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Integration of Facies Models in Reservoir Simulation

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Integration of Facies Models in Reservoir Simulation

By

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REPORT

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Dedication

This report is dedicated to my husband, Gong Li Wang, my son, Alex Wang,

and

my parents, Cunwen Chang and Xiufang Liu

Who have always been there to support, encourage, understand, and help me through the hard times

Acknowledgements

After two and a half years' study, it is time and a great pleasure to thank so many people who have accompanied me on this long journey in pursuit of my Master's degree.

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Abstract

Integration of Facies Models in Reservoir Simulation

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The University of Texas at Austin, 2010

Supervisor: William L. Fisher

The primary controls on subsurface reservoir heterogeneities and fluid flow characteristics are sedimentary facies architecture and petrophysical rock fabric distribution in clastic reservoirs and in carbonate reservoirs, respectively. Facies models are critical and fundamental for summarizing facies and facies architecture in data-rich areas. Facies models also assist in predicting the spatial architectural trend of sedimentary facies in other areas where subsurface information is lacking.

The method for transferring geological information from different facies models into digital data and then generating associated numerical models is called facies modeling or geological modeling. Facies modeling is also vital to reservoir simulation and reservoir characterization analysis. By extensively studying and reviewing the relevant research in the published literature, this report identifies and analyzes the best and most detailed geologic data that can be used in facies modeling, and the most current geostatistical and stochastic methods applicable to facies modeling.

Through intensive study of recent literature, the author (1) summarizes the basic concepts and their applications to facies and facies models, and discusses a variety of numerical modeling methods, including geostatistics and stochastic facies modeling, such as variogram-based geostatistics modeling, object-based stochastic modeling, and multiple-point geostatistics modeling; and (2) recognizes that the most effective way to characterize reservoir is to integrate data from multiple sources, such as well data, outcrop data, modern analogs, and seismic interpretation. Detailed and more accurate parameters using in facies modeling, including grain size, grain type, grain sorting, sedimentary structures, and diagenesis, are gained through this multidisciplinary analysis. The report concludes that facies and facies models are scale dependent, and that attention should be paid to scale-related issues in order to choose appropriate methods and parameters to meet facies modeling requirements.

Keywords: Facies, Facies model, Facies modeling, Model integration.

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CHAPTER 1: INTRODUCTION

The term "facies" was first introduced in geology by Nicholas Steno in 1669, and it was subsequently developed by Gressly (1838), Johannes Walther (1893), Teichert (1958), de Raaf et al. (1965) and Middleton (1973), (Walker 2006). Walther's Law of Facies states that the vertical succession of facies reflects lateral changes in an environment. This law proposed the connection between modern and ancient environments (Walker, 2006). Walther suggested that "the most satisfying genetic explanation of ancient phenomena was by analogy with modern geological processes" (quoted by Middleton, 1973, p.981). Middleton 1978 concluded that the key to interpretation of facies was the integration of spatial relations, internal sedimentary structures and lithology, and information about well-studied stratigraphic units and modern sedimentary environments.

A facies model is described as "a general summary of a particular depositional system, involving many individual examples from recent sediments and ancient rocks" (Walker, 1992, p. 2). The main objective in establishing facies models is to understand the characteristics of different environments, including scale, heterogeneity, and controlling physical processes (Walker, 2006). A successful facies model contains a large amount of information that comes from different examples, but the facies belong to the same depositional system (Walker, 2006). Facies models therefore can serve as a reference, a norm, a framework, and a predictor (Walker, 1992) for interpreting and predicting future observations of new cases with the same depositional system and in some areas with limited information and data. These powerful predictive and integrative capabilities have made facies models a vital method for exploration in the petroleum industry.

The essential step in constructing a facies model is to fully understand facies, facies architecture (which includes facies-stacking pattern and cyclicity), and diagenesis (Ruppel et al., 2006). Sedimentary facies architecture or spatial distribution (Fisher and Galloway, 1983, Fisher, 1987; Tyler et al., 1984, Tyler, 1988) in clastic depositional systems and petrophysical rock fabric distribution in carbonate reservoirs (Lucia, 1983, 1999) are the most important parts of facies models. In petroleum reservoirs, all these factors, from a small scale such as facies, to a large scale (for example, depositional system (Fisher and McGowen, 1967)), can be analyzed. At reservoir scale, they control the reservoir heterogeneities and fluid flow characteristics; therefore reservoir heterogeneity is scale dependent as well. The parameters derived from facies models are provided as inputs in subsequent reservoir simulations.

An accurate model of the reservoir geology is a crucial input to the complete field-development planning process. Without it, costly decisions such as the placement of wells and future predictions about production volumes, using reservoir simulation, will be unreliable. Thus, knowing how to utilize geological data sufficiently and efficiently appears to be crucially important.

The goal of this report is to identify and analyze the best and most detailed geologic data and to clarify how to use this data to build subsurface facies models and then apply them in reservoir simulation. This process begins through extensive study of the relevant research in recent geologic literature.

With this goal in mind, the report is organized in four parts. Chapter 2 provides some basic definitions related to facies and facies models and discusses the parameters involved in the definitions and their particular applicabilities in facies modeling and reservoir simulation. In Chapter 3, multidisciplinary methods of constructing facies models and facies modeling research are introduced; these methods include both geologic and numerical methods. Software used in the industry is briefly reviewed in this chapter. Case studies are presented in Chapter 4. Using field examples, the objective of this chapter is to show the workflow of integrated facies modeling at different sedimentary reservoirs. Finally, in Chapter 5, some final comments and conclusions are presented.

Three main terms are used in this report: facies, facies models, and geostatistic facies modeling. Each of these terms has been discussed and analyzed in hundreds of published papers, books, and presentations. Because it is impossible to discuss all the literature within the scope of this report, only the most relevant sources are reviewed.

CHAPTER 2: BASIC CONCEPTS IN FACIES AND FACIES MODELS

The goal of this chapter is to review some fundamental concepts of facies and facies models, and to identify the important parameters associated with them that affect reservoir characterization.

Facies and Facies Models

The term"facies" (Moore, 1949) was developed by Gressly in 1838 (Walker, 2006), but the most useful working definition (Walker, 1992) of facies was that by Middleton (1978). Facies was defined by Middleton as "a body of rock characterized by particular combination of lithology, physical and biological structures that bestow an aspect (facies) different from the bodies of the rock above, below and laterally adjacent" (Walker, 1992, p. 2). Middleton (1978) also stated that the key to interpreting facies is to integrate all the information from observations of spatial relationships and internal characteristics, and to combine the data from other fully understood stratigraphic units. Middleton especially emphasized the importance of the modern sedimentary environment to facies research. The detailed data used in facies studies will be discussed later in this report, after an overview of facies models.

Facies can be subdivided into many different scales. The scale of subdivision depends on the objectives of the study. From small scale to large scale, facies can be combined into facies association, architectural element, and facies succession (Walker, 1992). To clarify and interpret the depositional environment, a small-scale facies focusing on architecture element or facies association should be addressed. A rather wide facies study can be proposed for description and interpretation on a relatively large scale.

Depositional Systems and architectural elements

It is difficult to identify the subtle change in small-scale facies units, such as the small change in the style of laminations. This minor change could not be quantified in reservoir simulation because the scale is too small. It is reasonable and useful to combine the closely related facies into depositional systems (Fisher and McGowen, 1967) (Walker, 1992) or facies architecture elements (Allen, 1983), a term that also implies the three-dimensional geometry of facies associations. More specific definition was given by Collinson (Collinson, 1969, p.207) as “groups of facies genetically related to one another and which have some environmental significance”(Walker, 1992).

Facies succession means that a certain facies property changes gradually in a specific direction (vertical or lateral). These certain properties could be the grain size pattern changing in the vertical direction, for example, fining upward or coarsening upward. The trends of changes in properties affect the characteristics of reservoir heterogeneities, including both formation porosity and permeability. This will be discussed further in later chapters of this report.

Facies models

A facies model is a general summary of a particular depositional system, involving many individual examples from recent sediments and ancient rocks. In “Facies Models: Response to Sea Level Change” (Walker and James, 1992) depicted the relationships among facies, depositional environments and systems, and systems tracts as shown in Figure 2.1.

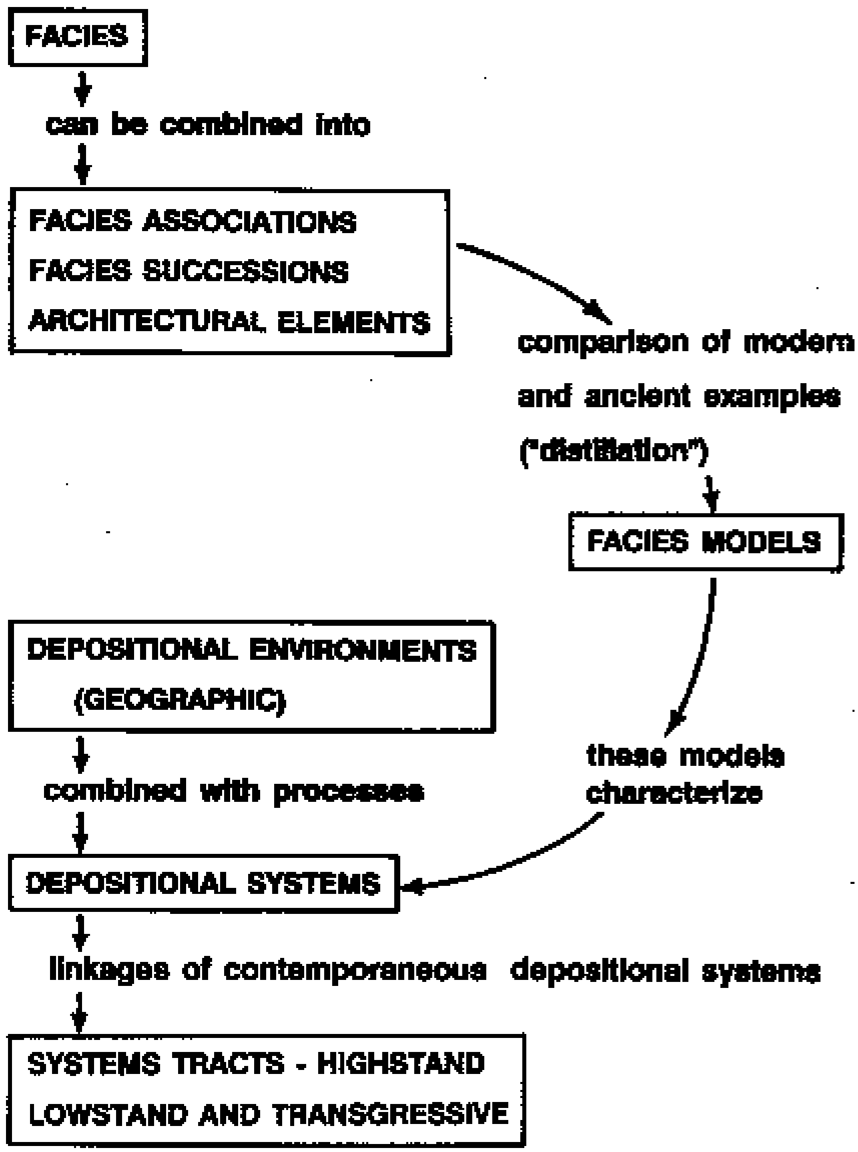

Figure 2.1: Relationship among facies, depositional environments and systems, and systems tracts. From Walker (1992).

What are the functions of facies models, and why do we need facies models? Facies models have four functions (Walker, 1992, 2006). The models can be used as (1) a norm for purposes of comparison; (2) a framework and guide for future observation; (3) a predictor in new situations, and (4) a basis for interpretation. Among these functions the most important one (Walker, 1992, 2006) is that facies models can be as a predictor. First, the known data, such as core and well log data, can provide clear-cut information about the depositional environment; then these data can be input into a particular model. This model then will be applied to predict the rest of the depositional system. This prediction and appropriate model selection can be modified as more data are obtained. Walker (1992) used turbidites and submarine fans as an example to show the principles, methods and motives of how to perform facies modeling. Walker's framework of facies modeling is shown in Figure 2.2.

In Figure 2.2, there are three important steps: distillation, comparison, and prediction. First the relationships between the individual examples need to be found. The individual examples could be the modern sedimentary environments, and they could come from the ancient rock, from cores, or from outcrops. The relationship means the specific and same characteristics from different individual cases. Taking away the local details, the information from the relationships is extracted into a common and general summary. Walker (1992, 2006) called these processes "distilling" and "boiling, "respectively). The result is the facies model.

Comparison is how to use models (the norm) to interpret new cases. Comparing the new examples with the possible facie models, the similarities and the differences are then exposed, and questions arise. These questions can help the interpreter to continue to find more information and data from the example or to add new ideas to modify the model.

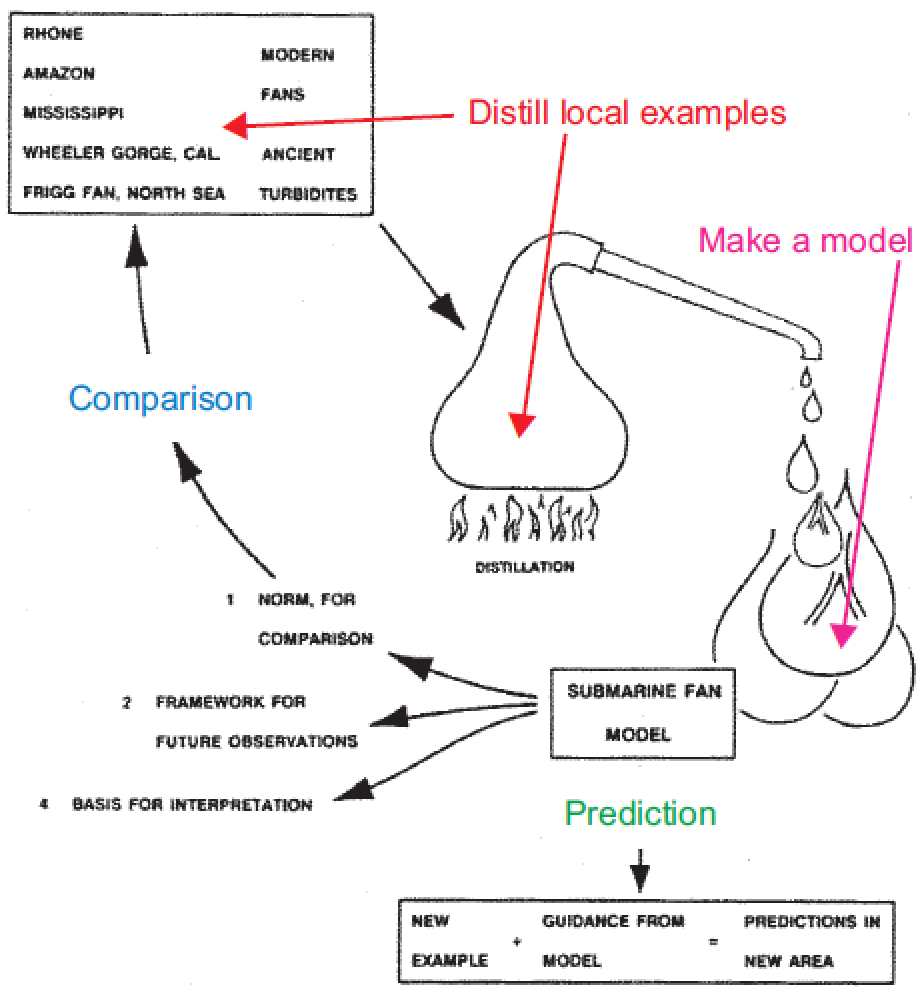

Figure 2.2: Distillation of a general facies model for submarine fans. From Walker (1992).

As mentioned, the most important function of facies models is as a predictor. With the assistance of facies models, new information can be utilized to predict the environment where data are lacking. This function relies on the accuracy of the interpretations of the new data and selection of a correct facies model (Walker, 2006). Building a facies model can be thought of as a refining process: “as more examples become available, as more distinct architectural elements are recognized, and as depositional processes become better understood” (Walker, 2006, p. 8).

Scale issue of facies models

As mentioned in facies definition and study methods, a facies model is also scale related. Different research purposes in the same environment may yield different facies models. Table 2.1, Figure 2.3, and 2.4 (Bridge, 2006) give the different scales of fluvial forms and associated sediment deposits. Table 2.1 (Bridge, 2006) shows 11 different scales for describing fluvial systems, from small-scale cross stratasets—ripples, and medium-scale cross stratasets—dunes, to large-scale groups, such as alluvial architecture, alluvial valley with channel belts, and basin fill alluvial system. Figure 2.3 clearly shows small-scale stratasets inside of a larger-scale fluvial channel, and Figure 2.4 (Bridge, 2006) gives an example on superimposed scale of fluvial stratasets. Every scale of strata can yield a model to describe the structures and architectures. Then smaller-scale models can probably be upscaled into larger-scale models (Walker, 2006). Because of reservoir heterogeneities depending on the properties of facies models, reservoir heterogeneity is also scale dependent, and heterogeneity exists at a range of different scales. Figure 2.5 shows the scales of reservoir heterogeneity, from smallest scale (20 um) to largest scale

(10MI) (Slatt, 2006). Dreyer (1993) used this scale classification as a framework for a study of fluvial-dominated sequence analysis (Figure 2.6).

Fluvial form	Strataset
Ripples	Small-scale cross stratasets
Dunes	Medium-scale cross stratasets
Low-relief bedwaves on plane beds	Planar stratasets
Antidunes	Low-angle cross stratasets
Seasonal flood deposit	Large-scale (inclined) stratum
Unit bars and compound bars	Large-scale inclined stratasets
Channels	Channel fills
Channel belt composed of channels and bars	Group of large-scale inclined stratasets and channel fills
Floodplain with levees, crevasse splays, channels, lakes, floodbasins	Groups of large-scale inclined stratasets and channel fills
Alluvial valley with channel belts and floodplain (or fan or delta)	Groups of groups: alluvial architecture
Alluvial river system	Basin fill (or part of basin fill)

Table 2.1 Different scales of fluvial forms and associated stratasets. From Bridge, J.S. (2006).

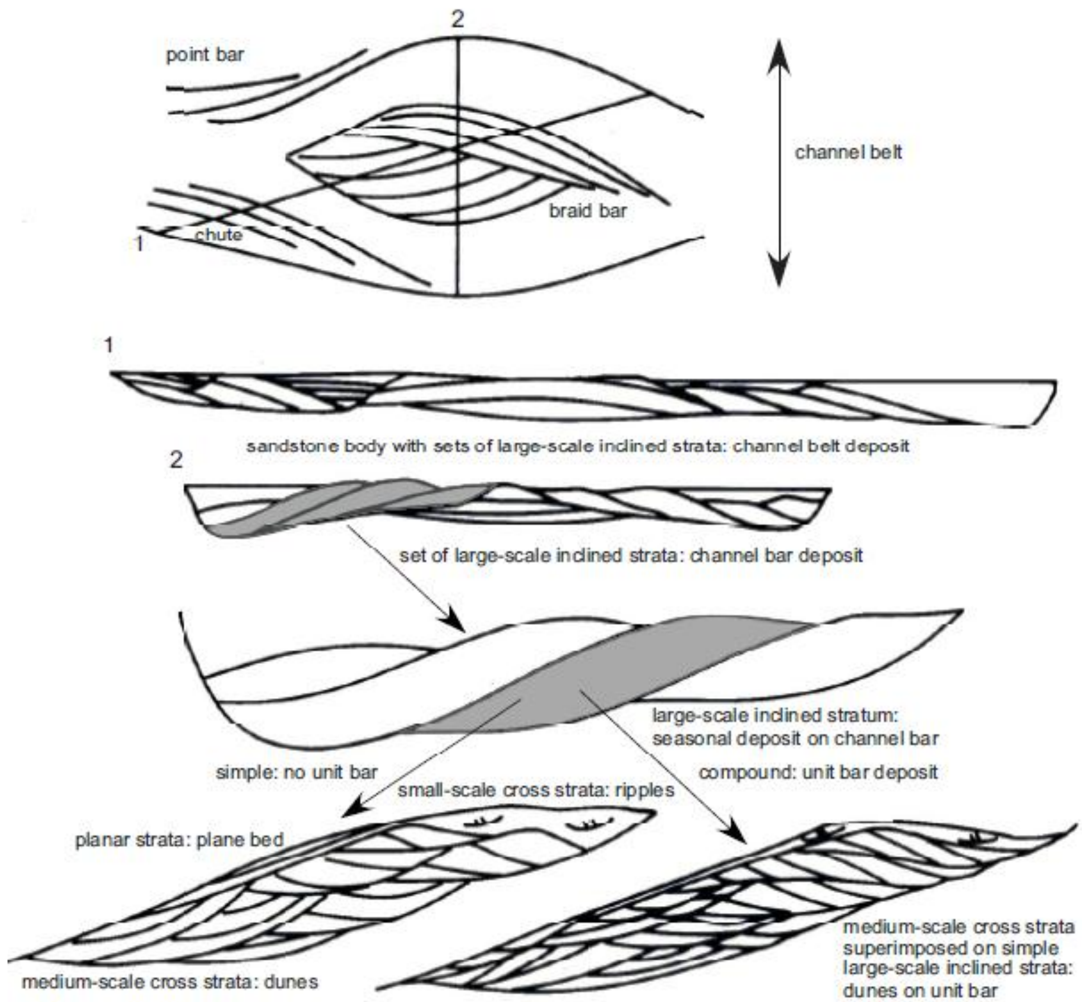

Figure 2.3: Superimposed scales of fluvial forms. Cross sections (1) and (2) through an idealized braided channel belt. The cross sections show several sets of large-scale inclined strata formed by deposition on channel bars. Each large-scale inclined stratum can be simple (deposited during a single flood) or compound (deposited as a unit bar over one or more floods). Large-scale inclined strata contain smaller-scale stratasets associated with passage of ripples, dunes, and bedload sheets over bars. From Bridge, J.S. (2006).

Figure 2.4. Superimposed scales of fluvial stratasets. Upper picture is an alluvial valley of the Senguerr River, southern Argentina, containing a floodplain with a channelbelt (about 100 m wide) on one side, adjacent to the valley margin in the foreground. Lower picture shows channel-belt sandstones (gray) and floodplain deposits (red) from the Miocene Siwaliks of northern Pakistan. The channel-belt sandstone body is 10–15 m thick. From Bridge, J.S. (2006).

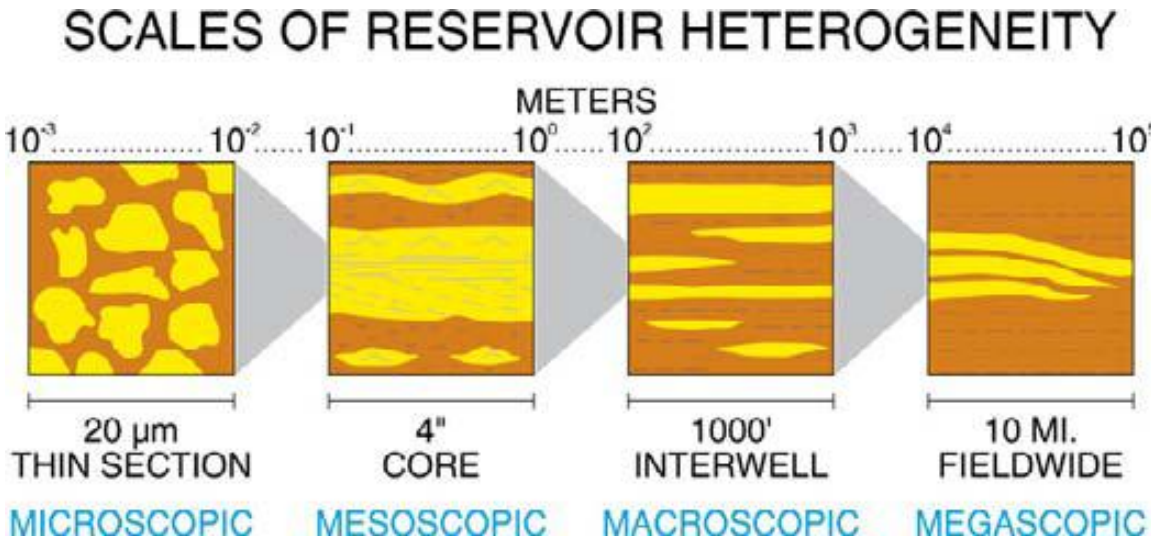

Figure 2.5. Classification of heterogeneities in reservoirs according to scale. From the smallest to the largest, these are microscopic, mesoscopic, macroscopic, and megascopic heterogeneities. From Slatt (2006).

