3-D Seismic Interpretation: A Primer for Geologists

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PREFACE

A few years back, while at an "introductory" workshop on 3-D seismic technology, I noticed that there was a disjoint between the speakers and the audience. The speakers were geophysicists and the audience seemed to consist mostly of geologists. I watched as the audience's eyes rolled backwards, closed or started drifting when the speakers began talking about the "distribution of azimuths" in a 3-D survey or other relatively advanced (at least for geologists) topics. It became clear to me that a sizeable portion of the audience was only moderately familiar with the principles of the seismic method, but that they were trying to familiarize themselves with the technology since it was having such an impact on their lives in the petroleum industry. A short while later I was asked to be a co-instructor on a 3-D seismic short course for small independent producers. I thought that I should start with a "refresher" on the basics of the method before diving into 3-D seismic techniques. The response was quite good and, since then, this format has been well received in other courses that I have taught. As such, I have kept it for this course.

Nowadays, 3-D seismic technology is spreading out beyond the domain of the petroleum industry. The environmental and mining industries and academic groups are collecting and interpreting 3-D seismic data. Academic groups are working with industry donated 3-D data sets on problems in structural geology, stratigraphy, rock properties and other fields. Groups are collecting 3-D ground penetrating radar data and applying 3-D seismic interpretation methods to the analysis of those data. Increasing numbers of geologists (often with little or no geophysical training) are being exposed to the technology, or results derived therefrom. Despite this interest, there are few opportunities for the practicing geologist (or engineer) to become acquainted with 3-D seismic technology at the appropriate level. This course is an attempt to fill that gap.

This course is designed to help participants to become familiar with the principles, terminology and methodology of 3-D seismic technology to define subsurface stratigraphy, structure and rock/sediment properties. The focus is on *interpretation* because that is where a geologist is most likely to become involved.

In my years working with 3-D seismic data and collaborating or visiting with industry professionals, it has become clear to me that there is no single preferred way for viewing the data. As such, I have deliberately tried to vary the style of presentation of the figures so that participants in this class will have a greater familiarity with the different types of presentation that are currently being used by interpreters.

3-D seismic technology can be a wonderful tool for working on geological problems. In many cases, it has allowed me to visualize and interpret stratigraphic and/or structural features that could not previously be imaged. I have completed simple mapping tasks in a fraction of the time they would have taken with well data or 2-D seismic data. I have tested multiple hypotheses rapidly. I have made predictions of subsurface rock properties with high levels of confidence. I have had a lot of fun working on these projects. However, the technology is simply an enabler that helps me to do my work as a geologist. Without geologic insight, gained through field work, lab work and subsurface studies, 3-D seismic technology is a spaceship looking for someplace to go.

Bruce Hart

ACKNOWLEDGMENTS

Data sets used in these notes and the accompanying course have been provided by a number of companies over the past several years. These companies include Pennzoil, Chevron, Shell, Exxon, Marathon, Amoco, Harvey E. Yates, Strata Production, Enerdyne Corporation, Cross Timbers Oil, Longleaf Energy, Ardent Resources, and other donors who wish to remain anonymous. The interpretation software I have been using in the past three years (and while at Penn State) was provided by Landmark Graphics Corporation as part of their University Grant Program. Seismic attribute analysis software has been provided by Hampson-Russell Software Services. Seismic modeling software has been provided by GX Technology Corporation. Flagship Geosciences and GeoQuest provided images and funding to help offset the cost of color figures. I express my thanks to all of these companies and individuals. I also thank the (too many to list separately) friends and colleagues who have helped me to become familiar with 3-D seismic technology. Dan Leiphart and Robin Pearson checked the manuscript for typographical errors, grammar and clarity of presentation, but I alone am responsible for any errors or omissions. Finally, I thank Aline, Mallorie, Kelsey and Gillian for being so patient while I spent so many evenings and weekends working on this project.

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INTRODUCTION

OBJECTIVES

This course seeks to help geologists or other professionals (e.g., engineers) with little or no geophysical training to understand how and why 3-D seismic data are acquired, processed and interpreted. There are few opportunities for these people to become acquainted with the technology, although it is likely that geologists in a variety of fields (stratigraphy, structural geology, mineral exploration, environmental geology, etc.) will be increasingly exposed to results that are based on 3-D seismic interpretations. This course is designed to fill that training gap. It will emphasize the qualitative, rather than quantitative, aspects of seismic technology.

No two-day course can qualify someone to be a seismic interpreter - 3-D or otherwise. Additionally, there will be no hands-on practice with interpretation software. Learning the basics of how to use some software packages can take several days. I prefer to focus on the underlying principles of the technology rather than on the mechanics of where to search for applications in menu bars. This course aims to familiarize class participants with the methods and terminology employed by 3-D seismic interpreters. In this way, following the class, participants will be in a more capable position to understand the implications of results based on 3-D interpretations (and possible "problems" with those results!) and the potential for using 3-D seismic data in their own particular fields of interest.

OUTLINE

The course begins (Chapter 1) by trying to get inside the mind of the 3-D seismic interpreter, to see what he/she hopes to accomplish and how. This forward-looking chapter sets up the tone and content of the subsequent course material. This course assumes participants have no previous experience with seismic technology (or have a dated, or "fuzzy" background) and, as such, I include a short "refresher" treatment of the principles of the seismic method in Chapter 2. Chapter 3 looks at how 2-D seismic data are acquired and processed (many processing steps are shared between 2-D and 3-D processing). We then look at how 2-D data are interpreted in Chapter 4 (it is good to learn how to walk before learning to run, and the contrasts between 2-D work and 3-D work are enlightening). In Chapter 5 we will see how 3-D seismic data are acquired, processed and viewed. We contrast those methods with 2-D methods to see why 3-D data are superior. Chapter 6 examines how 3-D data are interpreted to image subsurface structure, stratigraphy and rock/sediment properties. Finally (Chapter 7), we will look at some selected case studies that give a flavor for some of the things people have done with 3-D seismic data. The case studies have been selected from the author's previous experiences and illustrate a variety of applications, limitations, and possibilities.

CHAPTER 1: THE 3-D SEISMIC REVOLUTION

Three-dimensional (3-D) seismic data are having a phenomenal impact on the petroleum exploration and development industry. According to some estimates, technological advances (including 3-D seismic, horizontal drilling and other technologies) have caused exploration and development costs in some companies to drop by as much as 75% in recent years, whereas wildcat drilling success rates in some areas are approaching 40-50%. One major oil company reported that switching from 2-D seismic to 3-D seismic technology caused the number of dry holes (wells drilled without producing oil or gas) the company drilled to fall from 53% to 25%. Other, similar successes have been documented elsewhere (e.g., Nestvold, 1996; Aylor, 1998). Declining world oil prices in the decade since 1985 are thought to have led to nearly 450,000 job losses in the United States' hydrocarbon exploration and production industry, and yet during that time demand for those resources was steady or even increased. Together, these observations suggest that the petroleum industry is becoming faster *and* better (i.e., more efficient) at finding and producing hydrocarbon reserves, and most analysts agree that 3-D seismic technology has contributed greatly to these improvements.

Simply put, 3-D seismic data provide the most accurate and continuous *volume* of information that can be obtained to image stratigraphy, structure and rock properties. Routinely in the petroleum industry, interpretations based on well data, outcrop analogs or 2-D seismic have been shown to be wrong, to varying degrees, by drilling. These same data types are often used as the basis of structural and stratigraphic interpretations in the academic world (fault kinematics, sequence stratigraphy, etc.). This leads one to consider whether, or perhaps how much, these interpretations need to be "revisited".

Figure 1.1 illustrates a rather nice example of why the petroleum industry has come to rely so heavily on the technology. The graph shows production as a function of time for an oil field from the offshore Gulf of Mexico. Drilling in this field began in 1972. Production peaked in the mid-1970s at nearly 4 million barrels of oil per year, then began to decline precipitously. By the late 1980s, less than 1 million barrels of oil were being produced. Acquisition of a 3-D seismic survey took place in 1988 and drilling based on interpretations of the seismic data began in 1991 (turn-around times are much shorter these days). Production increased dramatically, such that by 1996 it was better than it ever had been. Quite simply, the 3-D data allowed the reservoir development teams to define structural and stratigraphic complexities that could not be defined with well data and 2-D seismic data. These complexities were compartmentalizing the reservoirs in this area, leaving hydrocarbon accumulations that were being undrained by existing wells. These compartments became targets for highly deviated wells (all wells are drilled from drilling platforms in this offshore area; individual wells can cost over $2 million), and the real success of the program is attested to by the graph.

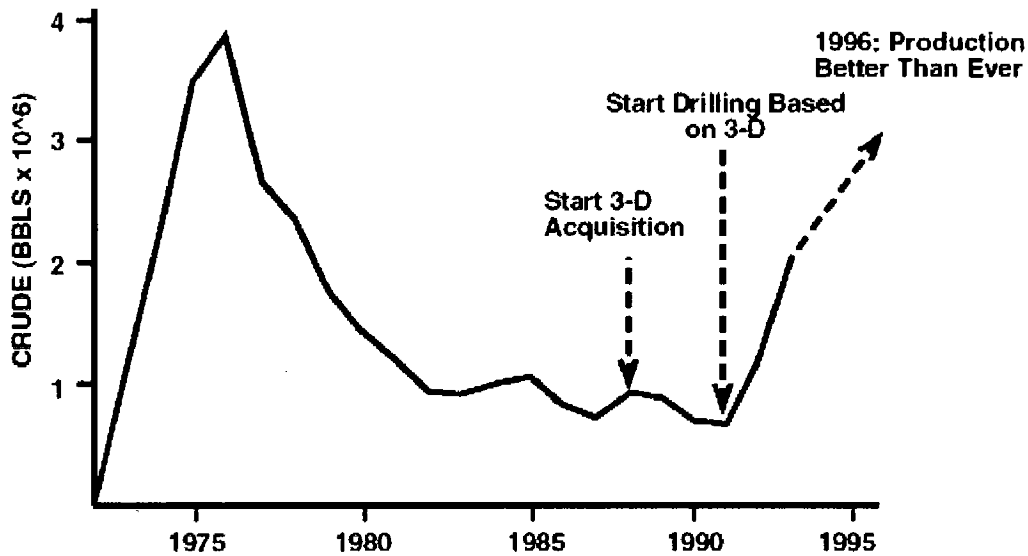

Figure 1.1. Graph of annual oil production as a function of year for a field in the offshore Gulf of Mexico. Note the dramatic increase in production once development drilling targets started to be based on 3-D seismic interpretations. Based on Sibley and Mastoris (1994) with 1996 data from M. Mikulich (pers. comm.).

Concomitant with advances in 3-D seismic acquisition, processing and interpretation, advances in other related branches of reflection seismology (such as amplitude variation with offset or "AVO") have allowed interpreters to leverage the massive amounts of data that are collected during a 3-D survey. Predictions of rock properties (porosity, fluid content, pore pressure, fracture orientation, etc.) ahead of the drill bit from 3-D volumes are becoming very accurate - at least in some settings.

In addition to the improved understanding of the geology, the 3-D seismic workstation has become a focal point for integrated, multidisciplinary teams in many companies. Geophysical, geological and engineering data and concepts are typically integrated in order to arrive at the most robust interpretation possible of the subsurface. The workstation (or powerful personal computer) allows the team to automate time-consuming tasks, to visualize and integrate disparate data types, and ultimately to present the results of their work to other team members, management, investors or others. Digital data and computer technology allow the time between data acquisition and interpretation to be decreased, and interpretations can be quickly updated or revised as new data become available (e.g., through drilling).

The benefits of 3-D seismic are widely recognized in the petroleum industry. Many articles in trade journals (*Oil and Gas Journal*, *World Oil*, etc.) have presented success stories, but there are relatively few such articles in mainstream geologic literature (geophysical journals such as *Geophysics* do a little better). As such, the power and the potential of 3-D seismic may not be fully understood by the geologic community at large.

Until relatively recently, 3-D seismic data have been almost exclusively collected by the petroleum industry. Recently, however, the mining industry has begun to investigate the potential of 3-D seismic to identify and map ore bodies, and to plan mine development (Eaton et al., 1997). Furthermore, it may be possible to cost-effectively transfer the technology to the environmental sector, although differences between the economic considerations in that realm and the petroleum world (the environmental sector is *cost* driven whereas the petroleum industry is *profit* driven) are currently an impediment (House et al., 1996). Innovative data collection methods need to be developed for the technology to become cost-effective (Siahkoohi and West, 1998). The cost and technical requirements of collecting and interpreting 3-D seismic data have prevented, until recently, most academic researchers from obtaining and utilizing them, although some 3-D seismic data have been collected to study deep crustal structure (e.g., Kanasewich et al., 1987, 1995) and others have been collected in conjunction with the ocean drilling program (Shipley et al., 1994) or other marine settings (Singh et al., 1999). 3-D ground penetrating radar surveys are being collected and analyzed in a manner that is similar to 3-D seismic methods (Beres et al., 1995, 1999; McMechan et al., 1997).

WHY SEISMIC TECHNOLOGY?

To understand 3-D seismic technology, one must first understand why people would collect seismic data in the first place. By far, the primary "consumer" of reflection seismic data (or, henceforth, more simply "seismic data") is the oil and gas industry (Sheriff and Geldart, 1995). There, seismic data (2-D, 3-D and other types) are used to find and delineate hydrocarbons that are located in structurally and/or stratigraphically controlled reservoirs. At one time, mapping of surficial geology (for anticlines, etc.) was adequate to look for hydrocarbons. However, pools have become smaller, more complex, deeper and are being sought in areas where surficial mapping is either inadequate for defining subsurface structure or impossible (e.g., offshore). Having an accurate image of the subsurface is critical to successfully (and economically!) finding and producing oil and gas.

On a more basic level though, seismic data are collected for 3 fundamental purposes. These are to define: a) subsurface structural elements, b) subsurface stratigraphic features, and c) subsurface rock/sediment properties. The benefits of such data to the geologist are enormous - imagine how incomplete our knowledge of earth history and tectonics would be if we did not have seismic data from passive margins, fold and thrust belts, rift zones, subduction zones, associated accretionary prisms, etc. Seismic data allow the geologist to do more than just "scratch the surface" as one might do working with outcrop data alone. Our understanding of tectonic processes, sedimentary geology, earth history and many other disciplines is greater (and significantly so) because of seismic data.

Despite the many "academic" uses, seismic data are used primarily to answer applied questions about the lateral extent and connectivity of reservoirs, aquifers and other geobodies. The intent may be not only to define their "geometry", but also the physical properties (porosity, mechanical properties, fluid content) of subsurface units. Depending on the objectives, different acquisition, processing and interpretation options will be selected for any given project. Geophysicists, geologists, and (increasingly) engineers may be involved at all levels of the process. The geologist's role in these applied studies must be to ensure that the interpretations are firmly grounded in the world of the geologically plausible.

A BRIEF HISTORY OF SEISMIC EXPLORATION

Sheriff and Geldart (1995) summarized previous accounts of the development of the seismic method. Here, we will summarize their account and focus primarily on the reflection seismic method (i.e., where we record reflections from subsurface layers) and only very briefly discuss refraction methods (i.e., where we record waves that propagate relatively long distances along interfaces between two beds).

Experimentation with the use of acoustic pulses (both subsurface waves and airwaves) to detect enemy artillery locations by triangulation began during World War I. Following the war, several different groups began proposing and testing different methods to identify subsurface features of interest such as interfaces between specific rock layers. Some refraction successes at detecting salt domes are recognized for the 1920s but it was not until 1928 that the first success for the reflection method was demonstrated. By about 1930, the reflection method had begun to supplant the refraction method in the petroleum industry.

The industry's interest in seismic methods grew in the 1930s and 40s. But some key developments in the 1950s and early 1960s are credited as being major turning points for the seismic industry. First, the common midpoint (CMP) method for collecting and processing data (see Chapter 3) was pioneered in the 1950s but became mainstream in the 1960s. One of the key elements in the acceptance of the CMP method was the advent of analog and then digital data recording on magnetic tapes. This technique allowed for the collection and processing of large, then truly massive (as computer power has increased), amounts of field data that could be collected and processed.

Despite some early experimentation in the 1960s, it was not until the 1970s that the techniques of 3-D seismic acquisition and processing were truly developed. Workstation interpretation methods started being adopted during the 1980s and the mix of 3-D seismic and workstation techniques has developed at a breathtaking pace since. Much of what people new to the field consider to be "standard" has in fact only become so in the past few years.

THE MODERN 3-D SEISMIC INTERPRETER

Before starting into the methods of seismic interpretation, it is helpful to have an idea of what makes a seismic interpreter. Data collected and analyzed by Hart (1997) help to clarify the qualifications, motivations, and techniques of 3-D seismic interpreters. Nearly all current 3-D seismic interpreters work in the petroleum industry. The modal average indicates that most have been in that industry for 15-20 years, but have been interpreting 3-D seismic data for 5 years or less. Generally, these people have had little formal training with the software and hardware they use in their work. Instead "on the job training" (a.k.a. "trial by fire") has been the norm. Despite the implied grief associated with this need to learn as you go, about 70% of 3-D seismic interpreters strongly agree that the technology has changed the way they work in a positive way. The message is clear: the learning curve can appear daunting, but the technology *is* exciting to work with!

It is also clear that seismic interpretation is no longer the exclusive realm of the geophysicist. In fact, 42% of the respondents to the questionnaire identified their background as "geology", "geophysics" came in 2nd at 35%, and 17% of respondents had a mixed geology/geophysics background. The reason for the prominence of geologists is that as technological improvements generate seismic data that image the subsurface with increasing fidelity, people who have training in stratigraphy and structural geology are needed to understand the details of what the seismic images are showing. Think of an analogy - who would best interpret CAT scan images in the medical profession: a) a physician with training in anatomy, or b) a physicist who can describe the physics of the interaction between the waves and the body being imaged?

In fact, like the CAT scan analogy, the best interpreter will be someone who has a knowledge of both the thing being imaged (subsurface geology or a body part) and the principles of the technology being used to image it. One needs to be able to understand the limits on resolution of the system, what causes features to be imaged in the first place, and what types of "artifacts" of the technology are present in the image and how they might be mistaken for something "real". As such, and as a challenge to geologists or others wishing to work with seismic data, most respondents to the questionnaire replied that some formal training in geophysics is needed to competently work with 3-D data.

It is now axiomatic that the true power of 3-D seismic is unleashed only when the geophysical data are integrated with geologic and engineering data (Fig. 1.2). Digital wireline logs, synthetic seismograms, production data, interpretations of depositional history and other analyses and data are all routinely incorporated into 3-D seismic interpretations. Interpreters who can single-handedly appreciate the subtleties of geophysical, geological and engineering data are rare, and so the multidisciplinary team has become the standard operating procedure for working with 3-D data. In forward looking companies (there *are* dinosaurs!) geophysicists might define the limits on resolution, the expected character of the strata of interest and attempt to quantitatively define lithologies, geologists look for stratigraphic and structural features that influence where oil or gas might form or accumulate and attempt to work out the geologic history of the area, and finally, the engineers might examine how the reservoir compartments defined by the geologist correspond (or not!) to the compartments that he/she has defined on the basis of pressure histories, fluid contents, etc. Landmen and utilities engineers might work out which leases to go after and where to put multi-million dollar offshore drilling platforms. All of these professionals will work together as a team.

