Corecom - A Practical Application of Core Analysis

C. K. OSBORN and C. A. HOGAN
Core Laboratories, Inc.

INTRODUCTION

A computational technique, named CORECOM, has been developed for the purpose of calculating interstitial water saturation distribution in the vicinity of a wellbore employing routine core analysis as basic input data. In addition, CORECOM permits reasonable prediction of water-cut behavior of producing intervals to assist in describing the best zones of completion. Also, reasonable estimates of waterflood mobile oil saturation distribution throughout the length of the borehole and water-oil contact are provided. The technique described in this paper requires the well to penetrate a transition zone where mobile interstitial water is in evidence.

In order to establish the feasibility of this computational technique, the San Andres formation in the Permian Basin of West Texas was selected for investigation. All available data indicate the San Andres to exhibit the characteristics of a long transition zone; i.e., mobile interstitial water is generally present throughout the producing interval. Many reservoirs are described in the San Andres formation of the Permian Basin, thus providing a quantity of reliable data for establishment of necessary rock and fluid property correlations.

APPLICATION OF THEORY

CORECOM is a digital computer program developed around the procedure of employing the rock properties of capillary pressure and water-oil relative permeability to quantitatively define water-cut behavior of a transition zone as discussed by Amyx, Bass and Whiting.[1] The procedure is considered to be valid, particularly when applied to water-wet reservoirs. However, the authors have experienced difficulty in obtaining accurate results with this procedure in the past when performing individual field reservoir studies. The results of the work done in the formulation of CORECOM show two predominant reasons for the difficulty, especially when heterogenous reservoirs are involved where capillary pressure data indicate excessively long intervals of interstitial water production. Firstly, a sufficient quantity of certain rock property measurements was not available on individual fields for the construction of mutually compatible correlations which describe the complete range of basic rock characteristics encountered. Secondly, reliable results could not be obtained by employing zonal averages of basic rock properties in the computation.

The difficulties can be resolved through the performance of sufficient core analyses to construct the necessary correlations and by performing, essentially, a foot by foot fluid saturation evaluation of the formation. If it is assumed that a portion of a reservoir exhibiting a given set of rock properties will be saturated in accordance with a capillary pressure curve derived for the given rock properties, the water saturation at any level in the reservoir can be determined if the level at which capillary pressure equals zero is known. The point of zero capillary pressure in a long transition zone is not reliably discernible from either routine well testing, electrical log interpretation or results of routine core analysis. Therefore, it is necessary to employ a trial and error approach in locating the level of zero capillary pressure. However, once this point is established for a reservoir it can be used in computations describing initial saturation conditions for every well penetrating the reservoir if the reservoir is in capillary equilibrium at the time of discovery and development.

The CORECOM technique assumes a level of zero capillary pressure and assigns a water saturation to each core sample from capillary pressure relationships in accordance with its porosity and/or absolute permeability and its position above or below the assumed level of zero capillary pressure. The assigned water saturation is used to obtain a value for water-oil relative permeability ratios from a water-oil relative permeability ratio vs. water saturation curve peculiar to each sample. With this ratio and predefined reservoir fluid properties, the water-cut from each sample can be calculated using the fractional flow equation.[1] These individual sample water-cut values are accumulated over the zone of interest to yield the total zone water-cut. Iterations are made on the level of zero capillary pressure until the calculated total zone water-cut closely approximates actual well test data. Upon accomplishing this data match, the interstitial water saturation distribution in the immediate vicinity of the wellbore, and the point of zero capillary pressure in the reservoir are defined. Inconsistencies in well completion and testing practices often cloud the issue. It is advisable to perform the computation on from 10 to 20 wells dispersed throughout a reservoir in order to establish a common level of zero capillary pressure.

USE OF LOG-DERIVED PROPERTIES

In a reservoir where sufficient routine and special core analysis information is available to properly describe the relationship between log response and the measured rock property, digitized log-derived rock properties can be employed in the CORECOM computation with a reasonable degree of reliability.

PROPERTIES OF THE SAN ANDRES FORMATION

The procedure previously described is applicable to any water-wet petroleum reservoir; however, the methods used in assembling data necessary to perform the computation may vary depending upon the peculiarities of a specific formation. The following is a discussion of the methods employed in the practical resolution of rock properties for the San Andres formation of the Permian Basin.

