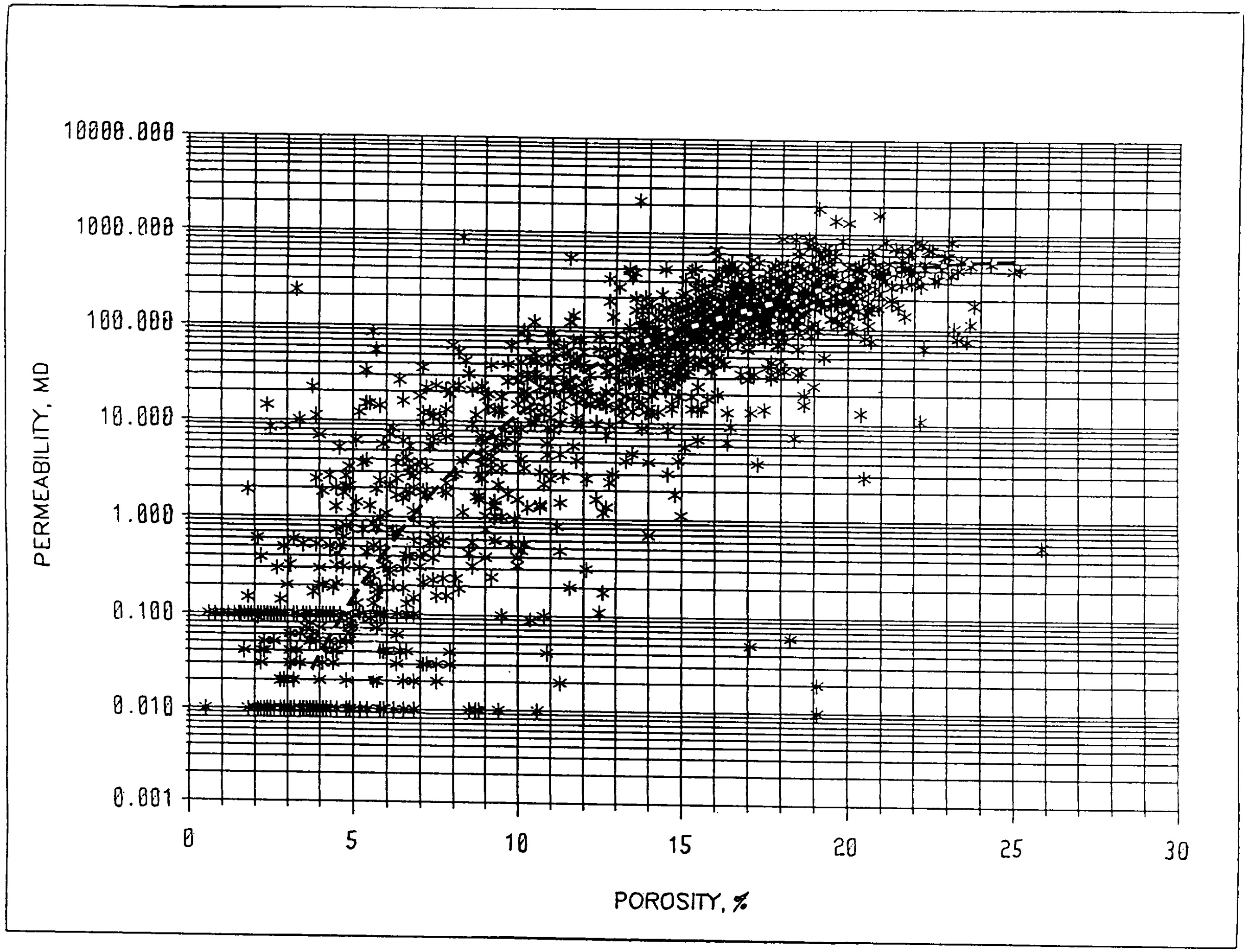

Figure 1. The graphical relationship of permeability to porosity from the example reservoir. Core test samples with absolute permeability values on or very near the best fit regression curve tend to have representative fluid flow characteristics (Heymans, 1992).