These petroleum industry teams have potential analogs in the academic world and in other applied disciplines. For example, a study of fault geometries from seismic data might (?should) include: a) a structural geologist to work on the fault kinematics, b) a geophysicist to determine what can physically be imaged in the data and whether the fault geometries are real or have been distorted by velocity anomalies, c) a rock mechanics person to examine relationships between stress and strain, and d) a stratigrapher to work out the depositional history of an area. Similarly, a ground water evaluation study might include a geophysicist (acquisition and processing), a geologist

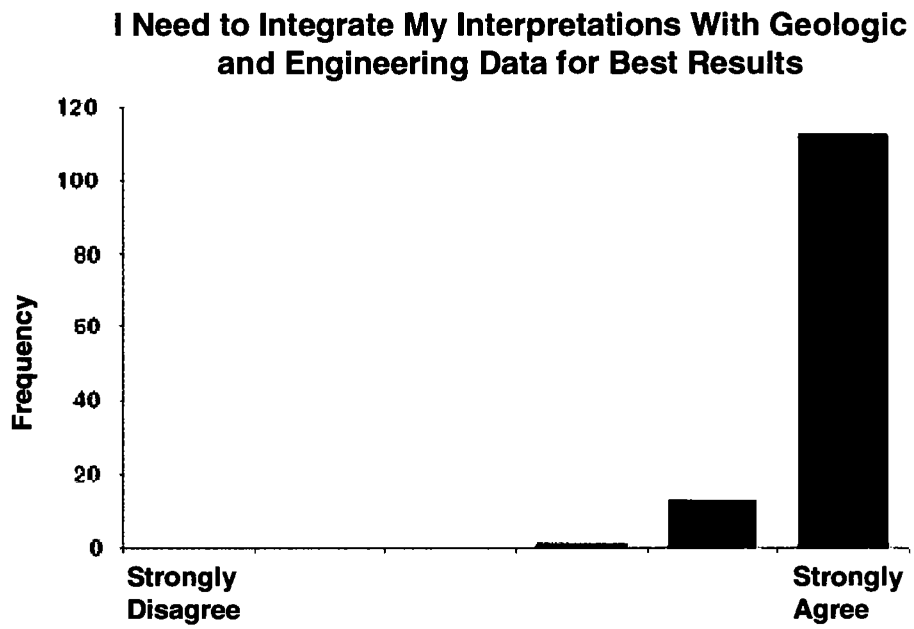

Figure 1.2. Most seismic interpreters recognize that integration of the seismic data with other data types is required to properly interpret a 3-D seismic survey. Based on Hart (1997).

(stratigraphic and structural features) and a hydrogeologist (flow paths, resource estimates).

SEISMIC METHODS – WHAT THE INTERPRETER NEEDS TO KNOW

When we (geologists) look at high quality seismic data, we see faults, folds, clinoforms, erosional truncation and other geologic features. We may be tempted to believe that we are looking at geological cross-sections through a part of the earth. In fact, this is only a partial, and sometimes even erroneous, understanding of a seismic image.

As discussed earlier in this chapter, the fundamental reasons for collecting reflection seismic data is to "see" the subsurface structure, stratigraphy and rock properties. To understand seismic work, we can assume that there is some subsurface "geology" laying passively below the surface (at least for the timeframe of any one particular seismic survey). We will use some sort of active source (explosives, vibroseis trucks, airguns, etc.) to generate acoustic waves that will "illuminate" the geology by reflecting off subsurface features of interest. These reflections will be recorded as "field data" that bear little resemblance to the geology. To convert the field data to something that looks like geology, we need to process it. The end product is "seismic data" (either on paper or, more commonly nowadays, in digital form) that can be integrated with other data types and interpreted.

It must be recognized therefore that the seismic image we see may be influenced by, or depend on, a variety of factors, such as:

- The characteristics of the acoustic pulses used to illuminate the subsurface (frequency, bandwidth, energy, etc.)
- The way that the acoustic sources and receiving devices were deployed (how many, spacing, orientation, recording parameters, etc.)
- The various choices that need to be made during the data processing (migration, stacking, etc.)
- The way we view the data (color, black and white, scale)
- And, most importantly, the properties of the rocks (bed thickness, mineralogy, porosity, fluid content, etc.) we are trying to image.

Before proceeding further, we must ask ourselves some questions:

a) *Is it possible to interpret seismic data without knowing how rocks are put together?* A physicist might be able to describe the mathematics of the wave propagation and reflection exceptionally well. However, can he/she recognize mass-wasting deposits, Reidel shears or other geologic features of interest that might be visible in a seismic image? If the interpreter has no understanding of geology, we may have wasted time and money (perhaps millions of dollars) collecting the data, especially if the definition of subtle geologic features is the primary focus of the investigation.
b) *Can we interpret seismic data without understanding how the data were acquired and processed?* The seismic images we view contain "artifacts" generated during the acquisition and processing stages. These artifacts can sometimes be mistaken for geological features (e.g., faults) and to do so would be erroneous. Equally important, the vertical axis on most seismic sections is *time*, not *depth.* As such, the geometries of faults, stratigraphic horizons, etc. we see in a seismic image can be misleading or even false. For example, an apparent anticline at one stratigraphic level might be due to an increase in velocity in the layers above that level ("velocity pull up", see Chapter 4) and not due to any real relief on the surface. If we fail to recognize the true origin of the structure we might drill for oil in a feature that doesn't exist. For these and other reasons, a person with some geophysical training should be involved in the interpretation.
c) *Should we be looking at seismic data if we don't understand the geology or geophysics?* I am amazed (perhaps "disturbed" is a better word) by a trend that is present amongst some engineers and mathematicians/statisticians to view digital seismic data as variables that can be analyzed numerically without consideration of the geology or geophysics. The interpretations made by these folk are attractive (at least to some) because they are based on mathematically rigorous concepts, rather than "fuzzy" geological ones. In reality, accepted practice dictates that integration of all available data types (geologic, geophysical and engineering) is the way to best utilize 3-D seismic data (Fig. 1.2). A prediction of rock properties based on mathematical analyses needs to be rejected if it is geologically implausible (although the geologist may wish to go back and check his/her own interpretations!).

In summary, the geologist has many reasons for wishing to collect and use seismic data to interpret subsurface geology. Additionally, the geologist has needed expertise to bring to the table when it is time to interpret the seismic data. The geologist who deliberately chooses not to become involved in a seismic interpretation-based project is marginalizing his/her own discipline and missing out on some potentially exciting and rewarding work. The flip side is that the geologist should not undertake an interpretation project without either some geophysical training or having a qualified geophysicist as part of the interpretation team.

CHAPTER 2: PHYSICAL BASIS OF REFLECTION SEISMOLOGY

INTRODUCTION

Figure 2.1 illustrates the general principle of the seismic reflection method. We start with some acoustic pulse (a "bang") that generates an expanding wavefront. The bang is located at some elevation "A" (ground surface, water surface, etc.). At any given point along the expanding wavefront, we can imagine a raypath that is perpendicular to the wavefront. The wavefront will expand until it reaches some interface, here located at depth "B", that causes some of the energy to be reflected back

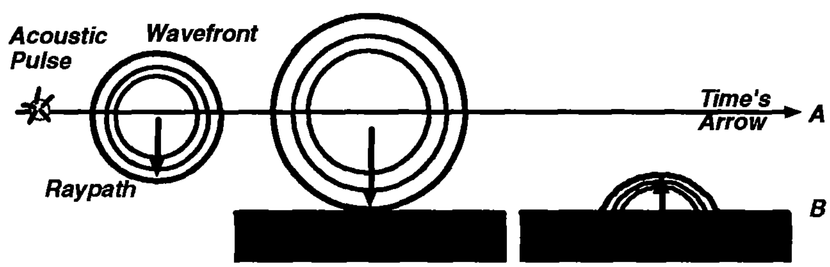

Figure 2.1. Simple schematic diagram illustrating the underlying principles of the seismic method. One wishes to define something about the surface "B" at some depth below the interface "A" (the land surface or water surface). At the left, an initial acoustic pulse is generated. The energy expands out as circular *wavefronts* (in an isotropic medium) like ripples in a pond, although this illustration shows a vertical profile. At any given point along the wavefront, we can define a vector normal to the wavefront that is called a *raypath.* The energy expands out until it is reflected from an interface back towards the source - an "echo" is generated. If we record how long it takes for the sound to travel from A to B and back again (the two-way traveltime, TWT), we can determine the distance AB by multiplying the velocity of sound in the intervening medium by TWT/2. In practice, the velocity can often be poorly characterized or unknown prior to the seismic survey, and may still be inadequately known for detailed work following the survey.

to the surface where it can be recorded. What is physically measured by the recording instruments (located back at the "surface") are: a) the strength of the reflected energy, and b) the time it takes for the energy to travel from the surface down to the reflecting horizon, then back up to the surface again. This time is referred to as the two-way traveltime or "TWT". In principle, if we measure the TWT at many points along an interface, we can get a picture of the relief on that interface - echosounders are a good example of this process.

In reality, we have some other things to worry about. First, we are generally interested in many interfaces, not just one. Although some of the energy from the bang will be reflected, some will be transmitted through each interface as well. Furthermore, we need to understand what dimensions of features can physically be imaged with seismic methods. We must understand something about the acoustic pulses that are used to illuminate the subsurface, and also what it is about rocks that causes some of the energy from our acoustic sources to be reflected back to the surface were it is recorded.

This chapter will briefly review some of the characteristics of acoustic waves and the physical properties of rocks that cause waves to be reflected. Finally, we will examine the controls on the spatial and vertical resolution of seismic data.

P AND S WAVES

When a solid body is disturbed by something such as an explosion, the disturbance propagates through the body as waves. There are a variety of different types of waves. Some travel only at interfaces between two different media and are called surface waves. Waves on the ocean surface are of this type. Other types of waves propagate through the solid body itself. These are called body waves. Our training as geologists exposed us to two different type of body waves, namely P and S waves that are generated by earthquakes. The "P" stands for "primary" and the "S" stands for "secondary" since that is the order in which the waves are recorded by seismographs.

The reality is that these two types of waves correspond to two different types of disturbances. The faster P waves involve changes in volume (compression) and the slower S waves involve shear motions. As such, they can be referred to as compressional and shear waves respectively. In reflection seismic work (e.g., 3-D data), it is nearly always compressional waves that are generated and recorded, although more expensive shear wave surveys are becoming more popular (e.g., Arestad et al., 1996). The P waves correspond to acoustic waves ("sound"), and so we refer to "acoustic energy" and "acoustic pulses" in this course.

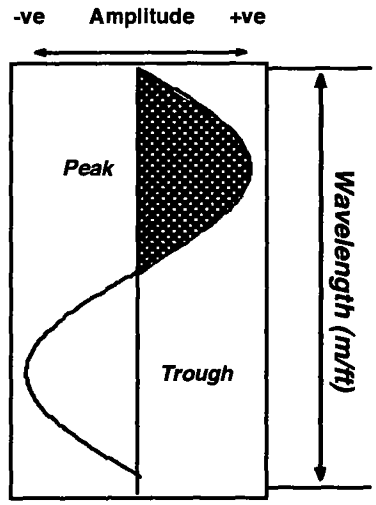

Figure 2.2. Definition diagram for wavelets. This simple wavelet consists of positive and negative amplitude values (peaks and troughs respectively). The frequency is the number of wavelets (cycles) to pass by a given point per second (units: Hertz, or cycles per second). The wavelength can be determined by dividing the velocity (measured or estimated) by the frequency.

There are certain terms that can be employed to describe any wavelet. These are illustrated in Figure 2.2 for a simple sinusoidal wave, although in Chapter 3 it will be seen that wavelets generated by seismic sources are far from being simple sinusoids. The first aspect of a wave we might wish to describe is the wavelength (λ) which is a measure (in feet or meters) of the distance between successive repetitions of the waveform. The frequency (f) is the number of waveforms that will pass by a given point per unit time. Frequency is measured in cycles per second, or Hertz. Finally, the amount of displacement from a resting position is called the amplitude of the wave. Amplitudes can have positive or negative values, and for seismic interpretation the absolute range of amplitudes we see in a seismic record depends on how the data were scaled (see Chapter 3). Positive amplitude values are referred to as peaks, negative amplitudes are referred to as troughs.

The reflections of seismic data are recorded and (usually) displayed as traces that show variations in amplitude as a function of time. That is to say that the Z axis of a seismic profile is a measure of time (TWT). If we can count the number of peaks (or troughs) in a given time interval, we can estimate the dominant frequency of the data in that interval. Given a particular frequency for an interval, and having an estimate of velocity (from a sonic log, "intuition", or some other source) for that interval, the wavelength can be derived from:

$$\lambda = v/f$$

where v is the velocity of sound in the rock/sediment.

REFLECTIONS AND ROCK PHYSICAL PROPERTIES

Acoustic energy is reflected where there is a change in acoustic impedance (AI) of two adjacent rock layers (Fig. 2.3). The acoustic impedance is the product of a rock's velocity (v) times its density (ρ):

$$AI = \rho v$$

When two adjacent layers (1 and 2) have differences in acoustic impedance, some of the energy will be reflected. For normally incident raypaths, the following equation provides a ratio that defines how much incident energy will be reflected at an interface:

$$RC = \frac{\rho_2 v_2 - \rho_1 v_1}{\rho_2 v_2 + \rho_1 v_1}$$

This ratio is referred to as the reflection coefficient (RC) and its value depends on the nature of the changes in physical properties between adjacent beds.

The amplitude of the reflection from a bedding contact is proportional to the reflection coefficient. A large change in AI will result in a large RC and a strong, or "high amplitude" reflection. A small change in AI will result in a small RC and a weak or "low amplitude" reflection. If the underlying layer has an impedance that is greater than the overlying layer, we have a positive reflection coefficient. If the underlying layer has an impedance that is less than the overlying layer, we have a negative reflection coefficient. In seismic data, a positive reflection coefficient might be represented by a

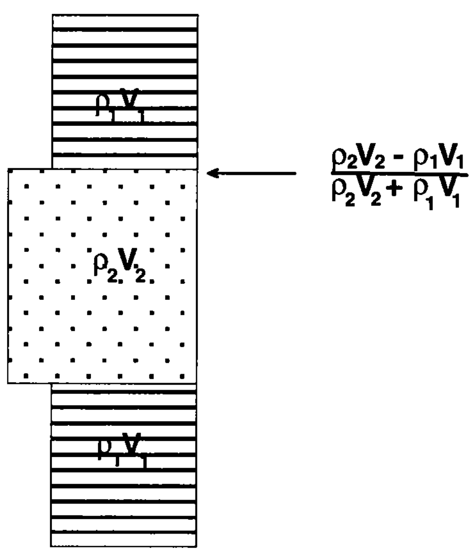

Figure 2.3. How much energy will be reflected from an interface between two beds depends on the difference in physical properties between them. In particular, it is the change in acoustic impedance (the product of the velocity - v - times the density - ρ) that determines the reflection coefficient.

peak that is centered on the change in physical properties, whereas a negative reflection coefficient might be represented by a trough that is centered on the change in properties.

Each change in physical properties in the subsurface will generate a reflection. Rarely, if ever, do we have a single bed enclosed in an otherwise homogeneous medium. Instead, the stratigraphic column consists of beds, bedsets, parasequences, etc. of variable thickness and lithology. The seismic signature of the entire stratigraphic column will be the algebraic sum of all the reflections (of varying amplitude) generated by the acoustic pulse. Mathematically, we say that we convolve the wavelet with the time series of impedance changes.

To understand the controls on impedance, and so reflection coefficients, we need to look at the density and velocity terms a bit more. The density or, more correctly, the bulk density (ρ_b) of a sedimentary depends on the density of the matrix grains (ρ_{ma}), the density of the fluids in the pore spaces (ρ_f) and the porosity (ϕ) such that:

$$\rho_b = (1 - \phi)\rho_{ma} + \phi\rho_f$$

As porosity increases, the bulk density decreases as does the impedance of the rock. Additionally, for a given porosity and fluid content, a calcarenite (mineral density = 2.71 g/cc) will be denser than a quartz sandstone (mineral density = 2.65 g/cc).

It would be nice if we could express the compressional wave velocity (v_p) of a rock as a simple function of some easily measurable properties such as porosity and mineralogy. Instead, V_p depends quantities known as elastic moduli, and can be expressed as a function of the shear modulus (μ), the bulk modulus (κ) and the bulk density (ρ_b):

$$v_p = ((\kappa + 4\mu/3)/\ \rho_b)^{1/2}$$

The bulk modulus is an elastic constant, sometimes referred to as the "incompressibility" that describes the changes in pressure required to produce a change in volume. High values of κ correspond to relatively incompressible rocks that have relatively high velocities. Cemented rocks have a higher bulk modulus than unconsolidated deposits of similar lithology. Pressure (the higher the pressure, the more tightly grains are pushed against one another and the higher the bulk modulus and so the velocity) and other factors influence the value of κ as well. The shear modulus is a measure of the resistance to shearing strain.

The shear velocity (v_s) of a rock depends only on the shear modulus and the bulk density:

$$v_s = (\mu/\rho_b)^{1/2}$$

Both V_p and V_s are inversely proportional to the bulk density, which itself is inversely proportional to the porosity. Although the effects of density changes on velocities are real, they are usually subsidiary to other factors that affect velocity. Cementation, for example, causes a decrease in pore space (increase in density) but, more importantly, increases the bulk and shear moduli and so velocities increase. Fluid content is another important variable. The shear modulus is unaffected by the fluid content whereas the effect on the bulk modulus can be significant. As such, shear wave velocities are relatively unaffected by the fluid content (e.g., water, oil, gas) of a rock whereas P wave velocities can be greatly affected. These differences can be exploited to advantage when analyzing multicomponent (P and S wave) seismic data. Changes in fluid content are exploited by 4-D seismology (Chapter 6).

Sometimes an empirical equation known as the Wylie Equation is used to describe the compressional wave velocity of sedimentary rocks as a simple function of easily measured (or guessed at) properties. For this formula:

$$1/v_p = \phi/V_f + (1-\phi)/V_m$$

where V_f and V_m are the velocities of the pore fluids and rock matrix materials respectively. It must be noted that this equation was empirically derived for well-cemented sandstones. Application to other types of rocks (e.g., limestones, shales) or deposits (e.g., unconsolidated sands) is unfounded and will give erroneous results. Unfortunately the equation is widely used for rocks/sediments it was not designed for.

When we consider how acoustic impedance varies as a function of velocity and density for various types of sedimentary rocks, some interesting things become apparent. For example, lithology (mineralogy) and porosity help to define velocity and bulk density. Thus one can predict that changes in rock type and porosity may be visible in seismic data. However, different combinations of v_p and ρ_b can result in the same acoustic impedance, and therefore impedance itself is not an unambiguous indicator of lithology. Additionally, a bedding contact between two different types of rock (e.g., dolomite and anhydrite) may be invisible seismically if there is no change in acoustic impedance. Finally, different combinations of absolute values of acoustic impedance can give the same reflection coefficient. Therefore, the amplitude of a reflection is not a reliable indicator of the lithologies responsible for it. It is possible that many different lithologic successions might produce the same (or a very similar) seismic response. In short, seismic data are non-unique - the amplitudes (if not the stratigraphic geometries) from a carbonate/shale succession could conceivably look like those from a sandstone/shale succession.

SEISMIC RESOLUTION

Having now examined the principal characteristics of acoustic waves and relevant rock properties, we are now in a position to think about what can actually be resolved in a seismic transect. Figure 2.4 examines, conceptually, this issue.

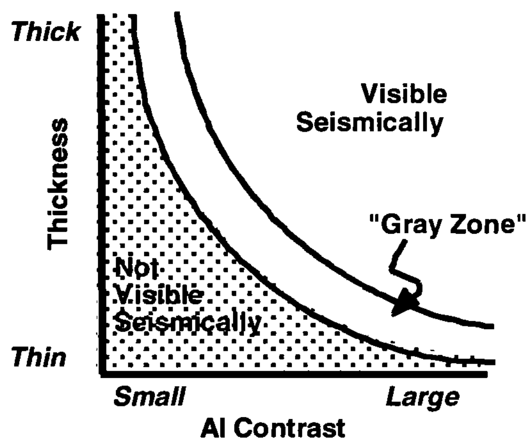

Figure 2.4. Conceptual diagram showing how thickness and acoustic impedance (AI) contrast interact to determine whether a bed will be resolved seismically. Adapted from Meckel and Nath (1977).

A "thick" bed that has a high AI contrast with the surrounding units will be visible seismically. A "thin" bed that has minimal impedance contrast with the surrounding beds will not be visible seismically. A "relatively thin" bed can be visible seismically if the change in physical properties with the surrounding beds is great enough and, conversely a "thick" bed that has minimal change in rock properties with its surrounding rocks may also be visible. There is a "gray area", where our ability to detect a bed depends on things like the signal to noise ratio of the data, the type of wavelet used, and (to some extent) our skills as interpreters.

