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REFINED GEOLOGICAL MODEL OF A RESERVOIR IN THE BARRIER ISLAND DEPOSYSTEM

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SUMMARY

A geological/engineering model from a 4 to 5 square mile area of Unit 'A' in Bell Creek field, Montana was previously developed, and the effect of various geological heterogeneities in controlling fluid production in such a reservoir was investigated.[1] Further refinements were made to the geological model by incorporating results from additional studies using log, geologic, core and engineering data. The refinements were as follows:

1. A more detailed description of the nature of permeability and porosity variations in the various barrier island facies was made, and the distribution of these facies in different parts of the barrier island deposit was determined.

2. A log-derived cross-correlation technique was developed for distinguishing the barrier island sandstones from the genetically different nonmarine and marginal marine valley fill sediments. Since the fluid flow characteristics in the two major sandstone units are different, separation of the two sandstone bodies will allow individual studies of the production performance of the two sandbodies.

3. Geological information, pressure transient test results, and production data were integrated for more precise mapping of faulting which has locally affected fluid flow patterns.

4. Petrographic studies confirmed a direct relationship between porosity and total cement and the preponderant effect of clay cement in controlling permeability in the reservoir.

5. Analyses of Muddy formation water and injected water confirmed that only negligible amounts of water-sensitive clays are present and precluded the possibility of the reservoir rocks being susceptible to permeability reduction due to either formation or injected water.

With these results, the geological model can be used to explain some of the fluid flow anomalies in the barrier island field studied. The fluid flow characteristics of this refined model are being studied to develop

methodologies for exploitation of reservoirs in a barrier island type of depositional environment.

INTRODUCTION

The objective of this research is to develop methodologies for characterizing reservoir heterogeneities for efficient exploitation of hydrocarbon resources from reservoirs having a barrier island type of depositional environment. A geological model[1,2] was previously constructed from all available geological, log, core, and engineering data to determine how the different geological heterogeneities influence sweep efficiency and fluid flow patterns.

For easier analysis the heterogeneities that influence fluid production were grouped into four classes, depending upon their source of origin: depositional, diagenetic, structural, and formation fluid. Models can be developed for each class, and refined. Then all of the partial models can be integrated into a comprehensive fluid flow model that can explain fluid flow patterns in different parts of a barrier island field. In our earlier development of the geological model several heterogeneities were identified.

1. Clay content in barrier island sandstones was found to be both diagenetic and detrital in origin. The distribution of diagenetic clay is highly variable and has significantly affected permeability and porosity distributions in different parts of the field.

2. Structural heterogeneities investigated were mainly of three types: faulting in localized regions, possibly associated with fracturing in some cases; valley fill deposits unconformably overlying the reduced barrier island sequence and creating fluid flow anomalies because the genetically different nonbarrier sandstones have totally different fluid flow properties compared to those of barrier island sandstones; and structural dip which influenced secondary recovery.

3. Depositional heterogeneities significantly affected reservoir quality and are therefore very important. The sandstone in the core of the barrier island deposit was comparatively clayfree compared to the distal parts of the barrier front and the backbarrier facies where thinner and lower energy facies intercolate with nonproductive facies.

4. A few other heterogeneities locally had important effect on fluid production; for example, compaction which provided strong variations in packing across small vertical intervals and thereby greatly influenced fluid flow rates.

Although a good correlation of production performance obtained with geological heterogeneities mapped previously is an indirect verification of the geological model, we recognize that explanation of production patterns in certain localized areas of Bell Creek field requires further refinement of the geological and engineering models. Additional core, log, and engineering data were collected, and further analysis of the previously identified heterogeneities was conducted. For example, with more log and core data, a new technique for separating the barrier island sandstones from the nonbarrier sandstones was developed, and a net pay thickness map of barrier island sandstones deposits was prepared.

The refined geological model will help us understand the role of the different geological heterogeneities in controlling fluid production during primary, waterflood, and EOR recovery.

METHOD OF INVESTIGATION

Including the cores used in the earlier investigations, 16 cores were examined for developing the refined geological model. The core information was supplemented by new log data because comparatively few cores from Bell Creek wells completely spanned the entire productive intervals. Only 2 out of 20 production wells drilled in 1980 for enhanced oil recovery were cored (wells P-1 and P-2). Consequently, for geological modeling and investigations of the heterogeneities, we had to rely upon electrical, spontaneous potential (SP), gamma ray, sonic, density, and neutron logs as available. Data from well and production tests, when integrated with core and log data, provided additional information for studies of fluid flow patterns.

