CONSTRUCTING CORE PETROPHYSICAL GROUPS: A KEY STEP TO RECONCILE PETROPHYSICAL AND GEOLOGICAL CORE DATA IN RESERVOIR MODELLING

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ABSTRACT

This paper outlines a method for improved mapping of reservoir properties using Petrophysical Groups derived from core analysis.

The method is illustrated through a case study of a mixed lithology oil reservoir. This reservoir is characterized by a large vertical variability of reservoir properties within each sedimentary facies as a result of combined sedimentological and diagenetic effects. Hence, in order to determine rock properties, for reservoir simulation purposes, reliance could not be placed on sedimentary facies. It was therefore decided to develop a new modelling method which gives a more accurate representation of the actual petrophysical heterogeneities. A three stage modelling process was tested on a 20m-thick interval.

- The first stage consisted in subdividing the whole reservoir into Petrophysical Groups. A petrophysical Group is a set of reservoir zones having similar porosity, permeability, grain density and capillary pressure curves. Six Petrophysical Groups were constructed from the whole set of core measurements using clustering techniques. Within each Group, variability of petrophysical parameters was relatively narrow and relationships between properties such as water saturation as a function of permeability and capillary pressure were established. Relative permeability functions were assigned to each Group using two phase flow measurements. These measurements were conducted on full size samples representative of the Petrophysical Groups.

- The second stage consisted in the recognition of five sedimentary bodies based on core description and sedimentological interpretation of the facies associations. Sedimentary bodies were then generated in three dimensions using a geostatistical conceptual model.

- The third stage consisted in distributing Petrophysical Groups in each sedimentary body. Study of thin sections within each petrophysical Group proved that diagenetic effects could be related to petrophysical properties. The areal and vertical extensions of the Petrophysical Groups within each sedimentary body were therefore determined through diagenetic trends. Petrophysical attributes were then generated using the narrow distributions and the relationships established during the first stage for each of the six Groups.

In this complex reservoir, the method proved to enhance the representation of petrophysical heterogeneities compared to the conventional deterministic modelling methods.

INTRODUCTION

Constructing and updating reservoir models is critical as they are used to predict reservoir performance and total recoverable reserves. Results from these predictions directly influence all development plans (well spacing, pattern, recovery processes, production rate, production facilities...).

Generally, the first step in model-designing consists in describing accurately the reservoir geometries, both external and internal: field limits, faults and extents of individual flow units (both areal and vertical) (Mattax, 1990). At this stage, it is essential to have a good understanding of the depositional environment as well as the diagenetic processes to estimate the continuity of productive and non-productive zones throughout the reservoir. This phase often results in a set of maps of facies within stratigraphic sequences. These facies usually provide the basis for mapping reservoir rock properties such as porosity and permeability. Unfortunately, for many carbonate fields, the problem with this approach sometimes is the great variability of reservoir properties within each facies (Hearn *et al.*, 1984) because the influence of textural properties, such as pore geometry and pore throat size, on reservoir performance is not enough taken into account compared to other geological characteristics. This variability results in important uncertainties during the assignment of rock properties to individual gridblocks. Consequently, more attention should be paid to petrophysical characteristics when subdividing reservoir intervals into facies since mapping reservoir rock properties remains the main objective of reservoir modelling.

In this paper, we present a method which improves the mapping of petrophysical properties based on the notion of Petrophysical Groups. The advantage of this method is that it integrates reservoir properties in the earliest phases of reservoir modelling. The method is tested on a stratigraphic sequence of an oil-bearing carbonate reservoir.

The method consists of three stages:

1- construction of Core Petrophysical Groups

2- understanding of the depositional environment and recognition of sedimentary bodies

3- study of the vertical organization of the Petrophysical Groups within the sedimentary bodies and modelling of the sequence.

We will then show the advantage of this method over the conventional ones in which facies definition is controlled mainly by sedimentological considerations rather than by petrophysical data.

Geological Outlook of the Reservoir

The focus is on a mixed lithology oil field formed during the Albian. It is composed of reservoirs that are complex in nature with vertical and lateral variations related to mixed siliclastic and carbonate depositional environments. Diagenetic effects strongly influence reservoir characteristics. Two cored wells were used for the study. Several hundred meters of consolidated cores were recovered on a (nearly) continuous basis.

Phase 1: CONSTRUCTION OF CORE PETROPHYSICAL GROUPS

Our first objective is to subdivide the cored intervals into Petrophysical Groups.