What do "thick" and "thin" mean in the discussion above? To the seismic interpreter the thickness of a bed is measured with respect to the wavelength of the acoustic pulse. The top and base of a bed will produce separate reflections down to $^1/_4$ of the wavelength (see below). Anything thinner than this is referred to as a seismic thin bed. The thinnest bed that will produce a reflection is cited as $^1/_{16}$ or $^1/_{30}$ of the wavelength. The exact number depends the signal-to-noise level of the seismic data, interference from adjacent reflections and other factors.

Earlier on in this chapter, we defined the wavelength as being equal to the velocity of the propagating medium divided by the frequency of the acoustic pulse. The obvious implication is that the higher frequency of the wavelet the shorter the wavelength. We want higher frequencies to be able to resolve fine-scale stratigraphic details. What may not be obvious is that for a given frequency, the faster the rock velocity, the longer the wavelength. Therefore, for a given seismic source frequency, our ability to resolve stratigraphic features will be reduced in relatively fast rocks (e.g., Paleozoic limestones) as compared to relatively slower rocks (e.g., Tertiary sandstones).

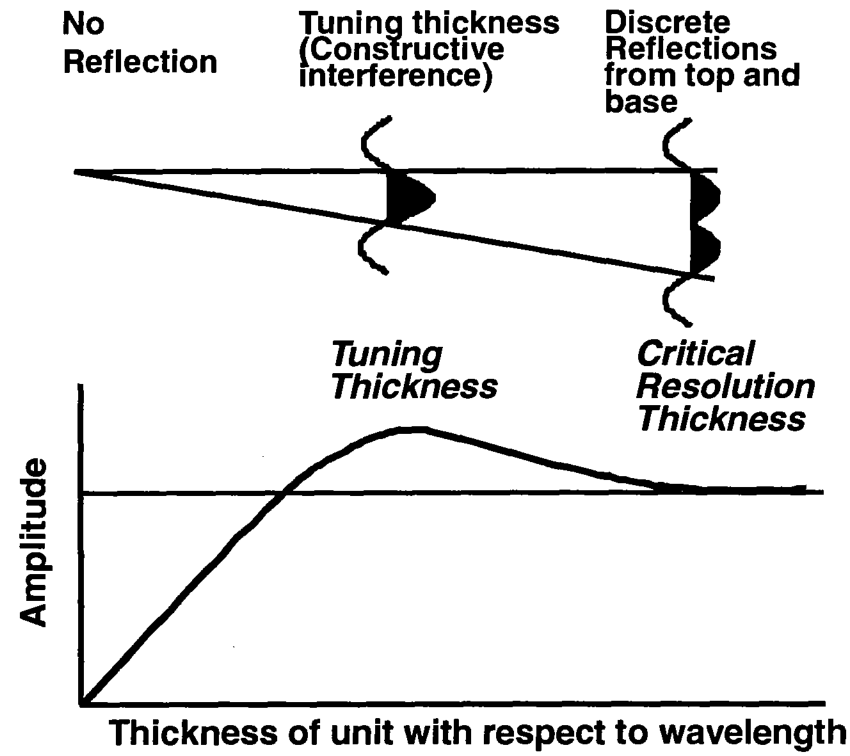

Figure 2.5. Reflections from the top and base of a bed will be separate seismic "events" until the thickness of the bed decreases to 1/4 of the wavelength. Below this thickness, the bed will still generate a seismic reflection, but it will not be possible to determine the true thickness of the bed using the peak to trough separation. Constructive and destructive interference of the reflections from the top and base of the bed will have an effect on amplitudes as well.

In most settings, the age of rocks increases with depth. They usually become more consolidated and less porous and, as such, velocity tends to increase with depth. At the same time, the earth tends to filter out higher frequencies[1], and so the average frequency of an acoustic pulse decreases with depth. Since velocity is increasing and average frequency is decreasing with depth, the average wavelength increases and our ability to resolve fine-scale stratigraphic details decreases.

Figure 2.5 illustrates some other concepts about seismic resolution. The top part of the figure shows a wedge-shaped bed that pinches to the left, with the reflections produced at the top and base of the bed. Let us assume that the rocks above and below the wedge are of exactly the same material. For simplicity, we will assume that the bedding interface that causes a reflection corresponds to the center of our simple sinusoid. For a thick bed (i.e., on the right) the reflections from the top and base of the bed are separate, and of opposite polarity. As the bed gets thinner, the reflections from the top and base start to constructively interfere and the amplitude of the peaks increases. At $^1/_4$ of the wavelength we have the maximum constructive interference - the two peaks now directly coincide and form 1 high amplitude peak. Below $^1/_4\ \lambda$ there is destructive interference and the amplitude of the combined r eflections decreases. Thus, beds are

[1] The effect is like hearing music coming out of a car or a neighboring apartment. The high frequencies (cymbals, etc.) are filtered out, and all that is heard is the low frequency content (bass, etc.) of the music.

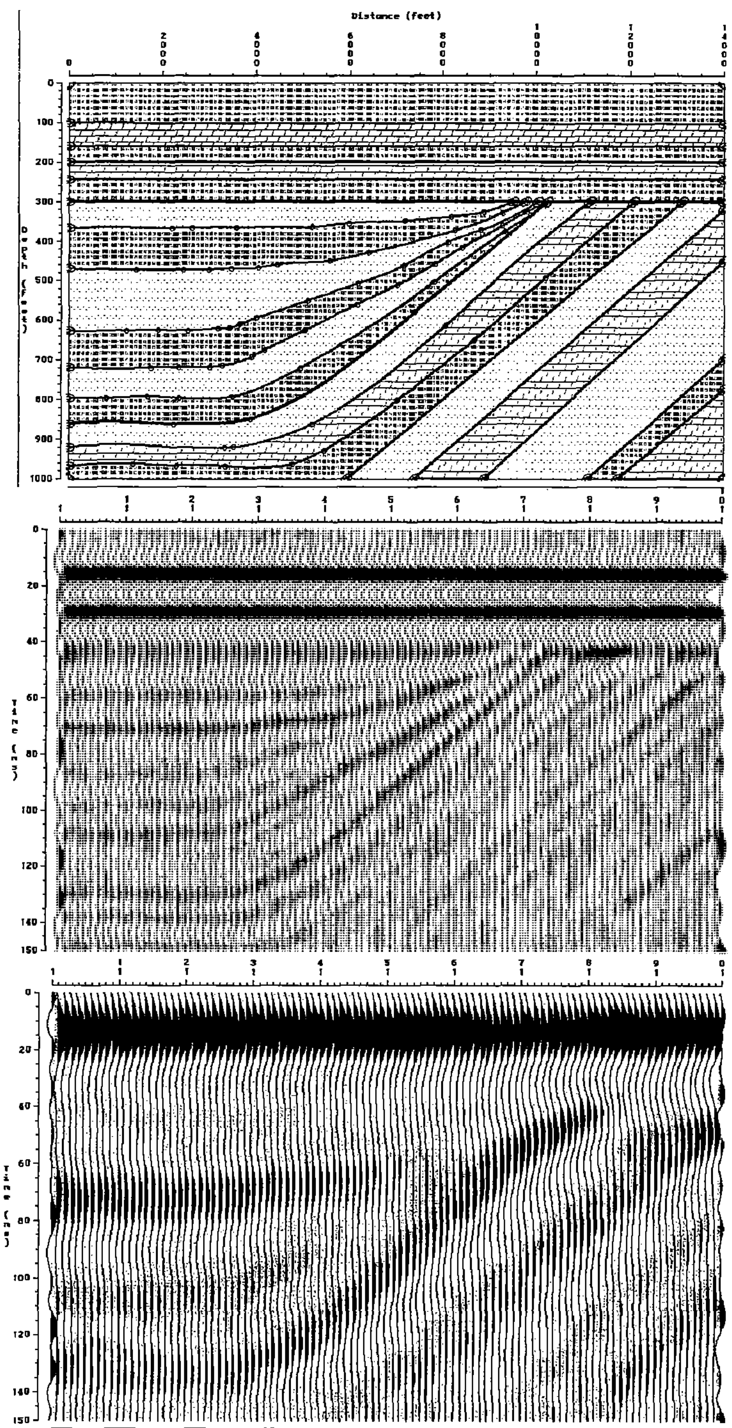

Figure 2.6. Effects of frequency on observed stratigraphic geometry. Geologic model (top) shows strata converging upward (to right) below an unconformity. This geometry is visible in the seismic model constructed with a 75 Hz wavelet (middle). However, if the frequency of the input signal is low enough (e.g., 20 Hz, bottom), reflection geometries suggest onlap below the unconformity, which itself is hardly visible. It follows that reflection geometries (e.g., terminations) observed on seismic transects are not always representative of true stratal geometries, especially when wavelengths are long compared to bed thickness.

visible seismically below $^1/_4$ λ, but the amplitude of the composite reflection (separate reflections from the base and top are not visible) decreases with decreasing thickness.

Limitations on vertical resolution have important consequences for our ability to interpret stratigraphy (Fig. 2.6). For example, we would expect to get better stratigraphic resolution in younger rocks than in older rocks because the velocities of the latter are likely to be higher. We will see more fine-scale details in the shallow part of the record than in the deeper part because the higher frequencies will be attenuated in the deeper units. We can even start to think that seismic technology will be more useful for defining depositional sequences in "high accommodation" settings (i.e., high subsidence rates) than in "low accommodation" settings because the thickness of each sequence will be greater in the high accommodation settings. Resolving stratigraphic sequences in low accommodation settings might take special techniques (e.g., Hardage et al., 1994, 1996).

In terms of lateral resolution, we need to step back and re-examine the raypath concept. Although raypaths are relatively easy to visualize (and draw), the truth is that the wavefront of the acoustic pulse expands out in a spherical fashion. As such, rather than imaging a point along a bedding interface (as might be expected looking at a raypath diagram) the acoustic pulse images a zone (Fig. 2.7), known as the Fresnel Zone. In principle, as the width of this zone increases, the lateral resolution decreases. The radius (R) of the Fresnel Zone is given by:

$$R = (v/2)(t/f)^{1/2}$$

where t is TWT. Inspection of this equation reveals that (again) the higher the velocity the less we can resolve. Additionally, the greater the TWT, the wider the Fresnel Zone

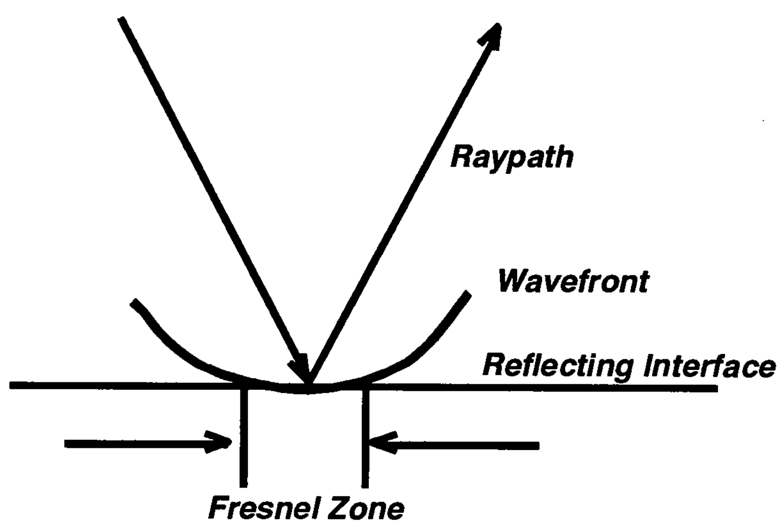

Figure 2.7. The Fresnel zone. One might imagine, by looking at raypath diagrams, that a reflection will come from a single point along a reflecting interface. In reality, since the acoustic energy is really an expanding wavefront, a *zone* is imaged (sometimes referred to as the "acoustic footprint"). The size of the zone depends on the velocity, TWT to the reflector and frequency of the seismic energy.

and the less lateral resolution. During the data processing stage (Chapter 3), data processors try to shrink the Fresnel zone and so improve the lateral resolution using a step called migration.

CHAPTER 3: SEISMIC ACQUISITION AND PROCESSING

INTRODUCTION

The data recorded by seismic receivers in the field bears little resemblance to geology. The objective of seismic processing is to take the field data and produce as clear an image of the geology as possible. In the past, the steps of data acquisition, data processing and data interpretation were carried out by separate groups who had (it seemed) little communication between them. The results were not always optimal. The need for integration all long the workflow is now generally realized. For example, data acquisition people need to know the depth to the targets of interest, their dimensions and structural dips. Seismic processing incorporates "judgment calls" that can affect the interpretability of the data. Also, increasing numbers of seismic interpreters are interactively reprocessing seismic data themselves in order to enhance features of interest.

One of the primary problems related to reflection seismology that needs to be overcome is that the reflections we wish to record are very weak. Many of the methods used during acquisition and processing are designed to amplify the reflections of interest and to help boost the signal-to-noise ratio. This theme will be emphasized throughout this chapter.

To be a good interpreter, one needs to have some understanding (albeit qualitative) of the steps involved in data acquisition and processing. This chapter will introduce some of the basic concepts in these two fields. The focus will be on 2-D seismic acquisition and processing as it is best to understand the relatively simplified procedures involved in 2-D work before looking at 3-D seismic methods (Chapter 5). Furthermore, by acquainting ourselves with 2-D methods we will better understand the benefits of working with 3-D data. In any event, many of the techniques employed in acquiring and processing 2-D data are identical or similar to those used for 3-D work. Data acquisition methods are discussed by Sheriff and Geldart (1995) and Evans (1995). A comprehensive treatment of processing issues (both 2-D and 3-D) is presented by Yilmaz (1987).

SOURCES AND RECEIVERS

To generate reflections, we need some source of acoustic energy. The choice of what source to use will be a function of several variables. These include whether the seismic data are being collected at sea or on land, the depth and thickness of the principal targets of interest, environmental concerns and, last but not least, the amount of money available for the project.

In the marine realm, the preferred seismic source for petroleum exploration is the airgun. Airguns store pressurized air in chambers until it is abruptly discharged into the water, creating an expanding bubble that generates an acoustic pulse with peak frequencies in the 10s of Hz to 100s of Hz range (depending on the size of the air chamber). Airguns are towed behind ships and discharged at pre-designated shotpoints.

On land, two main types of sources are employed in the petroleum industry: a) explosives, and b) vibroseis trucks. Explosives (such as dynamite) are set down in shot holes, the depth of which depends on local terrain factors and local regulations, then detonated. The Vibroseis method involves making heavy (e.g., ~20 tonnes) trucks vibrate up and down on baseplates and sweep through a pre-designated range of frequencies in a pre-designated amount of time (e.g., increasing from 10 to 100 Hz in 10 seconds).

Some points to consider:

- Generally, several sources are used concurrently. For example, in a marine survey a ship would tow several airguns in an array that are discharged at a shotpoint simultaneously. On land, a vibroseis "shotpoint" might in fact consist of 4 trucks sweeping through the pre-designated range of frequencies simultaneously. The idea is to impart as much energy into the ground as possible in order to boost the signal-to-noise ratio.
- As a general rule, the greater the amount of energy put into the ground by an explosive source (e.g., airgun, dynamite), the lower the frequencies produced by the source. Thus, there is a trade-off between penetration and resolution that needs to be considered when acquiring the data.
- During the survey design phase, acquisition people will attempt to determine the optimum source characteristics by examining seismic data previously acquired in the region, or by conducting various types of source testing experiments.

Two types of devices are used to record the reflected energy. At sea, hydrophones are towed behind a ship and convert pressure changes (from the reflected acoustic pulse) into electrical energy that can be recorded digitally. On land, geophones are implanted into the ground to convert ground motions (from the reflected acoustic pulse) into electrical energy. Similar to shot points where source arrays are deployed, several receivers are typically deployed at each "receiver location" (sometimes referred to as a "group") in an effort to boost the signal-to-noise ratio.

THE COMMON DEPTH POINT METHOD

The reflected energy recorded by receivers is weak and can be contaminated by a variety of noise sources, such as ambient noise (from wind blowing across fields, waves crashing on beaches, ships' noise, etc.), instrument noise, air waves and ground roll (on land surveys), mode converted waves, etc. As noted previously, the signal-to-noise ratio

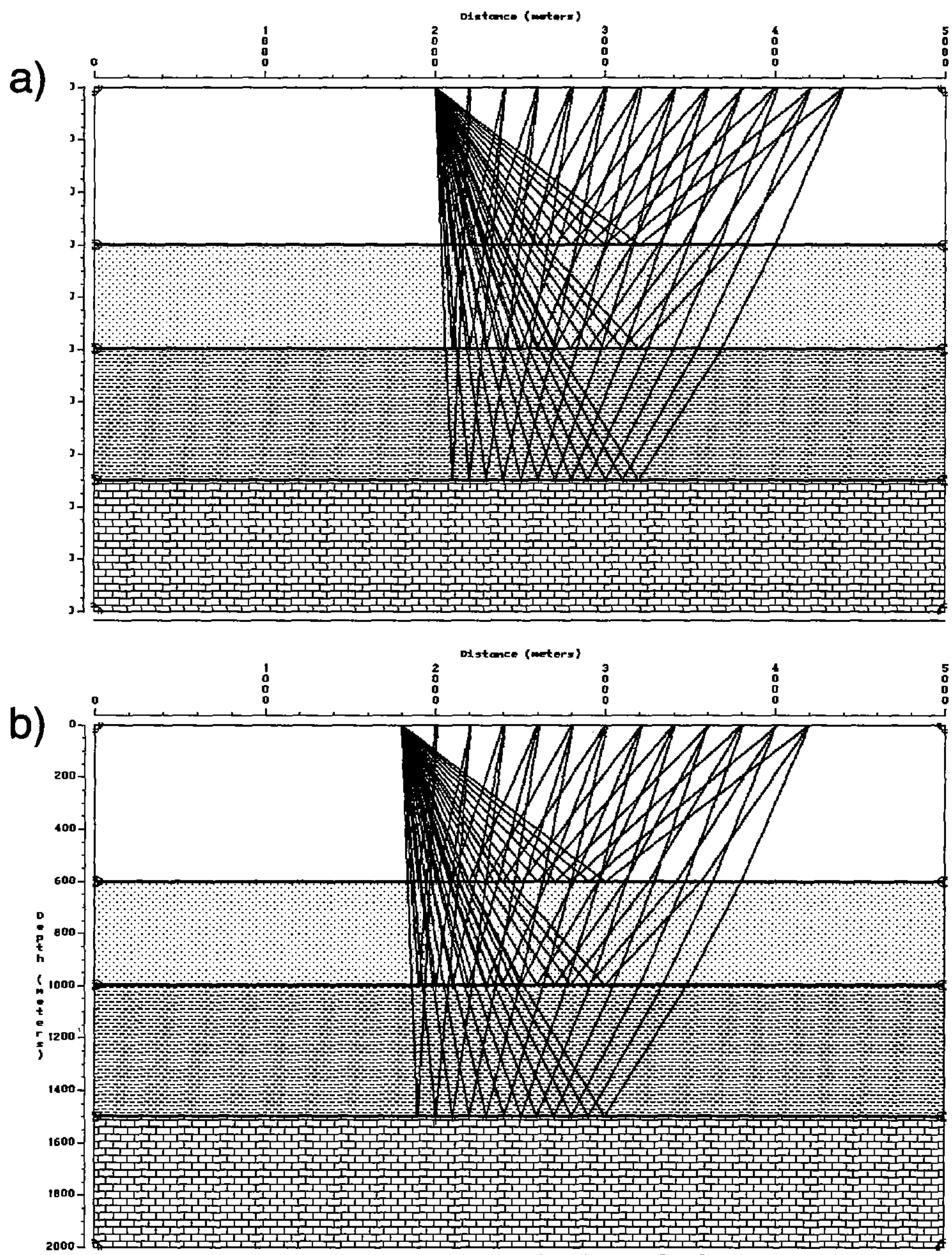

Figure 3.1. Two shots from a hypothetical 2-D seismic survey. a) the first shot has a source at the 2000m mark and receivers strung out to the right every 200 m. Raypaths are reflected mid-way between each source-receiver pair (i.e., every 100 m in the subsurface). b) For the second shot, the source and receivers are moved to the left 200 m. Some (most) of the midpoints from this second shot will have the same location as midpoints from the first shot.

needs enhancing to adequately interpret details of subsurface stratigraphy and structure. First mentioned in Chapter 1, the common midpoint (or CMP) method was developed as an effective, efficient means of retrieving quality subsurface images.

