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# LITHOFACIES MODULE METHODOLOGY FOR CHARACTERIZING AND MODELING CLASTIC HYDROCARBON RESERVOIRS

A Dissertation

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By

RENQI JIANG
Norman, Oklahoma
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UMI Number: 9724429



UMI
300 North Zeeb Road
Ann Arbor, MI 48103

**LITHOFACIES MODULE METHODOLOGY FOR CHARACTERIZING AND MODELING CLASTIC HYDROCARBON RESERVOIRS – A CONCEPT AT THE INTERFACE OF GEOLOGY, GEOSTATISTICS, AND RESERVOIR ENGINEERING WITH A CASE STUDY OF FLUVIAL SANDSTONES AT THE GYPSY OUTCROP SITE**

A Dissertation APPROVED FOR THE
SCHOOL OF GEOLOGY AND GEOPHYSICS

BY

Mohan Kelkar

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ABSTRACT

A lithofacies module concept and methodology for the purpose of interdisciplinary studies of reservoir characterization are proposed in this research. Accurate reservoir models derived from the application of this concept and methodology will render significant improvements of oil recovery from reservoir simulation studies.

A lithofacies module is a package of sediments restricted within a chronostratigraphic sequence and distinguished by a similar depositional environment and similar petrophysical properties that have similar effects on fluid flow within the unit. Genetically, a lithofacies module is identical with a unique position within a chronostratigraphic sequence. This makes reservoir heterogeneity predictable. Within an individual channel sequence of the Gypsy fluvial reservoir, four types of lithofacies modules can be systematically recognized from the bottom to the top of a channel sequence: mudclast low permeability module, cross-bedded and plane-bedded high permeability module, ripple low permeability module, and overbank flow barrier module.

Four reservoir modeling scales are classified here: stratigraphic sequence scale, reservoir scale, lithofacies module scale, and sample scale. The lithofacies module scale is the most important for reservoir characterization applied in petroleum exploitation. At this scale, a highly heterogeneous reservoir with a wide variation of properties can be subdivided into compartments with much narrower variations of reservoir properties. Geostatistical

techniques can be useful tools for the prediction of reservoir heterogeneity if they are used properly in combination with geological knowledge. The lithofacies module concept provides a detailed reservoir framework suitable for geostatistical prediction.

The geological framework and concept used in building the reservoir model determine the distribution of reservoir properties that control fluid flow. Reservoir simulation studies at the Gypsy outcrop site show different concepts for defining a reservoir model can result as much as a 30% difference in hydrocarbon recovery. The selection of vertical resolution is a critical parameter of the reservoir model. The concept of lithofacies modules provides a reasonable and accurate guideline for a geologically controlled method of reservoir upscaling. Simulation based on an accurate reservoir model provides an economic and quick method for evaluating various development strategies to select the scenario that provide the optimum economical return.

# Lithofacies Module Methodology for Characterizing and Modeling Clastic Hydrocarbon Reservoirs

*"No substantial part of the universe is so simple that it can be grasped and controlled without abstraction. Abstraction consists in replacing the part of the universe under consideration by a model or similar but simpler structure. Models, formal or intellectual on the one hand, or material on the other, are thus a central necessity of scientific procedure."*

——— *A.Rosenblueth, 1944*

## CHAPTER 1. INTRODUCTION

The biggest challenge facing petroleum exploration and production is to improve significantly hydrocarbon recovery from newly and previously discovered reservoirs. A key to achieving this goal is to compile detailed and accurate reservoir descriptions (Sneider, 1990). The importance of reservoir characterization to the petroleum industry is shown by the dramatic increase during the last ten years in the number of technical papers published and conferences, seminars, forums, and training courses arranged. However, despite this high level of activity and many new ideas and technological advances, the mainstream day-to-day geoscience/reservoir engineering approach to characterizing, modeling, visualizing, and forecasting the behavior of reservoirs in a typical oil company has not changed noticeably. The average recovery factors have not been increased significantly, as illustrated schematically in Figure 1-1 (Haldorsen & Damsleth, 1993). The failure of many reservoir models to predict adequately reservoir behavior is directly related to their failure to

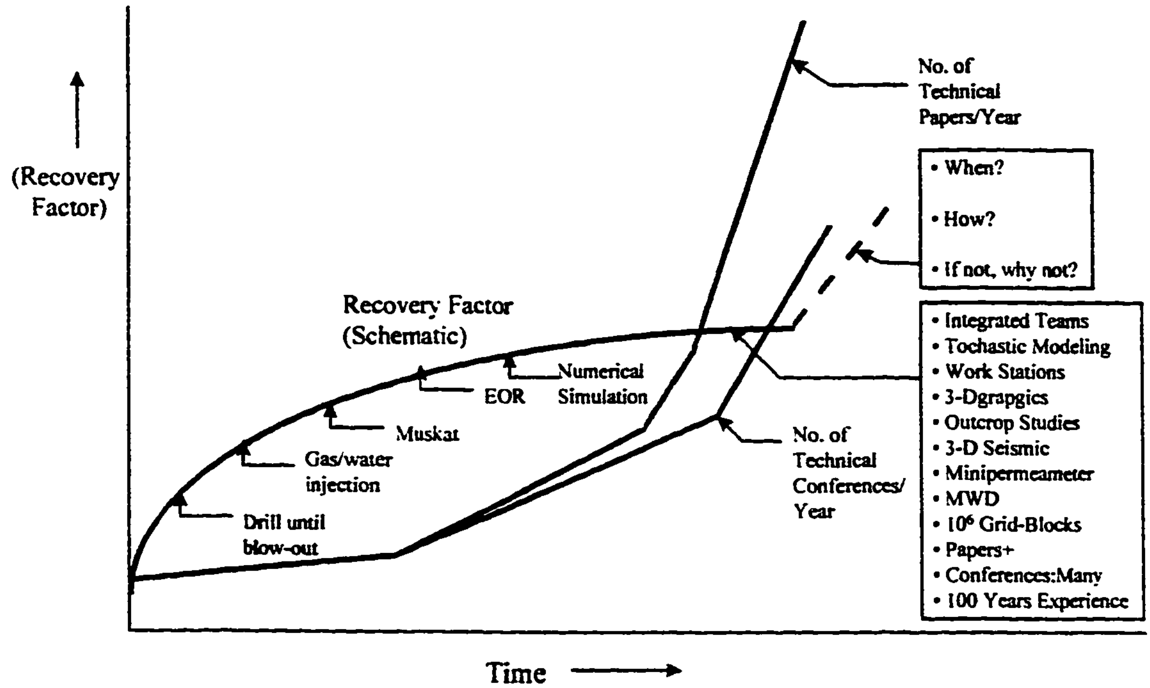



**Figure 1-1 Recovery factors vs. number of papers and conferences per year (Haldorsen & Damsleth, 1993).**

exemplify accurately the 3-D distribution of the reservoir properties that control production rates and recoveries. A new concept/methodology that can provide a tool or framework for interdisciplinary reservoir characterization studies is needed to provide necessary and accurate communication across disciplines. The advances within individual disciplines make this cross-disciplinary concept and methodology possible and practical.

## 1.1 Purpose and Significance of This Research: A Methodology for Interdisciplinary Studies

This research is aimed at presenting a concept, the **Lithofacies Module,** which resides at the interfaces between geology, reservoir engineering, and geostatistics. It provides the

**Lithofacies Module Methodology** that can be used to structure the work flow across disciplines. Examples of the 3-D distribution of reservoir heterogeneity using this concept and methodology indicate the potential for improving hydrocarbon recovery.

The major points of this investigation are as follows:

- The proposed **Lithofacies Module** concept or methodology provides a tool and environment within and across disciplines for accurately characterizing and modeling clastic hydrocarbon reservoirs for fluid flow simulation studies.
- The **Lithofacies Module** concept embraces the needs and goals of multiple disciplines that are related to reservoir characterization, and facilitates communication between disciplines.
- The **Lithofacies Module Methodology** furnishes a hierarchy or framework for directing multi-disciplinary studies and data collection to build a computer based reservoir model that accurately represents the real subsurface hydrocarbon reservoir.
- The genetic relationship between Lithofacies Modules and depositional environments and between Lithofacies Modules and reservoir properties make the heterogeneity of reservoirs predictable and mappable.
- The suggested lithofacies modules subdivide highly heterogeneous clastic reservoirs into units with relatively low heterogeneity that are suitable for modeling reservoir heterogeneity and simulating fluid flow in clastic reservoirs.
- The present study suggests that this technique promises an accurate reservoir model containing detailed data on reservoir heterogeneity. Reservoir management using

simulation studies based on this more accurate model should be able to improve oil recovery depending on reservoir type and conditions by up to 10% or more.

- The case study described herein indicates that the Gypsy outcrop site, which exhibits the complex geology of fluvial reservoirs, provides a high resolution model for developing, testing, and evaluating existing and future geostatistical methods

### 1.2 Benefit: Improving Oil Recovery

The history of the oil industry has been one of boom and bust, indirectly reflecting the geological distribution of oil and the natural laws of its depletion. "After more than a hundred years of expansion, world oil production slowed down abruptly in the 1970s" (Figure 1-2) (Hartshorn, 1993). This rapid deceleration, concentrated into little more than five years, ended more than a century of growth, in the last quarter of which oil's expansion rate had been increasing exponentially. For the United States, between 1985 and 1991, crude oil production dropped over 17 percent and proved crude oil reserves fell by over 13 percent in the lower 48 states (DOE, 1993). Decreasing production and reserves have naturally led to reduced extraction industry revenues, lower employment, and reductions in related economic activity. Declining industry activity has also caused significant reductions in state and federal royalty, severance, taxes, and income tax revenues.

Based on the Department of US Energy, the lower 48 states onshore reserve additions attributable to new field discoveries have decreased from nine percent to just over one

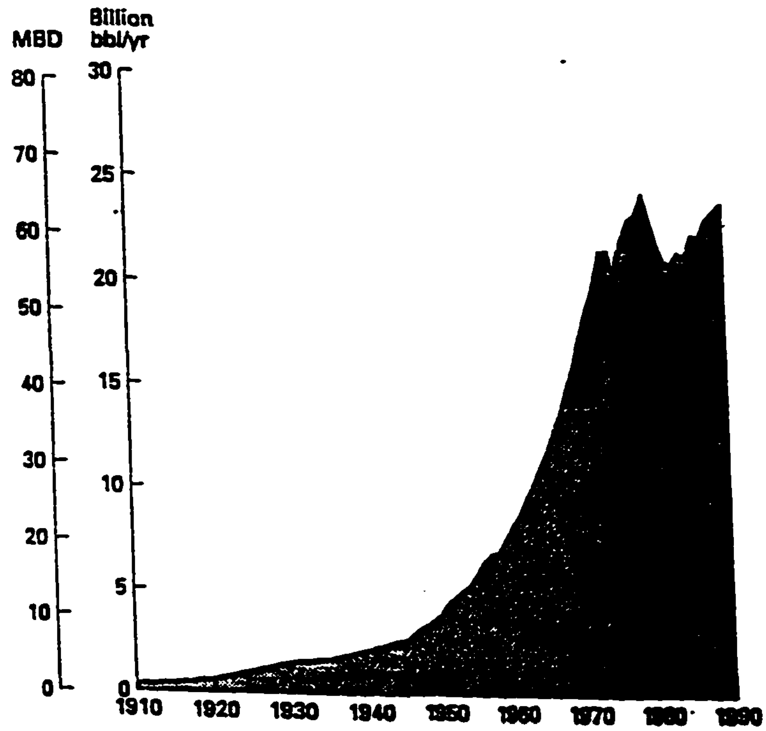



**Figure 1-2 World crude oil production, 1913 — 1990. (Hartsshorn, 1993).**

percent since 1982. The well abandonment rate increased by over 160 percent over the course of the past decade. "The prevention of premature well abandonment is crucial for maximum production of the oil resource because it ensures economic access to oil that may be producible using advanced recovery technologies" (DOE, 1993). Forgotson (1993) summarized "the opportunity and the challenges are indeed significant. On completion of conventional primary and secondary oil recovery, nearly two-thirds of all oil discovered in the lower 48 states will remain trapped in existing reservoirs. It is estimated that over 340 billion barrels of unrecovered oil resources will remain trapped in known reservoirs under current operating practices unless advanced recovery technologies can be developed to cost-effectively access and produce theses resources (Figure1-3). The target for reserve growth attributable to improved recovery from existing oil and gas fields is very large".

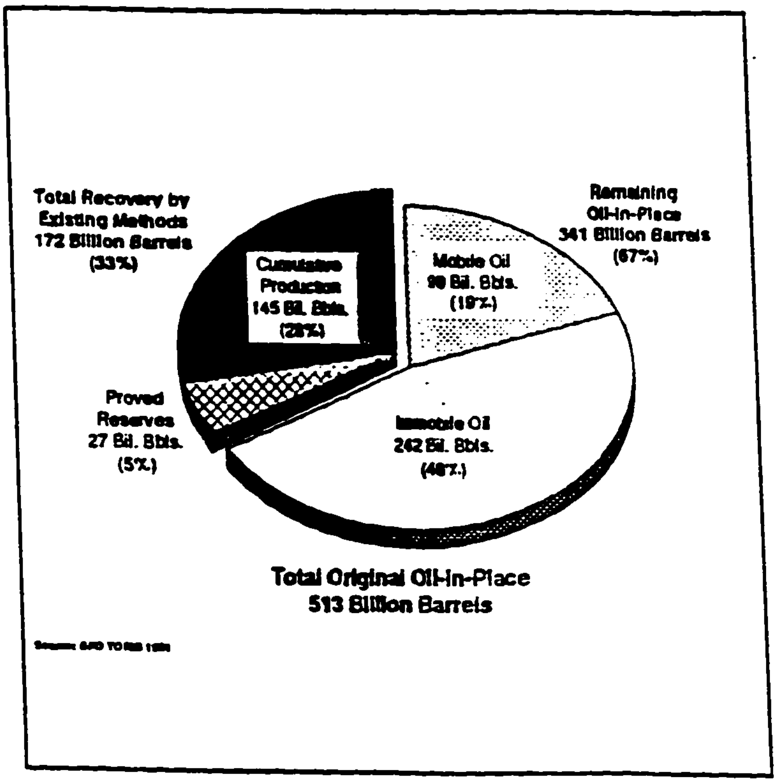



**Figure 1-3 U.S. domestic oil resource (DOE, 1993).**

The Interstate Oil and Gas Compact Commission (1993) pointed out "if improvements in geoscientific understanding and improved reservoir description and oil recovery processes can contact even ten percent of this remaining resource, U.S. proved reserves could more than double (Figure1-4)". The additional production may extend the life of the field and provide access to reservoirs suitable for the application of advanced recovery technologies that may be developed within the next decade. This extension of the productive life of existing fields is necessary if a significant part of the mobile and immobile oil that will not be recovered by current production operations is to be obtained.

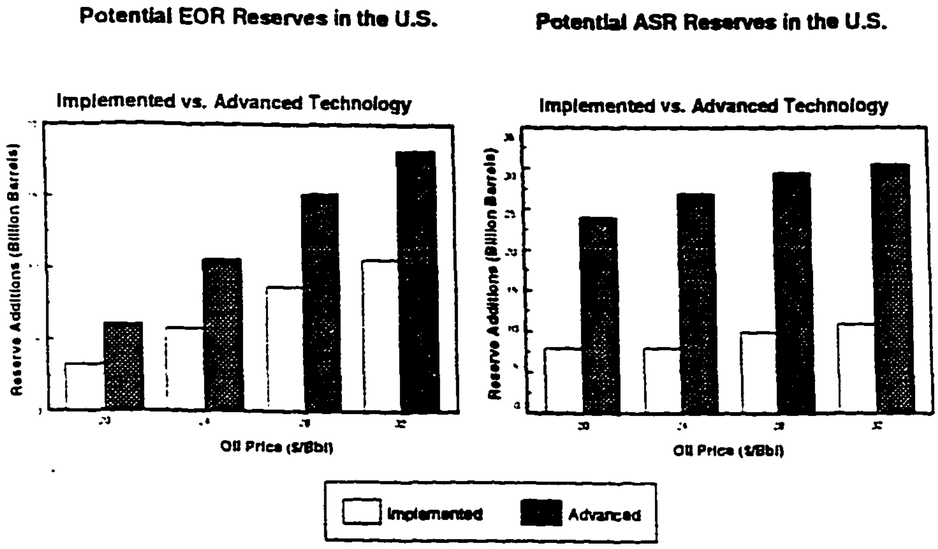



**Figure 1-4 Potential reserves additions from enhanced oil recovery and advanced secondary recovery (DOE, 1993).**

## 1.3 Overview and Discussion: Outlining the Target

Reservoir characterization has been defined by Forgotson (1993) as "the quantitative description of the physical and chemical properties of a porous medium and its contained fluids over the broad range of dimensions from pore throat through reservoir sizes". The purpose of such a description is to develop an accurate computer-based physical model for the subsurface reservoir. This quantitative reservoir model can be used with numerical reservoir simulators to predict oil and gas recoveries, under various production scenarios, to determine the most efficient and economic production strategy.

Reservoir characterization embraces both description and prediction, because the geological model must cover the entire reservoir, not just that which is penetrated by wells. North and Prosser (1993) pointed out that "even for densely drilled fields the amount of rock that can be described is less than 0.1% of the reservoir. In other words, the geological model is 99.9% prediction" (Table 1-1). This shows that what we choose to do with the geologic data is the most significant consideration, and highlights the importance of framework and methodologies for reservoir interpreting and modeling.

**Table 1-1 Area sampled by core and wireline logging for a range of well spacing typical of highly developed oil or gas fields (North, C.P., and Prosser, D.J., 1993).**

| Distance between wells m | No. wells per sq. km | Equivalent acre spacing | Area sampled by core % | Area sampled by logs % | Field example | Reference |
|---|---|---|---|---|---|---|
| 70 | 204 | 1.21 | 0.000662 | 0.0641 | El Dorado, Kansas, USA | Tillman & Jordan 1987 |
| 100 | 100 | 2.47 | 0.000324 | 0.0314 | South Belridge, Ca., USA | Miller *et al.* 1990 |
| 200 | 25 | 10 | 0.000081 | 0.0079 | Tia Juana, Venezuela | Kruit 1987 |
| 400 | 6 | 40 | 0.000020 | 0.0020 | Peco, Alberta, Canada | Gardiner *et al.* 1990 |
| | | | | | Little Creek, Miss., USA | Werren *et al.* 1990 |
| 500 | 4 | 62 | 0.000013 | 0.0013 | Brent, UKCS | Struijk & Green 1991 |
| | | | | | Prudhoe Bay, Alaska | Atkinson *et al.* 1990 |
| 1000 | 1 | 247 | 0.000003 | 0.0003 | Forties, UKCS | Wills 1991 |
| | | | | | Leman, UKCS | Hillier & Williams 1991 |
| 1500 | 0.44 | 556 | 0.000001 | 0.0001 | Auk, UKCS | Trewin & Bramwell 1991 |
| 2000 | 0.25 | 989 | 0.0000008 | 0.00008 | West Sole, UKCS | Winter & King 1991 |

### 1.3.1 Sequence stratigraphy: geological approach

Stratigraphy is fundamental to all geological studies. Stratigraphic methods, techniques, and principles are applicable to all earth material and are used in the study of the geometry, structure, sequence, and history of any rock body investigation (Schoch, 1989; Cotillon, 1992). Schoch (1989) pointed out that "within mainstream geology, fields as diverse as structural geology or paleoecology and paleoenvironmental interpretation, a sound stratigraphic framework is necessary".

Sequence stratigraphy has become a key topic during the past decade. It is the study of rock relationships within a chronostratigraphic framework of repetitive, genetically related strata bounded by erosional or non-depositional surfaces, or their correlative conformities. Fundamentals of sequence stratigraphy and key definitions in sequence stratigraphy are summarized by Van Wagoner et al. (1987; 1990). The terms used in sequence stratigraphy are fully defined and discussed by Bally (1987). The fundamental aspects of stratigraphy and sequences are further discussed in James and Leckie (1988), Fraser (1989), Schoch (1989), Posamentier et al. (1993), Hailwood and Kidd (1993), and Williams and Dobb (1993).

"Sequence stratigraphy focuses on the recognition of cycles in the rock succession and the recognition of the utility of establishing a time-stratigraphic framework" (Posamentier et al., 1993). Data needed by engineers for reservoir simulation are reservoir compartments or flow units that consider the reservoir heterogeneities that control fluid flow during production. The keys for engineering studies are the petrophysical properties that control flow behavior during oil and gas production. Thus, the difference between the focus of sequence stratigraphy and the concept of flow units makes the sequence stratigraphic framework for a reservoir not necessarily consistent with the framework of reservoir flow units.

### 1.3.2 Hydraulic flow units: engineering concerns

Fluid flow behavior within a reservoir unit during the process of hydrocarbon production is the most important concern of petroleum engineers. One of the key challenges of engineering methods for reservoir characterization is to predict the fluid flow behavior by characterizing reservoir heterogeneities. The flow unit is the most used concept in characterizing reservoir fluid flow. The term "flow unit" has different definitions depending on the application. The common criteria is that fluid flow behavior during production should be similar within the same flow unit and significantly different between different flow units. Ebanks, Jr., et al. (1992) gave a good brief summary including geological and petrophysical aspects of flow units for reservoir characterization. Gian (1994) provided a concise explanation of reservoir zonation based on flow units using a cluster analysis technique where the similarities or dissimilarities between samples is involved (Davis, 1973). Data used in this analysis can be obtained from core analysis, typically permeability and porosity, and those well logs that respond to lithology. However, the engineering concept of a flow unit may not be as meaningful to geologists. It would be difficult for geologists to use this concept to study depositional facies and environments to predict the reservoir and its properties.

### 1.3.3 Stochastic modeling: geostatistical method

The stochastic method has been one of the leading techniques applied to reservoir characterization in the past several years (Yarus & Chambers, 1994). The confidence that can be attributed to the results from stochastic modeling depends on the degree of integration of multiple disciplinary concepts, methods, and data to obtain the geological framework used for stochastical modeling.

Many factors essentially affect the results of stochastic modeling. Any change in the methods or parameters may result in a significant change in the predicted reservoir model. No systematic evaluation is available to determine how the methods and parameters used effect the results for different reservoirs and types of data sets. For example, sinuosity and depth/width ratio are some of the main features that are used to define the type of fluvial system, and have been used as two of the key features in fluvial reservoir prediction and modeling. Two possible problems are: (1) using a uniform sinuosity for predicting and modeling a reservoir is far from reality. (2) modeling of a reservoir should include not only the shape and distribution of the reservoir but also the features within the reservoir which control the fluid flow. Sand/shale ratio used in some stochastic modeling is typically used to randomly arrange sand and shale bodies within a defined space to match the known sand/shale ratio encountered in wells. The resulting reservoir model could be a very close substitute for the reservoir or it could be totally different.

A major improvement in the results of stochastic modeling can be obtained by subdividing the reservoir into subsets which have narrow and different ranges to reduce the errors in the applications of geostatistical techniques. Those subsets of data should be meaningful to both the geological and engineering aspects of the model.

### 1.4 Approaches: Problem Summary and Solution

Although robust frameworks or methodologies have been developed in each related discipline of reservoir characterization, no significant increase in hydrocarbon recovery factors has occurred. Haldorsen and Damsleth (1993) gave an example of a performance review of many water-flooded oil fields in the United Kingdom zone of the North Sea. "Those fields discovered, appraised, and evaluated in the 1970s and then produced through the 1970s and 1980s showed a large percentage of overruns on the capital costs of development. The average overrun was 95%, with a maximum of 974%! The first oil production reached market 1-3 years behind schedule. On average, only 65% of the planned oil plateau rate was achieved, and the timing of oil recovery delayed because water breakthrough times were much shorter than predicted. A similar analysis of the development history of other areas probably would yield comparable results". What is wrong with the planning and prediction? Not enough data? Poor data? Poor use of data?

#### 1.4.1 Problem: no solid ground for interdisciplinary communication and integration

All scientific research is conducted within a certain framework. Advances in an individual branch of petroleum reservoir characterization can not promise the same magnitude of progress in another field or improved communication between disciplines. A key problem is the lack of correspondingly significant improvements at the interfaces between the individual disciplines.

A common concept with similar terminology for geologists to describe the reservoir and for engineers to simulate the fluid flow does not exist. The communication across disciplines during the process of reservoir characterization is based on different concepts/frameworks and different scientific backgrounds. Thus losses of information during the communication between and transfer of knowledge across disciplines are inevitable.

Geologists describe and characterize a reservoir based on geological attributes that typically are not what engineers need for conducting fluid flow studies. On the other hand, engineers generally use a much simplified model to simulate the fluid flow within a reservoir using numerical or analytical methods. This simplified model may make a highly heterogeneous reservoir appear to be a uniform homogeneous reservoir.

An example is presented schematically in Figure 1-5 to show the contrast between geologists and reservoir engineers in terms of characterizing and modeling a reservoir. Usually geologists are concerned with cyclic phenomena related to different orders in the hierarchy of sequence boundaries, sedimentary structures, textures, and other features related to depositional environment and diagenesis. For example, three channel units could be subdivided by geologists within the reservoir section as shown on the left side of figure 1-5. However, the channel units are not the units controlling fluid flow. Engineers may overlook the geological data and focus on those reservoir properties and

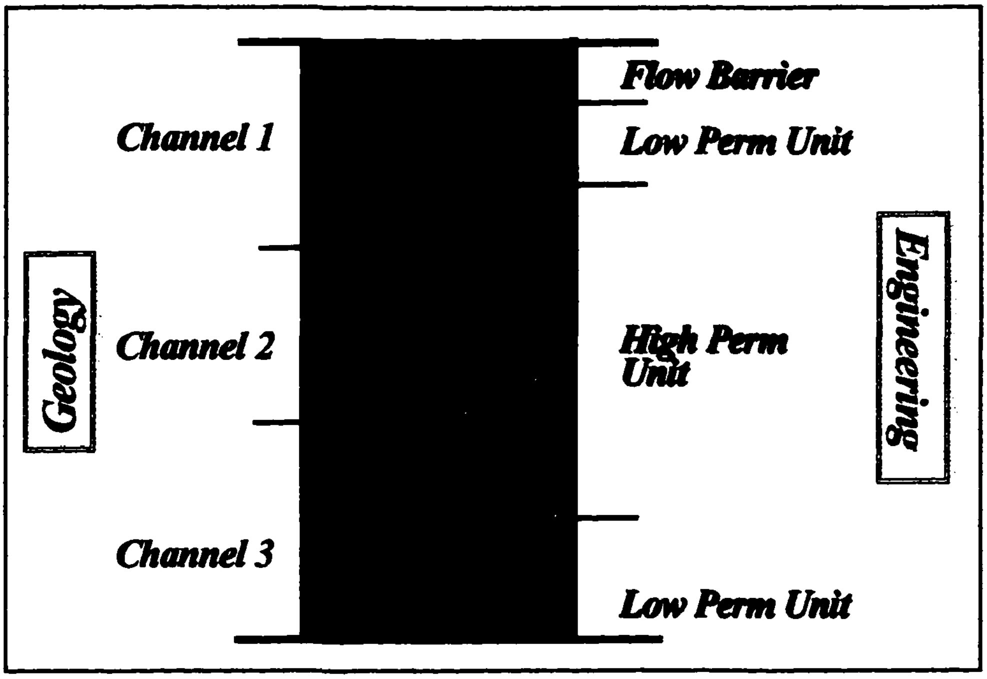



**Figure 1-5 Schematic display of the contrast between geological and engineering concepts of a reservoir section.**

factors controlling fluid flow. The reservoir units would be organized by engineers in terms of fluid flow potentials as shown on the right side of figure 1-5. The inconsistency of geological units and engineering units is derived from the inconsistency of concerns and focuses. The geologists focus on the channel sequences shown on figure 1-5. The colored units selected by engineers are based on flow properties. Geologists can not use the engineering concept and units to predict and characterize the reservoir. Data losses are obvious and inevitable across disciplines because geologists and engineers use different frameworks for their studies.

This study proposes a framework for reservoir characterization that can satisfy both the concerns of geologists and engineers. The proposed framework provides a tool and an environment for interdisciplinary integration of data that ensure no-gap cross-disciplinary communications.

### 1.4.2 Suggested approach: lithofacies module concept and methodology

**Lithofacies module** is a package of sediments restricted within a chronostratigraphic sequence and distinguished by a similar depositional environment and similar petrophysical properties that have similar effects on fluid flow within the unit. It is a basic geological unit that can be correlated and mapped within a reservoir. Fluid flow behavior during oil and gas production is similar within a given lithofacies module and is significantly different between different units. Lithofacies modules provide the basic framework for relating geological properties determined by depositional or diagenetic factors to flow properties within the reservoir, thus linking geological descriptions to flow behavior. This concept fills the gap at the interface of geology, geostatistics, and reservoir engineering.

The methodology uses lithofacies modules as the basis for data acquisition and the prediction of both geological and engineering properties. Instead of modeling geological units of a reservoir, the defined lithofacies modules of that reservoir should be modeled. Chapter 2 gives a detailed explanation of the proposed lithofacies module concept and methodology.

The genetic relationships between lithofacies and depositional environments, and between lithofacies and reservoir properties are briefly reviewed and discussed in chapter 3. As the basic descriptive rock units, lithofacies and their associations are the key parameters for the interpretation of depositional environments, and the key factors for controlling the distributions of reservoir properties. Links between depositional environments and reservoir properties through lithofacies module make the reservoir heterogeneities predictable and measurable.

Data acquisition and correlation under a lithofacies module framework are discussed in chapter 4. Four scales of reservoir modeling are proposed: regionally chronostratigraphic sequence scale, reservoir scale, lithofacies module scale, and sample scale.

Geostatistics can play a major role in the prediction of reservoir geometry and reservoir properties. The procedures for reservoir modeling and the applications of geostatistical methods are discussed in chapter 5. The impact of geostatistical methods on reservoir characterization results and the importance of geological input to the applications of geostatistical methods are illustrated. Lithofacies modules provide a useful reservoir framework for applying geostatistical methods. They subdivide the relatively high heterogeneous reservoir into relatively low heterogeneous or homogeneous parts. Instead of using the whole data set with a wide range of reservoir properties to predict variations within the reservoir, geostatisticians can focus on lithofacies modules within a reservoir which have a narrower variation of reservoir properties.

Chapter 6 shows the impacts of different reservoir characterization concepts, scales, and methodologies on hydrocarbon production. The results of simulations reveal significant differences depending on the concepts and methodologies used for characterizing and modeling a reservoir. Simulation studies using an accurate reservoir model can be used for obtaining optimum development programs and production strategies.

As an example, the Gypsy Outcrop data and reservoir model are used throughout this dissertation for illustrating the principle and application of the proposed lithofacies module concept and methodology. BP Exploration began gathering data from the Gypsy sandstone of Oklahoma as part of its Integrated Reservoir Description (IRD) program In 1988. The project has subsequently been donated to the University of Oklahoma. The primary Gypsy outcrop site is offered by the north face of a roadcut twenty-five miles from Tulsa of Oklahoma, along Highway 64. Detailed spatial distributions of the channel sandstone and their internal heterogeneities are shown along exposures of strike and dip oriented roadcuts and a grid of twenty-two cored boreholes within three hundred meters behind the primary strike oriented roadcut (Figure 1-6, Figure 1-7). Thousands of data have been obtained quantitatively and qualitatively from extensive sampling and mapping of the geological units of the formation. The purpose of the Gypsy project was to establish a field laboratory for testing and developing reservoir characterization tools and methodologies.