The construction is based on the conventional plug measurements that were carried out every foot on small plugs along the cores of the two wells. More than one thousand measurements of single phase gas permeability, porosity and grain density were available. After a critical data analysis (detection and elimination of anomalous measurements), data were sorted into different Groups as follows:

1. plugs originating from the two wells were mixed into a common set.
2. plugs with gas permeability values less than 0.1 mD were placed out of the common set into a specific Group (called Group #0).
3. the remaining plugs were clustered into five groups according to their porosity, gas permeability and grain density.

The clustering technique is a statistical procedure (Pabian, 1991, Saporta, 1990, SAS, 1990) in which plugs with similar porosity, permeability and grain density values are placed in the same cluster while plugs with dissimilar properties are sorted into different Groups. In our case, we retained five clusters for two major reasons: 1) the number of Petrophysical Groups to be used later on as a basis for Rock-Types definition must be restricted , 2) the division into 5 Groups gives a minimum of inertia within the clusters and a maximum of inertia between the clusters. In this case, the inertia is equivalent to a mechanical inertia where the three physical dimensions x, y and z are replaced by the three petrophysical dimensions: porosity, permeability and grain density. In Table 1, a mean value and a standard deviation are given for each parameter within each Group. Porosity and grain density are assumed to be Gaussian variables and permeability to be log-normal. Relationships between porosity and permeability were found for Groups #4 and #5 (see Table 1). In the other Groups, permeability and porosity are not well correlated and estimating permeability from porosity values would lead to important uncertainties. Let us remember that permeability is physically related to pore throat size which is not always correlated to pore volume (EPS course, 1991). One can notice in Table 1 that Groups #2 and #4 have relatively high grain density values which means that dolomite is the dominant mineral in these two Groups. They differ in porosity and permeability values (i.e., in reservoir quality). The mean of grain density in Group #5 is close to 2.65 g/cm^3 which indicates that this petrophysical Group should be dominant in sandstone reservoirs.

The next step consisted in performing capillary pressure measurements both by mercury injection and by the restored states technique. Although these measurements largely vary within each Group, we were able to correlate water saturation versus permeability and capillary pressure for Groups #3, #4 and #5 (see Table 1) (Johnson, 1987, Wright, 1955). Normalized relative permeability curves were assigned to each of the six Groups based on experiments performed on representative full-size samples for 4 out of the six Groups. For the two other Groups permeability curves were assigned using data obtained from samples from other cored wells having similar textural properties. These data are assumed to be valid for each Group as the variations in permeability and initial water saturation are limited within each Group. These curves were applied within each Petrophysical Group, assuming a constant oil recovery.

	Group #0	Group #1	Group #2	Group #3	Group #4	Group #5
Porosity (p.u.)	4.71 +/- 2.30*	7.95 +/- 2.90	15.70 +/- 3.85	16.85 +/- 3.45	24.90 +/- 3.85	21.07 +/- 3.00
Permeability (geometric mean + range*)	< 0.1mD	0.22mD 0.11-0.42	0.92 mD 0.32-2.68	3.4 mD 1.2-9.9	12.9mD 4.4-38	85.3 mD 29.3-248
Grain Density (g/cm^3)	2.71 +/- 0.02*	2.70 +/- 0.03	2.78 +/- 0.03	2.70 +/- 0.02	2.80 +/- 0.03	2.68 +/- 0.03
Porosity (fract.)- vs. Permeability (mD)	independent variables	independent variables	independent variables	independent variables	log k = 4.4*porosity + 0.014	log k = 5.2*porosity + 0.835
Initial Water Saturation (fract.) Pc (bars) [gas-water], K (mD)				logSw= -0.481*logk +0.04/$Pc^{2.23}$	logSw= -0.46*logk +0.279/$Pc^{0.773}$	logSw= -0.453*logk +0.174/$Pc^{1.017}$
Part of each Group along the cored intervals of both wells	8.5%	26%	18.5%	17%	19%	11%
Reservoir Quality: sqrt(k/phi) [from Amaefule, 1993]	kg < 0.1md	0.17	0.24	0.45	0.72	2.01

Table 1 - Characteristics of the six Petrophysical Groups (Mean Values + Ranges)
*The range is expressed for a 68% confidence interval

