Geological Classification of Domestic Light Oil Reservoirs

Preliminary Report

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ACKNOWLEDGMENTS

Geological Classification of Domestic Light Oil Reservoirs is the first of two reports to be completed by the Interstate Oil Compact Commission (IOCC) in its current study, the "Evaluation of the Domestic Oil Resource and Economic Recovery of Mobile and Immobile Light Oil." The overall effort by the IOCC, under the Project on Advanced Oil Recovery and the States, has developed important findings related to the oil production potential in the states of New Mexico, Oklahoma, and Texas in previous studies. The overall project was initiated by a "seed money" grant from the State of Oklahoma in 1985. This report was prepared under a grant from the U.S. Department of Energy (DOE), Bartlesville Project Office (BPO), to the IOCC.

BPO also supported the study through in-kind contributions of reservoir data and computer time using the Tertiary Oil Recovery Information System (TORIS). Mr. Thomas Wesson and Mr. R. Michael Ray, Director and Deputy Director of BPO, respectively, coordinated DOE's effort in this evaluation. Mr. Ray also served as technical project officer for the grant.

Special recognition is due to those who directly performed the work of this project. ICF Resources Incorporated of Fairfax, Virginia, served as the IOCC's principal contractor, responsible for the study design, analysis, interpretation, and report preparation. ICF's Project Directors were Dr. Jerry Brashear and Dr. E. Hunter Herron; Mr. Khosrow Biglarbigi was the Project Manager; the critical project staff included Mr. George Dacre (geologic analysis), Mr. Brian Wood, Mr. Joshua Barker, and Mr. Geoff Hobday (editing, research, and analytical support), Ms. Barbara Jones (Administrative Assistant), Ms. JoAnne Grabowski, and Ms. Yoko Morita (Staff Assistants).

Dr. Frank Morra of Frank Morra and Associates provided invaluable assistance in the design and interpretation of the statistical analysis that was critical to the determination of the groupings used in the geological classification system.

A multidisciplinary task force headed by the Geoscience Institute for Oil and Gas Recovery Research, in consultation with BPO, developed the initial geological classification system that was later enhanced by an IOCC review committee for application to this study. Dr. Marcus Milling and Mr. Jerry Lucia directed the Institute's efforts. Five geologists coordinated the regional collection

of additional reservoir data needed to enhance the TORIS data base and the geologic assessment of each reservoir: Mr. John Echols, Director of the Basin Research Institute of Louisiana State University (Southeastern Gulf region); Dr. Lee Gerhard, Director of the Kansas Geological Survey (Central region); Dr. Donald Oltz, Head of the Oil and Gas Section of the Illinois State Geological Survey (Eastern region); Mr. Gary Glass, Director of the Geological Survey of Wyoming (Rocky Mountain region); and Mr. Donald Zieglar, a West Coast consultant (Pacific region). Dr. Charles Mankin, Director of the Oklahoma Geological Survey, coordinated the efforts of that office to provide geologic information on Oklahoma reservoirs.

While acknowledging the assistance of all these contributors, errors of fact, analysis, or interpretation are the responsibility of the Interstate Oil Compact Commission and the principal contractor's Project Directors.

W. Timothy Dowd
Executive Director
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EXECUTIVE SUMMARY

Of the total known domestic oil resource of over 500 billion barrels, approximately two-thirds will remain unrecovered in reservoirs at the completion of conventional production. One of the major constraints on the production of a portion of this oil is reservoir heterogeneity, variations in permeability and porosity, especially at the inter-well scale. Such heterogeneity, considered to reflect the internal architecture of the reservoir, determines the flow paths by which oil can be recovered. It is widely held that these heterogeneities can be attributed to the deposition, diagenesis, and structural deformation of the reservoir, or, collectively, the geologic history of the reservoir (Geoscience Institute, 1990). Insofar as these heterogeneities and flowpaths can be better understood, more predictable and effective recovery processes can be designed.

The Interstate Oil Compact Commission (IOCC) is conducting a series of studies in order to estimate the incremental recovery potential of known U.S. oil reservoirs under a variety of technological, economic, and regulatory conditions. The current effort, "The Multi-State Study," includes as one of its objectives the determination of whether, on a quantitative basis, reservoir history can be linked to reservoir heterogeneity. This report presents the results of this phase of the study.

In the present effort, over 1,900 major reservoirs were classified according to a detailed system of descriptors of lithology, deposition, diagenesis, and structure by a committee of geologists who have extensive experience in their respective areas of the country. The resulting candidate reservoir classes were then subjected to a series of statistical analyses to establish a manageable number of classes that were (1) collectively exhaustive, (2) mutually exclusive, (3) internally consistent, and (4) meaningfully different with regard to heterogeneity. The indicator of heterogeneity used in these tests was volumetric sweep efficiency as adjusted to remove the effects of differing oil-water mobility ratios and differing well spacing.

Reservoirs containing heavy oil and those with anomalous data on reservoir characteristics or performance were set aside from the statistical portion of the study. In all, 1,358 reservoirs were included in the detailed analysis.

The distribution of reservoirs caused the elimination of one dimension in each lithology group: the structure dimension was not considered for carbonates, leaving deposition and diagenesis; the diagenesis dimension was not considered for clastics, leaving deposition and structure. Using the remaining dimensions, twenty-five classes — sixteen for clastics and nine for carbonates — were found to satisfy the statistical standards of the analysis of variance, i.e., minimizing the within-class variance relative to between-class variance. Both finer subdivision and greater aggregation failed to improve the results by this standard.

The twenty-five geologic classes (Table 1) range in size from 8 to 278 reservoirs (including only those used in the detailed analysis) and from 400 million to 24 billion barrels of oil remaining in place after conventional recovery. The indicator of heterogeneity, adjusted volumetric sweep, was ordered approximately as would be expected across the depositional classes and between unstructured and structured clastic reservoirs. The few exceptions represent explainable anomalies worthy of further investigation. A two-factor analysis of variance found that deposition for both lithologies and the interaction of deposition and diagenesis for carbonates and of deposition and structure for clastics was significant, underscoring the necessity of using two-dimensional classification approaches in each lithology.

The largest ten of the twenty-five classes contain seventy-six percent of the remaining oil-in-place. This finding, coupled with the demonstration that this simple geological classification can be quantitatively related to a crude indicator of reservoir heterogeneity, suggests that focusing on the largest potential classes would be a fruitful direction for future research and development.

Table 1
Summary of Findings: Final Geological Classes

Reservoir Class			Number of Reservoirs Analyzed	Adjusted Volumetric Sweep Efficiency Mean	Adjusted Volumetric Sweep Efficiency Variance	Remaining Oil in Place (BBbl)
Clastics						
Deposition and Structure						
Eolian		Unstructured	26	0.609	0.035	1.3
		Structured	14	0.583	0.081	0.8
Fluvial		Unstructured	31	0.498	0.071	2.4
		Structured	8	0.537	0.062	0.4
Alluvial Fan		All	13	0.492	0.065	0.7
Delta		Unstructured	278	0.546	0.059	23.6
		Structured	121	0.597	0.060	9.4
Strandplain -	Barrier Core/ Shorefaces	Unstructured	104	0.658	0.042	6.1
	All Others	Unstructured	60	0.573	0.057	2.2
	All	Structured	48	0.509	0.068	5.1
Shelf -	Sand Ridges	Unstructured	17	0.643	0.046	4.3
	All Others	Unstructured	54	0.553	0.061	4.1
	All	Structured	16	0.499	0.059	1.0
Slope Basin -	Turbidite Fans	Unstructured	53	0.506	0.071	10.1
	All Others	Unstructured	46	0.584	0.051	6.3
		Structured	19	0.503	0.070	4.0
Subtotal - 16 Clastic Classes			908			81.8
Carbonates						
Deposition and Diagenesis						
Peritidal		Non-Dolomitized	51	0.703	0.038	4.1
		Dolomitized	57	0.706	0.030	3.4
Shelf		Non-Dolomitized	48	0.633	0.066	12.1
		Dolomitized	79	0.676	0.054	22.0
		Dolomitized w/ Evaporites	109	0.582	0.063	5.5
Reefs -	Atolls	Non-Dolomitized	35	0.698	0.036	2.6
	All Others	Non-Dolomitized	25	0.576	0.042	1.4
		Dolomitized	28	0.715	0.039	3.7
Slope-Basin		All	18	0.667	0.033	0.9
Subtotal - 9 Carbonate Classes			450			55.8
Total - All Classes			1,358			137.7

Note: Clastic Slope-Basin class includes Slope/Basin and Basin reservoirs.
Alluvial Fan class includes Alluvial Fan and clastic Lacustrine reservoirs.
Carbonate Shelf class includes Shallow Shelf and Shelf Margin reservoirs.

I. BACKGROUND AND OBJECTIVES

The remaining oil resource in known U.S. reservoirs constitutes a 340 billion-barrel target for future recovery efforts (Figure 1). Nearly 100 billion barrels of the resource are estimated to be unrecovered mobile oil (UMO) that is left in the reservoir because of reservoir heterogeneity and inefficient secondary recovery efforts. Over 240 billion barrels of the resource is estimated to be immobile oil, which can be recovered only with the application of enhanced oil recovery (EOR) methods to overcome the viscous and capillary forces holding the oil in place. While the recovery technologies of UMO and EOR differ, in both cases efficient recovery depends in significant part on in-depth understanding of the reservoir's internal architecture and derivative flow paths.

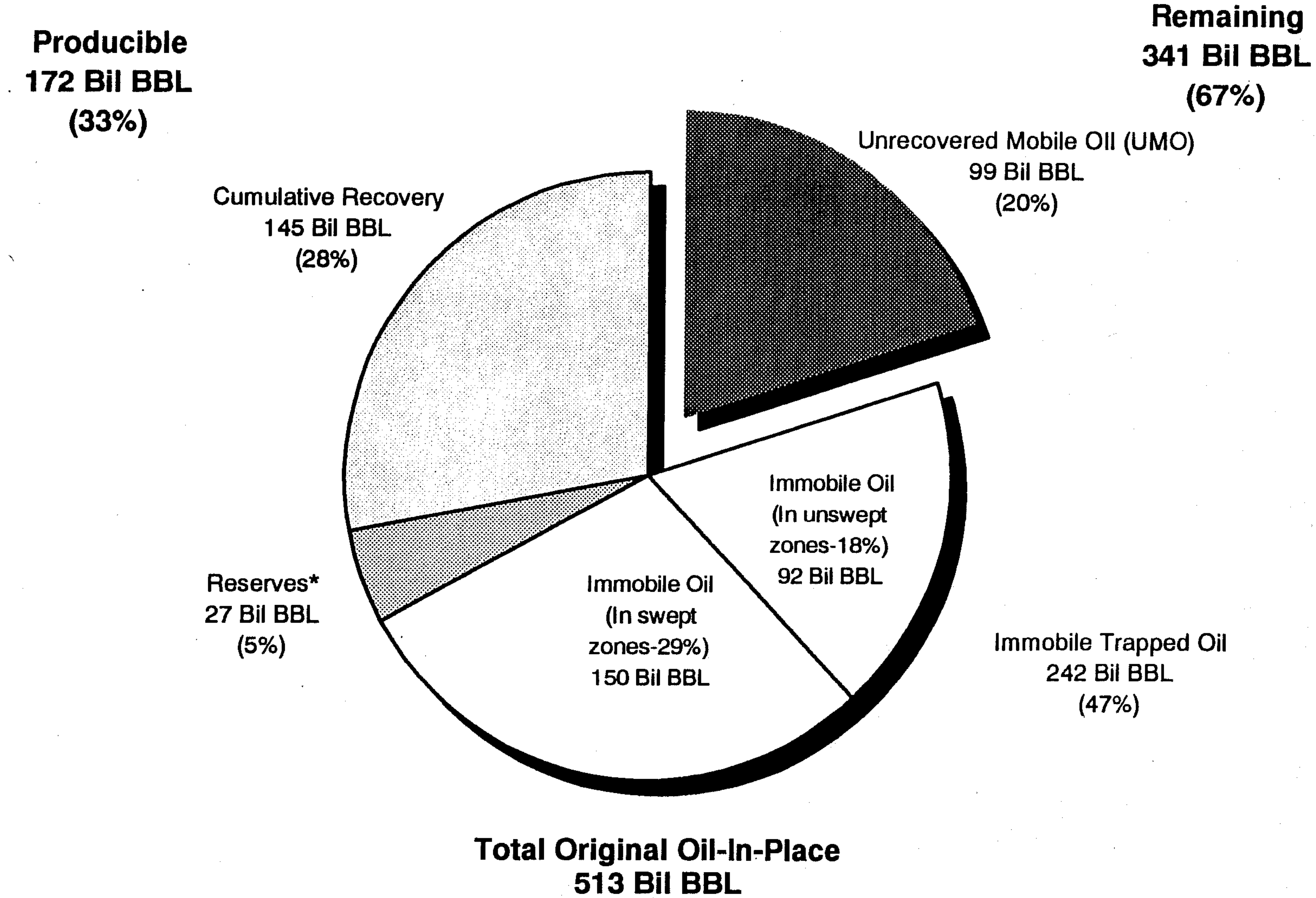
The goal of this study is to classify reservoirs into distinct groups whose members have geologically similar heterogeneity at the interwell scale. These reservoir groups, or classes, are expected to exhibit similar recovery constraints on at least one dimension, reservoir heterogeneity. By limiting the scope of technical constraints within classes, research efforts can be more focused on the identification of critical barriers to recovery and the development of solutions using advanced technology.

Previous studies by the Interstate Oil Compact Commission (IOCC), the National Petroleum Council (NPC), and the U.S. Department of Energy (DOE) have shown that improvements in technology could dramatically increase recovery potential from the known resource. Tax incentives and improved technology transfer can also improve significantly the degree to which future recovery potential is realized. In 1985, the IOCC initiated the Project on Advanced Oil Recovery and the States. This series of studies of the recovery potential in oil-producing states, and of fiscal, regulatory, and research policies that might stimulate advanced recovery, has so far generated three reports:

- In New Mexico, the potential of carbon dioxide miscible flooding could be amplified significantly by tax incentives at oil prices below $30 per barrel (IOCC, 1986).
- In Oklahoma, tax incentives and advanced technology applied together demonstrated significant synergies that increase EOR production from all recovery processes (IOCC, 1987).

Figure 1

Distribution of Known U.S. Oil Resource



Source: BPO, 1989, API/AGA 1980, EIA 1980 - 87

*Includes proved EOR Reserves

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- In Texas, both UMO extraction and EOR could make substantial contributions to future reserves, especially if R&D proved successful in advancing recovery technologies (IOCC, 1989).

In the Texas study, application of a geologic classification system developed by the Texas Bureau of Economic Geology showed that the bulk of the state's recovery potential resides in a small number of key groupings of reservoirs having similar geologic history. This was the first large-scale study to link future recovery potential with geologic history. The study was extended to apply the geologic classification to all three states and investigate UMO recovery potential (ICF Resources, et al., 1990). Again, recovery potential was concentrated in a few classes. This study also demonstrated the dramatic impact that improved geologic understanding of reservoir heterogeneity and internal structure could have on future reserves, increasing UMO recovery potential three-fold to over 6 billion barrels in the three states.

Each of these studies used the data and models of the Tertiary Oil Recovery Information system (TORIS), maintained by the Bartlesville Project Office of the U.S. Department of Energy. TORIS is the direct result of the definitive national assessment of enhanced oil recovery performed by the National Petroleum Council (NPC, 1984) and has been updated with new data, model refinements, and extensions to include advanced secondary recovery methods.

The IOCC is currently extending these studies to 22 additional oil-producing states, again using TORIS, in the "Evaluation of the Domestic Oil Resource and Economic Recovery of Mobile and Immobile Light Oil," also called the Multi-State Study. This study has five objectives: (1) characterize as much of the remaining domestic oil resources as possible; (2) determine the most cost-effective, technologically sound, and environmentally safe methods to increase future recovery; (3) assess the impact of state economic incentives; (4) identify the most promising known oil reservoirs and geologic settings; and (5) identify and evaluate emerging methods for increasing recovery.

The development of a geological classification system that could be applied to reservoirs throughout the U.S. became a key objective following the results of the studies cited above and the benefits suggested by more broadly linking geologic history to heterogeneity. This addresses the first, and fourth objectives of the Multi-State Study as enumerated above. By classifying reservoirs with similar geologic history into distinct groups which also exhibit similar heterogeneities, it is thought that a significant dimension of recovery constraints can be isolated within the group, and that more focused research on reservoir constraints can proceed with greater chance of achieving the needed technology advances to produce significant portions of the remaining oil.

A set of objectives was established to guide of this study to ensure that the resulting reservoir classes would meet the needs of the ongoing Multi-State study. These objectives are:

- Develop a system that captures the major elements of geologic history, with which reservoirs may be readily classified using data that are generally available.
- Establish a manageable number of reservoir classes that are 1) collectively exhaustive (a class exists for every TORIS reservoir with sufficient descriptive data), 2) mutually exclusive (each reservoir can belong to only one class) and 3) meaningfully different (variation between classes is much greater than within-class variation) with regard to heterogeneity.
- Evaluate the relationship between geologic history and reservoir heterogeneity using actual reservoir data.

The analytical approach was designed to meet these objectives. The resulting classification system establishes the foundation for the next phase of activities in the ongoing Multi-State study. Analytical models which are unique to the specific geologic classes will be developed to help project incremental recovery by advanced secondary recovery and EOR techniques. The results are expected to be useful in planning activities underway for the federal oil RD&D program, as described in DOE's 1990 implementation plan (DOE, 1990), and will benefit the producing states by making available analytical results useful for their evaluation of fiscal, regulatory, and research policies.

II. ANALYTICAL APPROACH

To develop and test a classification system that meets the objectives listed in the previous section, the analysis was designed to proceed in five stages:

- Development of the geological classification system. Based on previous work and the primary variables thought to control reservoir heterogeneities, a panel of experts developed a system to be assessed against actual reservoir data.

- Development of a measure of heterogeneity. An indicator was developed to quantify the extent of heterogeneity in reservoirs based on their historical performance.

- Reservoir classification. The reservoirs in the TORIS data base were further characterized by state geologists, who enhanced the existing data and described each reservoir according to the classification system.

- Trial grouping of reservoirs. Based on the geologic assessments, the distribution of reservoirs was examined and trial groupings of distinct, yet internally consistent, reservoir classes were compiled for statistical testing.

- Statistical methods. The trial groupings were analyzed using Analysis of Variance (ANOVA) and regrouped in an iterative process to develop final groupings which were geologically meaningful, statistically distinct, and internally consistent.

A. DEVELOPMENT OF THE GEOLOGIC CLASSIFICATION SYSTEM

The first step in the analysis was to review previous attempts at geological classification systems and evaluate the principal geological elements that should be considered to describe reservoir heterogeneity. Quantitative and qualitative variables needed to be identified to define the procedure for enhancing the TORIS reservoir data base and to enable subsequent analysis. Development of the classification system began with consideration of the causes of reservoir heterogeneity.

Reservoir heterogeneity is the variation in rock properties that affects fluid flow. Reservoir heterogeneity exists on a variety of scales, ranging from microscopic (variations in pore size and geometry) to megascopic (external architecture of the reservoir on a field-wide, multi-field, or subregional scale). Between these two extremes is the macroscopic scale, which refers to the variation in the internal geometry and facies distribution of the reservoir at the interwell distance (ICF Resources, 1990). The macroscopic level of heterogeneity is the subject of the present study.

In general, the internal architecture and heterogeneity of reservoirs are dominantly controlled by processes operative at the time of deposition, as the reservoir rock was originally formed. However, diagenetic processes and structurally imposed reservoir compartmentalization may, at times, play a more dominant role in determining reservoir heterogeneity at the interwell scale (Geoscience Institute, 1990). The classification system developed for the present analysis, thus, incorporates assessments of (1) depositional system, (2) diagenetic overprint, and (3) structural compartmentalization, the three factors together referred to as the geologic history of a reservoir.