The idea behind the CMP method is that a given subsurface reflection point should be imaged several times. The separate images can then be combined, or stacked, in such a way that the coherent signal (reflections from subsurface features of interest) in each image will constructively interfere whereas random noise from successive images should tend to cancel itself out in the final product. The result should be a stronger, clearer image of the subsurface.

In practice, receiver groups are spread out in a line away from the shotpoint for 2-D acquisition, with a fixed interval between groups (Fig. 3.1a). The number of receivers (or channels) that are active for each shot depends on the survey design. Energy from the shot expands out into the subsurface, is reflected from buried interfaces and is recorded by receivers (now usually in digital format). For horizontal beds, the reflection points will be half the distance, or the midpoint, between the source location and the receiver of interest. For example, if the receiver spacing is 60 m, the subsurface reflection points will be spaced 30 m apart. The distance between a source and receiver is called the offset.

The next shot is moved along the line a distance equal to the receiver spacing (Fig. 3.1b), and the receivers are moved the same distance[1]. The shot will generate a new set of reflections, with new midpoints. Note however that since the shotpoint and receivers were moved a distance equal to the receiver spacing, some of the midpoints from the second shot will correspond to midpoints from the first shot. The only difference will be the reflection angle. As the sources and receivers are moved along the line, reflection points will be imaged by many source-receiver combinations.

The key to the CMP method involves sorting through the field data to find all the source-receiver combinations that share a common midpoint. These traces are then combined, or stacked, together to boost the signal-to-noise ratio and produce a single seismic trace that represents the series of reflections produced by the subsurface interfaces at the CMP. The details of this method are described in a later section of this chapter. The stacking fold or multiplicity refers to the number of field traces that have been combined together to produce the final trace. All else being equal, the higher the fold, the better the data quality.

DATA PROCESSING

Figure 3.2 illustrates a simplified processing flow for seismic data. The processing flow for any given data set will be different from this simplified example, and may include steps not considered here.

The first processing step is demultiplexing, a type of data reorganization that produces a set of distinct field traces for each shotpoint. Processors then need to consider

[1] For land surveys, the geophones are planted into the ground before the survey begins. As such, different combinations of geophones are selectively recorded for each shot. The effect is identical, but much more cost effective, to moving the entire line of geophones.

energy loss as the acoustic pulse travels down into the earth and is reflected, through attenuation, mode conversion (e.g., P waves to S waves) and spherical divergence. As such, deeper reflections are not as strong as shallower ones. However, as interpreters, we are interested in looking at relative changes in impedance laterally and with depth, and so need to account for the loss of energy with depth. Various gain recovery methods have been designed to recover the true relative amplitudes of reflections.

Another consideration, especially on land, relates back to the fundamental measurements that are made by the seismic method. In Figure 2.1 we measured the two-way traveltime for sound to make a round trip from the surface to subsurface reflectors

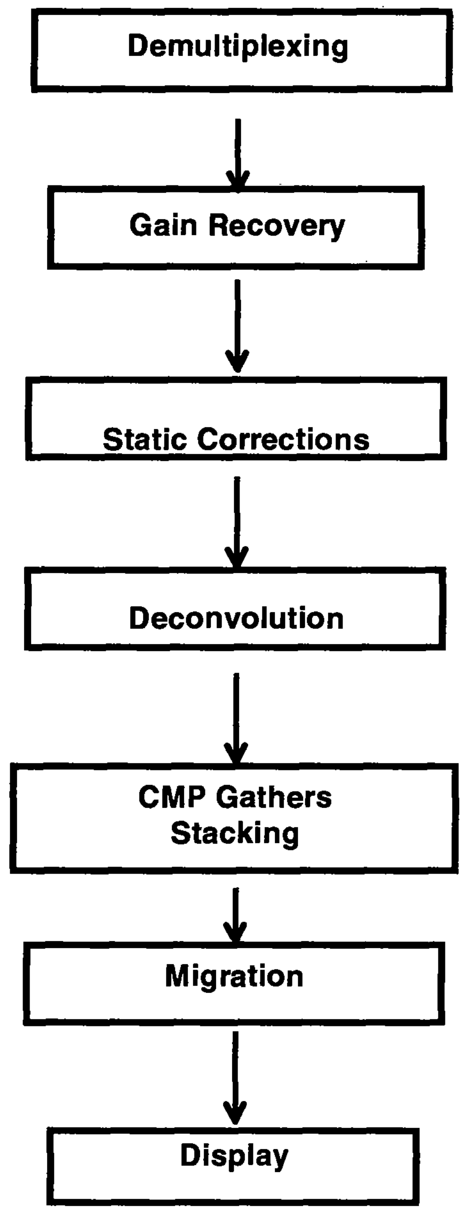

Figure 3.2. Simplified processing flow.

and back. If we could do this at several points, then we could look at subsurface structure. The assumption is that the surface is a planar, horizontal feature. In many, if not most, areas this is not the case (Fig. 3.3). As such, the surface topography needs to be accounted for to prevent us from observing false subsurface structures. Additionally, variations in the thickness of the relatively slow "surface layer" of unconsolidated material or weathered rock can result in false structures or processing problems. Static corrections are an attempt to compensate for these problems. An arbitrary seismic datum (Fig 3.3), corresponding to 0 ms TWT is defined at this time.

In the theoretical examples shown so far, the wavelets have been relatively short and simple (e.g., sinusoids). In reality, the wavelets generated by seismic sources are much longer and more complex. This can make it hard to distinguish reflections from individual interfaces in a seismic section (Fig. 3.4). Since the original seismic trace consists of the convolution of the earth's impulse response (i.e., reflection coefficients) with a wavelet, seismic processors use processes called deconvolution in an effort to "remove" and shorten the propagating "messy" wavelet and wavelet shaping to replace it with a "cleaner" wavelet of known character. Deterministic deconvolution relies on measurements of the propagating wavelet, however these are not always available. Predictive deconvolution uses statistical methods and some basic assumptions about the source wavelet and series of reflection coefficients to estimate the wavelet.

What is meant by the "character" of the wavelet discussed in the last paragraph? One of the most important aspect is the wavelet's phase (Fig. 3.5) which indicates where to accurately pick a horizon. A zero phase wavelet has the peaks or troughs centered on the reflecting interface. A minimum phase wavelet begins at the interface, whereas a wavelet with a phase of 90° has the interface centered on the zero crossing between a peak and a trough (or vice versa). Most interpreters prefer to have seismic data processed to give a zero phase character. Despite this, the data generally end up with something of a "mixed phase" character and the phase of the data can even be variable within a single data set. Ziolkowski et al. (1998) explored some of the reasons for these problems in 3-D data.

Even if data are truly zero phase, it is not the case that bedding surfaces will always exactly correspond to peaks or troughs in the data. Interference effects from adjacent reflections can distort the wavelet such that bedding surfaces may lie at some intermediate position on the waveform. In these cases, it has been suggested (Brown, 1998) that the best idea still is to pick the stratigraphic surface as corresponding to the nearest peak or trough. An alternative methodology was presented by Hardage et al. (1994).

Following deconvolution, typically the next process is to stack the data. There are several steps to this process. The first involves generating CMP gathers, or groupings of traces that share a common CMP. Next, they need to account for the different source-receiver offsets. In the simple example of Figure 3.6, it can be seen that for greater offsets, the TWT increases for a given reflection in each field trace as well. For horizontal beds, a hyperbolic curve (known as normal moveout or NMO) can be fit to individual reflections in CMP gathers. This shape of this curve is function of the subsurface velocity structure. All the reflections from a given interface need to line up horizontally in a CMP gather to accurately stack the traces together. As such, processors

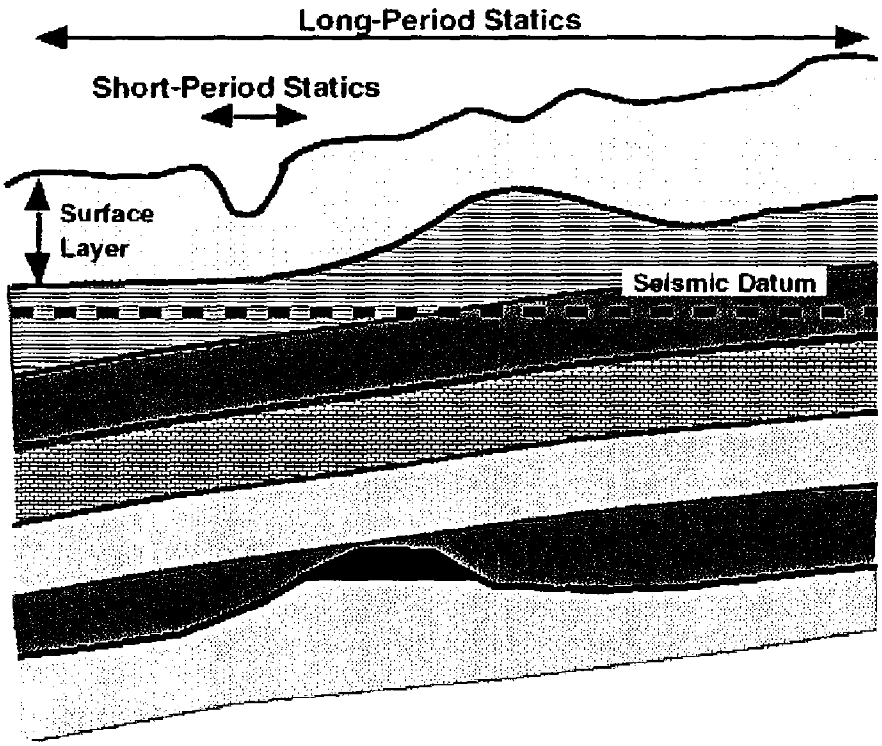

Figure 3.3. Variations in surface topography and the thickness of the surface weathered layer need to be accounted for during processing. These processing steps are called static corrections or "statics".

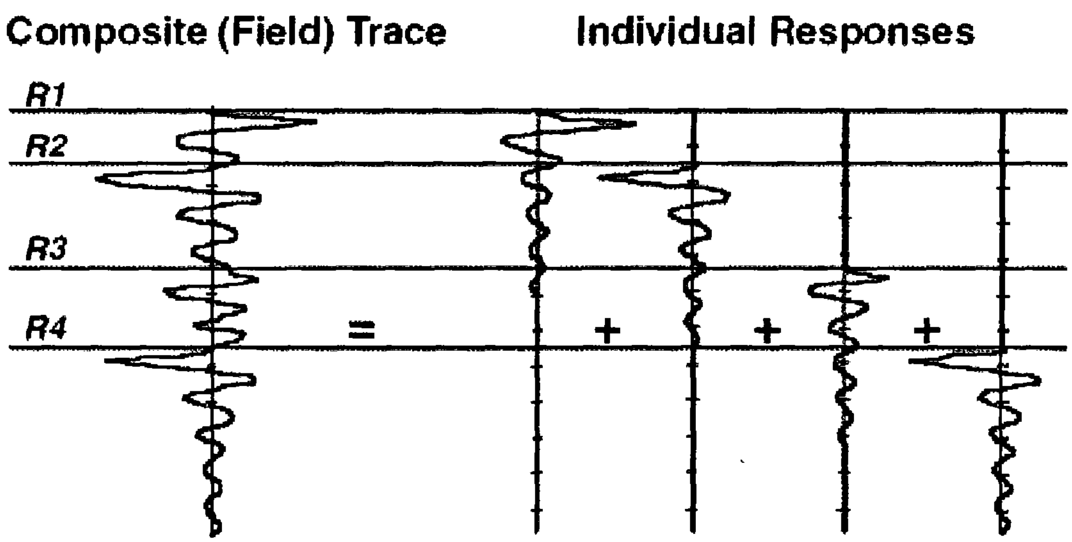

Figure 3.4. On the right are four separate reflections from four interfaces (R1-R4, labeled on the left). Each reflection consists of a long "messy" wavelet such as might be produced by an explosive source (e.g., airgun, dynamite). On the left is the seismic trace, the composite of the four reflections, one would actually observe. It would be hard to tell how many interfaces are present in the subsurface from this trace. Deconvolution and wavelet shaping attempt to replace the original messy wavelet with sharper wavelets of known phase characteristics.

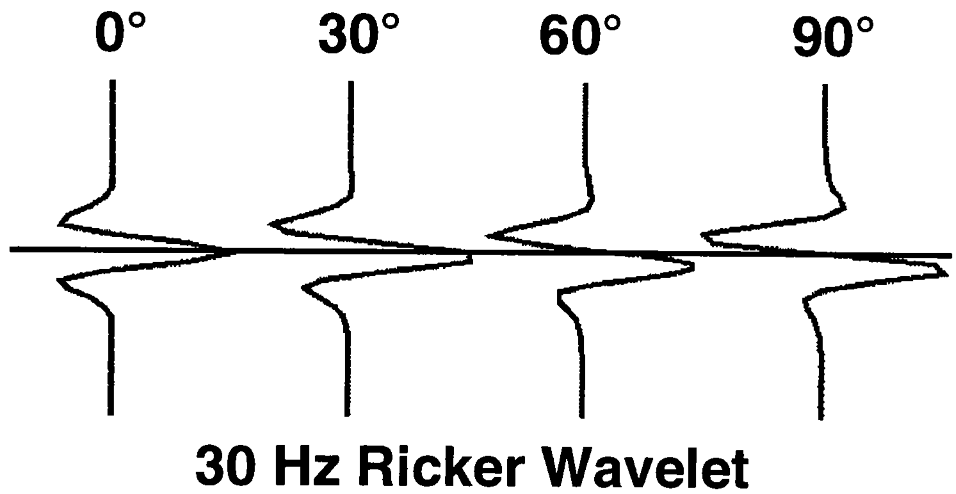

Figure 3.5. Illustration showing the effects of phase on a simple wavelet. The zero phase wavelet (left) has a peak centered on the reflecting interface. As the phase gets rotated, the interface begins to fall somewhere else on the waveform. By 90° phase (right), the interface falls on the zero crossing between the overlying trough and the underlying peak. We can conclude that knowledge of the phase of the data is important to understanding what to pick in seismic data.

attempt to determine the velocity structure in an iterative manner to correct for NMO and so be able to properly stack the traces together. After stacking, the traces corresponding to CMPs can be assembled sequentially, and the seismic data start to become recognizable as images of subsurface geology.

Until now, we have assumed that the subsurface stratigraphy is horizontal, and velocities are either constant with depth or increase monotonically. Unfortunately this is not always, or perhaps even generally, the case. In areas where velocities vary laterally and vertically, or where the structure and stratigraphy are complex, the reflections seen in a stacked trace are assumed to come from the midpoint between the source and receiver. This is not always the case. Reflected energy might come from locations to either side of the assumed midpoint. Multiple source-receiver pathways may be possible (Fig. 3.7) Also, energy can be diffracted at faults, stratigraphic pinch-outs or other features.

Migration is a process which has as a primary goal the repositioning of reflected energy to its true subsurface location. A secondary benefit is that migration helps to collapse diffractions. Thirdly, migration helps to shrink the Fresnel Zone. Several different algorithms are currently employed, each has its advantages (cost, range of applications, etc.) but all involve intensive mathematical and computational efforts and so are beyond the scope of this course. An example of the effects of migration is shown in Figure 3.8. Migration is generally carried out on the data after they have been stacked. However, in areas where velocity fields are complex, such as below thrust sheets or salt bodies, migration may be carried out prior to stacking ("pre-stack migration"). Nearly all seismic data collected today is migrated during processing, although this may not always be the case for older data

One might be tempted to think that processing is a straightforward science. In fact, there is a significant amount of art involved. Two different processing companies can work on the same data, and produce results that look different. Although some of the differences may be related to computer power (faster computers can run more

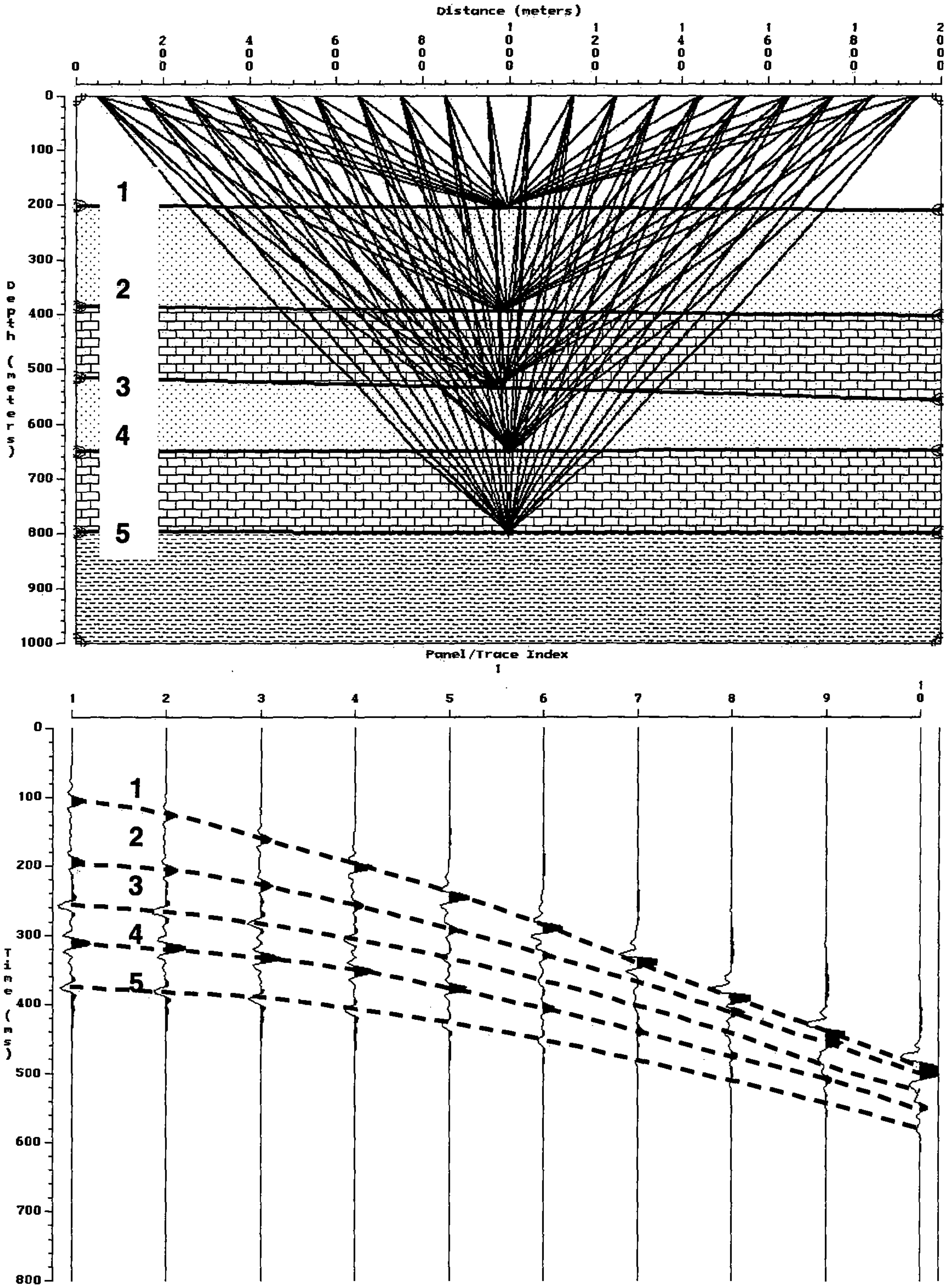

Figure 3.6. The image at top shows an hypothetical series of 10 source-receiver combinations that all share the same common midpoint (CMP). Note that raypaths are longer with longer offsets, meaning that the TWT for a reflection from a given interface will increase as well. Below, a CMP "gather" shows the 10 recorded traces from each geophone. The trace with the shortest offset is on the left, the longest offset is on the right. A distinct hyperbola fits each of the 5 reflections, and each hyperbola represents a specific velocity.