General Considerations

The controlling rock property of the San Andres for data correlation purposes is considered to be porosity. Attempts to obtain correlations with individual sample data showed considerable scatter; however, the best grouping of individual sample data was obtained using porosity as the controlling correlation paramater. The scatter encountered, even in the best grouping, did not permit accurate correlation. Extensive studies of capillary pressure behavior performed during the course of this work have shown the primary reason for the scatter to be the wide variation of pore size and pore size distribution exhibited by the San Andres. Since sufficient measurements have not been made on all cores extracted from the San Andres to define the pore size and its distribution for each sample, it was necessary to formulate a practical approach to the resolution of the problem.

Most of the core analysis data available from the San Andres has been obtained from whole core samples. Thus, the available data represent an average of the different types of rock contained in each sample. Observation of cores has led to the conclusion that most, if not all, of the different pore sizes are contained in each core sample. Therefore, it was decided to group all samples for correlation by increments of one porosity percent and obtain a group average of the properties to be correlated. This approach essentially eliminated scatter and permitted reasonable correlations to be obtained. Reference is made to this approach later in the discussion by the phrase: incremental porosity grouping technique.

Porosity-Permeability Relationships

Core analysis data on approximately 34,000 samples was used in formulating the relationship between porosity and permeability shown on Fig. 1. The Permian Basin was divided into areas extending from Cochran and Hockley Counties, Texas, south to Crane County, Texas. A correlation between porosity and permeability was developed for each area and they were essentially coincident. This suggests that the San Andres exhibits similar characteristics throughout the basin and that correlations developed from available data could be applied to reservoirs throughout the basin. The separate area curves were combined to give the relationship shown on Fig. 1.

Capillary Pressure

Mercury injection capillary pressure data were available on 276 samples from San Andres reservoirs throughout the basin. A correlation between porosity and wetting-phase saturation over a range of capillary pressures was established using the incremental porosity grouping technique. From this correlation, capillary pressure curves covering a complete range of porosity were drawn and are presented on Fig. 2.

CORECOM reduces the mercury injection capillary pressure values on Fig. 2 to height above zero capillary pressure through the use of input fluid data peculiar to the reservoir under investigation. Input fluid data requirements are: reservoir oil and water densities and reservoir oil-water interfacial tension.[1]

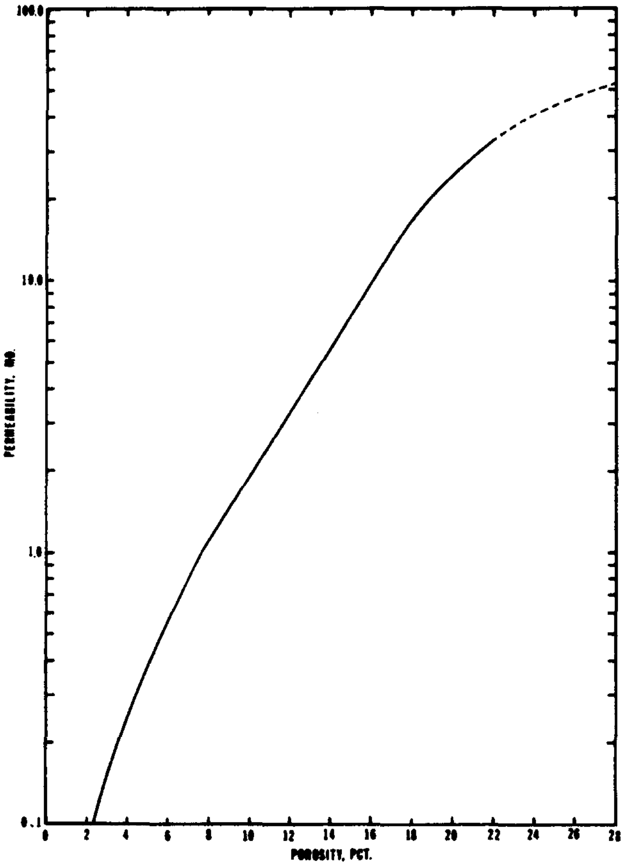

FIGURE 1
PERMEABILITY-POROSITY CORRELATION FOR THE SAN ANDRES FORMATION

Water-Oil Relative Permeability

Considerable difficulty was encountered in correlating the water-oil relative permeability data. This is not uncommon in extremely dense formations such as the San Andres. The problem is believed to be associated with the difficulty involved in establishing initial saturation conditions for performing the laboratory tests which would be consistent with those described by capillary pressure data.