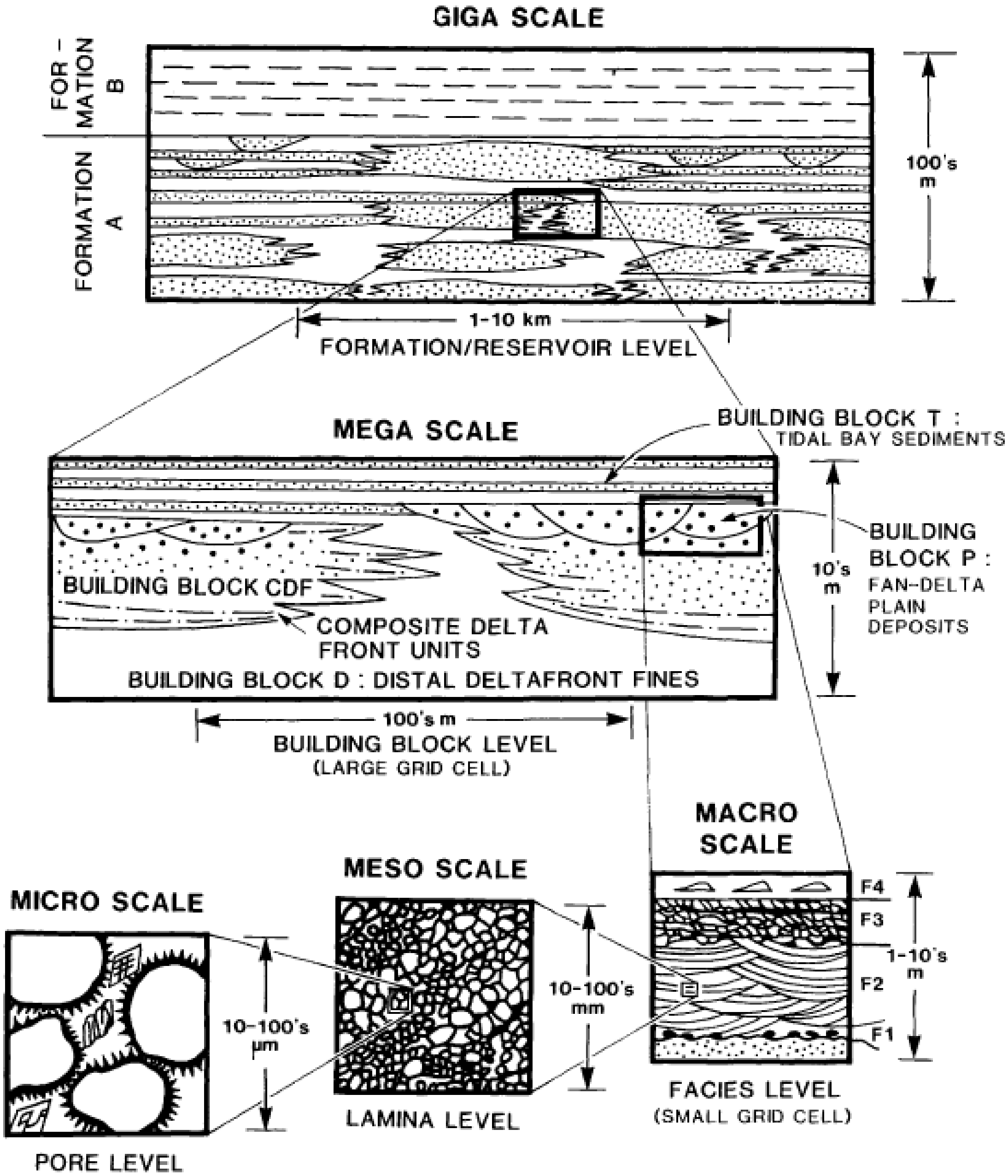

Figure 2.6. Levels of heterogeneities in fluvial/tide-dominated shallow marine-sediments, Tilje Formation, in the Halten Terrace, mid-Norwegian Shelf. From Dreyer (1993).

Geological reservoir heterogeneity with its scales and types

Microscopic or pore/grain-scale heterogeneities (Slatt, 2006) depend on grain size, grain types, grain stacking pattern, and pore properties. Porosity and permeability are fundamentally controlled by microscopic-scale grain heterogeneities. Pore volume affects porosity and grain stacking pattern, and the connectivity between pores controls permeability.

Mesoscopic or well-scale heterogeneities (Slatt, 2006) are controlled by bedding styles, heterolithic, vertical bedding stacking pattern and inside bedding structure types.

Macroscopic or interwell scale heterogeneities (Slatt, 2006) are determined by lateral bed continuity properties. This continuity or discontinuity may have resulted from stratigraphic pinch out, faulting, or even erosional cut out. But the heterogeneities at this scale level are hard to describe and quantify using only the available subseismic data. Interwell seismic data are too rough to clarify the between strata features and could not be employed to determine features such as the pinch out end point or the erosional cut out surfaces.

Magascopic or fieldwide heterogeneities (Slatt, 2006) are controlled by depositional environments, for example, deltaic depositional systems. At this scale, heterogeneities at a large level can be defined by 2D or 3D seismic data. Well tests, production information, and fieldwide well logging correlation can serve to delineate megascopic reservoir heterogeneities.

Levels of reservoir geological heterogeneity

Using fluvial systems as an example, Slatt and Mark (2004) defined four levels of hierarchical scales of reservoir geologic heterogeneity: Level 1: regional environments of deposition; Level 2: major type of deposits (Figure 2.7); Level 3: more specific types of deposits (Figure 2.8); Level 4: architectural elements of specific reservoir types (Figure 2.9). According to this hierarchy, Level 4 might be the most important scale level to define and identify, since this level scale reservoir heterogeneities always control the reservoir performance.

In addition to the importance of stratigraphic and sedimentologic features of reservoir (such as Level 4), tectonic features, such as folds, faults, fractures, diapirs, microfractures, and stylolites (chemical compaction) also play important roles in reservoir performance (Figure 2.10). Faults can break the continuities of the horizontal formations, and faults also can serve to help hydrocarbon migration into a reservoir interval and increase fluid connection and flow through the fault intervals. But in this report these tectonics-related features are not discussed.

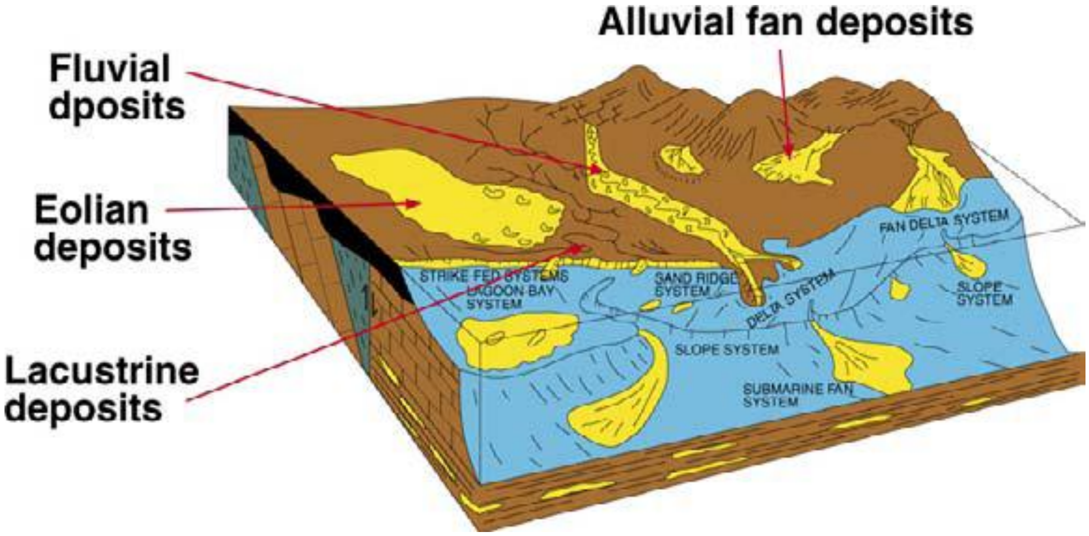

Figure 2.7. Level 2 environments include all those within the continental (as this example shows), mixed, or marine environments (Level 1). (Modified from Fisher and Brown, 1984). Slatt (2006).

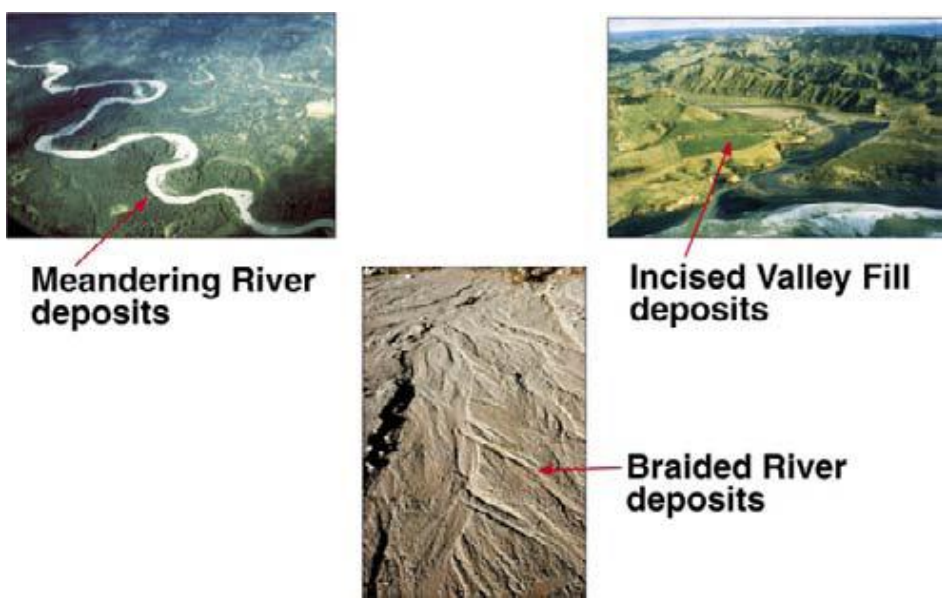

Figure 2.8. Level 3 environments that may occur within each Level 2 environment. In this example, Level 2 fluvial environments and deposits occur as meandering river, incised valley fill or braided river systems. Each system has its own unique characteristics and trends. The three photos are of modern surficial deposits. From Slatt, (2006).

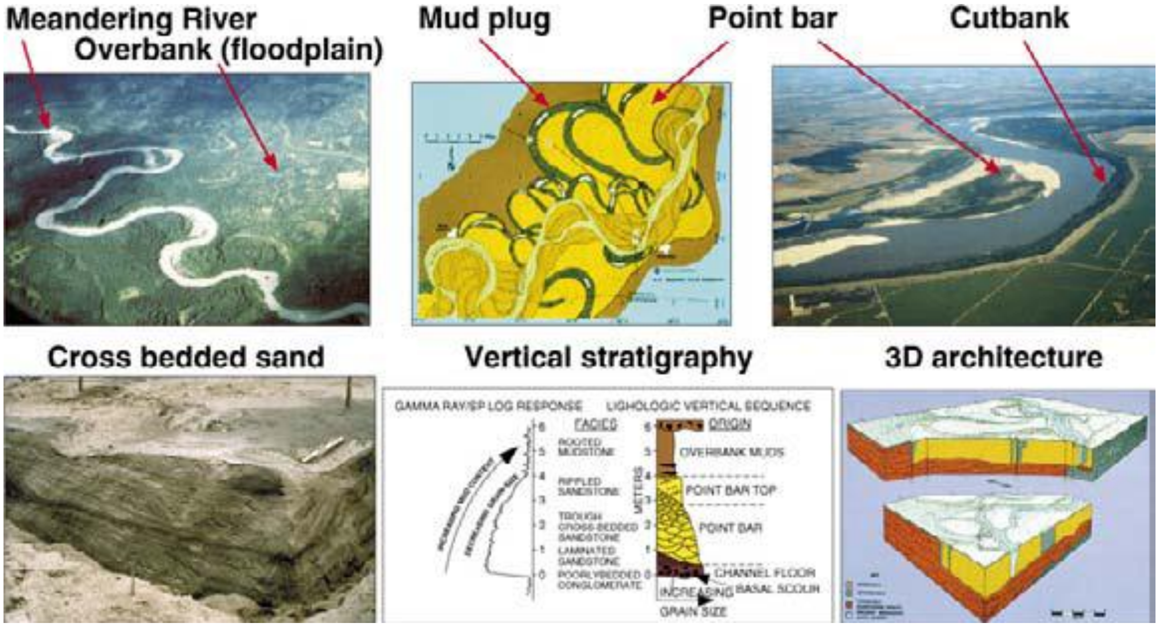

Figure 2.9. Level 4 environments and deposits are composed of smaller scale features that are part of Level 3 deposits. In this example, the meandering river (Level 3) is composed of a series of features. From upper left to lower right, these features are a modern meandering river and floodplain, a map reconstruction of part of the modern Mississippi River showing point bar (reservoir) sands isolated by mud plugs, the point bar and cutbank sides of a meander bend, cross-bedded, point bar sands along a trench wall, the ideal vertical stratigraphy of a point bar deposit, and a 3D model showing the complexities of the modern Mississippi River example. (Mississippi River examples were provided by D. Jordan.). From Slatt (2006).

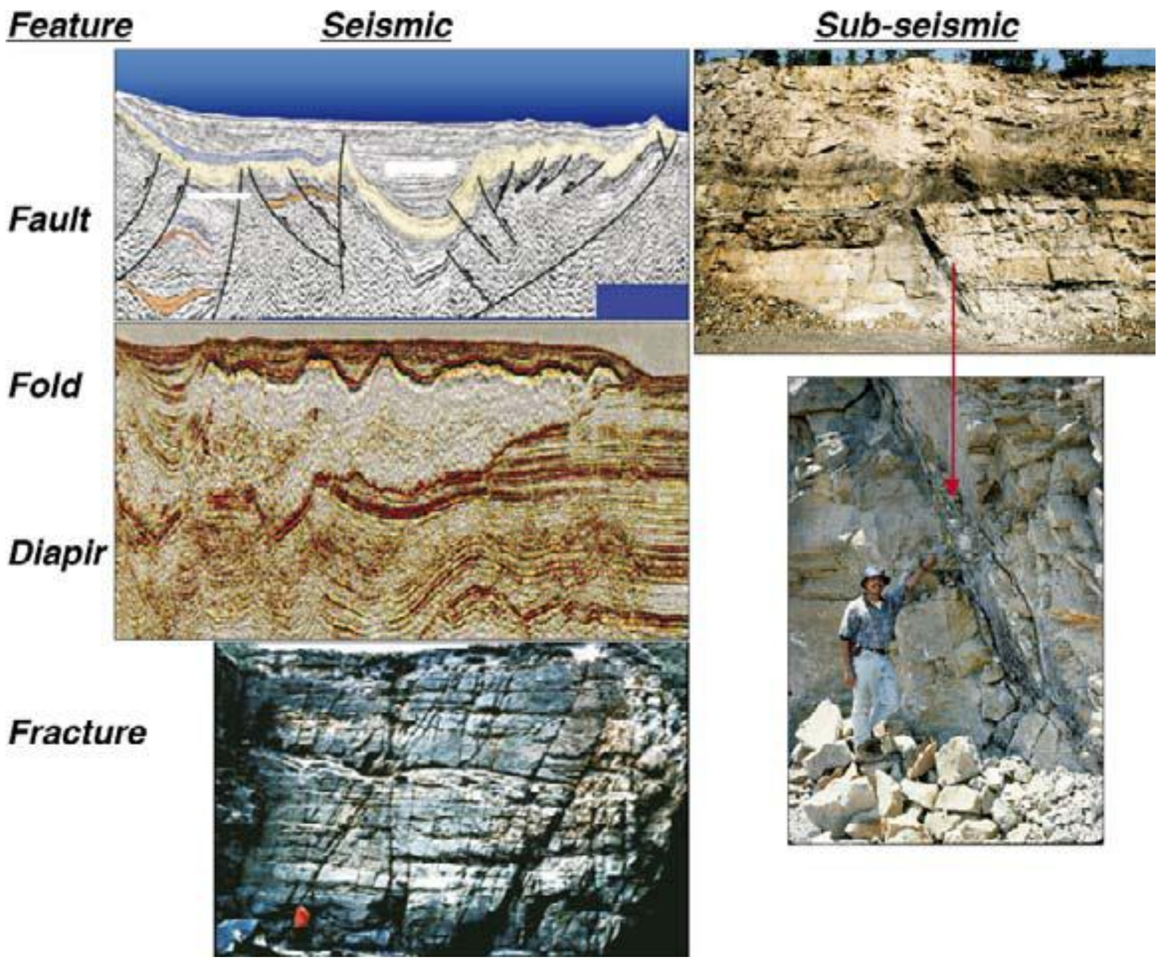

Figure 2.10. Tectonic features at both seismic and subseismic scales, including faults, folds, diapirs and fractures. These features, both large and small, can influence reservoir performance. From Slatt (2006).

Diverse scale parameters of facies models involved in facies modeling and reservoir simulation

The most difficult process in facies modeling is deciding how to use various large- to small-scale facies parameters to describe reservoir heterogeneities at diverse scales. These parameters range from large-scale faults, external and internal sand body characteristics, to microscopic features, and fractures (Table 2.2, Weber and Geuns 1990). Related to reservoir heterogeneities, these parameters affect fluid flow characteristics at different levels and directly influence sweep and reservoir efficiencies.

Reservoir heterogeneity type	Reservoir continuity	Sweep efficiency horizontal	Sweep efficiency vertical	Residual oil saturation in swept zones	Rock/Fluid interaction
Sealing fault	Strong	Strong			
Semisealing fault	Moderate	Strong	Strong		
Nonsealing fault	Moderate	Strong	Strong		
Boundaries of genetic units	Strong	Strong	Strong		
Permeability zones within genetic units		Moderate	Strong	Moderate	
Baffles within genetic units		Moderate	Strong	Moderate	
Lamination,crossbedding		Moderate	Moderate	Strong	
Microscopic heterogeneity				Strong	Moderate
Texture types				Strong	Strong
Minerology					Strong
Fracturing					
Tight		Moderate		Strong	
Open		Strong	Strong	Strong	

Table 2.2. Significance of reservoir heterogeneity type for oil recovery (Weber and Van Geuns, 1990)

Ainsworth (2003, 2005) stated that the parameters related to facies models could be divided into two groups, depositional connectivity parameters and structural connectivity parameters. Depositional connectivity parameters are dominated by sedimentary depositional processes, such as sand/shale ratios and depositional architectures; structural connectivity parameters are controlled by secondary connectivity such as syn- and post-faulting and fault transmissibility characteristics. Parameters of facies models will be presented after discussion of these two groups.

Sedimentary control parameters of facies models--corresponding to depositional connectivity of reservoirs

In the early days of reservoir modeling, constructing geological facies models was rather simple. These models emphasized mud and sand distribution but had limited information or data related to characteristics that influenced flow simulation. These important data include facies distribution, inter- and intra-facies boundaries, small-scale heterogeneity (sedimentary bedding), and intra-facies trends (Mikes and Geel, 2006). A relatively accurate facies model should include: all the facies of the modeling objective, facies spatial distribution, facies shape, flow boundaries, and bedding types (Mikes and Geel, 2006). Compared to traditional geological models, facies models have two advantages. First, facies models are more accurate in reflecting the real strata by attempting to include all hydraulic elements. Second, these models can be used directly in reservoir flow simulation. Mikes and Geel, (2006) provided an upscaling procedure to incorporate all heterogeneity levels in a reservoir model (Figure 2.11). Table 2.3 gives terms that are used to define every parameter inside of this procedure.

In this procedure, geological models are built step by step from small scale to large scale. Six-scale modeling steps are included in the procedure, and every step represents a specific scale heterogeneity, from lamina→bed→facies→facies association/ parasequence→systems tract/ parasequence set→sequence (Table 2.4) (Mikes and Geel, 2006). There are two fundamental geological elements, facies and beds; and two reservoir key elements, flow unit and flow cell, involved. Mikes and Geel (2006) defined "flow unit" as "consisting of a repetition of one flow cell", and it is influenced by the characteristics of facies. The properties of bed dominate flow cell. So the main task of describing a reservoir model is to choose facies properties that are built by bedding information.

Nomenclature

		t_B	thickness of bottomset
		t_F	thickness of fine foreset
T	thickness	t_C	thickness of coarse foreset
W	width	D_B	mean grainsize of bottomset
L	length	D_F	mean grainsize of fine foreset
t	thickness of crossbed	D_C	mean grainsize of coarse foreset
w	width of crossbed	φ_B	mean porosity of bottomset
l	length of crossbed	φ_F	mean porosity of fine foreset
α	foreset angle dip	φ_C	mean porosity of coarse foreset

Table 2.3. Nomenclature used in upscaling procedures. From Mikes and Geel (2006).

Reservoir units	Geological units	Facies example
Sequence		
Parasequence set		Alluvial plain
Facies association/parasequence		River
Flow-unit	Facies	Meander belt
Flow-cell	Bed	Trough bed
Lamina		Foreset

Table 2.4. Six-scale hierarchy of heterogeneity levels for facies and reservoir models. From Mikes and Geel (2006).

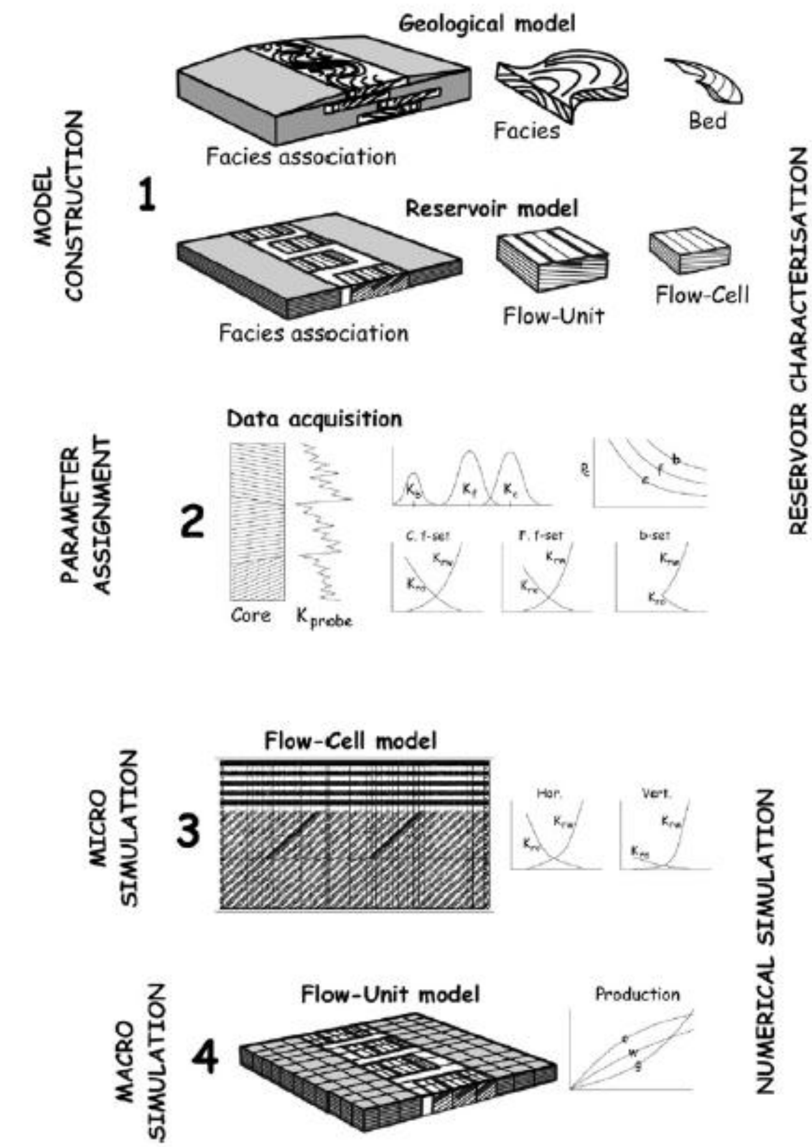

Figure 2.11. Schematic representation of the 4-step upscaling procedure. Step 1, model construction, consisting of geological and reservoir model and assignment of its elements; Step 2, parameter assignment, consisting of permeability sampling, data analysis, and calculation of relative permeability and capillary pressure; Step 3, micro-simulation, consisting of numerical flow simulation on all flow cell models of the reservoir, yielding effective 1- and 2- phase permeabilities, and capillary pressures; Step 4, macro-simulation consisting of numerical flow simulation on the entire reservoir, yielding production history. Steps 1 and 2 form reservoir characterization; Steps 3 and 4 form numerical flow simulation. From Mikes and Geel (2006).