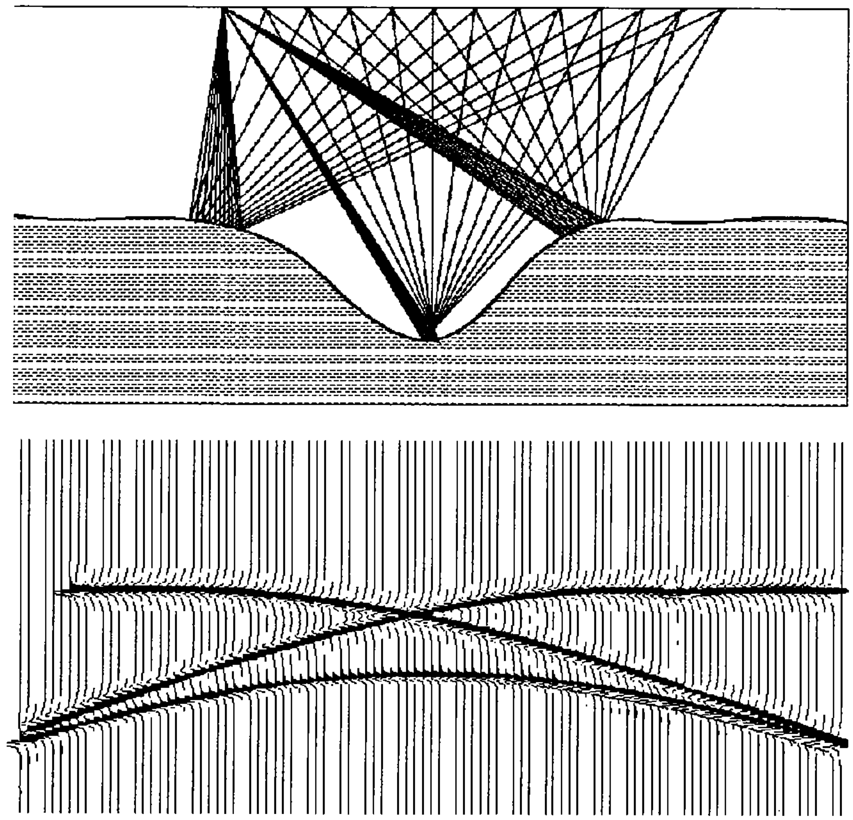

Figure 3.7. When subsurface geometries are complex, the reflection point is no longer mid-way between source and receiver. In the upper panel, raypaths from a shot on the left take multiple pathways to reach the receivers. The result, as shown below, is a classic "bowtie" reflection pattern. We need a way (migration) to correct for these problems during processing.

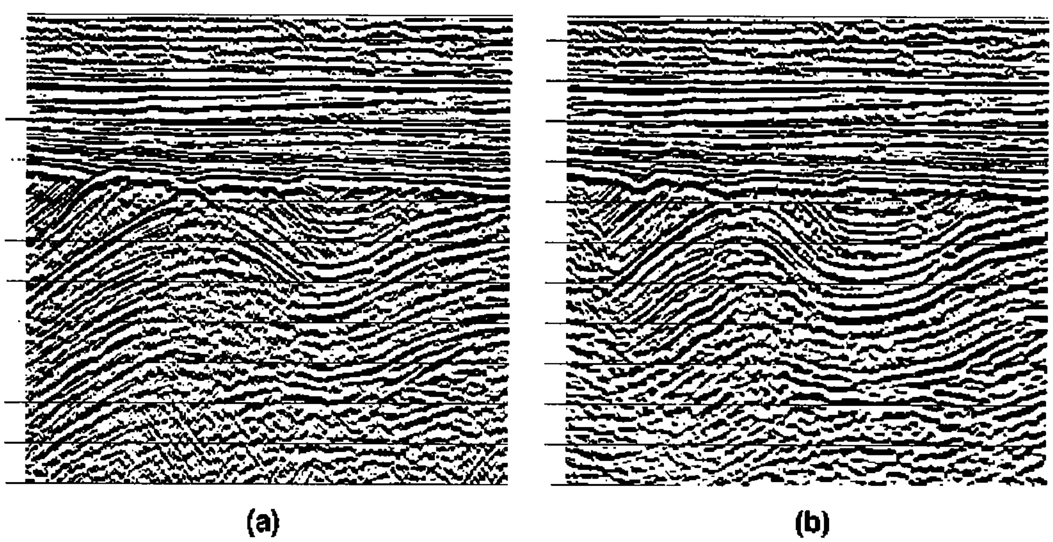

Figure 3.8. Unmigrated (a) and migrated (b) versions of a seismic transect. Note the improved definition of the syncline and anticline and the reduction of diffractions from the unconformity. Reproduced from Yilmaz (1987) by permission of the Society of Exploration Geophysicists.

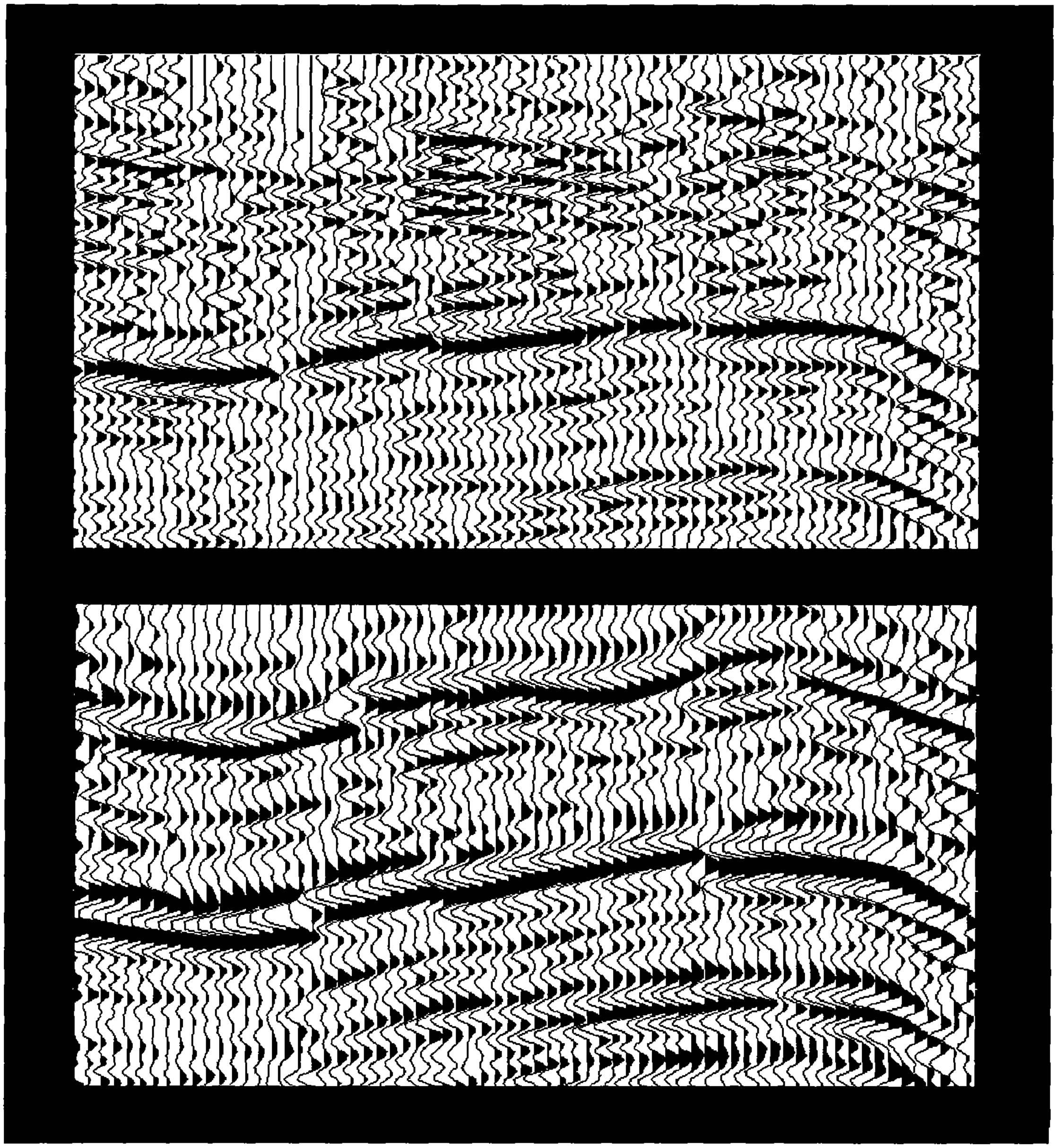

Figure 3.9. Two differently processed versions of the same seismic transect, illustrating the effect processing can have on the interpreter's ability to interpret the data. Modified from Hart (1999).

numerically intensive algorithms and work on larger data sets), some differences remain a matter of preference. For example, Figure 3.9 shows the same seismic transect as processed by two different companies. The upper example has higher frequency content, and so better resolution, but more noise. In the lower example, the high frequencies have been filtered out, lowering the resolution, but increasing the structural definition of the uppermost part of the section. (There are other differences in processing, but discussion of these is beyond the scope of these notes) Which version is "better" depends on the interpreter's objectives.

DATA DISPLAY

Once the data have been processed, they are generally considered ready for interpretation. In the past, paper seismic sections were the norm. Today, most seismic data (2-D and 3-D) are stored digitally and analyzed on workstations or powerful personal computers. This allows interpreters to automate (and so speed up) certain tasks, to play "what if" games (a.k.a. "testing multiple hypotheses") more rapidly, to directly interface with other computer applications (e.g., mapping packages), and to perform numerical analyses that are not possible with paper records.

On paper, data have traditionally been displayed as wiggle displays (where the seismic trace is displayed as a continuous curve), variable area displays (where the peaks are filled in with black), or the combination variable area wiggle display (wiggle with infilled peak; Fig. 3.10). As discussed by Brown (1999) however, these displays can cause the viewer to concentrate mostly on the peaks and essentially ignore the information that is contained in the troughs.

Digital data and computer graphics capabilities allow interpreters to generate and interpret variable density displays (Fig. 3.10). In this type of display different ranges of amplitudes are assigned different colors. Generally, positive values ("peaks") are colored blue, with stronger positive values being darker blue. Zero values are white and negative values ("troughs") are red (more negative values are darker red). With variable density displays the peaks and troughs have approximately equal weight visually, and the interpreter can (hopefully) derive more information from the data display. Although the blue-white-red color scheme is a common choice, with all computer-based interpretation packages the interpreter has the ability to interactively define his/her own color selection. If desired, wiggle traces can be overlain on the variable density displays.

One other important aspect is the polarity of the data (Fig. 3.11). This determines whether a positive reflection coefficient will be displayed as a peak or as a trough. There is much confusion concerning this issue, as there is no universally accepted standard (although the Society of Exploration Geophysics has defined a "normal polarity"). One company's "normal polarity" will be considered "reverse polarity" by another. To overcome this obstacle, the interpreter can ask a simple question: "Will a slow to fast transition be imaged as a peak or as a trough"? Once he/she knows the answer to this question, the polarity of the data should not be in doubt.

Computer-based seismic interpretation packages have other advantages over paper. They allow the interpreter to selectively 'zoom in' on areas of interest, or to 'zoom out' for the interpreter to obtain an overview of the data. Digital log data can be overlain on the seismic data, allowing the interpreter to visually make the link between the log-based geology and the seismic data (Chapter 5). Both the data and the interpretations are stored digitally, taking up less space and eliminating much of the damage to paper records through wear and tear. Of course, paper records of the digital data can be produced whenever needed.

POST-STACK PROCESSING

In the past, once a seismic data set had been delivered from the processing shop it was typically considered to be the Final Product that the interpreter would use – for better or worse. If needed, and in relatively rare circumstances, the entire seismic data set could be sent back for reprocessing but this was (and still is) a costly and time-consuming endeavor. However, the results can make a marked improvement on the quality of the data being interpreted.

With the advent of workstation-based interpretation has come the desire and (subsequently) the ability to implement certain processing steps on processed (stacked and migrated) seismic data and then see the results in near-real time. For example, an interpreter might judge that a certain data set has significant high frequency noise that obscures stratigraphic or structural features. Filtering out those high frequencies could make the low frequency information more readily interpretable. At other times, the interpreter might attempt to attenuate artifacts of the acquisition and processing steps.

Post-stack processing allows the interpreter to undertake various types of processing on the stacked and migrated data, typically with the intent of enhancing the interpretability of the data (e.g., Fig. 3.12). Various manipulations can be applied to the seismic data (e.g., bandpass filtering, deconvolution, dip filtering, trace averaging). The interpreter needs to realize that generally these operations are a double-edge sword and need to be used with caution and appropriate judgment. While they *may* enhance data interpretability, these methods can also remove important information or, worse, introduce artifacts that can be mistaken for data.

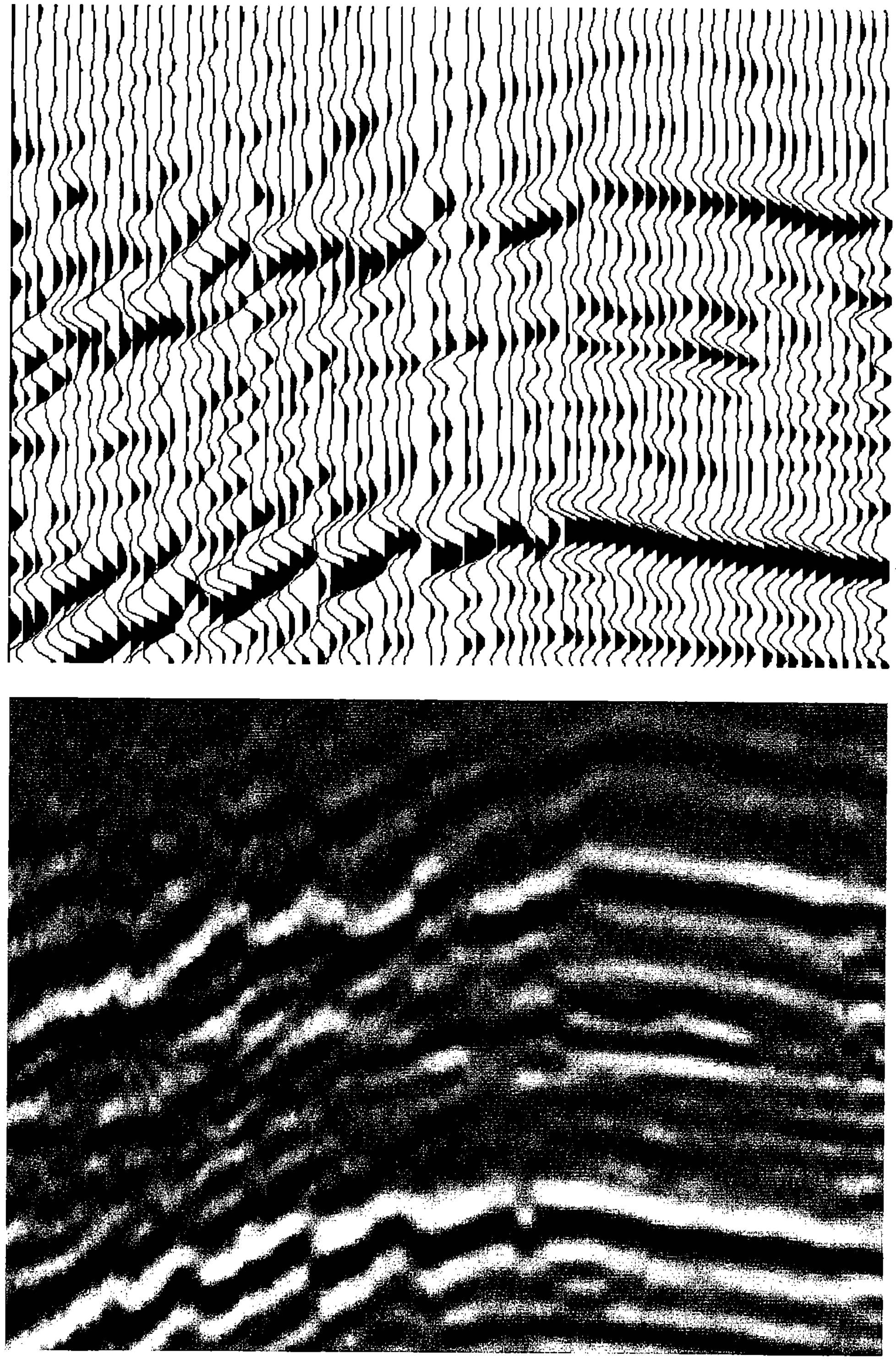

Figure 3.10. The traditional way of viewing seismic data (top, this page) is the variable area wiggle display. Computer graphics packages can color code the amplitudes in variable density displays, removing the wiggle trace and giving the appearance of data continuity. The choice of color scale for the display is up to the interpreter. A simple black-white gradational scale, with the peaks in black, troughs in white and intermediate amplitudes in gray, is shown in the lower image on this page. This type of display is useful for identifying faults and noise (e.g., left side of image. A blue-white-red

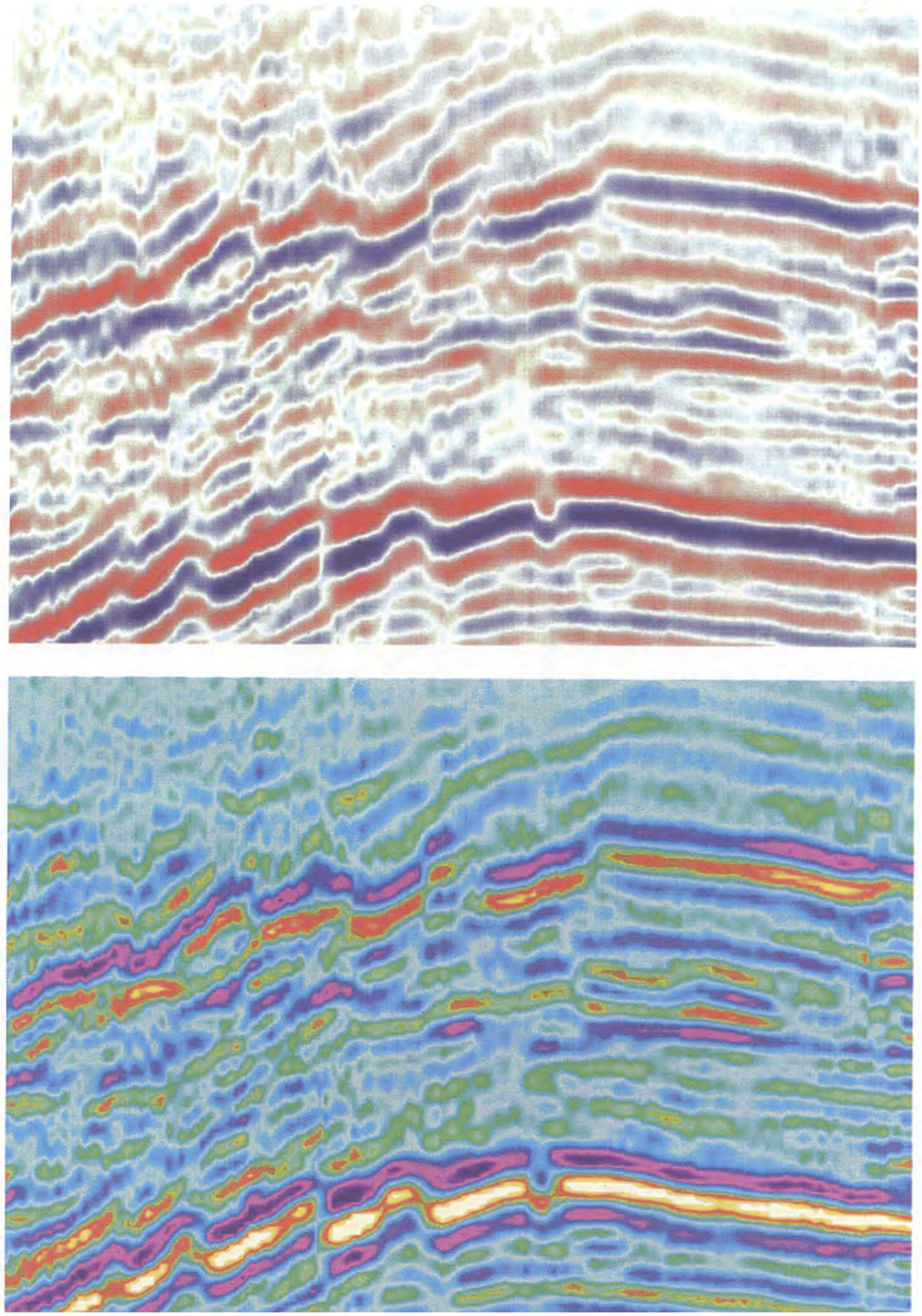

Fig. 3.10 (cont.) color scale is shown on the top of this page. Strong peaks are in blue, strong troughs are red and near zero amplitudes are in white. This is the preferred color scale of many interpreters. A different scale bar is shown in the lower image on this page. There, peaks are in white to yellow, troughs are in purple and intermediate amplitudes are in cyan and green. This type of display can highlight subtle amplitude changes along a horizon that might be less visible in a red-white-blue display. The choice of color bar is a subjective issue, although some are more appropriate for some tasks than others.