Brief descriptions of the investigations we conducted are as follows:

Structural Heterogeneities

(a) Faults and Fractures

The structural contour maps drawn earlier at the top of the barrier island sandstone[2,3] indicated the presence of faults in certain localized regions of the TIP (Tertiary Incentive Project) area within Bell Creek field. Studies of results of well test and log correlations and examination of the 75% water-cut advancement map[1,4] indicated the possibility of more faulting parallel to the NW and NE lineament trends. Most of these faults have small throws (from 10 to 20 ft) and except for a few cases have not affected the hydraulic communication between wells.

Natural fractures were not obvious in the 16 cores examined from the TIP area, but their presence could not be entirely excluded because many of the cores were incomplete.

Field observations in analogous outcrops[4] and elsewhere indicated that the density of natural fractures decreases rapidly outside the fault plane in "soft," less consolidated sediments. The width of heavily fractured zones should not exceed 100 to 200 ft in this case. In brittle, more diagenetically cemented layers, however, the density of tectonic fractures increases, and the fractured zone may be much wider.

Fractures in thin, diagenetically altered zones may be responsible for the exceptionally high injectivity or total fluid production in those wells where the low permeabilities measured on core samples can not explain such high flow rates. An example is well W-7 which accepted 2.6 million bbl of injected water even though intergranular rock transmissivity is relatively low (less than 10,000 md-ft for the best flow unit with expected injectivity rates of about 700 BOWD).

(b) Methodology for Distinguishing Barrier From Nonbarrier Facies

The producing Muddy sandstone in Bell Creek field is composed of two genetically different facies: barrier island and nonbarrier sediments (marine or nonmarine valley fill sediments). These two sandstones have markedly different petrophysical properties (Fig. 1) and a method to distinguish them on logs is needed for analysis of fluid production characteristics of the Muddy sandstone. The two sandstones quite often are indistinguishable from individual electrical, SP, or gamma ray logs, mainly because of the varying log responses in the clay-filled sections of the sandstones.

A methodology was developed for distinguishing the two sand deposits by cross plotting formation resistivity, R_t, obtained from induction logs against log-derived porosity, ϕ, obtained from density logs -- the so-called Pickett plot. For the initial investigations, 11 wells were selected which had both resistivity and density logs. The nonbarrier and barrier facies and the different facies of the barrier island were distinguished and lithologically described in these wells. After proper depth adjustments, the core data were used to "calibrate" the resistivity log signatures. The formation resistivity values at each 1 ft interval were plotted against the corresponding log-derived porosity values. An example of plots from well P-2 (Fig. 2) shows that such a cross-plot clearly separates the high-productive barrier island facies (foreshore and shoreface) from the nonbarrier sandstone (mostly marine or nonmarine valley-fill sediments) and the lagoonal sediments.

(c) Distinguishing Other Barrier Island Facies

A Pickett plot (Fig. 2) can also distinguish the high productive barrier island facies from the clay-rich, low-porosity, low-resistivity lower shoreface facies. In the examples studied thus far, the two main productive facies of the barrier island (the foreshore and the shoreface) cluster together, and the porosity and resistivity differences between the two facies are small and cannot be clearly separated. In addition, with this type of plot, data from the washover facies also tend to cluster with the main barrier facies.

Distribution of Petrophysical Properties

By integrating information from core descriptions, wireline logs, and laboratory-measured values of porosity and permeability, we prepared a net sand thickness map of the barrier island deposit (Fig. 3). In constructing this map, cutoff values for permeability and oil saturation were 50 md and 5%, respectively, because below these values the reservoir is not expected to contribute much to overall production. A comparison of the net pay map (Fig 3) with the gross thickness map brings out the following interesting features of the barrier island deposit.

Need Figure

1. Because of reservoir heterogeneities, the maximum thickness of the good quality barrier island sandstone is shifted slightly to the west of the maximum gross sandstone thickness zone.

2. Sharp changes in net pay contours are probably indicative of

structural heterogeneities (such as faults and valley incisions) or diagenetic heterogeneities (clay content, compaction).