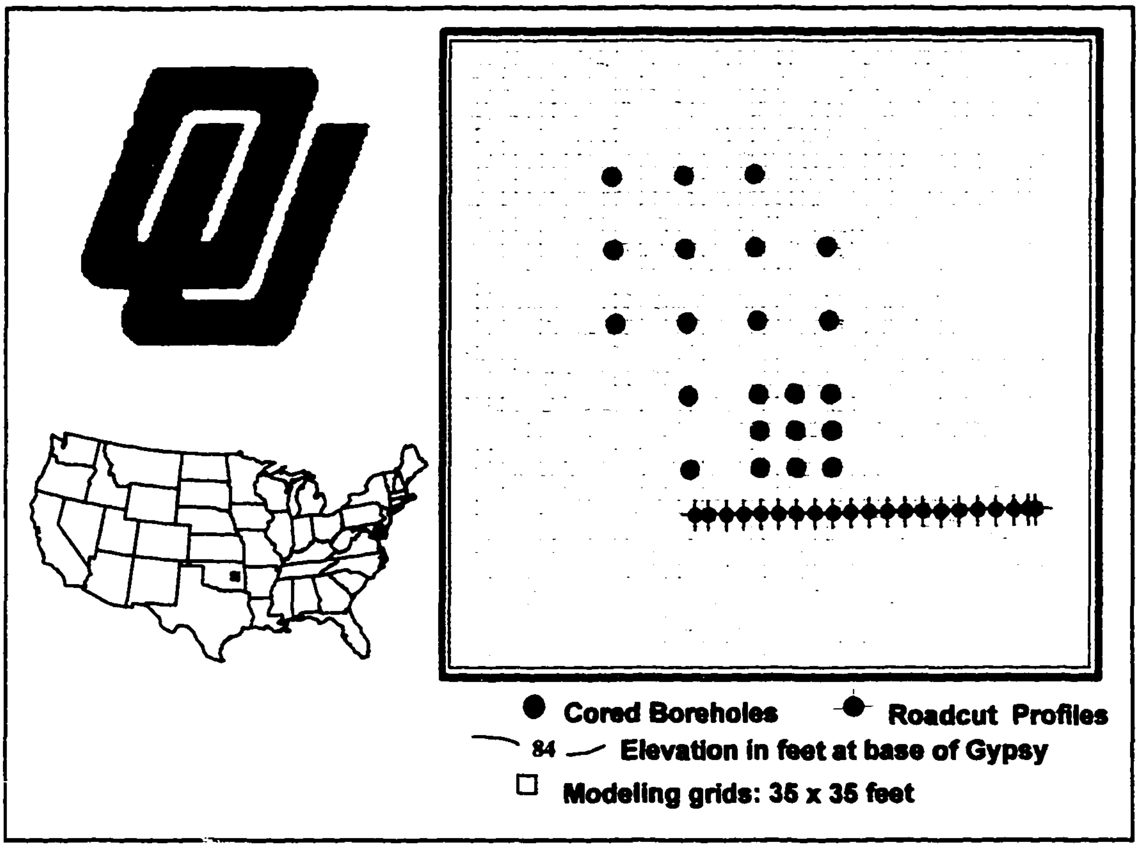



**Figure 1-6 Location Map of The Gypsy Outcrop Site, Northern Oklahoma.**

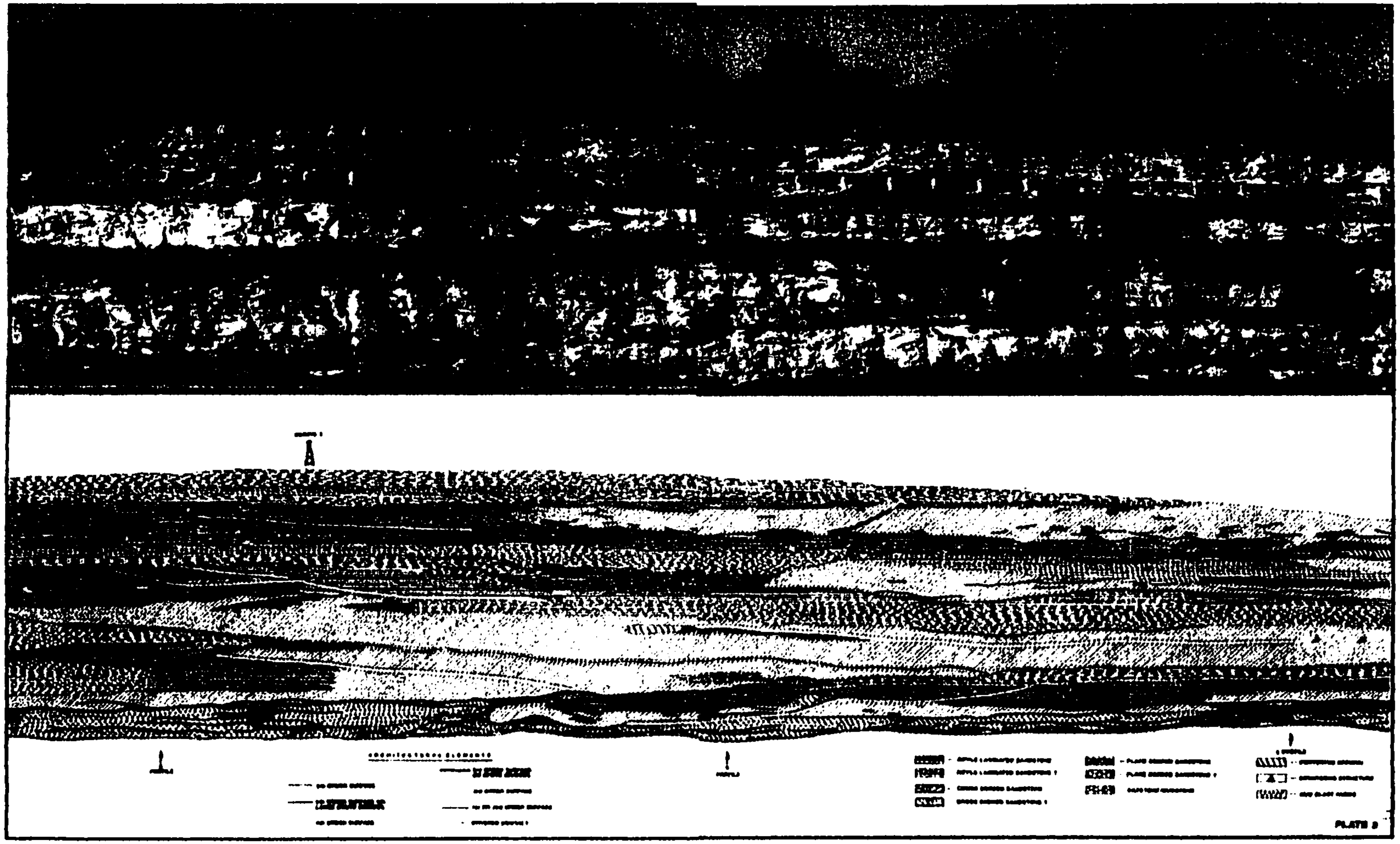


**Figure 1-7 Photography of part of the roadcut at the Gypsy outcrop site.**

# CHAPTER 2. CONCEPT AND METHODOLOGY

## 2.1 Definition

**Lithofacies Module** is a package of sediments restricted within a chronostratigraphic sequence and distinguished by a similar depositional environment and similar petrophysical properties that have similar effects on fluid flow within the unit. It is a basic geological unit that can be correlated and mapped within a reservoir. Fluid flow behavior during oil and gas production is similar within a given lithofacies module and significantly different between different modules. Lithofacies modules provide the basic framework for relating geological properties determined by depositional or diagenetic factors to flow properties within the reservoir, thus linking geological descriptions to flow behavior. The concept of the lithofacies module stresses both geological concerns and engineering emphasis.

A lithofacies is the rock unit within a sedimentary facies and is distinguished by physical characteristics such as color, lithology, texture, and sedimentary structures such as mudclast sandstone, cross-bedded sandstone, plane-bedded sandstone, and shale. A lithofacies module can have one or more lithofacies of same type or different types depending on their genetic relationships and reservoir properties.

## 2.2 Criteria

The major criteria for defining a lithofacies module are:

- A lithofacies module must be restricted within a stratigraphic sequence which can be correlated regionally or reservoir-wide.
- An individual lithofacies module could consist of several different types of lithological units with beds of varying thickness depending on data resolution and depositional environments.
- Different lithofacies modules within an individual stratigraphic sequence must be in the same relative vertical position to ensure their correlatibility.
- Each lithofacies module must have unique geological features (such as sedimentary structures, textures, fracture, or features on logs, etc.) to distinguish from others within an individual stratigraphic sequence, and to ensure its geological predictability.
- Each lithofacies module must have a thickness significant enough to be recognized by available data to ensure its recognizability and mappability.
- Lithofacies modules should subdivide wide ranges of permeability and porosity into ranges of permeability and porosity that are relatively narrow within the same lithofacies module and significantly different between different lithofacies modules.
- Reservoir properties controlling fluid flow are relatively homogeneous within a lithofacies module and heterogeneous between lithofacies modules.
- Special geological features which have significant impact on reservoir fluid flow, such as shale or fracture zones within a reservoir, should be described as separate units if they can be correlated geologically.

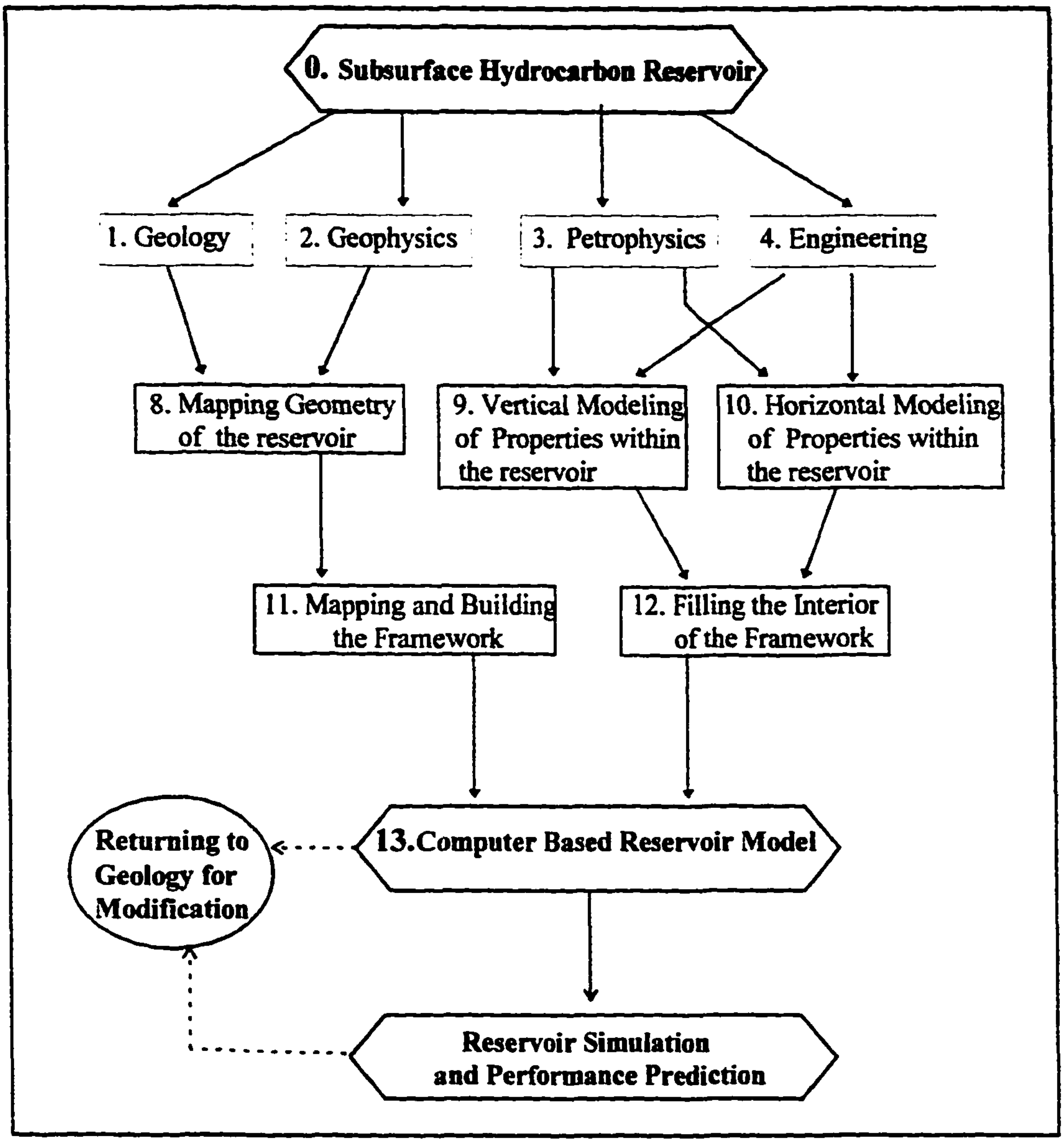
## 2.3 Typical Work Flow For Reservoir Characterization And Modeling

The profitability of an oil or gas field may depend on how meticulously one plans its development and a key element of that planning is a conceptual model of the hydrocarbon reservoir. Because this model ultimately serves as the basis for predicting the return on the huge financial commitment that developing the field entails, the accuracy of the model is critical. Work flow or hierarchy for characterizing and modeling hydrocarbon reservoirs defines what the evaluation team should do to accurately convey the properties of a subsurface reservoir into a computer-based numerical model for reservoir simulation and planning. However, different hierarchies derived from different concepts of reservoir characterization and modeling may result in totally different reservoir models and development plans for the same subsurface reservoir. A typical work flow for building a reservoir model is shown in figure 2-1.

Modern three-dimensional seismic data can sometimes assist in predicting reservoir quality and continuity in the inter-well areas. Careful processing of seismic data allows a conversion of the seismic reflection amplitudes to estimates of acoustic impedance which in turn can be related to rock properties. Wireline logs can be classified into three groups based on the information they provide (Grier & Marschall, 1993): (1) lithology indicators – gamma ray, SP, sonic, density, neutron logs, FMI, and FMS; (2) porosity logs – sonic, density, and neutron logs; and (3) fluid saturation logs – resistivity logs. Core analysis measurements performed on representative core samples can more accurately assess reservoir quality and heterogeneities, typically permeability, porosity, density, lithology, relative permeability, and so on. Capillary pressure can also be measured in the laboratory on core samples. In summary, four kinds of data are measured or interpreted from a subsurface reservoir: geological, geophysical, petrophysical, and engineering data. Geological and geophysical data and interpretations are mostly used for defining the distribution of a reservoir and provide the framework for modeling a reservoir. Petrophysical and engineering data usually are used for interpreting and modeling reservoir properties vertically and horizontally within the geological framework. Therefore, a reservoir model is the result of the geological framework from geologists and geophysicists filled with reservoir properties from petrophysists and reservoir engineers.

Although reservoir characterization is a comprehensive integration of all the data and knowledge from different disciplines, it is not simply compiling all the information and interpretations of the reservoir obtained from each discipline. It is an abstraction of the characteristic features of a reservoir that embrace both geological concerns and engineering interests. The geological framework must meet the need of reservoir engineers for simulating fluid flow within the reservoir to plan the development of the oil and gas field. The result should not be a purely geological model. Therefore, the typical modeling hierarchy showed in Figure 2-1 could potentially cause the following problems:

**Figure 2-1 A typical hierarchy for modeling hydrocarbon reservoirs based on current reservoir characterization concepts and methodology.**




- **The geological framework is not the one that engineers need for predicting and planning the reservoir development:** the geological model represents the stratigraphic framework which could be depositional cycles, stratigraphic units, or depositonal facies. Petrophysical and engineering data are only used for statistically filling the interior of this geological framework. The modeling framework is not the integration of the concerns of both geologists and engineers. Thus it would not suit the need to predict fluid flow during oil and gas production.

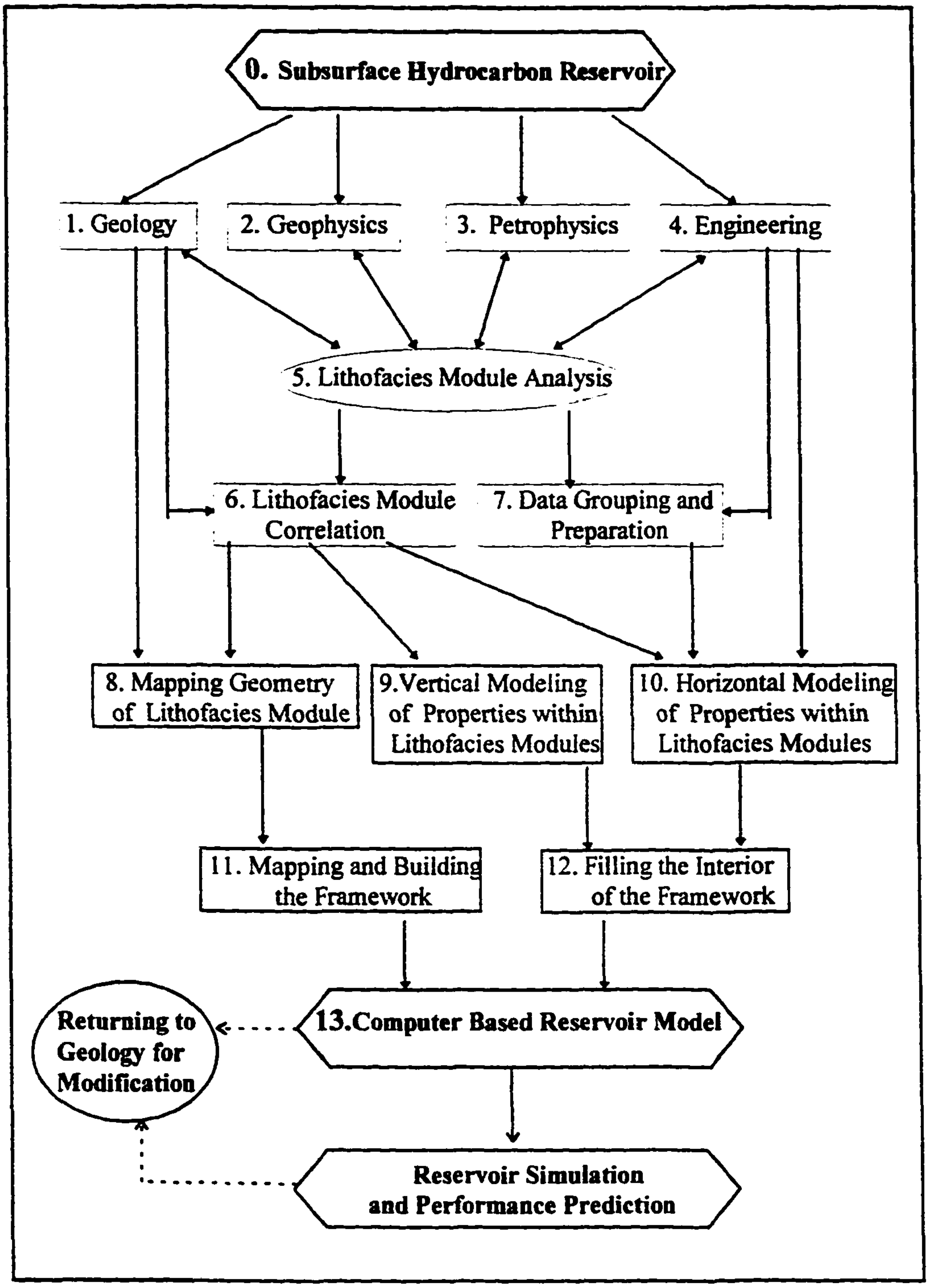
- **Predictions of reservoir properties for filling the geological framework could turn a highly heterogeneous reservoir into a low heterogeneous or nearly homogeneous model:** Each block of the model has to be assigned a set of data. Certain types of geostatistical techniques are used for averaging the available data to predict data values in the areas without control. However, improper data averaging and predicting within the geological framework may distortedly mark critical reservoir heterogeneities. For example, averaging the properties of shales and highly permeable sandstones within a geological framework could result in a uniform, low permeable reservoir within this framework.

## 2.4 Proposed Hierarchy For Reservoir Characterization And Modeling - Lithofacies Module Methodology

Figure 2-2 illustrates an improved hierarchy based on lithofacies modules. The key factor in this proposed work flow is the identification and evaluation of lithofacies modules.

Lithofacies modules should be defined after an initial investigation of geology, geophysics, engineering, and petrophysics. Lithofacies modules should be genetically related to each other and thus predictable. They must also adequately represent reservoir

**Figure 2-2 Improved hierarchy for characterizing and modeling hydrocarbon reservoir -- *Lithofacies Module Methodology***



heterogeneities that control fluid flow. Each lithofacies module must be recognizable using available data. Therefore lithofacies module based models serve to integrate data from multiple disciplines. The model produced from this integration will meet the needs of different disciplines for building a reservoir model that can be used for simulation studies that will accurately predict reservoir performance under various development strategies.

## 2.5 Discussion

Miall (1988a, b) proposed a sixfold hierarchy of bounding surfaces used to define the architecture of fluvial deposits as shown in figure 2-3. In this scheme, the highest order is sixth-order surface which defines groups of channels, or paleovalleys. Fifth-order surfaces are the erosional lower surfaces of channel sandbodies and meanderbelts. Fourth-order surfaces represent the upper bounding surface of macroforms which are complex, compound bars (e.g., point bars). Underlying bedding surfaces and first to third order bounding surfaces are truncated at a low angle or may be locally parallel to the upper bounding surface. Mud drapes underlying this surface are common. Third-order surfaces are cross-cutting erosion surfaces within macroforms. They are commonly draped by intraclast fine-grained sediments. Second-order surfaces are simple coset bounding surfaces and indicate changes in flow conditions, or a change in flow direction, but no significant time break. The first-order surfaces separate individual bedforms of the same type.

Figure 2-4 illustrates the bounding surfaces defined by the sixfold hierarchy of Miall (1988) in the typical Gypsy channel sequence. Twelve third-order surfaces and many second-order and first-order surfaces may be recognized in this vertical section. Those surfaces may represent changes of different hydrodynamic conditions of sedimentation. It is difficult to predict and correlate third-order bounding surfaces between wells even if core data are available. The recognition of first-order, second-order, and third-order bounding surfaces using logs seems impossible and most of these features have dimensions less than interwell spacing. Moreover, reservoir units separated by those surfaces generally do not honor differences in reservoir properties.

Instead focusing on bounding surfaces, the proposed hierarchy of lithofacies modules focuses on reservoir units that embrace both geological characteristics and reservoir properties. Four lithofacies modules can be recognized on the typical Gypsy channel sequence as shown in figure 2-5. From bottom to top, these lithofacies modules are: mudclast low permeability lithofacies module, cross-bedded and plane-bedded high permeability lithofacies module, ripple low permeability lithofacies module, and overbank flow barrier lithofacies module. Those units can be used for studies of not only depositional environments but also to construct geological models containing reservoir heterogeneities that control fluid flow. Detailed discussion of lithofacies modules will be included in chapter 3.

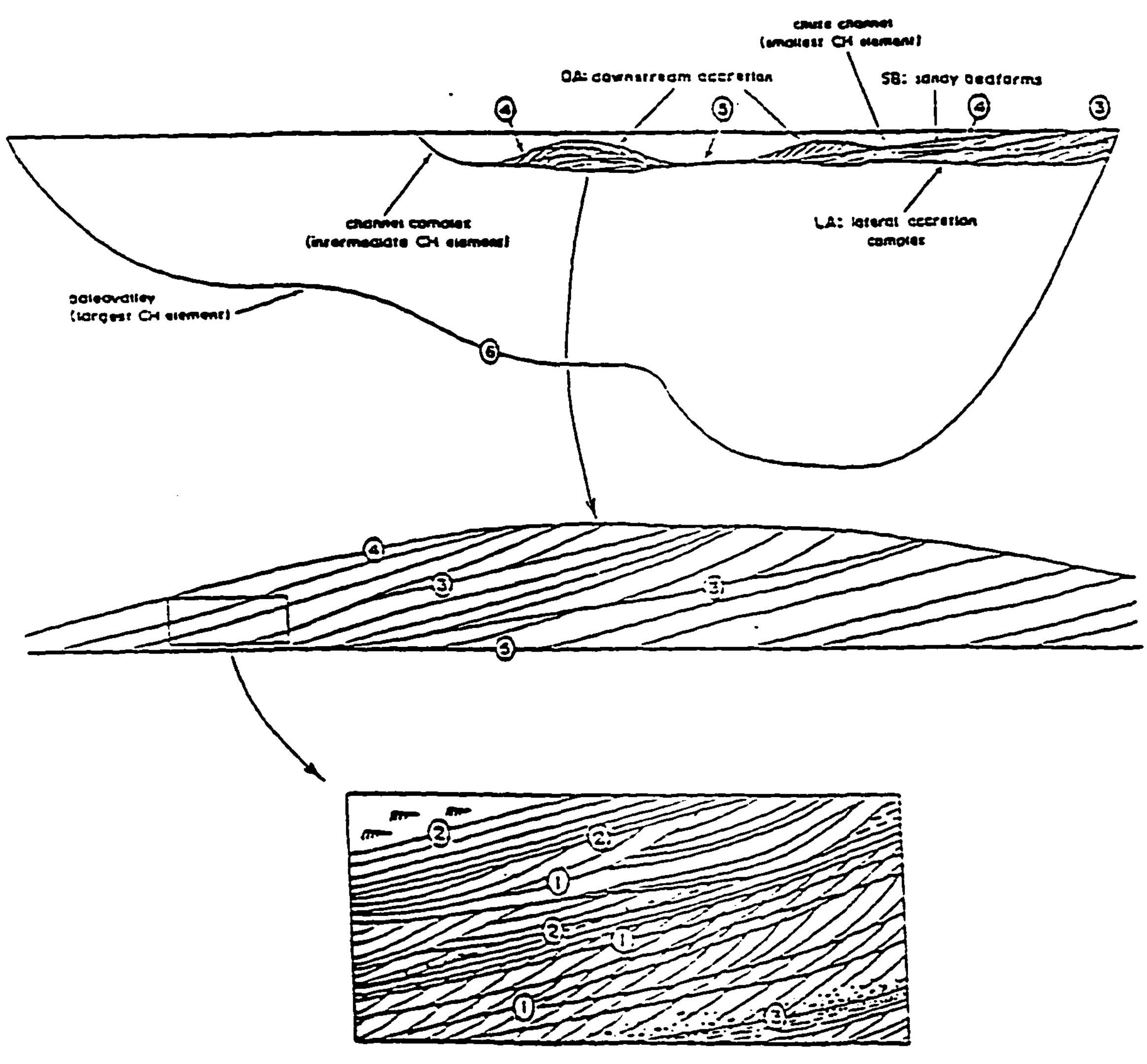



**Figure 2-3 Terminology of Miall (1988) for the hierarchy of bounding surfaces used to define the architecture of fluvial deposits (Doyle, 1989a).**

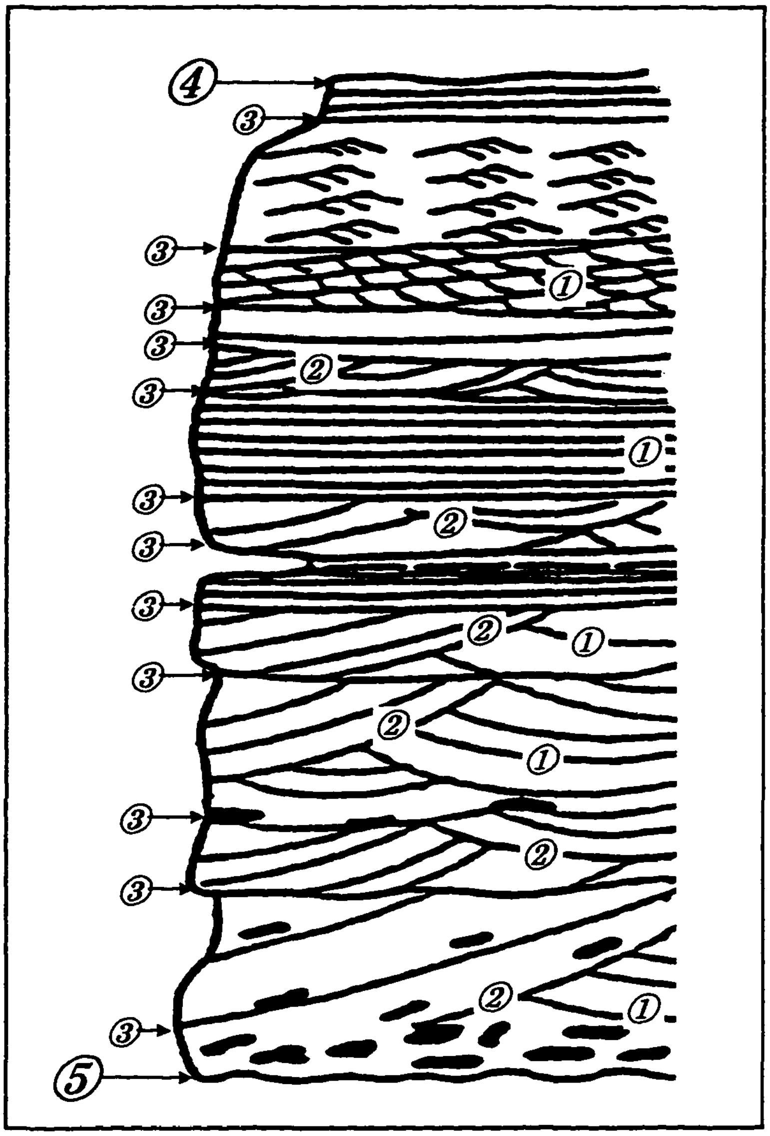
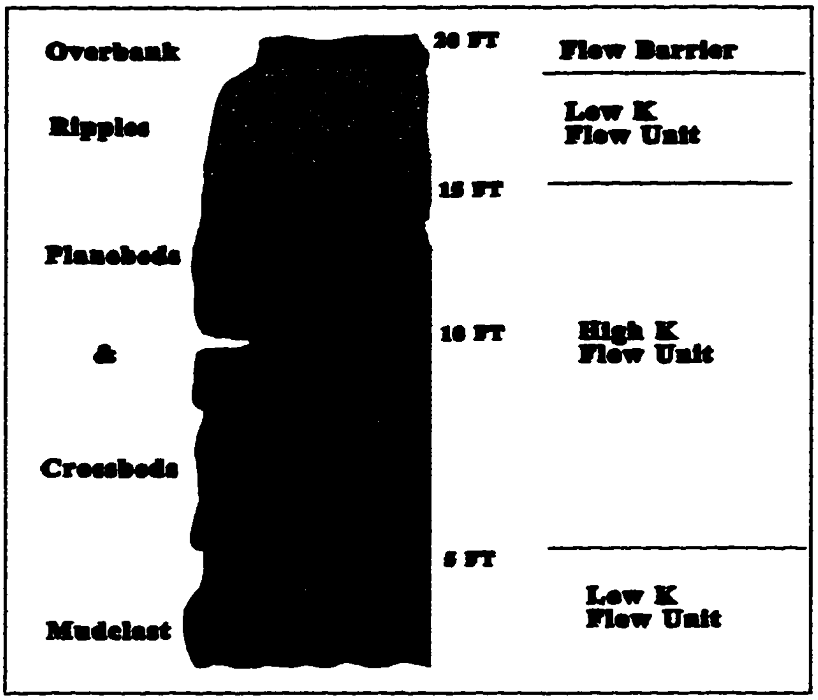



Figure 2-4 Bounding surfaces in the typical Gypsy channel sequence using the terminology of Miall (1988). Circled numbers indicate orders of bounding surfaces. See text and figure 2-3 for discussion.