Good correlations for a range of relative permeability values from 49 samples were established using the incremental porosity grouping technique when laboratory test water saturations were normalized with the irreducible wetting-phase saturation as determined from the capillary pressure data. Care should be taken in establishing the

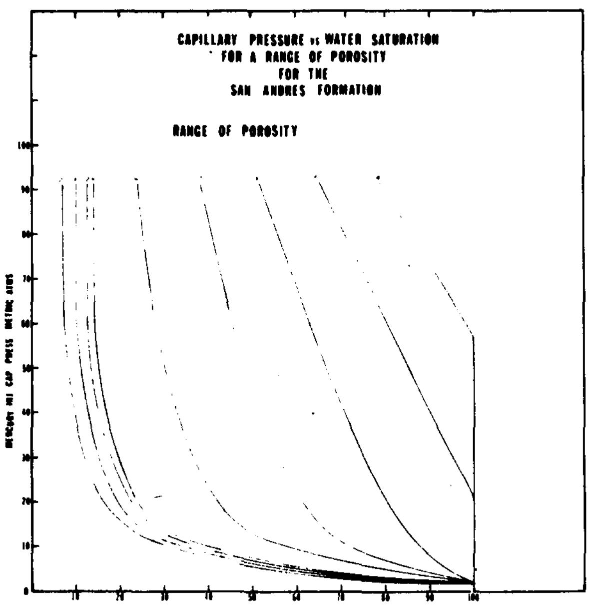

FIGURE 2

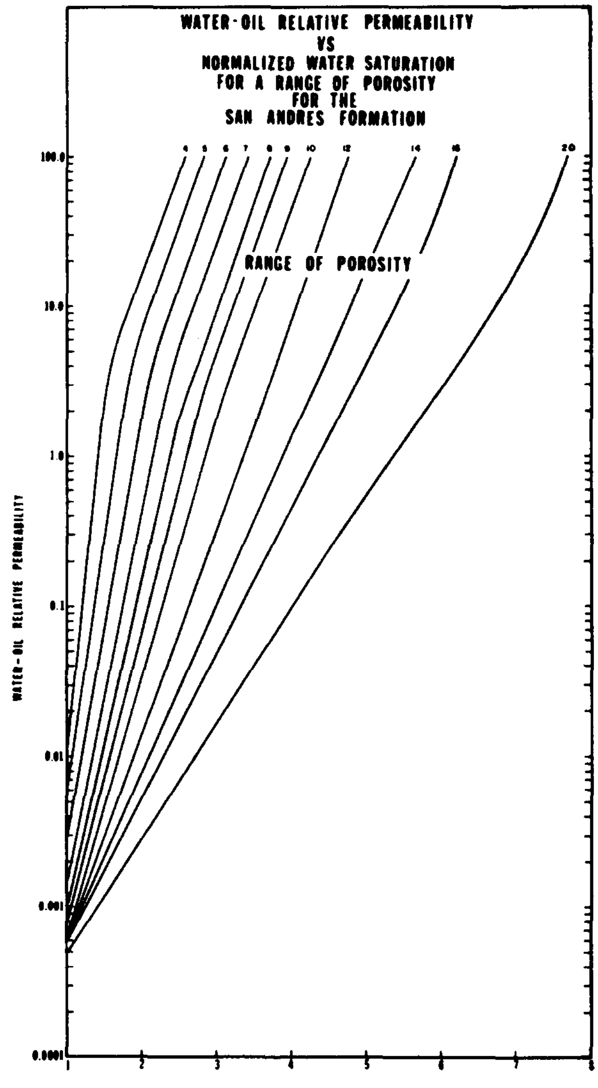

FIGURE 3

irreducible wetting-phase saturation. The water-oil relative permeability curves representing a complete range of porosity as shown on Fig. 3, resulted from the correlation.

In order to compute water-cut from the fractional flow equation, certain reservoir fluid data are required as input to the program. These are: reservoir flash formation volume factor, reservoir oil viscosity and reservoir water viscosity.[1]

Data used in the development of Figs. 2 and 3 are by definition of analysis procedure, "drainage" and "imbibition", respectively. The inconsistency of employing "imbibition" relative permeability data in a situation of apparent decrease in wetting phase saturation was recognized. Considerable study was given to the effects of the hysteresis between "drainage" and "imbibition" properties of a rock. Several empirical approaches to the computation of "drainage" relative permeability data from the literature were investigated and used in the computations.[1,2] Comparison of results indicated that transition zone behavior was better described by the measured "imbibition" relative permeability data. There are some theoretical implications which tend to substantiate this. However, until the saturation history of a reservoir is known along with a knowledge of effect on relative permeability by saturation changes caused during drilling, completing and producing a well, a completely accurate description of relative permeability behavior on a well to well basis will not be possible. The practical approach offered in CORECOM appears to yield reasonable results.