We prepared an average core-derived porosity map Fig? and observed that core-porosity was on the average 4% higher than the ~~density~~ log-derived porosity. This was expected because in a loosely consolidated reservoir like Bell Creek, removal of the net confining stress of more than 3,000 psi may easily account for the observed differences. This is also corroborated by the observed pore volume compressibility of close to 40×10^{-6} vol/vol/psi in pressure transient analysis between wells C-4 and P-11 and C-4 and P-12. In a reservoir like the Bell Creek, where there are significant clays in the sandstone pores in certain areas, the density log should provide accurate information about porosity distribution. Combining the log-derived porosity map Fig with the net thickness map Fig will allow accurate determination of storage capacity (product of porosity and net pay thickness) in the reservoir.

Except for those wells where the sandstone quality has been significantly altered because of diagenesis, a good linear relationship exists between the log of permeability and porosity values obtained from laboratory measurements. Limited data from permeability measurements conducted using air, brine, and distilled water on samples covering a large permeability range (20 to 4,500 md) show that the absolute air permeabilities of the rocks examined do not differ significantly from brine or distilled water permeabilities.[4] X-ray diffraction analysis of the rock samples showed that expandable clay is generally absent from the barrier island sandstones in the area surrounding Unit 'A'. A similar conclusion was indicated by normal and reverse flow tests conducted on a few core samples; therefore, air permeability data provided good estimates of absolute brine permeabilities of the formation.

Vertical Distribution of Permeability and its Effect on Production and ROS Distribution

A significant finding of our work is determining the strong control that vertical distribution of permeability has on primary production rate and distribution of residual oil saturation. A plot of the Dykstra-Parsons coefficient (V_{DP}) obtained from core permeability data which gives a measure of vertical variation in permeability shows a striking corrrespondence between these coefficients and the primary production rate (Fig. 4). The low values of V_{DP} coefficients are obtained from areas which show less vertical variation in permeability and coincide with areas showing highest production rates.

The ROS map prepared from laboratory-measured oil saturation values obtained from cores recovered in 1980 after waterflooding the area and averaged over the entire productive interval is shown in figure 5. Higher ROS distribution coincides with the highly heterogenous parts of the reservoirs which shows high values of Dykstra-Parsons coefficients, clay content, and heterogeneity index.[1] Geologically, it implies that regions of high residual oil saturation coincide with regions with strong sedimentary or diagenetic layering. These are the areas of poorer sweep efficiency during the waterflood.

CONCLUSIONS

The refined geological model has provided the following information.

It has explained fluid flow anomalies in certain regions which were not previously apparent. Integrated studies indicated the possibility of more faulting which could locally change fluid flow patterns. Most faults have very small throws and are not likely to act as complete transmissibility barriers. Indirect evidence of the presence of fractures was obtained from production rate analysis.

It has provided a methodology for distinguishing barrier island sandstones from nonbarrier deposits and highly productive barrier facies from clay-rich, low productive lower shoreface facies.

It has clearly demonstrated the strong influence of vertical permeability distribution on primary production rates and residual oil saturation distributions.

Accurate information on the storage capacity of the reservoir is now obtainable by combining the net pay thickness and the density log-derived porosity distribution maps.

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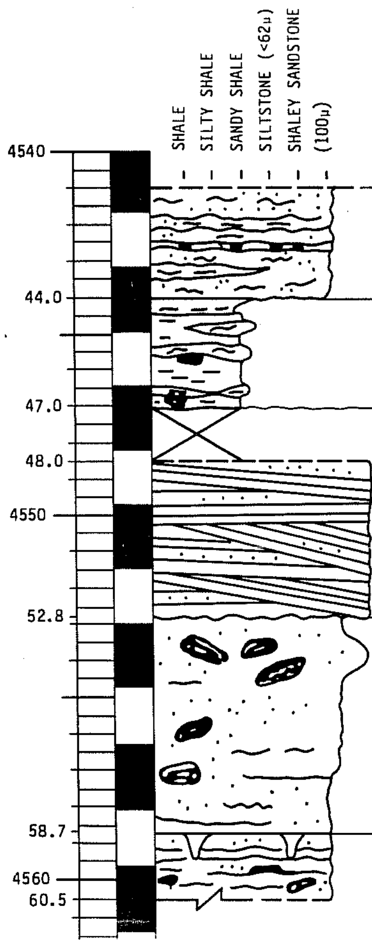