***Lithofacies:* defined by certain types of constituents and sedimentary textures and structures, are genetically related to depositional environments that control properties in fluvial reservoirs.**

**Figure 2-5 Lithofacies modules within an individual Gypsy channel.**

# CHAPTER 3. GENETIC LINKS BETWEEN ROCK PROPERTIES AND DEPOSITIONAL ENVIRONMENTS

The genetic relationships between lithofacies and depositional environments, and between lithofacies and reservoir properties are briefly reviewed and discussed in this chapter. As the basic describable rock units, lithofacies and their associations are the key parameters for the interpretation of depositional environments, and the key factors for controlling the distributions of reservoir properties. Links between depositional environments and reservoir properties through lithofacies make the reservoir heterogeneities predictable and measurable.

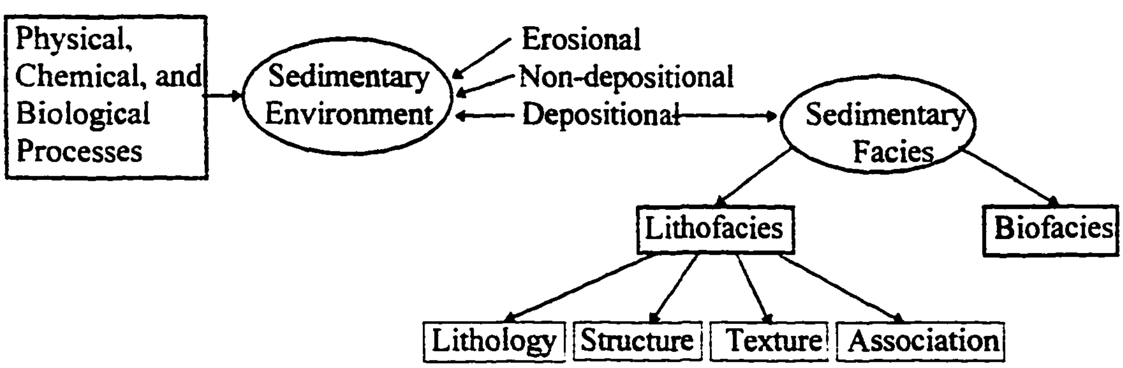
## 3.1 Concepts

A *depositional environment* is "a part of the earth's surface which is physically, chemically, and biologically distinct from adjacent terrains. Examples include deserts, river valleys, and deltas. The three defining parameters listed above include the fauna and flora of the environment, its geology, geomorphology, climate, weather, and, if subaqueous, the depth, temperature, salinity, and current system of the water. A sedimentary environment may be a site of erosion, non-deposition, or deposition. As a broad generalization, sub-aerial environments are typically erosional while sub-aqueous environments are mostly depositional areas. Some environments alternate through time between phases of erosional, equilibrium, and deposition. River valleys are a case in point" (Selley, 1978).

A *sedimentary facies* is a unit of sedimentary rock that, owing to deposition in a particular environment, has a characteristic set of properties which can be defined and distinguished from others by lithologic, structural, and organic characteristics detectable in the field. Examples include point bar, natural levee, crevasse-splay, and floodplain facies in a fluvial environment (Selley, 1978; Boggs, 1987).

*Lithofacies* are the rock units within a sedimentary facies and are distinguished by physical characteristics such as color, lithology, texture, and sedimentary structures such as mudclast sandstone, cross-bedded sandstone, plane-bedded sandstone, and shale. A *biofacies* is "defined on the basis of paleontological characteristics" (Boggs, 1987).

**Figure 3.1 The relationship between depositional environments, sedimentary facies, and lithofacies (modified from Selley, 1978).**




The point emphasized here is that depositional environments generate sedimentary facies, and sedimentary facies generate lithofacies and biofacies. The characteristic properties of lithofacies and biofacies are in turn a reflection of the sedimentary facies. The characteristic properties of the sedimentary facies are in turn a reflection of the conditions in the depositional environment. These concepts of depositional environments, sedimentary facies, lithofacies and biofacies are summarized in figure 3.1.

### 3.2 Interpretation of Depositional Environments

Lithofacies and lithofacies associations (groups of related lithofacies) are the basic units for the interpretation of depositional environments. One of the first steps in the facies analysis of a clastic reservoir is the description and interpretation of lithofacies which bear a direct relationship to the depositional processes that produced them.

However, "environmental interpretation is commonly hampered by the facts that very similar lithofacies can be produced in different environmental settings. It is often impossible to make a unique environmental interpretation on the basis of a single lithofacies. For example, cross-bedded sandstones can be formed by either wind or water transport. If deposited in water, they can originate on a beach, in a river or tidal channel, on a shallow marine shelf, or in any other environment where traction transport occurs. Environmental interpretation is improved if lithofacies associations and sequences rather than individual lithofacies are studied. Lithofacies associations can be thought of as groups of lithofacies that occur together and are genetically or environmentally linked. For example, if cross-bedded sandstones are closely associated with overlying or underlying peat, coal, or silty shale containing roots, leaves, and stems, we could make an interpretation of deposition in a river system with some confidence. Such an interpretation might be very difficult to make on the basis of the cross-bedded sandstones alone" (Boggs, 1987). Walker (1984) stresses that "the key to (environmental) interpretation is to analysis all of the facies communally, in context. The sequence in which they occur thus contributes as much information as the facies themselves."

**Table 3-1 Criteria for recognition of ancient sedimentary environments (Boggs, 1995).**

**Criteria based on primary depositional properties**

- Mainly physical properties
  - Geometry of facies units—useful only if very distinctive, e.g., ribbon shape of channels; lobate shape of deltaic deposits.
  - Gross lithology and mineralogy of strata—a very general environmental indicator: e.g., fossiliferous limestone suggests shallow-marine shelf settings; coal indicates swampy environments; the mineral glauconite suggests marine conditions.
  - Facies associations (stratigraphic successions)—e.g., fining-upward successions are characteristic of meandering-stream deposits; regressive shelf environments (shoreline advancing seaward with time) produce coarsening-upward successions.
  - Sedimentary structures
    - Nondirectional structures—not unique environmental indicators but suggest depositional process; e.g., ripples indicate current flow, graded bedding indicates settling of grains from suspension, mudcracks indicate subaerial exposure.
    - Directional structures (paleocurrent indicators)—paleocurrent patterns may have environmental significance; e.g., bimodal patterns suggest tidal influence; unimodal patterns of high variability suggest meandering-stream environments.
  - Sedimentary textures—grain-size data of limited usefulness; grain shape measured by Fourier analysis may be significant; grain orientation (e.g., imbrication) a useful paleocurrent indicator.
- Mainly chemical properties
  - Major-element composition—very limited usefulness.
  - Trace-element composition—some application in paleosalinity interpretation; e.g., boron more abundant in marine shales than in freshwater shales.
  - Isotope ratios—carbon and oxygen isotopes may be used to interpret marine vs. nonmarine conditions; oxygen isotopes a possible ocean paleotemperature indicator.
- Many biologic properties
  - Kinds of fossils and their ecologic characteristics—very useful indicators of salinity, temperature, depths, energy, and turbidity of ancient oceans; also an indicator of substrate type (rock, sand, mud).
  - Types of trace fossils—water depth indicators.

**Criteria based on derived sediment properties**

- Properties measured or interpreted from instrumental well logs
  - Properties such as rock resistivity, velocity of sound transmission, and natural radioactivity can be measured in well bores and used, for example, to interpret coarsening- and fining-upward successions in subsurface strata.
- Characteristics interpreted from seismic reflection records
  - Seismic reflection characteristics identified from seismic records indicate features such as inclined bedding, truncations, and pinch-outs that have environmental significance.

Table 3-1 is a list of the most important criteria for environmental recognition by Boggs (1995). No single parameter can generally provide definite environmental interpretation.

The interpretation of a depositional environment must use all available information. An environment can be definitely interpreted only when several independent criteria yield the same interpretation and on conflicts with any other information. Gross lithology, lithofacies association, sedimentary structures, and fossils are the most important criteria for environmental interpretation.

### 3.3 Effects of Diagenesis

As sedimentation continues in subsiding basins, older sediments are progressively buried by younger sediments and eventually converted into consolidated sedimentary rock. "The processes that bring about change in sediments during burial and lithification is called diagenesis" (Boggs, 1995). The physical processes of diagenesis leads to compaction and lithification of sedimentary rocks while the chemical processes bring about cementation and recrystallization. These processes affect the mineral composition, texture, structure and porosity of sedimentary rocks. In addition to the physical and chemical conditions of the subsurface environment and the tectonic settings that the sedimentary rocks have experienced, the original mineral compositions of the sediments have the critical influence on the nature of diagenetic changes in the rocks.

Textures are the principal physical changes that occur in sedimentary rocks during diagenesis including bioturbation, compaction, cementation, and solution. Bioturbation brings about changes in grain size and sorting owing to organisms mixing together sediments of different sizes from different layers. Compaction results in the grains being packed into a tighter fabric. Cementation plugs pore spaces with cements and adds overgrowths to siliciclastic grains and some fossil fragments that result in an increase in grain size and alternation of shape and an decrease in porosity. Solution may cause reduction in size of grains or complete destruction of the grains and increase of the rock porosity (Larsen et al., 1983; McDonald et al., 1984; Pettijohn et al., 1973; and Boggs, 1987).

### 3.4 Porosity and Permeability

The porosity of a rock is the ratio of its total pore space to its total volume. Conventionally porosity is expressed as a percentage ratio. Hence:

$$\text{Porosity} = \frac{\text{volume of total pore space}}{\text{volume of rock sample}} * 100$$

Most measured porosities in reservoir studies are effective porosity. Effective porosity is the amount of mutually interconnected pore spaces present in a rock and gives a rock the property of permeability.

Permeability is the rock property that allows a liquid or gas to flow through this porous medium. The permeability is controlled by many variables that include the effective porosity of the rock, the geometry of the pores, pore tortuosity, the size of the throats between pores, the capillary force between the rock and the invading fluid, fluid viscosity, and pressure gradient. Permeability is conventionally determined from Darcy's law using the equation:

$$Q = \frac{K \, A \, \Delta P}{\mu \, L}$$

Where Q is the rate of flow in $cm^3$/second, $A$ is the cross-sectional area in $cm^2$, $\Delta P$ is the pressure drop in atm, $\mu$ is the fluid viscosity in cP, L is the length in cm, and K is the permeability in darcy.

The primary porosity of a rock is a result of five variables: grain size, sorting, grain shape (sphericity), grain roundness (angularity) and packing. Considerable work has been done on the way that these five factors affect primary porosity. This work includes theoretical and mathematical studies, experimental analyses of artificially made spheres, unconsolidated modern sediments, and ancient rocks (Fraser, 1935; Krumbein and Monk, 1942; Rogers and Head, 1961; Beard and Weyl, 1973; and Pryor, 1973). Selley (1988) has concisely summarized the results of these works for the five parameters listed above.

Those five variables that dominate primary porosity are also the key parameters for defining a lithofacies. The rock composition and textures, at the same time, have a important influence on the diagenesis of the rock along with the physical and chemical environment of the subsurface and the tectonic setting. Thus under the same diagenetic environment, different lithofacies modules generally show different rock properties because of the differences of composition, sedimentary structure, and textures between lithofacies modules.

## 3.5 Bridging the Interpretation of Depositional Environments and the Prediction of Reservoir Property by Lithofacies Modules, an Example from the Gypsy Outcrop Sandstones

Lithofacies modules are the solid geo-units of the integration of sedimentary structure, texture, and lithology which control reservoir properties. Lithofacies and lithofacies associations are the basic units for interpretation and reconstruction of sedimentary environments. These two-fold characteristics link sedimentary environments to reservoir properties. The data from the Gypsy Outcrop Site show a close relationship between the lithofacies modules, which are restricted and can be predicted genetically, and the reservoir porosity and permeability.

### 3.5.1 Stratigraphy and depositional setting of the Gypsy fluvial sandstone

The Gypsy sandstone is an informal name for the lowermost interval of the upper Pennsylvanian Vamoosa Formation (Greig, 1959; Ford, 1978). An outcrop study by Ford (1978) indicated the Gypsy alluvial deposits vary from conglomeratic, near their source in the Ouachita Mountains, to medium and fine sandstone in the study area where the Gypsy sandstone is interpreted as a mixed load meanderbelt system (Doyle, 1989, 1995). Net sandstone mapping and paleocurrent data taken by Ford (1978) and Doyle et al (1989, 1995) indicate the Gypsy streams flowed into west to northwest direction.

Within the study area, Ford placed the lower contact of the Gypsy where massive channel sandstones incise shales of the Tallant Formation which in turn uncomformably overlies a sandstone of the Tallant Formation. "This Tallant sandstone interpreted as a lower to middle shoreface deposit displays hummocky cross-stratification and contains brachiopod fossils. In most of the boreholes at the Gypsy Outcrop site, Gypsy channel sandstones are separated from the marine Tallant sandstone by an interval of shales and shaley sandstones. These are interpreted to be comparable to the alluvial plain deposits at the top of the Tallant Formation on outcrop. Locally, however, the Gypsy channel sandstones incise into or completely through the Tallant marine sandstone. The upper contact of the Tallant sandstone displays solution features and probable root traces. Overlying shales in the Tallant have abundant plant fossils and root traces and are interpreted as alluvial plain deposits. Although the upper contact of the Gypsy is not seen in the outcrops studied, in the subsurface it is conformably overlain by marine shales and sandstones of the Vamoosa Formation" (Doyle and Sweet, 1995). For the rest of this dissertation, the term, Gypsy sandstone, will be used to describe the strata between the top of alluvial plain deposits (or bottom of Gypsy channel) at the top of the Tallant Formation on outcrop and the flooding surface at the top of the Gypsy.

Six channels and one crevasse-splay have been recognized within the Gypsy sandstone interval. The floodplain deposits which surround and partially separate Gypsy channel sandbodies are largely impermeable siltstone and silty mudstone. However, they contain a significant proportion of low permeability sandstone which may serve to further interconnect the higher permeability channel sandbodies (Doyle et al., 1989 a,b, 1992, 1995; Fitchen, 1989; Lorenz, 1989; Thomas, 1990 a, b; and Fontao, 1991). Within channel sandbodies, lithofacies comprise the major heterogeneities (O'Meara & Jiang, 1996).

### 3.5.2 Lithofacies modules defined in the Gypsy fluvial sandstone

Detailed description of lithofacies and correlation of channels were based on the direct observation of outcrop sections and cores from the 22 cored boreholes behind the outcrop (Doyle et al, 1992). Figure 2-5 shows a typical stratigraphic section within an individual Gypsy channel. Four types of dominant lithofacies modules have been defined and labeled at the left side of the figure and are illustrated as different patterns of curves in the stratigraphic section. From bottom to top, these lithofacies modules are: mudclast dominated sandstone lithofacies module, cross-bedded and plane-bedded dominated sandstone lithofacies module, ripple dominated sandstone lithofacies module, and overbank siltstone and shale lithofacies module.

The vertical relative position of the lithofacies modules serves as a stratigraphic table for correlating and mapping details within a reservoir and provides the foundation for building a reservoir model. For example, mudclast-dominated modules must be at the bottom of channels. Within an individual channel, a mudclast-dominated module can not occur above a cross-bedded dominated lithofacies module. Where a mudclast dominated lithofacies module occurs overlying a cross-bedded dominated lithofacies module, it marks the base of a separated channel. Similarly, within the same channel the ripple-bedded module must overlie the cross-bedded lithofacies module. Cross-bedded and plane-bedded lithofacies may occur interchangeably within a channel and thus are defined as the same lithofacies module. In addition, the reservoir properties of cross-bedded and plane-bedded lithofacies show similar distributions.

**Mudclast lithofacies module:** This unit occurs at the bottom of a fully developed channel sequence and exhibits cross bedded structures. Its major distinguishing characteristic is the presence of cobble to medium sand-size intraclasts of red, green, and/or gray mudstone ranging in abundance from negligible to close to 100%. Mud clasts usually are alligned parallel to bedding and occur in discrete horizons. Calcite, limonite, and dolomite cements are the main diagenetic minerals with the greatest effect on porosity (Thomas, 1990a). These mudstone fragments were probably eroded from solid or semi-solid river banks. The mudclast lithofacies module is the most internally heterogeneous strata found within the channel sequence. The mudstones are encased in a sandstone framework. The sandstones are dominated by fine-grained quartz, feldspar, and very fine to medium grains rock fragments.

Within an individual channel sequence, the thickness of this mudclast unit is generally less than 2 meters. The intra-mudclasts decrease in size and abundance away from the base of the channel sandstone. The mudclast lithofacies module gradually changes upwards into the cross-bedded and plane-bedded lithofacies module. Well developed mudclast units occurs within channel 1 and 2. This lithofacies module is only locally distributed within the upper channels. This lithofacies module is interpreted as the channel lag deposit along the main axis of Gypsy channels.

**Cross-bedded and plane-bedded lithofacies module:** This unit was deposited under hydrodynamic conditions of relatively high energy in channel or point bar environments. The sand is largely fine-grained, with some very fine and medium grained. The cross-bedded lithofacies is dominated by low angle cross-bedded sandstone locally containing shaly or silty laminations. Quartz is the dominant detrial mineral, calcite cement and in situ quartz overgrowths are the major authigenic constituents. The planar-bedded lithofacies is composed of horizontal to sub-horizontal laminations of clay-rich and clay-poor sandstones with very little carbonate cement. Due to the relative lack of limonite and carbonate cement, quartz overgrowths are the dominant diagenetic constituents. Changes in the shale and cement content within this lithofacies module increase its internal heterogeneity. This facies is well developed in channels 2 through 5 and occurs sporadically in other channels. The thickness of this unit is usually 2 to 4 meters within an individual channel sequence.

**Ripple lithofacies module:** Climbing-ripple laminations are the main characteristics of this facies that is composed of thin sandstones interbedded with siltstones and shales. Isolated carbonate cement with minor amounts of limonite occasionally occur within this unit. This lithofacies could be deposited in several ways: as crevasse-splay, channel fill, natural levee, or as the upper part of a channel point bar. The sand within this unit is mostly very fine-grained, with some fine-grained. Significant amounts of mud and silt deposited as thin layers make this unit second only to mudclasts in its level of internal heterogeneity. The ripple unit is locally developed within Gypsy channel sequences and is typically one to three meters in thickness.

**Overbank lithofacies module:** This unit mainly consists of siltstone and mudstone deposited in a fluvial flood plain environment. It is preserved as the top of an individual channel sequence or the boundary between two channels. The development of this unit is very limited at the top of channels 1, 2, 3, and 5 attaining a thickness of 0.3 to 0.6 meters. It is well developed at the top of channels 4 and 6, with thicknesses of 1.3 to 3.3 meters.

### 3.5.3 Characteristics of reservoir properties by lithofacies modules

The Gypsy sandstones characteristically exhibit a combination of primary intergranular and dissolution/weathering-related porosity. Dissolution porosity is caused by partial to complete dissolution of feldspars and rock fragments. Samples taken from a single facies typically have similar porosity values but the permeability values may differ by an order of magnitude. Permeability variations are usually attributable to the extent of clay laminations present and, to a lesser extent, the amount of quartz overgrowths and perhaps to heterogeneities out of the plane of the thin section (Thomas, 1990a). Samples with numerous, closely spaced laminations and fine-scale bedding features (i.e. very fine-scale ripple-laminations) usually displayed lower permeability.

The relationship between lithofacies modules and reservoir permeability is also shown on Figure 2-5. The cross-bedded and plane-bedded lithofacies modules have the highest porosity and permeability. The ripple lithofacies module has good reservoir properties second to the cross-bedded and plane-bedded lithofacies modules. The mudclast lithofacies module has relatively poor and highly variable reservoir properties, and the overbank lithofacies module is mainly impermeable.

If only permeability and porosity are considered as the main controlling factors for fluid flow within a reservoir, the flow paths or flow behavior within different lithofacies modules would show significant differences between each other. The cross-bedded and plane-bedded unit is definitely the best path with least resistance for fluid flowing through. The ripple unit has good properties for fluid flow but contains silt/mud drapes that increase the resistance to fluid flow and markedly decrease the vertical permeability. Mudclast unit should have the most complicated flow path because of its highly irregular internal heterogeneity. The overbank unit mainly act as a flow barrier between two flow units locally or reservoir-wide depending on its distribution.

Figure 3-2 illustrates the distributions of permeability and porosity vs. lithofacies modules. These data are based on core analysis of samples obtained from the 22 cored boreholes in the Gypsy outcrop site. It shows the strong relationships between lithofacies modules and permeability and porosity distributions. Table 3-2 gives details of the statistical characteristics of permeability and porosity distributions within each lithofacies module and reveals a significant differences of reservoir properties between lithofacies modules. The cross-bedded and plane-bedded lithofacies module exhibits the best reservoir quality with mean permeability of 864 md and mean porosity of 24.2%. The overbank lithofacies module is likely to act as a major flow barrier, although it does have a non-zero, measured mean permeability of 0.635 md and mean porosity of 11.5%. Mudclast and ripple lithofacies modules contain both reservoir quality rock and flow barriers. The mudclast unit has a mean permeability of 73.1 md and a mean porosity of 15.0%. The ripple unit has a mean permeability of 165 md and a mean porosity of 20.0%.

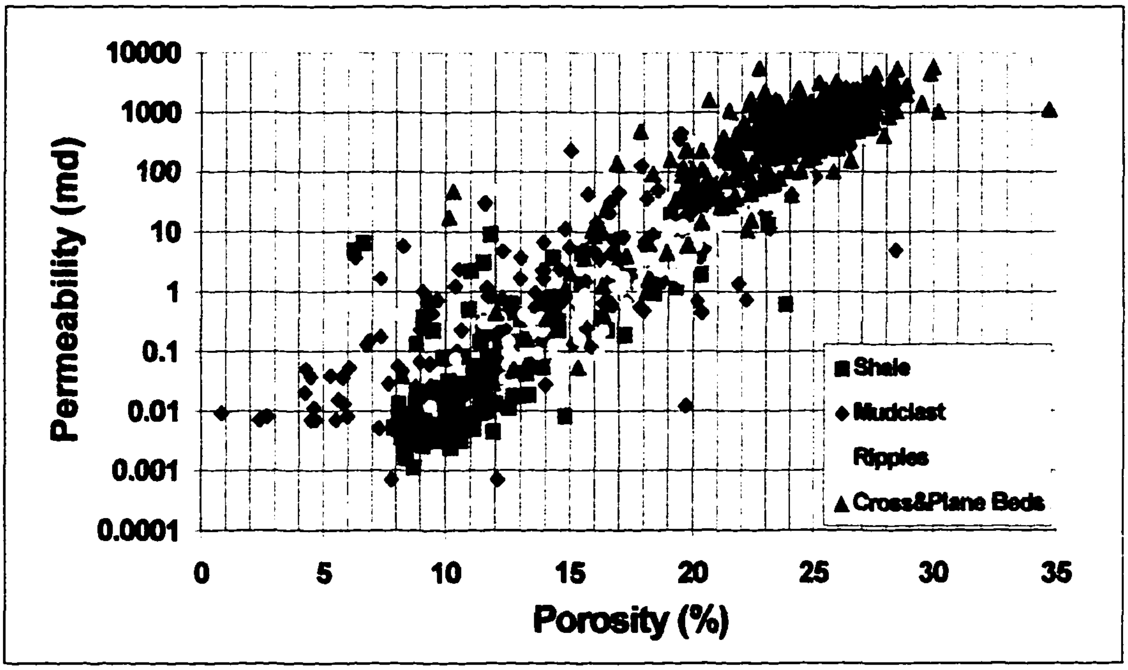



**Figure 3-2 Permeability vs. Porosity by Lithofacies modules from the Boreholes at the Gypsy Outcrop Site.**

The internal variations of reservoir properties or reservoir heterogeneities within a lithofacies module can be illustrated by the differences between lower quartile (25%) and upper quartile (75%) values as shown in Figure 3-3. It is obvious that the above four lithofacies modules subdivide a highly heterogeneous reservoir with a wide variation of properties into parts each having relative low heterogeneity and a much narrower variation of reservoir properties. The cross-bedded and plane-bedded lithofacies module has a lower quartile porosity of 26.1% and permeability of 1220 md, and an upper quartile porosity of 23.1% and permeability of 323 md. The ripple lithofacies module has a lower quartile porosity of 23.0% and permeability of 144 md, and upper quartile porosity of 17.3% and permeability of 2.7 md. The mudclast lithofacies module has a lower quartile porosity of 19.7% and permeability of 20.6 md, and upper quartile porosity of 10.5% and permeability of 0.147 md.

**Table 3-2 Characteristics of Porosity and Permeability by Lithofacies Modules at the Gypsy Outcrop Site.**

| Properties | Lithofacies Unit | Overbank | Mudclast | Ripple | Cross&Plane Beds |
|---|---|---|---|---|---|
| Porosity (%) | Mean | 11.516 | 14.987 | 19.980 | 24.234 |
| | Median | 11.100 | 15.346 | 20.700 | 24.946 |
| | Quartile 1(25%>) | 12.585 | 19.704 | 23.015 | 26.127 |
| | Quartile 3(75%>) | 9.605 | 10.466 | 17.262 | 23.102 |
| Permeability (md) | Mean | 0.635 | 73.080 | 164.804 | 863.695 |
| | Median | 0.022 | 1.429 | 34.326 | 668.166 |
| | Quartile 1(25%) | 0.200 | 20.539 | 144.091 | 1215.371 |
| | Quartile 3(75%) | 0.0075 | 0.147 | 2.695 | 322.770 |

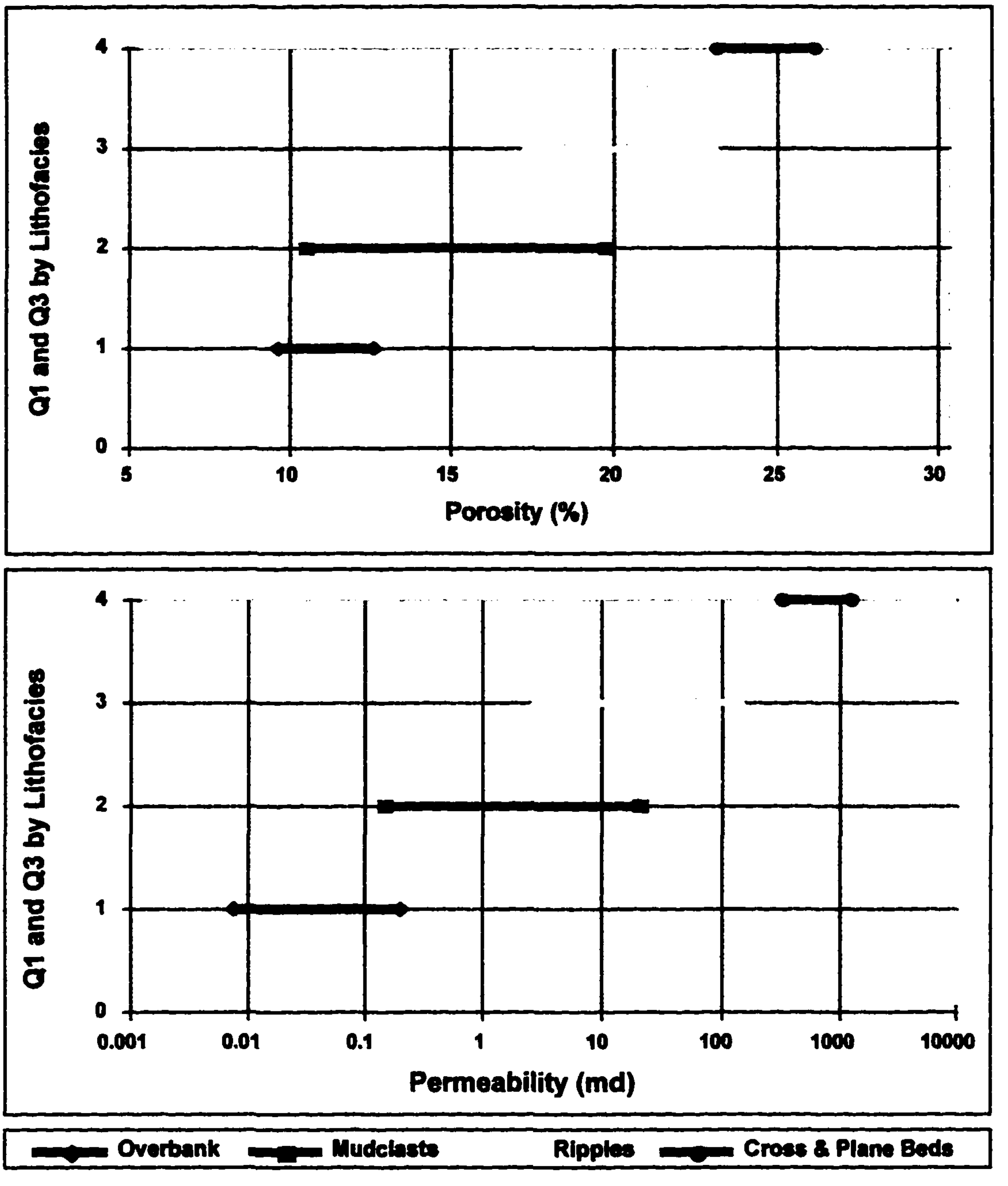



**Figure 3-3 Interquartile ranges of permeability and porosity by lithofacies modules.**

# CHAPTER 4. CHARACTERIZING A RESERVOIR AND OUTLINING ITS FRAMWORK

As soon as a reservoir has been discovered, its depositional nature has to be inferred from the geological knowledge about the region and the available geological data, which are acquired from cores and well logs. One of the first steps in characterizing a reservoir is the interpretation of lithofacies from available core. However, because usually only a few wells are cored but nearly every well is logged, the core data mostly serve to calibrate the logs. Once the lithofacies in all wells have been identified, their vertical and horizontal associations then are delineated according to a model of the depositional setting.

Stratigraphic correlation is the basic foundation for defining a reservoir, data acquisition, and outlining the reservoir modeling framework. Once the stratigraphic sequences are identified, lithofacies modules within each sequence have to be defined based on both geological features and reservoir properties, at a scale that shows the reservoir heterogeneity based upon available data.

A modeling framework reflects how geoscientists interpret the reservoir . It is the outline of the reservoir's characteristics and defines how reservoir heterogeneity be stressed. Different frameworks or outlines of a reservoir may be derived depending on modeling purposes, modeling scales, resolutions of available data, and geological interpretation.

## 4.1 Data Acquisition

### 4.1.1 Core values

Of the billions of tons of rock that may constitute a large reservoir, perhaps no more than several hundred kilograms will ever actually be seen by petroleum geologists. The rock samples are extracted from the reservoir in the form of cylindrical cores. As soon as it is retrieved, the core may be examined at the wellsite. A visual inspection is often enough to reveal fractures and faults as well as the bedding surfaces that separate different layers of rock. Most probing of the core material, however, is done in a laboratory. There, a core is typically sawed into slabs from which small plugs are bored. Selection of the samples should be carefully planed before plugging according to a clear picture of the different lithofacies and reservoir properties that will be measured. The plugs are flushed with various solvents not only to clean them but also to determine their oil and water content. A clean plug's permeability and porosity is measured by recording the volumes and pressures of various fluids pumped through it. Slices of core samples are also ground into translucent, paper-thin wafers that can be examined under an optical microscope. Alternatively, the slices are impregnated with epoxy and cut into blocks as that a polished surface of a block can be examined under a scanning electron microscope to reveal highly magnified images of grain surfaces and pore structure. Both the optical and the electron microscopy reveal the size and shape of rock grains as well as their mineral composition. That information, in turn, determines the sample's lithology, or physical characteristics.