Waterflood Residual Oil

In addition to the initial saturations involved in the correlation of relative permeability data, it was necessary to describe an endpoint oil saturation for each sample at which the oil phase is no longer mobile. This was done by employing waterflood susceptibility test data from 112 samples and developing a correlation between porosity and residual oil saturation using the incremental porosity grouping technique. The correlation thus developed is presented on Fig. 4.

Total Zone Water-Cut

The computed individual sample water-cuts are weighted with the product of total effective fluid permeability for each saturation condition and the sample thickness to yield a running cumulative water-cut from the top to the base of the zone of interest. Table 1 shows CORECOM results on a typical well along with comparative actual well behavior.

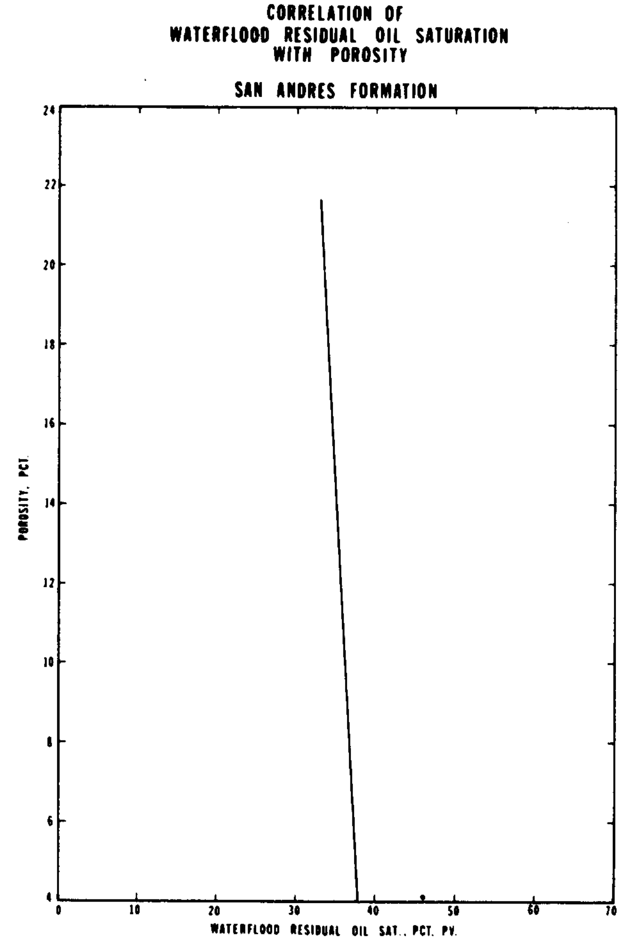

FIGURE 4

CORECOM FIELD TEST

The Wasson (San Andres) Field, Yoakum County, Texas, was selected to test the CORECOM technique. This field provided 22 wells having both good production test data and core analysis data, for the most part, through the entire San Andres reservoir. These 22 wells utilized in the test describe, essentially, North-South and East-West cross sections through the field. Figure 5 presents the results of the field test computation which shows extremely good agreement between actual and calculated water-cut behavior of the wells. Calculated water-cut behavior was obtained by assuming the absolute water-oil level, i.e., point of zero capillary pressure, to be described by a horizontal plane underlying the field at 1650 ft subsea. Well No. 5 in the test is the only well which shows a large deviation from actual and calculated results. This well has a completion

TABLE 1

COREC0M DATA

NOTE: ALL SAT. DATA ARE REPORTED AS PERCENT OF PORE VOLUME
MOBILE OIL SATS. REPRESENT WATERFLOOD MOBILE OIL AT 100 PCT. WATER CUT WITH NO INITIAL GAS SAT.
WATER SATS. ARE CALCULATED INTERSTITIAL VALUES

CAP. PRESS. EQ. 0.0 AT -900.0 FT. SS.