For much smaller scale parameters, such as grain size, grain sorting and grain stacking pattern are also very important for fluid flow properties. Beard and Weyl (1973) mentioned that grain size exerts significant control on petrophysical properties. Pranter et al. (2007) used parameters shown in Table 2.5 to deal with lithology and grain-size models.

Facies	Lithology	Modal Grain Size	Grain Shape and Sorting	Dominant Features	Depositional Process
Trough cross-bedded sandstone	Lithic sandstone	Lower medium to upper fine	Subangular to subrounded; moderately sorted	Trough cross-bedding, also planar cross-bedding, soft sediment defined, scoured surfaces	Unidirectional tractive flow deposit, dune height indicates water depths between 1.2 and 3 m (3.9 and 10 ft)
Current rippled sandstone	Lithic sandstone	Upper to lower fine	Subrounded; moderately sorted	Current ripple laminations, climbing ripples	Tractive flow deposit; climbing ripples indicate fluctuations in aggradation rate; mud drapes indicate periods of little to no ripple migration
Nodular sandstone	Mudstone	Silt dominated	NA*	Nodular texture, siderite concretions, rooting	Vertical accretion; suspension fallout and pedogenesis
Laminated siltstone	Mudstone	Silt rich	NA	Millimeter-scale laminations, bioturbation, rooting	Vertical accretion; suspension fallout and pedogenesis
Conglomeratic mud-chip sandstone	Conglomeratic lithic sandstone	Upper to lower medium	Subangular; poorly sorted	Mud-chip lag, woody plant debris, scoured surfaces	Scour and fill generated by flow separation indicates disequilibrium in flow conditions
Coal and bentonite	Coal and bentonite	NA	NA	Regularly spaced cleats in coal (2–7 cm; 0.8–2.75 in.)	Vertical accretion processes such as suspension fallout; continuity of coals indicates low channel activity

Table 2.5. Fluvial facies recognized in the Coal Canyon outcrops and their characteristics. From Pranter et al. (2007).

Compared to clastic reservoirs, characteristics of carbonate reservoirs are much more complicated because of cementation and dissolution processes. These processes modify the mineralogy and pore structure of carbonate rocks. In some cases, this modification can totally change carbonate rock properties (Grammer et al., 2004) and, thus, can alter the original rock petrophysical properties, such as porosity and permeability. For example, the original pore volume could decrease because of cementation; or, the pore space could increase since grains are dissolved. So it is important to add diagenesis as one of the critical parameters to carbonate facies modeling. Figure 2.12 shows that diagenesis can occur at different facies along a carbonate platform, using the Bahama transect as an example.

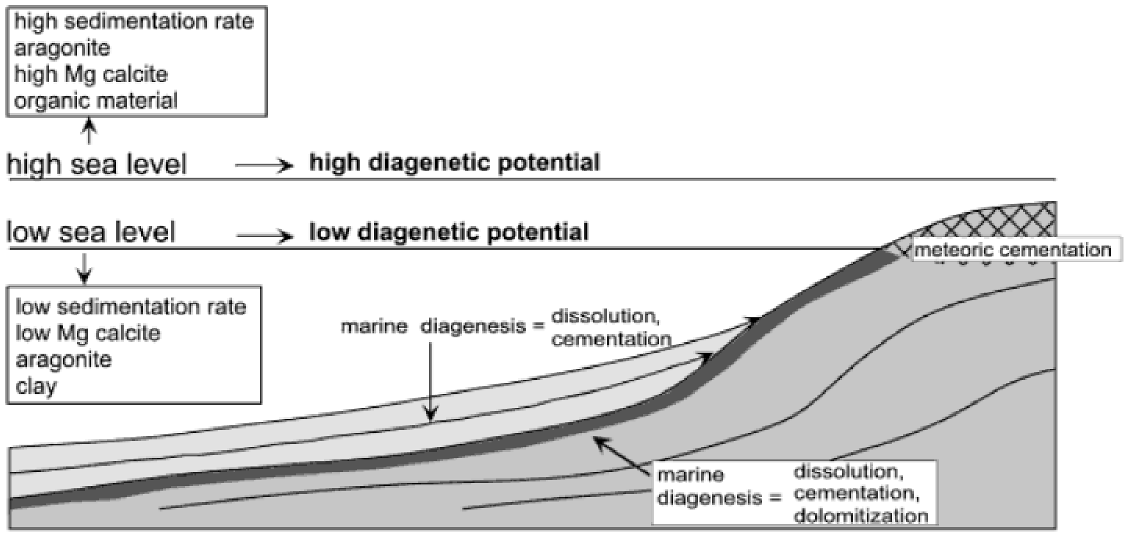

Figure 2.12. Schematic display showing diagenetic processes could occur at different facies. From Grammer (2004).

All these parameters described above are used to define or describe the reservoir properties including reservoir connectivity. Ainsworth (2003, 2005) addressed one type of the connectivity, termed as "depositional (or primary) connectivity", which is dominated by the interaction of sand/shale ratios, sandbody geometries, and sandbody distributions. The other connectivity, which is controlled by the properties of syn- and post-depositional faults and fault transmissibility, is termed "structural (or secondary) connectivity" by Ainsworth (2003, 2005).

Structural control parameters of facies models--corresponding to structural connectivity of reservoir

The properties of faults, such as strike and dip of fault plane, orientation of fault plane, the cutoff lines and piercing points, and faults density, are the other critical parameters that should be taken into account in facies modeling and reservoir simulation. The effect of faults on reservoir heterogeneities is shown in Figure 2.10 and Table 2.2.

CHAPTER 3: METHODS TO INTEGRATE FACIES MODELS IN RESERVOIR SIMULATION

The basic concepts related to facies, facies models, and their dominant features such as scales were described in Chapter 2. The goal of Chapter 3 is to introduce some main methods. These methods can be used to (1) measure and define facies and facies models and (2) transfer geological information into digital data to quantify geological facies and facies models. The numerical data based on geological facies models can then be upscaled and used in reservoir simulations. These methods include subsurface facies analysis methods; geostatistics and stochastic simulation methods, and so on.

Subsurface measuring methods and subsurface facies analysis

Below is a brief review of subsurface methods for applying subsurface information, including geological methods (well logs and cores), and geophysical methods.

Geological methods - Well logs

Since almost every well is designed to use well log instruments to measure subsurface rock physical properties such as resistivity, sonic velocity and density, log data become the most popular, frequently used information for subsurface studies such as subsurface mapping, correlation, and facies analysis. Table 3.1 lists different types of logs, the property they measure, and their geological uses (Cant, 1992).

Log	Property Measured	Units	Geological Uses
Spontaneous potential	Natural electric potential (compared to drilling mud)	Millivolts	Lithology (in some cases), correlation, curve shape analysis, identification of porous zones.
Resistivity	Resistance to electric current flow	Ohm-metres	Identification of coals, bentonites, fluid evaluation.
Gamma-ray	Natural radioactivity — related to K, Th, U	API units	Lithology (shaliness), correlation, curve shape analysis.
Sonic	Velocity of compressional sound wave	Microseconds/metre	Identification of porous zones, coal, tightly cemented zones.
Caliper	Size of hole	Centimetres	Evaluate hole conditions and reliability of other logs.
Neutron	Concentrations of hydrogen (water and hydrocarbons) in pores	Per cent porosity	Identification of porous zones, cross plots with sonic, density logs for empirical separation of lithologies.
Density	Bulk density (electron density) includes pore fluid in measurement	Kilograms per cubic metre (gm/cm^3)	Identification of some lithologies such as anhydrite, halite, nonporous carbonates.
Dipmeter	Orientation of dipping surfaces by resistivity changes	Degrees (and direction)	Structural analysis, stratigraphic analysis

Table 3.1. Different types of logs, the property they measure, and their geological uses From Cant (1992).

Among these logging methods, the most useful information for geological analysis comes from spontaneous potential (SP) logs and gamma-ray (GR) logs (see Table 3.1). These two types of logs are always applied to correlate subsurface lithologies and to describe lateral facies distribution through curve shape analysis, subsurface mapping, and subsurface facies analysis.

Correct correlation of stratigraphic units is critically important and necessary for facies analysis and resulting facies models. There are two ways to use correlation logs. One is tracing and overlaying logs, and the other is a numerical method, which will be introduced in subsequent sections of this report.

Cant (1992) cited three main correlation methods: marker beds, pattern matching, and slicing techniques. Some beds with distinctive log features are considered to be marker beds, such as those in a condensed zone. These marker beds are always applied at some specific surface and at a stratigraphic time line; for example, the surface on top of a condensed zone could be a maximum flooding surface. Pattern matching has two components, (1) to find or recognize the distinctive pattern and then (2) to try to correlate patterns (Figure 3.1). Pattern matching can help to correlate different logs and obtain the lateral distribution and variation of the facies. The slicing technique is seldom used since it may cut the depositional units and yield large errors.

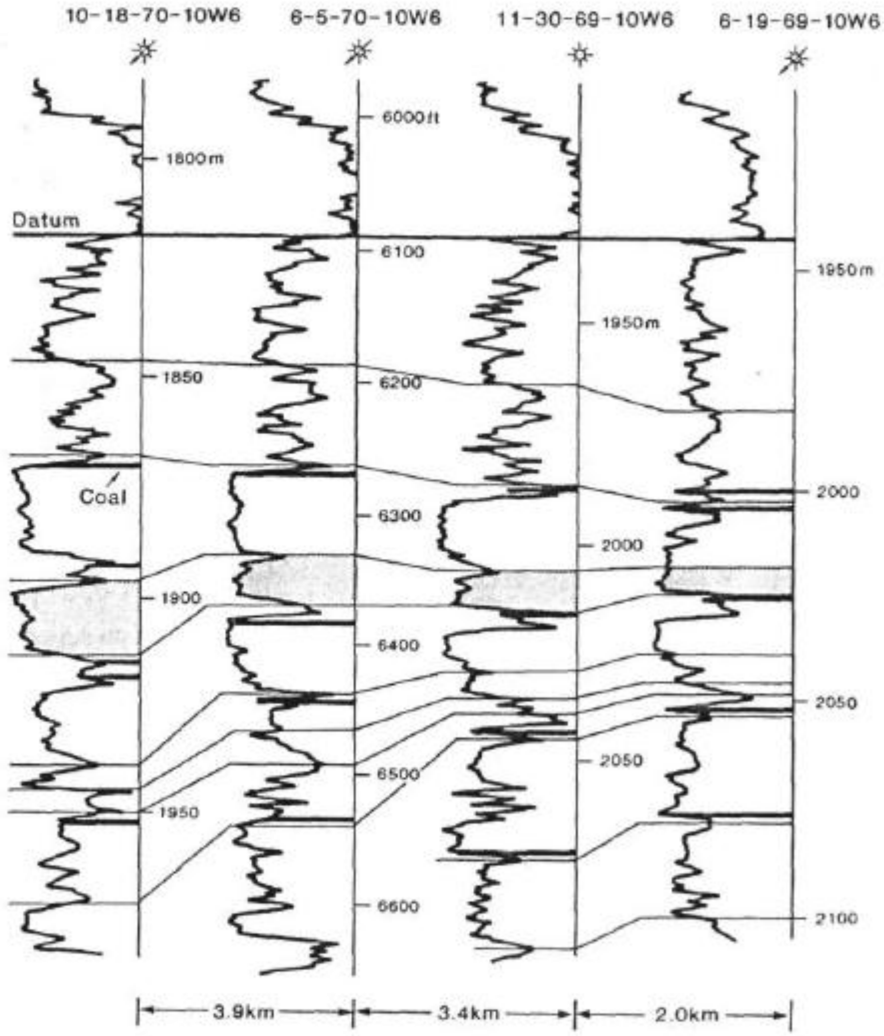

Figure 3.1. A gamma-ray cross section in the Upper Mannville Group of Alberta illustrating correlation by pattern matching. The correlations have been made using the following criteria: 1) facies successions do not show abrupt lateral changes in character, 2) facies successions do not show abrupt changes in thickness, 3) facies successions do not show seaward (right to left) coarsening, 4) correlated surfaces slope seaward (to the left; Coals (blank) were identified on sonic logs. These logs are not spaced proportionally to the distances between wells. From Cant (1992).

Subsurface mapping depends not only on well log data from a large number of wells, but also on well data from seismic acquisitions. Subsurface maps are either compilations of data, or interpretive summaries (Cant, 1992). These maps include structure maps, isopach maps, and lithological maps. These maps can be used for large-scale flow unit analysis and facies modeling. Accurate subsurface mapping is absolutely necessary and significant to facies modeling and reservoir simulation.

Another usage of geological logs is in subsurface facies analysis. And the most useful way is to apply the shape of well log curves correlated to grain size successions (Selley, 1978) to interpret the depositional facies. Cant (1992) listed the most typical vertical patterns seen on GR, SP, and resistivity logs and their possible geological interpretations, as shown in Figure 3.2. All these interpretations are based on the shapes of the well logs. Final interpretation of depositional facies should be obtained through combining shape-based logs with data from cores, outcrops and other available information.

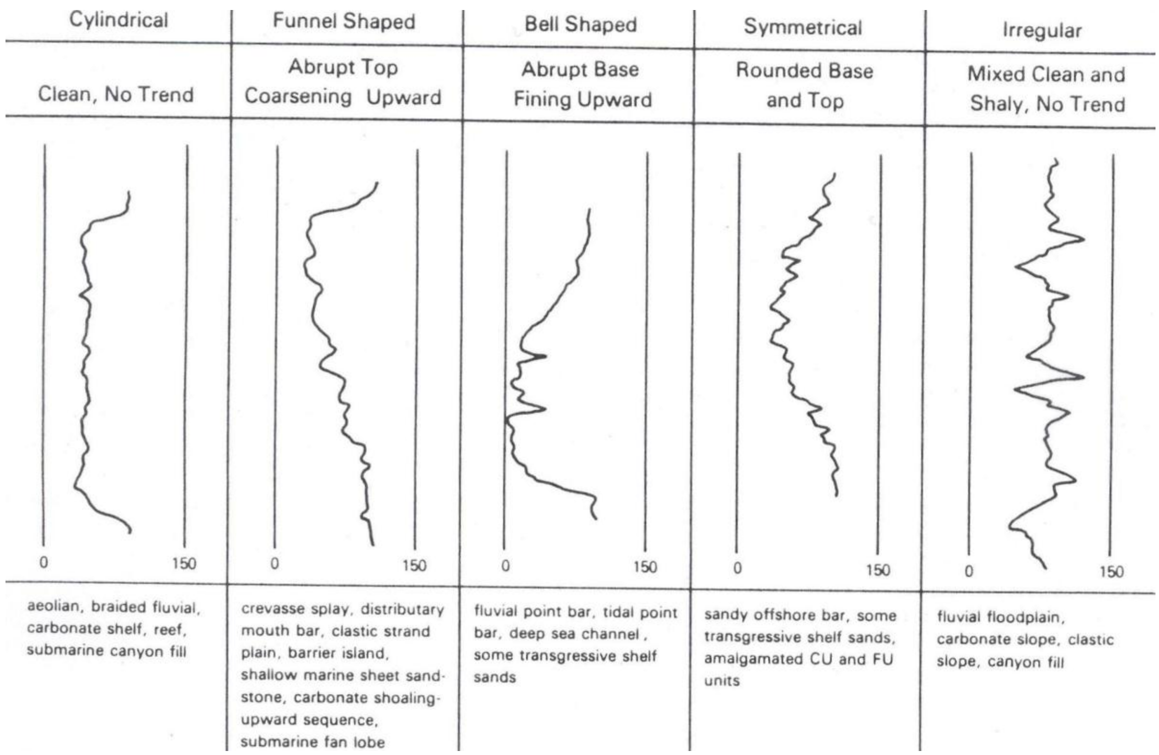

Figure 3.2. The most common idealized log curve shapes, which may be interpreted by correlation with many different core samples. From Cant (1992).

Geological methods - Seismic stratigraphy and facies analysis

Compared to well log data and outcrop profiles, seismic data can always provide a larger scale view of a basin. Great lateral continuity and gross sediment geometry with larger resolution can be obtained through seismic data interpretation. Stratigraphic patterns shown on seismic lines can be used to identify the sedimentary depositional environment (Figure 3.3). These very classical patterns can be interpreted as basin floor fan, deltaic progradation, sea-level rise transgressive surface, etc. (Figure 3.4). Using seismic data for smaller scale facies analysis is based on seismic internal reflection characteristics, such as the amplitude, frequency, and continuity of reflections (Cant, 1992). All these analyses must be calibrated by well log data and core data if such data are available; otherwise, the accuracy of the interpretation is difficult to prove since seismic data are of lower resolution in a relatively small scale.

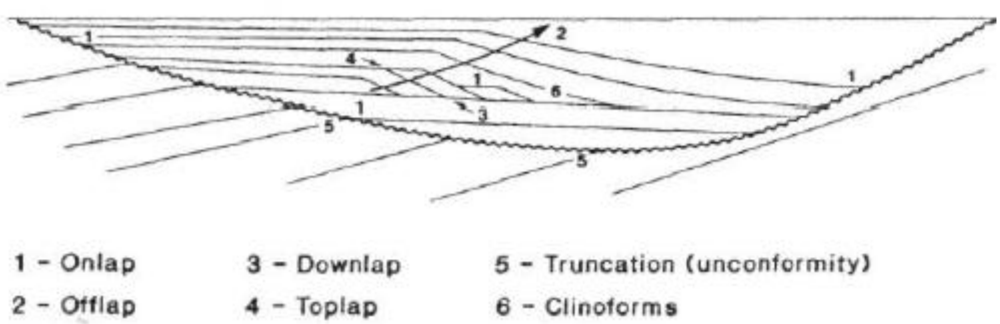

Figure 3.3 Different scales of stratigraphic pattern commonly seen on seismic lines. From Cant (1992).

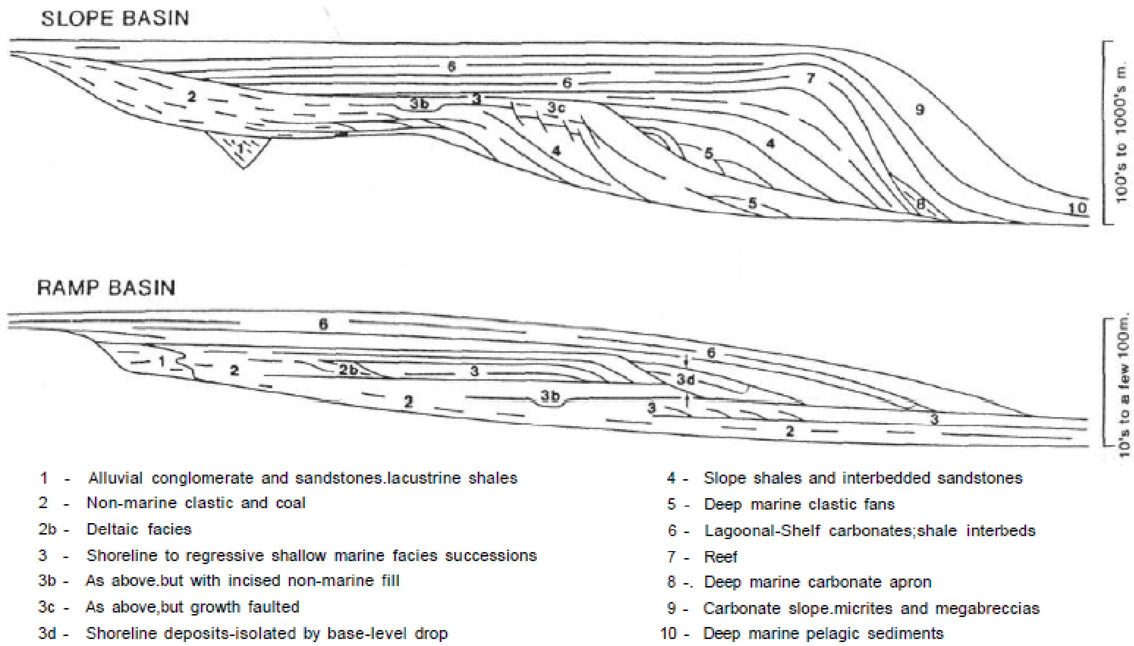

Figure 3.4 Composite diagrams of lateral facies relationships shown on seismic data in a slope basin (one with deep water such as passive continental margin), and a ramp basin (one on the craton lacking very deep water). The depositional facies can be generally identified by the overall lateral relationships, and by the large-scale features such as the slope, the mounds, and the reefs that can be imaged. From Cant (1992).

Numerical Methods in Facies Modeling

Quantitative models of reservoir geometry, including reservoir facies distribution and stacking pattern, rock properties are the fundamental features. Rock attributes are keys to production prediction, field development, and economic evaluation (White et al., 2004). Thus, determining how to transfer geological information from different facies models into digital data and generate associated numerical models is critical for reservoir simulation and reservoir characterization analysis. In the above section, some methods related to defining and measuring facies and facies models were introduced. In the following sections, a brief review of geostatistics and stochastic modeling are presented. Some principal methods to quantify geological facies models' data are then addressed. These methods include stochastic and geostatistics modeling (including variogram-based geostatistics modeling, object-based stochastic modeling, multiple-point geostatistics modeling), and deterministic modeling. A standard facies model is introduced here as a methodology that differs from those techniques.

Brief Review of Geostatistics and Stochastic Simulation

Geostatistics was introduced by Daniel Krige (Krige, 1951) and developed by Georges Matheron (Matheron, 1962, 1965). Today geostatistics is widely applied as a spatial modeling method and as a tool in petroleum geology modeling and other fields, such as hydrogeology and hydrology. Compared to traditional reservoir modeling, which is processed by geologists and geophysicists to interpret and integrate information from well data (well-log and core), outcrop, seismic profile and facies models on depositional systems to obtain the depositional-facies maps, geostatistical techniques rely on the mathematical theories and computer technology to integrate algorithms to generate multiple equiprobable realizations (Liu et al., 2004), whose difference reflects uncertainty (Deutsch and Journel, 1998).

The original task of geostatistics focused on providing some information on estimates of spatial attributes or variations of geological variables. These attributes include any geological subsurface properties that exhibit spatial changing and can be assessed using real numerical values. All spatial variations come from the characteristics of the subsurface, such as anisotropy, spatial complexity, and internal heterogeneities of sedimentary bodies. Also these spatial differences can range from large to small scale (Figure 2.5).

Kriging can present a minimum estimation variance through linear interpolation of the neighboring data (Zhang, 2008), but it has now been developed far beyond simple interpolation. Random function (or random variable) theory is used in estimating the unknown spatial distribution. For the subsurface environment of facies modeling, structure is one of the most important affects reservoir heterogeneities and influences fluid flow properties. But kriging estimation cannot describe the structure of the subsurface because structural connectivities are smoothed out in kriging estimation maps (Zhang, 2008).