The Geoscience Institute for Oil and Gas Recovery Research, in consultation with the DOE Bartlesville Project Office, established a multidisciplinary task force to develop a geological classification system to describe the geologic history of a reservoir in summary form. The task force consisted of 20 professionals from a variety of technical backgrounds representing industry, government, and academia. The task force completed the classification system in January 1990 and circulated it in draft for review and comment.

The IOCC organized a committee to review the Institute's classification system and assess its applicability to the Multi-State Study.[1/] In this review, the committee concluded that as data collection and reservoir classification were to proceed before knowing which elements would prove to be most descriptive of heterogeneity, a more detailed preliminary system was needed. The IOCC committee added subcategories to the depositional and structural categories in the Institute's draft system, resulting in the classification system shown in Figure 2. Subsequently, the Institute's committee adopted the more detailed structure for its final report (Geoscience Institute, 1990). The following is a brief description of the three major dimensions of the reservoir classification system:

1/ Professionals from the following organizations participated in the review of the classification system: ICF Resources Incorporated, Interstate Oil Compact Commission, Illinois Geological Survey, Kansas Geological Survey, Louisiana State University, Mobil Oil Company, Oklahoma Geological Survey, Pennsylvania State University, Shell Oil Company, University of Wyoming, and the U.S. Department of Energy. Representatives of the Geoscience Institute presented their initial classification and its underlying rationale.

Figure 2

GEOLOGICAL RESERVOIR CLASSIFICATION SYSTEM

CARBONATE RESERVOIRS

Depositional System

- Lacustrine
- Peritidal
  - Supratidal
  - Intertidal
  - Subtidal
- Shallow Shelf
  - Open Shelf
  - Restricted Shelf
- Shelf Margin
  - Rimmed Shelf
  - Ramp
- Reefs
  - Pinnacle Reefs
  - Bioherms
  - Atolls
- Slope/Basin
  - Debris Fans
  - Turbidite Fans
  - Mounds
- Basin
  - Drowned Shelf
  - Deep Basin

Diagenetic Overprint

- Compaction - Cementation
- Grain Enhancement
- Dolomitization (Evaporites)
- Dolomitization
- Massive Dissolution
- Silicification

Structural Compartmentalization

- Unstructured
- Natural Fracture Porosity
- Faulted
- Folded
- Faulted/ Folded

SILICICLASTIC RESERVOIRS

Depositional System

- Eolian
  - Ergs
  - Coastal Dunes
- Lacustrine
  - Basin Margin
  - Basin Center
- Alluvial Fan
  - Humid (Stream-Dominated)
  - Arid/Semi-Arid
  - Fan Deltas
- Fluvial
  - Braided Streams
  - Meandering Streams
- Delta
  - Wave-Dominated
  - Fluvial-Dominated
  - Tide-Dominated
- Strandplain
  - Barrier Cores
  - Barrier Shorefaces
  - Back Barriers
  - Tidal Channels
  - Washover Fan/Tidal Deltas
- Shelf (Accretionary Processses)
  - Sand Waves
  - Sand Ridges/Bars
- Slope/Basin
  - Turbidite Fans
  - Debris Fans
- Basin
  - Pelagic

Diagenetic Overprint

- Compaction - Cementation
- Grain Dissolution
- Authigenic Clay
- Chertification

Structural Compartmentalization

- Unstructured
- Natural Fracture Porosity
- Faulted
- Folded
- Faulted/ Folded

Depositional System. The depositional history and associated facies distribution within the reservoir are usually the primary factors controlling heterogeneity at the interwell scale. Facies, or amalgamated groups of facies, compose the fundamental flow units through which a reservoir drains (Finley and Tyler, 1987). Lateral and vertical variations in grain size, porosity, and permeability between and within associated lithologic units influence the recovery efficiency of a reservoir and are primarily determined by its depositional history. The classification system has defined seven major categories and fifteen subcategories for carbonate reservoirs, and nine major categories with twenty-two subcategories for clastic reservoirs. The depositional categories were designed to be mutually exclusive and collectively exhaustive.

Diagenetic Overprint. Diagenesis is the chemical, physical, and biological alteration of sediments after initial deposition as well as during and after burial and lithification. A variety of processes comprise diagenesis, including compaction, cementation, authigenesis (in-situ formation of cements and clay minerals), replacement (changes in mineralogy due to chemical reactions), leaching, crystallization, bacterial action, etc. Diagenetic effects can occur in combination and over several different episodes of time, and can either enhance or reduce effective porosity and permeability in a reservoir. In the classification system, the diagenetic overprint dimension addresses the pore types present in the reservoir, the diagenetic processes responsible for the pore types, and the relationship between pore-type and fluid flow in the reservoir. While diagenesis primarily affects reservoirs at the microscopic level of pores, it also influences heterogeneity at the macroscopic or interwell scale. Diagenetic alteration can be grain-selective, as in the dissolution of feldspar versus quartz in clastics or fossil fragments versus mud in carbonates. Conversely, it can be pervasive through the entire pore system, as in the case of silica or carbonate cementation. In addition, the effects of diagenesis are not symmetric in a lateral or vertical sense, and it is this asymmetry which causes variations in reservoir character, or heterogeneity, at the interwell scale. While compaction and cementation are common to both carbonate and siliciclastic reservoirs, other diagenetic processes act principally on only one lithology or the other. The classification system includes six diagenetic overprint categories for carbonates and four categories in clastic reservoirs.

Structural Compartmentalization. Whereas structure often provides a trapping mechanism for petroleum accumulations, it may or may not be responsible for introducing geologic heterogeneity at the interwell scale. The structural dimension is designed to differentiate reservoirs in which fluid flow has been influenced by faulting, folding, or natural fracturing. The classification system provides five main categories and six subcategories of structural effects on reservoir heterogeneity for both carbonate and clastic reservoirs.

Overall, the classification system presented here describes the essential geologic information needed for the summary description of geologic history.

B. DEVELOPMENT OF A MEASURE OF HETEROGENEITY

While there is no accepted indicator of heterogeneity at the interwell scale, volumetric sweep efficiency (E_v) directly reflects reservoir heterogeneity along with a number of other factors. Broadly defined, it is the portion of a reservoir's hydrocarbon pore volume that is effectively swept by a waterflood. In the present study, E_v was modified to control for variations in some of these "other factors" to serve as an indicator of heterogeneity.

E_v can be estimated as the ratio of ultimate recovery by primary and secondary methods to the volume of displaceable mobile oil:

$$E_v = \frac{\text{Ultimate Recovery}}{\text{Displaceable Mobile Oil}} \quad \ldots\ldots\ldots\ldots \quad (1)$$

Ultimate recovery is estimated by decline curve analysis of historical production. Such data are available on an annual basis from 1979 to 1988 for the majority of reservoirs in the TORIS data base. Displaceable mobile oil is the amount of oil that would be theoretically produced if the entire reservoir were reduced to its residual oil saturation. The volume of displaceable mobile oil can be estimated with the following formula:

$$D_{mo} = 7758 * A * h * \phi * \left(\frac{S_{oi}}{B_{oi}} - \frac{S_{orw}}{B_{oa}} \right) \quad \ldots\ldots\ldots\ldots \quad (2)$$

where:

D_{mo} = Displaceable mobile oil volume (STB)

A	=	Reservoir area (acres)
h	=	Average net pay thickness (ft)
ϕ	=	Average reservoir porosity (frac.)
S_{oi}	=	Initial oil saturation (frac.) $S_{oi}=(1-S_{wi}-S_{gi})$ S_{wi} = Initial water saturation; S_{gi} = Initial gas saturation
B_{oi}	=	Initial oil formation volume factor (reservoir bbl/stock tank bbl)
S_{orw}	=	Residual oil saturation in the swept zone at the end of water flooding (frac.)
B_{oa}	=	Oil formation volume factor at the end of waterflooding (reservoir bbl/stock tank bbl)

Volumetric sweep efficiency may be characterized as the interaction of several factors:

$$E_v = E_{het}*E_{fluid}*E_{well}*E_{other} \quad (3)$$

where:

E_{het}	=	Volumetric sweep efficiency attributable to reservoir heterogeneity
E_{fluid}	=	Volumetric sweep efficiency attributable to the fluid behavior in the reservoir, characterized by the mobility ratio of injection fluid relative to oil
E_{well}	=	Sweep efficiency attributable to by well spacing
E_{other}	=	Sweep efficiency attributable to all other influences, including primary drive mechanism, mechanical design of waterflood (such as injection rate, pressures, type of injection water), etc.

Ideally, E_{het} would be isolated to serve as an indicator of reservoir heterogeneity in which all other factors have been removed. Due to the limitations of the data, however, only two adjustments can be made to E_v: for fluid behavior (E_{fluid}) and well spacing (E_{well}). These adjustments were made by normalizing all the sweep data to a mobility ratio of 1.0 and a well spacing of 40 acres. The residual influences of all other factors (E_{other}) cannot be segregated in the analysis at the present time and remain as "noise" in the indicator. The methodologies to adjust for fluid and well spacing are described below.

1. Adjustments for Fluid Behavior

Volumetric sweep efficiency can also be defined as the product of vertical and areal sweep efficiency, denoted as E_h and E_a, respectively:

$$E_v = E_a * E_h \quad (5)$$

Areal sweep efficiency is the fraction of the reservoir that is contacted by injection water. It depends on pattern geometry, mobility ratio, fractional water cut, and displaceable pore volume injected. Vertical sweep efficiency is defined as the fraction of net pay thickness that is effectively swept by the injection water. It depends very strongly on the degree of vertical conformance (permeability variation) along the producing interval.

E_a is typically determined from the empirical curves developed by Dyes et al. (Fassihi, 1986). These curves represent the standard procedure to estimate areal sweep efficiency for any waterflood operation. The curves are based on the measured sweep efficiency in a two-dimensional homogeneous model for three different pattern geometries: five-spot, staggered line drive, and direct line drive. Fassihi fitted these curves based on the mobility ratio (M) and fractional water cut (FWC), as given below (Fassihi, 1986):

$$\frac{1-E_a}{E_a} = (a_1 * \ln(M+a_2)+a_3)*FWC + a_4 * \ln(M+a_5) + a_6 \quad (6)$$

The empirical constants a_1 through a_6 are shown in Table 2 for the three pattern geometries.

Table 2
Coefficients in Areal Sweep
(Fassihi, 1986)

Areal Sweep Coefficient	Five Spot	Direct Line Drive	Staggered Line Drive
a_1	-0.2062	-0.3014	-0.2077
a_2	-0.0712	-0.1568	-0.1059
a_3	-0.5110	-0.9402	-0.3526
a_4	0.3048	0.3714	0.2608
a_5	0.1230	-0.0865	0.2444
a_6	0.4394	0.8805	0.3158

By inserting the mobility ratio (M) into equation (6), it is possible to calculate the value of E_a that is consistent with both the M and the E_v values from the data base. Using equation (5), a value for E_h can also be calculated that is consistent with data on M and E_v. The next step is to calculate a value for E_a at a mobility ratio of 1.0, by substituting M=1.0 into Fassihi's correlation. This value is denoted as $[E_{a1.0}]$. Because volumetric sweep is the product of areal and vertical sweeps, it is possible to use these values to adjust the E_v for the fluid effects.

$$E_{v2} = E_h * E_{a1.0} \quad \text{..........} \quad (7)$$

E_{v2} is the adjusted volumetric sweep, after the effects of E_{fluid} have been standardized to a mobility ratio of unity.

2. Well Spacing Adjustment

The effect of well spacing was removed from the analysis by standardizing the sweep data for all reservoirs to a well spacing of 40 acres. This was accomplished by using a generalized function which incorporates the effect of well spacing on reservoir continuity. Reservoir continuity is defined as the percentage of the total bulk volume of reservoir rock that is in pressure communication between injector-producer well pairs. Gould et al. (1984) evaluated a series of continuity functions using actual field data, as shown in Figure 3. One major conclusion from Gould's evaluation is that, for a given reservoir, there is a log-linear relationship between reservoir continuity and interwell distance. This relationship can readily be seen in Figure 3, where plots of the log of continuity against distance between wells are straight lines. Based on this observation, the following steps were taken to standardize the volumetric sweep data to a well spacing of 40 acres:

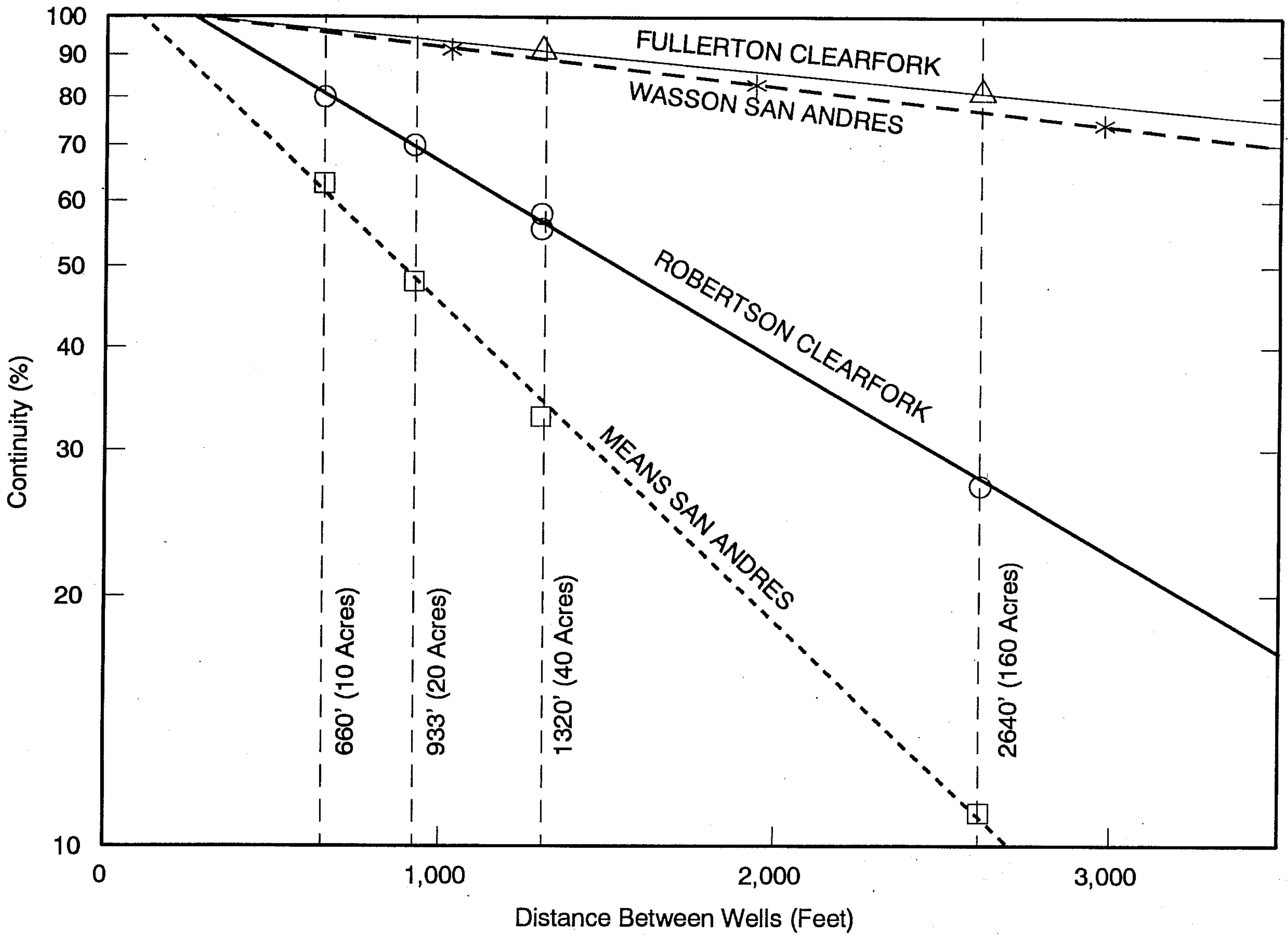
- Volumetric sweep efficiency (E_v) for a reservoir was estimated using volumetric data and ultimate recovery information in equations (1) and (2) above.
- E_v was adjusted to a unit mobility ratio (E_{v2}) using equations (5), (6), and (7).
- The well spacing of the reservoir was converted to interwell distance by the following geometric relationship:

$$WD = 208.66 *(AC)^{0.5} \quad \text{..........} \quad (8)$$

where:

Figure 3

Continuity Vs. Distance Between Wells



Source: Gould, et al. (1984).

WD	= Interwell distance (ft)	
AC	= Well spacing (acres)	

- A straight line was established from two points on a plot of $\ln(E_{v2})$ vs. interwell distance: one point has the coordinates of zero interwell distance and nearly perfect sweep efficiency (0, ln[.999]), the second point has the coordinates of the actual interwell distance and sweep efficiency for the reservoir (WD, E_{v2}).

- Using the straight line, an interpolation or extrapolation was conducted to obtain E_{v2} at an interwell distance of 1,320 ft (40-acre well spacing). E_{v2} at 40-acre well spacing is defined as E_{het}. This procedure has the following mathematical form:

$$F(E_{v2}, WD) = e^{(m*WD + b)} \quad (9)$$

where:

$F(E_{v2}, WD)$ = Log-linear function specific to each reservoir

m = Slope of the log-linear relationship between node (1) and node (2)
= $(\ln(E_{v2}) - \ln(0.999))/WD$

b = Intercept of the log-linear relationship with the y axis
= ln (0.999)

WD = Interwell distance (ft)

Inserting the standardized well distance (1,320 ft for 40-acre spacing) into equation (9), the value of E_{v2} is adjusted for well spacing to yield E_{het}.

$$E_{het} = F(E_{v2}, 1320) \quad (10)$$

C. RESERVOIR CLASSIFICATION

This study considered 2,528 reservoirs in the 25 states, as listed in Table 3. These are all the reservoirs represented in the TORIS data base for those states. State geologists and consultants, each with extensive experience in their respective areas of the country, were selected to classify the reservoirs according to the classification system. For states other than Texas, New Mexico, and Oklahoma, individual data sheets (Figure 4) were provided to the geologists for each reservoir in the data base along with detailed data on reservoir rock and fluid properties. The geologists recorded

Table 3
IOCC Multi-State Data Collection
Number of Reservoirs by State

States	Number of Reservoirs in TORIS	Number of Reservoirs in Multi-State Analysis*
Alabama**	3	0
Alaska	8	3
Arkansas**	43	0
California	232	214
Colorado	63	59
Florida**	4	0
Illinois	55	54
Indiana	3	3
Kansas	78	63
Kentucky	5	5
Louisiana**	440	99
Michigan	25	25
Mississippi**	76	26
Montana	98	91
Nebraska	38	35
North Dakota	49	40
Ohio	8	8
Pennsylvania	6	5
South Dakota	1	0
Utah	22	17
West Virginia	27	16
Wyoming	161	153
Multi-State Total	1,445	916
New Mexico	94	94
Oklahoma	120	113
Texas	869	824
Three State Total	1,083	1,031
Grand Total	2,528	1,947

* Reservoirs with key engineering data elements necessary for the analysis.
** Data collection is currently in progress, and will be completed by November 30, 1990.