Environment		(ft) Depth	Horizontal Permeability K_h	Ave	Vertical Permeability K_v	Ave	Kv/Kh	Percent Porosity	Oil	Water
		4541.5	43		18			25	Tr.	75
Brackish Marine to		4542.5	94	106.6	36	67.3	0.63	23	Tr.	63
Continental		4543.5	183		148			28	7	61
	Valley Fill	4544.5	25		1			20	Tr.	58
Brackish Marine		4545.5	21	455.3	2	151.6	0.33	19	0	65
		4546.5	1320		452			33	13	37
		4547.5	1290		1690			32	16	35
		4548.5	2370		2060			32	16	40
Foreshore		4549.5	1390	1928.3	1440	1975.0	1.02	32	19	42
		4550.5	2790		2790			33	16	32
		4551.5	2630		2790			33	11	33
		4552.5	1100		1080			32	16	41
	Barrier Island	4553.5	2670		2670			33	16	34
		4554.5	412		500			31	18	43
Shoreface		4555.5	1190	1470	594	1067.6	0.76	33	15	43
		4556.5	1440		1220			33	15	40
		4557.5	1480		864			34	12	45
		4558.5	1250		558			33	17	34
Environment?		4559.5	15	15	6	6	0.40	24	14	59

Note: Core description is preliminary and revision is needed.

FIGURE 1. - Petrophysical properties of barrier island and nonbarrier facies in well 26-7. Note the variation for k_v/k_h ratio.