Stochastic simulation was then introduced in early 1970s to modify the limitations of the kriging estimation method, and to overcome the smoothing effect from structure mapping. Stochastic simulation can provide the spatial variance maps if a variogram model is given. Different but equiprobable results can be generated by conditional stochastic simulation through the same data set. Today conditional stochastic simulation is the tool that is routinely used to predict reservoir heterogeneities and to resolve the spatial uncertainties in reservoir modeling processes (Caers, 2005). Overeem (2008) outlined the different tracks of geological modeling (Figure 3.5).

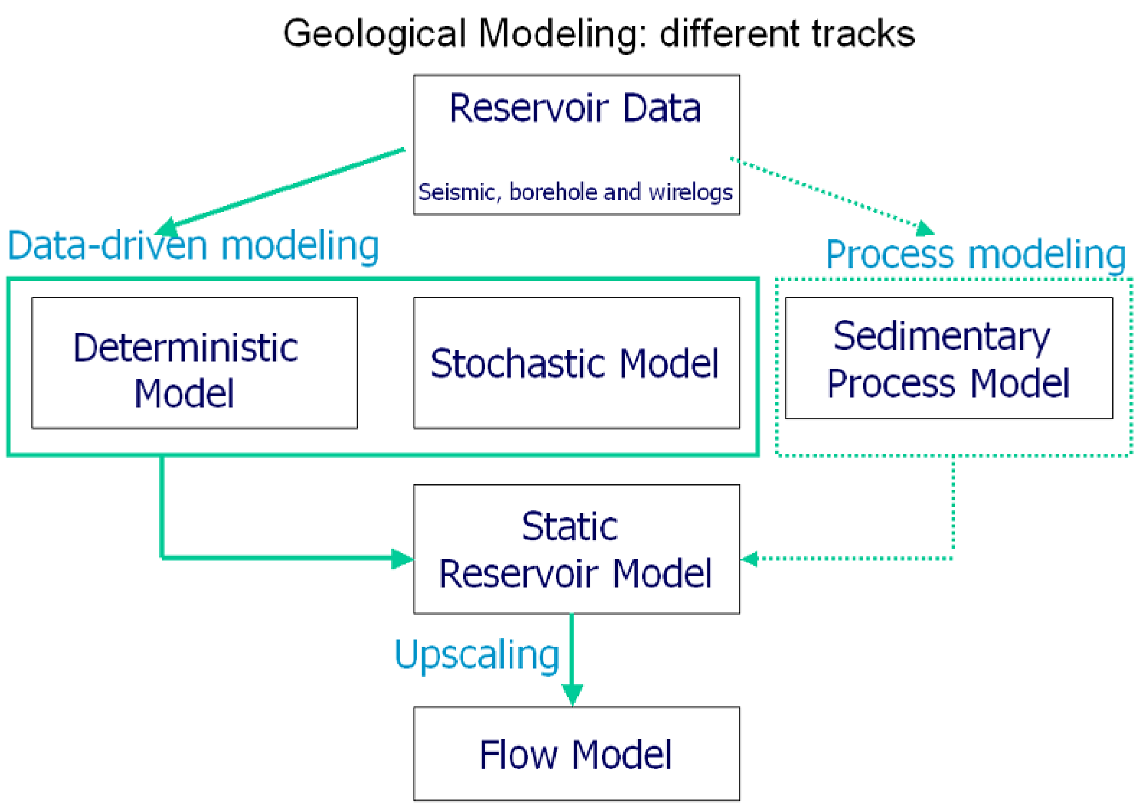

Figure 3.5. Different tracks of geological modeling. From Overeem (2008).

Methods and Applications of Geostatistics and Stochastic Simulation

As noted in previous chapters and sections, the important information carried by facies models, from large-scale facies architectures to small-scale grain size and sorting properties, has a profound influence on reservoir heterogeneity. How to transfer all this information into digital data in geostatistical reservoir modeling is quite a challenge (Caers and Zhang, 2004). Geostatistics and stochastic simulation are tools to generate the multiple reservoir models that are defined by geologic, seismic, and production data. Caers and Zhang (p.383-384, 2004) listed three goals of geostatistical reservoir characterization:

> "(1) Provide reservoir models that depict a certain believed or interpreted "geological heterogeneity"; (2) Provide a quantification of uncertainty through multiple reservoir models, all honoring that same geological heterogeneity; (3) Integrate various types of data, each type bringing information on possibly different scales and with different precision."

Many researchers have made remarkable progress in this field during the last decade (Coburn et al., 2006). AAPG published a volume (AAPG Memoir 80) to showcase recent developments in principles, methods and applications, and to present case studies in geostatistics and stochastic simulation. This section of this report reviews two methods (shown in Figure 3.5), the deterministic model and the stochastic model. These models encompass variogram-based geostatistics modeling, object-based stochastic modeling, and multiple-point geostatistics modeling. Other methods, including standard facies modeling, are mentioned subsequently.

Variogram-Based Geostatistics Modeling

As depicted in the previous section of this report, geological heterogeneities at different scales are the most difficult but also the most important questions that geostatistical modeling addresses. Geostatistics is a mathematical language that uses strict rules and equations to describe a geological body. Usually this description must simplify complex geological facies that have heterogeneity hierarchies. Variograms could be the model of that simplification in geostatistics; they use mathematical language to define geological heterogeneity or continuity (Caers and Zhang, 2004).

Variogram-based geostatistics is a traditional statistical method that uses variogram models and describes variations between different investigations or the spatial structure at any two spatial locations (Caers and Zhang, 2004). These variogram models always try to capture information from two points of the available data; thus, variogram-based geostatistics modeling is also called two-point statistics (Zhang, 2008, Liu et al., 2004) or traditional two-point geostatistics (Deutsch and Journel, 1998).

The mathematical definition of the variogram is:

$$\gamma(\Delta x, \Delta y) = \frac{1}{2}\,\mathcal{E}\left[\{Z(x+\Delta x, y+\Delta y) - Z(x,y)\}^2\right] ,$$

where **Z(x,y)** is the value of the variable of interest at location **(x, y)**, and $\boldsymbol{\varepsilon}$ [ ] is the statistical expectation operator**.** Note that the variogram, **γ**( ), is a function of the separation between points **(Δx, Δy)**, and not a function of the specific location **(x, y).** (Bernes, Golden Soft, Inc.)

Since the methodology of variogram is to describe the possibilities of the spatial distribution between two locations, different models give various distribution possibilities. The most important models are the exponential variogram model, the spherical variogram model, and the Gaussian variogram model (Chiles and Delfiner, 1999; Cressie, 1993).

Successful vairogram-based geostatistical modeling depends on the choice of variograms (Figure 3.6, Figure 3.7). Although it is a traditional method and popularly used to predict subsurface uncertainties in reservoir architecture simulation (White et al., 2004, Ma et al., 2009, Dutton et al., 2002), variogram-based geostatistical modeling still has limitations. Because a variogram is a mathematical concept, its oversimplification can result in a limited connection with geologic reality. Caers and Zhang (2004) showed examples of different geological heterogeneities resulting in similar variograms (Figure 3.8). Also, the quantity of well information is still not enough to provide a reliable 3-D variogram model (Liu et al., 2004), especially in the lateral direction. Through describing the correlations between only two spatial locations, it is too difficult for a variogram model to contain or catch all features, such as channel shapes or cross-bedding, mathematically.

Three-dimensional description is another challenge in variogram-based modeling. Variograms may capture the heterogeneity of one stratigraphic direction of the reservoir very well, but lateral facies distribution is hard to describe when few well data are available (Caers and Zhang, 2004). Therefore, variogram-based geostatistical modeling could not reproduce and capture curvilinear structures and/or shapes, which create the abundant subsurface heterogeneities such as structures (including faults, fractures, facies distribution), stacking pattern, and spatial distributions, that profoundly influence fluid flow properties.

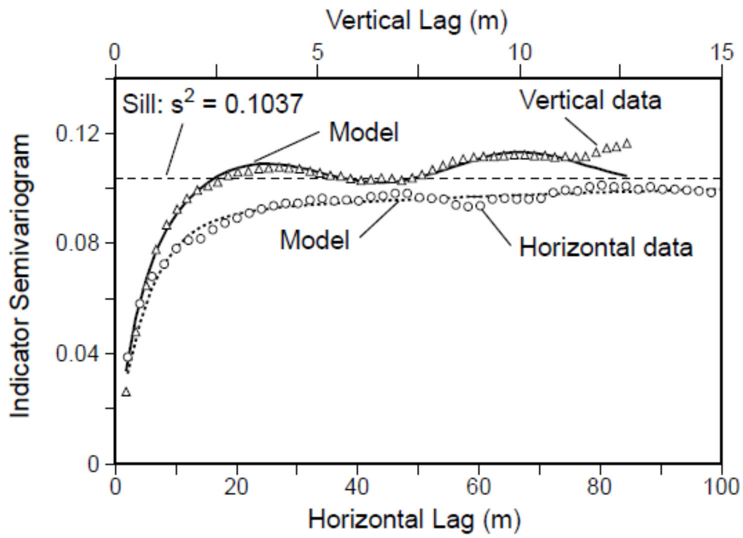

Figure 3.6 Horizontal and vertical semivariograms for the concretion indicator. The observations were computed using a regularly gridded array of concretion indicators. The horizontal and vertical ranges are approximately 30 and 2.5 m, respectively. From Dutton et al. (2002).

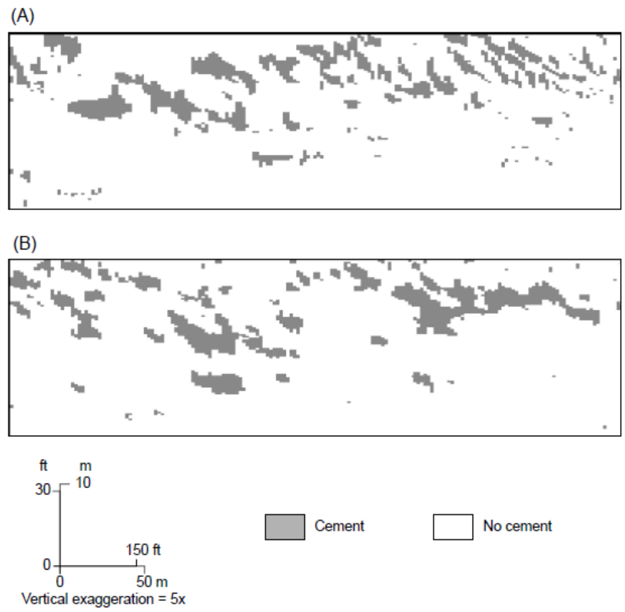

Figure 3.7 Concretion images. (A) The observed concretion map was discretized onto a regular rectangular grid. (B) A conditional geostatistical simulated image using semivariograms in Figure 3.12. This image was prepared for using truncated sequential Gaussian simulation, simulated annealing, and multipoint statistics. From Dutton et al., (2002).

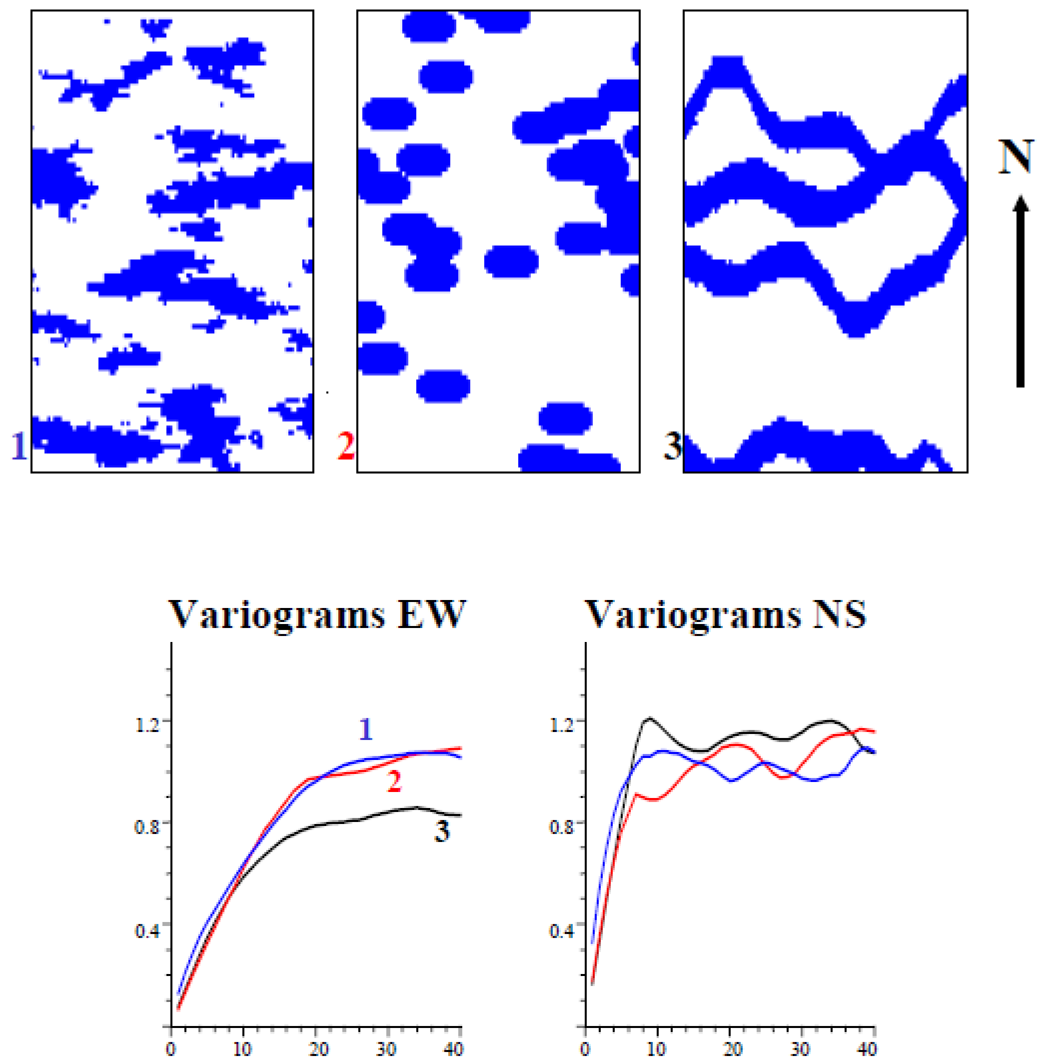

Figure 3.8. The variogram as a poor descriptor of geological heterogeneity. Three different geological heterogeneities result in three similar variograms. From Caers and Zhang (2004).

Object-Based Stochastic Modeling

As mentioned in a previous section, since the variogram has limited connection to real subsurface geological environments, variogram-based geostatistics is poor at describing and reproducing the subsurface heterogeneities linked with structures, facies architectures and other geologic conditions. This is especially true of complex reservoirs that have much less data available.

Object-based techniques (Haldorsen and Damsleth, 1990) were then proposed and first used in fluvial reservoir modeling (Deutsch and Wang, 1996, Holden et al., 1998). Object-based models simulate the spatial distribution (such as facies distribution, grain size changing pattern) of objects that are described by specified geometries in three-dimensional space. Well data are always obtained to constrain object-based stochastic simulations. This technique is based on performing the simulation through sequentially putting different geologic bodies (from large scale such as channel complexes to small scale, for example individual channels) onto the simulation field (Deutsch and Wang, 1996; Liu, 2005) and operating on the scale of sedimentary architecture. Object-based stochastic modeling allows crisp reproduction of facies geometry by parameterizing shape parameters (Liu, 2004; Zhang, 2008).

"Hierarchical object-based stochastic modeling of fluvial reservoirs" (Deutsch and Wang, 1996 shows how to establish the stochastic modeling in different scale of fluvial reservoir. Table 3.2 summarizes the eight-step coordinate transformations, from largest to smallest scale, when using object-based stochastic modeling to simulate fluvial reservoir (Deutsch and Wang, 1996). In this paper, the authors demonstrated the stochastic modeling of channels and channel complexes within a major reservoir layer. All the reservoir layers were then modeled sequentially, and the outputs of the modeling were combined in a unique reservoir model ready for reservoir fluid flow simulations. The following data were considered as constraining parameters for object-based modeling in their research. They are lithofacies, porosity and permeability data from wells, size and shape of channel complexes and individual channels, vertical facies proportion curves, and areal facies proportion maps (Deutsch and Wang, 1996).

Transform		Figure no.	From			To		
			X	Y	Z	X	Y	Z
1	Vertical Stratigraphic Coordinates	1	x_1	y_1	z_1	x_1	y_1	z_2
2	Areal Translation and Rotation	2	x_1	y_1	z_2	x_2	y_2	z_2
3	Channel Complex Translation and Rotation	3	x_2	y_2	z_2	x_3	y_3	z_2
4	Channel Complex Straightening	5	x_3	y_3	z_2	x_4	y_3	z_2
5	Relative Channel Complex Coordinate	6	x_4	y_3	z_2	x_5	y_3	z_2
6	Channel Translation	7	x_5	y_3	z_2	x_6	y_3	z_2
7	Channel Straightening	8	x_6	y_4	z_2	x_7	y_3	z_2
8	Relative Channel Coordinate	9	x_7	y_4	z_2	x_8	y_3	z_2

Table 3.2 Summary of eight-step coordinate transformation from largest to smallest scale From Deutsch and Wang (1996).

As shown in Table 3.2, the authors operated their object-based stochastic modeling by continually adjusting the coordinate system to 'the appropriate principal directions of continuity'. This critical direction is dominated by the scale of observation and specific geologic characteristics. As a hierarchical modeling procedure, the coordinate system is adapted from step 1 (large scale) to step 8 (small scale), therefore each reservoir layer has its specific coordinate system. Inside of each layer a number of the channel complexes is then identified. Finally the channels are then put into each channel complex. Marked point process is used to position each sand-filled channel location, and its features are defined by a starting location, size parameters, and sinuosity parameters.

Figure 3.9 shows the first procedure (of 8 procedures, as shown in Table 3.2) for generating the coordinate system hierarchically. Other processes can be checked using the details in Deutsch and Wang (2006).

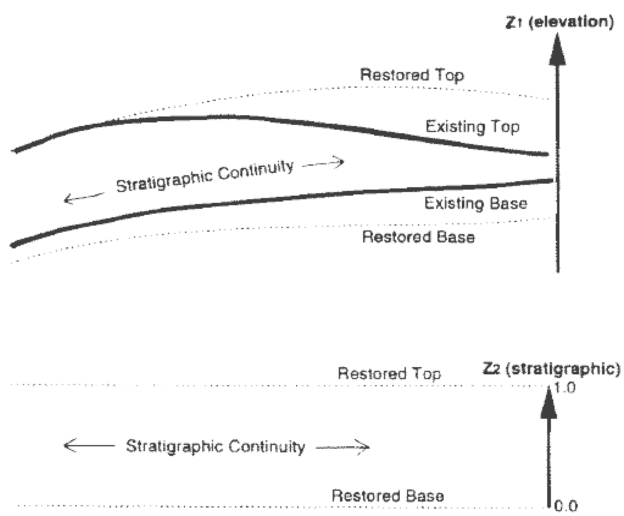

Figure 3.9 Coordinate transformation from original depth coordinate Z1 to stratigraphic vertical coordinate Z2. (Step 1 in Table 3.2). From Caers and Zhang (2004).

Figure 3.10 is an overview of object-based model processes (Overeem, 2008). Figure 3.10A is conceptual characterizations of a channel deposition system, including channel dimensions (L, W) and orientation, overbank deposits, crevasse channels, and levees. Figure 3.10B is the same coordinate transformation and position for channel complex or individual channel as addressed by Deutsch and Wang, 1996. Figure 3.10C utilizes probability laws (such as object-based stochastic modeling, and marked point process) to capture geological information about spatial lithology distribution, in this example, fluvial channel-fill sands. This procedure provides the geometries of the single channel or channel belts. Figure 3.10D shows an object-based model of a channel belt generated by random avulsion at a fixed point, and some series of realizations conditioned to wells (equiprobable). Figures 3.10E and F show different scales of the fluvial reservoir simulation models; E is the model with 100 m width, and the width of model F is 800 m. Then the models are conditioned by 5 wells in Figure 3.10F. Although this procedure is a stochastic process, integration of all the information from well logs, cores, modern analogues, and outcrops is still extremely important to condition and constrain the stochastic modeling. Well log and core data are used to define the facies stacking pattern, and outcrop and modern analogues provide information on the geometry of the depositional system. The more information available to constrain the modeling process, the more accuracy the model attains.

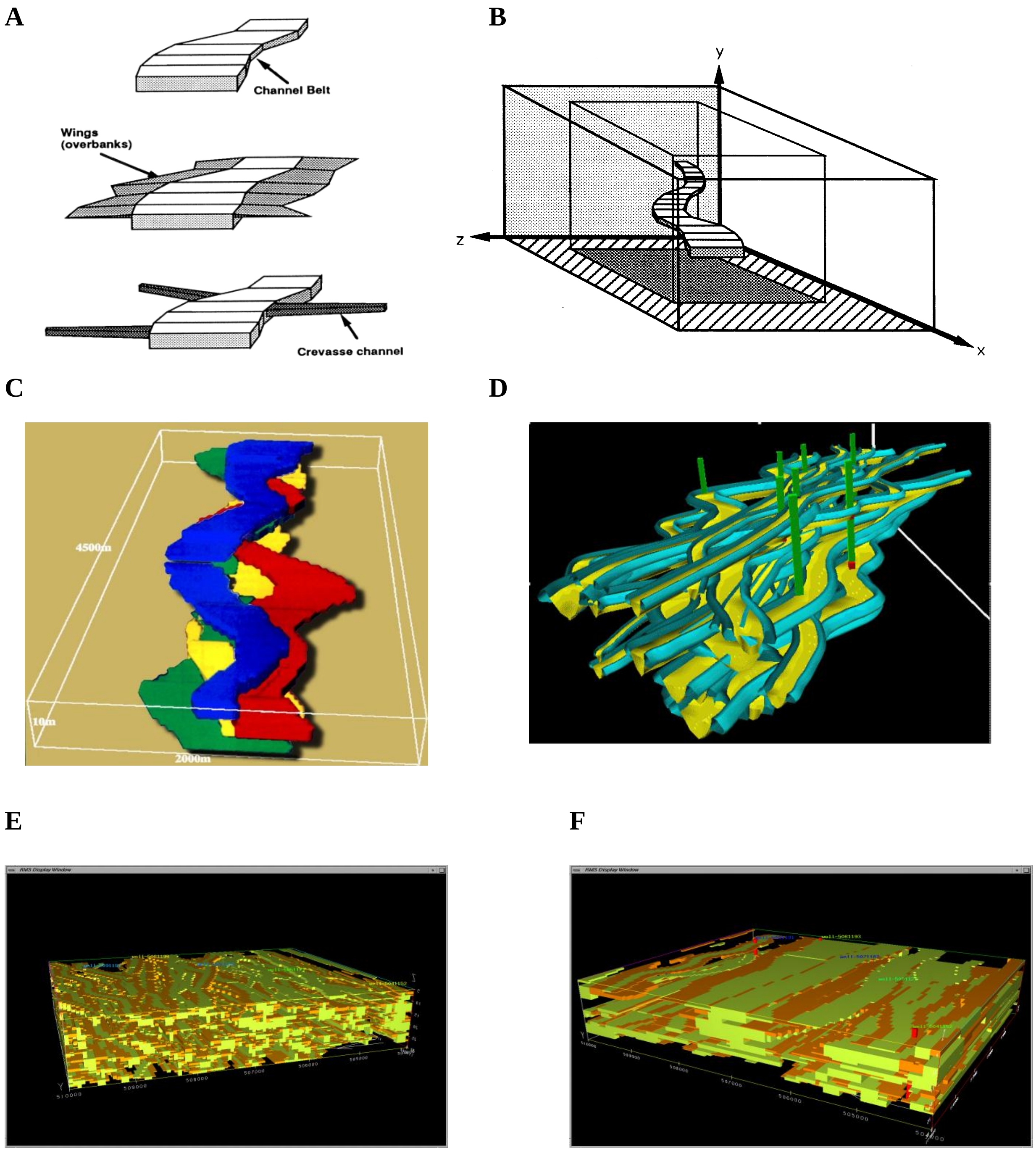

Figure 3.10. Overview of object-based stochastic modeling. A-D from Overeem (2008); E and F from Geel and Donselaar, (2007) .