Figure 4

Reservoir Classification Sheet

Reservoir Heterogeneity Classification System for TORIS

1. Reservoir Identification

Reservoir Play: ______

Reservoir Name: ______ Geologic Province: ______ Date: ______

Field Name: ______ Geologic Age: ______ Prepared By: ______

State: ______ Formation: ______ Version: ______

2. Depositional System ☐ 1 ☐ 2 ☐ 3 Degree of Confidence in Selection (1=Highest, 3= Lowest)

Carbonate Reservoirs

☐ Lacustrine

☐ Peritidal
- ____ Supratidal
- ____ Intertidal
- ____ Subtidal

☐ Shallow Shelf
- ____ Open Shelf
- ____ Restricted Shelf

☐ Shelf Margin
- ____ Rimmed Shelf
- ____ Ramp

☐ Reefs
- ____ Pinnacle Reefs
- ____ Bioherms
- ____ Atolls

☐ Slope/Basin
- ____ Debris Fans
- ____ Turbidite Fans
- ____ Mounds

☐ Basin
- ____ Drowned Shelf
- ____ Deep Basin

Clastic Reservoirs

☐ Eolian
- ____ Ergs
- ____ Coastal Dunes

☐ Lacustrine
- ____ Basin Margin
- ____ Basin Center

☐ Fluvial
- ____ Braided Streams
- ____ Meandering Streams

☐ Alluvial Fan
- ____ Humid (Stream-Dominated)
- ____ Arid/Semi-Arid
- ____ Fan Deltas

☐ Delta
- ____ Wave-Dominated
- ____ Fluvial-Dominated
- ____ Tide-Dominated

☐ Strandplain
- ____ Barrier Cores
- ____ Barrier Shorefaces
- ____ Back Barriers
- ____ Tidal Channels
- ____ Washover Fan/Tidal Deltas

☐ Shelf (Accretionary Processes)
- ____ Sand Waves
- ____ Sand Ridges/Bars

☐ Slope/Basin
- ____ Turbidite Fans
- ____ Debris Fans

☐ Basin
- ____ Pelagic

3. Diagenetic Overprint ☐ 1 ☐ 2 ☐ 3 Degree of Confidence in Selection (1=Highest, 3= Lowest)

Carbonate Reservoirs

☐ Compaction/Cementation ☐ Dolomitization (Evaporites)
☐ Grain Enhancement ☐ Massive Dissolution
☐ Dolomitization ☐ Silicification

Clastic Reservoirs

☐ Compaction/Cementation ☐ Authigenic Clay
☐ Intergranular Dissolution ☐ Chertification

4. Structural Compartmentalization ☐ 1 ☐ 2 ☐ 3 Degree of Confidence in Selection (1=Highest, 3= Lowest)

☐ Natural Fracture Porosity ☐ Unstructured

☐ Faulted
- ____ Normal Fault
- ____ Reverse Fault
- ____ Strike-Slip Fault

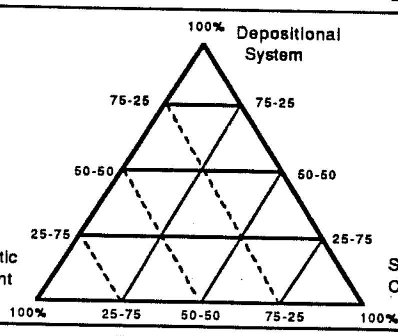
☐ Fault/Fold
- ____ Normal Fault
- ____ Reverse Fault
- ____ Strike-Slip Fault

☐ Folded

5. Reservoir Heterogeneity Ternary Diagram

Predominant Element of Reservoir Heterogeneity:
(Check Only One)

- Depositional System ____
- Diagenetic Overprint ____
- Structural Compartmentalization ____



6. Trap Type ☐ Stratigraphic ☐ Structural ☐ Combination

7. Optional Comments (References, Details on Above Selections, Etc.) ______

their classification judgments for each reservoir on the data sheets in accord with a consistent set of definitions and procedures (Appendix A). This effort was managed by the Geoscience Institute, and frequent quality checks ensured cross-regional consistency in the geologic assessments. Reservoirs in Texas, New Mexico, and Oklahoma had been partially classified by the Texas Bureau of Economic Geology in the pilot test for the present study (ICF Resources, et al., 1990). These earlier classifications were reviewed and amended to conform with the current classification approach by ICF Resources and, for Oklahoma, by the Oklahoma Geological Survey.

Of the 2,528 reservoirs submitted for classification to the geologists, 2,099 have been classified as of this writing. Of these, 152 reservoirs were eliminated because TORIS did not have sufficient engineering data to determine E_{het}, leaving 1,947 reservoirs available for analysis. Four screens were defined to establish a sample in which E_{het} could be determined in a consistent manner with the assumptions described in the previous section. The screens included: (1) high mobility ratio and/or low API gravity oil, indicating heavy oil reservoirs; (2) well spacing less than 5 acres per well; (3) unadjusted volumetric sweep efficiency greater than or equal to 0.95; and (4) anomalous or missing data. Heavy oil reservoirs were not included in the analysis because the corrections made to the volumetric sweep efficiency relied on assumptions that are valid only for light oil reservoirs. Well spacings of less than 5 acres were eliminated because the reservoir continuity function used to correct to 40-acre spacing does not apply at very dense well spacings. Sweep efficiencies of 0.95 are a result of default algorithms in TORIS and are therefore not based on actual reservoir data. The screening process eliminated 589 reservoirs (Table 4), leaving 1,358 reservoirs for the statistical analysis.

D. TRIAL GROUPINGS OF RESERVOIRS

The goal of the classification system is to define reservoir classes, the members of which have similar types and levels of geological heterogeneity at the inter-well scale. To identify these classes, it is important to determine what dimension(s) of the classification system most effectively differentiates the reservoirs in terms of heterogeneity. Reservoir classes may be grouped on the basis of any one of the three major dimensions (disregarding the other two), different combinations of two dimensions, or by each unique combination of all three dimensions.

Using only the major categories within each of the three main dimensions, there are a total of 210 possible combinations of deposition, diagenesis, and structure for carbonates and 180 possible

Table 4
Reservoir Screening Process
for Statistical Analysis

Screening Criteria	Number of Reservoirs
Total number of reservoirs available for the analysis	1,947
Excluded from analysis:	
Heavy oil reservoirs	133
Well spacing <5.0	80
Volumetric sweep efficiency >0.95	136
Missing key data elements	67
Anomalous data	173
Total excluded	589
Total number of reservoirs included in the analysis	1,358

combinations for clastic reservoirs. If all the subcategories for each dimension are used, there are 1,452 possible combinations for carbonates and 1,364 for clastics, giving a total of 2,816 possible cells in the two lithology-specific, three-dimensional matrices. As this is clearly too large a number of classes to analyze on an individual basis, the analysis proceeded by grouping geologically related classes so that a manageable number could be defined for statistical analysis.

A series of trial groupings were composed. By inspection, some groupings could be eliminated or collapsed due to the absence or small number of reservoirs in certain cells of the overall classification system. The first examination suggested that sparsely populated deposition classes should be grouped together with others that were geologically very similarly deposited. The second examination noted that certain whole dimensions (structure among carbonates, diagenesis among clastics) essentially used only one of the available alternatives, permitting those dimensions to be geologically similar cells that also had similar mean values of the heterogeneity indicator. The merit of these latter groupings, however, could only be assessed by more formal statistical analysis.

E. STATISTICAL METHODS

Statistical tests were applied to the trial groupings to assess whether, on the basis of the heterogeneity indicator, E_{het}, the groups showed significantly distinctive reservoir heterogeneities, and the reservoirs within each group exhibited relatively low levels of variance in E_{het}. The Analysis of Variance (ANOVA) statistical method was used for this analysis. The results of the tests identified the geological elements with the most (and the least) influence on heterogeneity. In some cases, the trial groups were changed so that classes were defined by the most significant geological elements. Thus, within bounds that were defined by geologic principles (the classification system itself), statistical methods were used to assess the link between geologic history and the heterogeneity indicator and to determine which groups of reservoirs having similar geologic characteristics also showed similar levels of heterogeneity.

For a given trial grouping, ANOVA tests the hypothesis that the variance between the groups (derived from the classification) is greater than the variance within the groups (Myers, 1966). In general, when the ratio of between-groups variance to within-groups variance increases, the classification system more effectively groups similar entities together.

The applicability of this statistical test relies on the assumption of homogeneity of within-groups variation. This means that differences in E_{het} between the reservoirs is primarily due to geological factors. Ideally, all reservoirs within a class would have the same value of E_{het} , or no within-class variation. This ideal situation is not likely to be reflected in real world data, especially where, as in the present case, the variable being tested contains considerable "noise." The ANOVA method allows reservoirs to differ within classes, but requires that the cause of these differences originate in uncontrolled factors which are not related to the classification system. The variance statistic, a standard descriptive measure, is computed for each group and forms the basis for the statistical tests.

The test for homogeneity of within-group variation involves two independent checks. If the data pass these checks, one may proceed to the actual ANOVA. The tests are:

- *Hartley's Test:* If all group variances are the same, then the ratio of the largest to the smallest will be unity (1.0). As this ratio, denoted F_{max}, becomes larger than 1.0, the assumption of homogeneity becomes less tenable. For example, the final classification system selected includes 25 groups. For a system involving 25 groups with an average of 54 reservoirs per group, F_{max} values less than 2.73 are "acceptable" in that one would fail to reject the hypothesis that the group variances are not homogeneous with 90% confidence (Myers, 1966, pp. 73 and 388).

- *Cochran's Test:* This test is based on the ratio of the largest group variance (V_{max}) to the sum of all the group variances (V_{sum}). This quantity is denoted as C. If there are "A" groups, and all group variances are the same, then V_{max} ought to be very close to the quantity (V_{sum}/A). For example, for an analysis with 25 groups, V_{max}/V_{sum} would be equal to 0.04 (=1/25) if the group variances were identical; "acceptable" values of C must be less than 0.070 at 90% confidence (Myers, 1966, pp. 73 and 389).

The Analysis of Variance is a series of calculations that partitions variance in the total data set into two quantities:

- *Between Group Variance,* which is an indication of the amount of variability that is "explained" by the classification system. The specific measure is the Mean Squares Between Groups, denoted MS_A, which is the sum of the squares between groups (SS_A) divided by the degrees of freedom between groups (DF_1). The degrees of freedom between groups is equal to the number of different groups.

- *Within Group Variance,* which is an indication of the amount of variability that is "unexplained" by the classification system. The specific measure is the Mean Squares within groups $MS_{S/A}$, which is the sum of the squares within groups ($SS_{S/A}$) divided by the degrees of freedom within groups (DF_2). The degrees of freedom within groups is equal to the total number of observations in the largest group minus the number of groups increased by one (DF_1+1).

Ideally, a totally effective classification system would explain all variation; $MS_{S/A}$ would be zero. The ratio of MS_A to $MS_{S/A}$, known as the "F-ratio", would be infinite in this ideal case. On the other hand, if the classification system were totally ineffective, the between group and within-group variances would be equal, and the F-ratio would be unity (1.0). Thus, large values of the F-ratio are associated with effective classification systems. The actual value of the F-ratio that is needed to conclude that the classification system is effective is a function of the number of classes and the number of reservoirs classified. For example, if 25 classes are to be tested, values of the F-ratio greater than 2.13 are significant at 90% confidence, considered to be evidence of an effective classification system. (Myers, 1966). Appendix B provides a complete discussion of ANOVA and shows the calculations required for its use.

The approach was to evaluate successively each of the trial groupings using as the criterion the maximum ratio of the F-ratio subject to the constraints that the groupings be geologically meaningful (only geologically similar groupings combined) and the Cochran's and Hartley's tests be satisfied at a minimum of 90% significance.

III. RESULTS

The data collection effort resulted in the classification of 1,947 reservoirs according to the geologic descriptors of deposition, diagenesis, and structure. These reservoirs were initially grouped according to each unique combination of deposition, diagenesis, and structure to determine their distribution within the lithology-specific, three-dimensional matrices. The resulting two matrices contained 2,816 possible cells. However, 2,663 of these cells contained no reservoirs, while many of the remaining 153 cells were sparsely populated. Tables C-1 and C-2 illustrate the distribution of reservoirs among the 153 classification cells which were not empty. Reservoir grouping charts are presented in their entirety in Appendix C; all tables with references prefixed by C can be found there.

To reduce the number of classes to a manageable number, it was necessary to combine some of the preliminary groups on the basis of deposition, diagenesis, or structure. The reservoir distribution in Tables C-1 and C-2 guided the first pass at combining sparsely populated cells with more populous cells that were also geologically similar. For example, most of the depositional subcategories were combined into their respective major categories, and the six clastic Lacustrine reservoirs were combined with Alluvial Fans.

A. CONSTRUCTION OF TRIAL GROUPS

A number of trial groups were considered, based on geologic principles and inspection of the distribution of reservoirs in the classification cells. Trial groupings in each of the lithology-specific tables could be defined by aggregating reservoirs by depositional categories only, diagenetic or structural categories only, or a combination of deposition, diagenetic, or structural categories. The selection of the various trial groupings was guided by (1) aggregating similar geologic entities together, particularly depositional subcategories into their respective major categories, (2) similarities in the means of the heterogeneity indicator, E_{het}; and (3) number of reservoirs in each of the cells.

Because deposition is usually the primary factor controlling heterogeneity (Geoscience Institute, 1990), the reservoirs were first grouped by depositional categories and subcategories alone (combining all diagenetic and structural elements for a particular depositional element). This grouping scheme resulted in 15 classes for carbonates and 25 classes for clastics (Table C-3).

However, several of these classes were very poorly represented by the data sample, having only one or very few reservoirs. This suggested aggregation of some of the depositional subcategories. Other classes were very large, the largest having 375 reservoirs. However, there was no depositional basis to suggest whether subdivision would be appropriate for these large classes. The validity of this grouping scheme was evaluated by statistical analysis, discussed in the next section.

The second set of trial groupings considered depositional system in combination with either diagenetic overprint or structural compartmentalization. Table C-4 shows that 88% of carbonate reservoirs are unstructured, while 9% have natural fracture porosity. The other structural elements are essentially vacant, suggesting that carbonate reservoirs can best be classified by a combination of deposition and diagenesis, and that structure may be ignored for the prupose of defining reservoir classes. Table C-5 illustrates that 97% of the clastic reservoirs have undergone compaction and cementation, and that all other diagenetic processes are represented only in the remaining 3% of clastic reservoirs. This suggests that clastic reservoirs can best be classified by a combination of depositional and structural elements, and that diagenesis may be ignored. These naturally occurring correlations among both clastics and carbonates served to eliminate one dimension from the classification scheme for each respective lithology.

The reservoirs were then displayed again by the remaining two dimensions for the respective lithologies: deposition and diagenesis for carbonates, deposition and structure for clastics (Tables C-6 and C-7). For carbonate reservoirs, 64% have undergone dolomitization (with or without evaporites), while 20% exhibit compaction and cementation as the diagenetic overprint. The remainder of the carbonates are distributed among grain enhancement (7%), massive dissolution (7%), and silicification (2%). Only the shallow shelf depositional system has enough reservoirs which have undergone dolomitization with evaporites to consider subdividing the depositional system into two dolomitization categories (with vs. without evaporites). Among the clastic reservoirs, 73% are unstructured, 17% are faulted, 4% are folded, another 4% are subject to faulting and folding, and 2% exhibit natural fracture porosity as the dominant structural element.

Although dolomitization was the dominant diagenetic element for carbonates and most clastics were classified as unstructured, this dominance was not so pronounced to suggest that other diagenetic or structural subcategories should be aggregated without further analysis. Several groupings were identified, guided primarily by aggregations of similar geologic entities and relative values of mean E_{het}. These groupings were compared by statistical methods.

B. STATISTICAL ANALYSIS OF TRIAL GROUPINGS

Of the 1,947 reservoirs that had been classified, 1,358 passed the screens discussed in Section II-C and were included in the statistical analysis. These 1,358 reservoirs were arranged according to the trial groups and subjected to the analysis of variance. Groupings were analyzed using the statistical tests discussed in the previous section. Groups were considered valid only on passing both the Hartley and Cochran tests. An improvement in the F-ratio was considered to be an indication that a more descriptive set of classes had been achieved.

Grouping by depositional system only was tested first, combining all diagenetic and structural elements within each depositional element. The analysis of variance indicated that there were groups with large variances in E_{het}, and that some of the groups should be subdivided. This finding suggested that grouping the reservoirs by depositional system alone was inappropriate, and that further subdivision of depositional groups by diagenesis or structure should be investigated. (A later, two-factor ANOVA, reported below, confirmed and clarified this preliminary assessment.)

Inspection of the reservoir distribution for each lithology, discussed above, had suggested groups defined by combinations of deposition and diagenesis for carbonates, and deposition and structure for clastics. Two-dimensional tables listing the mean E_{het} and number of screened reservoirs were constructed for each lithology (Tables C-8 through C-11).

For peritidal carbonate reservoirs, the following combinations of diagenetic categories were tested by analysis of variance:

1) Compaction-Cementation vs. Grain Enhancement vs. Massive Dissolution vs. Dolomitization (with or without evaporites)

2) Compaction-Cementation and Grain Enhancement vs. Massive Dissolution vs. Dolomitization (with or without evaporites)

3) Dolomitization (with or without evaporites) vs. all other diagenetic elements (Compaction-Cementation, Grain enhancement, and Massive Dissolution).

The third diagenetic combination defined the best F-ratio in the analysis of variance and passed both the Hartley and Cochran tests.

For the other carbonate depositional systems, with the exception of Shallow Shelf reservoirs, there were insufficient reservoirs in each of the diagenetic categories to run the analysis of variance on the three diagenetic groupings used for the Peritidal group. The Shallow Shelf group contained a relatively large number of reservoirs in each of the dolomitization categories, accompanied by significant differences in mean E_{het} between the two diagenetic elements. Hence, three diagenetic categories were defined for Shallow Shelf reservoirs: dolomitization, dolomitization with evaporites, and all other diagenetic elements.

Several combinations of depositional groupings were analyzed for carbonate reservoirs in conjunction with the diagenetic groupings discussed above. For the most part, the carbonates were grouped within their major depositional categories. Several depositional subcategories were considered as distinct trial groups, including Intertidal, Atolls, and Pinnacle Reefs. The analysis of variance failed to show that these subdivisions improved the classification system (the F-ratio did not improve). Therefore, they were combined within their respective major categories.

Clastic reservoirs were grouped in various combinations of depositional and structural elements. Generally, the depositional subcategories were grouped within their respective major categories, although Tide-dominated Deltas, Fluvial-dominated Deltas, Strandplain Barrier Cores and Shorefaces, Shelf Sand Ridges, and Slope-Basin Turbidite Fans were kept as separate groups. Results of the Hartley test, which measures the ratio of the largest to the smallest group variance, indicated that the data did not support this degree of subdivision of depositional categories. The Delta subcategories were subsequently aggregated, leaving the others as separate groups. This reduced the within-group variance to an acceptable level, and the Hartley test was passed at 90% confidence.

The structural component of the clastic reservoirs was examined in several combinations, including:

1) Unstructured vs. Structured (all other structural elements)
2) Unstructured and Natural Fracture Porosity vs. Faulted, Fault/Fold, and Folded.
3) Unstructured and Natural Fracture Porosity vs. Faulted vs. Fault/Fold and Folded.

Because 73% of the clastic reservoirs are classified as unstructured and the remaining 27% are split between faulted (14%) and the other structural elements (13%), the structural categories were defined as unstructured vs. structured (all other structural elements).

C. FINAL GROUPING OF RESERVOIRS

The validity of aggregating reservoirs in each successive grouping scheme was guided by improvements in the statistical measurements, specifically the F-ratio, which compares the variance between groups with the variance within groups. The goal of the reservoir grouping procedure was to define geologically significant and valid classes that had relatively small variance in E_{het} within groups compared with the variance between groups. As described above, several groupings along the depositional dimension were considered, and the statistical results indicated the subcategories that should be kept distinct and those that should be aggregated. Statistical results also confirmed the approach taken for the second dimension of the classification. The carbonate reservoirs are characterized according to diagenesis as dolomitized or non-dolomitized in conjunction with the discrete depositional categories. Clastic reservoirs are characterized according to structural style as structured or unstructured in conjunction with the discrete depositional categories. Table 5 summarizes the final grouping of reservoirs.