Depositional and post-depositional factors influencing reservoir properties

X-ray diffraction experiments were performed and thin sections were analyzed from rocks that are representative of the Petrophysical Groups in order to determine depositional and postdepositional factors that have influenced the reservoir properties of these Groups. These data show that rocks of the fifth Petrophysical Group contain an average of 45% detrital quartz with a visible primary inter-granular porosity. Quartz grains are of medium size (140μm in diameter). Groups #2 and #4 include a large fraction of dolomitic cement (55%) and pore geometry in these two Groups is a result of dolomitization. Dolomitization occured differently in each sedimentary facies because of differences in original proportions of constituent minerals. Groups 1 and 3 contain muddy limestones and high energy limestones. In these two Groups, porosity is mostly related to selective dissolution of carbonate particles. Some dolomitic fine grained sandstones, can also be found in Groups #1 and #3. Low energy sedimentary facies compose Group #0. Dolomitization and carbonate dissolution are therefore the two main factors influencing reservoir properties.

Phase 2: UNDERSTANDING THE DEPOSITIONAL ENVIRONMENT

The whole reservoir formation is made up of mixed siliclastic and carbonate deposits. The studied interval consists of a 20m-thick sedimentary unit which belongs to a 150m-thick depositional sequence. This sequence is characterized by the vertical stacking of retrogradational, aggradational and progradational assemblages. The selected interval is the basal unit formed during the retrogradation phase associated with a relative sea-level rise. This phase was characterized by:

- mixed siliclastic-carbonate shallow water system
- high siliclastic supply and reduced carbonate production
- low to medium depositional gradient
- massive dolomitization during rise of marine phreatic zone and mixing with freshwater lens
- thin and continuous zones of alternatively intertidal sands and subtidal limestones

The sedimentological model of retrogradation is presented in Figure 1 (width of around 15 km) (Caline, 1994). In the 20m-thick sequence, five types of sedimentological bodies were identified on cores (see Figure 2): sand flat, carbonate mud flat, oolitic bar, sand/mud flat, clastic sand estuarine bar. Correlations between the two wells (A and B) are shown in Figure 2. Dimensions of these sedimentary bodies are relatively well known thanks to comprehensive studies of current deposits, analogous outcrops and subsurface data (see Table 2).

Sedimentary Bodies	Length (km)	Width (km)	Thickness (m)
Mud Flat	4 - 7	2 - 4	6 - 8
Sand Flat	1.5 - 4	0.5 - 1.5	6 - 8
Sand/Mud Flat		Background	
Clastic Bar	4 - 6	2 - 3	3 - 6
Oolitic Bar	5 - 6	1 - 2	3 - 5

Table 2 - Dimensions of Sedimentary Bodies

Phase 3: RECONCILIATION OF GEOLOGICAL AND PETROPHYSICAL CORE INFORMATION - MODELING OF THE SEQUENCE

As illustrated by Figure 2, Petrophysical Groups are vertically organized within the sedimentary bodies: Groups 2 and 4 are dominant in mud flats that were strongly affected by dolomitization, Group 5 is dominant in sand flats and Groups 1 and 3 are mostly present in the oolitic bars. This means that the subdivision of the reservoir in Petrophysical Groups based on physical parameters is consistent with our sedimentary model.

MODELLING

First stage: Mapping of Sedimentary Bodies
In order to build maps of Sedimentary Bodies, we used a 3-D object modelling technique (Petit *et al.*, 1994) which consists in generating "objects" (i.e., sedimentary bodies in this case) within the sequence considering the following constraints: honoring of well data, reproduction of a-priori facies proportions, and spatial relationships between objects. The distal/proximal polarity of sediment deposition was taken into account through trend maps of sedimentary body proportions (see example in Figure 3 where the proportion of sand flat is assumed to evolve linearly in a 10-km wide transitory zone). In order to generate very large sedimentary bodies, the simulation had to be performed in a so-called "ergodic" domain, i.e., a domain that is larger than the sedimentary body dimensions: an area of 18*30 km^2 centered on the two cored wells was chosen. A simulation result is shown in Figure 4 and its restriction to the reservoir area ($7.2 * 14.1$ km^2) is displayed in Figure 5.