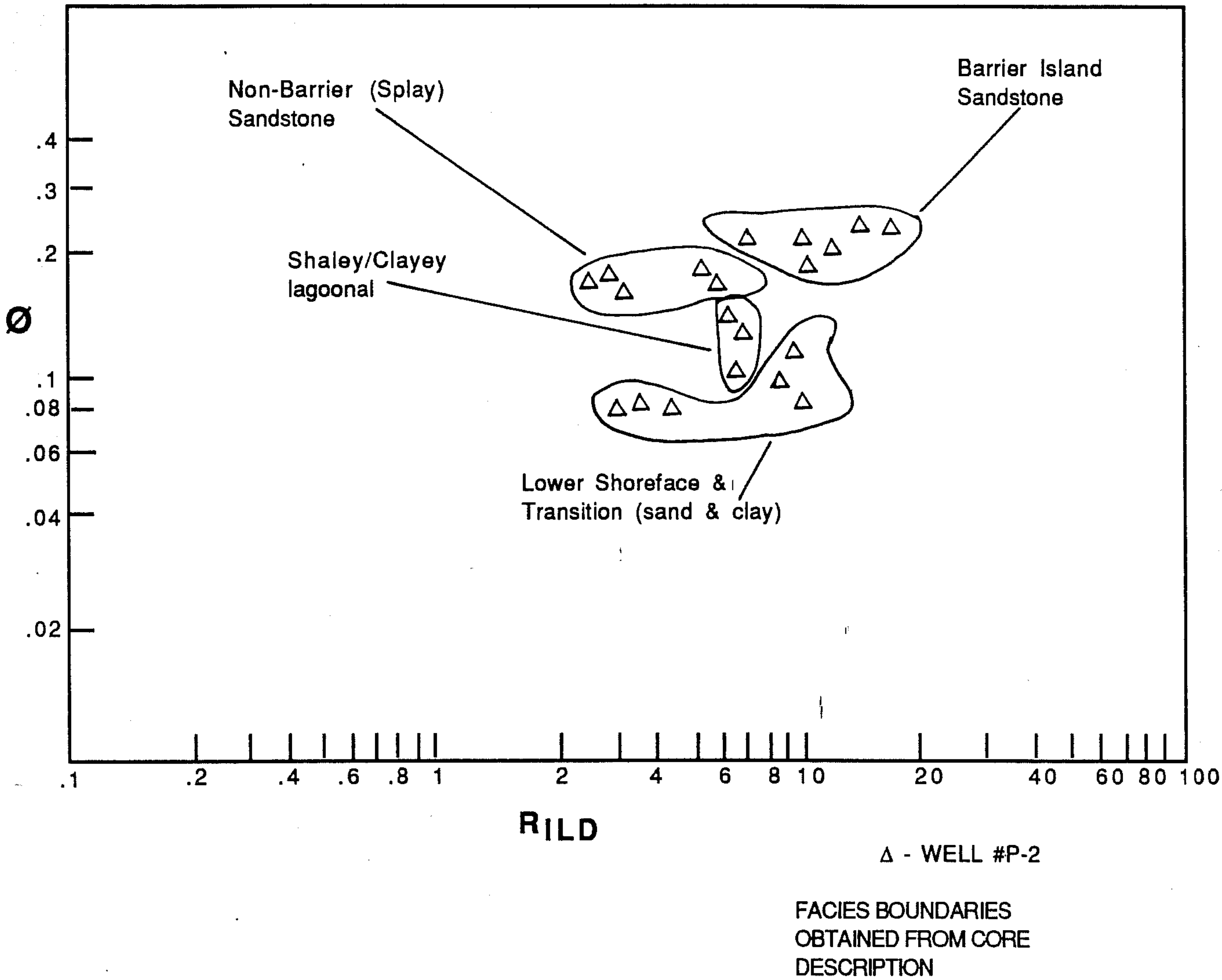

FIGURE 2. - Cross-plot of formation resistivity (R_t) against porosity (ϕ) for well P-2 for distinguishing barrier island from nonbarrier sandstone facies.