The clastic reservoirs have been classified into 16 categories, defined by deposition and structure. The depositional dimension consists of most of the major categories and three depositional subcategories: (1) Strand Plain Barrier Cores and Shorefaces, (2) Shelf Sand Ridges, and (3) Slope-Basin Turbidite Fans. Clastic Lacustrine reservoirs were aggregated with Alluvial Fans because these depositional environments are frequently related. The structural dimension was divided into unstructured and structured (including all structural elements) categories based on similarities in mean E_{het}. The depositional, structural, and diagenetic components of the final clastic reservoir classes are listed in Table C-12.

The carbonate reservoirs have been classified into 9 categories, defined by deposition and diagenesis. The depositional dimension contains most major categories represented in the data analysis, with the exception of Shelf Margin reservoirs, which were combined with Shallow Shelf reservoirs. The only depositional subcategory that defined a distinct class based on mean E_{het} was Atoll Reefs. The diagenetic overprint dimension was divided into dolomitization (with or without

Table 5
Summary of Findings: Final Geological Classes

Reservoir Class			Number of Reservoirs Analyzed	Adjusted Volumetric Sweep Efficiency Mean	Variance
Clastics Deposition and Structure					
Eolian		Unstructured	26	0.609	0.035
		Structured	14	0.583	0.081
Fluvial		Unstructured	31	0.498	0.071
		Structured	8	0.537	0.062
Alluvial Fan		All	13	0.492	0.065
Delta		Unstructured	278	0.546	0.059
		Structured	121	0.597	0.060
Strandplain -	Barrier Core/ Shorefaces	Unstructured	104	0.658	0.042
	All Others	Unstructured	60	0.573	0.057
	All	Structured	48	0.509	0.068
Shelf -	Sand Ridges	Unstructured	17	0.643	0.046
	All Others	Unstructured	54	0.553	0.061
	All	Structured	16	0.499	0.059
Slope Basin -	Turbidite Fans	Unstructured	53	0.506	0.071
	All Others	Unstructured	46	0.584	0.051
		Structured	19	0.503	0.070
Subtotal - 16 Clastic Classes			908		
Carbonates Deposition and Diagenesis					
Peritidal		Non-Dolomitized	51	0.703	0.038
		Dolomitized	57	0.706	0.030
Shelf		Non-Dolomitized	48	0.633	0.066
		Dolomitized	79	0.676	0.054
		Dolomitized w/ Evaporites	109	0.582	0.063
Reefs -	Atolls	Non-Dolomitized	35	0.698	0.036
	All Others	Non-Dolomitized	25	0.576	0.042
		Dolomitized	28	0.715	0.039
Slope-Basin		All	18	0.667	0.033
Subtotal - 9 Carbonate Classes			450		
Total - All Classes			1,358		

Note: Clastic Slope-Basin class includes Slope/Basin and Basin reservoirs.
Alluvial Fan class includes Alluvial Fan and clastic Lacustrine reservoirs.
Carbonate Shelf class includes Shallow Shelf and Shelf Margin reservoirs.

evaporites) and non-dolomitization (other diagenetic elements). Only the Shelf depositional system differentiates two dolomitization categories (with vs. without evaporites). The depositional, diagenetic, and structural components of the carbonate reservoir classes are listed in Table C-13.

The statistical results very strongly support the validity of the geological classes (Table 6):

- Both the Hartley and Cochran tests are passed at the 90% confidence level, indicating that the assumption that group variances are homogeneous is warranted. Thus, variability within groups is due to uncontrolled factors which are not related to the geological classification system.

- The F-ratio is significant at 99% confidence, indicating that the classification is effective in the sense that the between-groups variance (that which is explained) is much greater than the within-groups variance (that which is unexplained). In other words, the differences in heterogeneity among reservoirs are attributable to identifiable geological factors (expressed in the classification system), and differences noted among like reservoirs (those in the same group) are quite small by comparison.

The aggregation of depositional elements within each lithology was based on geologic principles and similarities in mean E_{het}. Aggregation among the structural elements for clastics and among diagenetic elements for carbonates were guided by the same principles. Therefore, the classification defines statistically valid and geologically distinct reservoir classes which have similar measures of heterogeneity within classes and different levels between classes.

The grouping schemes developed for this study were tested using a "two-way" analysis of variance for both clastic and carbonate reservoirs. This analysis sought to examine the effects of the two factors in the classification system and their joint interaction: depositional history and diagenetic overprint for carbonate reservoirs, depositional history and structure for clastic reservoirs.

There was an unequal number of reservoirs in each class; consequently, the method of unweighted means was used to approximate the results (Myers, 1966). This method is usually sensitive to the assumption of homogeneity of variance, and a standard statistical technique known as a data transformation was employed to maximize the homogeneity of within-group variance. The E_{het} values are proportions, for which the arc sin transform is the most appropriate technique (Winer,

Table 6
Statistical Results
for Final Geological Classification System

Analysis of Variance

Source of Variance	Degrees of Freedom	Sum of Square	Mean Square
Geological Classes	24	5.57	0.23
Reservoir Classes	1,333	73.38	0.06
Total	1,357	78.95	

F-Ratio:	4.2168
Confidence Level	99%

Hartley Test

Largest Variance	0.081
Smallest Variance	0.030
Degrees of Freedom	
between classes (DF_1)	25
withing classes (DF_2)	277
F_{max}	2,6505
Confidence Level	90%

Cochran Test

Largest Variance	0.081
Sum of Variance	1.359
Degrees of Freedom	
between classes (DF_1)	25
within classes (DF_2)	277
C	0.595
Confidence Level	90%

1971).[2/] Because some cells of the two-factor design were empty, additional combinations (not intended for the final groupings) were made for this analysis.

For the carbonate model, the depositional elements included Peritidal, Shelf, Reefs, and Slope-Basin; the diagenetic elements were Dolomitized and Non-Dolomitized. Table 7A shows the statistical results. Of the two dimensions, depositional system has the strongest effect on heterogeneity and is significant at the 95% confidence level. Diagenesis alone is not a strong indicator for carbonate reservoirs. However, the interaction of both deposition and diagenesis is also significant. This confirms the approach that classifies carbonate reservoirs by deposition, then subdivides the groups by diagenesis.

For the clastic model, the depositional elements include Eolian, Fluvial, Delta, Strandplain, Shelf, and Slope-Basin, each being analyzed as Structured and Unstructured. Table 7B provides the results of this analysis. Both deposition and the interaction of deposition and structure are significant at the 95% confidence level. This result also supports the hypothesis that clastic reservoirs should be grouped by both depositional system and structural compartmentalization dimensions.

2/ The transformation is the arc sin of the square root of the data point:

$$Y'_{ijk} = \text{arc sin}(\text{sqrt}(Y_{ijk}))$$

The transformed score is the angle whose sine is equal to the square root of the original score.

Table 7
Results of the Analysis of Two-Way Variance

A. Carbonate Reservoirs

Source of Variance	Degree of Freedom	Sum of Squares	Mean Squares	F-Ratio
A (Deposition)	2	0.005634	0.002817	3.4877*
B (Diagenesis)	1	0.00734	0.000734	0.9094
AB (Interaction)	2	0.003438	0.001719	2.1284**
S/AB	429	0.346498	0.00808	

B. Clastic Reservoirs

Source of Variance	Degree of Freedom	Sum of Squares	Mean Squares	F-Ratio
A (Deposition)	5	0.01035	0.00207	2.470***
B (Structure)	1	0.00164	0.00164	1.956
AB (Interaction)	5	0.01132	0.00226	2.703***
S/AB	889	0.74482	0.00084	

* Significant at the 5% level, on 2 and 429 degrees of freedom (df)
** Significant at the 10% level, on 2 and 429 df
*** Significant at the 5% level, on 5 and 889 df

IV. DISCUSSION

This study set out to develop and test a reservoir classification system relating reservoir history to reservoir heterogeneity. The classification system developed was to be mutually exclusive, collectively exhaustive, internally consistent, and geologically meaningful. The results suggest that this objective has been met. Through the resolution of the original 153 geological classes into 9 carbonate classes and 16 clastic classes, the geological classification produced a manageable number of distinct classes for future analysis. The statistical tests argue that they are internally consistent. Alternative groupings not yet analyzed could, perhaps, improve on the statistical results. However, they appear adequate to support the next steps in the Multi-State Study and may be useful in other contexts as well.

That these results were achieved is all the more remarkable when the "noisiness" of the data is considered:

- First, the independent variable, the geologic descriptors, are qualitative and interpretive in nature, not infrequently permitting of alternative views.
- Second, the independent variable, E_{het}, is only an indirect measure of heterogeneity, which, permits differentiation only of the *level* of heterogeneity, but not the *type* of heterogeneity. There are clearly a number of quite different physical configurations in the reservoir that could yield identical values of E_{het}. Grouping reservoirs by geologic similarity presumably contributed consistency by type, while the statistical tests contributed to consistency by level of heterogeneity.
- And third, as noted earlier, the residual "noise" in the body of unavoidably imperfect reservoir volumetric and performance data remains in E_{het} even though fluid mobility and well spacing differences were analytically removed.

Future research will doubtless sharpen the concept of reservoir heterogeneity and improve both the independent and dependent variables in its study. The present results, however, yield some additional insights.

The final classification system will provide analytical information that can be used in the evaluation of the reserve potential of the resource. Figure 5 and Table 8 display the 25 geological classes, ranked from highest to lowest in terms of remaining oil-in-place (ROIP). Among the clastics,

Figure 5

TORIS Geological Classes Ranked by Remaining Oil-in-Place

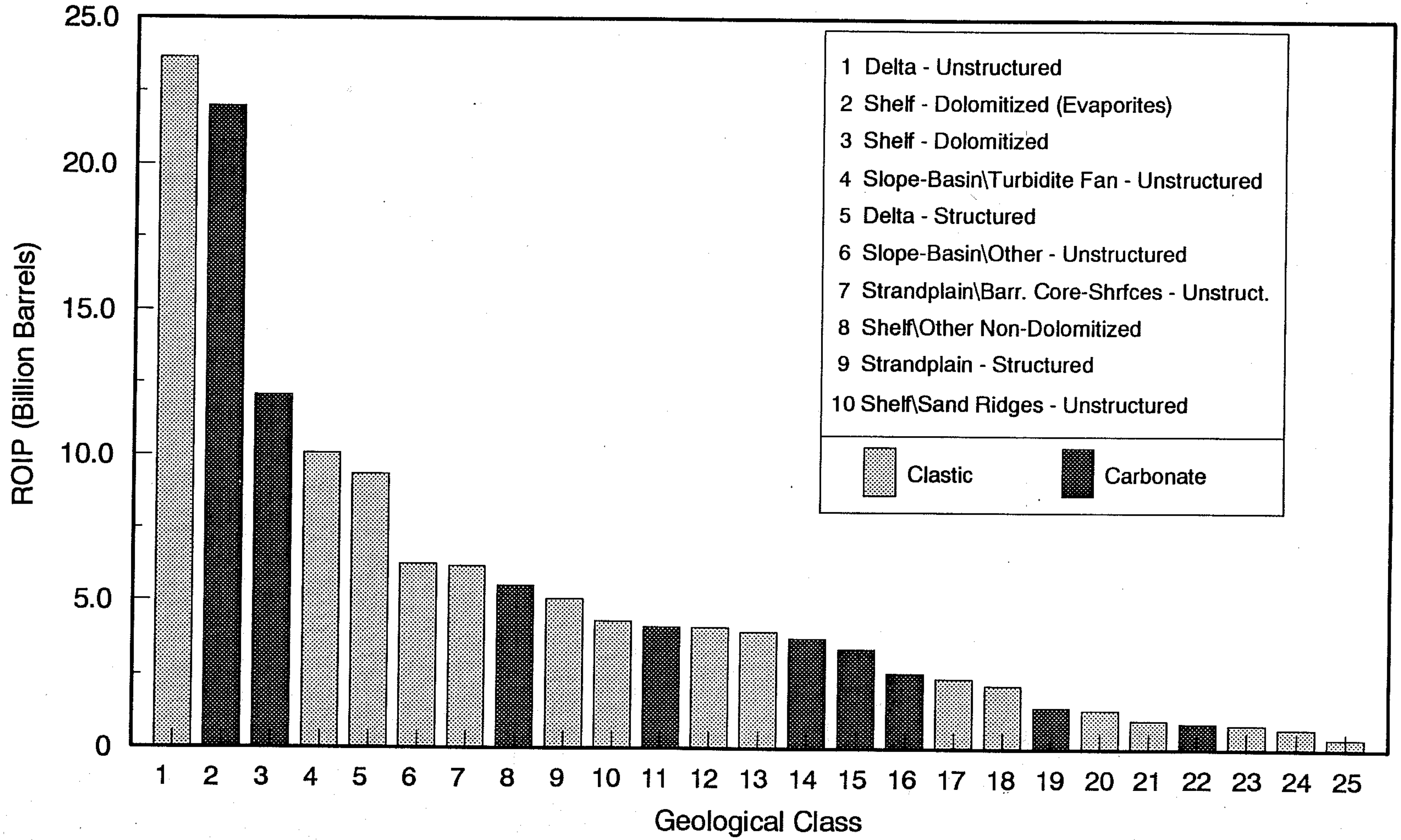


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Table 8

Geologic Classification System for TORIS Reservoirs
Oil Quantities by Geologic Class (MMBbl) Based on 1,358 Reservoirs

Class Title	OOIP	Cumulative Recovery	Ultimate Recovery	ROIP	Number of Reservoirs
Clastics:					
Delta - Unstructured	38,146.0	13,817.8	14,501.5	23,644.4	278
Slope-Basin - Turbidite Fan - Unstructured	15,014.2	4,245.5	4,942.3	10,071.9	53
Delta - Structured	17,528.3	7,700.9	8,168.1	9,360.2	121
Slope-Basin - Other - Unstructured	7,467.0	1,174.8	1,209.8	6,257.2	46
Strandplain - Barr.Core - Shrface - Unstruct.	10,223.0	3,818.7	4,041.3	6,080.7	104
Strandplain - Structured	8,457.3	3,143.9	3,382.0	5,075.4	48
Shelf - Sand Ridges - Unstructured	6,378.2	1,258.5	2,070.2	4,308.0	17
Slope-Basin - Structured	5,739.2	1,739.7	1,908.7	3,966.9	19
Fluvial - Unstructured	3,599.7	1,113.2	1,203.0	2,402.7	31
Strandplain - Other - Unstructured	3,331.2	1,131.1	1,151.4	2,179.9	60
Eolian - Unstructured	2,239.3	857.0	909.2	1,330.1	26
Shelf - Structured	1,246.8	233.8	246.3	1,000.5	16
Eolian - Structured	1,337.4	441.1	492.3	845.1	14
Alluvial Fan	991.1	271.9	281.7	709.4	13
Fluvial - Structured	546.4	136.0	162.9	383.5	8
TOTALS:	128,120.7	420641.1	46,289.1	81,837.7	908
Carbonates:					
Shelf - Dolomitized (Evaporites)	33,614.3	9,352.5	11,614.5	21,999.8	109
Shelf - Dolomitized	16,508.9	4,092.1	4,422.7	12,081.2	79
Shelf - Other - Non-Dolomitized	7,095.6	1,446.7	1,571.6	5,524.0	48
Peritidal - Dolomitized	5,563.4	1,309.9	1,422.9	4,140.4	57
Reefs - Other - Non-Dolomitized	5,153.3	1,303.4	1,390.1	3,763.2	25
Peritidal - Non-Dolomitized	5,146.5	1,706.2	1,741.1	3,405.4	51
Reefs - Atolls	5,015.8	2,241.8	2,421.7	2,594.0	35
Reefs - Other - Dolomitized	2,403.7	770.2	958.3	1,445.4	28
Slope-Basin	1,454.9	453.2	558.4	896.5	18
TOTALS:	81,956.4	22,676.0	26,101.3	55,849.9	450
GRAND TOTALS:	210,077.1	65,317.1	72,390.4	137,687.6	1358

Note: Clastic Slope-Basin class includes Slope/Basin and Basin reservoirs.
Alluvial Fan class includes Alluvial Fan and Clastic reservoirs.
Carbonate Shelf class includes Shallow Shelf and Shelf Margin reservoirs.

the Delta/Unstructured class has the greatest ROIP; among the carbonates, Shallow Shelf/Dolomitized reservoirs have the most remaining resource. Overall, the top ten geological classes account for 76% of the remaining oil resource in analyzed reservoirs. Coupling the target reservoir classes with their recovery potential could provide critical information for prioritizing key research and development efforts with the intent of maximizing economic producibility of domestic oil resources.

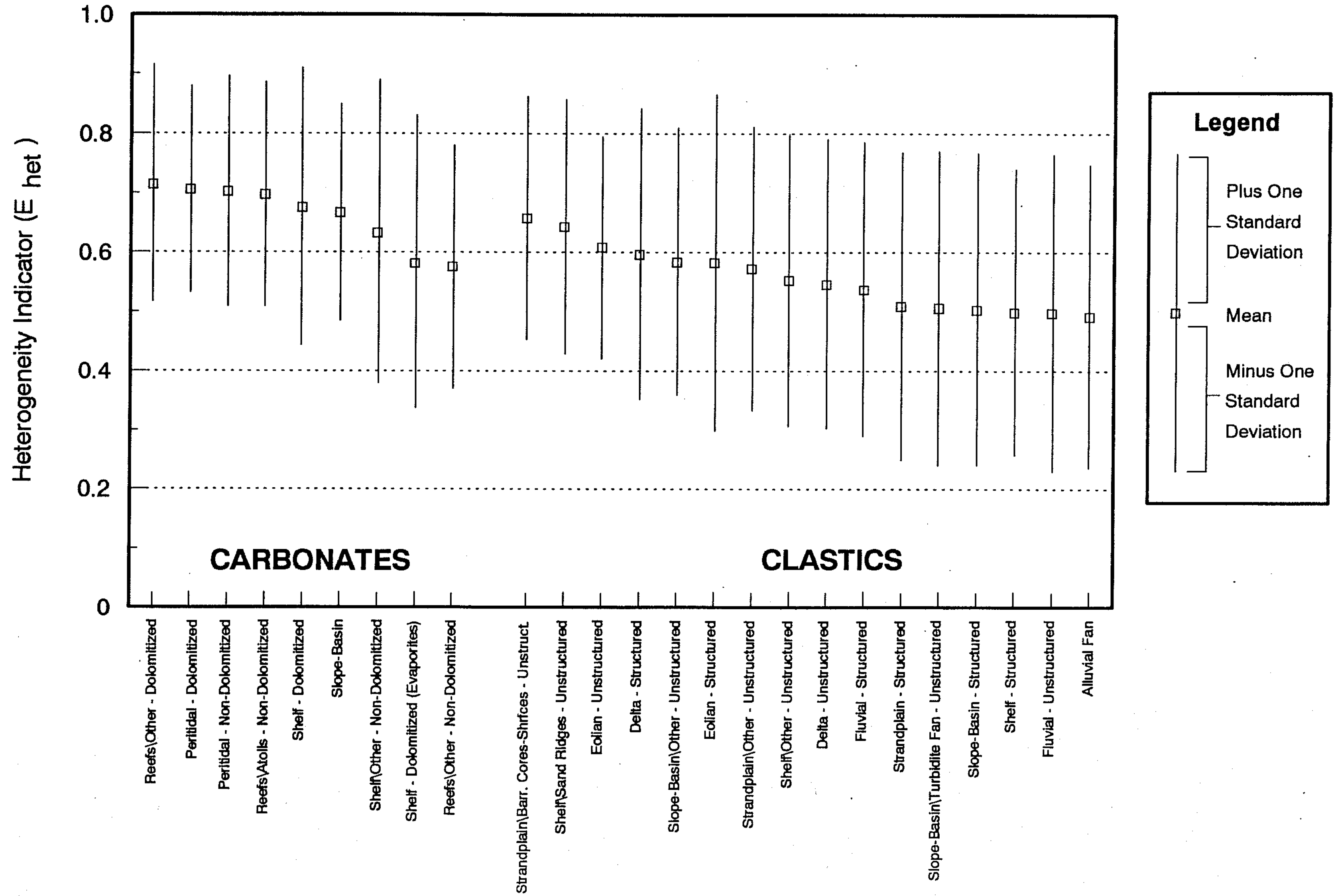
Generally, some depositional systems are more likely to produce reservoirs having a greater degree of heterogeneity than others. Depositional systems that are characterized by channel deposits, such as fluvial and slope-basin systems, are more heterogeneous than those which result in more continuous sheet deposits, such as strandplain systems. The results of this study indicated a similar trend. Figure 6 plots the heterogeneity indicator, E_{het}, against the 25 geologic classes developed in this study. The 25 classes are differentiated by lithology — 9 carbonates and 16 clastics — and ranked by the mean heterogeneity indicator for each, from highest to lowest. The rank order of geologic classes by the heterogeneity indicator is generally consistent with expectations. Because E_{het} is measured as adjusted volumetric sweep efficiency, a high value indicates a relatively low level of heterogeneity compared to a reservoir with a low E_{het}. Figure 6 shows that the Slope-Basin and Fluvial classes are generally more heterogeneous than the Strandplain and Eolian classes, as would generally be expected, with Deltas lying in between. The results are thus consistent with expectations with regard to the depositional dimension of the classification system.