Second stage: Mapping of Petrophysical Groups within sedimentary bodies.
Occurrences and proportions of Petrophysical Groups within sedimentary bodies were estimated using the data from the two cored wells (see Figure 2). For each type of sedimentary body, the corresponding Petrophysical Groups were simulated using sequential indicator simulation (Journel *et al.*, 1989) over the $7.2 * 14.1 km^2$ area. The first stage of this method consists in associating one indicator variable to each Petrophysical Group. For each well-gridblock, the indicator Ii of Group #i is set to one if Group #i is dominant or to zero if not. Then a gridblock accross the interval is chosen randomly as long as it belongs to the targeted type of sedimentary body. Values of the indicators are estimated by kriging the well-gridblocks indicators (Simple Kriging, Journel, 1989). A Monte-Carlo procedure is applied on these estimated values to assign a Petrophysical Group to the gridblock. Assignment of a Petrophysical Group to another randomly chosen gridblock is repeated but this time the kriging algorithm uses the well-gridblocks data as well as the previously estimated data. This procedure is repeated sequentially till a map of Petrophysical Groups is obtained within each sedimentary body (Figure 6). One may notice that despite the variability of Petrophysical Groups within sedimentary bodies, hints of the sedimentary architecture remain in this image.

Third stage: Mapping of individual physical properties
Porosity is mapped using a sequential Gaussian simulation per petrophysical Group. Results are shown in Figure 7. Depending on the petrophysical Group, permeability is either simulated (Gaussian simulation for Groups #0, 1, 2, and 3) or calculated from porosity (Groups #4 and 5, see Table 1).

Scale of Heterogeneity: Histograms of porosity were used within each petrophysical Group. These histograms were based on plug data and used to assign rock properties to gridblocks that have a vertical dimension of 40cm and a lateral dimension of 300 meters. Therefore, the heterogeneities measured at plug scale were assumed to be representative of the heterogeneities represented in the model by thicker gridblocks. The resultant uncertainty could have been reduced by deriving continuous core petrophysical logs of porosity, permeability and grain density prior to constructing Petrophysical Groups (Greder *et al.*, 1994, 1995).

PETROPHYSICAL GROUPS VS. CONVENTIONAL LITHOFACIES

In this section, we address the following question: "Does the use of Petrophysical Groups improve the mapping of rock properties compared to the conventional use of deterministic lithofacies?"

As stated earlier, the conventional approaches to reservoir modelling have consisted of determining the facies which are significant from a sedimentological viewpoint and which have consistent petrophysical characteristics. However, in complex carbonate reservoirs coherence between petrophysical properties and sedimentary characteristics can not be established because of diagenesis. In order to quantify the improvement brought by our method, we examined a previous model of the reservoir. Originally, 17 lithofacies had been identified on cores (e. g. bioturbated dolomitic sandstones, bioturbated dolomites, pelletoïdal dolomites, ...) with the objective of having both a precise sedimentological meaning and narrow ranges of petrophysical properties. In order to evaluate the improvement, we need to address two questions: Is the mapping of Petrophysical Groups more or less precise than the mapping of lithofacies within the sedimentary bodies ? Is the assignment of petrophysical attributes more precise when using Petrophysical Groups instead of lithofacies ? Concerning the first question, it happens that the geologist could not asserted with more confidence the lateral extensions of the 17 lithofacies within the sedimentary bodies than the ones of the Petrophysical Groups. This is due to the fact that the Petrophysical Groups contain some geological information thanks to the grain density parameter that was used in their construction. Concerning the second question, we found that porosity dispersion varied from 4.5 to 7 p.u. within the lithofacies whereas it never exceeds 3.9 p.u. within each Petrophysical Group (with a 68% confidence interval). Dispersion of permeability ranged from 0.7 to 1 decades within the lithofacies whereas it never exceeds 0.48 decades within the Petrophysical Groups. Therefore the assignment of petrophysical properties is more precise when using Petrophysical Groups instead of lithofacies.

CONCLUSIONS

Subdividing a mixed carbonate reservoir into Petrophysical Groups improves the petrophysical characterization of the meter-scale stratigraphic units which condition reservoir behavior. The vertical organisation of the Petrophysical Groups along cored intervals was found to be consistent with the sedimentary bodies identified on cores. They were therefore used as a basis for mapping reservoir rock properties. The mapping was performed in two steps: firstly, sedimentary bodies were (geostatistically) generated in three dimensions, then the Petrophysical Groups were generated within the sedimentary bodies. The whole model was constrained by cored data measured on two wells. The assignment of the petrophysical attributes to individual gridblocks proved to be more precise when using Petrophysical Groups instead of conventional facies.