Object-based stochastic modeling is the most direct method (Zhang, 2008) of reproducing the crisp shape of a geologic body (Liu et al., 2004, Zhang, 2008). However, it has its own limitation. It needs a high-capacity computer to process data to honor the extensive hard data, such as 3D seismic data. Since its limitation on integrating 3-D seismic data, in most case, object-based simulations just utilize 2-D areal proportion maps, which are derived from seismic data, as conditioning data to constrain the modeling procedure. Therefore high CPU demand and the difficulty of conditioning locally extensive, hard data limit the applicability of object-based stochastic modeling.

Multiple-Point Geostatistics Modeling

To surmount the limitations of variogram-based and object-based stochastic modeling, multiple-point geostatistics (Journel, 1992; Guardiano and Srivastava, 1993; Strbelle, 2000; Liu et al., 2004; Caers and Zhang, 2004) was introduced to model depositional facies and integrate information from both geologic and 3D seismic data. This approach allows reproduction of curvilinear facies structures and at the same time makes data conditioning flexible. In this respect, multiple-point geostatistics overcomes the limitations posed by variogram-based and object-based stochastic modeling.

Use of a training image is the core technique driving multiple-point geostatistics modeling. A training image is actually a database or a numerical geological model that contains three-dimensional information about a geological body. This model is considered to contain or capture the facies structures (including shapes, patterns, and distribution of the facies or facies architecture) and relationships assumed to exist in the real reservoir (Caers and Zhang, 2004; Liu et al., 2004, Zhang, 2008). All the information, including the data inside a training image used to depict facies architectures, can come from outcrops, modern analogues, well log data interpretation, core analysis, and seismic imaging. Training images must have stationarity and ergodicity (Caers and Zhang, 2004), just as any other statistical analysis should (Figure 3.11).

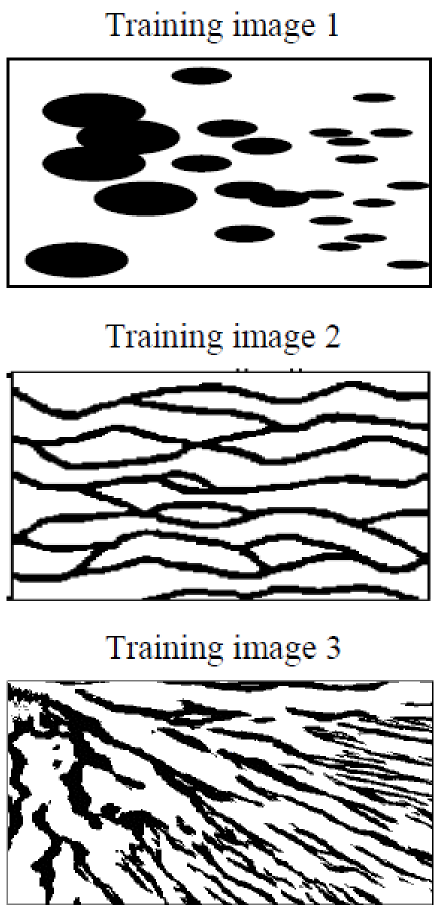

Figure 3.11 Three possible candidates for a training image: (1) elliptical shapes, (2) a fluvial type reservoir, (3) a deltaic type reservoir. Only image 2 can be used as a training image because its pattern is stationary over the entire image. From Caers and Zhang, (2004).

Since a training image can be considered as a prior structure model, all the conceptual geological models (for example, fluvial depositional systems) can be directly used or converted into training images. Zhang (2008) provided a list of tools to construct reservoir training images: (1) Geological analogs, including outcrops, modern depositional environments. (2) Sequence stratigraphy studies. This research can provide system tracts information and help to construct training images in different system tracts. For instance, channels show different geometries according to deposition in highstand or lowstand systems tracts. (3) Object-based algorithms. This method can provide realistic shapes for subsurface reservoir bodies and their spatial distribution. (4) Process-based models. These models can be created through forward modeling the geological processes and can be utilized as a foundation model to construct a conceptual facies model.

Reservoir heterogeneity and facies models are all scale-dependent; training images generated from prior geological models are scale-dependent as well (Figure 3.12). Training images can be either categorical variable or continuous variable (Zhang, 2008). Categorical variable could be facies parameters changing; continuous variable means reservoir continuity, that can be described as porosity and permeability. Training images should be illustrated in three dimensions to depict facies or reservoir continuity, vertical pattern, and lateral distribution. Vertical patterns of training images can be extracted from outcrop and well data (logging and core), and high-resolution seismic data can provide lateral distribution patterns.

Then the question becomes how to convert a stationary training image (such as Figure 3.11b), and how to keep and reproduce the pattern included in a training image into numerical language. A technique called a pixel-based algorithm can fulfill this task. A

“Snesim” algorithm (single normal equation simulation) is the core of this method, as described by Isaaks (1990), Gomez and Srivastava(1990), and Strebelle (2000, 2001).

Once a training image is built, the required patterns can be obtained from this numerical geological model database. Multiple-point geostatistics then allows catching facies architectures from a training image, then anchoring them (Caers and Zhang, 2004; Liu et al, 2004; Zhang, 2008) to local-specific reservoir data.

Multiple-point geostatistics is more powerful than variogram-based and object-based stochastic modeling because (1) it is a better integration of geology; Figures 3.13 and 3.14 show the differences when using variogram-based and multiple-point based stochastics to simulate the same data; (2) it allows easier data conditioning (Liu et al., 2004).

As described in previous paragraphs, a training image is generated from the integration of almost all the available information related to reservoir bodies, and a pixel-based algorithm makes it easy to condition the information from different sources (Figure 3.15). Compared to multiple-point modeling, it is impossible to constrain object-based simulation with all this information. Liu et al. (2004) proposed a workflow with three parts to show how to process multiple-point geostatistics (Figure 3.16).

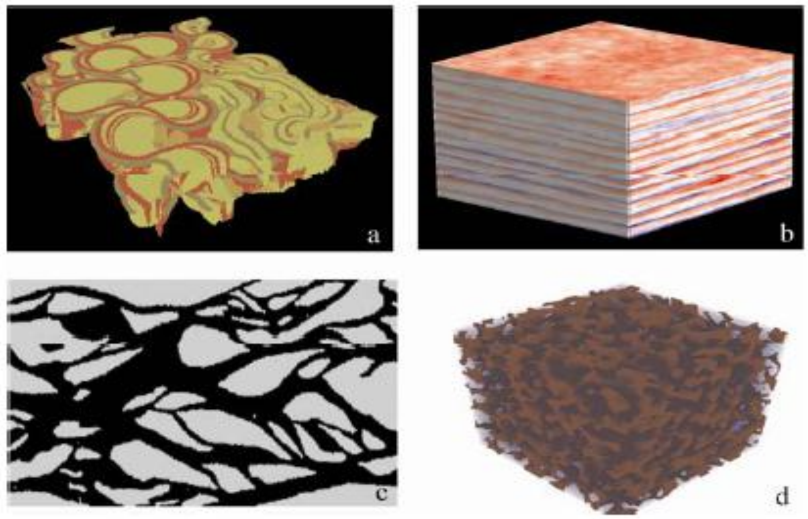

Figure 3.12. Different scale training image examples (Zhang, 2008). (a) Categorical (meandering channels); (b) Continuous (porosity distribution); (c) Large-scale (braided channels); (d) Small-scale (rock pore size). From Zhang (2008).

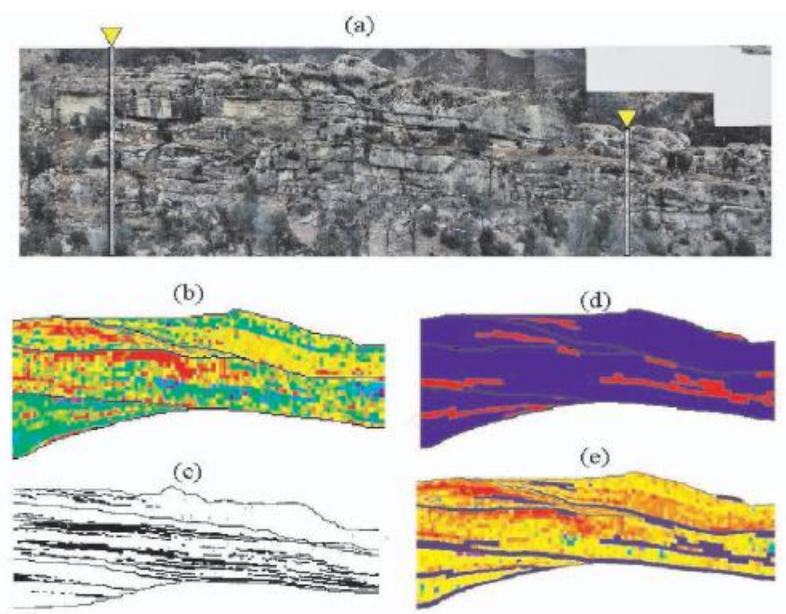

Figure 3.13 Integration of geology using a multiple-point simulation algorithm (Liu, et al. 2004). (a) the Wagon Rock Caves outcrop, from which two vertical columns are taken as well data; (b) one realization of permeability by the two-point model; (c) training image of mud layers, used for multiple-point simulation; (d) one multiple-point realization of mud layers; (e) one permeability realization including simulated mud layers. From Liu, et al. (2004).

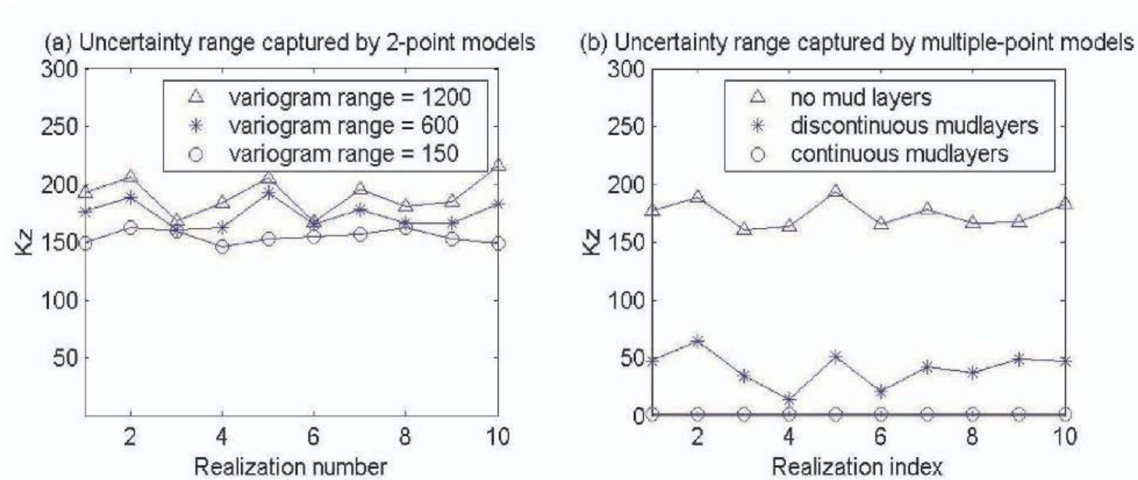

Figure 3.14. Vertical effective permeability (Kz) of different models (Liu, 2004) (a) Kz of three different variogram-based models; note the very similar results produced by different variograms; (b) Kz of three different multiple-point models; three different multiple-point models produced totally different results. From Liu et al. (2004).

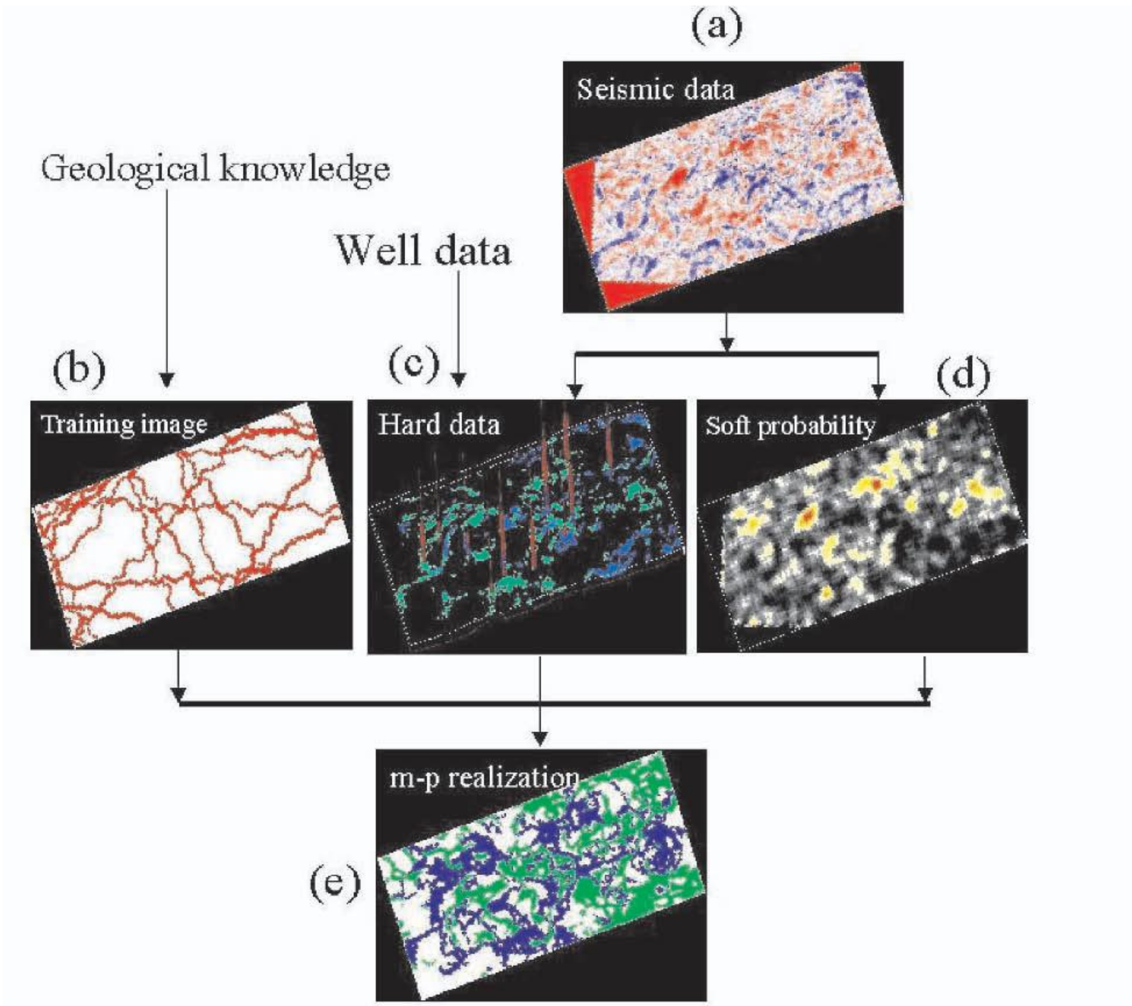

Figure 3.15. Multiple-point simulation integrating diverse types of information. (Note all the following data/information/realizations are in 3D, although only horizontal slices are shown here) (Liu, 2004). (a) seismic data; (b) a training image depicting the prior geological concepts; (c) hard data (well data + seismic imaged channel pieces); (d) seismic-derived soft probability for sand; (e) one multiple-point realization honoring the information shown in (b), (c), (d). From Liu et al. (2004).

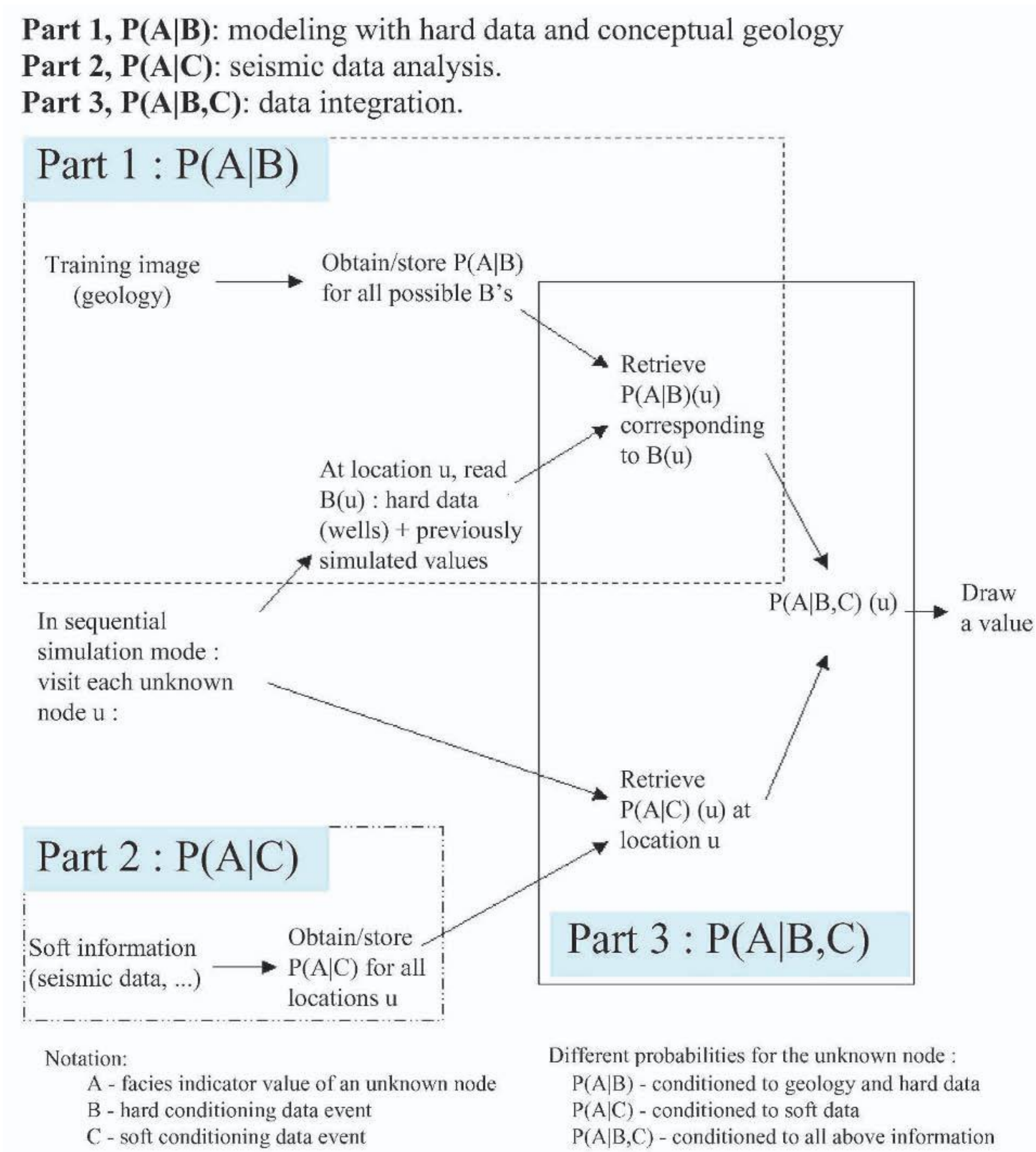

Figure 3.16. A multiple-point simulation workflow, decomposed into three parts (Liu et al., 2004).

Deterministic modeling

Another mathematical model, deterministic modeling (whether physically-based or process-based), uses one set of inputs and produces a single result. There is no random variation or component used in deterministic modeling. Overeem, (2008) concluded: Stochastic = Deterministic + Random

In geological modeling, seismic data are always used to constrain deterministic models to build the geometric model, such as in models of fault geometry (Figure 3.17) or sedimentary facies and, (Figure 3.18).

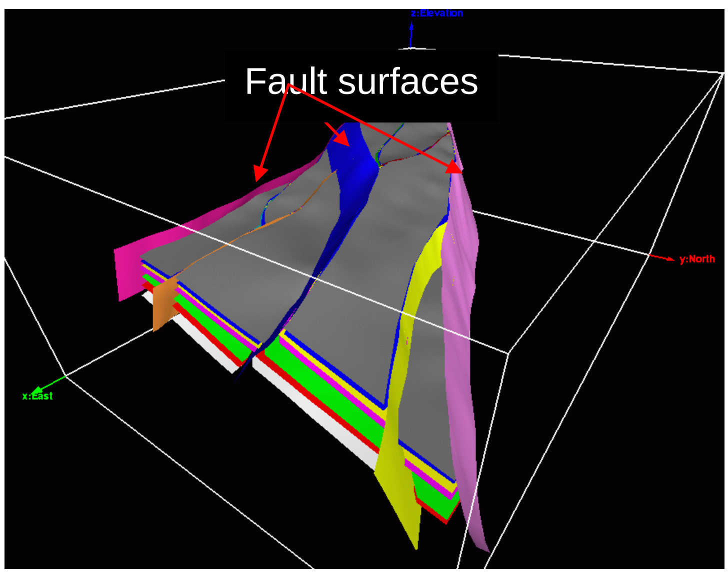

Figure 3.17 A deterministic fault model constrained by seismic data (using PETREL), Overeem (2008).

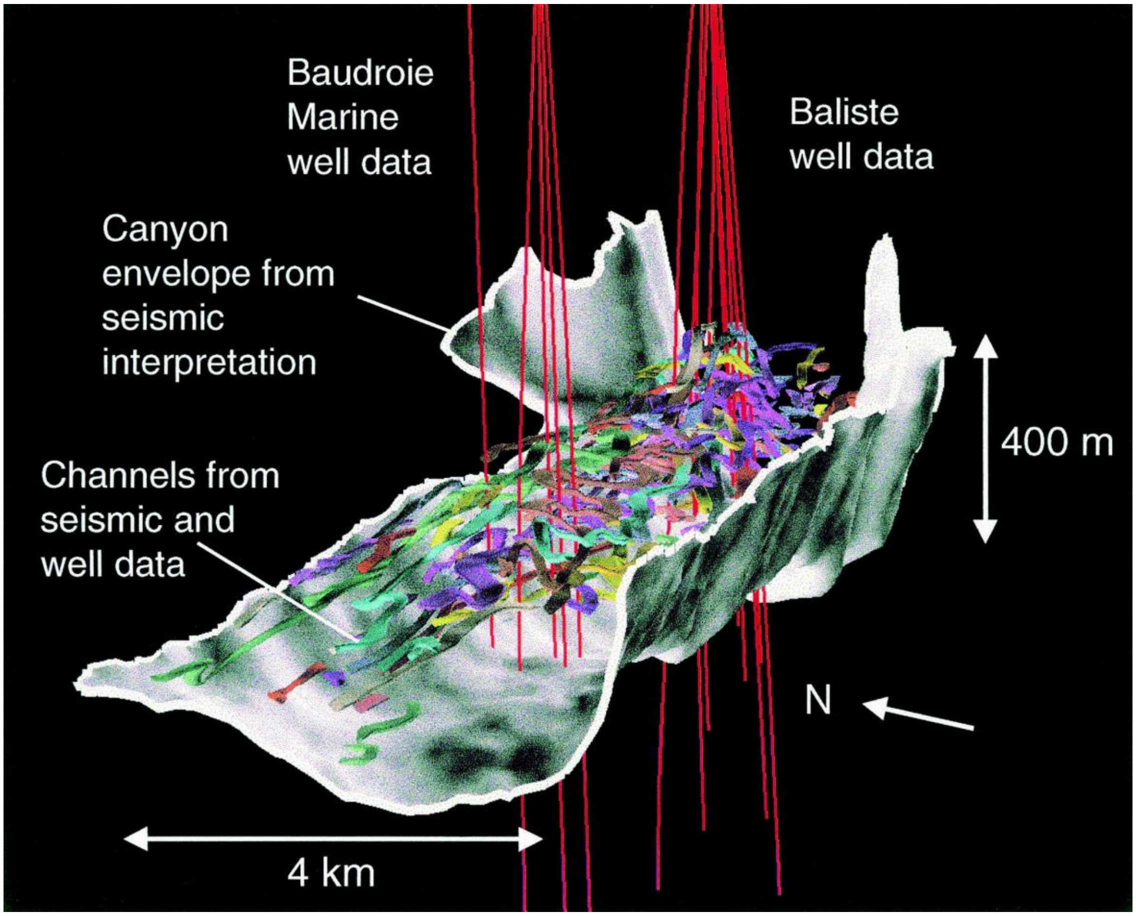

Figure 3.18 Deterministic sedimentary facies model from seismic attributes. A 3D model showing distribution of sinuous turbidite channels recognised from 3D seismic within the Baliste-CreÂ cerelle canyon. The image emphasises the labyrinthine complexity of these deposits. From Wonham et al. (2000).