The results appear anomalous for the clastic classes in the case of two depositional systems — Delta and Fluvial — for which the structured classes have higher E_{het} values than the unstructured classes. Generally, structured reservoirs would be expected to have more heterogeneity, other things being equal, as they are in all the other cases. For the Delta classes, this anomaly is attributed to the inclusion of nearly 120 Gulf Coast reservoirs, the majority of which are highly faulted but have very strong water drive, typically associated with high sweep efficiency, resulting in high values for E_{het}. The anomaly observed in the Fluvial classes may also be attributed to the measurement of E_{het}, which includes a number of factors that could not be controlled because of limitations in the data.

There is clearly a large range of uncertainty associated with the heterogeneity indicator for both clastics and carbonates. The variation in E_{het} within each group, indicated in Figure 6, is understandable, and may be attributed to uncontrolled and random factors that are not correlated

Figure 6

Range of Heterogeneity Indicator (E_{het}) for the Geological Classification System



with geology. Recalling equation (3) in Section II, the adjusted volumetric sweep efficiency used in the analysis included the product of E_{het} and E_{other}, where E_{other} accounts for other factors affecting sweep efficiency referred to above as data noise. Whereas E_{het} is defined as the portion of volumetric sweep efficiency due only to geologic factors, the adjusted sweep efficiency data includes other influences on sweep efficiency for which adjustments were not possible within the scope of this study. These influences include the reservoir drive mechanism and the mechanical design of the waterflood. Subsequent studies that account for these additional factors may explain the "noise" experienced in this study's measure of heterogeneity and reduce the variance of the estimates.

The results obtained for carbonate classes show two anomalies, in the ordering of the classes and in that carbonates have greater values of E_{het} than do clastics. An explanation for this lies in the assumption of default values for residual oil saturation (S_{orw}) used in the TORIS data base. Residual oil saturation is an important factor in calculating E_{het}. Much of the difference between carbonate and clastic classes, and perhaps the anomalous ranking among carbonate classes, can be explained by their differing default values. Clastics have a S_{orw} default value of 0.25, based on extensive literature (IOCC, 1978). The default value assumed for carbonates of 0.38 was much higher. All other parameters being equal, the estimate of E_v (and, hence, E_{het}) decreases as S_{orw} increases. Thus, a high value of S_{orw} could account for much of the statistical difference between carbonates and clastics. An evaluation of the default value for residual oil saturation in carbonates is a topic for future analysis.

While the one-way analysis of variance supports the conclusion that the groups are distinctly different and internally consistent, the two-way analysis yields the interpretation that, while deposition is clearly an important determinant of heterogeneity, it is not alone. A second factor — structure for clastics, diagenesis for carbonates — was found to be important also, not by itself alone (no B-factor main effect was noted), but contingent on deposition. That is, the importance of the second factor depends upon the deposition of the reservoir. For example, the effect of dolomitization is marked for shelfs and reefs but appears to be immaterial for peritidal reservoirs (Table 8). Similarly, some structured clastic reservoirs exhibit lower E_{het}, by ten per cent or more, than their unstructured counterparts (e.g., shelfs), some share little difference (e.g., eolian), some are complex (e.g., strandplains, slope-basins), and some even the reverse of the trend (deltas, fluvials). These complex interactions should also be studied more carefully and fully.

Notwithstanding these issues, a geological classification system has been established that relates reservoir history to reservoir heterogeneity. The system, based on geologic principles, has been shown by statistical analysis to be internally consistent and meaningful. It should be a valuable asset to that portion of the petroleum industry concerned with improving recovery from the nation's crude oil resources.

V. CONCLUSIONS

Reservoir heterogeneity is broadly held to be a major constraint on the efficient recovery of crude oil. Improved understanding of heterogeneity may contribute to increased oil production. The present study has developed a geologic classification system that relates geologic history to reservoir heterogeneity. While some might regard this relationship as axiomatic, no prior study has offered the rigorous demonstration presented here that reservoir history can be significantly correlated with heterogeneity. It suggests that the study of classes of reservoirs, as opposed to the study of individual reservoirs only (as "unique"), may hold promise for the future.

The classification system itself constitutes the primary conclusions of this effort. It provides a means for grouping reservoirs for further study. Because the classification system was developed using both geological and statistical criteria, the reservoirs in the resulting classes are expected to exhibit broad but meaningful similarities in terms of the level and types of their internal heterogeneities. By isolating these similarities, it may be possible to develop measurement and/or analytical approaches for the description of the heterogeneities of a full class. Further, it may be possible to design recovery processes that overcome the constraints on production imposed by heterogeneities and that would be broadly applicable to reservoirs within the class. The classification system developed and tested here and the resultant reservoir groupings represent a step in this direction.

More immediately, the results of this study permit continued development of more appropriate models for estimating future production potential of the nation's reservoirs. This is a major objective for the Multi-State Study, for the continuing enhancement of TORIS by the federal government, and the expansion of industry's analytical capabilities. The Multi-State Study may now proceed with the analysis of recovery potential under specific advanced recovery technologies and the evaluation of class-specific approaches for increasing oil recovery.

Of course, the present study represents only a beginning. Each of the anomalies discussed in the previous section deserve further investigation. As noted, the geologic descriptors and the heterogeneity indicator are imprecise and "noisy." Both conceptual and empirical work could enhance the precision and reliability of these variables. A clear, operational definition of heterogeneity, more directly measurable, would be an improvement over the indicator used here. Perhaps different indicators for different types of reservoirs will be needed to describe the physical differences among reservoirs. The desirable direct measure would be independent of reservoir performance so that the effects of different levels and types of heterogeneity on performance can be studied. However, if indicators based on reservoir performance continue to be used as indirect measures of heterogeneity, additional normalization or standardization will be needed to remove important factors now treated as residual "noise," e.g., drive mechanisms.

While this study may only be a beginning, it suggests a solid direction for that new work. The greatest benefit of the future research will accrue from examining the members of the reservoir classes with the greatest potential for future recovery. In these, a combination of reservoir performance studies, model studies, outcrop assessments, and pilot tests of improved recovery techniques should most contribute to improved understanding and increased oil production.

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Geoscience Institute

for Oil and Gas Recovery Research

Section 1

Description

of

Geologic Reservoir Classification System

DESCRIPTION OF

GEOLOGIC RESERVOIR CLASSIFICATION SYSTEM

The classification system used in earlier studies was focused on depositional system types and did not provide for a systematic assessment of the control of diagenetic overprint and structural compartmentalization on reservoir productivity. In general, the basic internal architecture and heterogeneity of reservoirs are dominantly controlled by processes operative at the depositional system level. However, in certain cases, diagenetic processes and structurally imposed reservoir compartmentalization play a more dominant role in determining reservoir recovery efficiency on an intradepositional systems scale. Therefore, the classification described here incorporates an individual assessment of (1) depositional system, (2) diagenetic overprint, and (3) structural compartmentalization in order that the control of these three basic elements on recovery efficiency can be measured.

In practice, the primary decision in applying the classification first requires determining the lithology of the reservoir, i.e., carbonate or siliciclastic. Each lithologic type is secondarily characterized by the three basic elements as outlined in figure 1. Each element axis includes a series of categories that are designed to include the range of most likely possibilities for that particular element but still be mutually exclusive. Each category has been further subdivided into subcategories in order to capture more detailed facies information if it is readily available.

Definition and characteristics of individual categories of the element axes are based on current acceptable usage as defined in

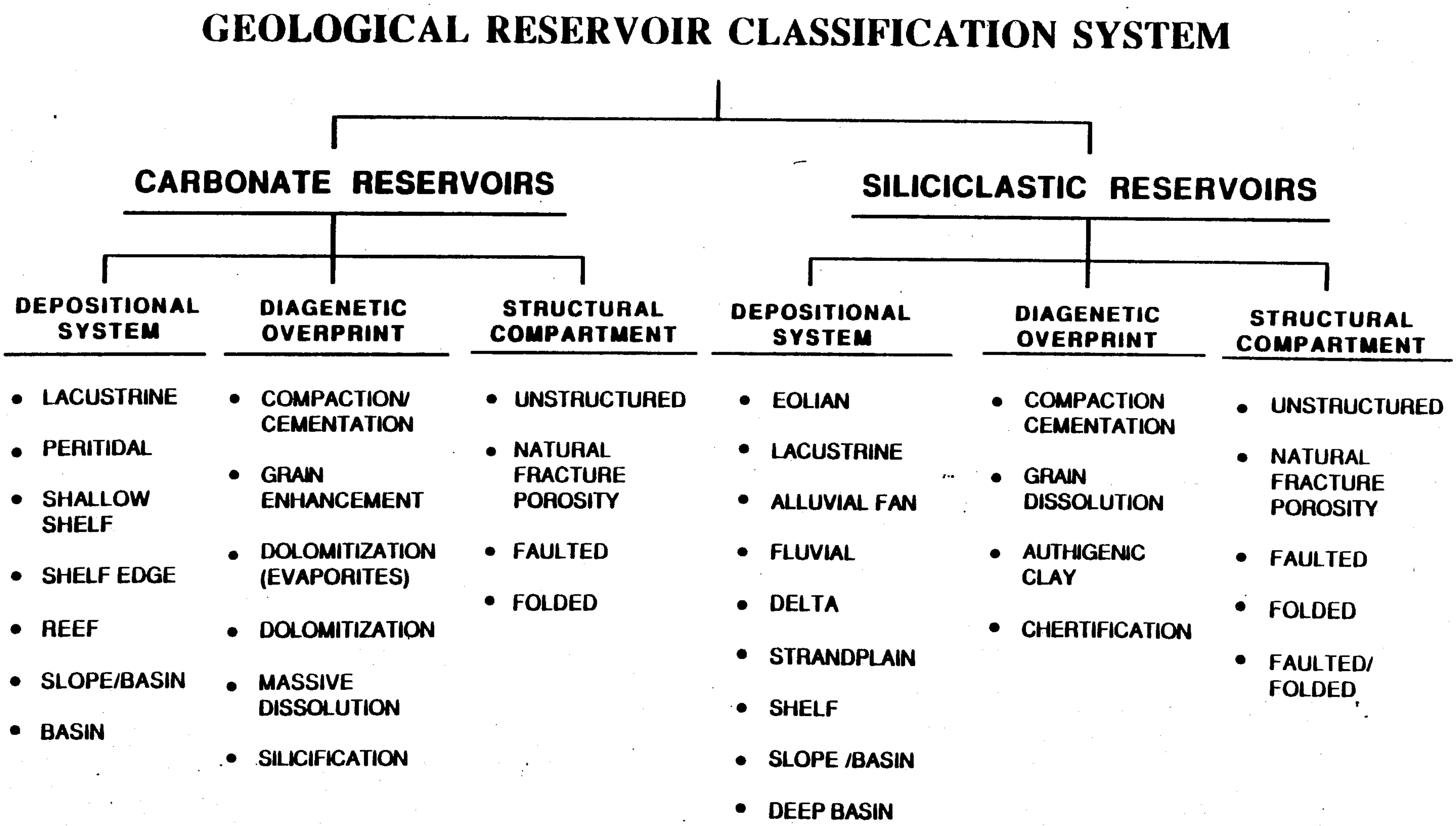

FIGURE 1

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standard geologic texts (Scholle and Spearing, 1982; Scholle et al., 1983; Galloway and Hobday, 1983; McDonald and Surdam, 1984; and Roehl and Choquette, 1985). Boundary conditions between categories are gradational and by their very nature interpretive, thus creating a subjective element in the classification. However, the categories are made sufficiently broad in order to minimize differences in interpretation.

Depositional System Element

The primary attributes of a reservoir are controlled by depositional processes. This is true because the physical, chemical, and biologic processes active in specific depositional environments and resulting depositional facies determine many attributes that are directly or indirectly related to hydrocarbon generation, migration, entrapment, and reservoir producibility (Fisher and Galloway, 1983). The concept of depositional systems (Fisher et al., 1969) encompasses interpretation of depositional environments and implies that component facies are spatially related and comprise predictable three-dimensional stratigraphic units. Recognition and delineation of depositional systems provide a framework for facies differentiation and mapping. This approach to facies analysis relies heavily on reconstruction of basin morphology and bedding architecture, determination of gross lithology, and recognition of vertical and lateral succession of facies that comprise individual reservoirs.

Individual facies components of a depositional system can have gradational or sharp lateral and vertical boundaries. Delineation of facies components provides the basis for establishing the field-wide internal reservoir architectural style. In most cases, individual reservoirs produce from more than one facies because reservoir quality facies can be vertically stacked and laterally juxtaposed. Variations within an individual facies component produce reservoir heterogeneities at an intra-reservoir scale.

The depositional system categories and their component facies as used in this classification have been defined in sufficiently broad terms to lump more discrete depositional entities in order to keep subjectivity to a minimum. Subdivisions of the categories have been defined to capture more detailed descriptions of depositional systems if readily available.

Carbonate Depositional Systems

In the classification used here seven major carbonate depositional categories are recognized (fig. 2). The categories are differentiated primarily based on position of their depositional environment as a function of relative water depth and basin morphology. Subcategories are provided to capture more detailed facies information if readily available (Table 1).

Lacustrine carbonates are best known as source rocks for lacustrine siliciclastic reservoirs (Dean and Fouch, 1983). They form the principal oil-shale deposits of the Green River Formation in the western United States. Carbonate lacustrine reservoirs are not common, but fractured carbonates of the Green River Formation are produced in the Unita Basin in Utah.

GEOLOGIC CLASSIFICATION - CARBONATE RESERVOIRS

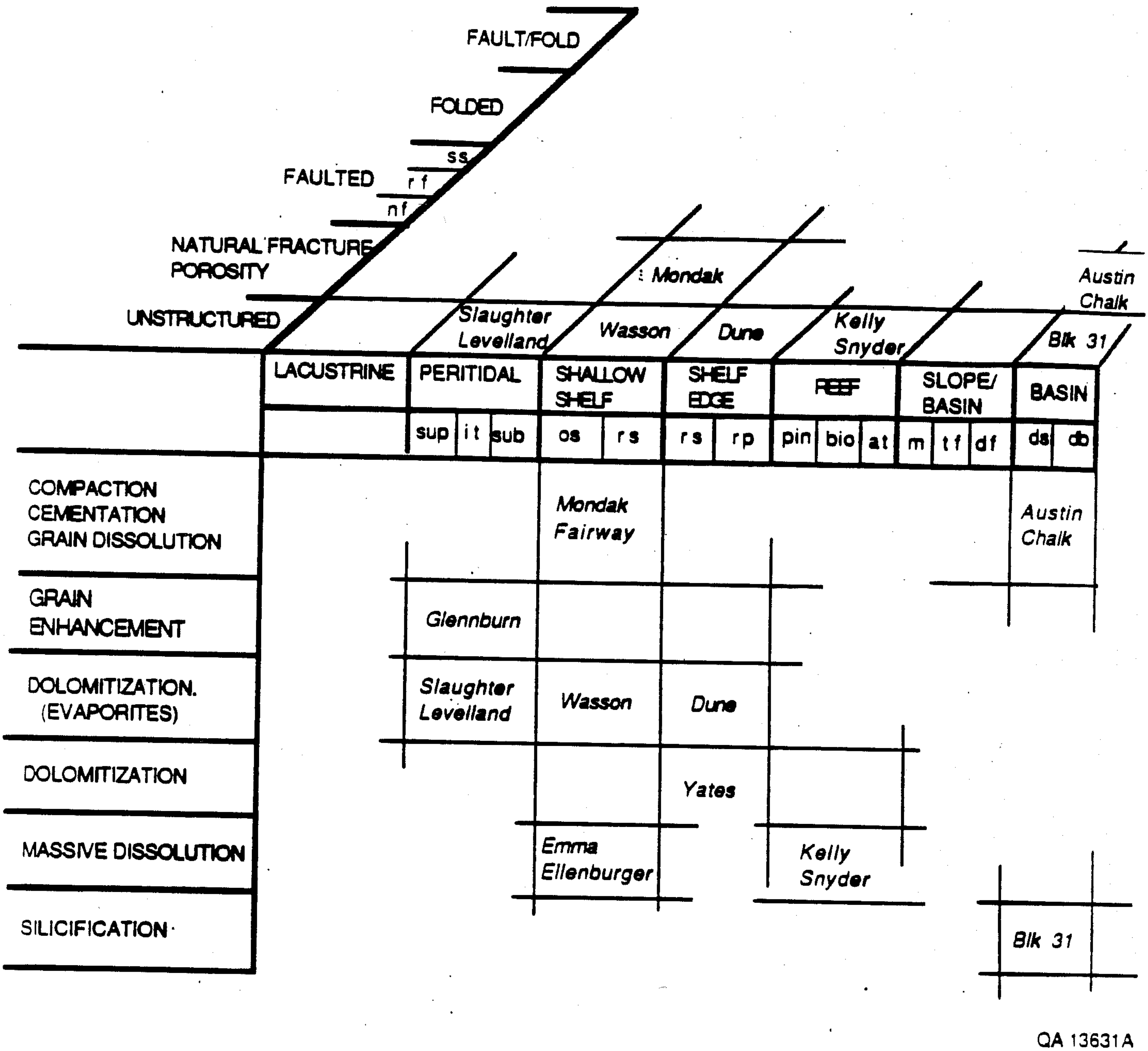

FIGURE 2

Table 1

Depositional Systems

Carbonate Reservoirs

Lacustrine

Peritidal
- Supratidal (sup)
- Intertidal (it)
- Subtidal (sub)

Shallow Shelf
- Open shelf (os)
- Restricted shelf (rs)

Shelf margin
- Rimmed shelf (rs)
- Ramp (rp)

Reef
- Pinnacle (pin)
- Bioherm (bio)
- Atoll (at)

Slope/Basin
- Debris fan (df)
- Turbidite fans (tf)
- Mounds (m)

Basin
- Drowned shelf (ds)
- Deep basin (db)

Peritidal reservoirs are composed of sediments that were deposited in subtidal to supratidal environments on and adjacent to tidal flats. Fenestral and pisolite porosity is locally well developed in supratidal mudstones and grainstones, but most production is from subtidal grainstones deposited as bars and beaches and associated dolomitized wackestones. Examples are the Slaughter/Levelland (San Andres) reservoirs in the Permian Basin and the Red River reservoirs in the Williston Basin. These reservoirs produce from stacked subtidal-supratidal cycles. Supratidal, intertidal, and subtidal facies are broken out as subcategories.

Shallow shelf reservoirs are developed in a wide variety of facies that were deposited on a broad carbonate platform under shallow water depths. The best reservoir facies include locally developed grainstones, deposited as bars, reworked beaches, and reefs. Associated widespread burrowed wackestones and packstones represent carbonates deposited under quiet-water conditions below wave base. These low-energy carbonates locally provide reservoirs particularly where regionally dolomitized or locally dolomitized. Examples are the Wasson (San Andres) reservoir in the Permian Basin and the Mondak (Mississippian) reservoir in the Williston Basin. Open shelf and restricted shelf subcategories are based on open marine versus restricted marine fossil assemblages.