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FIGURES

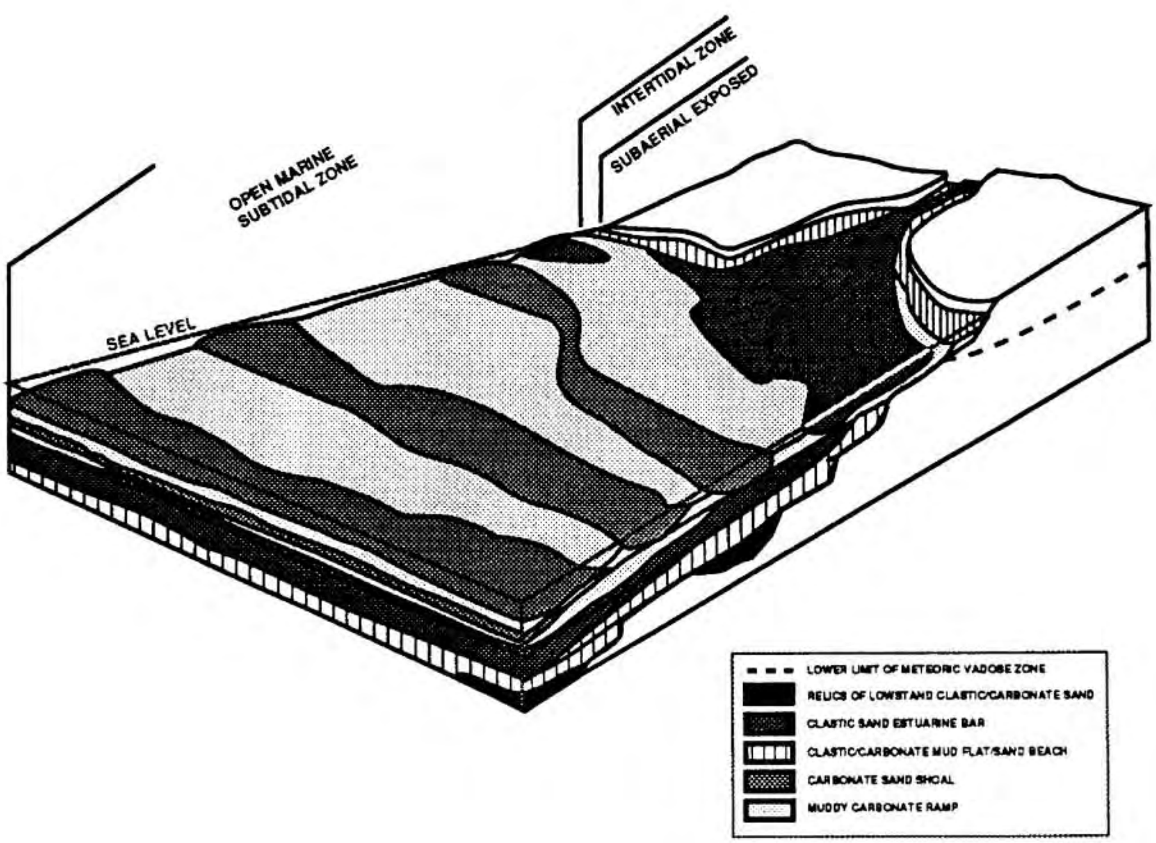

FIGURE 1 - RETROGRADATION SEDIMENTARY MODEL