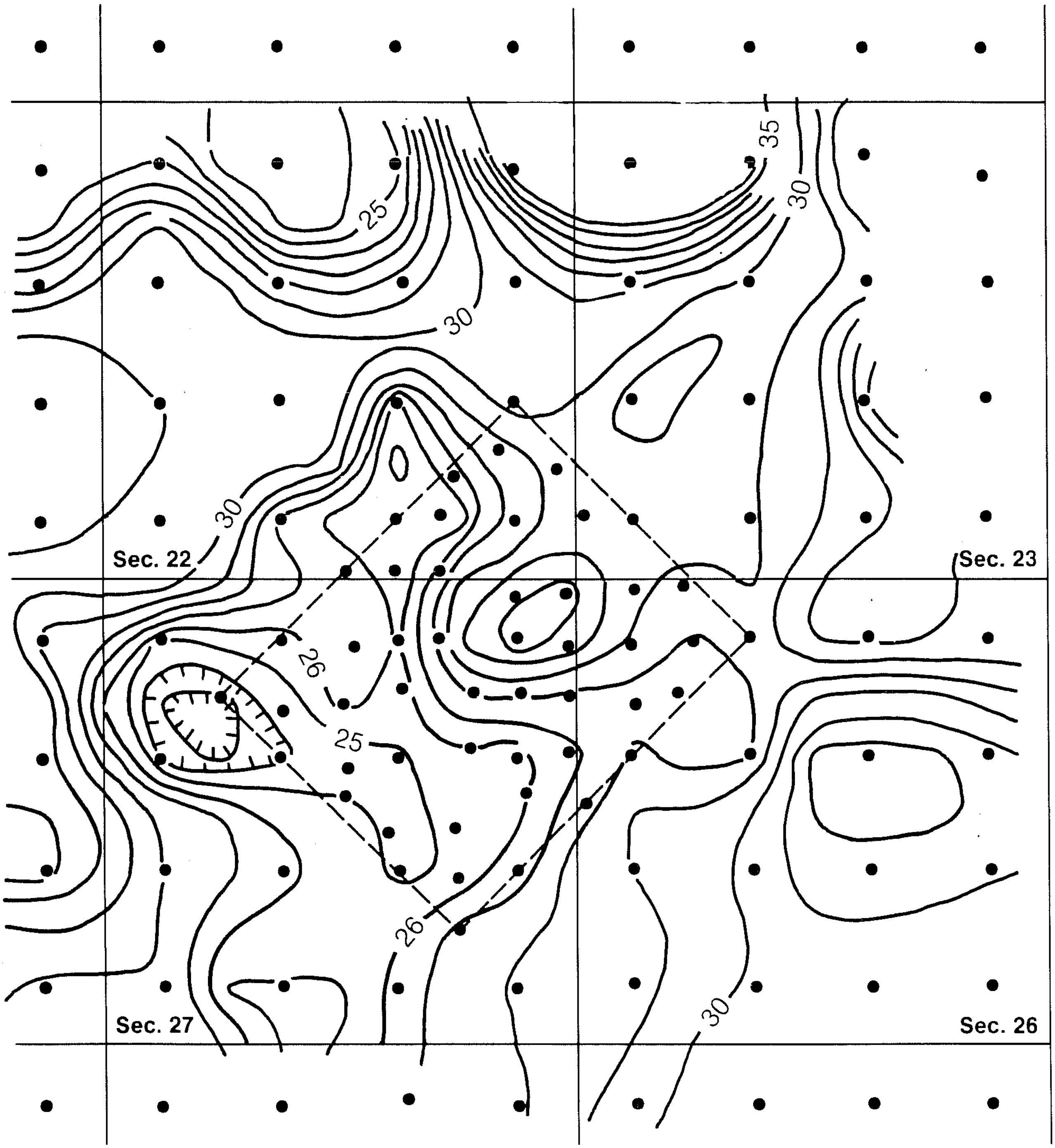

FIGURE 3. - Net pay thickness map of barrier island sandstone deposit in the study area. Contours are in feet. The TIP area is indicated by dashed line. Sections are 1 mile across.

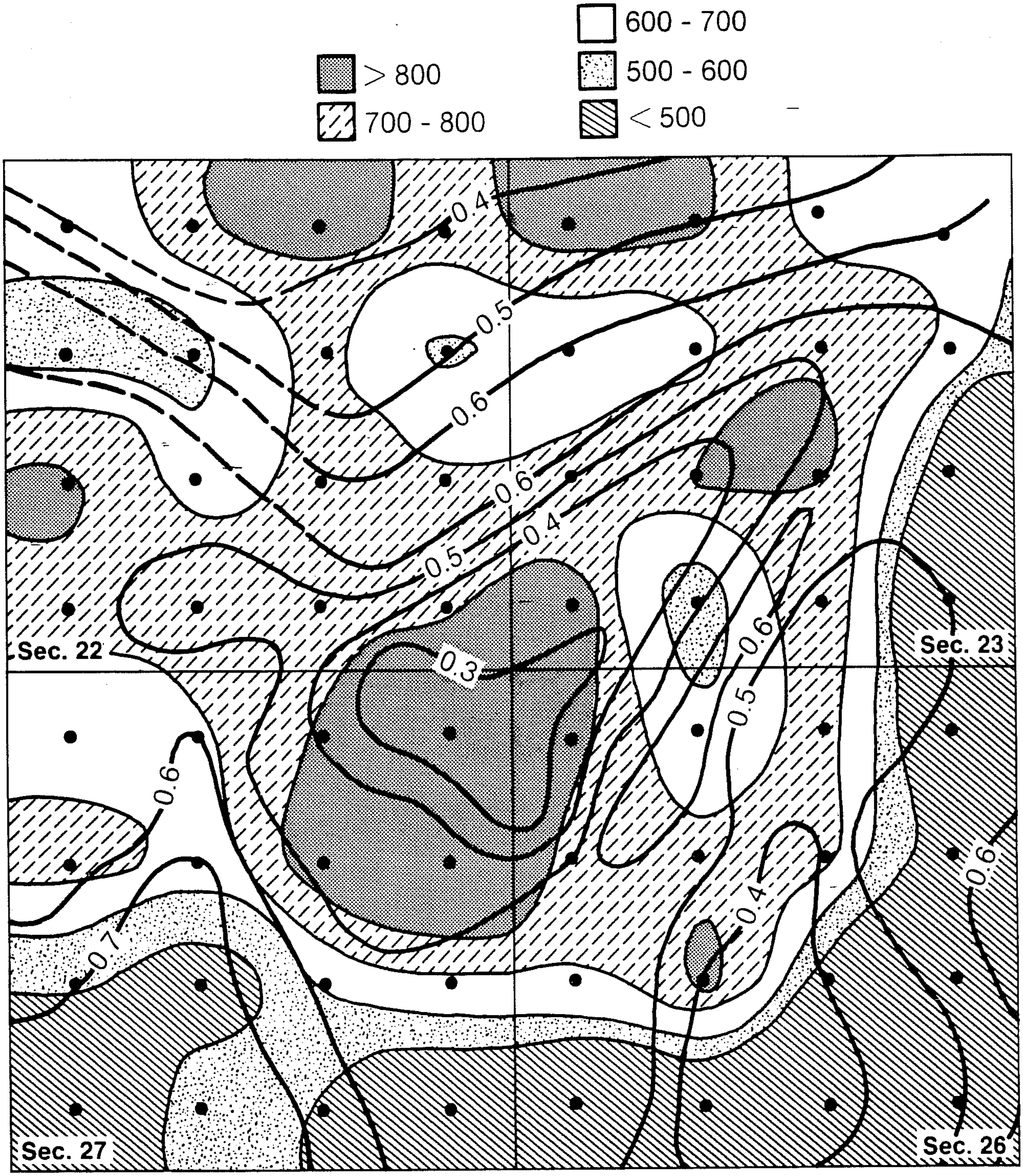

FIGURE 4. - Initial production rate potential (shaded, in STB/D) superimposed on Dykstra Parsons coefficient distribution.