Shelf-edge reservoirs produce from thick sections of subtidal grainstone bars and banks deposited along the outer edge of carbonate platform or ramps. Carbonate facies deposited in these settings lack well-defined reefs and are characterized by broad, low-relief bar, bank, and island facies deposited under low- to high-energy conditions. The

Grayburg reservoirs of the Dune and McElroy fields along the eastern edge of the Central Basin Platform, West Texas, are examples of this type of reservoir. Two subcategories of shelf-edge reservoirs are recognized: rimmed shelves, which may contain a barrier reef facies, and ramps.

Reefal reservoirs produce from stratigraphic reefs which commonly attain significant topographic relief. Framework and binding organisms are common constituents in the reef facies; associated facies include grainstones that accumulated as flanking beds around the reefs. Reefal reservoirs include the Michigan Basin pinnacle reefs and the Pennsylvanian/Permian Kelly Snyder reservoir of the Horseshoe Atoll, Midland Basin, Texas. Reefal reservoirs are further subdivided into pinnacle reefs, atolls, and bioherms.

Slope basin reservoirs are developed in carbonate submarine-fan and debris-flow deposits associated with basin slopes. Reservoirs developed in these deeper basinal positions are not common, but examples are known in the Bone Springs Formation in the Delaware Basin, West Texas, and the Poza Rica trend in northern Mexico. This category is subdivided into turbidity flows, debris flows, and carbonate mounds.

Basinal reservoirs occur in chalk deposits that accumulated from the raining down of pelagic organisms (coccoliths, coccospheres) onto drowned platforms and basin floors. Scholle and others (1983) recognize three categories of chalk reservoirs: (1) those that have never been deeply buried, lack significant compaction, and have high primary porosity (Niobrara Formation of western Kansas, eastern Colorado, and Nebraska); (2) those that have been buried to a moderate depth and must be extensively fractured to enhance porosity (Austin Chalk on the Texas

Gulf Coast); and (3) those that have been deeply buried but with high pore pressure to preserve high primary porosity. The category is subdivided into basin floor and drowned platforms based on basin morphology.

Siliciclastic Depositional Systems

Nine categories of siliciclastic depositional systems are defined in the classification (fig. 3). The categories are differentiated, similar to the carbonates, on the basis of depositional environment as a function of water depth and inferred sedimentary processes. Subcategories are provided to capture more detailed facies information if readily available (Table 2).

Eolian reservoirs can develop in a variety of depositional environments, e.g., associated with alluvial fans and braided streams, coastal zones, as well as desert regions. The geometry and internal characteristics of eolian reservoirs vary as a function of their depositional environment. In general, they are characterized by their complex internal stratification and limited lateral continuity. The Rangely field (Weber) is an example of an eolian reservoir in western Colorado. Subcategories are ergs and coastal dunes. Subcategories are provided to capture more detailed facies information if readily available.

Lacustrine reservoirs can be composed of a variety of sand-body types, e.g., beaches, deltas, and offshore bars that are associated with lakes. Examples of lacustrine reservoirs in the U.S. are the Duchesne field and Altamont field (Eocene) in the Uinta Basin in western Wyoming. Subcategories include basin margin and basin center.

GEOLOGIC CLASSIFICATION - SILICICLASTIC RESERVOIRS

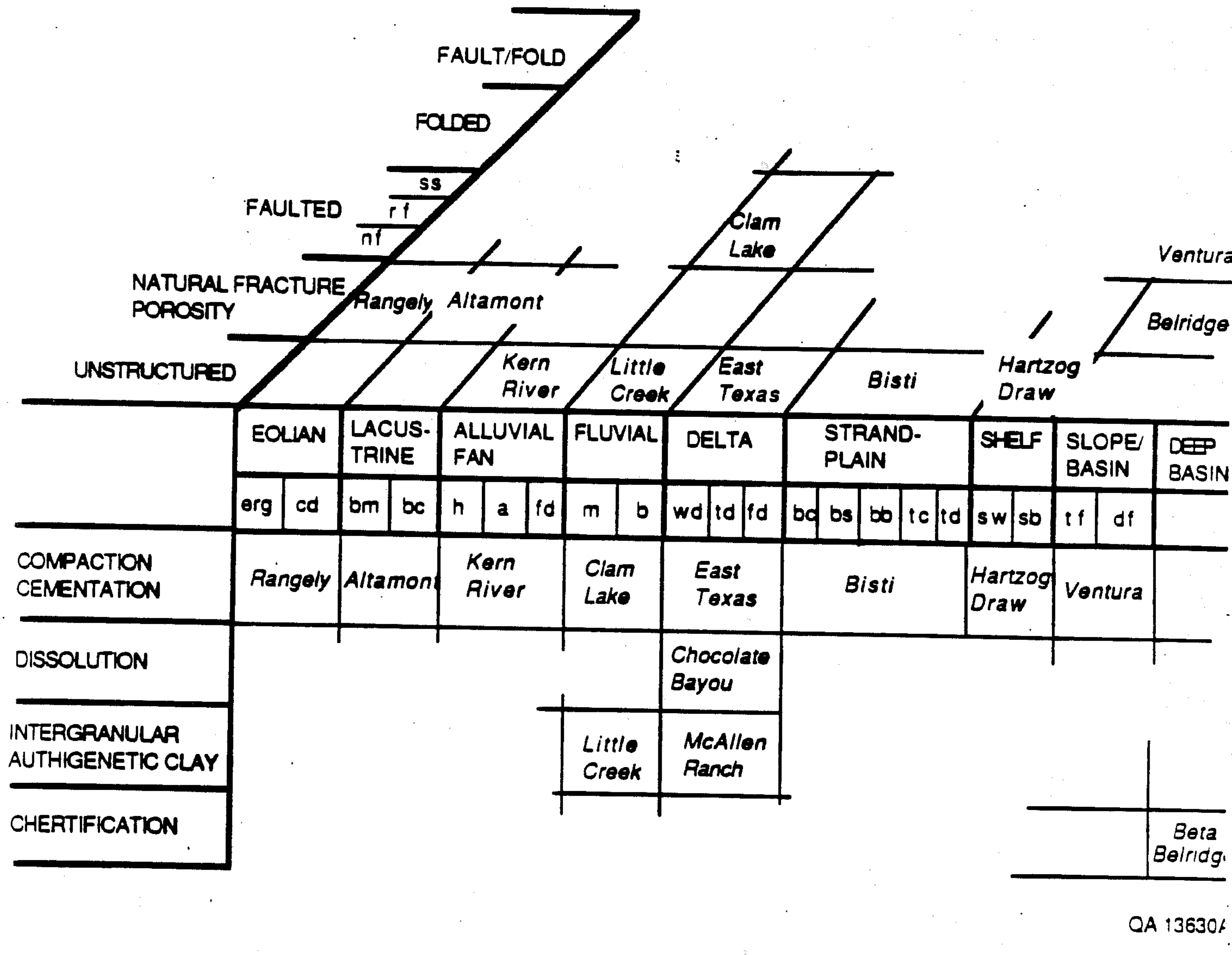

FIGURE 3

Table 2

Depositional Systems

Siliciclastic Reservoirs

Eolian
- Ergs (erg)
- Coastal dunes (cd)

Lacustrine
- Basin margin (bm)
- Basin center (bc)

Alluvial Fan
- Humid (stream-dominated) (h)
- Arid/semi-arid (a)
- Fan deltas (fd)

Fluvial
- Meandering (m)
- Braided (b)

Delta
- Wave-dominated (wd)
- Fluvial-dominated (fd)
- Tide-dominated (td)

Strandplain
- Barrier core (bc)
- Barrier shoreface (bs)
- Back barrier (bb)
- Tidal channel (tc)
- Washover fan/Tidal delta (td)

Shelf
- Sand wave (sw)
- Sand ridge/bars (sb)

Slope/Basin
- Turbidite fan (tf)
- Debris fan (df)

Deep Basin
- Pelagic

Alluvial-fan reservoirs are comprised primarily of braided-stream deposits. Alluvial fans are generally formed under relatively high-energy conditions, commonly along the front of higher standing mountain blocks. Alluvial-fan environments commonly grade downstream into braided-stream and/or playa-lake environments. Some fans build directly into standing bodies of water and are then referred to as fan deltas. Examples of alluvial-fan reservoirs include the Prudhoe Bay field (Triassic), North Slope of Alaska, and the Kern River field (Jurassic) of the San Joaquin Basin in California. Subcategories include stream-dominated fans, fan delta, and arid/semi-arid fans.

Fluvial reservoirs are composed of sand-body types ranging from braided-stream sheets to coalescing point-bars of meandering streams. Fluvial reservoirs in general are characterized by their lack of lateral and vertical continuity. Meandering fluvial sheet sands in the form of coalescing point-bars are not as continuous as braided-sheet sands and are characterized by oxbow clay plugs that form lateral flow barriers and seals. Examples of fluvial reservoirs are the Cutbank field (Cretaceous) of northern Montana and the incised Morrow Channel fields (Pennsylvanian) of southeast Colorado and southwest Kansas. Subcategories are meandering and braided.

Deltaic reservoirs in the main are characterized by distributary channel and stream-mouth bar type sand bodies and associated delta fringe strike sands. The size and shapes of deltas vary widely and, hence, so can the thickness and lateral extent of associated reservoirs.

Based on the dispersal energy of the receiving basin relative to the volume of sediment being introduced, deltas can be generally placed into one of three subcategories. Fluvial-dominated deltas are characterized by higher concentrations of sand in distributary channels and stream-mouth bars. Wave-dominated deltas are characterized by thick sequences of well-sorted, strike beach deposits. Tide-dominated deltas are characterized by tidal channel and delta deposits. Examples of deltaic reservoirs are the Mercy and Livingston (Eocene) fields in southeast Texas and the giant East Texas Woodbine field (Cretaceous).

Strandplain reservoirs occur in long narrow belts paralleling paleoshorelines. They are subdivided into a number of sand-body types: barrier core, barrier shoreface, back barrier, tidal channel, washover fan, and tidal delta. Barrier island core sand bodies are the highest quality strandplain reservoirs and are characterized by laterally continuous reservoirs in a strike sense. Examples of strandplain reservoirs are the Bisti field (Cretaceous) in the San Juan Basin and the TCB-East field (Oligocene) of South Texas.

Shelf reservoirs are usually relatively thin and form poorer quality reservoirs. For the most part, they are comprised of sand ridge/bars composed of reworked deposits formed during a transgression. There are exceptions where thick sand waves can develop on shallow marine shelves and serve as excellent high-quality reservoirs. Examples of shelf reservoirs are the House Creek and Hartzog Draw fields (Cretaceous) in the Powder River Basin of Wyoming.

Slope/basin reservoirs are divided into turbidite fans and debris fans. Submarine fans typically contain three distinct sand-body types: (1) thicker channel sands occur across the length of the upper and middle fan and thin downfan, (2) thinner lobate suprafan sands associated with distributary channels occur across the middle to distal end of the fan, and (3) thinly bedded sheet sands occur basinward of the fan proper. Fans, in general, provide excellent quality reservoirs. Examples of submarine-fan reservoirs are provided by the Tertiary fields in southern California, in particular the Elk Hills fields (Stevens) in the San Joaquin Basin and the Ventura field (Pliocene) in the Santa Barbara Basin.

Deep-basin reservoirs are reserved for those pelagic siliceous deposits that have accumulated in deep ocean basins and tectonic trenches. In many instances these types of deposits serve as both a major hydrocarbon source and reservoir. Four conditions are required for their formation: (1) high production rates of diatoms, radiolarians, etc., (2) low dilution by terrigenous sourced sediments, (3) adequate burial for advanced diagenesis, and (4) fracturing of the resultant deposit to increase permeability and porosity. The most important deep-basin siliceous reservoirs in North America are those associated with the Monterey Formation (Miocene) in the southern California area.

Diagenetic Overprint Element

Diagenesis can be generally defined as the chemical, physical, and biologic changes and alterations undergone by a sediment after its initial deposition and during and after its burial and lithification. It encompasses a wide range of processes, such as compaction, cementation, authigenesis, replacement, crystallization, leaching, hydration, bacterial action, and karsting, etc. Whereas depositional systems occupy a specific time and space and can be defined to have finite spatial boundaries, diagenetic processes cannot be so delineated. In contrast, multiple diagenetic processes can occur in the same space over variable time spans and with varying intensities.

Over the past few years, the importance of diagenetic processes in controlling reservoir quality has been better recognized. Many hydrocarbon reservoirs have significant diagenetic components directly affecting porosity and permeability characteristics. Modification of reservoirs by diagenetic processes can either reduce or enhance reservoir heterogeneities depending on specific circumstances.

In the classification presented here, diagenetic effects are not defined in spatial terms but in terms of the diagenetic processes that most directly influenced the present-day flow characteristics of the reservoir. The focus of the diagenetic overprint categories is on: (1) pore types present in the reservoir, (2) the diagenetic process most responsible for producing the pore types, and (3) the relationship of the pore types to reservoir-flow characteristics.

Carbonate Reservoirs

The most common diagenetic processes that most all carbonate reservoirs have undergone are compaction, cementation, and some degree of selective grain dissolution. Collectively, these processes are referred to as lithification. The most common pore types for this stage of diagenesis are intergranular and separate-vug. Compaction and cementation directly reduce intergranular pore space. Selective grain dissolution creates ineffective, nonconnected separate-vug pore spaces and provides a source of $CaCO_3$ for cementation of adjacent intergranular pore space.

All three processes reduce reservoir quality. Examples of reservoirs in this category are Fairway (Cretaceous) reservoir of the East Texas Basin and the Mondak (Mississippian) reservoir in the Williston Basin.

The grain enhancement category is included to identify reservoirs in which early subaerial diagenetic processes improve reservoir quality by altering mud-dominated tidal-flat sediment to fenestral and interpisolitic pore types. An example is the Glenburn field, Mississippian of the Williston Basin (Gerhard, 1985).

The dolomitization with evaporites category includes those reservoirs that produce from dolomites that contain considerable volumes of anhydrite or gypsum and whose principal pore types are intercrystalline, intergranular, and separate-vug. Examples are the Dune (Grayburg) reservoir and the Wasson (San Andres) reservoir of the Permian Basin.

The dolomitization category is included to identify dolomite reservoirs that produce from intercrystalline, intergranular, and separate-vug pore types but do not contain sulfates. Yates (San Andres) field is an example of this category.

The massive dissolution category is included because carbonates are susceptible to karsting processes that result in collapse breccias, connected vugs, cave fills, and fracturing. These processes are independent of lithology and, indeed, often provide flow paths for later dolomitizing solutions. The primary pore types in these reservoirs are fractures, interbreccia-block, large connected vugs, and caverns. Intercrystalline, intergranular, and separate-vug pore types may also be present. The Emma (Ellenburger) reservoir in West Texas is an example of this category.

Silicification of carbonate sediment is the dominant diagenetic process in some reservoirs. Pore space is located between small quartz crystals or globules and in small separate vugs. The Block 31 reservoir (Devonian) of the Permian Basin is an example.

Siliciclastic Reservoirs

Compaction and cementation are the major processes that reduce primary, intergranular porosity in sandstones. All sandstones lose some porosity by compaction and cementation, but extreme amounts of compaction, cementation, or both, can destroy almost all original porosity. Examples of reservoirs in this category include portions of the Nugget Sandstone in Anschutz Ranch East field, Utah, which have lost porosity dominantly by mechanical compaction and intergranular pressure solution, and the Travis Peak Formation in North Appleby field, East Texas Basin, which has lost porosity mainly by extensive quartz cementation.

The dissolution category is restricted to intergranular dissolution. This process improves reservoir quality. Many oversized pores are probably hybrid, representing primary pores that have been enlarged by dissolution. An example of a reservoir in which porosity has been secondarily enhanced by dissolution is the Frio Formation in Chocolate Bayou field in coastal Texas.

Precipitation of interstitial clay in a sandstone will alter reservoir characteristics by increasing water saturation and decreasing permeability, while having little effect on porosity. Preservation of porosity at depth has been ascribed to the presence of clay coatings on sand grains. The most common authigenic clays are illite, smectite, mixed-layer illite-smectite, chlorite, and kaolinite. Dissolution of unstable framework grains, such as feldspars and rock fragments, results in the formation of grain molds and in the precipitation of interstitial clay. Examples include reservoirs that produce from the Aux Vases Formation in the Illinois Basin and the lower Tuscaloosa Little Creek reservoir in Mississippi.

Chertification of siliciclatic sediments is not a common process, but it strongly influences reservoir properties where it occurs. Silica for chertification is derived from diagenetic alteration of siliceous organisms, forming a porcelaneous cement that later recrystallizes to chert. Reservoirs that contain abundant porcelaneous cement are characterized by high porosity but relatively low permeability. Much of the total porosity in the rock is microporosity contained within the porcelaneous cement, and fluid flow is restricted in the micropore system. Examples include reservoirs in the Miocene Monterey Formation, California, and laterally equivalent turbidite sandstones in Beta and Wilmington fields, Los Angeles Basin.

Structural Compartmentalization Element

The structural compartmentalization element has been incorporated into the classification in order to identify those reservoirs where structural complexities have induced intra-reservoir heterogeneities that effectively compartmentalize or significantly alter production response of reservoirs. Examples include reservoirs where natural fracture porosity controls production performance, faulting partitions the reservoir, and where folding subdivides the reservoir. Structural compartmentalization is not to be confused with structural trap. Structural trap defines the reservoir boundaries not the internal heterogeneity.

As in the case of diagenesis, structural activity can be recurring and results in superimposed structural elements. Therefore, the object of the classification is to select the structure category that best characterizes reservoir productivity. Five broad categories have been selected: (1) unstructured, (2) natural fracture porosity, (3) fault partitioned; (4) fold compartmentalized; and (5) combined folded and faulting.

Most major reservoirs do not exhibit significant structurally induced heterogeneities and are for purposes of this classification <u>unstructured</u> at the intra-reservoir scale. Examples of unstructured reservoirs are the Dune (Grayburg) field in the Permian Basin and the East Texas (Woodbine) field.

The <u>natural-fracture porosity</u> category is used to classify those reservoirs where tectonic fracture porosity is the principal permeability control in the reservoir. This category is reserved for fracture porosity produced principally by tectonic forces. Thus, massive dissolution reservoirs with fracture porosity resulting from collapse should not be included in this category. Examples of tectonically fractured reservoirs are Mondak (Mississippian) field, Williston Basin, and Spraberry (Permian) field, Permian Basin.

The <u>fault</u> category should be selected only for those reservoirs where faults effectively compartmentalize the reservoir at the inter-reservoir scale and where natural fracture porosity is not significant. The Clam Lake field, a piercement salt-dome field in the Texas Gulf

Coast, is an example of a fault-partitioned reservoir. The fault category has been further divided into normal, reverse, and strike-slip faults.

The fold category is proposed for those instances where the reservoir has been effectively compartmentalized by complex folding. The combined fold and fault category has been added to classify those reservoirs where folding and faulting compartmentalized are equally important.

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Section 2

Procedures

for

Geologic Classification of Reservoirs

Procedures for Geologic Classification of Reservoirs

The following procedural guide is provided to aid in the task of completing the geologic classification form (see attached).

Before completing the classification forms, first locate fields to be classified on the USGS Tectonic Province Map and then outline groups of reservoirs that have geographic proximity and geologic similarities (age, lithology, etc.). This is a first pass at defining a play so give the groups of reservoirs tentative play names. Final play names should be determined after the reservoirs have been classified.

Reservoirs should be classified starting with the largest reservoirs.

Section 1. Geologic Location

Geologic Province - Use USGS Tectonic Map.