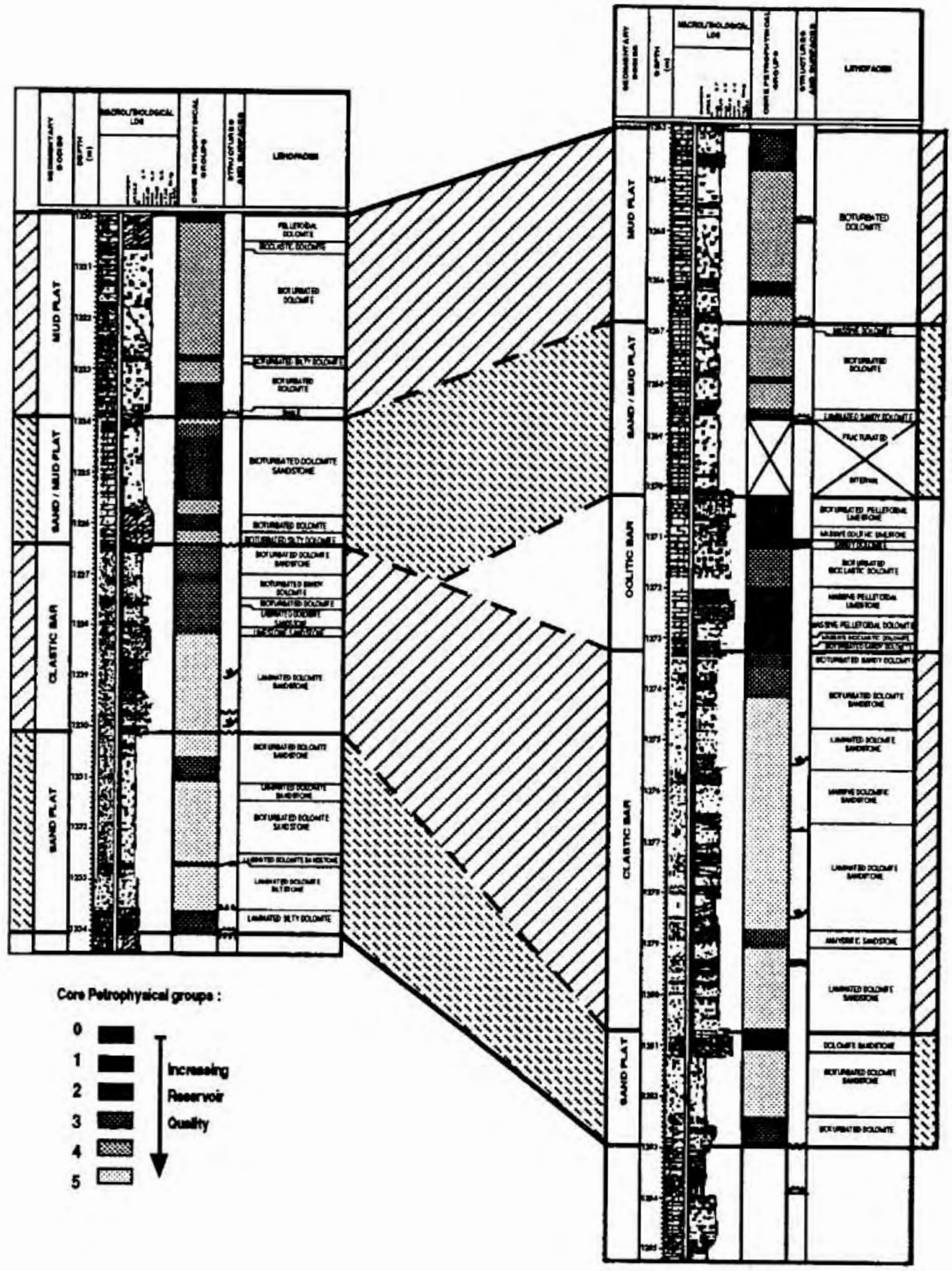

FIGURE 2 - PETROPHYSICAL GROUPS AND SEDIMENTARY BODIES

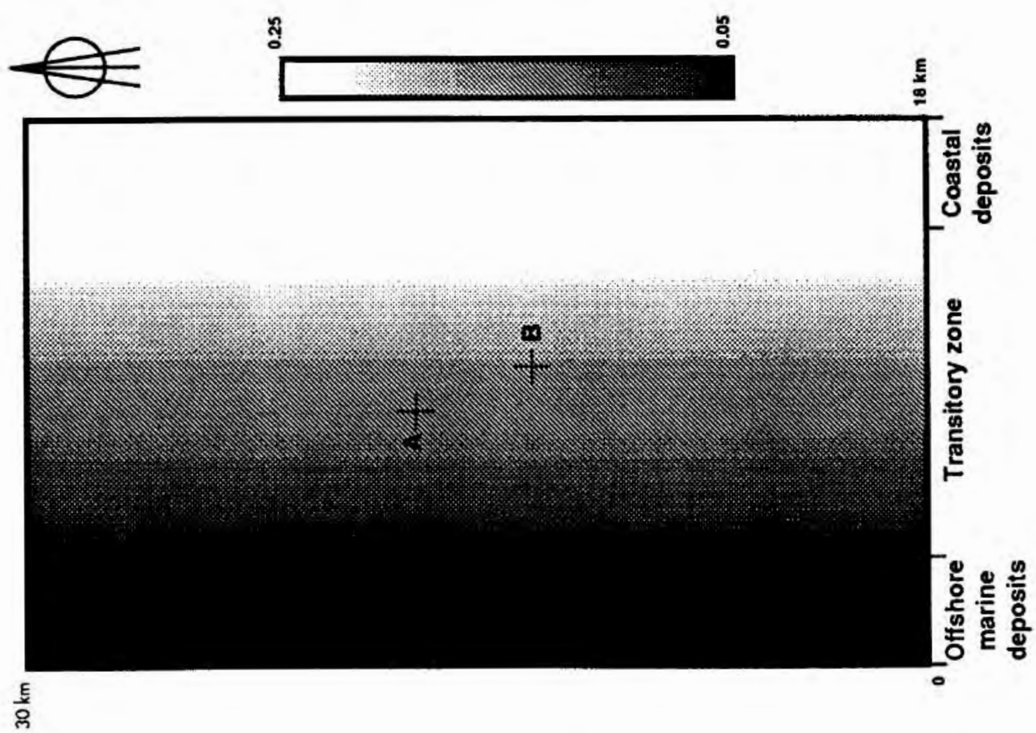