Stochastic models can usually be used to simulate deterministic systems, such as smaller scale reservoir characterizations that cannot be accurately observed or modeled (Overeem, 2008).

Techniques used in the oil industry

Currently, several software programs are used in the petroleum industry for geostatistics facies modeling. These include PETREL, the RML-Geosim.Shell in-house proprietary modeling system known as GEOCAP; the Sequential indicator simulation (SIS); a Shell proprietary software package called the Structure Geology Toolkit; stratigraphic modeling software Dionisos. Other software programs were also presented in *AAPG Computer Applications in Geology 5, Stochastic Modeling and Geostatistics: Principles, Methods, and Case Studies, Volume* II.

Standard facies models

As described in the previous chapter, facies models can be built in different levels, from large-scale facies architecture to small-scale grain size distribution. All these diverse scale features play a very important role and are critical to reservoir heterogeneities and thus to fluid flow characterization. Mikes and Geel (2006) proposed some "standard facies models" to describe geometry and distribution of facies systematically. This standard could incorporate all heterogeneity levels in a reservoir model (Mikes and Geel, 2006).

Flow units (facies) and flow cells (bed) are two fundamental elements to be described in this method. A flow unit is defined as "consisting of a repetition of one flow cell" (Mikes and Geel, 2006), for example, a meander belt; a flow cell is the unique flow unit, such as a trough cross-bed. This approach is based on two premises: (1) a depositional system is composed of a typical set of facies, and (2) the facies contains one repeated bedding type. These conditions can ensure that the depositional system is described using a "conceptual standard facies model" (Mikes and Geel, 2006).

Every flow unit is defined by dimensions, boundary characteristics, and flow cell characteristics, which can be obtained by the reservoir deterministically or from a data set (Mikes, 2006). This digital information contains a different scale of heterogeneity information and can be easily upscaled to reservoir simulation. Mikes and Geel (2006) presented the whole modeling procedure using two delta systems, a Gilbert-type delta and a mouth-bar type delta, as examples.

The first step is to define the geologic model. This procedure includes: (1) clarifying the geometrical appearances of different parts of delta composition (Figures 3.19 and 3.20) and then as step (2) characterizing delta properties in different scales (Table 3.2). These hierarchical scale properties supply a geometric framework for the geological model. Subsequently all these characterizations of the delta combine important properties for fluid flow, which will then be used in reservoir modeling. Step (3) is to schematize the models (Figure 3.21). As step (4), standard facies models, in a six-scale hierarchy with sedimentary structure and facies, are constructed. In this example, Mikes and Geel (2004) proposed the lamina, bed, facies, facies association / parasequence, parasequence set / systems tract, and sequence as the model hierarchy. The facies is interpreted first, and corresponding standard facies models are produced later (Figure 3.22).

Step (5), the reservoir model, contains two parts, flow unit models and standard flow unit models. In the first stage of reservoir model construction, complicated geometries of the different scale facies (flow unit), bed (flow cell), and lamina (flow grid) are simplified and implemented as different geometries, such as using a rectangular structure to express a facies (flow units). Even in the actual reservoir it is irregularly shaped (Figure 3.23). The second stage simplifies the flow unit geometry version and then produces the reservoir model that will be used in reservoir simulation (Figure 3.24). Here, flow cells are upscaled into flow units, and flow units are separated into grid blocks, so that every flow unit contains several grid blocks.

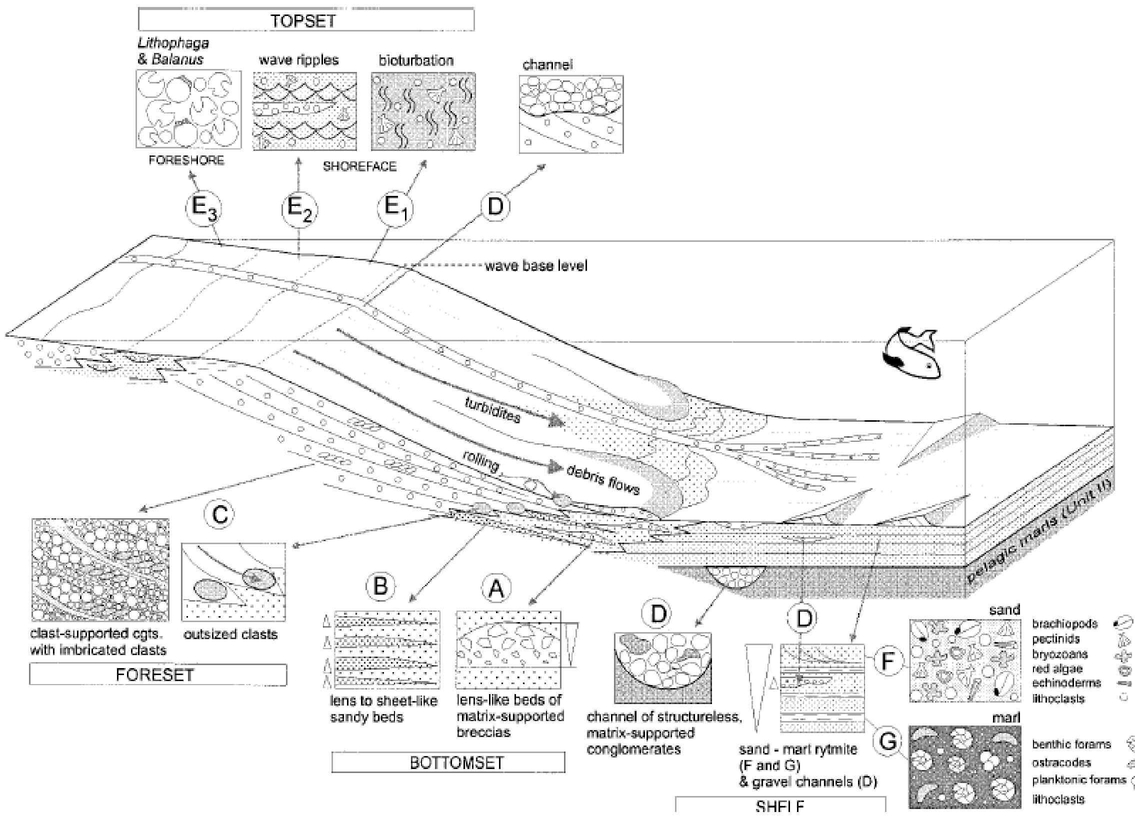

Figure 3.19 Facies distribution and main sedimentary processes of a Gilbert-type delta depositional system and its shelf. From Soria et al. (2003).

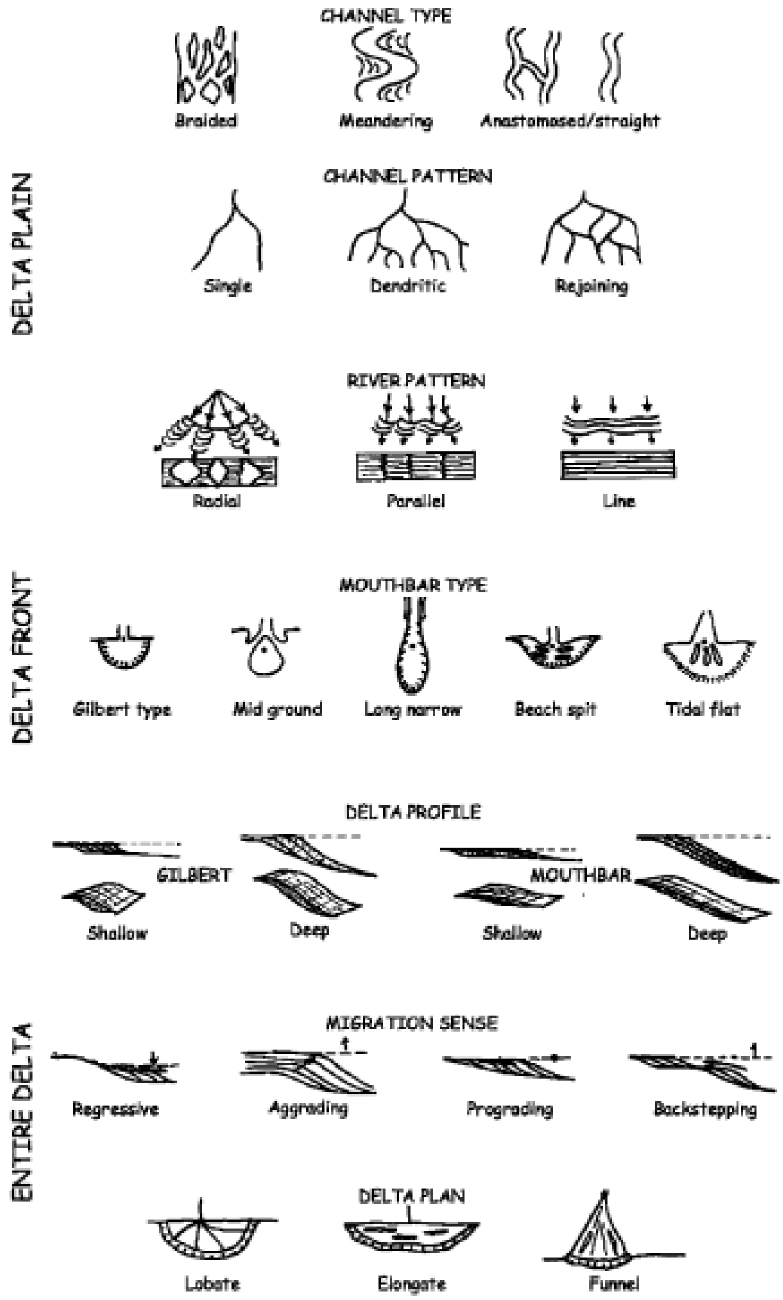

Figure 3.20 Geometrical appearances of delta plain, delta front, and entire delta. From Mikes and Geel (2006).

	Parasequence		
	Position	Depth	Setting
Basin	Shelf	Shallow	Gilbert-type
	Shelf margin	Deep	Mouthbar-type
	Size	Shape	Growth
Delta	Large	Lobate	Regressive
	Small	Cuspate	Aggrading
		Elongate/estuarine	Prograding
			Backstepping

	Facies association		
	River type	Supply	Grain size
Delta plain	Alluvial fan		Gravel, sand
	Braidplain	Bed load	Sand
	Meandering	Suspended load	Sand/mud
	Anastomosed		Mud
	Effluent type	Mouthbar type	Process
Delta front		Mid-ground	
	Inertia	Gilbert-type	River
	Friction	Long narrow	Waves
	Buoyancy	Beach-spit	Tides
		Tidal flat	

	Facies/bed			
	Delta plain	Delta front	Delta slope	Prodelta
Facies	Distributary	Mouthbar		
	Interdistributary	Clinoform	Offshore	Hemipelagic
	Beach	Coast	Slope	
	Floodplain			

	Distributary	Interdistr.	Floodplain	Mouthbar	Shore	Offshore
Sub-facies				Dune-bdg	hor.lam.	Hor.lam.
	hor.lam.	ripple-bdg	ripple-bdg	Ripple-bdg	HCS	Convolute bdg
	dune-bdg	hor.lam.	hor.lam.	Low-ang. x-bdg	low-ang. x-bdg	Slumps
				HCS		Turbidites

Table 3.3 Characteristic properties of a delta at three scales: parasequence, facies association, and facies/bed. From Mikes and Geel (2006).

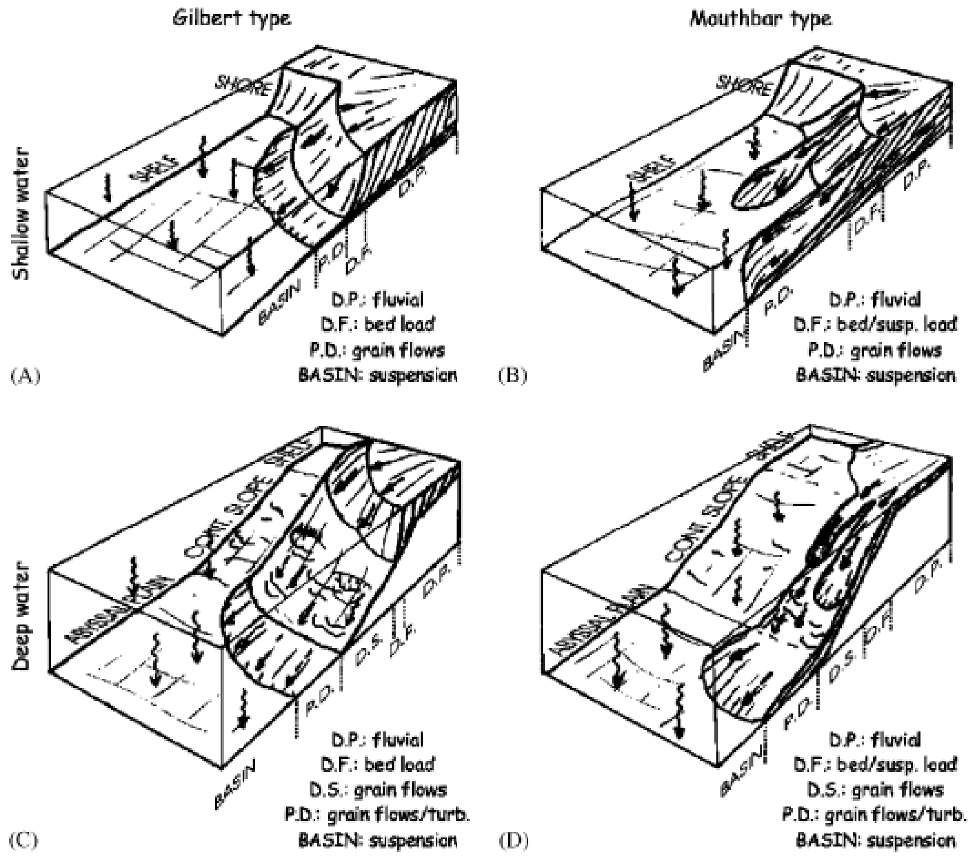

Figure 3.21 Schematic delta models. (A) shallow-water Gilbert delta; (B) deep-water Gilbert delta; (C) shallow-water mouthbar delta; and (D) deep-water mouthbar delta. D.P., delta plain; D.F., delta front; D.S., delta slope; P.D., prodelta; B, basin. From Mikes and Geel (2006).

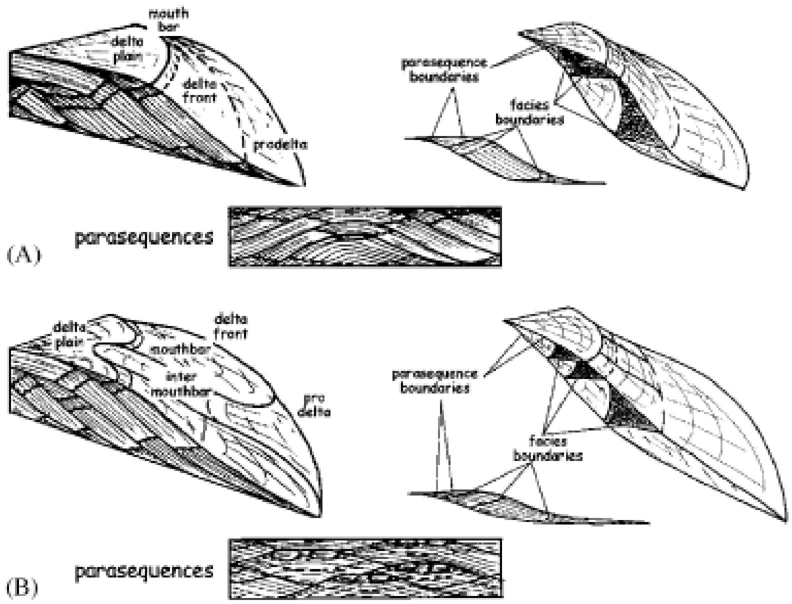

Figure 3.22 Standard facies models for shallow-water deltas: (A) Gilbert-type, and (B) mouthbar-type. These models contain geometric information, such as distribution of units and boundaries. From Mikes and Geel (2006).

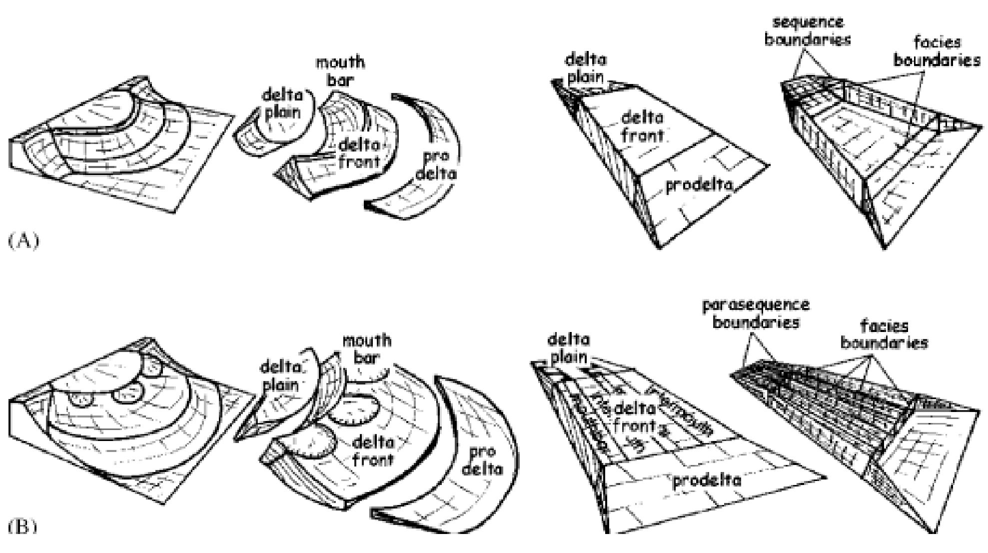

Figure 3.23. Flow unit models of shallow-water deltaic reservoirs: (A) Gilbert-type and (B) mouthbar-type. Facies association, facies, flow-unit model, and boundaries for one parasequence are shown. From Mikes and Geel (2006).

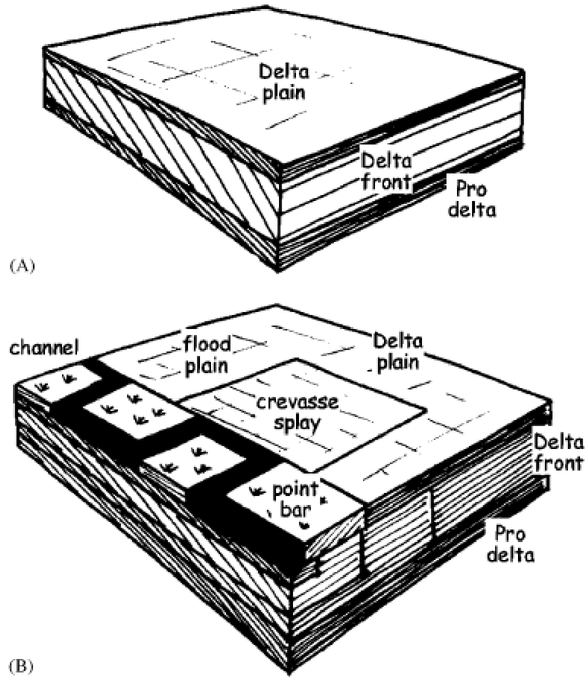

Figure 3.24 Hypothetical reservoir model of one parasequence of Gilbert-type and mouthbar-type delta (shallow varieties). The model and its elements are reduced to rectangular blocks, conserving vertical and lateral distribution of facies. From Mikes and Geel (2006).

Other geological methods

Sequence stratigraphy provides a greater ability to predict facies architecture and subsurface heterogeneity beyond the control points. It is an alternative way to do facies modeling. Walker (1990) gave a perspective about facies modeling and sequence stratigraphy. He mentioned that (1) systems tracts concepts can be used in many different scales, (2) every systems tract can be individually modeled, since each systems tract connects with a group of contemporaneous depositional systems (Brown and Fisher, 1977). With these concepts in mind, facies and facies modeling are then put into a sequence stratigraphy framework. This approach allows individual facies components to be analyzed in a more robust way in the 3D model. Sequence stratigraphy-based reservoir characterization analysis can help in building a 3D static model to understand the overall architecture of the reservoir, and finally to characterize reservoir heterogeneity more effectively (Ainsworth, 2005; Ainsworth, 2006; Cabello et al., 2010).

Ma et al. (2009) presented a method based on propensity and reference class concepts, to build a linkage between depositional conceptual models (depositional facies analysis) and stochastic modeling (facies modeling). This integration has been proved to help predict subsurface resources in the Judy Creek carbonate reef reservoir.

CHAPTER 4: CASE STUDIES

Chapter 2 and Chapter 3 in this report focus on reviewing the main concepts and methods, including geological and mathematical methods, involved in facies models and facies modeling for describing subsurface reservoir body characterization. Many research articles have been published related to facies models of different depositional systems and facies modeling approaches. AAPG published two volumes about methods and applications: (1) *Stochastic Modeling and Geostatistics: Principles, Methods, and Case Studies (AAPG Computer Applications in Geology 5)* and (2) *Integration of Outcrop and Modern Analogs in Reservoir Modeling (AAPG Memoir 80)*. Hundreds of case studies on stochastic and geostatistics are listed in the first volume. The second volume gives 18 case studies to demonstrate the importance of outcrop and modern analogues in reservoir modeling. Because of sheer numbers, it is impossible to review all of these studies.

The goal of this chapter is to present two case studies that exemplify the application of some of the methods reviewed in previous chapters. This chapter is divided into three parts. Part I is a case study of sequence stratigraphy-based analysis on reservoir connectivity; Part II is another case study, related to application of integration data from different disciplines in reservoir modeling; Part III is a review of outcrop modeling studies.

Case Study 1: Application of Sequence Stratigraphy in Analyzing Reservoir Connectivity.

Sequence stratigraphy has been a very powerful approach in predicting facies distribution and subsurface reservoir heterogeneity. Combining sequence stratigraphic methodology with numerical facies modeling methods is now widely used in subsurface reservoir characterization analysis.

Ainsworth presented two papers on sequence stratigraphic-based analysis of reservoir connectivity. One is the influence of depositional architecture (2005), which will be cited as an example in this report, and the other is the influence of sealing faults (2006).

In *Sequence stratigraphic-based analysis of reservoir connectivity: influence of depositional architecture – a case study from a marginal marine depositional setting* (Ainsworth, 2006), the author addressed the case study at the Sunrise and Troubadour fields (offshore northwest Australia). This is a marginal marine reservoir composed of fluvial-dominated and wave-dominated depositional environments (Ainsworth, 2005). The methodology presented in this research is shown in Figure 4.1.