Play Name - Tentative definition. Final play name to be determined after reservoirs have been classified.

Formation - Local usage is preferred.

Geologic Age - System or better using local usage.

Reservoir Name, Field Name, State - Provided by ICF.

Section 2. Depositional System

Refer to Description of Geologic Reservoir Classification System for definitions of depositional-system categories. Select the <u>one</u> depositional system that best characterizes the most productive section of the reservoir. Rank the certainty of your selection 1, 2, or 3, with 1 signifying most confident. If you can further describe the reservoir using the subcategories from readily available data, please do so.

Section 3. Diagenetic Overprint

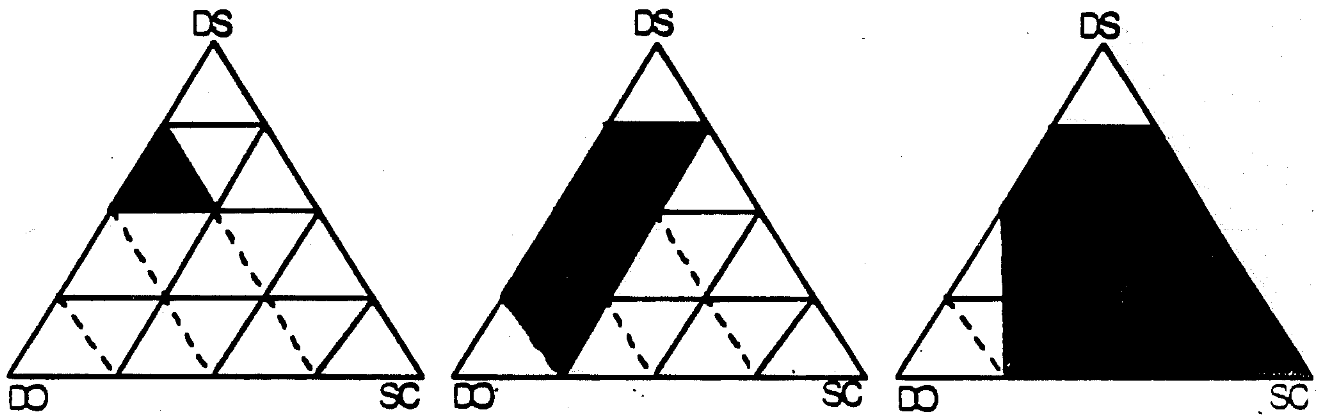
Refer to Description of Geologic Reservoir Classification System for definitions of diagenetic-overprint categories. Select the <u>one</u> diagenetic process that has the most dominant control on the productive characteristics of the reservoir. Rank the certainty of your selection 1, 2, or 3, with 1 signifying most confident.

Section 4. Structural Compartmentalization

Refer to Description of Geologic Reservoir Classification System for definition of structural-compartmentalization categories. Select the one structural category that best describes the structural controls on reservoir heterogeneity. The unstructured category should be selected for all reservoirs except where fracture permeability dominates production performance or where faulting and/or folding significantly compartmentalize the reservoir at an intra-reservoir scale. Rank the certainty of your selection 1, 2, or 3, with 1 signifying most certain. If readily available for fault compartmentalized reservoirs, indicate the type of faulting that compartmentalizes the reservoir.

Section 5. Reservoir Heterogeneity Ternary Diagram

Select the predominant element that, in your judgment, controls reservoir heterogeneity. On the ternary diagram, indicate the relative importance of the three elements by selecting the appropriate area. The degree of confidence can be indicated by the area selected. Three examples are shown below.



Confident of all three elements

SC - Confident
DS,DO - Little Confidence

DS,DO Confident
SC - Little Confidence

Section 6. Trap Type

This is not part of the classification and has been added to capture this information for future reference. Select the trap type that, in your judgment, best characterizes the reservoir. Please note that unconformity traps are considered a type of stratigraphic trap.

APPENDIX B

Worked Example of an Analysis of Variance (ANOVA)

Appendix B

Worked Example of an Analysis of Variance (ANOVA)

For purposes of clarity of presentation, this example shows the calculations required for an analysis of variance using three classes. Although the final geological classification system used 25 classes, this example illustrates all of the necessary computational steps.

The following notation is necessary for the calculations involved in making the test.

a: the number of geological classifications that have been defined in the category system.

n_j: the number of reservoirs in geological classification "j" $(1 < j < a)$; each class *does not* have to have an equal number of observations

Y_{ij}: the E_{het} measure for the "i"th reservoir in the "j"th group

$S_i(Y_{ij})$ Sum of all the "Y" values in the "j"th class Alternately, S_j

M_j Mean of the "j"th group $[= S_i(Y_{ij})/n_j]$

V_j Variance of the "j"th group
$= [S_i(Y^2_{ij}) - (n_j * M_j * M_j)]/[n_j - 1]$

The following data array illustrates some of the concepts to be used in the formulae to follow. For simplicity, we show three groups (i.e. a=3), with unequal frequencies

Group(j)	j=1	j=2	j=3
nj:	5	3	4
i = 1	0.45	0.55	0.67
i = 2	0.43	0.57	0.66
i = 3	0.46	0.56	0.68
i = 4	0.45	-----	0.67
i = 5	0.46	-----	-----

$S_i(Y_{ij})$	2.25	1.68	2.68
M_j	0.45	0.56	0.67
$S_i(Y^2_{ij})$	1.0131	0.9410	1.7958
V_j	0.000150	0.000100	0.000067

The table shows the calculation of the means and variances of each of the three groups. (note: the standard deviation is the square root of the variance).

- *Hartley's Test*: the statistic F_{max}, is the ratio of the largest to the smallest group variance. In our example, $F_{max} = 0.000150/0.000067 = 2.239$. In order to check this, we look up a critical value from special tables for F_{max}. There are two parameters for the critical value. The first is a, the number of groups, and the second is the number of observations in the largest group, less 1. In the example, these are 3 and 4 (=5-1). With reference to this table, the "critical value" at 1% significance is 37.0. That is, in our example, the calculated value of F_{max} must be greater than 37.0 in order to warrant rejection of the assumption of homogeneity of variance at the 1% level. Since we fail to reject this assumption, in this case, we may proceed as if homogeneity of variance was appropriate.

- *Cochran's Test:* the statistic C is the largest variance divided by the sum of the variances. In the example, C= 0.000150/0.000317 = 0.473. The parameters of the test for C are the same as for the Hartley Test, or 3 and 4. We use special tables for C to obtain the critical value. At 1% significance, this value is 0.7212; the data indicate that we fail to reject, and again, the assumption of homogeneity of variance is tenable.

These two easy-to-perform tests establish that the preconditions for the ANOVA have been met. What remains is the calculation of variance within and between groups according to the following formulae:

1. Correction term (K): this is defined as the square of the sum of all observations divided by the number of observations, or:

$$K = (S_1(Y_{ij}) + S_2(Y_{ij}) + ... + S_a(Y_{ij}))^2/(n1 + n_2 +... na)$$

In our example, this is given by:

$$K = (2.25 + 1.68 + 2.68)^2/ (5 + 3 + 4)$$
$$= (6.61)^2/12 = 3.697$$

2. SS_{tot} : this is the total sum of squares, a measure of the variability in the entire data array; it is computed according to the relationship:

$$SS_{tot} = (S_1(Y^2_{ij})\ S_2(Y^2_{ij}) +... + S_a(Y^2_{ij})) - K$$

In our example, this is given by:

$$SS_{tot} = (1.0131 + 0.9410 + 1.7958) - 3.697$$
$$= 0.0529$$

3. SS_A : this is the sum of squares for classes and is a measure of the variability between the classes; it is computed by the following equation:

$$SS_A = (S_1(Y_{ij})^2/n_1+S_2(Y_{ij})^2/n_2+ ... +S_a(Y_{ij})^2/n_a) - K$$

In our example, this is given by:

$SS_A = (2.25^2/4 + 1.68^2/3 + 2.68^2/4) - 3.697$
$= 0.0519$

4. $SS_{S/A}$: this is the sum of squares for observations within classes and is a measure of the variability within the classes. It is calculated as a residual:

$$SS_{S/A} = SS_{tot} - SS_A$$

In our example, this is given by:

$$SS_{S/A} = 0.0529 - 0.0519 = 0.0010$$

5. Degrees of Freedom: these are used in converting sums of squares to mean squares and in obtaining the critical value for making the statistical inference. The degrees of freedom, abbreviated as *df*, are as follows:

For SS_{tot} : $df = (n_1 + n_2 + ... + n_a) - 1$

For SS_A : $df = a$

For $SS_{S/A}$: $df = (n_1 + n_2 + ... + n_a) - 1 - a$

In our example, these are 11, 3, and 8 respectively

6. Mean Squares: the mean squares (abbreviated MS) are calculated by dividing the sums of squares (SS) by the degrees of freedom.

7. F-Ratio: the statistical test is based on the F-ratio, calculated by dividing MS_A by $MS_{S/A}$

Note that this is a direct comparison of the variability between groups with that within groups.

The parameters of the F statistic are the degrees of freedom for the numerator and the denominator. The critical value is obtained from a table of the F distribution. For our example, the critical value for F is 7.59 at 1% significance.

The analysis of variance is generally summarized in a table like the following:

Source	df	SS	MS	F
Total	11	0.0529	----	---
Between (A)	3	0.0519	0.017300	138.4
Within (S/A)	8	0.0010	0.000125	---

Note that the variance between the groups is much greater than the variance within groups. Note also that the F statistic greatly exceeds the critical value. Thus, we may infer that in the example, the classification system is very effective in capturing reservoir heterogeneity.

APPENDIX C

Supporting Data for Statistical Analysis

TABLE C-1

COMBINATION OF DEPOSITION, DIAGENESIS, AND STRUCTURE FOR CARBONATE RESERVOIRS

DEPOSITIONAL SYSTEM	DIAGENETIC OVERPRINT	STRUCTURAL COMPARTMENTALIZATION	NUMBER OF RESERVOIRS	OOIP (MMBbl)
Peritidal	Compaction & Cementation	Unstructured	1	4.4
	Grain Enhancement	Unstructured	6	426.0
		Natural Fracture Porosity	1	68.3
	Massive Dissolution	Unstructured	33	2,876.5
		Natural Fracture Porosity	4	190.7
	Dolomitization	Unstructured	60	1,695.0
		Natural Fracture Porosity	2	2.2
	Dolomitization (Evaporites)	Folded	3	126.7
Peritidal\Supratidal	Compaction & Cementation	Unstructured	1	404.1
Peritidal\Intertidal	Compaction & Cementation	Unstructured	8	606.8
	Grain Enhancement	Unstructured	3	187.4
	Dolomitization	Unstructured	4	239.6
		Natural Fracture Porosity	17	5,173.0
		Folded	1	106.1
	Dolomitization (Evaporites)	Natural Fracture Porosity	3	329.3
Peritidal\Subtidal	Compaction & Cementation	Unstructured	2	360.1
		Folded	1	57.5
	Grain Enhancement	Unstructured	13	706.6
	Dolomitization	Unstructured	7	680.0
		Natural Fracture Porosity	1	8.5
Shallow Shelf	Compaction & Cementation	Faulted\Normal	1	87.4
	Silification	Unstructured *	1	130.0
	Dolomitization	Unstructured	9	1,948.0
		Natural Fracture Porosity	4	398.8
		Faulted	1	160.0
		Folded	1	63.8
Shallow Shelf\Open Shelf	Compaction & Cementation	Unstructured	8	1,050.3
		Natural Fracture Porosity	5	410.3
		Fault/Fold\Normal	3	319.6
		Folded	1	106.5
	Grain Enhancement	Unstructured	21	2,406.9
		Folded	1	289.0
	Massive Dissolution	Natural Fracture Porosity	4	361.4
		Faulted	1	167.0
	Silification	Unstructured	2	219.2
		Natural Fracture Porosity	1	1,280.0
		Folded	1	39.2
	Dolomitization	Unstructured	62	8,915.6
		Natural Fracture Porosity	11	623.3
		Faulted	2	124.7
		Fault/Fold\Normal	3	1,326.5
	Dolomitization (Evaporites)	Unstructured	56	18,387.7
Shallow Shelf\Restricted Shelf	Compaction & Cementation	Unstructured	9	284.3
	Grain Enhancement	Unstructured	2	476.8
	Massive Dissolution	Unstructured	1	10.9
		Natural Fracture Porosity	1	91.2
	Dolomitization	Unstructured	7	5,876.3
		Natural Fracture Porosity	1	4.1
		Faulted	1	87.6
	Dolomitization (Evaporites)	Unstructured	79	22,131.1
Shelf Margin	Dolomitization	Unstructured	1	4,000.0
Shelf Margin\Rimmed Shelf	Compaction & Cementation	Unstructured	1	290.8
Shelf Margin\Ramps	Compaction & Cementation	Unstructured	1	1.1
	Silification	Unstructured	4	329.4
	Dolomitization	Unstructured	9	457.9
Reefs	Compaction & Cementation	Unstructured	6	4,165.0
	Dolomitization (Evaporites)	Unstructured	4	952.7
Reefs\Pinnacle	Dolomitization	Unstructured	18	189.0
Reefs\Bioherms	Compaction & Cementation	Unstructured	28	1,785.4
	Dolomitization (Evaporites)	Unstructured	8	1,271.0
Reefs\Atolls	Compaction & Cementation	Unstructured	45	5,695.1
Slope-Basin	Compaction & Cementation	Unstructured	2	29.9
	Silification	Unstructured	2	76.7
	Dolomitization	Unstructured	18	1,718.4
Totals			618	102,988.2

TABLE C–2

COMBINATIONS OF DEPOSITION, DIAGENESIS, AND STRUCTURE FOR CLASTIC RESERVOIRS

DEPOSITIONAL SYSTEM	DIAGENETIC OVERPRINT	STRUCTURAL COMPARTMENTALIZATION	NUMBER OF RESERVOIRS	OOIP (MMBbl)
Eolian	Compaction & Cementation	Unstructured	19	2,036.5
		Natural Fracture Porosity	6	943.3
		Faulted	4	187.3
		Faulted\Normal	7	1,373.7
		Faulted\Reverse	3	136.6
		Folded	1	58.0
Eolian\Erge	Compaction & Cementation	Unstructured	4	97.5
Eolian\Coastal Dunes	Compaction & Cementation	Unstructured	17	406.0
		Natural Fracture Porosity	1	1,595.0
Lacustrine\Basin Margin	Compaction & Cementation	Unstructured	5	846.0
		Natural Fracture Porosity	1	28.0
Fluvial	Compaction & Cementation	Unstructured	4	46.0
		Faulted	6	57.9
Fluvial\Braided Streams	Compaction & Cementation	Unstructured	11	2,567.7
	Intergranular Dissolution	Unstructured	5	22,781.5
	Compaction & Cementation	Natural Fracture Porosity	1	276.2
		Faulted	2	559.8
		Faulted\Normal	2	158.7
	Intergranular Dissolution	Fault/Fold\Normal	2	55.7
Fluvial\Meandering Streams	Compaction & Cementation	Unstructured	24	868.7
		Folded	2	70.8
Alluvial Fan\Arid/Semi-Arid	Compaction & Cementation	Unstructured	10	7,807.2
Alluvial Fan\Fan Deltas	Compaction & Cementation	Unstructured	12	547.9
		Folded	1	340.1
Delta	Compaction & Cementation	Unstructured	25	1,128.6
		Faulted	44	6,199.3
		Faulted\Normal	1	78.0
		Fault/Fold\Normal	1	130.6
Delta\Wave-Dominated	Compaction & Cementation	Unstructured	83	17,583.9
	Authigenic Clay	Unstructured	2	11.1
		Faulted	4	2,836.0
		Faulted\Normal	3	1,079.1
Delta\Fluvial-Dominated	Compaction & Cementation	Unstructured	231	20,408.7
	Intergranular Dissolution	Unstructured	4	241.4
	Authigenic Clay	Unstructured	4	37.2
	Compaction & Cementation	Faulted	20	2,321.1
		Faulted\Normal	76	4,512.1
		Fault/Fold\Normal	11	894.2
		Folded	23	2,291.6
	Intergranular Dissolution	Faulted\Reverse	1	29.7
		Folded	2	32.6
	Authigenic Clay	Folded	3	146.5
Delta\Tide-Dominated	Compaction & Cementation	Unstructured	22	4,874.9
	Authigenic Clay	Unstructured	4	435.4
	Compaction & Cementation	Fault/Fold	1	2.8

TABLE C-2, CONTINUED

Depositional System	Diagenetic Overprint	STRUCTURAL COMPARTMENTALIZATION	NUMBER OF RESERVOIRS	OOIP (MMBbl)
Strandplain	Compaction & Cementation	Unstructured	37	4,258.4
	Authigenic Clay	Unstructured	4	248.2
	Compaction & Cementation	Faulted	7	428.4
		Faulted\Normal	3	1,113.3
Strandplain\Barrier Cores	Compaction & Cementation	Unstructured	102	7,948.3
	Authigenic Clay	Unstructured	1	71.9
	Compaction & Cementation	Natural Fracture Porosity	1	165.0
		Faulted	1	26.4
		Folded	7	159.4
	Intergranular Dissolution	Faulted\Normal	1	223.9
Strandplain\Barrier Shorefaces	Compaction & Cementation	Unstructured	38	3,408.8
		Natural Fracture Porosity	1	10.0
		Faulted	6	816.5
		Faulted\Normal	3	168.7
		Fault/Fold\Normal	21	4,437.0
		Fault/Fold\Reverse	8	2,104.0
		Folded	4	805.4
Strandplain\Back Barriers	Compaction & Cementation	Unstructured	40	1,843.3
		Fault/Fold\Normal	4	462.6
Strandplain\Tidal Channels	Compaction & Cementation	Unstructured	5	349.1
		Folded	1	13.4
Strandplain\Washover Fan/Tidal Delta	Compaction & Cementation	Unstructured	2	113.9
		Fault/Fold	1	3.0
		Folded	2	115.7
Shelf	Compaction & Cementation	Unstructured	67	5,936.5
		Faulted	1	14.4
		Faulted\Normal	1	14.9
		Fault/Fold\Normal	1	301.0
		Folded	1	1,180.8
Shelf\Sand Waves	Compaction & Cementation	Fault/Fold\Reverse	2	1,451.0
		Folded	1	78.7
Shelf\Sand Ridges/Bars	Compaction & Cementation	Unstructured	30	7,084.0
	Intergranular Dissolution	Unstructured	1	22.2
	Compaction & Cementation	Faulted	4	77.3
		Faulted\Normal	8	236.4
		Fault/Fold\Reverse	1	422.0
		Folded	7	69.8
Slope-Basin	Compaction & Cementation	Unstructured	49	7,467.0
Slope-Basin\Turbidite Fans	Compaction & Cementation	Unstructured	105	34,162.5
		Natural Fracture Porosity	1	13.3
		Faulted	14	7,032.6
		Faulted\Normal	9	1,698.0
		Folded	1	102.8
Basin\Pelagic	Chertification	Natural Fracture Porosity	11	8,496.1
Totals			1329	214,253.7

TABLE C–3

NUMBER OF CARBONATE RESERVOIRS BY DEPOSITIONAL SYSTEM

DEPOSITIONAL SYSTEM	NUMBER OF RESERVOIRS
Peritidal	110
Peritidal\Supratidal	1
Peritidal\Intertidal	36
Peritidal\Subtidal	24
Shallow Shelf	17
Shallow Shelf\Open Shelf	182
Shallow Shelf\Restricted Shelf	101
Shelf Margin	1
Shelf Margin\Rimmed Shelf	1
Shelf Margin\Ramps	14
Reefs	10
Reefs\Pinnacle	18
Reefs\Bioherms	36
Reefs\Atolls	45
Slope–Basin	22
TOTAL CARBONATE RESERVOIRS:	618