FIGURE 3 - EVOLUTION OF SAND-FLAT PERCENTAGE

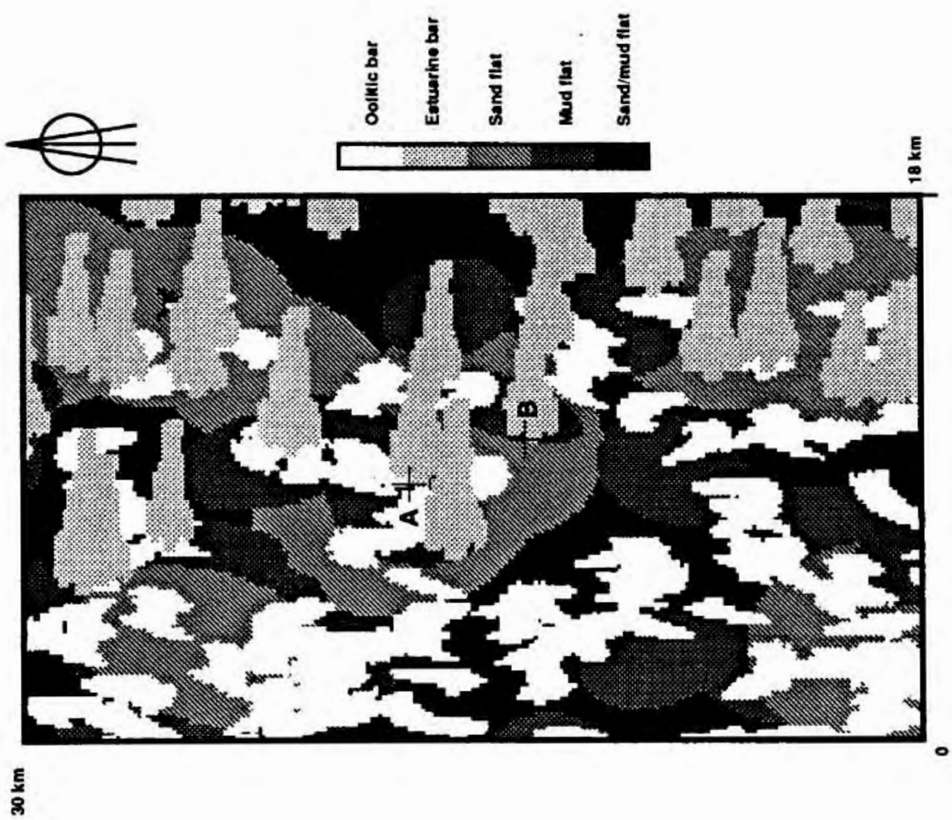

FIGURE 4 - SEDIMENTARY BODY MODEL (ERGOTIC DOMAIN)