AVG. ADJ. DEPTH OF SAMPLE FT.	FT.SS.	SAMPLE THIC. FT.	SAMPLE POR. PCT.	WATER SAT. PCT.	WATER CUT INCR. PCT.	WATER CUT CUM. PCT.	MOB. OIL SAT. PCT.
3688.5	-848.5	1.0	16.30	21.4	.7	.7	44.1
3689.5	-849.5	1.0	23.10	19.2	.9	.9	47.3
3690.5	-850.5	1.0	23.60	19.5	1.0	.9	47.0
3691.5	-851.5	1.0	19.50	20.2	1.0	.9	46.1
3692.5	-852.5	1.0	23.90	20.3	1.2	1.0	46.2
3693.5	-853.5	1.0	20.30	20.7	1.3	1.0	45.8
3694.5	-854.5	1.0	18.20	22.3	1.3	1.1	43.7
3695.5	-855.5	1.0	20.60	21.7	1.7	1.1	44.8
3696.5	-856.5	1.0	18.60	23.0	1.6	1.2	43.1
3697.5	-857.5	1.0	11.30	28.8	3.3	1.2	35.2
3698.5	-858.5	1.0	18.10	24.2	1.9	1.2	41.7
3699.5	-859.5	1.0	17.50	25.1	2.1	1.3	40.7
3700.5	-860.5	1.0	18.00	25.3	2.5	1.4	40.6
3701.5	-861.5	1.0	20.70	24.7	3.5	1.5	41.8
3702.5	-862.5	1.0	15.90	27.8	2.8	1.6	37.5
3703.5	-863.5	1.0	16.90	27.9	3.5	1.6	37.7
3704.5	-864.5	1.0	19.80	26.8	5.5	1.8	39.6
3705.5	-865.5	1.0	17.20	29.3	5.0	2.0	36.4
3706.5	-866.5	1.0	17.50	29.9	6.2	2.1	35.8
TOTALS AND AVERAGES --		19.0	18.79	23.7			42.3

COMPLETION INTERVAL	OIL PRODUCTION	WATER PRODUCTION	ACTUAL WATER CUT	CORECOM WATER CUT ZERO PC = -900FT.
3690-3706	44.8 BPD	0.5 BPD	1.1%	2.1%

interval of approximately 42 ft with only the bottom 30 ft being cored, thus emphasizing the necessity for having the entire completion interval of interest defined with respect to rock property.

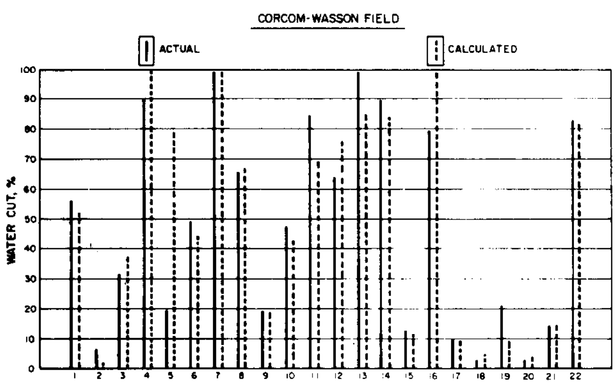

FIGURE 5

During the field test, a wide variation in the level below which production of 100 percent water (water-oil contact) was observed even though the point of zero capillary pressure remained constant. This is due to the wide variation in rock characteristics, both areally and vertically, in the reservoir. This offers an explanation for the "tilted" initial water-oil contacts encountered in this as well as other San Andres reservoirs. With sufficient definition of porosity and permeability distribution on a well-to-well basis, it would be possible to map water-oil contact using COREC0M data. This would be particularly valuable in studying the advisability of drill deeper programs. Approximately 160 additional computations have been made throughout the Permian Basin and satisfactory results have been obtained in most cases. It should be pointed out, however, that several San Andres fields indicate multi-reservoir characteristics. Therefore, for purposes of individual well and field study in connection with commingled reservoir production data, it is necessary to describe the point of zero capillary pressure for each reservoir.

CONCLUSIONS

1. The results of the work performed in for-

mulating and field testing CORECOM show the technique to be a reliable formation evaluation tool in reservoirs exhibiting long intervals of mobile interstitial water (long transition zones).

2. Basic rock property input data to the computation can be obtained from either routine core analyses or electrical log interpretations provided that adequate correlations of measured reservoir rock characteristics and log response have been made.
3. A thorough evaluation of rock properties such as porosity, permeability, capillary pressure, water-oil relative permeability and residual fluid saturations, is required for each formation under investigation.

REFERENCES

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2. Muskat, M., Ph.D.: "Physical Principles of Oil Production," McGraw-Hill Book Co., Inc., pp. 271-296, 1949.