NUMBER OF CLASTIC RESERVOIRS BY DEPOSITIONAL SYSTEM

DEPOSITIONAL SYSTEM	NUMBER OF RESERVOIRS
Eolian	40
Eolian\Ergs	4
Eolian\Coastal Dunes	18
Lacustrine\Basin Margin	6
Fluvial	9
Fluvial\Braided Streams	23
Fluvial\Meandering Streams	26
Alluvial Fan\Arid/Semi–Arid	10
Alluvial Fan\Fan Deltas	13
Delta	71
Delta\Wave–Dominated	92
Delta\Fluvial–Dominated	375
Delta\Tide–Dominated	27
Strandplain	51
Strandplain\Barrier Cores	113
Strandplain\Barrier Shorefaces	81
Strandplain\Back Barriers	44
Strandplain\Tidal Channels	6
Strandplain\Washover Fan/Tidal Delta	5
Shelf	71
Shelf\Sand Waves	3
Shelf\Sand Ridges/Bars	51
Slope–Basin	49
Slope–Basin\Turbidite Fans	130
Basin\Pelagic	11
TOTAL CLASTIC RESERVOIRS:	1,329

TABLE C–4

COMBINATIONS OF DEPOSITIONAL SYSTEM AND STRUCTURAL ELEMENT FOR CARBONATE RESERVOIRS
(NUMBER OF RESERVOIRS)

DEPOSITIONAL SYSTEM	STRUCTURAL ELEMENT					TOTALS
	UNSTRUCTURED	NATURAL FRACTURE POROSITY	FAULTED	FAULT/FOLD	FOLDED	
Peritidal	100	7	0	0	3	110
Peritidal\Supratidal	1	0	0	0	0	1
Peritidal\Intertidal	15	20	0	0	1	36
Peritidal\Subtidal	22	1	0	0	1	24
Shallow Shelf	10	4	2	0	1	17
Shallow Shelf\Open Shelf	149	21	3	6	3	182
Shallow Shelf\Restricted Shelf	98	2	1	0	0	101
Shelf Margin	1	0	0	0	0	1
Shelf Margin\Rimmed Shelf	1	0	0	0	0	1
Shelf Margin\Ramps	14	0	0	0	0	14
Reefs	10	0	0	0	0	10
Reefs\Pinnacle	18	0	0	0	0	18
Reefs\Bioherms	36	0	0	0	0	36
Reefs\Atolls	45	0	0	0	0	45
Slope-Basin	22	0	0	0	0	22
TOTALS	542	55	6	6	9	618

TABLE C–5

COMBINATIONS OF DEPOSITIONAL SYSTEM AND DIAGENETIC OVERPRINT FOR CLASTIC RESERVOIRS (NUMBER OF RESERVOIRS)

DEPOSITIONAL SYSTEM	DIAGENETIC OVERPRINT				TOTALS
	COMPACTION/ CEMENTATION	INTERGRANULAR DISSOLUTION	AUTHIGENIC CLAY	CHERTIFICATION	
Eolian	40	0	0	0	40
Eolian\Ergs	4	0	0	0	4
Eolian\Coastal Dunes	18	0	0	0	18
Lacustrine\Basin Margin	6	0	0	0	6
Fluvial	9	0	0	0	9
Fluvial\Braided Streams	16	7	0	0	23
Fluvial\Meandering Streams	26	0	0	0	26
Alluvial Fan\Arid/Semi-Arid	10	0	0	0	10
Alluvial Fan\Fan Deltas	13	0	0	0	13
Delta	71	0	0	0	71
Delta\Wave-Dominated	90	0	2	0	92
Delta\Fluvial-Dominated	361	7	7	0	375
Delta\Tide-Dominated	23	0	4	0	27
Strandplain	47	0	4	0	51
Strandplain\Barrier Cores	111	1	1	0	113
Strandplain\Barrier Shorefaces	81	0	0	0	81
Strandplain\Back Barriers	44	0	0	0	44
Strandplain\Tidal Channels	6	0	0	0	6
Strandplain\Washover Fan/Tidal Delta	5	0	0	0	5
Shelf	71	0	0	0	71
Shelf\Sand Waves	3	0	0	0	3
Shelf\Sand Ridges/Bars	50	1	0	0	51
Slope-Basin	49	0	0	0	49
Slope-Basin\Turbidite Fans	130	0	0	0	130
Basin\Pelagic	0	0	0	11	11
TOTALS	1,284	16	18	11	1,329

TABLE C–6

COMBINATIONS OF DEPOSITIONAL SYSTEM AND DIAGENETIC OVERPRINT FOR CARBONATE RESERVOIRS (NUMBER OF RESERVOIRS)

DEPOSITIONAL SYSTEM	DIAGENETIC OVERPRINT						TOTALS
	COMPACTION/ CEMENTATION	GRAIN ENHANCEMENT	DOLOMITIZATION	DOLOMITIZATION (EVAPORITES)	MASSIVE DISSOLUTION	SILICIFICATION	
Peritidal	1	7	62	3	37	0	110
Peritidal\Supratidal	1	0	0	0	0	0	1
Peritidal\Intertidal	8	3	22	3	0	0	36
Peritidal\Subtidal	3	13	8	0	0	0	24
Shallow Shelf	1	0	15	0	0	1	17
Shallow Shelf\Open Shelf	17	22	78	56	5	4	182
Shallow Shelf\Restricted Shelf	9	2	9	79	2	0	101
Shelf Margin	0	0	1	0	0	0	1
Shelf Margin\Rimmed Shelf	1	0	0	0	0	0	1
Shelf Margin\Ramps	1	0	9	0	0	4	14
Reefs	6	0	0	4	0	0	10
Reefs\Pinnacle	0	0	18	0	0	0	18
Reefs\Bioherms	28	0	0	8	0	0	36
Reefs\Atolls	45	0	0	0	0	0	45
Slope-Basin	2	0	18	0	0	2	22
TOTALS	123	47	240	153	44	11	618

TABLE C-7

COMBINATIONS OF DEPOSITIONAL SYSTEM AND STRUCTURAL ELEMENT FOR CLASTIC RESERVOIRS
(NUMBER OF RESERVOIRS)

DEPOSITIONAL SYSTEM	STRUCTURAL ELEMENT					
	UNSTRUCTURED	NATURAL FRACTURE POROSITY	FAULTED	FAULT/FOLD	FOLDED	TOTALS
Eolian	19	6	14	0	1	40
Eolian\Ergs	4	0	0	0	0	4
Eolian\Coastal Dunes	17	1	0	0	0	18
Lacustrine\Basin Margin	5	1	0	0	0	6
Fluvial	4	0	5	0	0	9
Fluvial\Braided Streams	16	1	4	2	0	23
Fluvial\Meandering Streams	24	0	0	0	2	26
Alluvial Fan\Arid/Semi-Arid	10	0	0	0	0	10
Alluvial Fan\Fan Deltas	12	0	0	0	1	13
Delta	25	0	45	1	0	71
Delta\Wave-Dominated	85	0	7	0	0	92
Delta\Fluvial-Dominated	239	0	97	11	28	375
Delta\Tide-Dominated	26	0	0	1	0	27
Strandplain	41	0	10	0	0	51
Strandplain\Barrier Cores	103	1	2	0	7	113
Strandplain\Barrier Shorefaces	38	1	9	29	4	81
Strandplain\Back Barriers	40	0	0	4	0	44
Strandplain\Tidal Channels	5	0	0	0	1	6
Strandplain\Washover Fan/Tidal Delta	2	0	0	1	2	5
Shelf	67	0	2	1	1	71
Shelf\Sand Waves	0	0	0	2	1	3
Shelf\Sand Ridges/Bars	31	0	12	1	7	51
Slope-Basin	49	0	0	0	0	49
Slope-Basin\Turbidite Fans	105	1	23	0	1	130
Basin\Pelagic	0	11	0	0	0	11
TOTALS	967	23	230	53	56	1,329

TABLE C–8

COMBINATIONS OF DEPOSITIONAL SYSTEM AND DIAGENETIC OVERPRINT FOR SCREENED CARBONATE RESERVOIRS (NUMBER OF RESERVOIRS)

DEPOSITIONAL SYSTEM	DIAGENETIC OVERPRINT						TOTALS
	COMPACTION/ CEMENTATION	GRAIN ENHANCEMENT	DOLOMITIZATION	DOLOMITIZATION (EVAPORITES)	MASSIVE DISSOLUTION	SILICIFICATION	
Peritidal	1	4	30	3	24	0	62
Peritidal\Supratidal	0	0	0	0	0	0	0
Peritidal\Intertidal	7	1	16	3	0	0	27
Peritidal\Subtidal	3	11	5	0	0	0	19
Shallow Shelf	1	0	9	0	0	1	11
Shallow Shelf\Open Shelf	12	17	59	50	4	4	146
Shallow Shelf\Restricted Shelf	3	1	4	59	1	0	68
Shelf Margin	0	0	0	0	0	0	0
Shelf Margin\Rimmed Shelf	1	0	0	0	0	0	1
Shelf Margin\Ramps	0	0	7	0	0	3	10
Reefs	5	0	0	4	0	0	9
Reefs\Pinnacle	0	0	17	0	0	0	17
Reefs\Bioherms	20	0	0	7	0	0	27
Reefs\Atolls	35	0	0	0	0	0	35
Slope-Basin	1	0	15	0	0	2	18
TOTALS	89	34	162	126	29	10	450

TABLE C-9

MEAN HETEROGENEITY INDICATOR (Ehet) FOR SCREENED CARBONATE RESERVOIRS

DEPOSITIONAL SYSTEM	DIAGENETIC OVERPRINT						
	COMPACTION/ CEMENTATION	GRAIN ENHANCEMENT	DOLOMITIZATION	DOLOMITIZATION (EVAPORITES)	MASSIVE DISSOLUTION	SILICIFICATION	AGGREGATE
Peritidal	0.1822	0.5770	0.6620	0.9180	0.7123	0	0.6806
Peritidal\Supratidal	0	0	0	0	0	0	0
Peritidal\Intertidal	0.8319	0.7363	0.7451	0.7414	0	0	0.7669
Peritidal\Subtidal	0.8754	0.6437	0.6916	0	0	0	0.6941
Shallow Shelf	0.5123	0	0.6555	0	0	0.6400	0.6411
Shallow Shelf\Open Shelf	0.6607	0.6367	0.6782	0.5876	0.6731	0.5561	0.6374
Shallow Shelf\Restricted Shelf	0.5494	0.8581	0.7563	0.5770	0.4850	0	0.5891
Shelf Margin	0	0	0	0	0	0	0
Shelf Margin\Rimmed Shelf	0.4637	0	0	0	0	0	0.4637
Shelf Margin\Ramps	0	0	0.6387	0	0	0.7065	0.6590
Reefs	0.5776	0	0	0.7916	0	0	0.6727
Reefs\Pinnacle	0	0	0.6787	0	0	0	0.6787
Reefs\Bioherms	0.5755	0	0	0.7611	0	0	0.6236
Reefs\Atolls	0.6985	0	0	0	0	0	0.6985
Slope-Basin	0.7362	0	0.6606	0	0	0.6771	0.6666
AGGREGATE	0.6603	0.6420	0.6796	0.6102	0.6991	0.6338	0.6538

TABLE C–10

COMBINATIONS OF DEPOSITIONAL SYSTEM AND STRUCTURAL ELEMENT FOR SCREENED CLASTIC RESERVOIRS (NUMBER OF RESERVOIRS)

DEPOSITIONAL SYSTEM	STRUCTURAL ELEMENT					
	UNSTRUCTURED	NATURAL FRACTURE POROSITY	FAULTED	FAULT/FOLD	FOLDED	TOTALS
Eolian	13	3	11	0	0	27
Eolian\Ergs	2	0	0	0	0	2
Eolian\Coastal Dunes	11	0	0	0	0	11
Lacustrine\Basin Margin	2	0	0	0	0	2
Fluvial	2	0	3	0	0	5
Fluvial\Braided Streams	12	1	1	1	0	15
Fluvial\Meandering Streams	17	0	0	0	2	19
Alluvial Fan\Arid/Semi-Arid	0	0	0	0	0	0
Alluvial Fan\Fan Deltas	10	0	0	0	1	11
Delta	19	0	33	1	0	53
Delta\Wave-Dominated	64	0	6	0	0	70
Delta\Fluvial-Dominated	180	0	58	6	16	260
Delta\Tide-Dominated	15	0	0	1	0	16
Strandplain	23	0	5	0	0	28
Strandplain\Barrier Cores	78	1	2	0	2	83
Strandplain\Barrier Shorefaces	26	1	6	25	2	60
Strandplain\Back Barriers	33	0	0	1	0	34
Strandplain\Tidal Channels	2	0	0	0	1	3
Strandplain\Washover Fan/Tidal Delta	2	0	0	0	2	4
Shelf	54	0	2	1	0	57
Shelf\Sand Waves	0	0	0	1	0	1
Shelf\Sand Ridges/Bars	17	0	9	0	3	29
Slope-Basin	46	0	0	0	0	46
Slope-Basin\Turbidite Fans	53	1	13	0	1	68
Basin\Pelagic	0	4	0	0	0	4
TOTALS	681	11	149	37	30	908

TABLE C–11

MEAN HETEROGENEITY INDICATOR (Ehet) FOR SCREENED CLASTIC RESERVOIRS

DEPOSITIONAL SYSTEM	STRUCTURAL ELEMENT					
	UNSTRUCTURED	NATURAL FRACTURE POROSITY	FAULTED	FAULT/FOLD	FOLDED	AGGREGATE
Eolian	0.5504	0.7809	0.5292	0	0	0.5674
Eolian\Ergs	0.4628	0	0	0	0	0.4628
Eolian\Coastal Dunes	0.7041	0	0	0	0	0.7041
Lacustrine\Basin Margin	0.5215	0	0	0	0	0.5215
Fluvial	0.4065	0	0.7084	0	0	0.5876
Fluvial\Braided Streams	0.5297	0.7260	0.2098	0.1113	0	0.4935
Fluvial\Meandering Streams	0.4855	0	0	0	0.5622	0.4936
Alluvial Fan\Arid/Semi-Arid	0	0	0	0	0	0
Alluvial Fan\Fan Deltas	0.4564	0	0	0	0.7912	0.4868
Delta	0.5379	0	0.6121	0.7722	0	0.5885
Delta\Wave-Dominated	0.5129	0	0.6815	0	0	0.5273
Delta\Fluvial-Dominated	0.5495	0	0.5921	0.6272	0.5377	0.5601
Delta\Tide-Dominated	0.6607	0	0	0.4699	0	0.6487
Strandplain	0.5596	0	0.4070	0	0	0.5323
Strandplain\Barrier Cores	0.6675	0.7742	0.6506	0	0.4064	0.6621
Strandplain\Barrier Shorefaces	0.6307	0.1280	0.5431	0.5450	0.2742	0.5660
Strandplain\Back Barriers	0.5788	0	0	0.2081	0	0.5678
Strandplain\Tidal Channels	0.8454	0	0	0	0.7547	0.8152
Strandplain\Washover Fan/Tidal Delta	0.3672	0	0	0	0.5047	0.4360
Shelf	0.5531	0	0.3090	0.1478	0	0.5374
Shelf\Sand Waves	0	0	0	0.7435	0	0.7453
Shelf\Sand Ridges/Bars	0.6426	0	0.5065	0	0.6404	0.6001
Slope-Basin	0.5843	0	0	0	0	0.5843
Slope-Basin\Turbidite Fans	0.5063	0.8801	0.5041	0	0.0631	0.5048
Basin\Pelagic	0	0.5171	0	0	0	0.5171
AGGREGATE	0.5669	0.6291	0.5712	0.5362	0.5210	0.5656

TABLE C-12

COMPOSITION OF CLASTIC RESERVOIR CLASSES

RESERVOIR CLASS	DEPOSITIONAL SYSTEMS	STRUCTURAL ELEMENTS	DIAGENETIC OVERPRINTS
Eolian\Unstructured	Eolian -Ergs -Coastal Dunes	Unstructured	All
Eolian\Structured	Eolian -Ergs -Coastal Dunes	Natural Fracture Porosity Faulted Fault/Fold Folded	All
Alluvial Fan	Lacustrine -Basin Margin -Basin Center Alluvial Fan -Humid (Stream-Dominated) -Arid/Semi-Arid -Fan Deltas	Unstructured Natural Fracture Porosity Faulted Fault/Fold Folded	All
Fluvial\Unstructured	Fluvial -Braided Streams -Meandering Streams	Unstructured	All
Fluvial\Structured	Fluvial -Braided Streams -Meandering Streams	Natural Fracture Porosity Faulted Fault/Fold Folded	All
Delta\Unstructured	Delta -Wave-Dominated -Fluvial-Dominated -Tide-Dominated	Unstructured	All
Delta\Structured	Delta -Wave-Dominated -Fluvial-Dominated -Tide-Dominated	Natural Fracture Porosity Faulted Fault/Fold Folded	All
Stranplain\Structured	Strandplain -Barrier Cores -Barrier Shorefaces -Back Barriers -Tidal Channels -Washover Fan/Tidal Deltas	Natural Fracture Porosity Faulted Fault/Fold Folded	All
Stranplain\Other\Unstructured	Strandplain -Back Barriers -Tidal Channels -Washover Fan/Tidal Deltas	Unstructured	All
Strandplain\Barrier Core-Shoreface \Unstructured	-Barrier Cores -Barrier Shorefaces	Unstructured	All
Shelf\Structured	Shelf -Sand Waves -Sand Ridges/Bars	Natural Fracture Porosity Faulted Fault/Fold Folded	All
Shelf\Other\Unstructured	Shelf -Sand Waves	Unstructured	All
Shelf\Sand Ridges\Unstructured	-Sand Ridges/Bars	Unstructured	All
Slope-Basin\Structured	Slope-Basin -Turbidite Fans -Debris Fans Basin -Pelagic	Natural Fracture Porosity Faulted Fault/Fold Folded	All
Slope-Basin\Other\Unstructured	Slope-Basin -Debris Fans Basin -Pelagic	Unstructured	All
Slope-Basin\Turbidite Fan\Unstructured	-Turbidite Fans	Unstructured	All

TABLE C–13

COMPOSITION OF CARBONATE RESERVOIR CLASSES

RESERVOIR CLASS	DEPOSITIONAL SYSTEMS	DIAGENETIC OVERPRINTS	STRUCTURAL ELEMENTS
Peritidal\Non–Dolomitized	Peritidal –Supratidal –Intertidal –Subtidal	Compaction–Cementation Grain Enhancement Massive Dissolution Silicification	All
Peritidal\Dolomitized	Peritidal –Supratidal –Intertidal –Subtidal	Dolomitization Dolomitization (Evaporites)	All
Shelf\Non–Dolomitized	Shallow Shelf –Open Shelf –Restricted Shelf Shelf Margin –Rimmed Shelf –Ramp	Compaction–Cementation Grain Enhancement Massive Dissolution Silicification	All
Shelf\Dolomitized	Shallow Shelf –Open Shelf –Restricted Shelf Shelf Margin –Rimmed Shelf –Ramp	Dolomitization	All
Shelf\Dolomitized (Evaporites)	Shallow Shelf –Open Shelf –Restricted Shelf Shelf Margin –Rimmed Shelf –Ramp	Dolomitization (Evaporites)	All
Reefs\Atolls\Non–Dolomitized	–Atolls	Compaction–Cementation Grain Enhancement Massive Dissolution Silicification	All
Reefs\Other\Non–Dolomitized	Reefs –Pinnacle Reefs –Bioherms	Compaction–Cementation Grain Enhancement Massive Dissolution Silicification	All
Reefs\Other\Dolomitized	Reefs –Pinnacle Reefs –Bioherms	Dolomitization Dolomitization (Evaporites)	All
Slope–Basin	Slope/Basin –Debris Fans –Turbidite Fans –Mounds Basin –Drowned Shelf –Deep Basin	Compaction–Cementation Grain Enhancement Massive Dissolution Silicification Dolomitization Dolomitization (Evaporites)	All