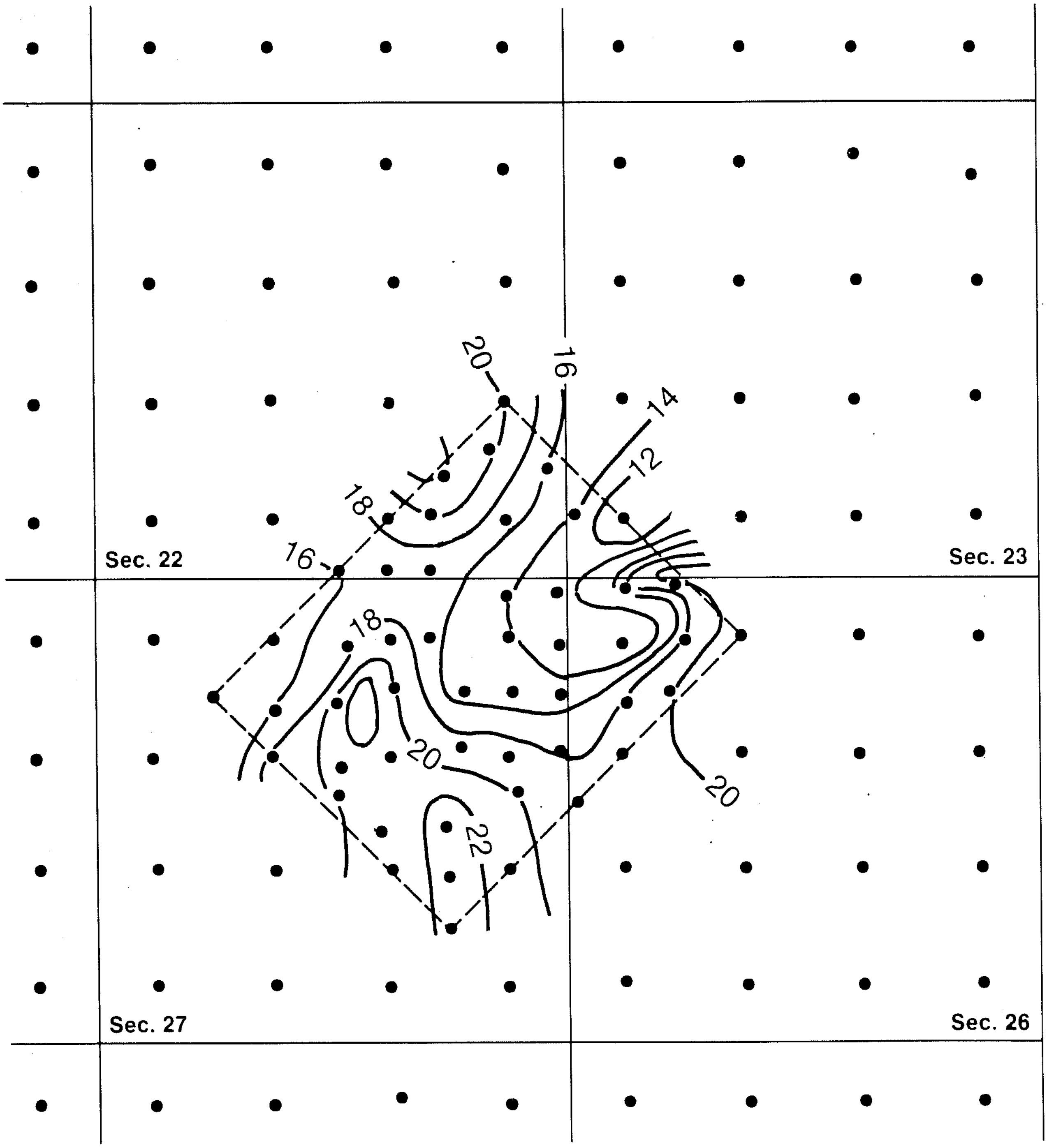

FIGURE 5. - Residual oil saturation distribution in 1980. The data were obtained by routine core analysis and are expressed in percent.