Also, the direction and position of the thin sections should be received special attention towards a clear intention.

Such core data enable the geologist to describe the sedimentary sequence in terms of lithological characteristics and rock properties. Because the data may include fossil content and internal sedimentary structures, they also provide important clues as to the rock's age and depositional environment, but the data's greatest value lies in their use for calibrating petrophysical logs.

#### 4.1.2 Log properties

Petrophysical logs are measurements of various electrical, nuclear, and acoustical properties recorded as a function of depth along boreholes. Unlike cores, logs are routinely taken over nearly the entire lengths of exploration and appraisal wells. They are the primary source of data for production geologists. The data from logs, however, typically have a vertical resolution an order of magnitude or two less than that obtained from core analysis. And although both reveal the sequence, thickness and orientation of rock layers, core data and log data generally are not directly comparable. Core analyses yield definitive assessments of lithology and provide accurate values of the layers' fluid content, porosity and permeability. Well logs, in contrast, provide values of the rock layers resistivity, their rate of natural gamma radiation, the speed of sound through them, and their capacity to scatter or capture neutrons and gamma rays. The petrophysical data therefore have to be processed and in certain cases combined before they can yield quantitative answers to questions about a rock layer's lithology, fluid content, and porosity.

The processed petrophysical data are compared with core data to determine the signature of a log or a composite of several logs over a certain depth that represents each lithofacies module. Logs also have to be calibrated against one another to provide consistent data available for comparison of quantitative results.

## 4.2 Stratigraphic Correlation

### 4.2.1 Definition of correlation

Correlation is a fundamental part of stratigraphy that demonstrates the equivalency of stratigraphic units. The concept of correlation goes back to the very roots of stratigraphy. Two kinds of correlation are used for reservoir characterization and modeling: (1) chronocorrelation, which expresses the correspondence in age and in chronostratigraphic position; and (2) lithocorrelation, which links units of similar lithology and stratigraphic position within a chronostratigraphic framework.

Even though the characterization of reservoir heterogeneity is based on lithology, it is important to clarify the relationship between chronocorrealtion and lithocorrelation. "Chronocorrelation can be established by any method that allows matching of strata by age equivalence. Correlation of units defined by lithology may also yield chronostratigraphic correlation on a local scale, but when traced regionally many lithostratigraphic units transgress time boundaries. Perhaps the most famous North American example of a time-transgressive formation is the Cambrian Tapeats Sandstone in the Grand Canyon region. This sandstone is apparently all Early Cambrian in age at the west end of the canyon and all Middle Cambrian in age at the east end. Thus, the Tapeats sandstone, which can be traced continuously through the canyon, correlates from one end of the canyon to the other as a lithostratigraphic unit but not as a chronostratigraphic unit" (Boggs, 1987). The important point stressed here is that the boundaries defined by criteria used to establish time correlation of stratigraphic units need not be the same as those defined by criteria used to establish lithologic correlation. Because of this fact, different methods of correlation may yield different results when applied to the same stratigraphic sequence.

### 4.2.2 Lithofacies module correlation

Lithofacies module correlation is the correlation of lithostratigraphic units restricted within a chronostratigraphic sequences of genetically related depositional units. A chronostratigraphic sequence is a rock unit defined by chronostratigraphic boundaries which can be correlated regionally or over the entire extent of the reservoir using conventional data such as seismic data or well logs. The concepts and techniques of sequence stratigraphy and the architectural elements within a sequence provide tools for the recognition of chronostratigraphic boundaries and sequences (Galloway,1989; Miall, 1985; Posamentier et al., 1993; Vail et al., 1977; 1987; and Wagoner et al., 1987; 1990).

Correlation of lithofacies modules involves not only lithologic similarities but also the succession of lithofacies modules within a chronostratigraphic sequence. Lithological similarity can be established on the basis of a variety of rock properties including gross lithology, color, distinctive mineral assemblages, primary sedimentary structures such as bedding and cross-lamination, log properties and shapes, and even thickness and weathering characteristics. The greater the number of properties that can be used to establish a match between strata the stronger the likelihood of a reliable correlation. A single property such as color or thickness may change laterally within a given stratigraphic unit, but a suite of distinctive lithological properties is less likely to change. The most reliable lithological correlations are made by matching not just one or two distinctive beds or rock types but a sequence of several distinctive units. Recognition of a distinctive and easily correlated bed or beds serves as control for correlation of other strata above and below. Such a marker bed that cannot be confused with any other bed enables the reliable correlation of strata that are in a similar stratigraphic position with respect to the control unit in other areas. The presence of two or more marker beds in a sequence provides even greater reliability in the correlation of units that lie between the marker beds.

Lithofacies module correlation is the integration of lithologic similarity and the position of genetically related strata within the chronostratigraphic sequence. Figure 4-1 is the correlation of lithofacies modules in selecting boreholes of the Gypsy outcrop site and shows the importance for stratigraphic correlation of the genetic position of the

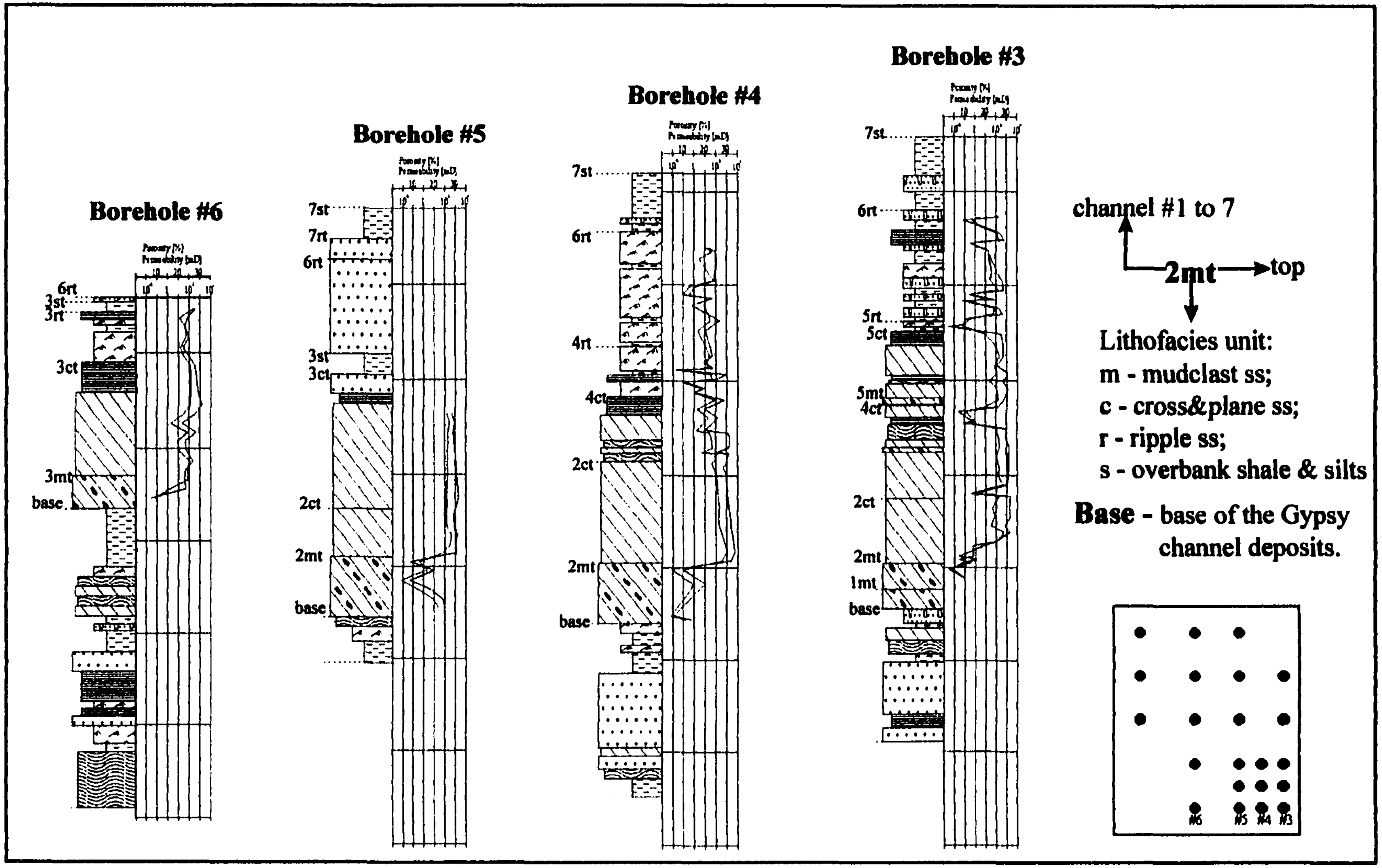



**Figure 4-1 Lithofacies modules in the boreholes #3, #4, #5, and #6 at the Gypsy outcrop site.**

lithofacies modules within the genetic sequence. Once the channel boundaries are identified and lithofacies modules are subdivided within a channel, identical lithofacies modules within the same channel must be correlative.

### 4.2.3 Correlation by well logs

Well logs are the most common data available to petroleum geologists for subsurface correlation. One common type of well log is the resistivity log, which records resistivity of rock units along the borehole. Resistivity is affected by the lithology of the rock units and the amount and nature of pore fluids in the rock. For example, a marine shale that has its pore spaces filled with saline formation water will have a much lower electrical resistivity (higher conductivity) than a porous sandstone or limestone filled with oil or gas. Lithology cannot be read directly from such logs, but the characteristics of the log traces are a reflection of lithology (and fluid content). With experience in a given geological area, petroleum geologists can recognize the particular signatures represented by the analog traces on the log and can relate these signatures to particular types of lithostratigraphic units or to a specific formation. Other types of logs such as gamma ray logs, SP logs, sonic logs, and density logs are commonly used with resistivity logs for subsurface correlation. They all have the common characteristics that their analog traces represent particular properties of subsurface lithostratigraphic units that are related in some way to lithology, fluid content, bed thickness, porosity, or other properties.

The curve shapes generated by a particular lithostratigraphic unit are not unique, but a trained, experienced well-log analyst can learn to recognize the signature of a particular formation or sequence of formations and can match up the signatures in logs from one area to those from nearby wells. Characteristically, the well-log curves of adjacent wells are very similar, but the degree of similarity decreases in more distant wells. By working with a series of closely spaced wells, however, a geologist can carry a correlation across an entire sedimentary basin, even when pinchouts or facies changes occur. In fact, one of the reasons petroleum geologists find correlation of well logs so useful in petroleum exploration is that correlation permits recognition of pinchouts and facies changes that may be potential traps for oil and gas. As stressed before, well logs are often calibrated by cores, thus correlation by well logs is not necessarily based entirely on the shapes of the curves. Correlation by well logs is actually based more on the position of each unit in a succession of units represented on the logs rather than on the character of any individual unit reflected in the curves. Therefore, an individual lithofacies is almost impossible to be recognized and correlated on well logs. However, a group of adjacent lithofacies that have similar characteristics and properties could be recognized and correlated. The significant differences of sedimentary characteristics and properties between lithofacies modules produces different shapes of curves on well logs. The unique position of lithofacies modules within a stratigraphic sequence provides a direct and reliable signature for their correlation.

## 4.3 Modeling Scale and Its Impacts on Reservoir Modeling Frameworks and Reservoir Heterogeneities

Four types of modeling scales based on the data available and desired resolution of the model are discussed here: stratigraphic sequence scale, reservoir scale, lithofacies module scale, and sample scale. Each modeling scale reflects different scales of reservoir heterogeneity and has different data requirements. Figure 4-2 illustrates the definitions and relationships of the four scales of reservoir modeling. Different scales of modeling reflect different scales of reservoir heterogeneities and require different levels of data sources (Forgotson, 1993; Grier and Marschall, 1995; and Slatt and Galloway, 1995).

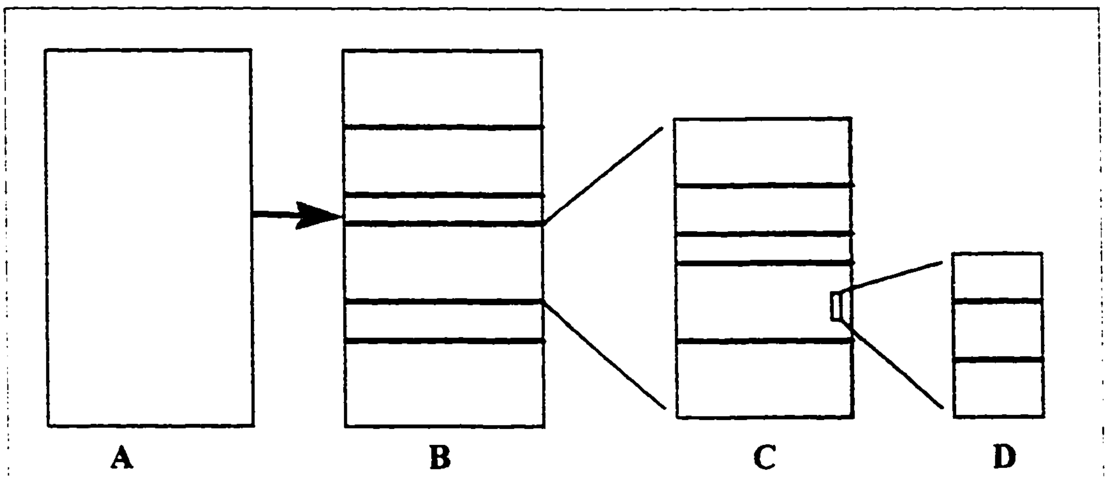



**Figure 4-2 Schematic Diagram shows the frameworks of the proposed four Modeling**

**Scales: A--Geological sequence scale defined by regional chronostratigraphic surfaces; B--Reservoir scale framed by major reservoir units; C-- Lithofacies module scale with stressed heterogeneity within reservoir and; D--Sample scale with micro-features investigated in laboratories.**

### 4.3.1 Stratigraphic Sequence Scale

The stratigraphic sequence scale models the strata limited by two chronostratigraphic surfaces which are geologically significant and can be correlated regionally such as boundaries of a formation, sequence, or parasequence. Stratigraphic units between the boundaries are not correlated geologically but are modeled geostatistically. Therefore, reservoirs are not well defined at this modeling scale which should be used only in the very early stage of reservoir assessment where limited data are available. Seismic data and regional geological data can be used for picking the stratigraphic boundaries at this scale. For example, the stratigraphic sequence modeling scale in the Gypsy outcrop site is bounded by the top and bottom of the Gypsy fluvial formation which can be clearly defined from seismic data as shown at the Gypsy subsurface site (Figure 4-3).

### 4.3.2 Reservoir Scale

The reservoir scale models the individual reservoir or sandbody bounded by lithological surfaces which can be correlated field-wide. This scale is the most common type of geological modeling applied in the early stage of production. Reservoir thickness, geometry, continuity, and bulk properties are carefully correlated and defined by high resolution 3-D seismic data and well logs. Internal heterogeneity within an individual reservoir is not defined geologically but can be estimated geostatistically. Figure 4-4, sections from the Gypsy model, shows the possible results of geostatistical interpretation and illustrates the big contrast between the results and the geological interpretations shown in Figure 4-5 and

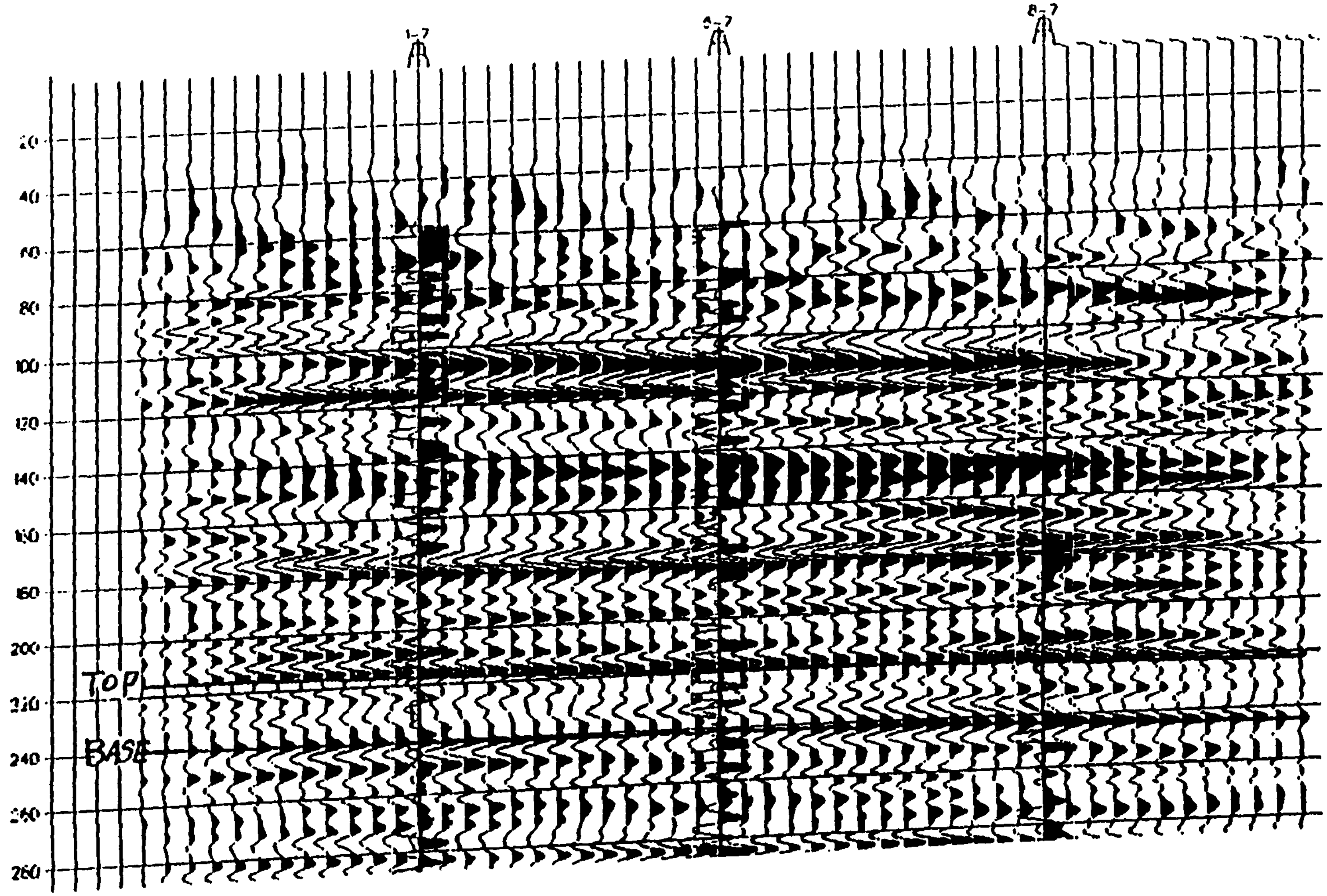



**Figure 4-3 Seismic profile shows the top and the bottom of the Gypsy channel deposits at the Gypsy subsurface site (Seifert, 1994).**

Figure 4-6. This comparison strongly emphasizes the importance of correctly using geological control to constrain the geostatistical interpretation, which will be further discussed in chapter 5. The Nearest Neighbor method available in the SGM software is used here for the channel and lithofacies module interpretations. Nearest Neighbor method searches for the closest data point and fill the cell with that data value (SGM Reference Guide, 1995).

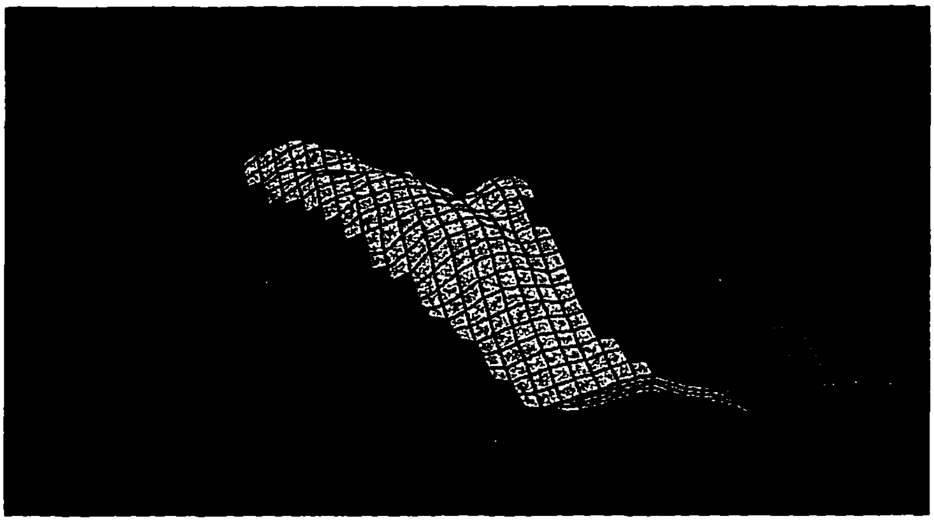
Possible Gypsy Channel Distributions Interpreted by Using the Nearest Neighbor Method (Colors Indicate Different Channel Sequences)

Possible Gypsy Lithofacies Module Distributions Interpreted by Using the Nearest Neighbor Method (Colors Indicate Different Types of Lithofacies Modules)

**Figure 4-4 Possible interpretations of the Gypsy channels and types of lithofacies modules.**

### 4.3.3 Lithofacies module Scale

The lithofacies module scale is used for field studies where data are available to indicate the internal heterogeneity of a reservoir. This scale should be used for accurate simulation and prediction of fluid flow behavior in most of the producing fields. Besides defining the distribution of reservoir geometry, thickness, and continuity, lithofacies module scale



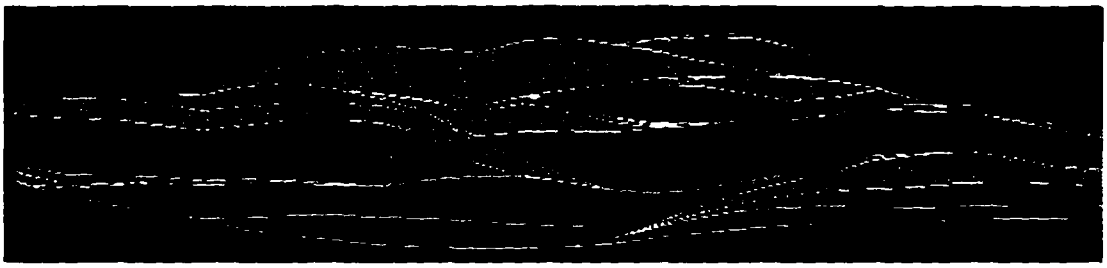
Channel Model: colors indicate different channel sequences

Lithofacies Module Model: colors indicate different types of lithofacies modules

**Figure 4-5 Contrast of channel model and lithofacies module models of the Gypsy outcrop reservoir.**

emphasizes on the internal reservoir heterogeneities within each individual reservoir unit and the controls of geological features on reservoir properties. Cores and high resolution logs are the key data source for this scale of modeling. Accurate description and analysis of core provide the verification and calibration of well log interpretations to be used for estimating reservoir properties in the interwell areas. High resolution 3-D seismic correlated with core-calibrated log data could assist in determining the geometry and distribution of the reservoirs and to aid the correlation and mapping of lithofacies modules between wells.

Channel Sequence Model: colors indicate different channel sequences



Lithofacies Module Model: colors indicate different types of lithofacies modules

**Figure 4-6 Geological interpretation of the Gypsy channel distributions and lithofacies module distributions.**

### 4.3.4 Sample Scale

This scale of modeling conducted only in the laboratory is focused on understanding the effects of detailed geological and petrophysical properties, such as, cements, textures, sedimentary structures, fabrics, fractures, and fluids on reservoir behavior. The results from this scale of modeling contribute valuable insight for field studies, geological modeling, and engineering input for simulation studies, that are especially useful for modeling at the lithofacies modules scale.

## 4.4 Contrasts Between Gypsy Fluvial Reservoir Models Using Lithofacies Modules and Channel Sequences

### 4.4.1 Different modeling frameworks: depositional cycles and reservoir heterogeneity.

Two types of models have been built for the Gypsy outcrop site: a model based on channel depositional sequences and a model based on lithofacies modules that control the reservoir heterogeneity, Figure 4-5 and Figure 4-6. The colors in these figures represent the geological frameworks used in the two different models. The difference between these two models of the Gypsy sandstone reservoir is obvious. The channel model shows the distributions of the channel sequences but has nothing to do with reservoir properties. However, the lithofacies module model not only show the distribution of lithofacies modules but also show the types of lithofacies modules that are corresponded to reservoir properties.

The channel model consists of six channel sequences and one crevasse-splay deposit. Each channel sequence represents a finning-upward depositional cycle. The model gives the channel distributions in 3-D space. Because the channel sequences do not correspond to flow units, this model does not reflect the distributions of reservoir heterogeneities which control fluid flow within the reservoir.

The model consisting of twenty-five lithofacies modules contains detailed information on geological evolution, sedimentary structures and textures of the sandstone, and depositional environments. The four colors indicate relative qualities of the reservoir and levels of reservoir heterogeneities. Reservoir properties are relative homogeneous within a lithofacies module and significantly different between lithofacies modules. This model provides a framework that represents both geological characteristics and reservoir heterogeneities that control fluid flow.

### 4.4.2 Different distributions of reservoir properties within a model

A reservoir model consists of a series of geological sequences such as channels and lithofacies modules. Those sequences are then subdivided vertically into layers to provide adequate detail within the model and the layers are subdivided laterally into cells according to the $x$ and $y$ increments selected (Figure 4-7). A model may contain millions of cells, and each cell has to be assigned attributes consisting of geological and reservoir properties.

Figure 4-8 schematically shows the assignment of raw well data to the cells of a reservoir model. The raw data sampled at one foot intervals is resampled at the resolution of the stratigraphic framework model, five feet, using a thickness weighted averaging calculation. Once data have been assigned to the cells penetrated by wells within the model, data for the cells between wells are interpolated laterally using the resampled well data within each layer as shown in Figure 4-9.

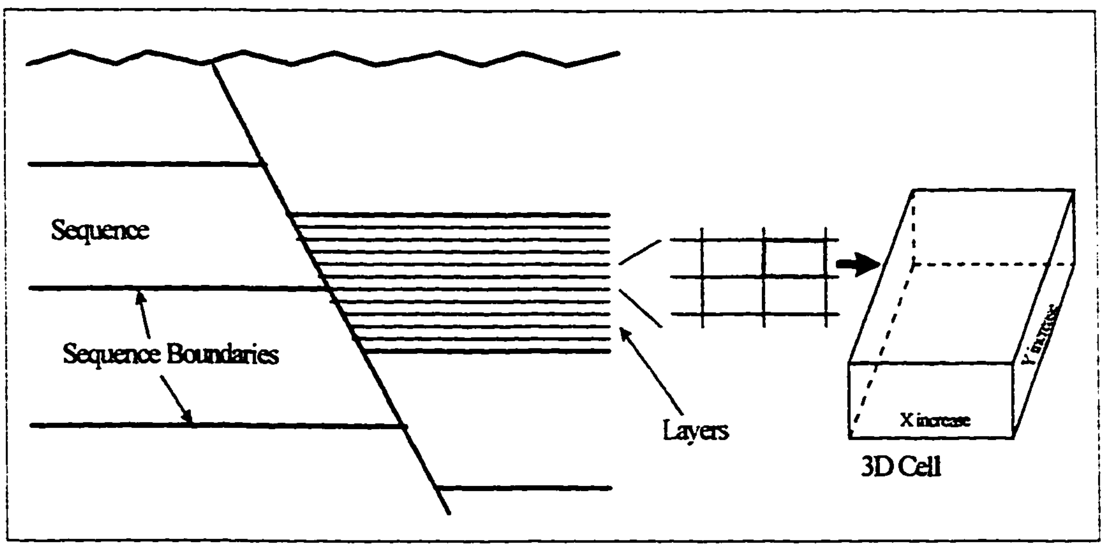



**Figure 4-7 Principle for building a reservoir model: Sequences are the basic modeling units and framework. The boundaries of sequences are the most important geological control in the model. Layers are generated by vertically equal subdivision of a sequence and cells are formed by further horizontal subdivision within a layer according X and Y increases.**

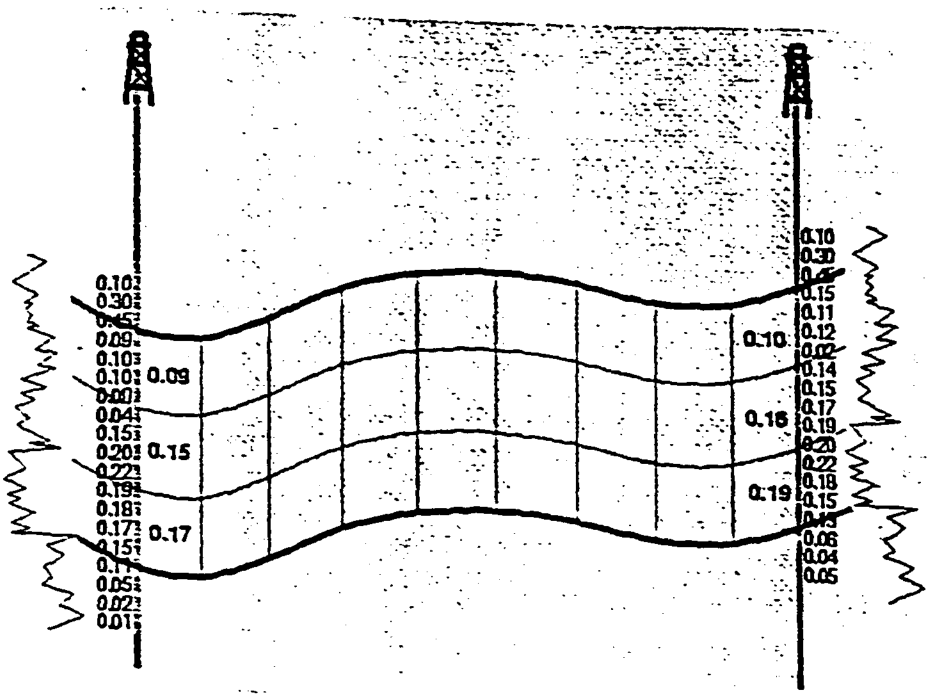



**Figure 4-8 Principle of vertically assigning data to a reservoir model along the wellbores (SGM manual, 1995).**

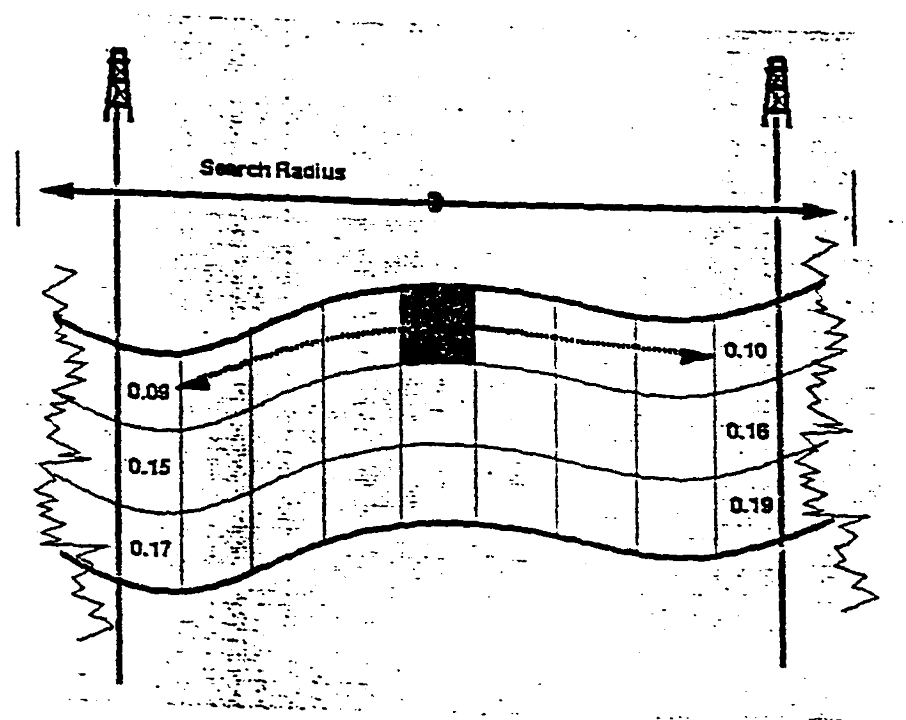



**Figure 4-9 Principle of horizontally assigning data to a reservoir model within a layer (SGM manual, 1995).**

Different models may result in significant differences in the distribution of reservoir properties. A geological model that represents the depositional sequences may overlook the reservoir heterogeneity that controls fluid flow and turn a heterogeneous reservoir into a homogeneous reservoir. Also an upscaled reservoir model based on lithofacies modules is more accurate than one based on depositional sequences.