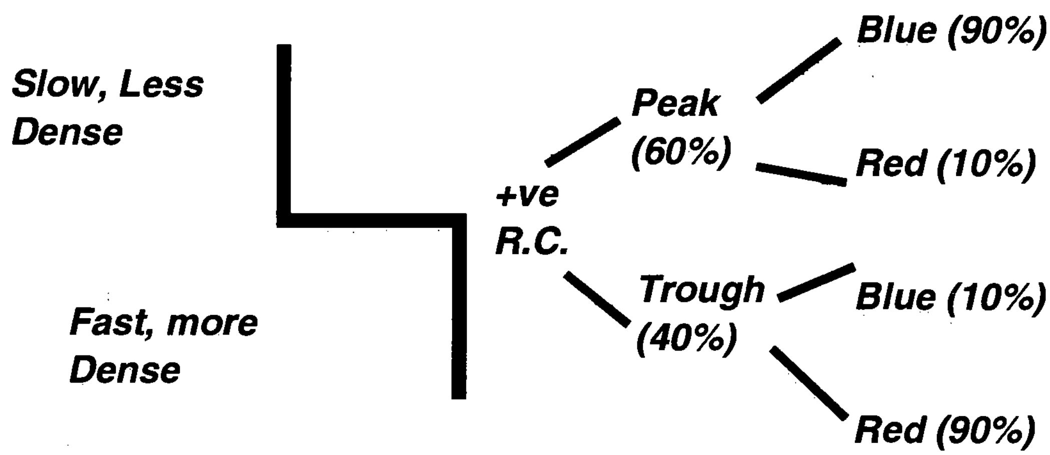

Figure 3.11. Display polarity. Unfortunately there is no universally accepted standard convention for showing seismic data. The transition from a slow to fast layer gives a positive reflection coefficient, but about 60% of interpreters show that as a peak in zero phase wiggle displays, while 40% show that as a trough. Nearly everyone views peaks as blue and troughs as red. Based on Brown (1999).

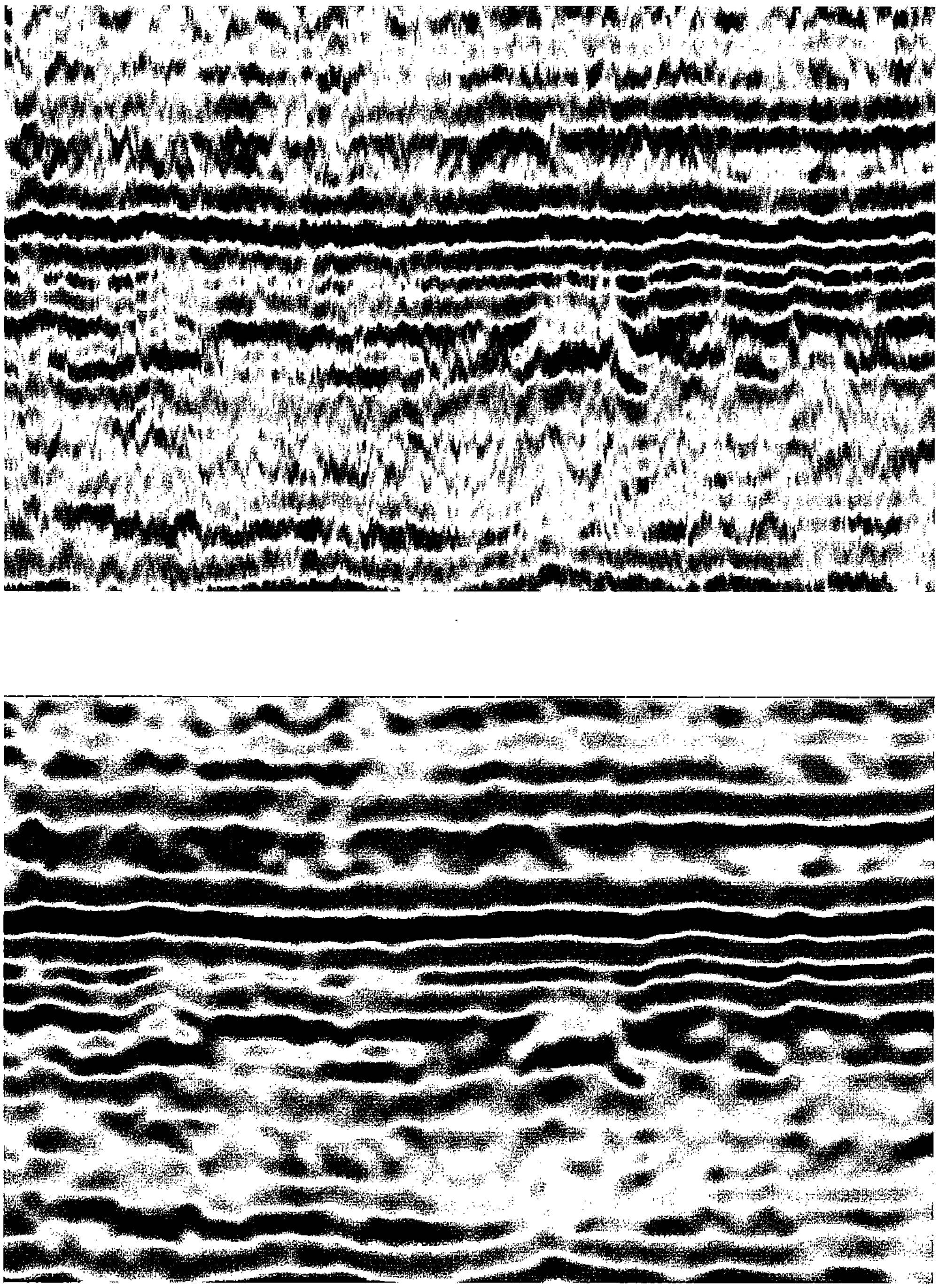

Figure 3.12. Post-stack data processing example. The upper image shows a transect through some Cretaceous rocks in the San Juan Basin. Note the prominent "chatter" (i.e., noise) in the data that locally obscures stratigraphic details. A post-stack processing flow (trace averaging to improve reflection continuity, fan filtering to remove high-angle noise, and trace equalization to balance amplitudes) was designed and implemented on this section to facilitate horizon picking. The results are shown below. Note the much improved reflection continuity. Horizon picking has been simplified, but whether stratigraphic and structural details have been adversely affected by the processing remains problematic.

CHAPTER 4: INTERPRETATION OF 2-D SEISMIC DATA

INTERPRETATION WORKFLOW

In previous times it was considered that the interpretation phase of a seismic project began when the processing people delivered a "final stack" (perhaps not even migrated) data set to the geophysical interpreter. Today, it is realized that the interpretation truly begins at the survey design phase, when choices about offsets, line orientation, source characteristics etc. are made. These choices can influence the interpretability of the resultant data. For example, a survey designed for deep targets may not have the high frequencies or fold needed to image stratigraphic details at shallow levels. Alternatively, the spacing between midpoints (seismic traces) might be too great to image subsurface features of interest (e.g., "shoestring" sandstones). The interpretive choices continue through the processing phase, as processors make decisions (often based on time/money considerations) that influence the character, and also interpretability of the stacked seismic data. Realizing the importance of processing, some larger companies routinely send their field data out to two or more processing shops and compare the results.

Another change from previous times is that an increasing amount of processing is occurring during the interpretation phase, interactively, by the interpreter. As noted at the end of the last chapter, interpreters can now interactively evaluate the effects of different processing routines (filtering, trace balancing, deconvolution, etc.) on stacked, migrated data sets ("post-stack processing"). This type of analysis might be employed to enhance certain aspects of the data, remove unwanted noise or to match two or more data sets of different vintages.

Although there is considerable variability (from interpreter to interpreter, and from project to project) as to what goes into a "seismic interpretation", a generalized workflow is shown in Figure 4.1. The steps in this workflow are described in the following sections in this chapter. Although this chapter is entitled "Interpretation Of 2-D Seismic Data", many of the procedures described below apply equally to 2-D and 3-D seismic interpretation. As such, they will not be repeated in the chapter on 3-D interpretation.

2-D SEISMIC WORKFLOW

①Collect all Pertinent Data
& Reports

②Scan Records for
Polarity, Static Shifts, etc.

③Scan Through Sections
(Line by Line)
Overview of
Data Quality, Structure,
Stratigraphy

④Tie Well and Seismic Data
Use: Paleo, Lithology,
Synthetics,
VSPs, Tops, etc.

⑤ Pick Horizons & Faults
(Loop tying)

⑥ Seismic Stratigraphic
Analyses

⑦ Structural Analyses

⑧Contouring/Mapping

Figure 4-1. An interpretation workflow.

"PREP WORK"

As noted previously, seismic data are non-unique. A seismic profile through a carbonate succession might look like a profile from a siliciclastic section. Therefore, a key step in effectively and efficiently making an interpretation involves the collection and analysis of data and reports available for the study area. For example, knowing that the stratigraphic succession has a couple of significant angular unconformities (perhaps based on outcrop or well data) can help the interpreter to know what to look for, and possibly where, in the seismic data. Similarly, knowledge of an area's tectonic history may help the interpreter to more quickly identify fault orientations and styles. Knowledge of what type of data is available (e.g., logs, core, biostratigraphy, pressures) will even help the interpreter to determine what types of analyses can be undertaken. This data assembly step is typically a time-consuming, but very necessary, process.

Once the interpreter has a feel for what he/she may be looking at (or for), the seismic data will be given a quick "going over" in an attempt to determine the polarity, and static shifts that have been applied. It may be that more than one vintage of seismic data is available, each with a different static shift, display polarity, etc., and the differences between these data sets need to be understood. With digital data and workstation capabilities, the interpreter may try to minimize these differences interactively at a later time. During this initial "reconnaissance" work, the interpreter will get an overview of the stratigraphic and structural framework of the study area, as well as the data quality. Each seismic line will be examined this way.

At the end of this phase, the interpreter will have defined (if they haven't already been) the key objectives of the study and will have some working hypotheses that will be tested during the interpretation.

THE WELL TIE

Well logs provide a vertical resolution that is much greater than that obtainable with seismic data. Well logs can resolve features that are decimeters thick (or less) whereas seismic methods (at least those used in the petroleum industry) can generally only resolve features a few tens of meters thick. Additionally, log shapes can be used to help identify specific depositional features (channels, parasequences, etc.) that may be poorly resolved seismically. Conversely, seismic data provide much denser lateral control, perhaps allowing the interpreter to view faults or stratigraphic pinch-outs that cannot be defined from well control alone. As such, the interpreter needs to be able to bridge the gap between the geologic information that is available for an area (e.g., well logs, outcrops) and the seismic data. In practice, this means establishing links between the stratigraphic units definable with well data (where the z axis is measured in feet or meters) and the reflection events that are visible in seismic data (where the z axis is measured in milliseconds, equivalent to tens of feet/meters). Several approaches are available, and all require some determination of subsurface velocities.

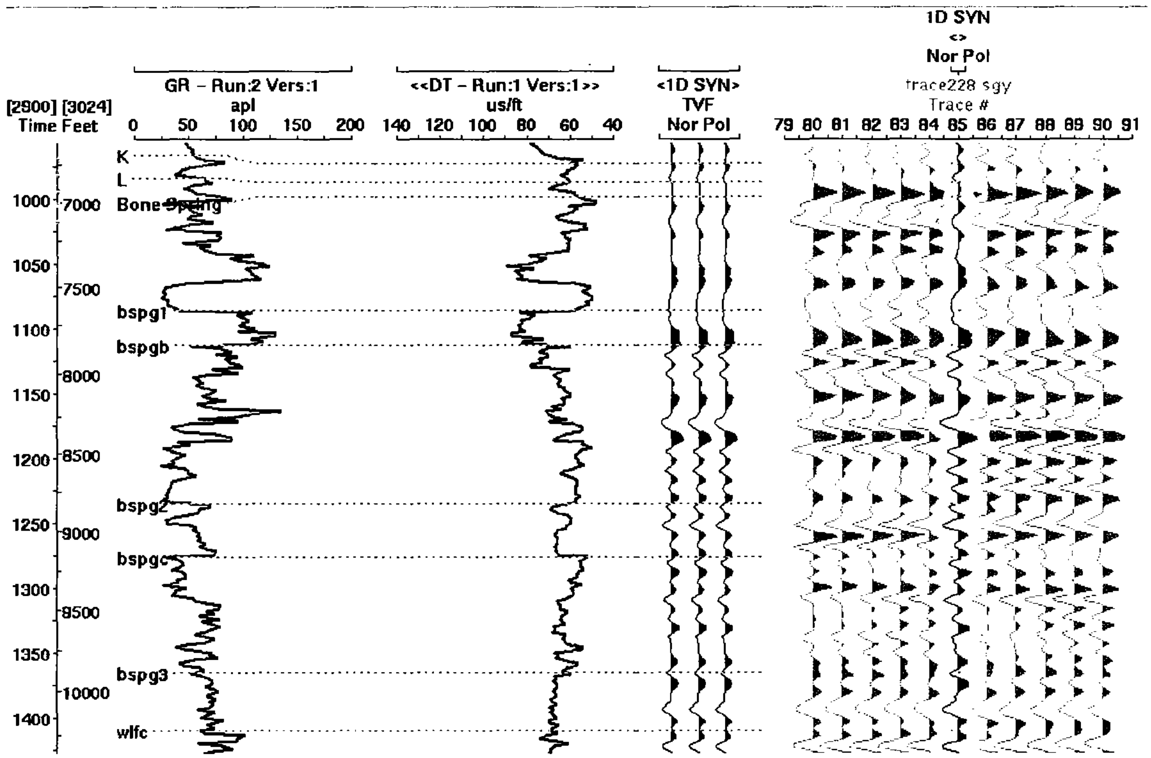

Figure 4.2 A synthetic seismogram display. From left to right the tracks show: a) the time-depth relationship, b) a gamma ray log with picks, c) the sonic log, d) the synthetic seismogram repeated 3 times, e) the synthetic (black) overlain on traces extracted from a seismic data set. The density log used in this example is not shown. The synthetic matches the seismic at some levels but not at others.

The traditional way of tying log and seismic data is through the generation of synthetic seismograms (Figure 4.2). These "synthetics" are generated by using sonic and density logs to generate acoustic impedance logs, then converting to reflection coefficients. The reflection coefficients are then convolved with a wavelet that is thought to match the frequency and phase characteristics of the seismic data. The resultant synthetic is considered (or hoped!) to be what the seismic data should look like for a seismic trace that corresponds to the borehole location. The quality of the log data obviously plays a key role in determining what the synthetic looks like.

One of the key needs when tying logs to seismic data is having a means of converting from depth to time units. In exploration areas, stacking velocities are sometimes used. Typically however, this information is considered to be only good to ± 10% of the actual velocity field. Another way of converting from depth to time is to integrate a sonic log. The units of a sonic log are in microseconds per meter (or foot, depending on the country), or how long it takes for a P wave to travel a specified distance. By integrating over the downhole depth, it is possible to use the sonic log to convert the distance to an equivalent time. Problems arise with this method because some sonic logs (especially older logs) can give erroneous readings in areas of poor borehole conditions, and also because sonic logs are generally not run all the way up to the surface. Additionally, the wireline logs sample a much smaller radius around the borehole as compared to seismic methods. As such, the velocity field of the upper part of the stratigraphic section is typically poorly known or unknown. Other problems (e.g., frequency dependence of velocity) can add to errors.

One of the most common and reliable means of establishing links between time and depth is to conduct a downhole velocity survey or "checkshot" survey (Fig. 4.3). In this method, a geophone is lowered down a borehole to pre-specified depths, often several meters or tens of meters apart. With the geophone in position, a

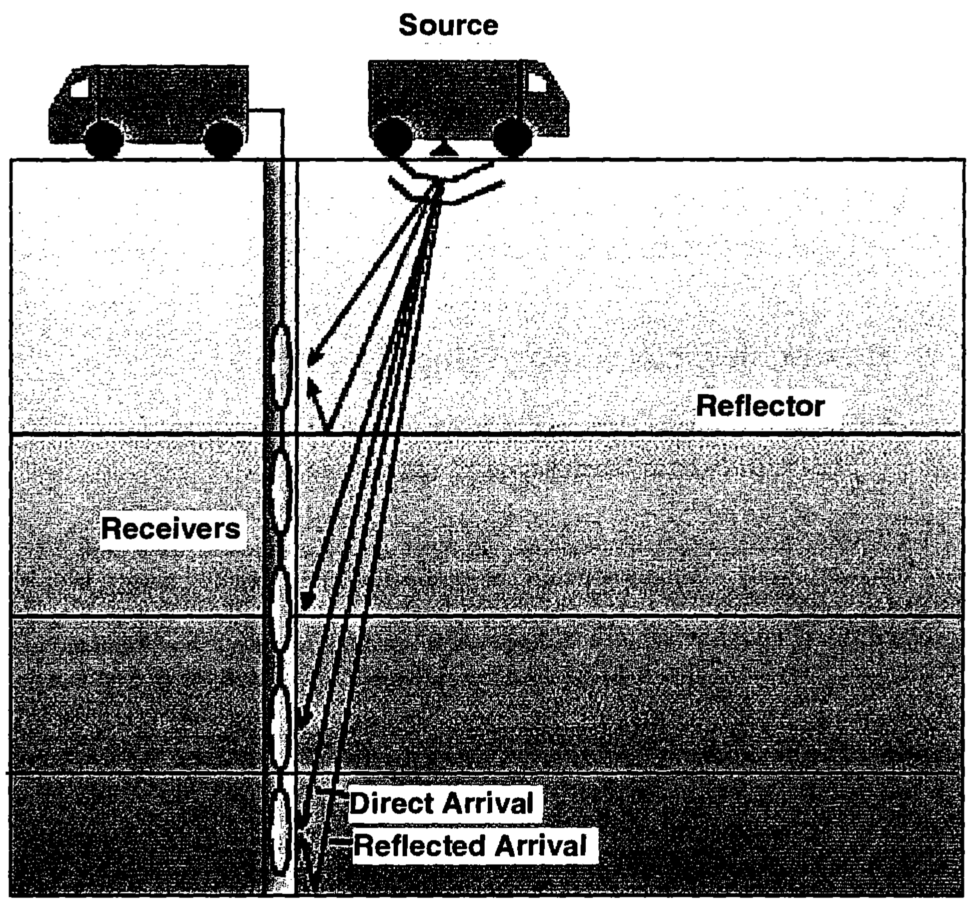

Figure 4.2. Schematic representation of checkshot and vertical seismic profile acquisition geometry. Receivers are lowered down the borehole to pre-defined depths. For a checkshot survey, only the direct arrivals are of interest as they define how long it takes for sound to travel from the surface to specific depths. For a vertical seismic profile, many more receiver locations (depths) are used and the primary interest is in the reflected arrivals.