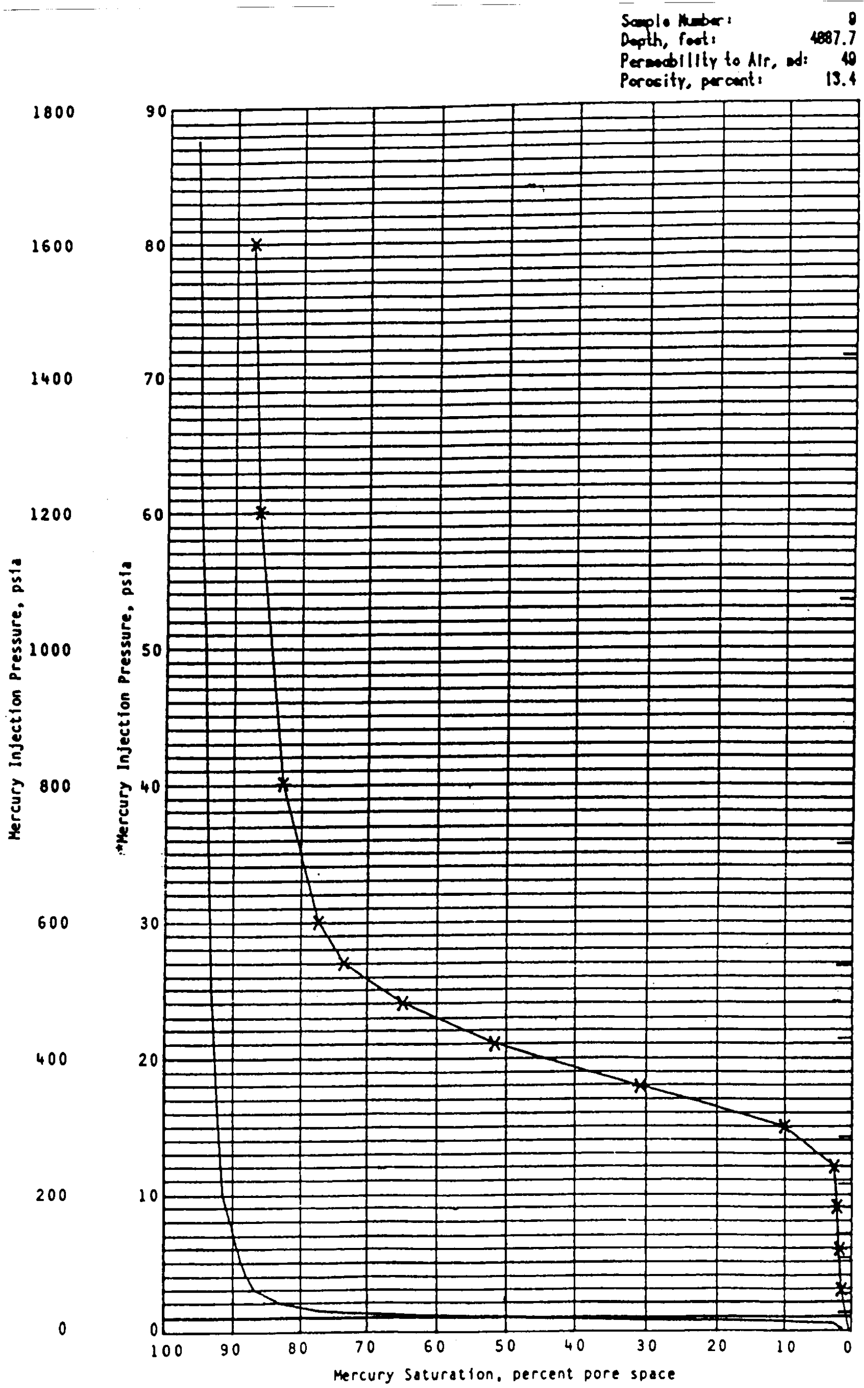

Figure 2. A low (left inside scale) and high pressure (left outside scale) plot of air/mercury intrusion as a percent of pore space for the statistically representative core sample from the example reservoir (Heymans, 1992).