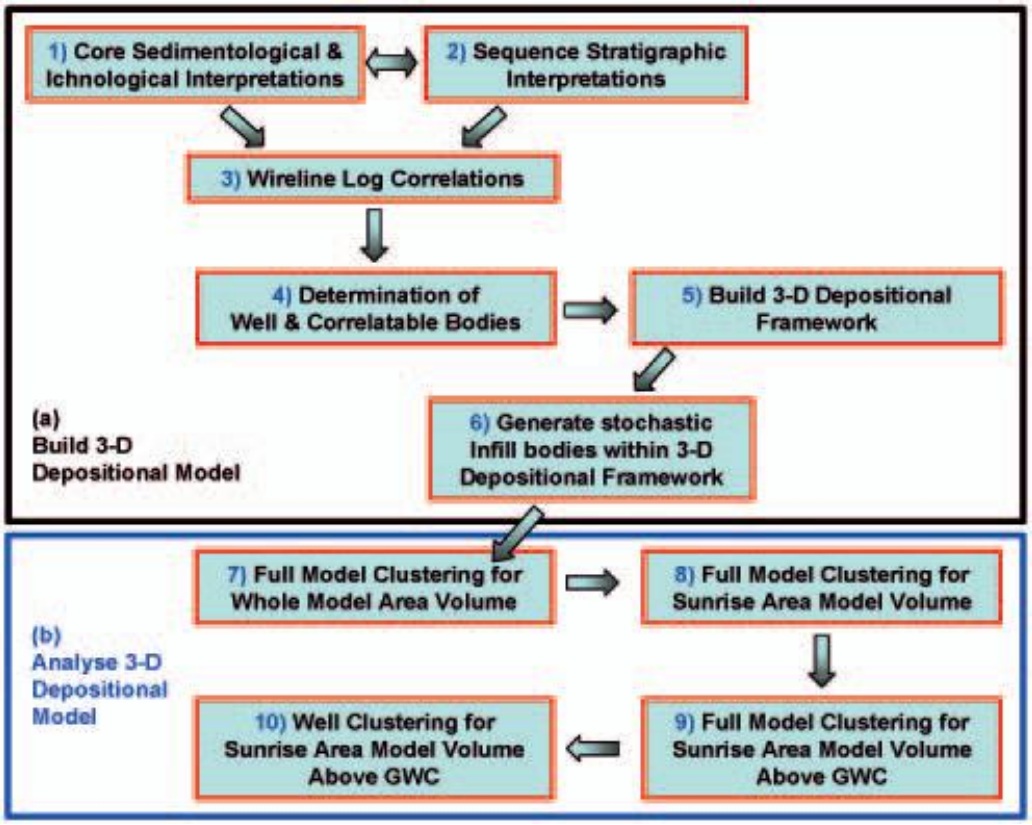

Figure 4.1 Three-dimensional depositional modeling and analysis workflow. (**a**) Workflow for building the 3D depositional model. (**b**) Workflow for analyzing the 3D depositional model. From Ainsworth (2005). GWC: gas-water contact.

There are two parts included in this methodology. The first part is to build the 3D depositional model. Different data such as tectonic evolution, stratigraphy, core facies description, and interpretation are all supplied as fundamental information for depositional trends and high-resolution sequence stratigraphic analysis. This step subdivides all the reservoir successions and puts them into a sequence stratigraphic framework (Figure 4.2). It allows the subsequent 3D reservoir modeling to be processed in any sequence stratigraphic hierarchy.

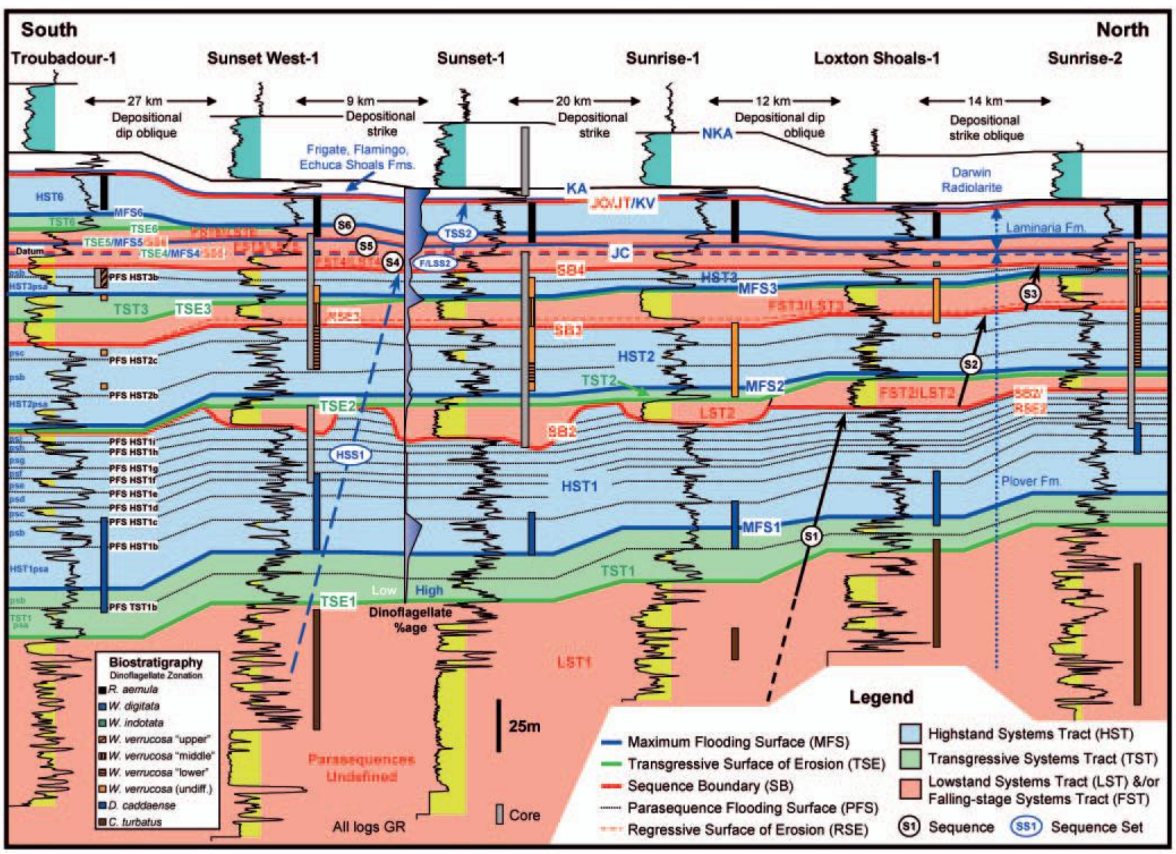

Figure 4.2 High-resolution sequence stratigraphy of study area in Sunrise and Troubadour fields. From Ainsworth (2005).

The second part is focused on three-dimensional depositional modeling. The process of generating the model is summarized in Figures 4.3 and 4.4.

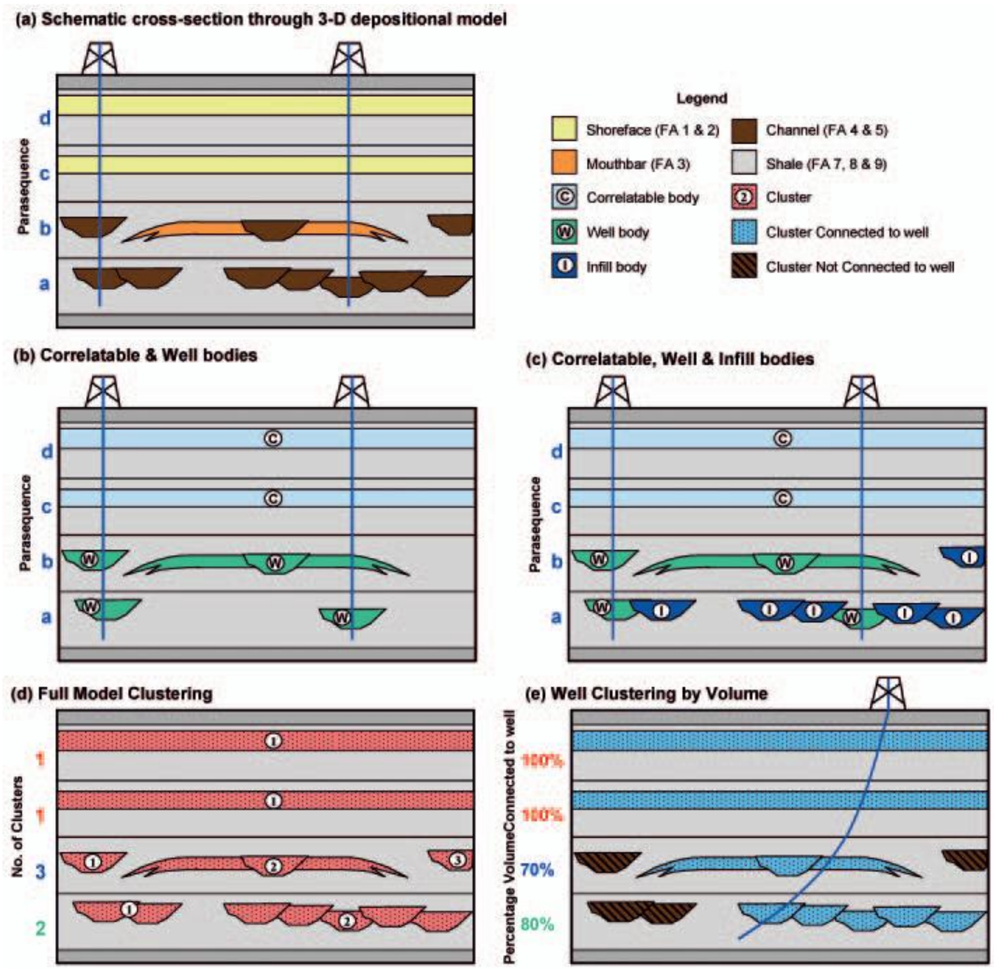

Figure 4.3 Explanation of 3D modeling terminology and processes used to generate a reservoir model (Ainsworth, 2005). (**a**) Schematic cross-section between two wells in a 3D depositional model showing facies and parasequences. (**b**) Bodies that are correlatable between the two wells (correlatable bodies) and those penetrated only by one well (well bodies). (**c**) The correlatable and well bodies seen in (b) plus stochastically generated bodies in the inter-well areas (infill bodies). (**d**) Example of full model clustering on a parasequence scale. Parasequence ‘a’ has two clusters, parasequence ‘b’ has three clusters and parasequences, and ‘c’ and ‘d’ both have one cluster. The fewer the number of clusters, the better the connectivity. (**e**) A well ‘drilled’ through the model. Parasequences ‘c’ and ‘d’ are 100% connected to the well while parasequence ‘a’ has 80% of its volume connected and parasequence ‘b’ has only 70% connected. Compare these well connectivities with the number of clusters for the same parasequence in (d) and

note the inverse relationship between the number of clusters and reservoir connectivity. From Ainsworth (2005).

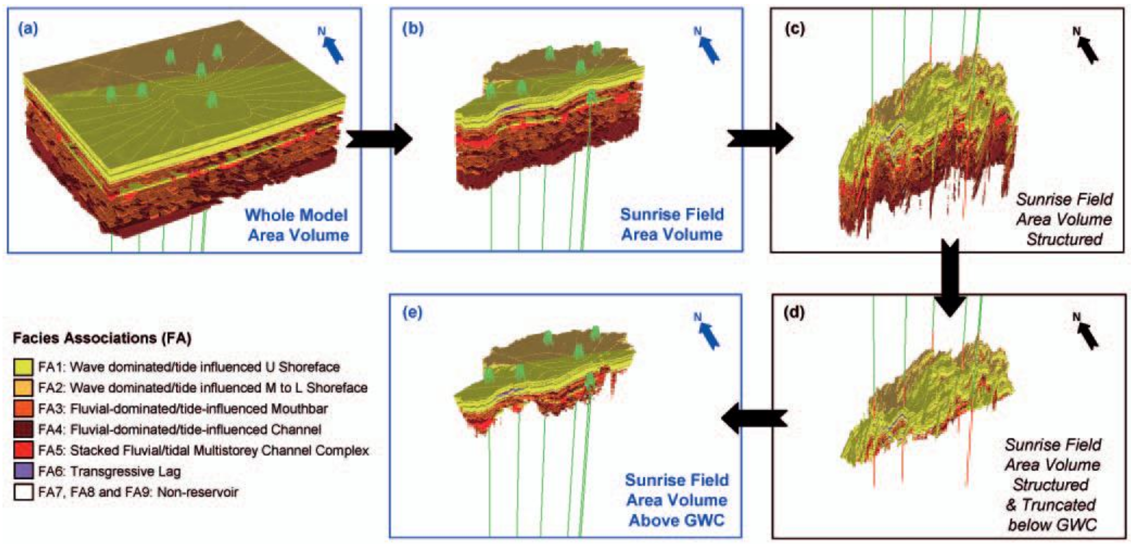

Figure 4.4 Three-dimensional reservoir modeling workflow used in the Sunrise field marginal marine depositional system. From Ainsworth (2005).

The three-dimensional depositional model was generated by combining a 3D sequence stratigraphic-based depositional model (Figure 4.3b) with a stochastic (Boolean stochastic methods) modeling technique (Figure 4.3c). Next the reservoir connectivity is identified through the clusters, the fewer the number of clusters, the better the connectivity (Figure 4.3d, 4.3e, Ainsworth, 2005). Average sand/shale ratios of the basic stratigraphic units or parasequence for each basic unit are used to control the number of generated infill sand bodies (Ainsworth, 2005). A Shell proprietary in-house modeling system (GEOCAP) was used to perform the modeling. Figure 4.5 gives the cross section through the 3D reservoir model (workflow Figures 4.1, 4.3, 4.4) showing sequence stratigraphic units with 3D depositional modeling results inside.

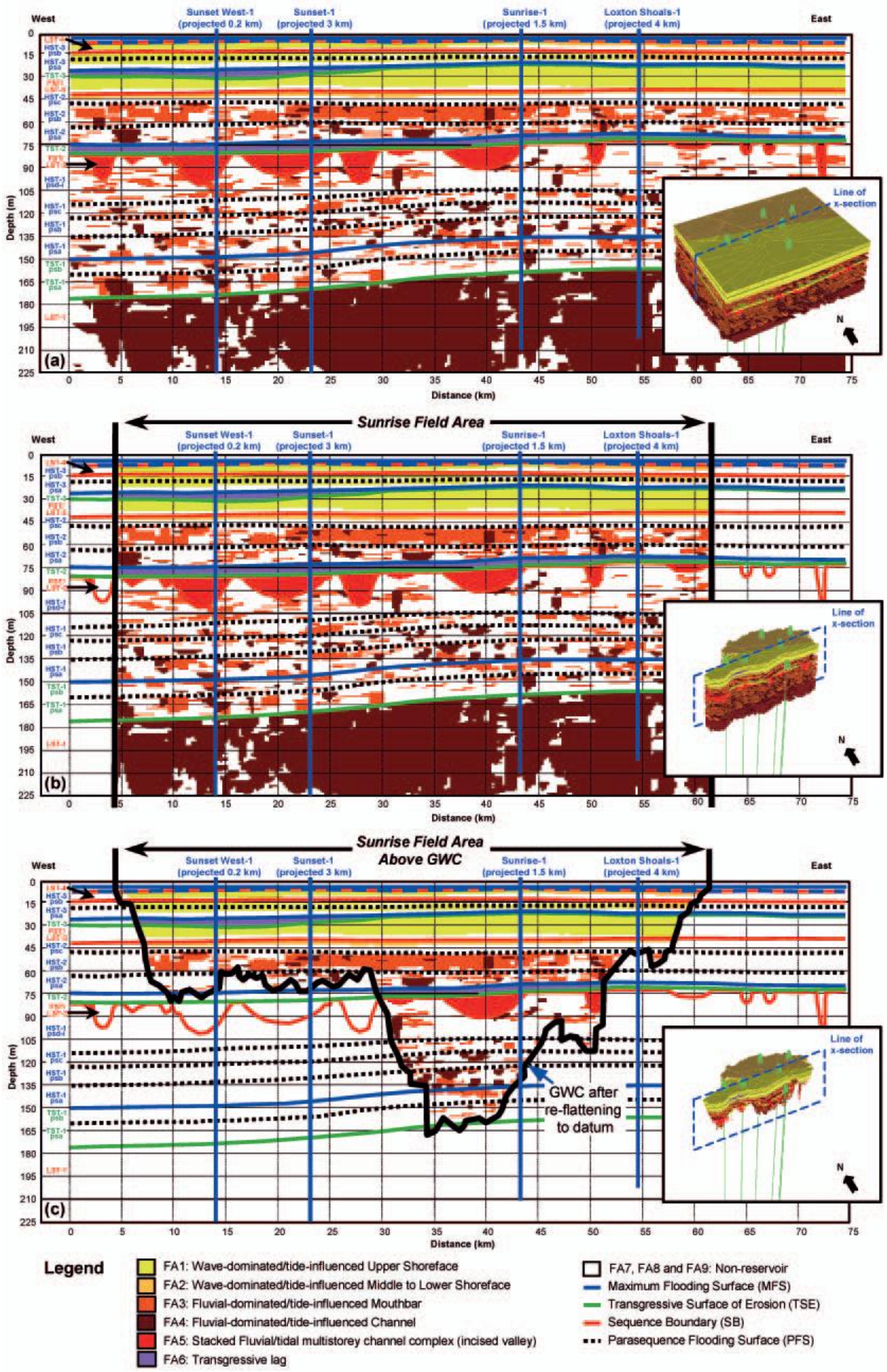

Figure 4.5 West-to-east cross-sections through the 3D reservoir model showing sequence stratigraphic units. (**a**) Whole model area volume; (**b**) Sunrise field area volume; (**c**) Sunrise field area volume above the GWC (gas-water contact). From Ainsworth (2005).

After producing the entire depositional connectivity model within the framework of sequence stratigraphy, the author then compared the full model and well cluster analysis trend in every stratigraphic unit, which is parasequence, systems tract, and sequence basis (Figure 4.6). Then the relationship between sequence stratigraphic and connectivity trends can be analyzed through all these sequence stratigraphic-based plots. These analyses include thickness trend, whole model connectivity, areal and volumetric connectivity dependency, and well connectivity at different sequence stratigraphic hierarchical levels (parasequence, systems tracts, and sequence).

This case study exemplifies the application of sequence stratigraphy to reservoir characterization. The methodology used in this study indicates that sequence stratigraphy can be a strong tool with which to predict reservoir parameters such as connectivity. By positioning depositional connectivity trends in the sequence stratigraphic framework, connectivity can be predicted at all stratigraphic hierarchical levels. This methodology is based on full understanding of various depositional settings and high-resolution sequence stratigraphic subdivisions of strata.

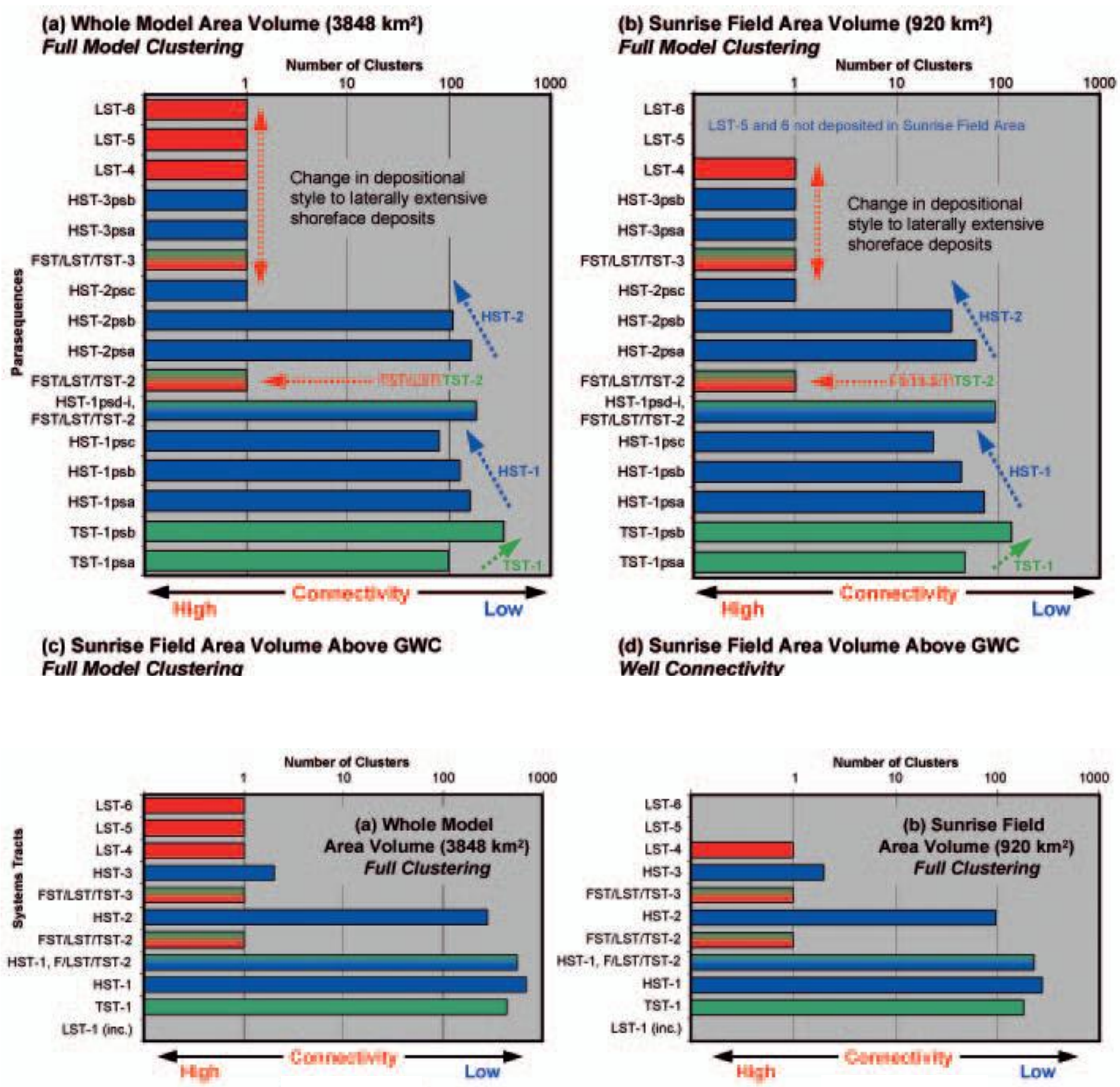

Figure 4.6 Examples of parasequence and systems tracts connectivity trends. All these trends clearly show the depositional connectivity in sequence stratigraphic hierarchical levels. From Ainsworth (2005).

Case Study 2: Application of Integration of Data from Different Disciplines in Reservoir Modeling

Integration disciplines for petroleum system analysis play a vital role in the oil industry (Ligtenberg and Neves, 2008). Since each datum and method (well data, seismic, outcrop, modern analogue, etc.) has its own strengths and limitations, it is impossible to use information from only one discipline to illustrate subsurface uncertainties. Integration and correlation is now a trend and is widely used for reservoir interpretation in oil exploration (Liu et al., 2004; Falivene et al., 2006; Waltham et al., 2008; Cacas et al., 2008). Different workflows were presented by researchers such as Liu et al. (2004), Liu (2005); Falivene et al., (2006), and Cabello et al. (2010), among others. This report presents one practice as an example to illustrate the application of integration data from different disciplines in reservoir facies modeling.

This case study of a fluvial-dominated reservoir was presented by Liu et al. (2004) on integrating well data, seismic data, and conceptual geological models. The methodology used here tries to overcome two challenges. First is the scale problem that exists between well data and seismic data: the reservoir information exists at different scales of resolution. For example, well logs can differentiate sand from shale, whereas seismic data are poor at distinguishing small-scale sand from shale but are better at distinguishing larger scale depositional geometries. The second challenge is how to apply and understand conceptual geological knowledge with resolution at multiple scales (Liu et al., 2004).

The authors proposed a workflow to meet these two challenges (Figure 4.7). This workflow consists of three steps. The first step is to identify characteristic patterns of certain depositional facies; here the principal component analysis (PCA) clustering technique is used. The second step is to build depositional facies models, which integrate the information from well logs, seismic, conceptual geological knowledge (depositional facies geometry); and multiple-point geostatistical simulation. The last step is to simulate different lithofacies (sand and shale) indicators and corresponding petrophysical properties. This simulation is restrained by the limited well data.