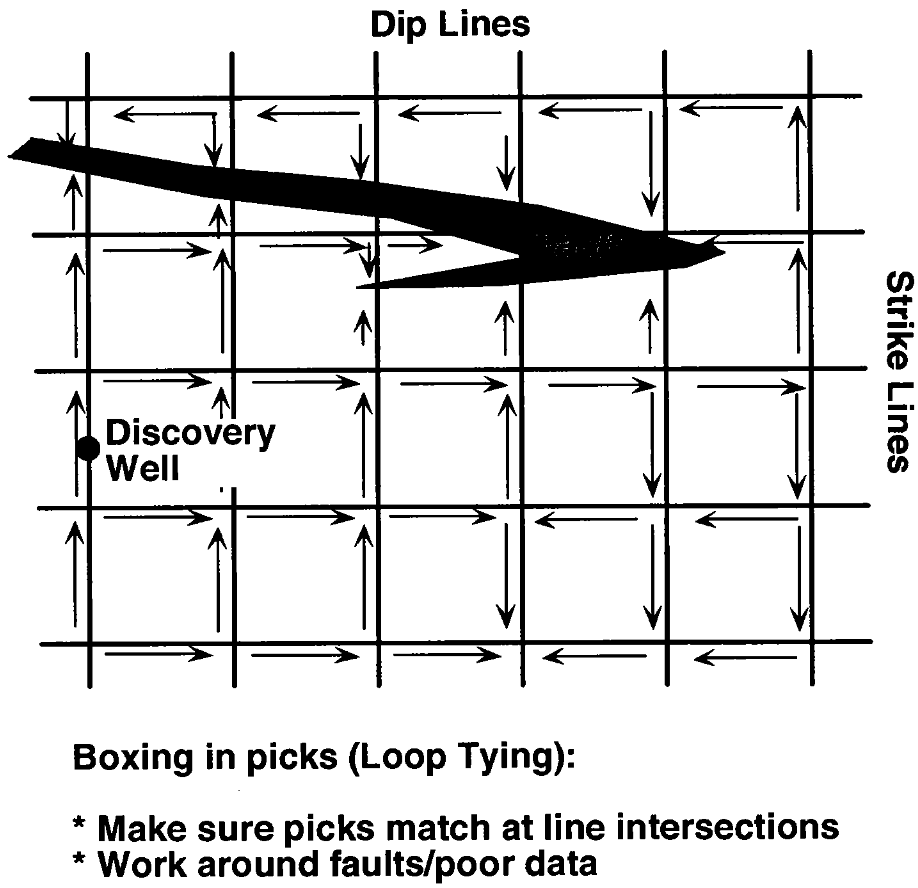

Figure 4.4. The seismic horizon picking method. The seismic data are tied to well data, perhaps via a synthetic at a "discovery well". The key horizons are picked along this seismic transect, then transferred from this dip line to several strike lines using the grid of intersecting lines. Picks that are transferred to a line from several intersecting lines (e.g., to a strike line from several dip lines) should fall along the same reflection, otherwise there is a *mistie*. In many cases, the grid of seismic lines will not be as regular.

"shot" is generated at the surface, and the time it takes for the acoustic pulse to reach the geophone is recorded (the "first arrival", as in earthquake seismology). This allows the establishment of a series of time-depth pairs that are generally quite accurate. The problem remains that the seismic response needs to be estimated by generating synthetic seismograms.

The preferred method of establishing links between logs (the geology) and seismic data (the geophysics) is to collect vertical seismic profiles (or VSPs). Like checkshot surveys, VSPs are collected by lowering receivers downhole, then generating acoustic pulses at the surface (Fig. 4.3). The key differences are that the receiver locations are more tightly spaced vertically and that the receivers record for a longer time, thereby obtaining not just the first arrivals but energy reflected from underlying horizons as well. After some processing, the data can be displayed as seismic traces that

Reflection Relationships
(Mitchum, Vail and Thompson '77)

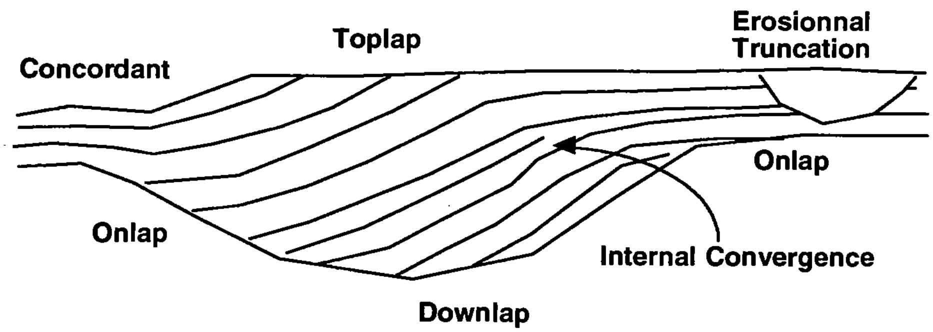

Figure 4.5. Reflection terminations observable in seismic data.

can be directly compared to the seismic data. Since the receiver depths are known, the VSP trace(s) can be displayed either in depth or in time. Ideally, the VSP is collected prior to collection of the seismic data, but with the same source (explosives, vibroseis, etc.). This type of "source testing" exercise allows the acquisition people to help optimize the source characteristics (e.g., energy, frequency levels). Furthermore, when the VSP and seismic data are collected with the same source and processed in a similar manner, the comparison between the two should be more or less direct.

In some cases, where no velocity data are available, it may be necessary to tie wells to the seismic based solely on the expected match between borehole stratigraphy (e.g., the presence of unconformities) and seismic character (e.g., erosional truncation surfaces). Previous experience working in an area obviously facilitates this method. The tie in this case is an approximation, rather than an absolute tie.

Once time-depth relationships have been established, current practice is to display well logs over the seismic data, allowing the interpreter to directly and visually compare the log character with the seismic facies. Examples of such displays will be shown in a later chapter.

BASICS OF SEISMIC STRATIGRAPHY

Having made the tie between wells and the seismic data, the next steps are to use those ties to subdivide the seismic data into discrete stratigraphic packages, then to analyze the variability and seismic character within and between those packages[2]. The analysis moves from the definition and analysis of large to small features of interest. The general methodology used by most interpreters was outlined over 20 years ago (Mitchum et al., 1977), although many changes and refinements have been proposed since.

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[2] In some cases structural features may be analyzed first. Often, stratigraphic and structural analyses proceed nearly simultaneously.

The first step has been termed seismic sequence analysis. During this phase, the major stratigraphic packages are defined by the picking of unconformities, flooding surfaces or sequence boundaries[3]. It is generally thought that these surfaces, manifest in the seismic data as reflections, represent "time lines" (chronostratigraphic surfaces) that separate younger rocks above the surface from older rocks below. Peaks and/or troughs in the seismic data that correspond to these surfaces are traced along the available seismic transects. The interpretation spreads out from locations where wells have been tied to the data. Ideally, a regular grid of seismic lines is available. This allows the picks to be "boxed in" (much as would be done during well log correlation), thus ensuring the integrity of the pick away from areas of well control (Fig. 4.4). Seismic reflection terminations (downlap, toplap, erosional truncation, etc.; Fig. 4.5) are generally used to help identify the major sequence boundaries. It will be recalled from Chapter 2 though that reflection termination geometries do not always indicate the true stratigraphic geometries (Fig. 2.6).

Once the major stratigraphic packages have been defined, the reflection configuration within each sequence is examined (Fig. 4.6). This process is referred to as seismic facies analysis. The objective of this phase is to determine depositional environments of the rocks being examined. During this phase the reflections in each sequence are described in terms of their frequency content, amplitude, continuity and other shape descriptors. For example, one might describe a sequence as consisting of low amplitude, parallel continuous reflections, whereas another sequence might consist of high amplitude, hummocky discontinuous reflections. The thought (?hope) is that there is a link between seismic and depositional facies. For example, deep water homogeneous (i.e., little contrast in physical properties) muds that form a continuous blanket over the sea floor might be expected to be imaged as low amplitude parallel reflections. Submarine failure deposits might be expected to be imaged as discontinuous, perhaps high amplitude (if there is a mix of lithologies) reflections. By determining the relative position of the seismic facies within each sequence, one attempts to define depositional systems tracts, and depositional histories. Rock/sediment physical properties can sometimes be inferred (at least in a qualitative sense) in this way (Fig. 4.7).

During the stratigraphic interpretation, seismic reflections are traced on a seismic transect (perhaps on a mylar overlay with paper records) and then the interpretations are viewed independently of the data. This methodology can help the interpreter to identify boundaries between seismic facies, reflection termination geometries or other features of interest.

Finally, detailed analyses might lead to reflection character analysis. The objective here is to fully understand the links between seismic reflections and the rock physical properties and geometries. This is generally done through modeling of some sort, either by generating synthetic seismograms or by using seismic modeling packages. One might be interested, for example in the expected effects of changes in pore fluids with structural position, or the change from a massive sand to a series of interbedded sands and shales. The model results help the interpreter to understand what he/she is seeing in the data, and so to reap maximum benefit from the interpretation.

[3] We will ignore the controversies going on in sequence stratigraphic circles about the origins of sequences and the terminology employed to describe them.

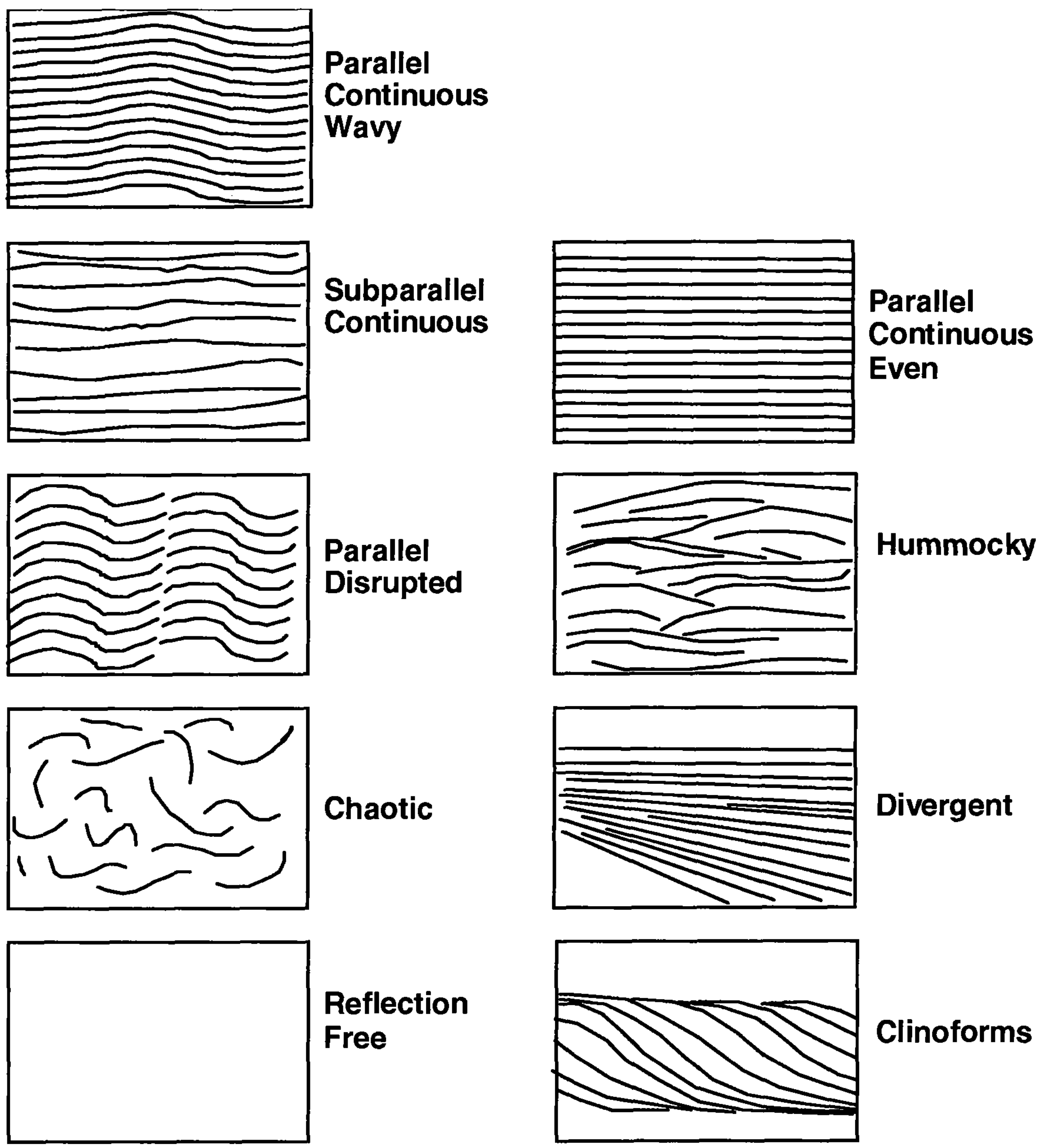


Figure 4.6. Selected reflection configurations (Mitchum et al., 1977)

Seismic Reflection Parameters

Facies Parameters	Geologic Interpretation
Reflection Configuration	Bedding Patterns Depositional Processes Paleotopography/erosion Fluid Contacts
Reflection Continuity	Bedding Continuity Depositional Processes
Reflection Amplitude	ρV Contrast Bed Spacing/Thickness Fluid Content
Reflection Frequency	Bed Thickness Fluid Content
Interval Velocity	Lithology Estimation Porosity Estimation Fluid Content
External Form and Linkages of Facies Units	Depositional Environment Sediment Source Geologic Setting

Figure 4.7. Physical properties that an interpreter might try to qualitatively evaluate from seismic characteristics ("attributes").

STRUCTURAL INTERPRETATION

In some respects, structural interpretations proceed in much the same fashion as stratigraphic interpretations. That is, one begins by defining the major patterns, then proceeds to add more and more detail. Some structural elements will become apparent during the stratigraphic interpretation. As a simple example, by tracing seismic horizons throughout a data set, it should become apparent whether one is dealing with a folded succession of rocks.

Faulting can be more problematic. One should try and define the major faults first, then add successive levels of detail. As the complexity of the faulting increases, so

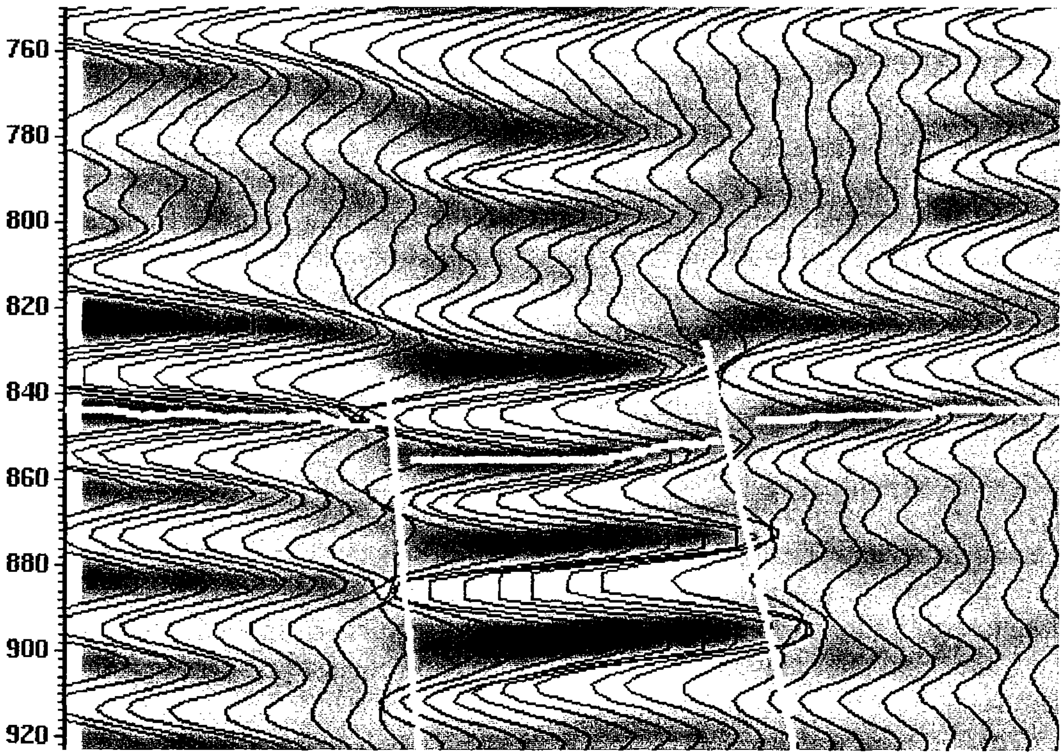


Figure 4.8. Seismic expression of a small graben. Note offset of reflections along the left fault, and change in reflection character along the right fault. Vertical axis in ms (TWT). Display is variable density overlain by wiggles. Based on Hart et al. (1996).

does the need to go back and forth between stratigraphic and structural interpretations. In some cases one needs to understand the nature of the faulting in order to be able to track seismic horizons from one fault block to another. Conversely, in other cases the detailed fault geometries cannot be defined until the stratigraphy has been determined. Knowledge of general tectonic setting and expected structural style can aid significantly.

The seismic signature of faulting is variable. In ideal cases, parallel reflections terminate against a planar or curviplanar trend (fault planes rarely produce reflections) and are uniformly offset in the adjacent fault block (Fig. 4.8). In unmigrated data, diffractions that line up can be indicators of faulting. Subtle dips in seismic reflections that line up from profile to profile could be indicators of small offset faulting. In principle, the minimum vertical offset that can be resolved is $^1/_4$ the wavelength (Sheriff and Geldart, 1995), although workstations are helping 3-D seismic interpreters to detect increasingly small-scale faults. Some advanced methods for fault detection using 3-D seismic data will be illustrated in Chapters 5 and 6.

MAPPING

For most work, the results of the interpretations on the vertically oriented seismic transects must be transferred to a map for presentation and, possibly, analysis in x,y space. The first step is to prepare a base map that shows the location of the seismic profiles. Once this step has been completed, values of a particular feature of interest are transferred from the interpreted seismic lines to the base map. For example, one might indicate the locations of faults (at a particular stratigraphic level) on the base map, then connect the faults up from line to line to obtain a fault map. Superimposed on the fault map one might transfer the thickness or structure as read from the seismic transects.

It should be reiterated here that the z axis on most seismic sections is time. Therefore, strictly speaking, a map that shows the variation in TWT to a particular reflection is a *time structure* map, rather than a true structure map (see Chapter 6). Additionally, a map that shows the difference in TWT between two horizons is an *isochron* map, rather than a true isopach map. The interpreter needs some means of converting from time to depth, generally involving checkshots and/or other means of determining interval velocities, in order to portray the seismically derived structure in depth units that are more familiar to the geologist or engineer. In addition to these types of maps, the interpreter may also wish to prepare maps of seismic facies or other features of interest.

PITFALLS

It must never be forgotten that the seismic profiles the interpreter works with incorporate artifacts of the way the seismic method works. Mistakes that he/she can make during the interpretation process are referred to as pitfalls, and even experienced interpreters are not immune to them. Only a few such problems are discussed here.

One family of pitfalls is due to velocity variations, both laterally and with depth. For an example of the effects of lateral velocity changes, consider a pinnacle reef of Paleozoic carbonates that is encased in shales. The carbonates will probably be denser and have higher velocities than the shales. As such, acoustic pulses traveling through the reef will go through it faster than through the shales. The reflection for a horizontal bed below the reef will consequently appear "pulled up" below the carbonate with respect to the shales forming a false structure. An interpreter might guess that the reef formed above a structural high, but he/she will be wrong. In other cases, a slow area might result in a velocity "push down" of the reflections beneath the body.