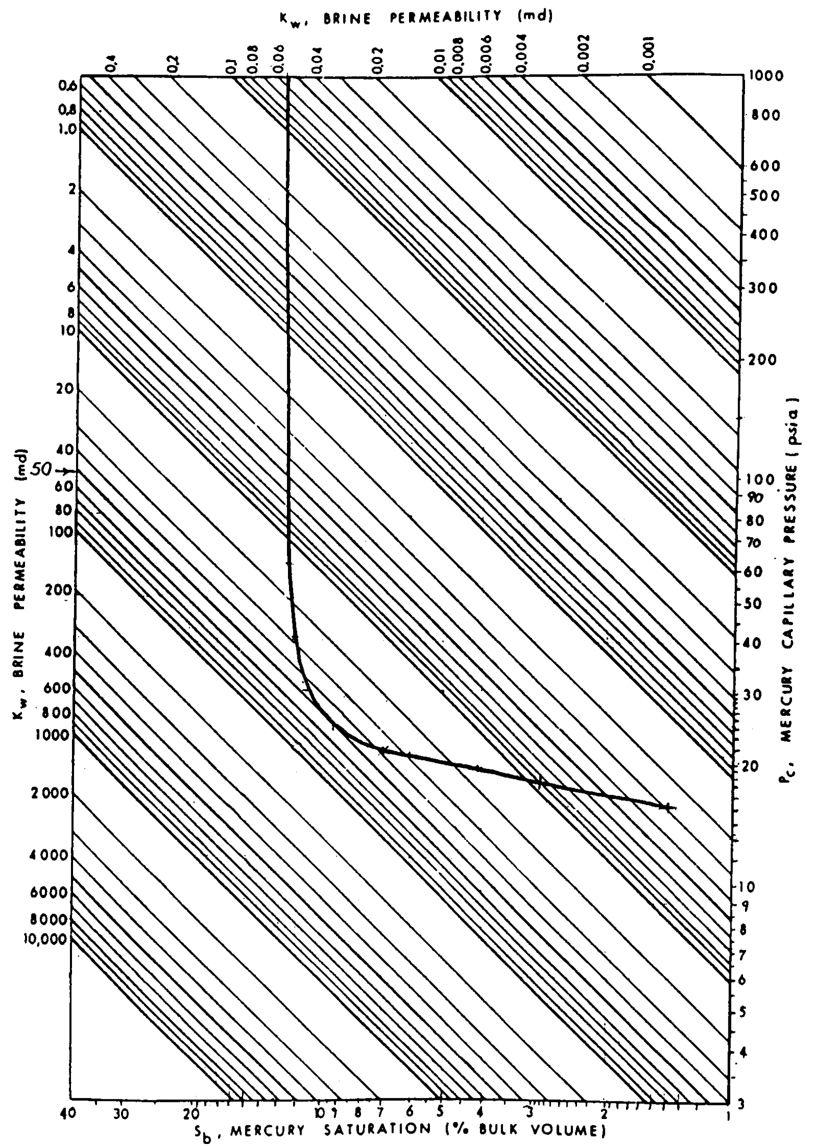

Figure 3. The curve from Figure 2 replotted on Swanson's (1981) nomograph. The absolute permeability of the core test sample, i.e. 49md is in close agreement with the tangent estimate from this graph, i.e. 50md. The saturation value of the tangent of this curve correlates to the top of the transition zone as defined in the text.