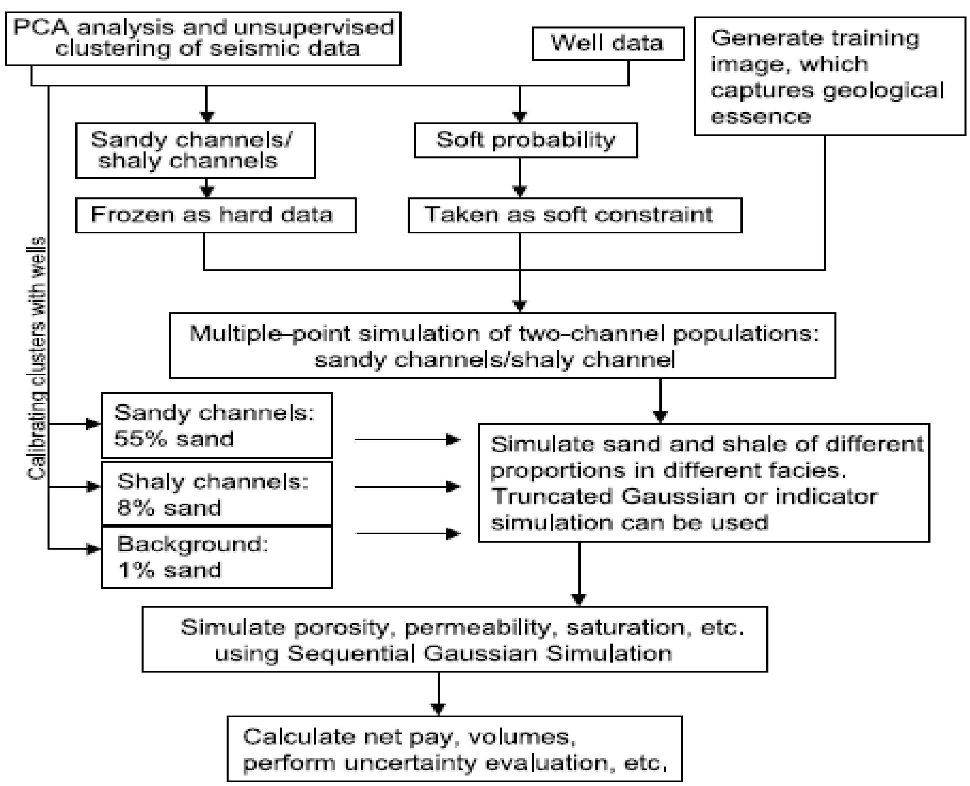

Figure 4.7 Summary workflow for reservoir modeling integrating well, seismic data, and prior geological knowledge. From Liu et al. (2004).

Two techniques, principal component analysis (PCA) and multiple-point geostatistics, are used in the workflow of this study. The PCA clustering technique (Scheevel and Payrazyan, 1999) is used to deal with some distinctive features related to depositional facies that are difficult to identify from the relative impedance data (Figure 4.8). This technique provides a way to recognize the spatial distribution, especially lateral distribution from lower resolution (comparing with well-log data) 3D seismic data (Scheevel and Payrazyan, 1999).

PCA is processed by:

(1) Resampling data into clusters.

$W(\mathbf{u}) = \{AI(\mathbf{u} + \mathbf{h}_1), AI(\mathbf{u} + \mathbf{h}_2),\ldots, AI(\mathbf{u} + \mathbf{h}_n)\}$, where $AI(\mathbf{u} + \mathbf{h}_i)$, $i = 1,\ldots,n$ represents the relative impedance datum $\mathbf{h}_i$ distant away from $\mathbf{u}$. Note that $\mathbf{h}_i$ accounts for not only distance, but also direction (Liu et al., 2004). This procedure attempts to catch different spatial patterns and to group the similar patterns into clusters using seismic data (such as impedance). Each cluster represents areas holding similar physical meaning (for example, impedance).

(2) Transferring resampled seismic data into the principal component space (Figure 4.9). Each component space (PC) intends to capture different characters of seismic data (Liu et al., 2004). These component spaces are illustrated as $PC(P_1)$, $PC(P_2)$,…, $PC(P_n)$. Here lower order PCs capture larger variation and higher order PCs capture smaller details. After principal component analysis, an accessible data size is obtained through reducing the original data with PC selected; and smaller order (may be caused by unwanted noise) PCs are removed, leaving a relative cleaner data set (Liu et al., 2004). The result provides

better information about and characterization of spatial patterns related to depositional facies, lithofacies, faults, fluid content, and so on (Liu et al., 2004).

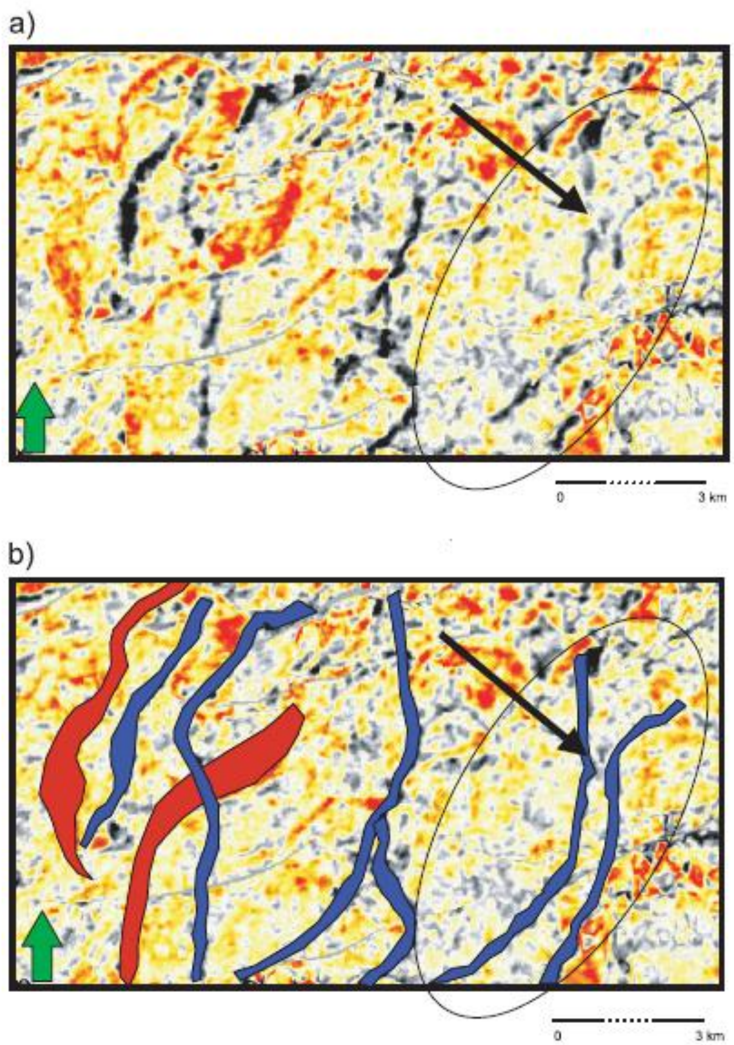

Figure 4.8 Horizon slices of seismic data showing that subtle depositional characteristics can be identified through integrating techniques (a) and an interpretation (b). Some channel segments of high relative-impedance (black) and low relative-impedance (red) can be clearly defined from these seismic data. With the volume use of edge detection, principal component analysis, and clustering, more subtle channels were also defined (as indicated by the black arrow). This example illustrates the evidence that multiple-point patterns, instead of the single-point seismic values, are sometimes more important for depositional facies interpretation. The green arrows point to. From Liu et al. (2004).

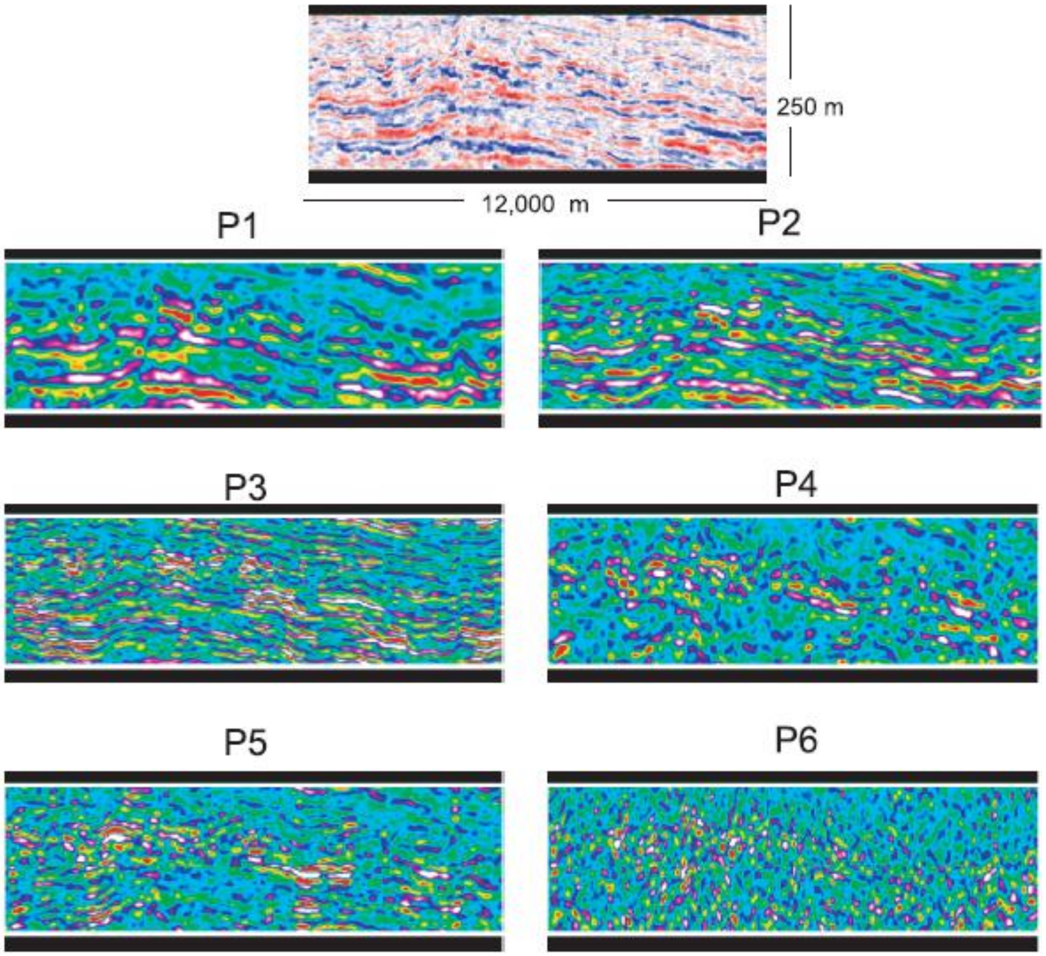

Figure 4.9 One vertical seismic slice (top) and the corresponding first six PCs. Each PC captures different characteristics of the original seismic slice, with the lower order PCs capturing larger variation and higher order PCs capturing smaller details (Liu et al., 2004).

(3) Deriving sand probability data.

Sand probability can be derived by: probability

$$\text{Probability}\{I(\mathbf{u}_0) = 1 | W(\mathbf{u}_0)\} = \frac{\sum_{i=1}^{N} \frac{I(\mathbf{u}_i)}{d_i}}{\sum_{i=1}^{N} \frac{1}{d_i}}$$

where $I(\mathbf{u}_i) = 1$, if $\mathbf{u}_i$ is in sand; otherwise, $I(\mathbf{u}_i) = 0$.

here, $I(\mathbf{u}_0)$ is sand probability at unknown position $\mathbf{u}_0$, $\mathbf{u}_i$ is each well data location, $I(\mathbf{u}_i)$ is the depositional facies datum, and $W(\mathbf{u}_i)$ is corresponding seismic window data.

Sand probability is then used as a soft constraint during depositional facies simulation (Figure 4.10).

In conclusion, after principal component analysis is conducted, channel segments can be identified. These channels may either be filled sand or shale. Channel segments are then applied as hard data in depositional facies simulation (Liu et al., 2004), which means that facies modeling is built on the constraint of this channel information.

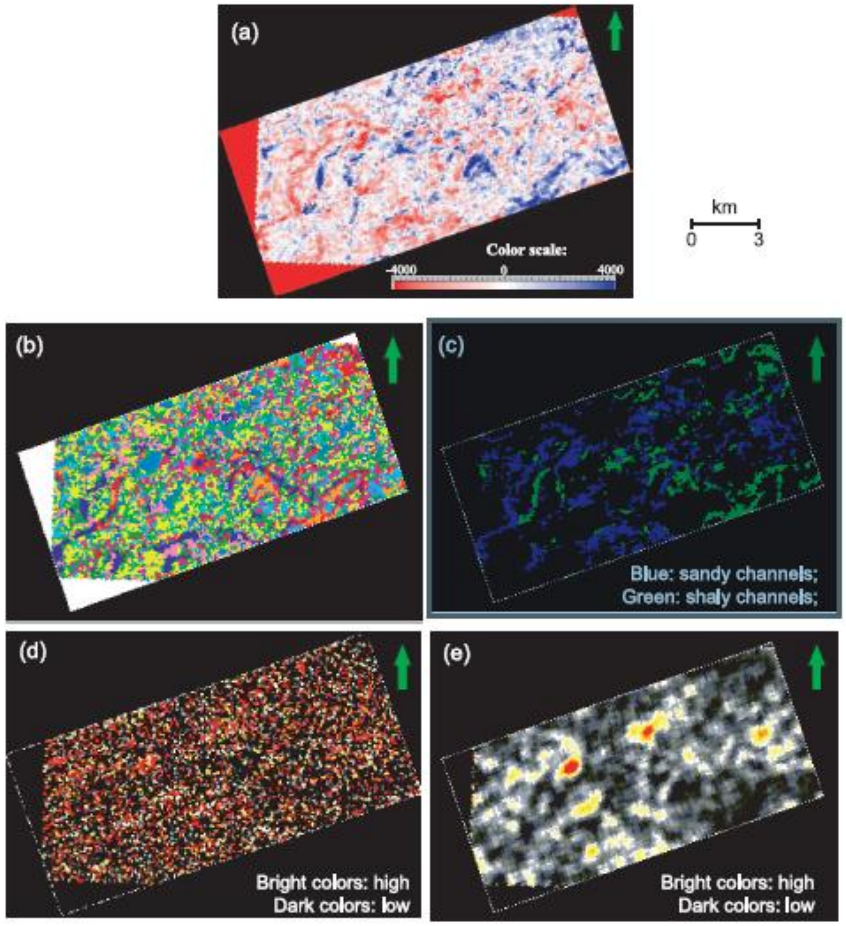

Figure 4.10 PCA and its application. (a) One horizontal slice of the original seismic data. Two types of patterns interpreted as channel segments can be observed: low relative-impedance (red) channels and high relative-impedance (blue) channels. (b) PCA clusters. Each different color represents a different cluster category. (c) Two selected groups of PCA clusters. The most certain channel segments on the seismic data are frozen as hard data during simulation of depositional facies. (d) Sand probability derived by calibrating seismic PCA data with the well data. It shows high frequency noise, which is removed using a moving-average low-pass filter. (e) Sand probability after filtering. It has fairly good correlation with the original seismic slice; bright colors represent high sand probability. It is used as a soft constraint during depositional facies simulation. The green arrows point to north. From Liu et al. (2004).

The multiple-point simulation technique was introduced in a previous chapter. The core methodology using in this technique is a training image, which provides prior geological concepts on the geometry of reservoir heterogeneity (Liu et al., 2004). In this case, the training image is a 3D model that was built by channel segments observed from seismic data (Figure 4.11).

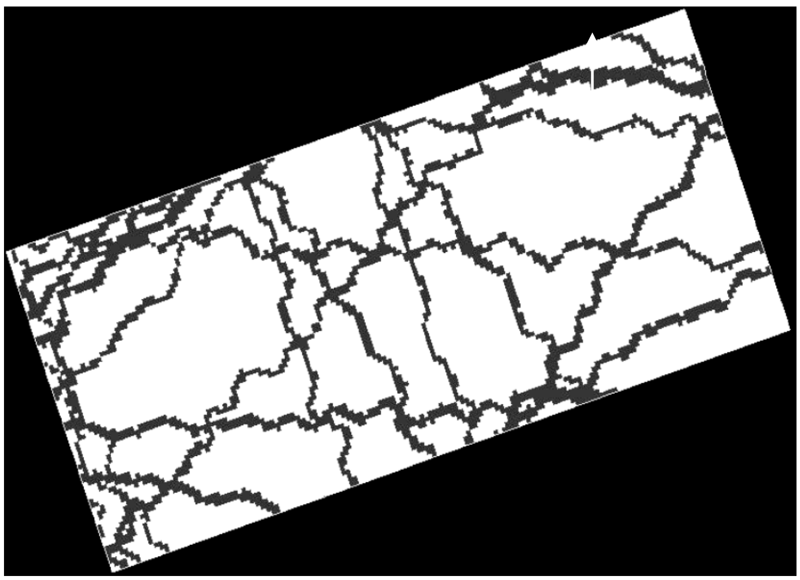

Figure 4.11 One horizontal slice for the 3-D training image used for multiple-point simulation of depositional facies. From Liu et al. (2004). The arrow points to north.

Hard data (channel segments, Figure 4.10c) and soft data (sand probability data, Figure 4.10e) are then provided as inputs to constrain multiple-point simulation. After the simulation, the fundamental characters present in the training image are reproduced with the two constraints (hard and soft data) (Figure 4.12b).

As the last step in this case study, lithology (sand and shale) and reservoir characterizations, porosity and permeability water saturation etc., are then simulated by using Truncated Gaussian and Sequence Gaussian simulations (Figure 4.12c, d).

Despite the strengths of the method shown above, Liu and colleagues mentioned some limitations of the approach that should improve when future work on multiple-point simulation has been completed. These limitations include the size of the training image, the stationary property of the training image, the capacity of the computer involved in complex training images and iterations of the method, and so on.

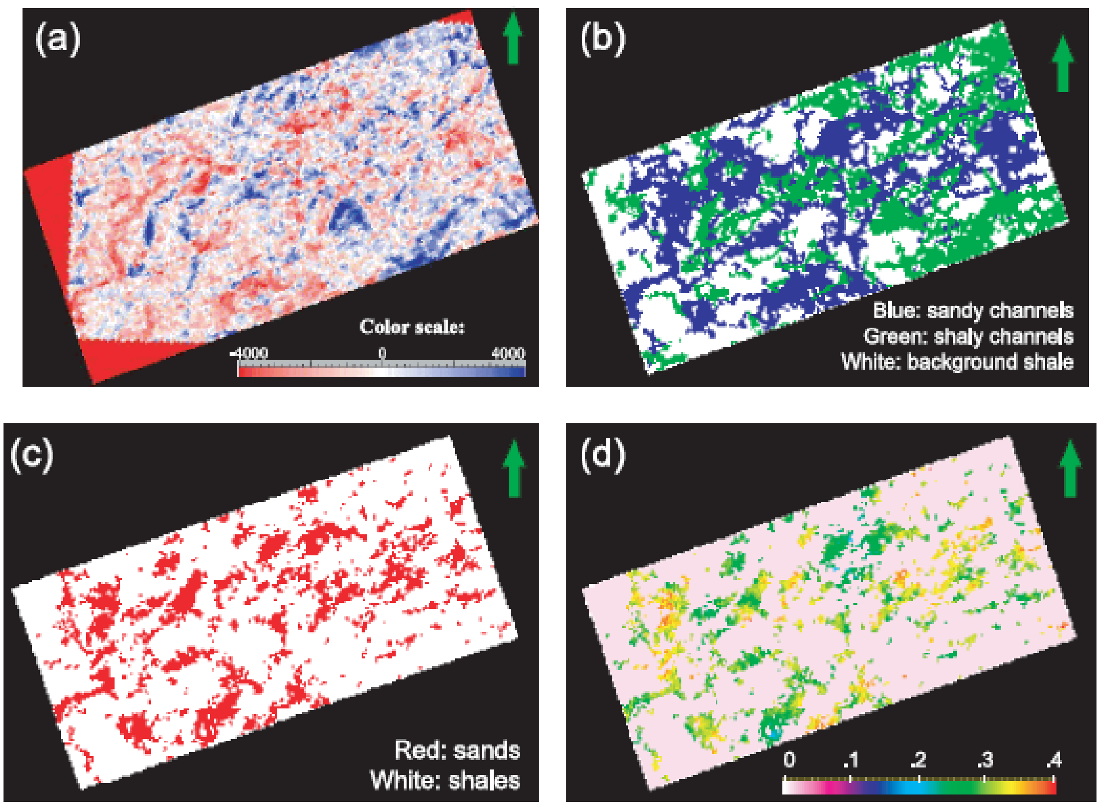

Figure 4.12. The final results of the case study (Liu et al., 2004). (a) Original seismic data; (b) simulated depositional facies; (c) lithofacies; (d) porosity. According to this model, the reservoir appears disconnected, which is supported by other independent sources of information. The green arrows point to north. From Liu et al. (2004).

Other Case Studies: Outcrop Facies Modeling

Outcrop as an analogue plays an extremely important role in subsurface reservoir facies modeling, because the modeling of outcrop analogues provides (1) the quantitative parameters (soft data) for similar subsurface modeling and (2) the constraints for facies modeling strategies (Cabello et al., 2010). AAPG's *Integration of Outcrop and Modern Analogs in Reservoir Modeling (AAPG Memoir 80)* presented numerous case studies of outcrop applications and the methods used in outcrop facies modeling.

Pranter et al. (2007) presented a fluvial point-bar outcrop analysis and modeling. The method released in this paper attempts to define and model small-scale reservoir heterogeneity, which the authors called the intermediate-scale reservoir heterogeneity. These smaller scale facies characters modeled in this research include fluvial point-bar lateral accretionary trends, mud drape surfaces, and grain size changing pattern. The results of these facies level heterogeneity models emphasized the vital importance of fluid flow characterizations. The paper by Pranter et al. (2007) provides an example and method for doing small-scale facies modeling.

The other outcrop example is the modeling in a fan delta outcrop, the Eocene Sant Llorenç del Munt (Ebro foreland basin, NE Spain) done by Cabello et al. (2010). This research describes the methodology that combines sequence stratigraphy with geostatistic facies modeling. Geostatistic outcrop facies modeling is based on outcrop sequence stratigraphy analysis. Different scale heterogeneities are modeled in the framework of sequence stratigraphy hierarchy (systems tracts and parasequences (which the authors called facies tracts)). The final results, 3D facies belt models, reproduce the outcrop depositional architecture and then serve as the inputs for the following petrophysical simulation. This process is described in Cabello et al. (2010).

CHAPTER 5: FINAL COMMENTS AND CONCLUSIONS

Depositional facies, facies models, numerical facies analysis and modeling are critical points in defining reservoir characterization and subsequent reservoir simulation. The input parameters associated with subsurface facies architecture (vertical stacking pattern and lateral facies distribution) for reservoir simulation are the fundamental elements, which can determine whether the reservoir is modeled successfully or not. Prediction of reservoir petrophysical properties (such as porosity and permeability) depends greatly on the facies distributions reflected in the facies model. "The more accurate and robust the facies model, the more precise and reliable the reservoir prediction and production decisions will be" (Cabello et al., 2010, p. 254). So facies models and facies modeling play the most important role in reservoir prediction and management.

The objective of this report was to determine (1) what is the best geological data to use as inputs for facies modeling and subsequent reservoir simulation; (2) what kinds of methods can be applied to obtain and measure the information related to subsurface geological facies; and (3) what kind of numerical methods can be used for reservoir facies and characterization modeling.

After reviewing recent literature, the most relevant conclusions are:

- Facies and facies models are scale dependent. Reservoir heterogeneities are scale dependent as well. Attention should be paid to the scale-related issues in order to choose the methods and parameters to meet facies modeling requirements.

- Since different methods and data have their own advantages and limitations, the integration of information or data from diverse disciplines can greatly enhance facies model analysis and numerical or geostatistical facies modeling.
- Geostatistics and stochastic facies modeling provide powerful tools for predicting facies architecture and reservoir characterizations. Results of these simulations (such as 3D subsurface facies architecture) present more detailed information and delineate the spatial distribution in the subsurface.
- Issues related to facies models and simulation (facies modeling), such as smaller scale facies and reservoir heterogeneity modeling, require striking a balance between having ample subsurface information and using extensive computer memory. These issues should be taken into account in planning future work.

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