Laterally, the same problem exits for data interpolation between wells. Figure 4-10 shows an example of the difference between a lithofacies module model and a channel sequence model. Three channel sequences and four types of lithofacies modules are illustrated in this example. The four types of lithofacies modules are cross-bed and plane-bed lithofacies module, ripple-dominated lithofacies module, mudclast-dominated lithofacies module, and shale-dominated lithofacies module that are represented in Figure 4-10 by red, green, yellow, and blue respectively. Channel sequences shows the channel distributions while the lithofacies modules illustrated more detailed sedimentary features and their distributions within channel sequences. Most importantly, the types of lithofacies modules that are illustrated by different colors are corresponding to different levels of reservoir heterogeneities and reservoir properties.

In the channel model, layers of equal thickness are subdivided within each channel sequence. Because the layers cut across lithofacies module boundaries several types of lithofacies modules can occur within one layer. Thus interpretation between wells could be based on data from different types of lithofacies modules. Two significantly different data points, one from a flow barrier shale with very low permeability and another from a highly permeable sand, could be used to predict values of cells between the wells. And the high permeability reservoir of cross-bed lithofacies module could be interpreted as low permeability reservoir or flow barrier if the data points used for the interpretation are from shale and mudclast lithofacies modules. The result could convert a highly heterogeneous reservoir into an apparently low heterogeneous one.

Layering within the lithofacies module model is restricted to within an individual lithofacies module. No layers cross the boundaries of lithofacies modules. Thus, interpolations should be more accurate because they are limited to within a lithofacies modules rather the channel sequence.

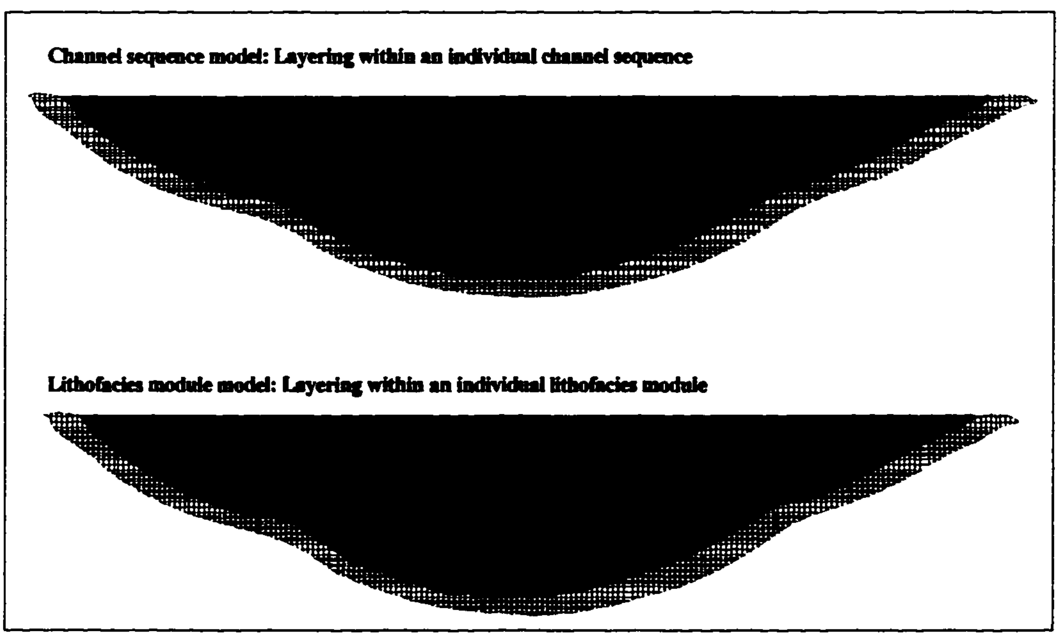



**Figure 4-10 Difference of geostatistical interpretations between channel sequence model and lithofacies module model (colors indicate different types of lithofacies modules).**

A channel model and a lithofacies module model of the Gypsy outcrop site illustrate the difference in modeling concepts. All data and parameters for each model are the same. Only modeling concepts are different. Figure 4-11 shows the contrast in permeability distributions between the Gypsy channel model and the lithofacies module model using the same core data. The red color represents the area that have a permeability of greater than 1000 md while dark blue represents the permeability of less than 100 md. The difference of permeability distributions between the channel model and lithofacies module model is illustrated clearly by the differences of areas covered by red and blue colors such as that indicated by the arrows.

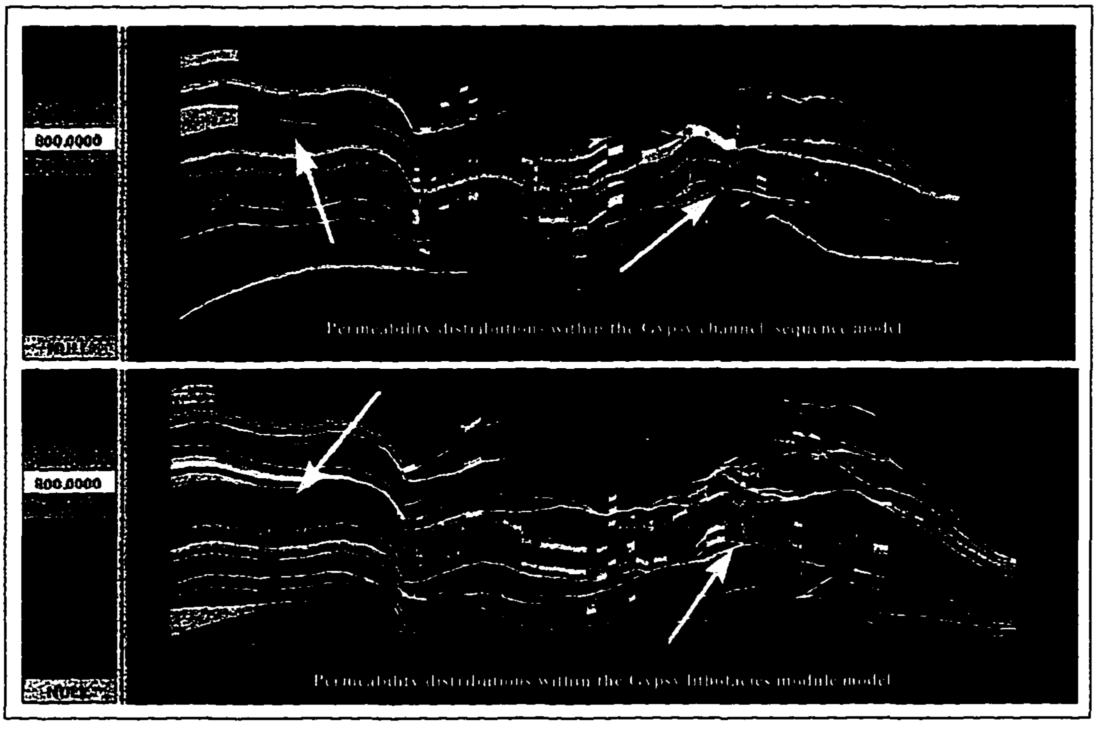



**Figure 4-11 Contrast of permeability distribution between the Gypsy channel sequence model and lithofacies module model.**

The differences would be more drastic if the reservoir permeability had been derived from porosity. In fact, most permeability values used in simulation are calculated from porosity. Figure 4-12 shows the correlation of permeability and porosity within each lithofacies module of the Gypsy outcrop sandstone. Not only are the porosity and permeability values different between each module but also their statistical relationships are different within each lithofacies module. Figure 4-13 illustrates the permeability distributions derived from different relationships of porosity and permeability. For the same porosity, permeability values can be significantly different depending on the type of lithofacies modules. For example, at 20% porosity the calculated permeabilities are 1md, 4 md, 5.5 md, 20 md, and 5.5 md in shale, ripple, mudclast, cross-bed and plane-bed lithofacies modules, and the whole reservoir respectively. A reservoir with shale and high variations in permeability could be averaged to a uniformly low permeability reservoir in the model regardless of lithofacies. The derived permeability could show even more diversity between lithofacies modules because of the difference in porosity ranges of each lithofacies module. For the Gypsy sandstone, porosity ranges from 9% to 13%, 10% to 20%, 17% to 23%, and 23% to 26% in shale, mudclast, ripple, and cross/plane-bedded lithofacies modules respectively. The corresponding permeability derived for each lithofacies module is 0.01 - 0.1 md, 0.2 - 15 md, 3 - 100 md, and 200 - 1000 md.

Figure 4-14 shows the distributions of predicted permeability from the Gypsy Channel Model and the Lithofacies module Model. Permeability in the lithofacies model is derived from the relationships of porosity and permeability by lithofacies. Permeability in

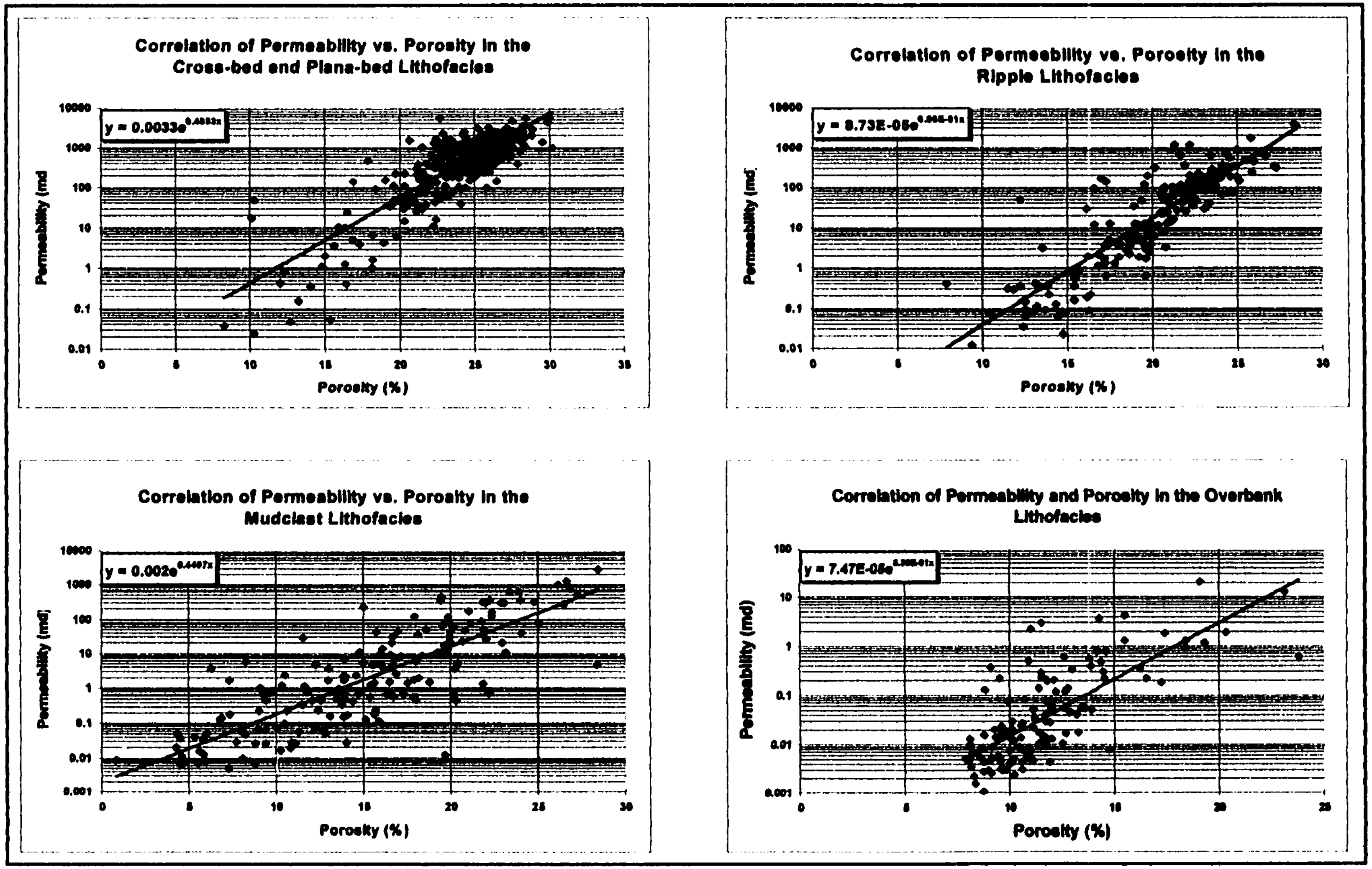



**Figure 4-12 Relationships of porosity and permeability within individual Lithofacies modules.**

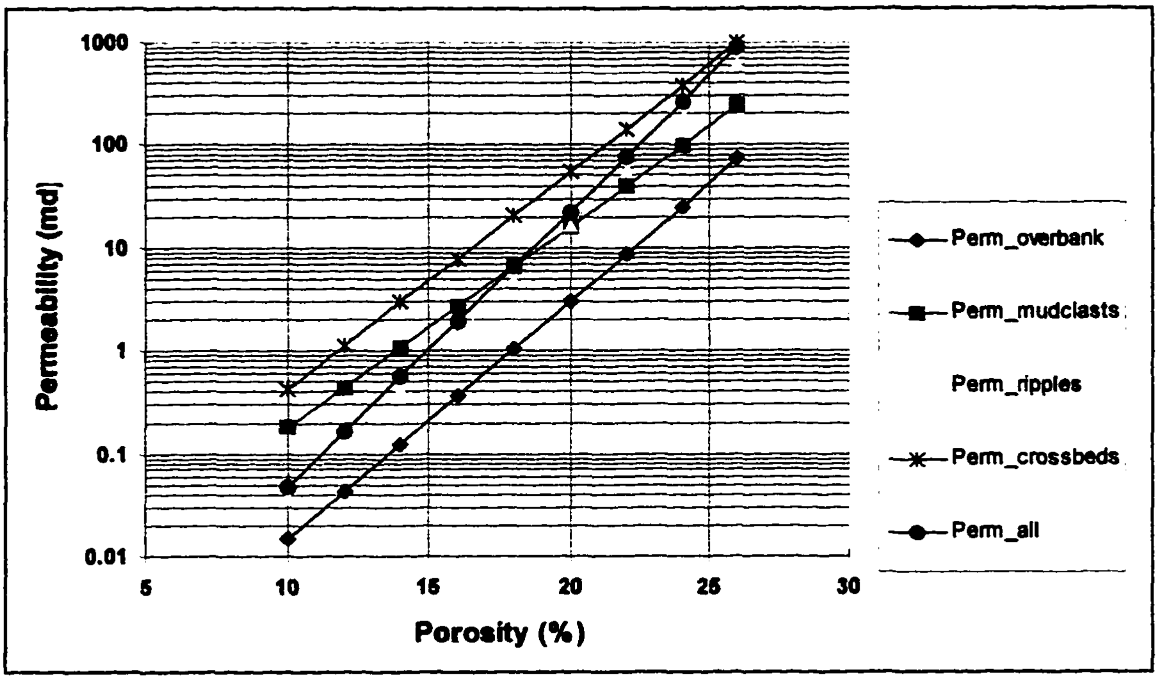



**Figure 4-13 Permeability distributions derived from different relationships of porosity and permeability by lithofacies modules.**

the channel model is calculated from the general relationship of porosity and permeability. The distributions of the red areas that represent the permeability of greater than 1000 md is different between the channel model and lithofacies module model as indicated by the arrows. The permeability ranges are 0.0005 to 7451.58 md in the channel model and 0.0029 to 4019.81 md in the lithofacies model. Comparing to the permeability distributions using the actual data as showed in figure 4-11 with the permeability ranges of 0.0032 – 3449 md in the channel model and 0.0032 – 4893 md in the lithofacies module model, permeability in the channel model has more significant change than that in the lithofacies module model. The permeability distributions between actual data and predicted data are more similar in the lithofacies module model than that in the channel model although the ranges of permeability distributions can be affected by several erratic data values.

In summary, interpolation and distribution of reservoir properties are controlled by the model frameworks or concepts: a lithofacies module model can reveal the reservoir heterogeneity; a geological sequence model could homogenize or mis-estimate a heterogeneous reservoir.

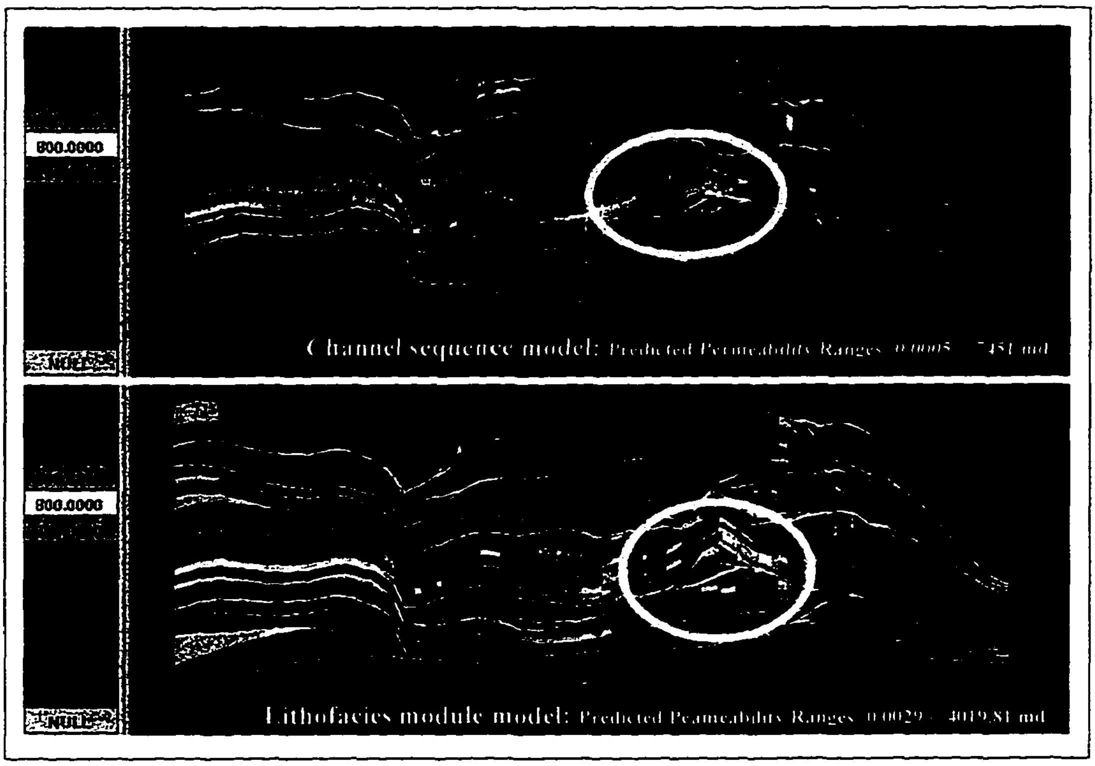



**Figure 4-14 Contrast of permeability distributions derived from permeability-porosity relationships between the Gypsy channel model and lithofacies module model.**

# CHAPTER 5. RESERVOIR MODELING AND GEOSTATISTICAL APPLICATIONS

After the well log, core, and seismic data have been collected and interpreted and the lithofacies modules have been defined and correlated, the interdisciplinary team must decide how to build the reservoir model and fill out the space between data points vertically and horizontally within the model. Even for densely drilled oil fields, the amount of rock that can be described from well logs and cores is less than 0.1% of the reservoir. Geostatistics has developed as an art and science within the petroleum industry during the past 10 years as geologists and engineers have tried to determine the variability associated with various types of data and to predict values between data points to use in petroleum exploration and production studies. The application of geostatistical methods to different problems and purposes requires different geostatistical techniques. Many books and papers have been published regarding the geostatistical principles, methods. and case studies in reservoir geological modeling (Isaaks & Srivastava, 1989; Yarus & Chambers, 1994). Three steps required to build a detail geological reservoir model and that require geostatistical applications will be discussed in this chapter: mapping the reservoir and reservoir units, building the framework of the reservoir model, and assigning reservoir properties to fill the interior of the model.

## 5.1 Mapping the Reservoirs And Reservoir Units

Accurately mapping the surfaces that define the limits of the reservoir and those surfaces that define the geometry, thickness, distribution, and heterogeneity of the reservoir is the first step toward building the reservoir model. Selection of the gridding and contouring algorithms that are most appropriate for the data and the use of geological constrains in the mapping process are critical.

### 5.1.1 Importance of geological control on reservoir mapping

To show the importance of geology on reservoir mapping, a hypothetical reservoir is assumed as shown in figure 5-1. Two sets of data were selected with different data spacing: data picked at every 3 grid blocks with a total of 105 data points and every 7-12 grid block with a total of 20 data points. Six simple gridding algorithms available in GeoGraphix software (GeoGraphix, 1995, 1996) have been used to reconstruct the hypothetical reservoir in the shape of the State of Oklahoma using the two different data sets. Table 5-1 is the brief summary of those techniques available used here.

Figures 5-2 through 5-7 show the maps produced by each of the six methods using the two data sets. All of the methods were able to reconstruct the isopach of the hypothetical reservoir using the densely sampled data set. Some methods did not handle the boundary problem as well as others. However, the reconstructed maps using the sparsely sampled data set are not good enough to compare to the original map and different reservoir distribution were produced. Relatively, adoptive fitting and minimum curvature have better results to this sparely sampled data set.

**Table 5-1 Brief summary of common mapping techniques (GeoGraphix Technical Reference, 1995)**

| Technique | Description |
| --- | --- |
| Minimum Curvature | An interactive gridding technique which actually derives grid node values multiple times. The initial gridding pass grossly averages the data and calculates a minimum number of grid nodes to express a regional trend fit of the data. Successive gridding iterations calculate additional grid nodes that reflect the influence of localized features. Thus, each gridding iteration produces a more complex surface as more localized features are added. |
| Adaptive Fitting | An technique that solves spatially constrained harmonic function equations. Rather than piecing together multiple local surfaces, Adaptive Fitting resolves a solution that considers all of the data values for a given surface. The result of this process is a system of equations that fits all of the data completely. |
| Triangulation | A technique used for topographic mapping where grid node values are derived by constructing triangles from all available data points. |
| Weighted Slope | A technique that uses an inverse-distance function to weight the slope of the surface at neighboring data locations. |
| Kriging | Building a surface by analyzing the directional, spatial persistence of the data using a semivariogram. |
| Weighted Least Squares | It uses a neighborhood of data values to determine the equation of a plane that passes through these data points with the least squared error. |

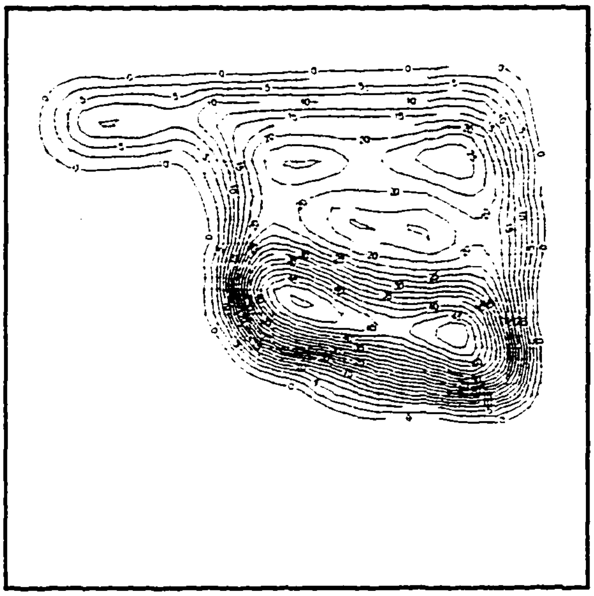
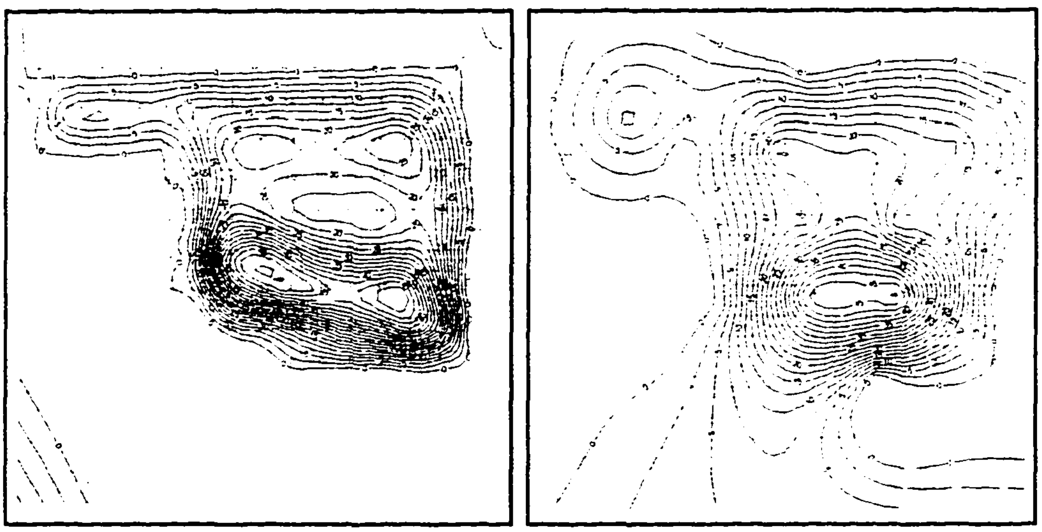
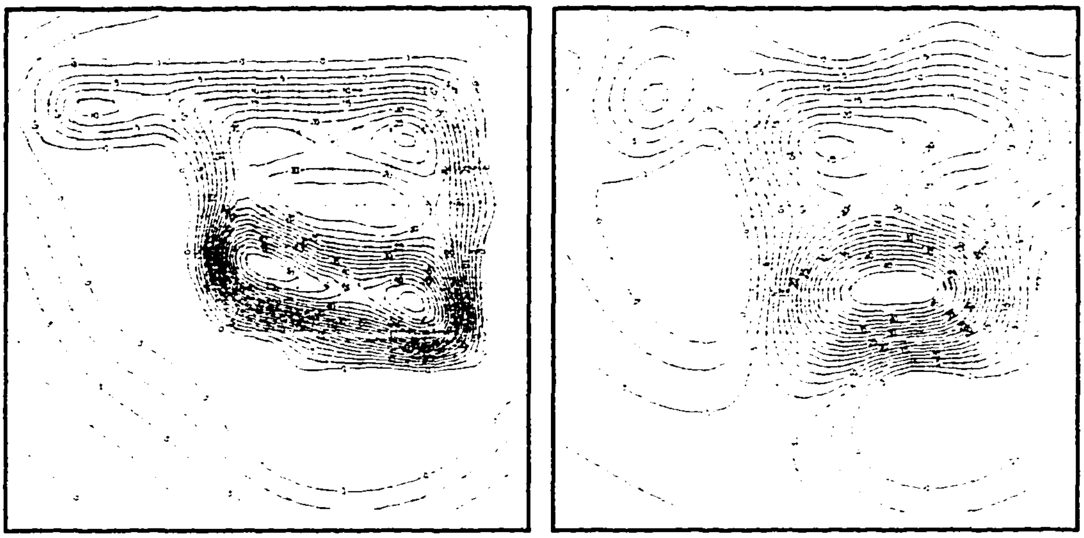


**Figure 5-1 A hypothetical reservoir in the shape of Oklahoma for showing the impact of geology on geostatistical applications.**



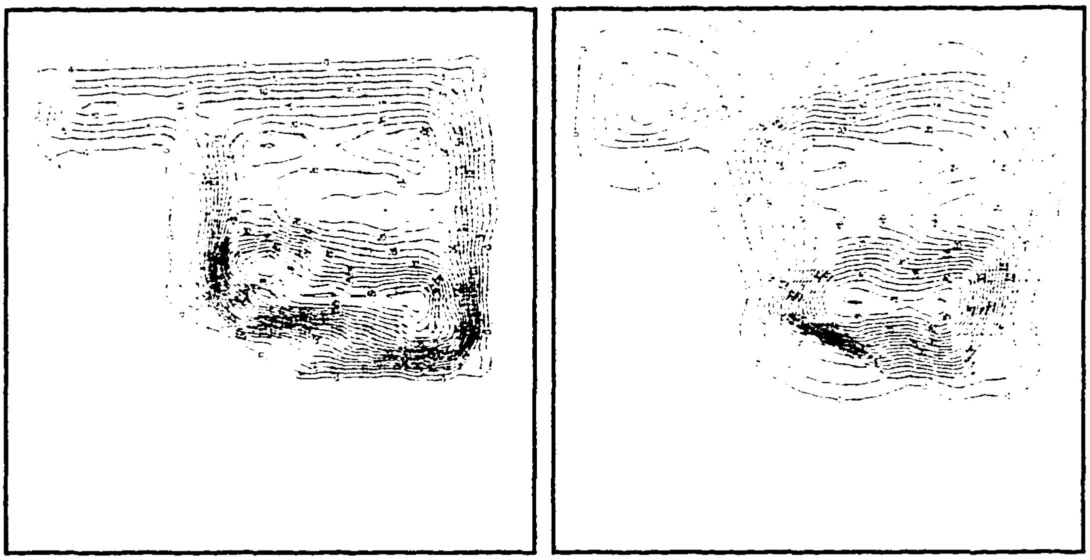
*105 data points* *20 data points*

**Figure 5-2 The hypothetical reservoir reconstructed by minimum curvature mapping technique using the two different data sets.**