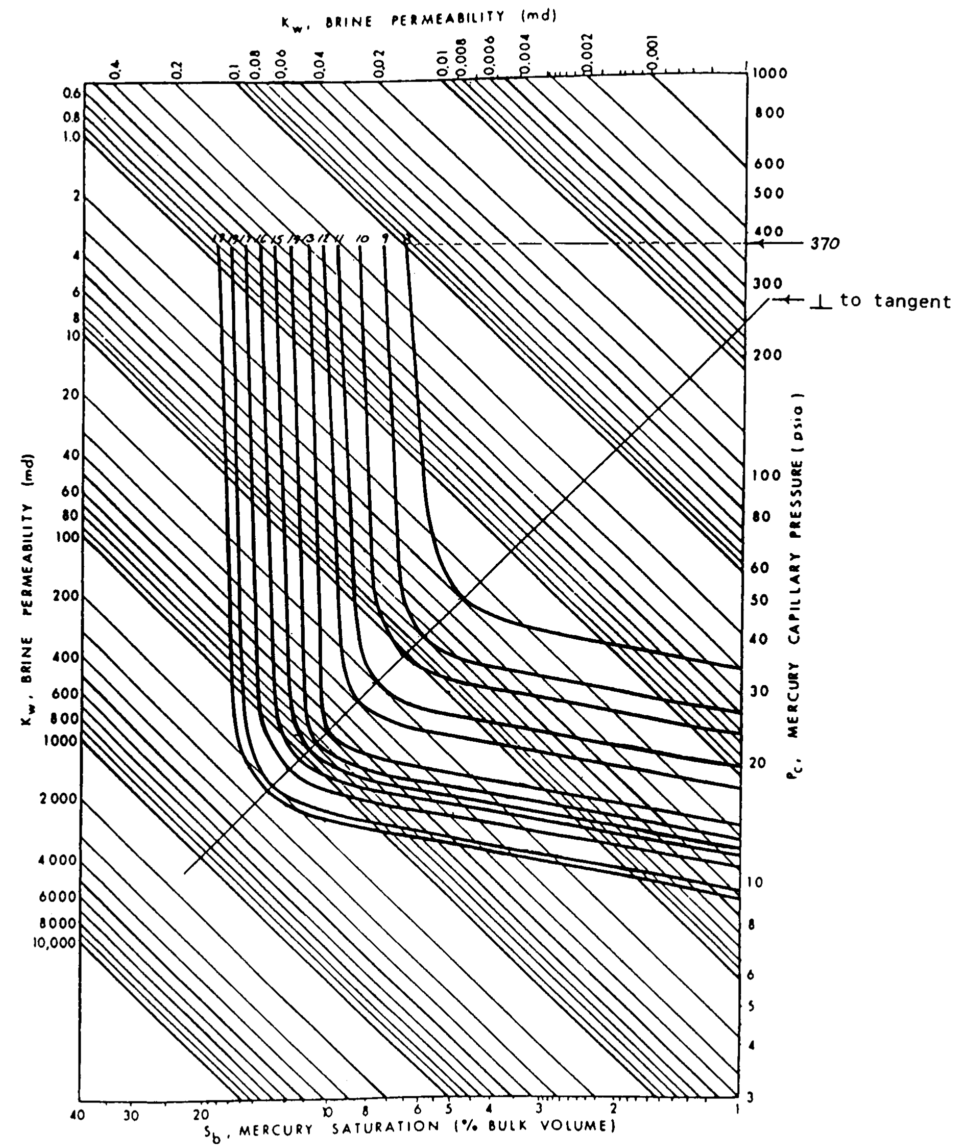

Figure 4. Paralleling curves to the hyperbolic curve in Figure 3 are traced such that their tangents correlate to an absolute permeability value for each porosity value from the porosity/permeability relationship shown in Figure 1, also listed in Table 1. The height of the curves, 370 psia on the Pc mercury capillary pressure scale, are constrained by the equivalent buoyancy pressure at the crest of the reservoir. The range of mercury saturation as a percent bulk volume at the crest of the reservoir is constrained by the range of initial water saturations measured in oil cut cores prior to water invasion.

FOR SCA NEWS

Paper SCA 9953 A Method for Developing 3D Hydrocarbon Saturation Distributions in Old and New Reservoirs by M.J. Heymans discusses a new methodology for integrating laboratory core test measurements with field data for a more rigorous determination of original hydrocarbons in place using volumetrics. The data generated can be used to populate nodes for numeric reservoir simulation.