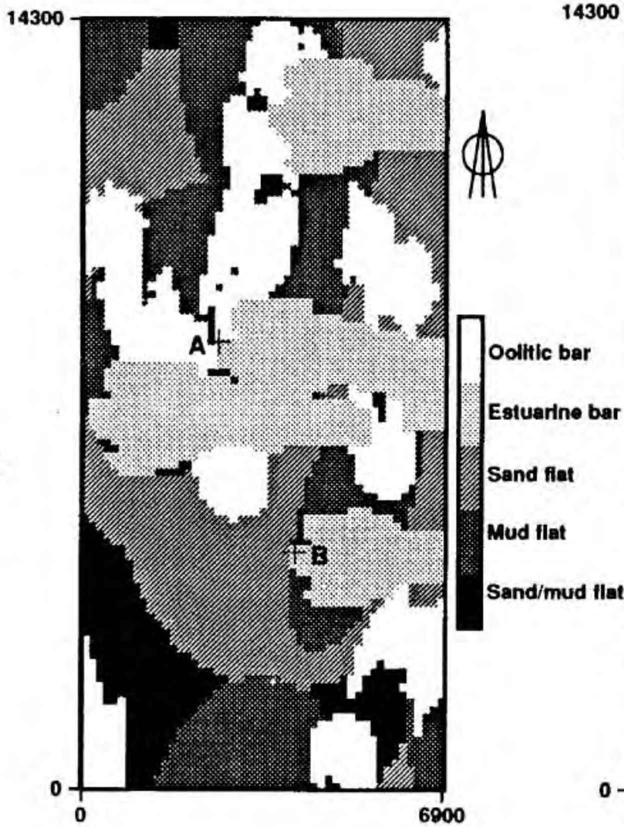

FIGURE 5 - SEDIMENTARY BODY MODEL

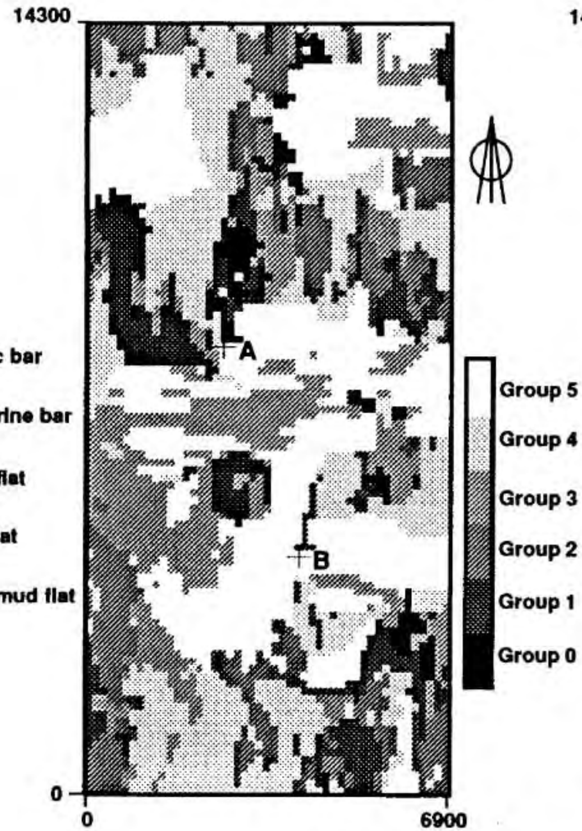

FIGURE 6 - PETROPHYSICAL GROUP MODEL

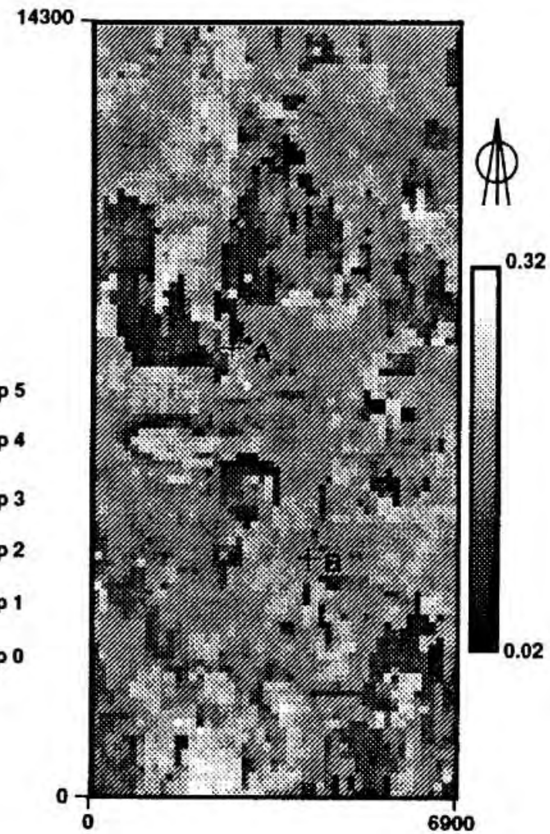

FIGURE 7 - POROSITY MODEL