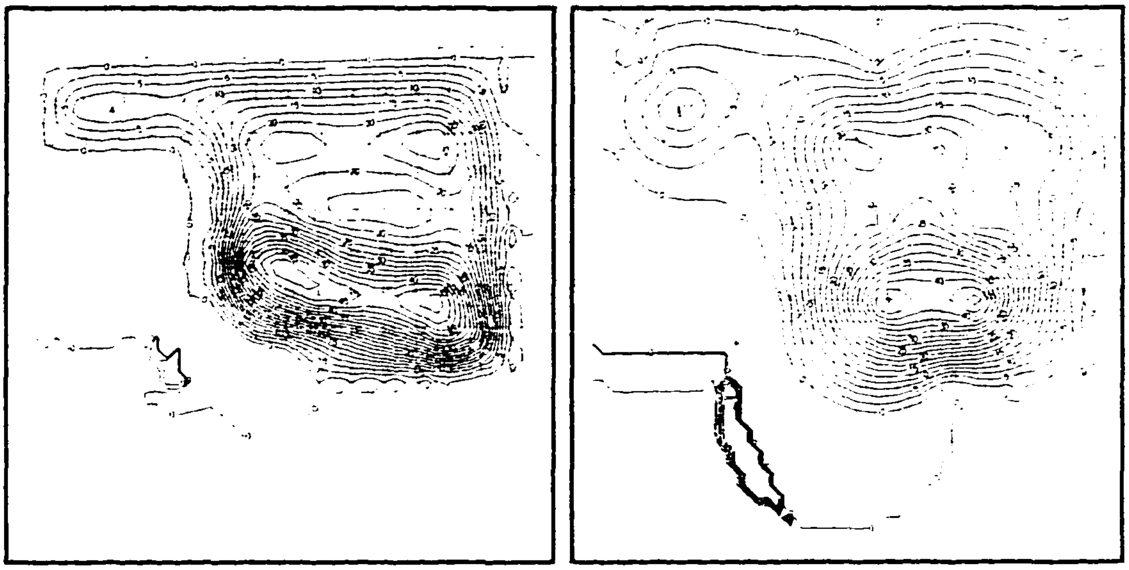
*105 data points* *20 data points*

**Figure 5-3 The hypothetical reservoir reconstructed by adaptive fitting mapping technique using the two different data sets.**



*105 data points* *20 data points*

**Figure 5-4 The hypothetical reservoir reconstructed by trangulation mapping technique using the two different data sets.**

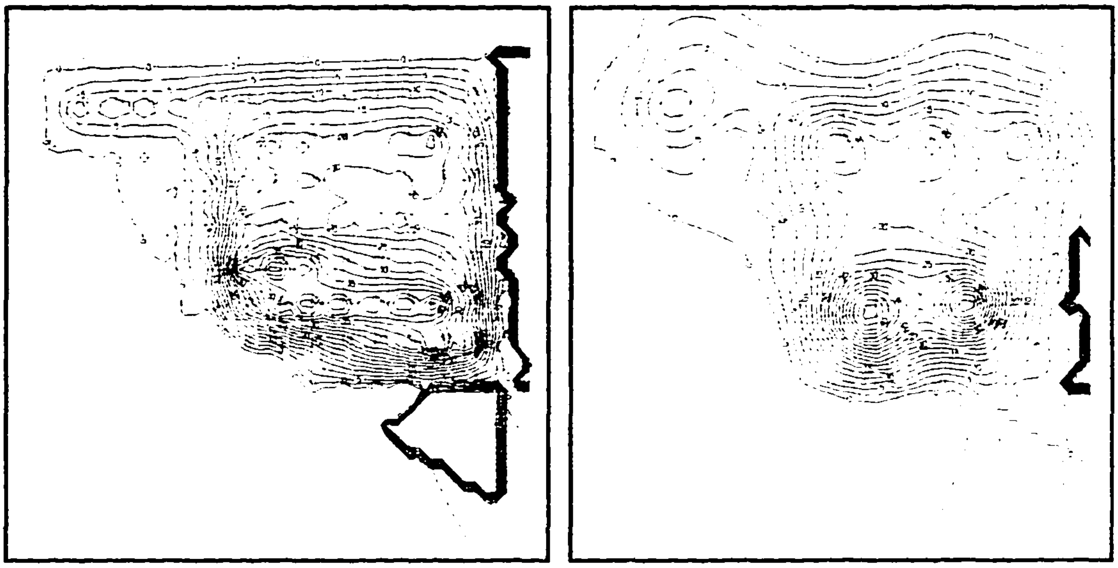


*105 data points* *20 data points*

**Figure 5-5 The hypothetical reservoir reconstructed by Kriging mapping technique using the two different data sets.**

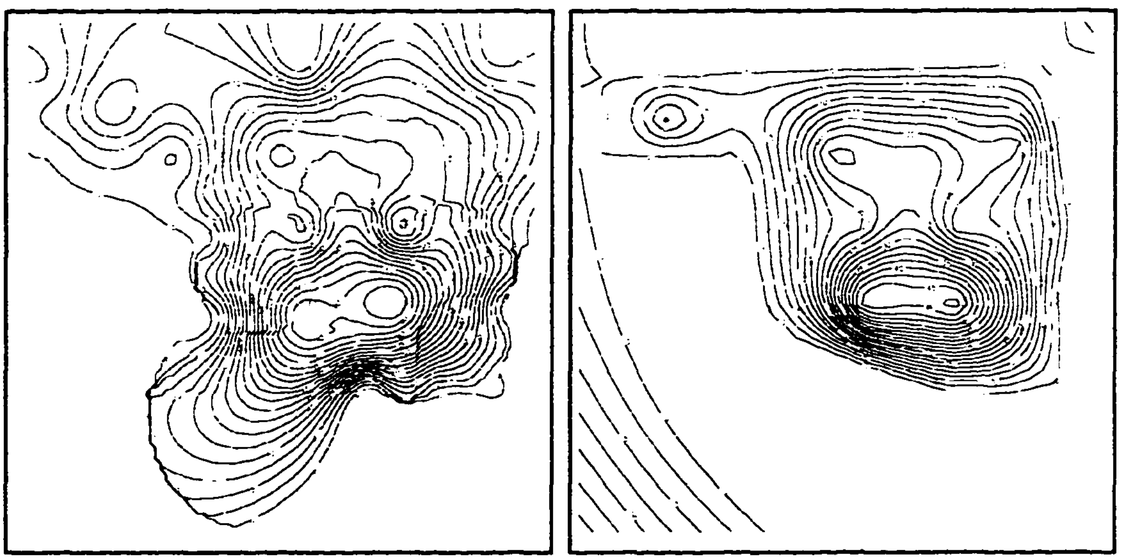
*105 data points* *20 data points*

**Figure 5-6 The hypothetical reservoir reconstructed by weighted slope mapping technique using the two different data sets.**



*105 data points* *20 data points*

**Figure 5-7 The hypothetical reservoir reconstructed by least squares mapping technique using the two different data sets.**



*a) Double grid density* *b) Geologically controlled boundary*

**Figure 5-8 Improved mapping accuracy by using finer grid system and geologically controlled boundary in weighted slope application.**

Can the prediction be improved by improving the calculating resolution or having finer mapping grids? Figure 5-8 (a) shows that doubling the grid density does not improve the results. Figure 5-8 (b) shows the significance of using geological data that constrain the reservoir boundary to produce a map very similar to the original one.

### 5.1.2 Mapping the Gypsy channels and lithofacies modules

GeoGraphix software was used to build a database using 22 boreholes and 21 outcrop profiles that contains locations, top elevations and thicknesses of the lithofacies modules and channels defined at the Gypsy outcrop site. The minimum curvature technique was selected for mapping the surfaces of the Gypsy lithofacies modules and channels because among those mapping methods available it provides the best fit to the Gypsy data set.

The minimum curvature is "an gridding technique which derives grid node values multiple times. The initial gridding pass grossly averages the data and calculates a minimum number of grid nodes to express a regional trend fit of the data. Successive gridding iterations calculate additional grid nodes that reflect the influence of localized features. Thus, each gridding iteration produces a more complex surface as more localized features are added" (GeoGraphix, 1995,1996).

Digitized channel boundaries and a double weighted north-west bias of channel direction were used as geological controls to grid and contour the isopachs of all channels. The isopach of each lithofacies module was mapped within the limit of the channel in which the lithofacies module is located. The base surface of the Gypsy channels was mapped carefully to serve as the reference surface. All surfaces at the tops of channels and lithofacies modules were generated by adding their isopachs and the isopachs below to this reference surface. Local improvements can be made by modifying the contours and then using the modified contours to re-grid the surface. Several iterations of this procedure may be needed.

Figure 5-9 shows the isopach of channel 1 at the Gypsy outcrop site mapped with and without geological controls. The upper diagram is from mapping the reservoir thickness constrained by the channel boundary. The lower map is generated by subtracting the elevation surfaces representing the top and bottom of the channel. The direct mapping of the channel is geologically more meaningful and easier to control than mapping the difference between elevations of the surfaces.

### 5.2 Building the Framework of the Gypsy Reservoir Model

In this research, 3-D geological modeling software, Stratigraphic Geocellular Modeling (SGM), was used for building the Gypsy reservoir model. The grid files of the top surfaces of channels and lithofacies modules and the reference surface, the base of the Gypsy interval, were imported from GeoGraphix. These surface grids provide the framework of the reservoir model. Reservoir sequences between these grids are subdivided further into layers based on the resolution of available data and depositional

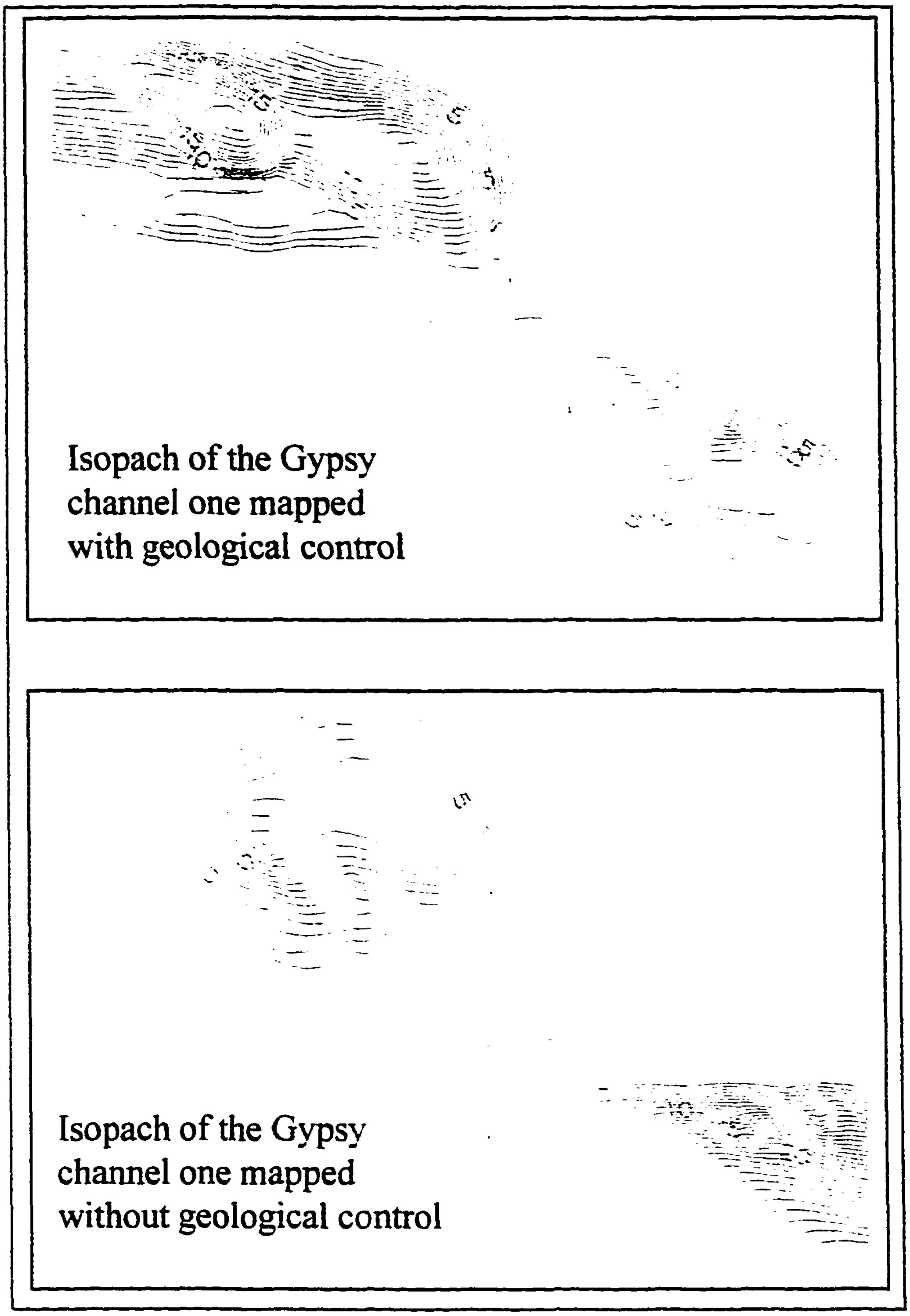



**Figure 5-9 Isopachs of the channel 1 at the Gypsy outcrop site mapped with and without geological controls.**

patterns (SGM Reference Guide, 1993, 1995). The truncation depositional pattern with the vertical resolution of 1 foot layer thickness was used for the Gypsy outcrop model. This truncation pattern assumes that the top of each sequence is bounded by an erosional surface, the layers within the sequence are parallel to the base surface of the sequence as shown in figure 5-10.

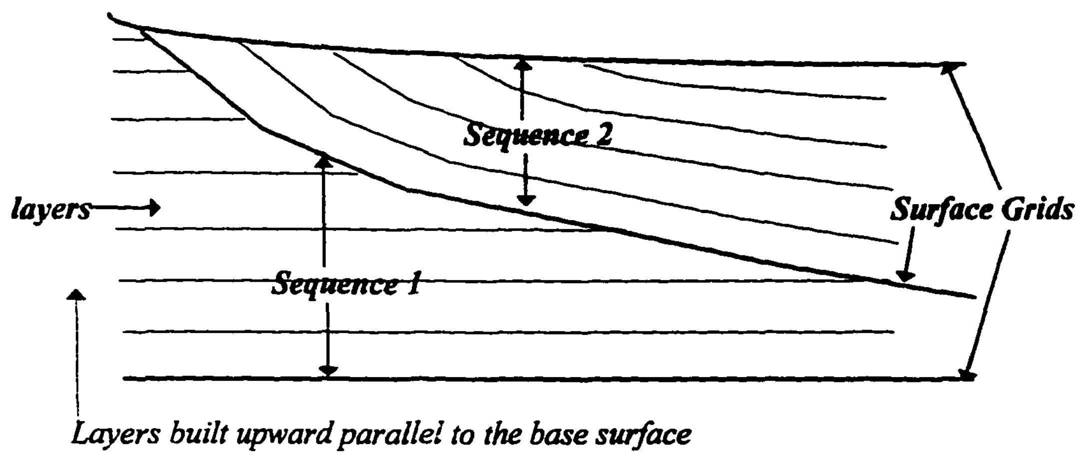



**Figure 5-10 The truncation layering pattern used in the Gypsy outcrop reservoir model.**

The model can be visualized in 3-D after the framework is built by adding all grids and applying the layering patterns. If errors or geologically unreasonable features are apparent, it is necessary to check the mapping of the surface grids or the data.

## 5.3 Assigning Reservoir Properties To The Model

### 5.3.1 Assigning well data into the cells penetrated by the wells

Once the framework of the reservoir model has been built, data are inserted into the cells penetrated by the wells and cells along the outcrop sections. Files for the 22 boreholes contained about 1000 samples and the outcrop section files contained over 2000 samples had been calibrated and formatted for use in the SGM Well Model. Each file contains porosity, permeability, grain size, bulk density, lithofacies module code, and channel number. The weighted averaging method was used to calculate the cell values from the vertical distributions of porosity, permeability, and density and the nearest neighbor method was used for grain size, channel number, and lithofacies module code.

### 5.3.2 Lateral interpolation of the well data

To fill the interior of the model, the values in the cells that contain the well and outcrop dada have to be laterally interpolated between the control points. Usually lateral interpolation is performed using only data within the same layer. Two major factors that have the most significant effects on the results of the interpolation in the SGM Attribute Model are the search radius and the calculation method.

The search radius determines which control points will be used for the interpolation and the weighting values within the search radius. "Carefully selecting the search radius can make the data sampled evenly and eliminates unrealistic distributions caused by data clustering. An excessively large search radius lessens the weighting function. On the other hand, a search radius that is too small can limit the number of values used and create a very sharp or peaked weighting function, resulting in unrealistic distributions" (SGM, 1995). Data density and geological setting are the two most important factors that can be used for selecting a reasonable search radius. For a beach reservoir with little lateral changes a large search radius may work well while in a fluvial reservoir, a large search radius may overlook the reservoir heterogeneities. In the Gypsy fluvial model, a distance of two well spacing (400 feet) was used as the search radius and a northwesterly directional bias was used to more heavily weight points along the channel for the interpolation.

Several algorithms for populating cells with discrete or continuous values are available in the SGM Attribute Model. The deterministic weighting technique is the most commonly used method for continuous values such as porosity, permeability, and fluid saturation. The most commonly used method for discrete data such as channel number and lithofacies module code is nearest neighbor. The deterministic method weights the data based on the distance from the control point to the center of the cell for which the value is being predicted. A power factor is used to vary the weighting function with distance. Increasing the power factor puts more weight on data points closer to the cell for being evaluated and less on those nearer the search limit edge. The nearest neighbor searches for the closest data point to the cell for which the value is being predicted and places this value in the cell. The search radius is the main variable in this method as it determine which control points are considered in the search.

In the Gypsy Attribute Model used in this study, deterministic weighting with a power factor of 3 was used for the interpolation of porosity, a power factor of 5 was used for permeability, and a power factor of 2 for density. The nearest neighbor method was used for the interpolation of channel numbers and lithofacies module codes.

## 5.4 Applications of Stochastic Techniques for the Prediction of Porosity and Permeability in the Gypsy Outcrop Model

Kriging has been the most commonly used stochastic computational method for reservoir modeling during the past several years. It is predicated on the assumption that the unknown spatial distribution of a particular geological property can be predicted from the spatial distribution of measurements of that property at specific locations. The key component of Kriging is to express the degree of dissimilarity between measurements of a property along a given direction. The dissimilarity is expressed by a variogram which is a statistical measure of the spatial correlation of a property sampled at two positions in a predefined direction. If the distance is small, the values are unlikely to deviate much from each other. But as the distance between the values increases the deviation of the values from each other tends to increase. Beyond a certain distance the values become uncorrelated, or completely independent of each other. At that point, they are related to each other by the standard deviation of the uncorrelated variable within the total population.

The stochastic prediction consists of two major steps: spatial modeling or variogram analysis and estimation of the reservoir properties using the derived variograms. In this study, $RC^2$, a commercial geostatistical software package was used.

### 5.4.1 Variogram analysis and modeling

The goal of spatial analysis is to calculate the degree of correlation in a property as a function of distance. Variogram analysis consists of two major steps, calculating the "experimental" variogram points, and then fitting these points with a theoretical model ($RC^2$ Manual, 1995). The theoretical model is then used in a variety of stochastic techniques for predicting the distribution of measured values such as reservoir properties.

The experimental variogram is a statistical measure of the spatial correlation of a property sampled at two positions in a predefined direction. In order to model reservoir properties in three dimensions, two types of variograms need to be constructed: a vertical variogram and an areal variogram.

Figures 5-11 and 5-12 are vertical variograms of permeability and porosity in the Gypsy sandstone. Points on the variogram plot are aggregate values which are the arithmetic average for all common lag distances for all wells. As an example, the variogram calculation is performed for the entire length of the well in Borehole #3. This calculation is then repeated for the rest of wells. The arithmetic average of the values from all of the wells at the 1 foot lag distance is plotted as a point on the variogram plot. In sparsely sampled areas of a reservoir, conditional simulation techniques become variogram dominated rather than data dominated. The vertical variogram model of bedding is used to simulate the vertical component of the geologic architecture of the reservoir. The data points are modeled using exponential model that can be expressed as: $\gamma(h) = 1 - \exp(3h/r)$; where h is the lag distance value along the x-axis, and r is the range parameter. Only the first five data points are used for the modeling in this case because that beyond the thickness of about 5 feet the data are related to each other by the standard deviation and the data values become unrelated.

Figure 5-13 shows the vertical variogram that was calculated and viewed interactively for each individual well. This allows the vertical variogram to be examined for each individual well that is contributing to the aggregate vertical variogram. The h-scattergram

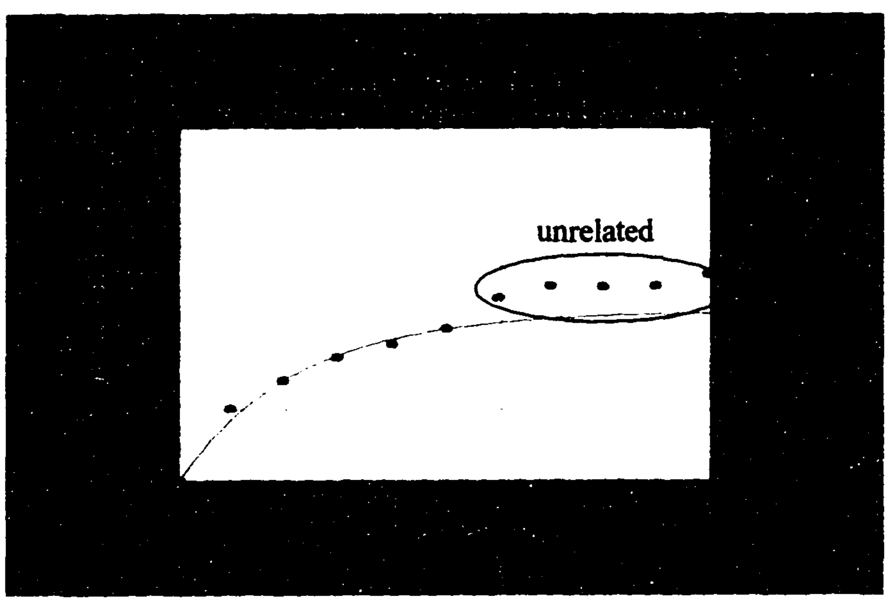



**Figure 5-11 Vertical permeability variogram in the Gypsy outcrop site.**

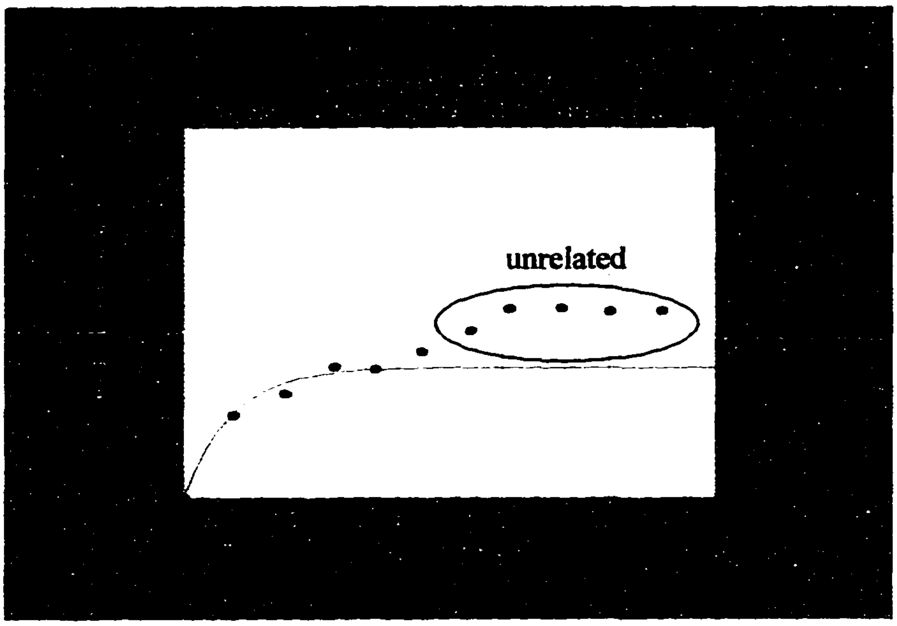



**Figure 5-12 Vertical porosity variogram in the Gypsy outcrop site.**

shows the reason for anomalously high or low variance at a particular lag in a given direction. This is very important for quality controlling the experimental variograms that are used to develop theoretical variograms needed for model estimation and simulation.

The basic principle can be applied to constructing areal variograms. However, construction of an areal variogram is more complex and difficult than construction of a vertical variogram. The reasons are fewer data points, irregular distribution of the data, much larger scale, and geological changes that vary with direction. A good variogram should combine available data with geological understanding of the reservoir.

Figure 5-14 shows the azimuth polar plot of the permeability data in the Gypsy reservoir. It gives a quick graphical view of the strong East-West bias in the orientation of the

Gypsy data values. Many factors such as a preferred alignment of wells in one direction, preferred orientation of directional drilling, geological anisotropy, and biased data sampling can contribute to a directional data bias. The bias in the polar plot suggests that subsequent variogram calculations could have a directional bias. It is necessary to question whether the trends in the polar plot are related to real geological/petrophysical variations in the subsurface reservoir or are they related, in part, to a data bias. If the bias is caused by data, the variogram calculated from these data should be interactively corrected using a geological interpretation. Fortunately, in the case of the Gypsy reservoir, the wells were drilled in a regularly spaced rectangular pattern. Thus the directional bias should reflect geology rather than a data bias.

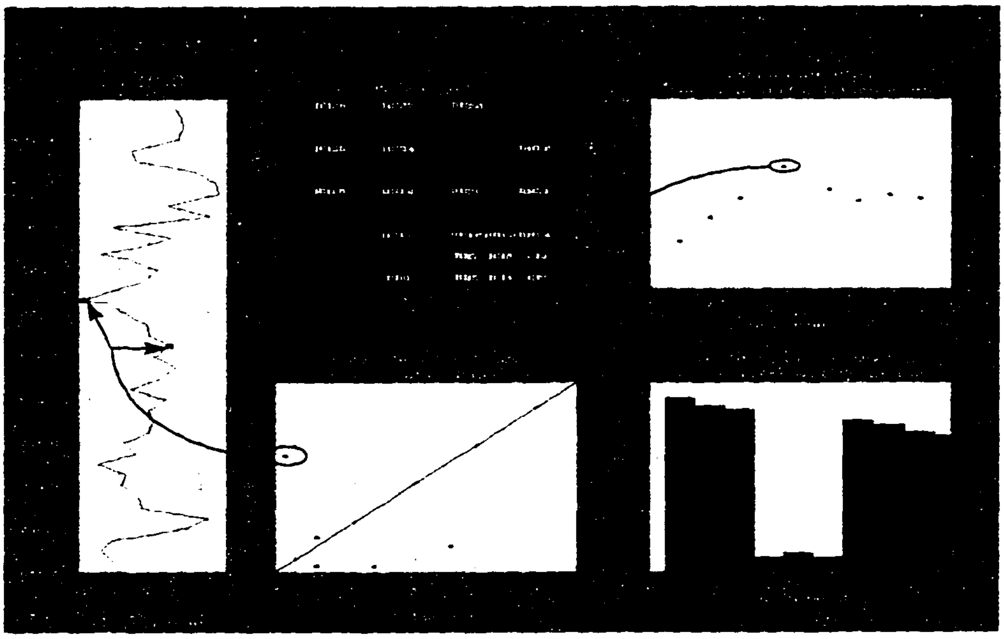


**Figure 5-13 Example of interactively interpreting a vertical variogram.**

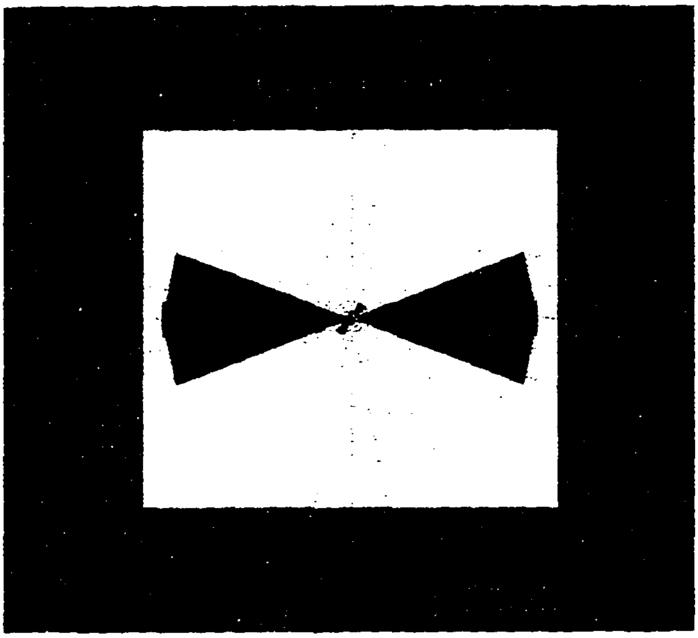


**Figure 5-14 Azimuth polar plot of permeability data in the Gypsy Outcrop site.**

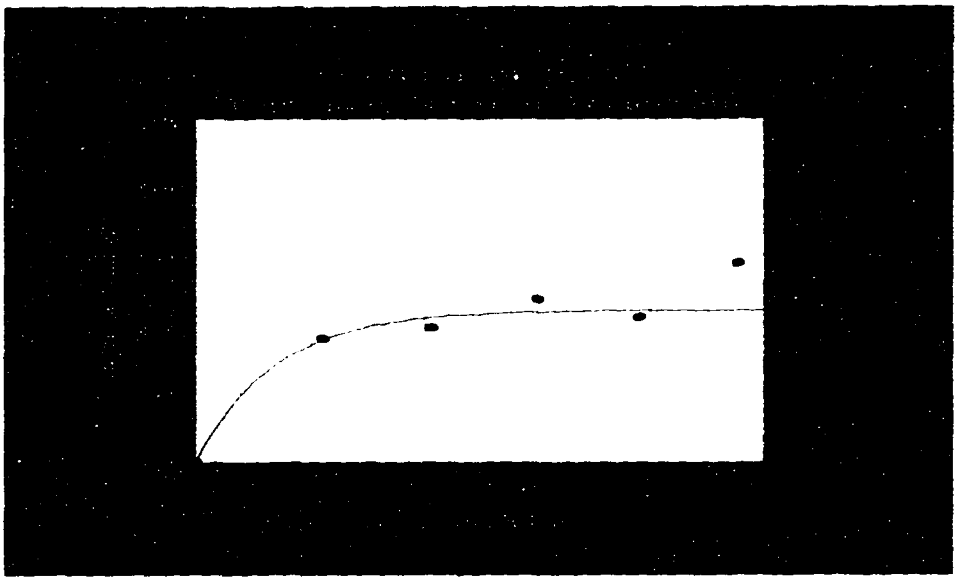


**Figure 5-15 Areal permeability variogram in the Gypsy outcrop site.**

Figures 5-15 and 5-16 are the areal variograms of permeability and porosity in the Gypsy outcrop site. The correlation is good within a range of 400 ft and becomes poor beyond 800 ft.

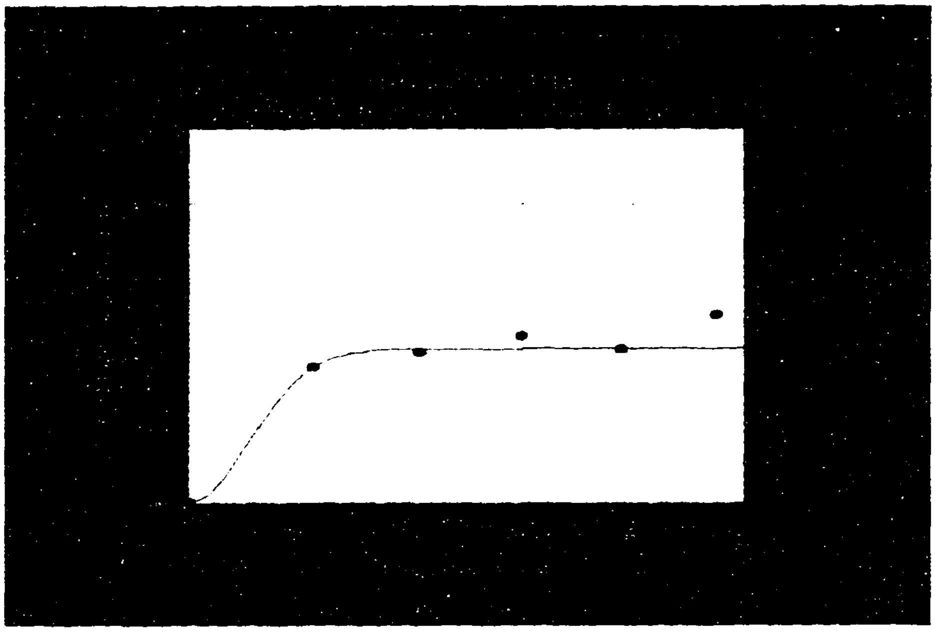


**Figure 5-16 Areal porosity variogram in the Gypsy outcrop site.**

### 5.4.2 3-D estimation and simulation of reservoir properties

Two geostatistical techniques included in the $RC^2$ software are used in this study: 3-D ordinary Kriging and sequential Gaussian simulation. Ordinary Kriging is a linear unbiased estimation method which aims to minimize the variance of the estimated errors. It is linear because the estimates are a weighted linear combination of the data values, and it is unbiased in that it produces estimated errors with zero mean. This method forms the core of most stochastic estimation and simulation techniques. The weights are computed from the solution of the ordinary Kriging system which is defined by a variogram. As the estimation location changes, so do the weights. These weights are not a function purely of geometric distances as most commonly used methods are, but are a function of "statistical" distance as defined by a customized variogram.

The similar inputs are required for stochastic simulations as for Kriging estimation techniques. However, since the simulations are using stochastic method, a seed number is required for all simulation techniques to generate a sequence of uniform random numbers. In the sequential Gaussian methods, ordinary Kriging is used to provide a local cumulative distribution function. The mean and the variance of the Gaussian distribution is the Kriging estimate and variance respectively ($RC^2$ Manual, 1995). A value randomly selected from the distribution is assigned to a node selected by an independent random path. Each newly simulated node value becomes part of the hard data for subsequently simulated nodes. The seed number defines the random path which defines the realization. Unlike Ordinary Kriging, Sequential Gaussian simulation is automatically performed in Gaussian space. The hard data values, original and simulated, are forward transformed to their standard normal counterparts. The computed weights are applied to these standard normal deviates and the resulting estimate is back transformed to its counterparts in the original data distribution ($RC^2$ Manual, 1995).

The two geostatistical methods mentioned above were applied to each of the geological models based on the Gypsy outcrop site: a channel model that uses individual channel sequences as a framework, and a lithofacies model in which the framework is defined by lithofacies modules. The purpose of this work is not only to show the results of applying geostatistical applications to the Gypsy reservoir, but also to demonstrate the importance and influence of geological concepts on the results of geostatistical applications.

The resulting permeability distributions are illustrated by a section along the Gypsy channels. In the lithofacies model, as shown in figures 5-17 and figure 5-18, both of the geostatistical applications produce a similar general trend. However, the 3-D ordinary Kriging estimation produces a smoother permeability distribution (figure 5-17) than the more heterogeneous pattern obtained from the sequential Gaussian simulation (figure 5-18). Figure 5-19, the lithofacies distributions interpreted from the geological correlation, illustrates the high and low permeability parts of the reservoir and the flow barriers. Comparison of the geological interpretation with the results of the geostatistical

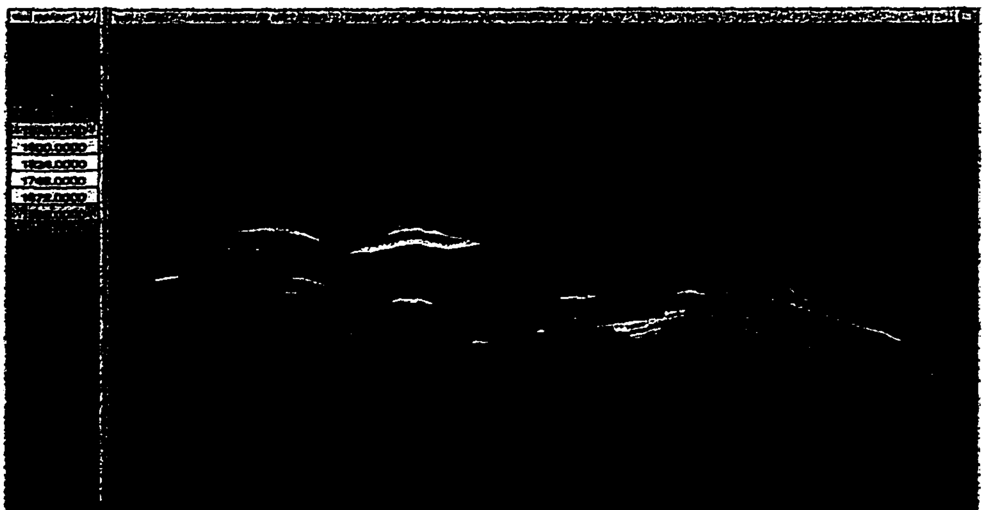


**Figure 5-17 Permeability distribution from 3D ordinary Kriging estimation in the lithofacies model.**

**Figure 5-18 Permeability distribution from sequential Gaussian simulation in the lithofacies model.**

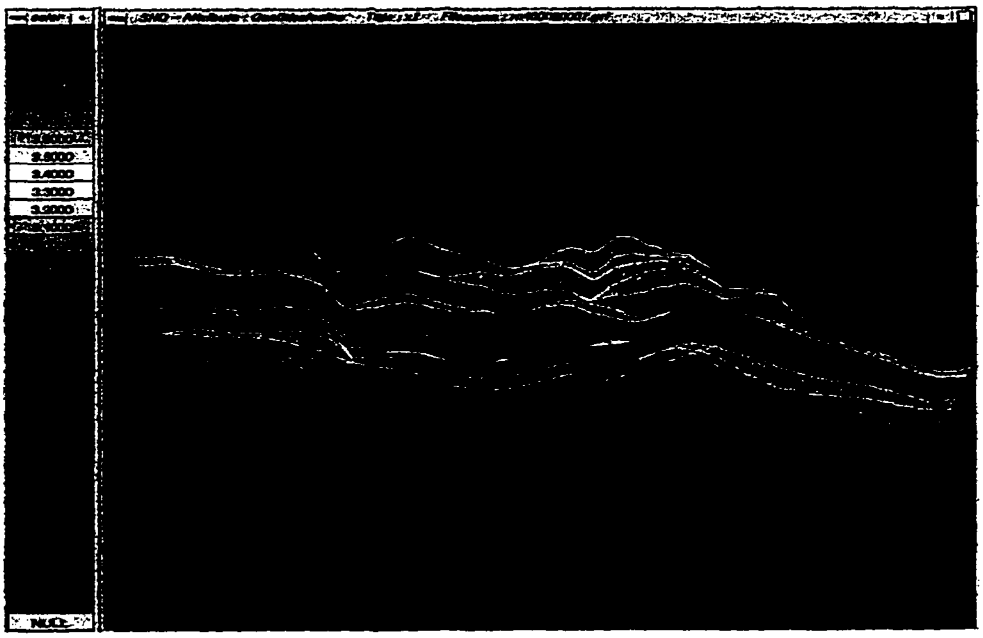


**Figure 5-19 Geological distributions of the Gypsy lithofacies modules.**

applications verifies the reliability of these statistical methods which accurately predicted the areas of high or low permeability and the locations of flow barriers. These geostatistical techniques predicted similar trends in the porosity distributions as shown in figures 5-20 and 5-21.

The results of these geostatistical methods applied to the channel model are similar to the results based on the lithofacies model. The 3-D ordinary Kriging produced a smooth distribution of permeability (figure 5-22); the sequential Gaussian simulation revealed more reservoir heterogeneities (figure 5-23). Similar trends are shown for porosity distributions illustrated in figures 5-24 and 5-25. Comparison of the geostatistical results using the lithofacies model with the results based on the channel model shows that heterogeneities have been averaged away in the channel model and major flow barriers have been missed such as those on the right side of the reservoir section. Moreover, the depositional sequences used to construct the channel model do not capture the reservoir heterogeneity (figure 5-26).

Figures 5-27 and 5-28 show only the impermeable parts of the reservoir which more clearly illustrate the effect of geological concepts on geostatistical predictions. The shale distributions estimated by 3-D ordinary Kriging for the lithofacies model and the channel model respectively clearly depict the differences between the two models. The shale appearing in the northern part of the lithofacies module model is disappeared in the channel model. However, a thick shale is showed in the southern part of the channel model which does not exist in the lithofacies module model.

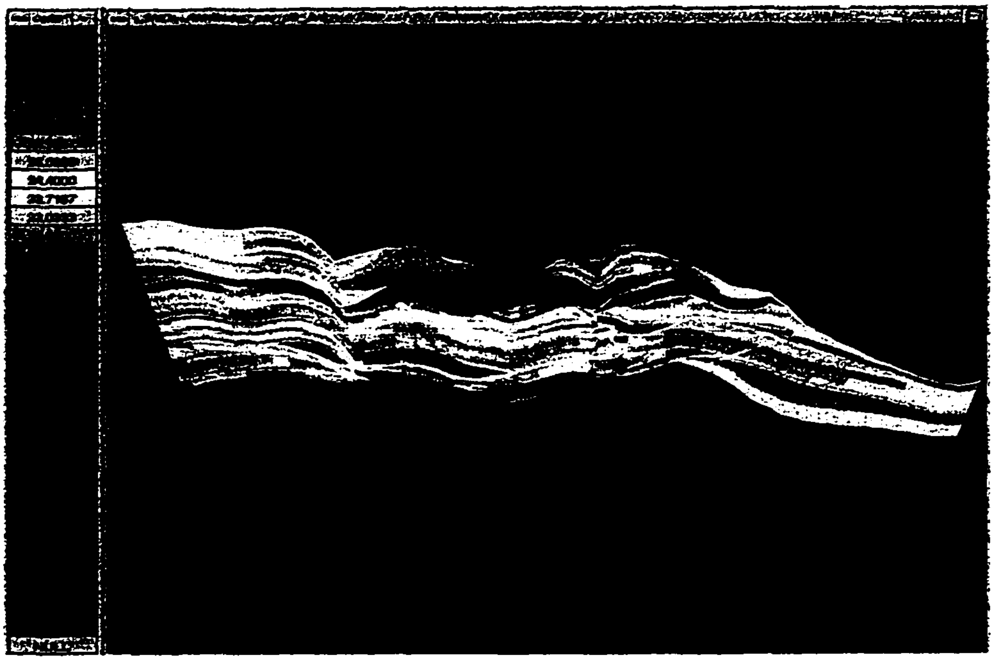


**Figure 5-20 Porosity distribution from 3D ordinary Kriging estimation in the lithofacies model.**

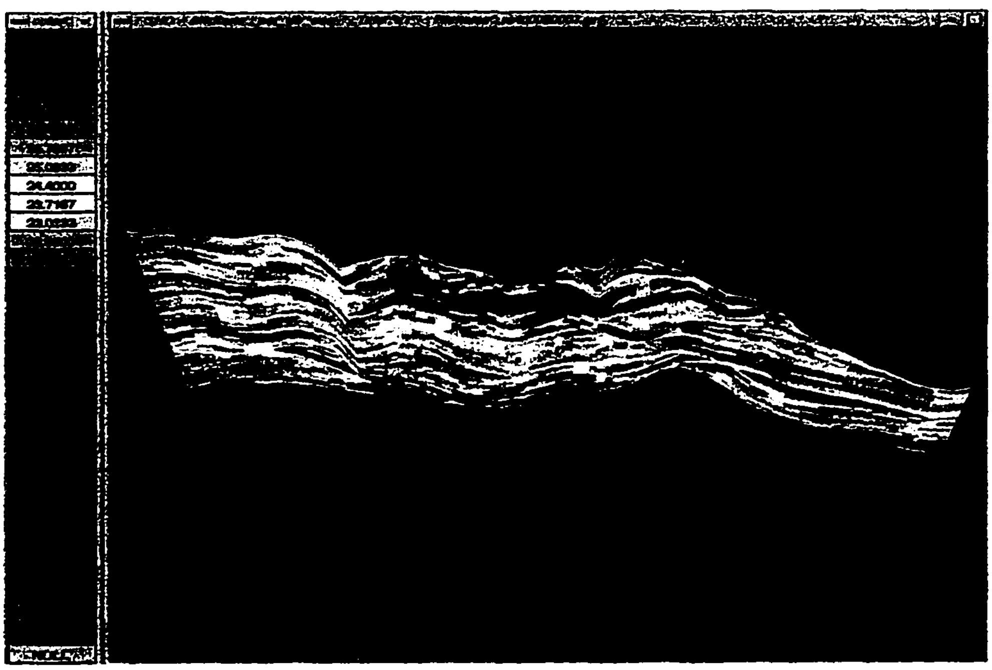


**Figure 5-21 Porosity distribution from sequential Gaussian simulation in the lithofacies model.**

**Figure 5-22 Permeability distribution from 3D ordinary Kriging estimation in the channel model.**

**Figure 5-23 Permeability distribution from sequential Gaussian simulation in the channel model.**

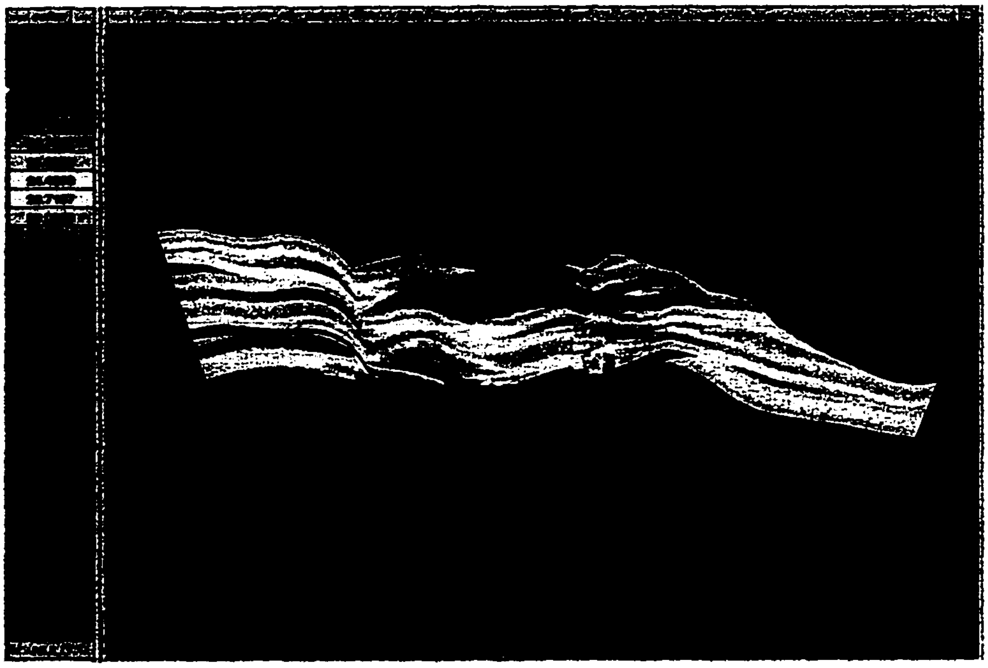


**Figure 5-24 Porosity distribution from 3D ordinary Kriging estimation in the channel model.**

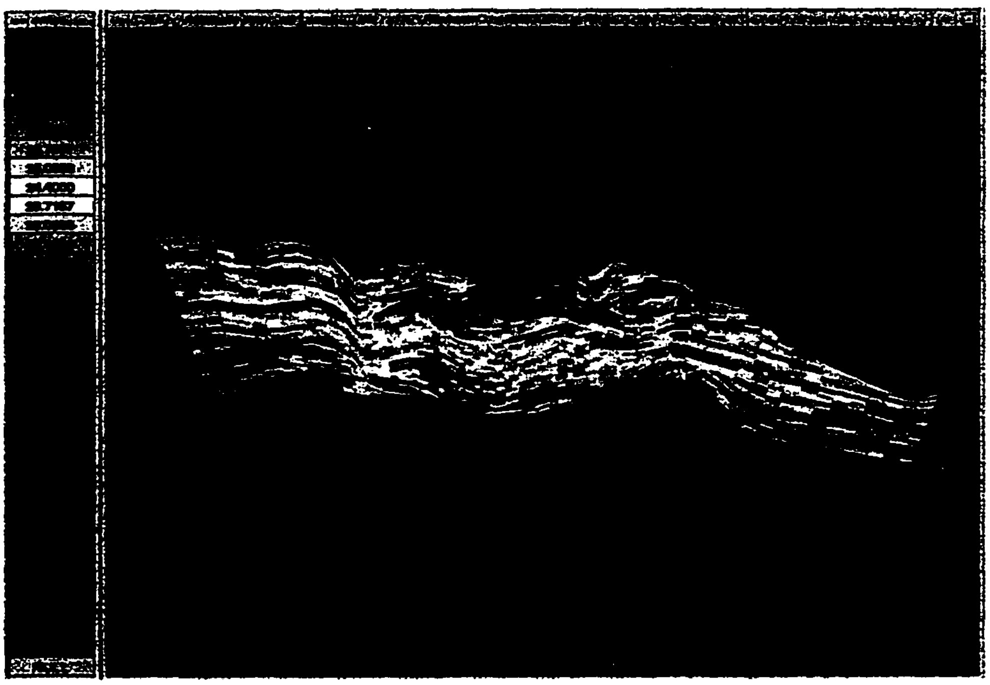


**Figure 5-25 Porosity distribution from sequential Gaussian simulation in the channel model.**

**Figure 5-26 Geological distributions of the Gypsy channel sequences.**

In summary, geostatistical techniques can be very powerful and reliable tools for the prediction of reservoir heterogeneity if they are used properly in combination with geological knowledge. Geological information and geostatistical consideration should be integrated from the beginning of data sampling through the prediction of reservoir properties using the established models. Sequential Gaussian simulation displayed the heterogeneity in the Gypsy Outcrop fluvial reservoir. The lithofacies module concept provides a detailed reservoir framework suitable for geostatistical prediction. Using sequential Gaussian simulation on the Gypsy lithofacies model produced reliably predictions of the reservoir heterogeneity. The channel concept does not provide a reasonable model of reservoir properties and is not suitable for geostatistical prediction.

**Figure 5-27 Shale distributions estimated from 3D ordinary Kriging in the Gypsy lithofacies model.**

**Figure 5-28 Shale distributions estimated from 3D ordinary Kriging in the Gypsy channel model.**

# CHAPTER 6. GEOLOGICAL IMPACTS ON OIL PRODUCTION

The purpose of reservoir characterization and modeling is to provide a solid foundation for reservoir simulation that is sufficiently accurate to be used for reservoir management. Because the quality and accuracy of the geological model largely controls the accuracy of simulation results, the model has a critical impact on reservoir management decision. Thus this study emphasizes the effects of model building and well placements on reservoir performance. The results of three cases are presented to show the impact of the factors listed below on hydrocarbon recovery.

(1) **Modeling concepts:** The geological framework and concept used in building the reservoir model determine the distribution of reservoir properties that control fluid flow. Different concepts for defining a reservoir model can result in as much as a 30% difference in hydrocarbon recovery as showing in Figure 6-1.

(2) **Vertical resolution & upscale:** The selection of vertical resolution is a critical parameter of the reservoir model. An example from the Gypsy model is showed in figure 6-6, 6-7, and 6-8. The resolution selected should satisfy the following criteria:

   a) The resolution is high enough to adequately represent the reservoir heterogeneity;

   b) The number of cells in the model can be handled by available computers;

   c) Both geologists and reservoir engineers should be comfortable with the detail provided and computational time required.

If the model needs to be upscaled from a detailed geological model to an engineering model with fewer cells, the concept of lithofacies modules provides a reasonable, and accurate guideline for the upscaling (figure 6-1).

(3) **Well placement:** Differences in the number and locations of production and injection wells and the distribution of injected fluids can result in large differences in hydrocarbon recovery. Simulation based on an accurate reservoir model provides an economic and quick method for evaluating various development strategies to select the scenario that provide the optimum economical return. An example is illustrated in section 6-3 showing as much as 50% difference of oil production.

## 6.1 Modeling Concepts

### 6.1.1 Modeling frameworks

Three cases using the modeling concepts listed below illustrate the differences in production from an inverted five spot configuration of wells.

1) Unimpeded flow across channel or facies boundaries;
2) No flow across channel boundaries; and
3) No flow across and within shale sequences that form flow barriers.

In the first case flow is determined entirely by the permeability distribution, irrespective of considerations of boundaries between channels or lithofacies modules. In the second case the transmissibility multiplier is set to zero between any grid blocks for which there is a change in channels. In the third case permeability is set at zero for all mappable shale sequences to ensure no flow across and within the shale facies. In all cases, the same volume is injected at a constant rate into a central well, with four production wells, at the corners, having the same constant bottom hole pressure.

The third case is the most sensible. It assumes that all of the major flow barriers have been explicitly mapped geologically and represents the "best" work a geologist can give to the engineer. The first case, based on lithofacies modules, relies on the low permeability of the shale module to produce realistic flow barriers. Case 2 is the least sensible insofar as it cuts off flow whenever channel changes across interface between grid block. This case assumes flow barriers had been deposited and are preserved between channels. Detailed outcrop and borehole evidence indicates channels incising one another with no apparent impermeable barrier between channels.

Figure 6-1 shows the differences in oil recovery for up to 2 pore volumes of water injected. As one would expect, the channel case and lithofacies case are substantially different; case 1 shows the highest recovery and case 2 shows the least. The results of case 3 and case 1 are similar because the interpretation of permeability is based on shale distribution in each of these cases. The higher recoveries for cases 1 and 3 compared to case 2 are because the high permeability cross-bedded sandstone lithofacies module are well connected across the model. irrespective of channel boundaries. The flow barriers are defined by existing impermeable shale not genetic sequence boundaries as in case 2 where no flow is allowed across a channel boundary.

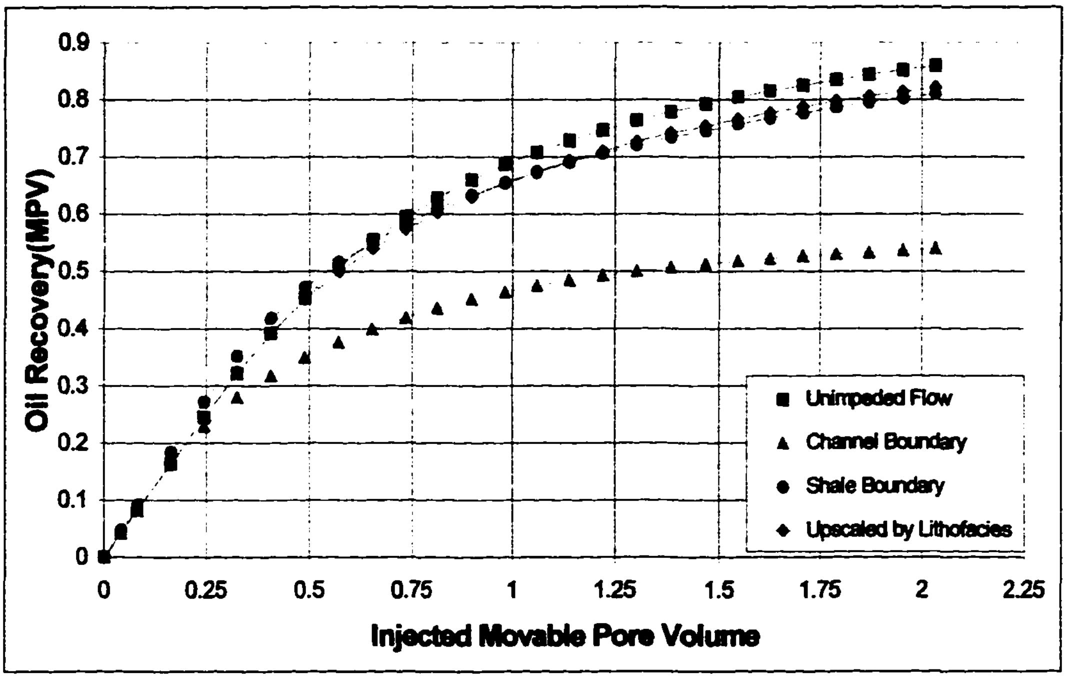



**Figure 6-1 Impact of modeling concepts on oil recoveries, see text for explanation.**

Figures 6-2 and 6-3 show oil saturation profiles along the Gypsy channels emanating from the central well after injection of 0.2 pore volumes of water. Figure 6-2 depicts case 1, unimpeded flow and figure 6-3 depicts case 2, no flow across channel boundaries. Channeling and water breakthrough occurs in case 2 but not in case 1. Figures 6-4 and 6-5 show the flood pattern within the geobody after 0.2 movable pore volumes of water for unimpeded flow and no flow across channel boundaries respectively. The shape difference between these two cases shows the differences in flow paths, flow directions, and flooded areas.

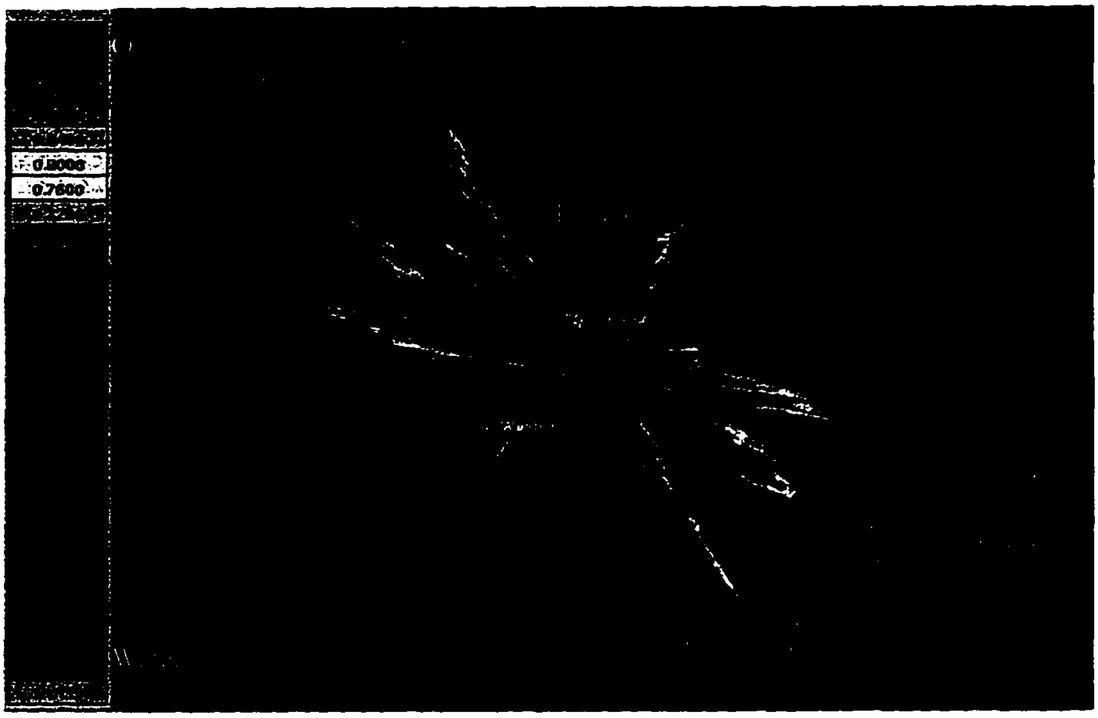


**Figure 6-2 Water flooding after 0.2 movable pore volume of unimpeded flow simulation.**

**Figure 6-3 Water flooding after 0.2 movable pore volume of no flow across channel boundary simulation.**

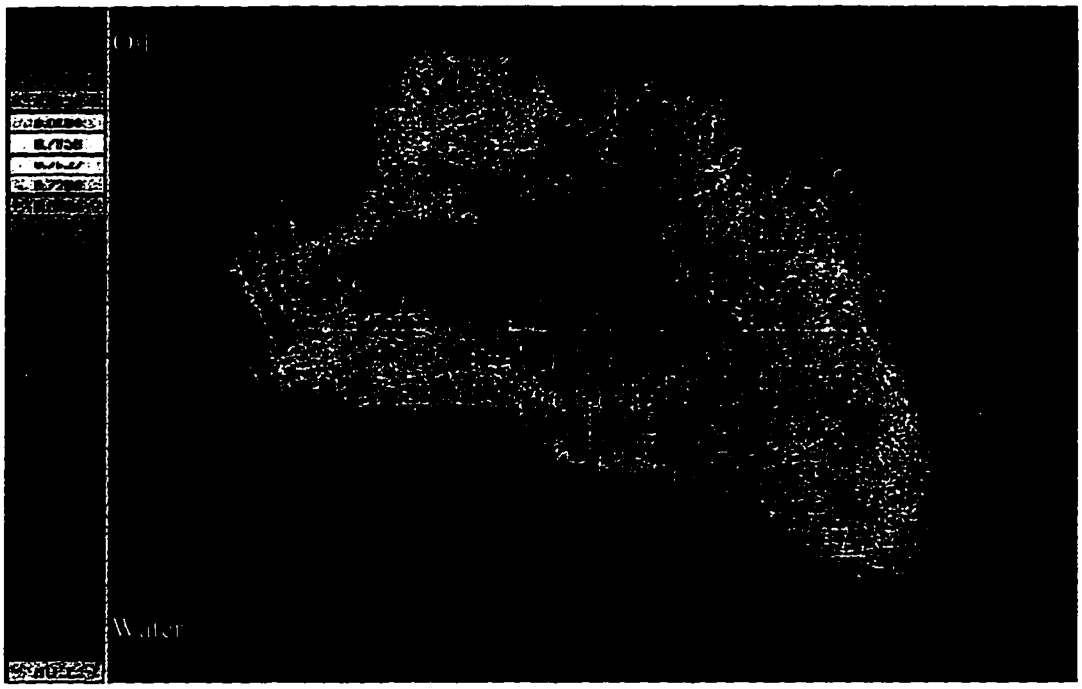


**Figure 6-4 Flooded geobody after 0.2 movable pore volume of unimpeded flow simulation.**

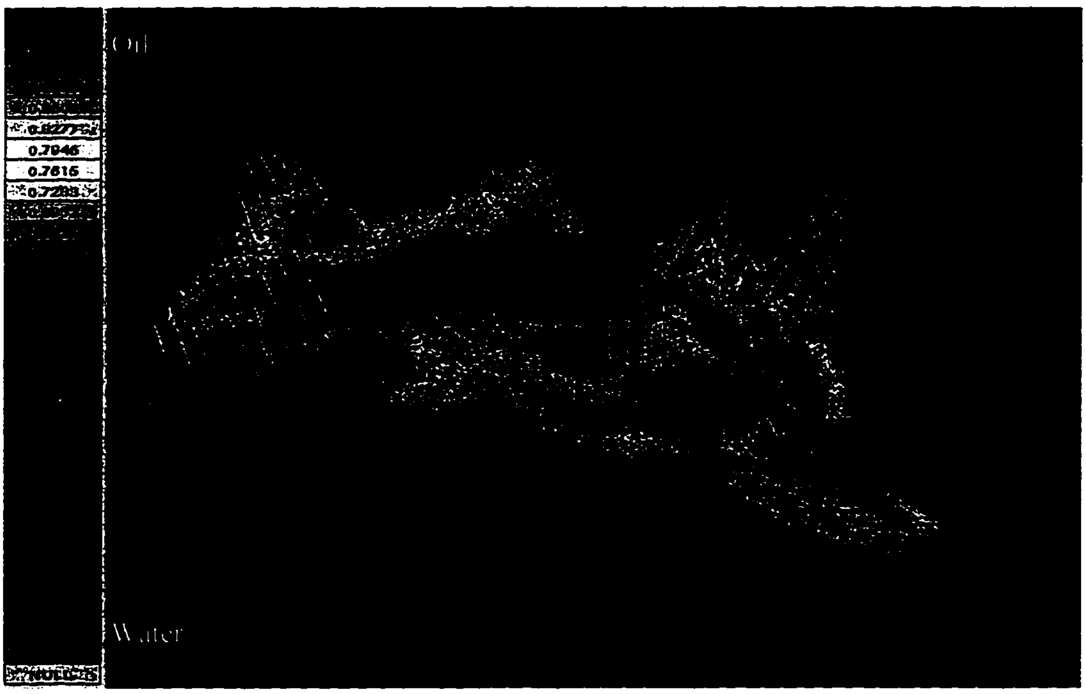



**Figure 6-5 Flooded geobody after 0.2 movable pore volume of no flow across channel boundary simulation.**

### 6.1.2 Flow Barriers

Four cases of flow barriers have been simulated for an isolated, inverted five spot configuration of wells as illustrated in Figure 6-6 (O'Meara & Jiang, 1996).

1) Unimpeded flow across channel or facies boundaries (red);
2) No flow across channel boundaries (yellow);
3) No flow across sequence boundaries (lithofacies module boundaries) (blue); and
4) No flow between different types of lithofacies modules (green).

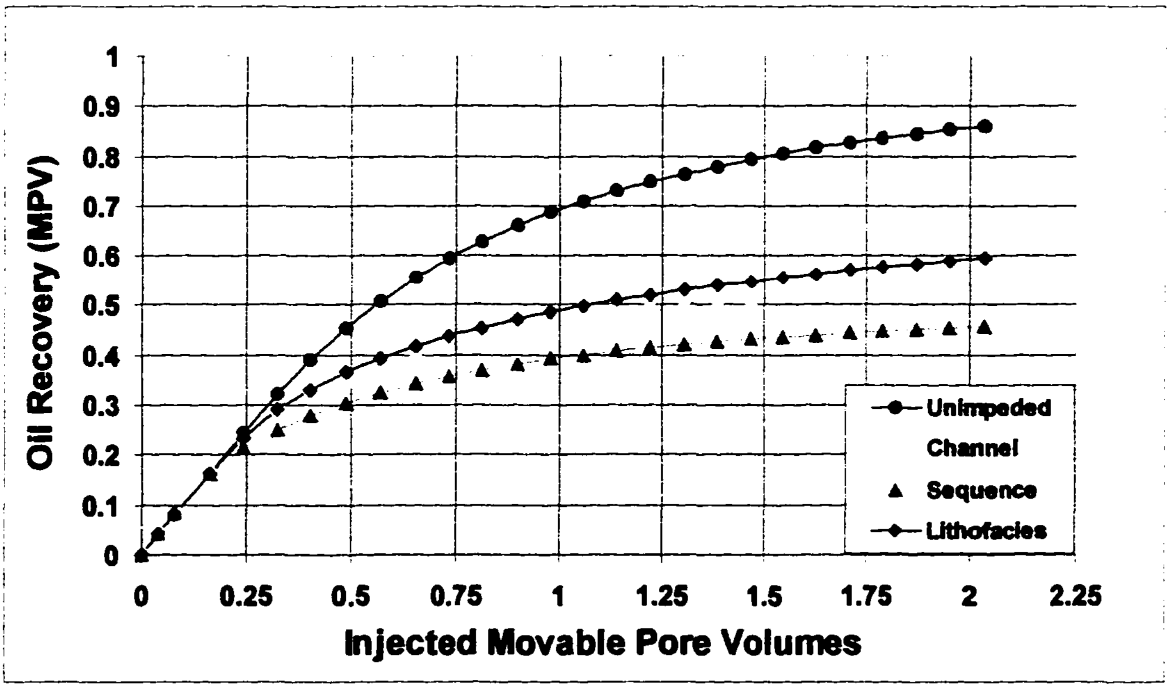



**Figure 6-6 Effects of flow barrier assumptions on oil recoveries. See text for explanations.**

To highlight the effects of different flow barriers that assume the exists of flow barriers along some kinds of geological boundaries, the Gypsy lithofacies module model is used for all these four cases of simulation. Therefore, all reservoir properties and parameters used for these simulation studies are the same except the assumptions of flow barriers.

Comparing to the unimpeded flow which allows flow to be determined entirely by the permeability distribution, all those assumptions have significant impact on fluid flow and oil recovery. However, the assumptions of no flow across sequence boundaries or individual lithofacies modules and no flow across channel boundaries have the most effect on oil recovery. The case of no flow across different types of lithofacies modules shows that there are more fluid flow along the same type of lithofacies modules than that along channels.

### 6.1.3 Internal heterogeneity

The consequences of impeding flow in the vertical (Z) direction are explored in this section for the case of an inverted five spot and a line drive directed alone the channels. The Z direction transmissibility multipliers used for the simulations are 0, 0.01, 0.02, and 0.1 for overbank, mudclast, ripple, and cross-plane bedded lithofacies modules respectively. The values of the transmissibility multipliers are quantitative estimates based upon the degree to which we expect flow to be impeded due to thin clay or silt layers or drapes within the modules. Overbank modules are modeled as flow barriers. Mudclast and ripple modules are modeled as offering relative more impedance to flow than cross-plane bedded modules. Four cases are investigated and illustrated in figure 6-7:

1) Five spot with unimpeded flow (red);
2) Five spot with Z direction transmissibility multipliers depending on types of lithofacies modules (yellow);
3) Line drive with unimpeded flow (blue); and
4) Line drive with Z direction transmissibility multipliers depending on types of lithofacies modules (green).

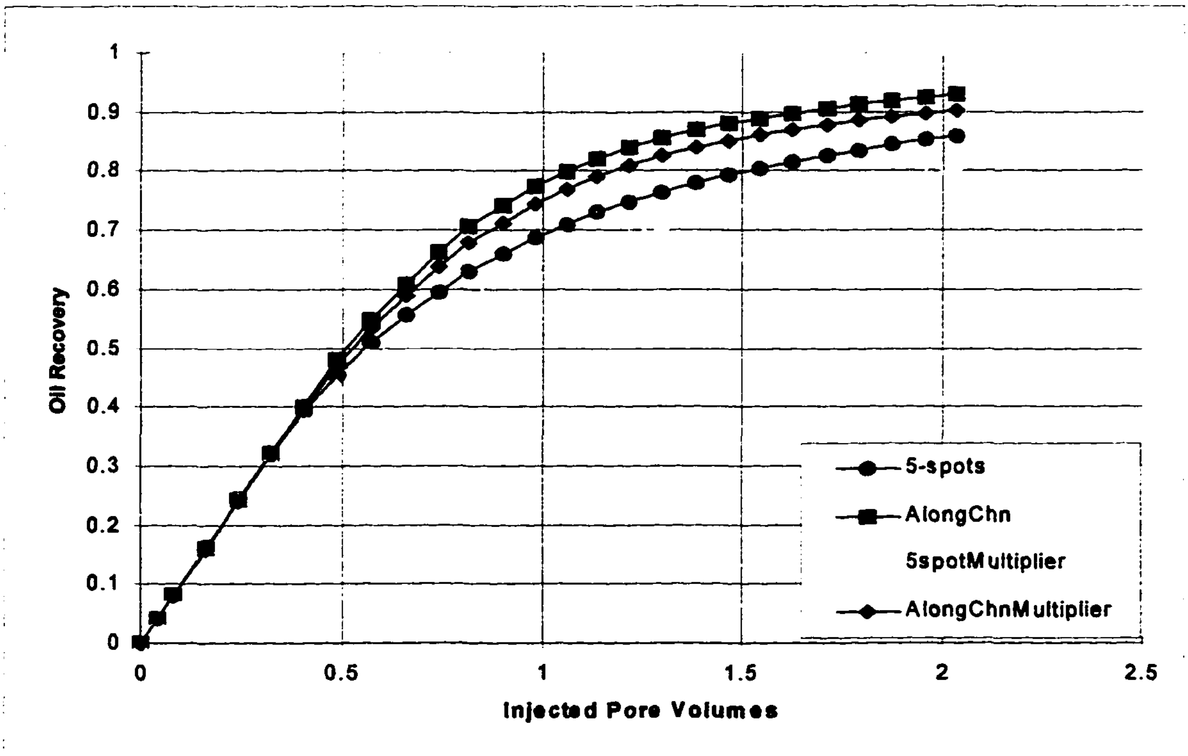



Figure 6-7 Effects of reservoir internal heterogeneity on oil recovery.

For up to 2 pore volumes of water injected, the oil recovery for the five spot is 0.06 pore volume less using the Z transmissibility multipliers. The line drive recovers 0.03 pore volume more oil for unimpeded flow than for using Z transmissibility multipliers. The results indicate fluid flow in this Gypsy model accounts more on lateral than on vertical directions.

Comparing the results in figure 6-6 and figure 6-7, the assignment of flow barriers has much more impact on oil recovery than the reservoir internal heterogeneity. The lithofacies module framework has the flow barriers mapped geologically and provides a more accurate distribution of flow barriers for reservoir simulation studies.

### 6.2 Vertical Resolution and Upscale

Three scales of vertical resolution were used to build the Gypsy reservoir models for illustrating the impact of modeling resolution on reservoir simulation: 1 foot, 3 feet, and 10 feet layer thickness. All models were built using the same set of data and the simulation parameters. Figures 6-8 show the cross sections of water flooding from these three models of different resolution. The flow in the 10 feet model illustrate the apparent reservoir homogeneity produced by low vertical resolution. Each of the models with 3 feet and 1 foot vertical resolution indicates heterogeneous flow paths. Comparing the results of 3 feet and 10 feet models, the 3 feet layer thickness may represent adequately the reservoir heterogeneity. In another word, the resolution should be sufficiently to

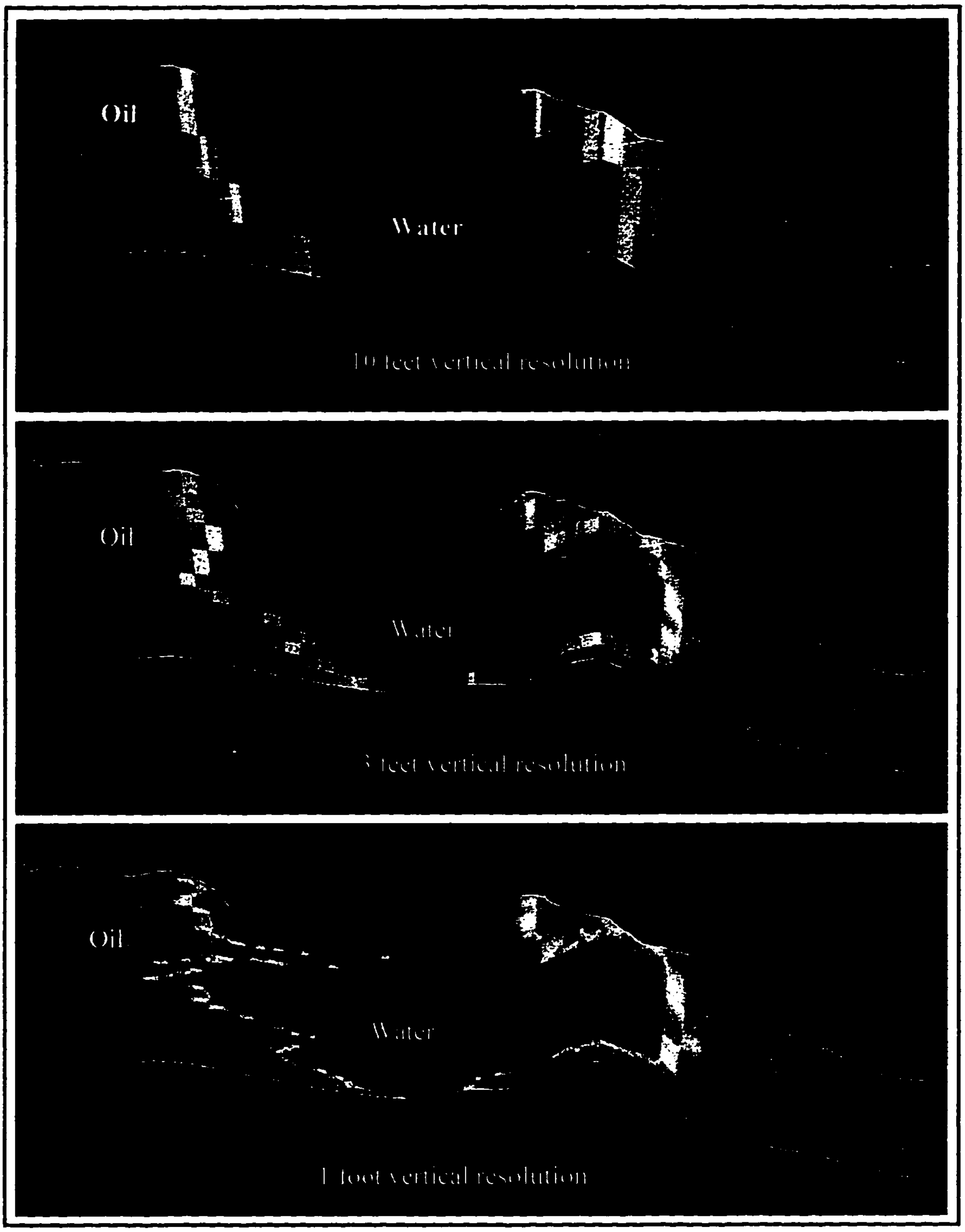



**Figure 6-8 Water flooding simulations on different vertical resolutions.**

reveal the major characteristics of reservoir heterogeneity and provide a model containing the number of cells that can be run easily and economically on available computers.

Upscaling can be achieved by using the unique characteristics of lithofacies modules which have already been defined as relatively uniform parts of a highly heterogeneous reservoir. An example of upscaling a reservoir using lithofacies modules in the Gypsy Outcrop site is shown on figure 6-1 (case 4, green diamond). The upscaled model contains one layer for each lithofacies module compared to one-foot layers in the detail model. The upscaled model contains 24 and 13,559 active SGM cells. The detailed model contains 190 layers and 54,859 active SGM cells. Shales in this upscaled model are defined the same way as in case 3. The upscaled model with a vertical resolution 1/8 that of the detailed model has nearly the same production results as the detailed model after two movable pore volumes of water flood simulation. This suggests an effective way for upscaling a detailed geological model of the reservoir to a coarser model for simulation.

### 6.3 Well Placement

Even for an accurate reservoir model, oil recovery still can be changed dramatically depending on the well placement and production scenarios. A model of a North Sea oil is used to illustrate the importance of the field development scenario to the petroleum recovery (figure 6-9). This model consists of 8 stratigraphic formations and one normal fault (the lithofacies module concept was not applied in this model).

The same reservoir model and the same total volumes of injected water at the same constant producing bottom hole pressure were used for a 10 year period of water flood simulation. The differences are the number and placement of injection and production wells and the allocate of the total injection water among the injectors.

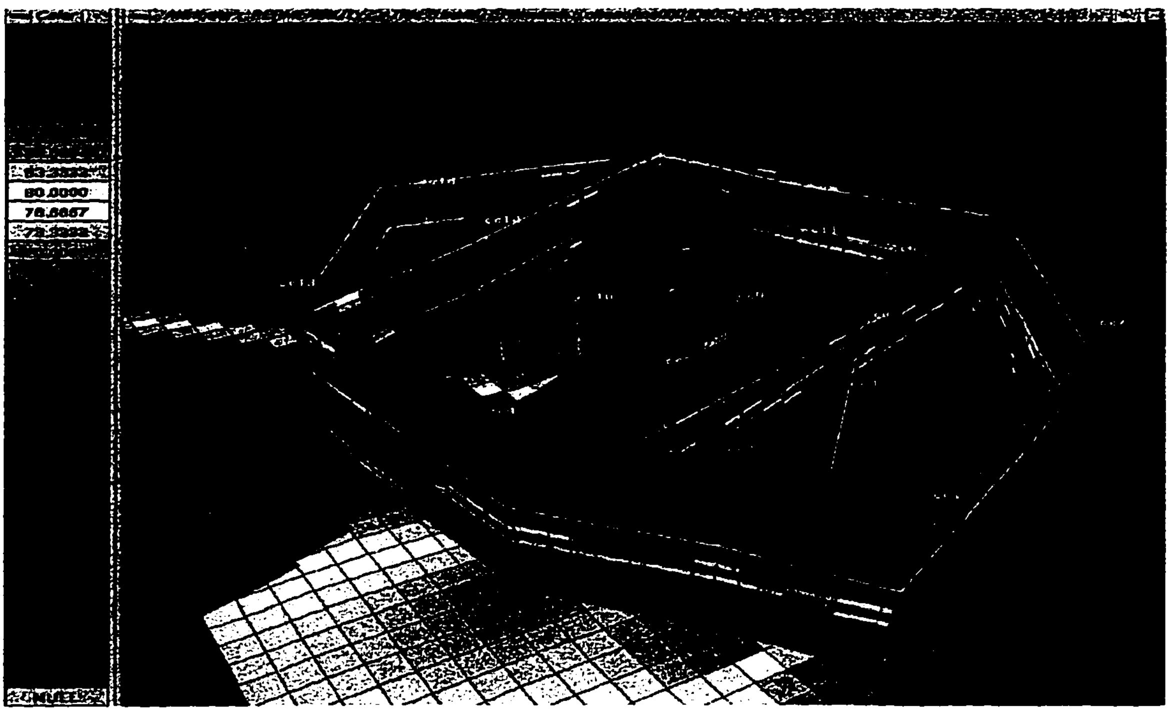


**Figure 6-9 Permeability distribution in a North Sea field model.**

The results of oil production after 10 years are:

- The best: 950 MM bbl of oil with a line-drive configuration using 4 injector and 4 producers (figure 6-10);
- The worst: 650 MM bbl of oil using 6 injectors and 8 producers (figure 6-11);

The best case is possibly not the optimum and the worst is possibly not the minimum, but the difference of about 50% more oil produced in 10 years with 50% fewer well drilled dramatically illustrates the importance of the development strategy selected. The value of the additional oil produced in 10 years at US$20.00/bbl is 6 billion USD. Figure 6-10 shows the permeability distribution within the model used. Figure 6-10 shows the flow path of the best water flooding scenario, the line drive from west to east and figure 6-11 shows the least successful case. The value of geological modeling and reservoir simulation to aid in the description of a development plan is obviously significant.

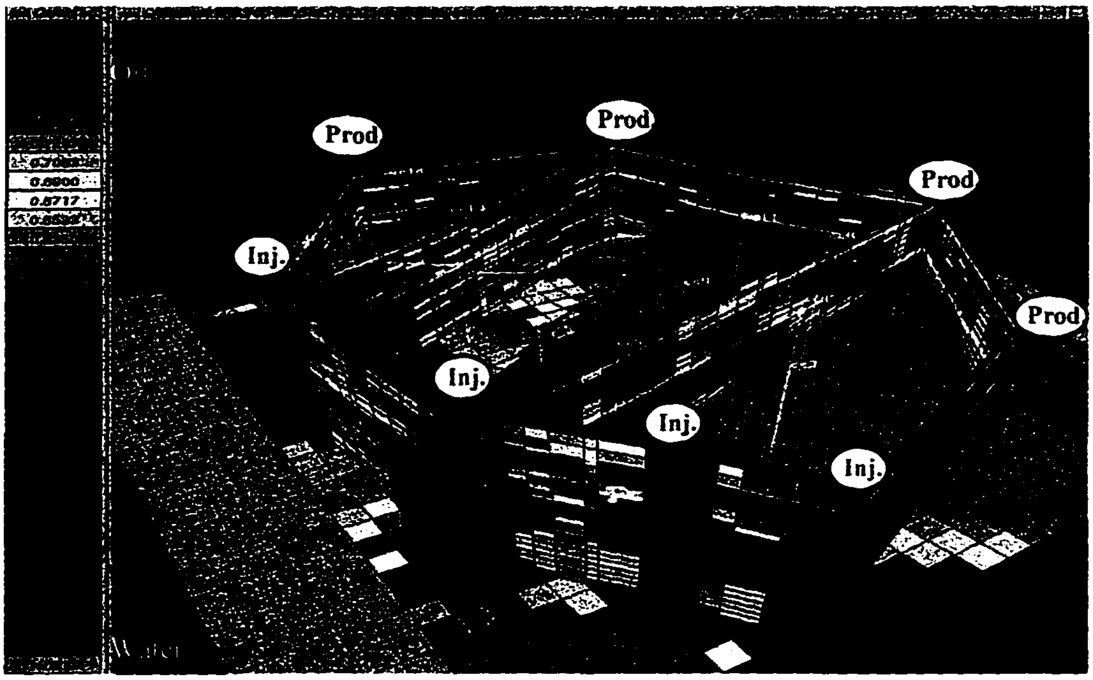



**Figure 6-10 The best water flooding case in the training program.**

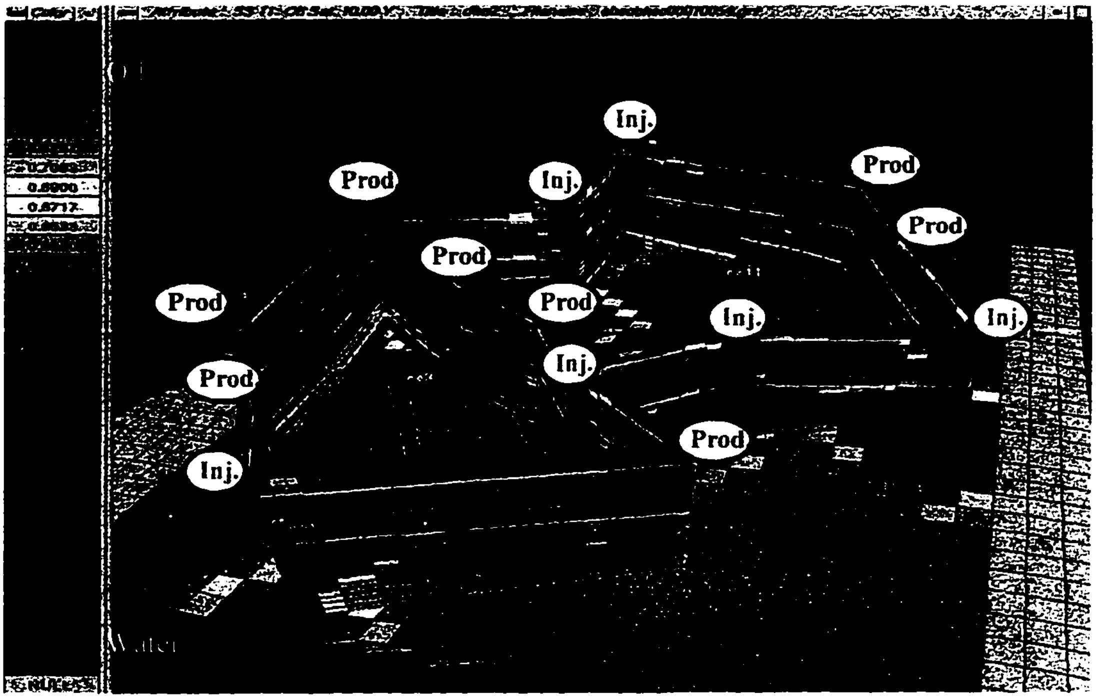



**Figure 6-11 The worst water flooding case in the training program.**

## CHAPTER 7. SUMMARY

The purpose of reservoir characterization is to economically improve hydrocarbon recovery through interdisciplinary efforts. The key for success not only relies on the results from individual disciplines, but more importantly depends on communication between disciplines and the methods and concepts used to integrate information. To ensure the maximum data transfer between disciplines during the processes of integration, this concept and methodology must suit the needs of all disciplines.

The lithofacies module, a concept for interdisciplinary reservoir characterization proposed in this investigation, is a package of sediments restricted within a chronostratigraphic sequence and distinguished by a similar depositional environment and similar petrophysical properties that have similar effects on fluid flow within the unit. Genetically, lithofacies are the basic describable rock units within a chronostratigraphic sequence. In turn, a chronostratigraphic sequence can be subdivided into different lithofacies modules (which may contain one or more lithofacies) that can be correlated and mapped within the sequence. The study of lithofacies modules gives a detailed understanding of the distributions of sedimentary environments and thus the depositional changes.

The differences of depositional environments between lithofacies modules produces deposits having different sedimentary structures, textures, and compositions. These characteristics of each unique lithofacies module in turn control the results of diagenesis under the same geochemical environments and geological history. Thus the observed reservoir properties are similar within the same lithofacies module and significantly different between different lithofacies modules as illustrated clearly by the data obtained from the Gypsy Outcrop site.

Geological control is the fundamental factor in reservoir characterization that has a great impact on the interpretation and application of data from different disciplines. The accuracy of a reservoir model can be improved by the use of computer software and geostatistics within geological constraints. Reservoir models based on lithofacies modules reveals the distributions and characteristics of the reservoir heterogeneities. Thus, significant improvement in oil recovery should be expected from reservoir simulation studies based on this more accurate model.

### 7.1 Conclusions

The following conclusions and recommendations can be derived from the results of this research effort:

- The lithofacies module is a package of sediments restricted within a chronostratigraphic sequence and distinguished by a similar depositional environment and similar petrophysical properties that have similar effects on fluid flow within the unit. It should be the basic unit for reservoir characterization and geological modeling.

- The concept of a lithofacies module embraces the common needs of multiple disciplines in reservoir characterization. It provides a common basis between geology and reservoir engineering.

- The lithofacies module based methodology furnishes a framework for directing the workflow of interdisciplinary studies. This hierarchy ensures that all parts of the study are useful and acceptable to each other in the reservoir characterization process: from data collection and observation to reservoir modeling and performance prediction.

- Genetic relationships between lithofacies modules and depositional environments, and between lithofacies modules and reservoir properties make reservoir heterogeneities predictable and mappable.

- Four types of lithofacies modules can be systematically recognized within each individual channel sequence in the Gypsy fluvial reservoir. From bottom to top, the lithofacies modules are: mudclast sandstone module with a mean permeability of 73 md and porosity of 15%, cross-bedded and plane-bedded sandstone module with mean permeability of 864 md and porosity of 24%, ripple laminated sandstone module with mean permeability of 165 md and porosity of 20%, and overbank shale and siltstone module with the mean permeability of 0.6 md and porosity of 11%.

Interquartile permeability of the Gypsy outcrop reservoir is 0.15 to 20.6 md, 323 to 1220 md, 2.7 to 144 md, and less than 0.2 md in mudclast sandstone module, cross-bedded and plane-bedded lithofacies module, ripple laminated sandstone module, and overbank shale and siltstone flow barrier module respectively.

- Lithofacies modules subdivide a highly heterogeneous clastic reservoir with wide variations of properties into segments with much narrower variations of reservoir properties. This enables available software to model reservoir heterogeneity more accurately.

- The correlation of lithofacies modules is a lithostratigraphic correlation restricted within a chronostratigraphic sequence. The correlation of lithofacies modules not only involves lithologic similarity but also the vertical succession of lithofacies modules within a chronostratigraphic sequence. Each lithofacies module has a unique position within a chronostratigraphic sequence. These identical characteristics and unique position provide a direct and reliable signature for correlating units within a reservoir.

- Four geological modeling scales have been classified here: stratigraphic sequence scale, reservoir scale, lithofacies module scale, and sample scale. Each modeling scale reflects a different scale of reservoir heterogeneity and has different data requirements. The reservoir scale is most commonly used in the petroleum industry although the lithofacies module scale provides more accurate prediction of fluid flow behavior.

- The modeling framework concept has a significant impact on the resulting reservoir model. Studies of the Gypsy fluvial reservoir have shown a great contrast between models built using the channel sequence concept and those using the lithofacies module concept. A channel sequence model reflects the depositional cycles represented by channels; the lithofacies module model highlights the distribution of reservoir heterogeneity. Reservoir properties are homogenized in the channel sequence model and heterogeneities are stressed in the lithofacies module model.

- Different data sets would produce different geostatistical reservoir models. However, a geological body could be represented by different data sets depending on differences in the sampling pattern and the concepts of interpretation and modeling. Geological factors must be considered in data collection to be used for geostatistical interpretation and the prediction of geological boundaries.

- Stochastic modeling techniques can be a useful tool for the prediction of reservoir heterogeneities if they are properly applied and include geological constraints. The application of 3D ordinary Kriging estimation and sequential Gaussian simulation produced reliable results of permeability and porosity distributions in the Gypsy lithofacies model.

- The concept of modeling framework is critical in defining fluid flow. Simulation results show as high as a 30% difference in recoveries between a channel concept reservoir model and a lithofacies module reservoir model.

- The positions of flow barriers within the reservoir have much more impact on oil recovery than other types of internal heterogeneity. The lithofacies module framework has the flow barriers mapped geologically and provides a more accurate distribution of flow barriers for reservoir simulation studies.

- The vertical resolution of the geological model has a significant impact on fluid flow within the reservoir. A low resolution model can make a highly heterogeneous reservoir appear homogenous. To model reservoir heterogeneity that can accurately predict fluid flow behavior, a suitable model resolution is important. Lithofacies modules provide an effective framework to geologically upscale a high resolution reservoir model to a coarser reservoir model for use in engineering simulation studies. An example from the Gypsy lithofacies model shows that an upscaled model of 24 layers very closely produces the production results of a high resolution model containing 191 layers.

- Different scenarios of reservoir production can have significantly different hydrocarbon recoveries which may be associated with large differences in economic criteria between the scenarios. An accurate reservoir model provides a reliable, practical, economical, and quick tool to define the production scenario that results in the most favorable values for selected economic criteria. An example from team exercises of geoscientists and engineers using the same geological model shows up to 50% difference in oil production between scenarios using different numbers and placements of injection and production wells.

- The concept of the lithofacies module can be applied for other types of reservoirs.

## 7.2 Recommendations

Many questions raised during this investigation remain unsolved. Several suggestions which are important to reservoir characterization and improving oil recovery are listed below for consideration by future researchers.

- Investigating the use of electrofacies models of different types of lithofacies modules based on wireline logs to obtain the properties of lithofacies modules to produce a velocity model for use in seismic processing and interpretation.

- Systematically classifying lithofacies modules in different depositional environments and building lithofacies models for each environment to integrate with sequence stratigraphic concepts for improving the ability to predict reservoir heterogeneity.

- Exploring the diagenetic and geochemical differences between lithofacies modules to aid our understanding and prediction of reservoir heterogeneity distributions.

Understanding the geochemical systems within different lithofacies modules can also benefit oil production during water flooding or EOR processes.

- Modeling capillary pressure, wettability, relative permeability and vertical permeability in different lithofacies modules to enable a more accurate prediction and simulation of oil production.

- Understanding the mechanical properties within different lithofacies modules to improve our understanding and prediction of the distributions of natural fractures and in designing reservoir stimulation treatments.

- Use of the Gypsy lithofacies module model and detailed data base as a tool for testing software and geostatistical methods.

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