Velocity gradients can distort the geometry of faults (Fig. 4.9). The planar fault appears curved in a seismic transect because velocity increases with depth (at least generally) and so a constant thickness of rock is represented by a smaller TWT at depth than shallower. Note that in addition to the distortion of the fault geometry, the apparent thickness of beds (as measured in TWT) also decreases with depth.

Other errors can occur during the mapping process. Generally, the interpreter has a grid of seismic transects and he/she must "infer" (i.e., guess) at how features correlate from one line to the next. This problem is shown in Figure 4.10. On the left at top, the interpreter has posted the locations of faults on a grid of four seismic lines ("Observations"). Inspection will show that there are several different ways in which one might connect the faults from line to line. Similarly, image another grid of four seismic lines shown on the right side of Figure 4.10. Structural "highs" are observed for a particular horizon in the middle of lines 3 and 4, whereas "lows" are present in the middle of lines 1 and 2. The interpreter may wish to contour these observations to show a saddle (which would have little opportunity for being a structural trap for hydrocarbons) or a dome (which would have considerable opportunity for being a structural trap for hydrocarbons). Seismic data are often ambiguous in this way. The interpreter may have some additional information that might constrain his/her mapping, but the possibility of error remains. As we will see in a subsequent chapter, 3-D seismic data allow the interpreter to remove much of the ambiguity inherent in such exercises.

PERSPECTIVES ON THE INTERPRETATION

The objectives of the study need to be kept in mind at all times during the interpretation process. For example, does the study need to look at the entire stratigraphic column, or is there a specific stratigraphic interval of interest? Time spent building detailed sequence stratigraphic interpretations for 20 depositional packages is probably wasted if the intent of the study is to examine one specific interval. Alternatively, if a stratigraphic and structural framework already exist for an area, an

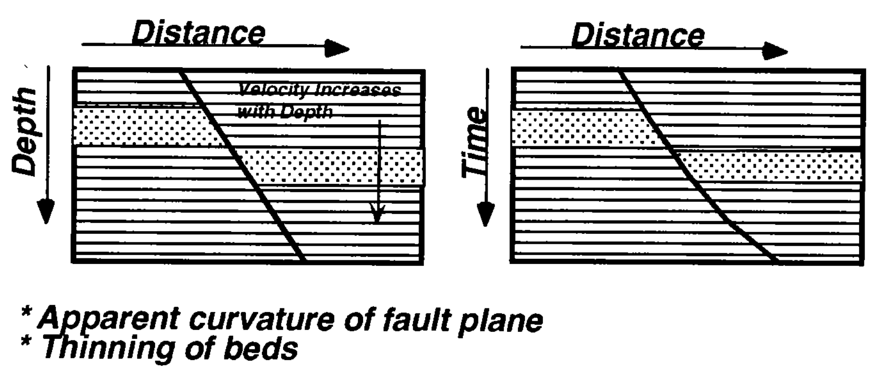


Figure 4.9. Ambiguities remain when using seismic data to map and interpret structural features. Since velocities are variable with depth, distortion of fault planes and bed thickness due to velocity effects is a possibility. This example shows a case where velocities increase with depth (the usual situation).

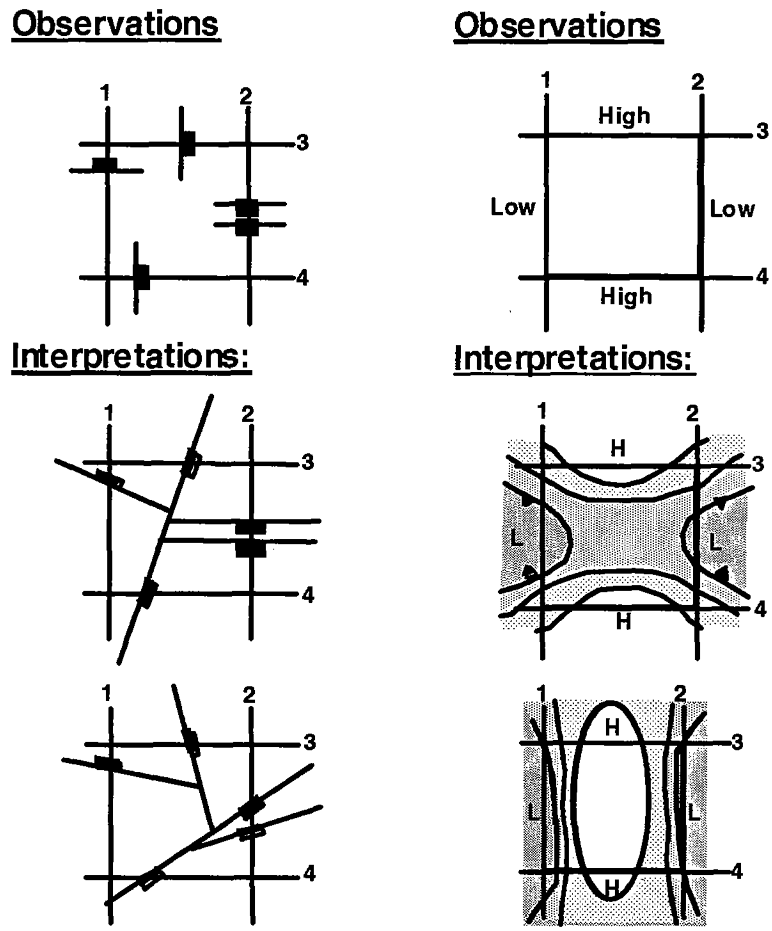


Figure 4.10. Ambiguities remain when interpreting features from 2-D seismic data. On the left, at top, faults have been interpreted on a grid of 4 intersecting seismic lines (1-4). Below are just two of the many possible ways one might correlate the faults. On the right, structural highs (H) and lows (L) are seen for a particular horizon on a grid of 4 seismic lines. Is the structure a saddle (middle) or a dome (bottom)? No scales are implied on either example.

interpreter might need to focus on the stratigraphic details. Even the objective of the study is likely to be affected by what work has been done previously, what data types are available, and what the current economic climate might be. Effectively organizing one's time can be a major interpretation aid.

In the petroleum industry, the objectives of a seismic project will generally consist of preparing increasingly finer detailed interpretations. For example, limited well log, biostratigraphic and other data might be available for a "frontier" area. In this case the interpreter's tasks might be to define the stratigraphic and structural history of a large area, and to recommend specific stratigraphic intervals for testing through drilling. The focus at this time might be on sequence stratigraphy and basin evolution. The study area might consist of a few hundred square kilometers. As drilling results become available, these new data will be used to confirm which stratigraphic horizons and/or structural features are likely to be of greatest interest. Production data might become available for specific intervals, in which case the focus might be on detailed mapping of structure, stratigraphy and possibly rock properties for those intervals. By this time, the study area might consist of only a few square kilometers, and the focus changed from "exploration" to "reservoir characterization". Similar "evolutionary paths" will probably apply in the academic world, the environmental industry, or anywhere that seismic data are interpreted.

CHAPTER 5: 3-D SEISMIC ACQUISITION, PROCESSING AND DISPLAY

SURVEY DESIGN

As mentioned at the beginning of the last chapter, the interpretation phase of a seismic project is considered by many to begin at the survey design phase. It is during this phase that the acquisition parameters are planned, and these can have a significant impact on what size of subsurface body can be imaged, how well they will be imaged and so on. These same considerations apply to the collection of 3-D seismic data as well.

To understand the need for 3-D seismic acquisition geometries, we need to go back to looking at how 2-D seismic data are acquired. It will be recalled (Chapter 3) that for most 2-D work the sources and receivers are spread out in a line. Reflections are assumed to come from the plane through the earth that corresponds to that line. In reality however, the acoustic energy from the shot expands out spherically (i.e., in 3 dimensions) from the source location. As such, reflected energy can be received from features (e.g., faults, reefs, channels) that are located outside of the plane of the section. These reflections, sometimes referred to as "sideswipe", will be recorded and show up in the 2-D seismic data. Since the true subsurface stratigraphy and structure are generally unknown, the features can be mistakenly thought to lie in the plane of the seismic section. In fact, the interpreter may have no way of telling where the reflections come from, even if he/she can recognize the features as sideswipe. The result will be a map that has subsurface features misplaced from their true locations. Several good applied and theoretical examples of this problem have been presented by Crawley Stewart (1995), French (1974), Yilmaz (1987), Brown (1999) and others.

Three-D seismic acquisition geometries actually exploit the spherical expansion of the acoustic pulse. A very simple acquisition geometry is shown in Figure 5.1. On land, receiver groups are typically spread out in lines that are oriented at 90° to the shot lines. Reflections from each shot are recorded by many geophones, producing a row of common midpoints that is perpendicular to the orientation of the source lines and parallel to the orientation of the receiver lines. By moving the shot location, a rectangular grid of common midpoints is generated (rather than a line of midpoints as in a 2-D survey). Typically, each survey consists of many parallel source lines and many parallel receiver lines that are oriented perpendicular to the source lines. In this way, individual midpoints are imaged by different combinations of sources and receivers, thus building up the fold (or "multiplicity") of the survey. Higher fold data, all else being equal, will result in a higher signal-to-noise ratio and, therefore, more interpretable seismic data. Experience has shown that the fold of a 3-D survey needs only to be about one half the fold of a 2-D survey to obtain the same interpretability (Hardage, 1997).

At sea, 3-D seismic data were originally acquired by ships towing airgun arrays and hydrophone streamers that sailed back and forth across the survey area. Increasingly

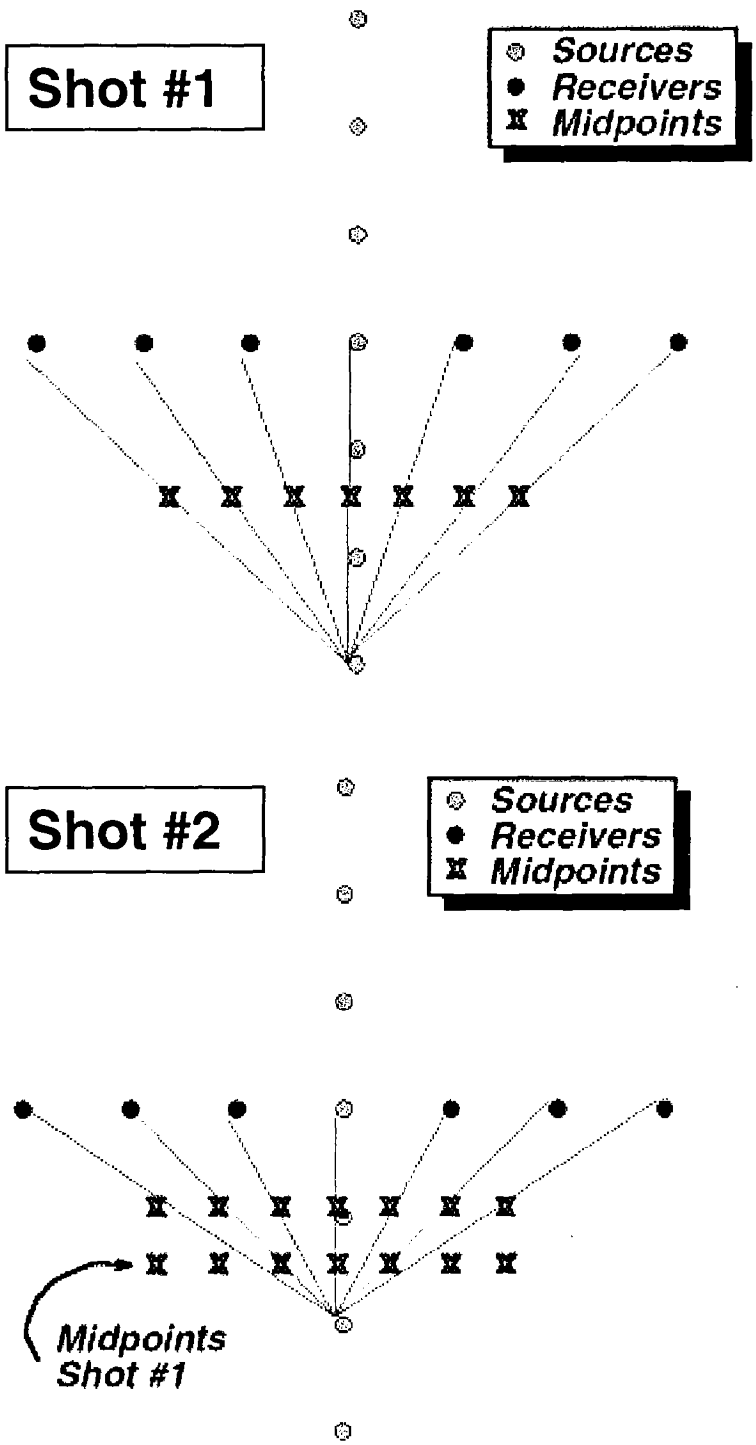


Figure 5.1. Simplified acquisition geometry for a land-based 3-D seismic survey. Each shot is recorded by a line of receivers, generating a series of midpoints. By moving the source locations, a rectangular grid of midpoints is generated. The distance between midpoints in the X direction is one half the distance between receivers, whereas the distance between midpoints in the Y direction is one half the distance between shotpoints. In a real survey, many parallel source and receiver lines would be used, building up the fold (and hence data quality) of the survey. Other, more complex, layouts are typically used in practice. Modified from Hart (1999b).

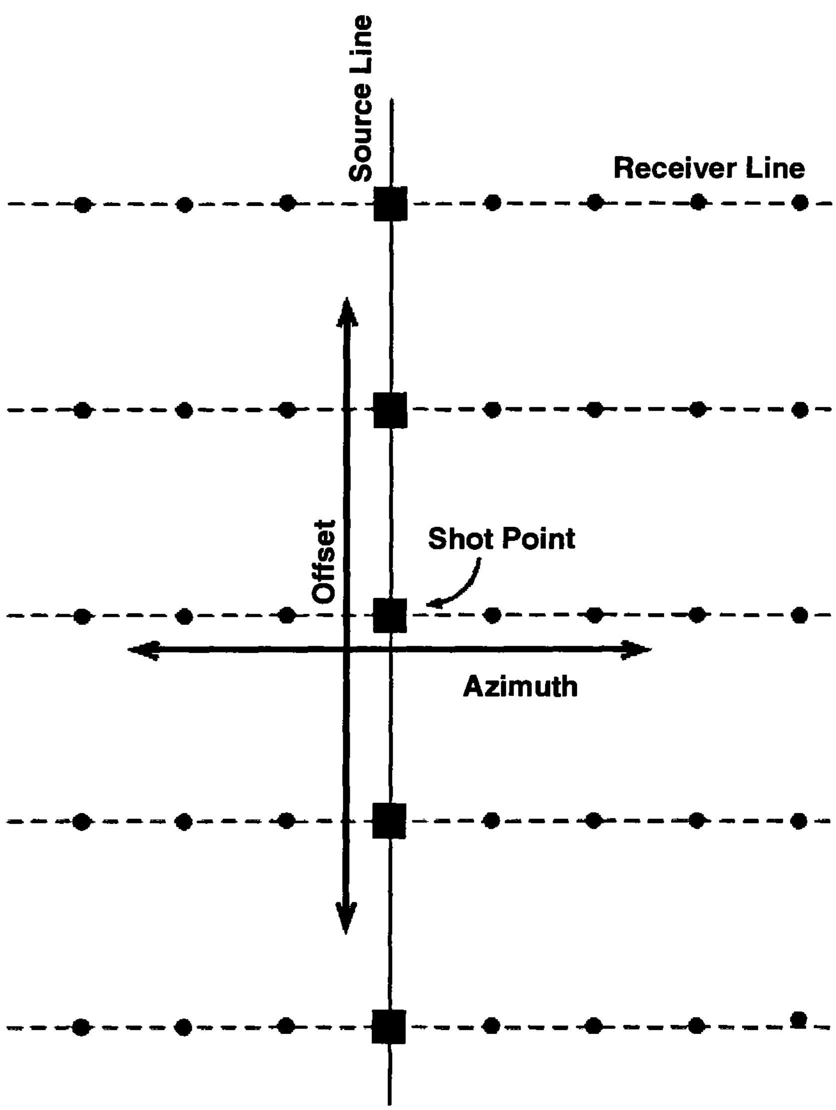


Figure 5.2. Hypothetical 3-D seismic survey design showing a single source line and multiple receiver lines (in reality, more than one source line would typically be employed). For each shot, the "offset" describes how far away receivers are activated ("listening") in a direction parallel to the source line. The "azimuth" is an angular measure that describes how far away receivers are activated in a direction perpendicular to the source line orientation. Whether one chooses to acquire far offsets and wide azimuths, near offsets only and narrow azimuths, or some other combination depends on factors such as survey objectives, subsurface geometry, costs, etc. and will vary from survey to survey.

though, innovative techniques such as using two vessels simultaneously, or implanting geophones on the sea floor, are being developed and exploited.

The spacing between the midpoints in the receiver direction is one half the distance between the receivers, while the spacing in the source direction is one half the distance between the source locations (Fig. 5.1). For example, assuming that source and receiver locations are both at 60 m intervals, midpoints (or traces) will be generated every 30 m x 30 m. In this case, each seismic trace represents an area or "bin" of 30 m x 30 m. The bin size might be rectangular, rather than square, if the distance between source and receiver locations is not identical.

The choice of seismic source and receiver spacing, and hence bin size, affects the interpretability of the final 3-D seismic volume. As a rule of thumb, most interpreters will want to see a stratigraphic feature on at least four adjacent traces in order to ensure consistent interpretability (Hardage, 1997). For example, if one is exploring for channel sandstones, and depositional models suggest that the channels are approximately 100 m wide, then ideally the bin size would be no larger than 25 x 25 m. Signal-to-noise ratio of the data and the interpreter's skill level are two other important factors that affect whether stratigraphic or structural features will be recognized.

Ideally, the fold will be uniform throughout the survey area. Variations in fold can lead to variations in reflection amplitude, continuity, or other attributes that might be mistaken for changes in subsurface geology. The range of offsets used in the processing phase should also be as uniform as possible, as should be the range of azimuths (Fig. 5.2). As recalled from Chapter 3, the offset refers to the distance along the shot line that receivers are active ("listening") for any given shot. The azimuth refers to the distance away from the source line that receivers are active. If only those receivers close to the source line are active for a given shot, then the survey would be considered "narrow azimuth", whereas if receivers far away from the shot line are active, then the survey would be referred to as "wide azimuth". Depending on the objectives of the study, a narrow or wide azimuth (or near or far offset) survey might be appropriate. In some cases, a company might record a wide range of offsets, then have the data processed into three distinct seismic data sets: a) a narrow azimuth data set, b) a wide azimuth data set, and c) a data set that was processed using the full range of azimuths (or offsets).

There are many types of 3-D survey design. Wright (1995), Evans (1997) and Hardage (1997) discussed this topic. Seismic acquisition contractors have software that will allow them to test different survey designs to see which is most appropriate for a particular data collection effort. Typically, more than one survey design can be created that will conform to the interpreter's needs.

3-D PROCESSING (MIGRATION)

In most respects, the processing of 3-D seismic data proceeds the same way as the processing of 2-D data. The biggest difference is between the migration (2-D versus 3-D) that is done to the data. We need to back up a bit and look at 2-D seismic acquisition and processing in order to understand the need for 3-D migration.

Two-dimensional seismic data are collected with the source and receivers strung out in a line (Chapter 3). Migration is used during processing to reposition subsurface reflections to their correct locations. Earlier in the chapter we discussed sideswipe, reflections that come from out of the plane of the seismic profile. A 2-D migration cannot reposition this reflected energy to its true subsurface location, which is outside the plane of the profile. The Fresnel zone is collapsed during 2-D migration, but only in the direction of the profile thus becoming an elliptical zone (Fig. 5.3).

If, however, instead of a single seismic profile we had a regular grid of seismic traces, we could perform the migration twice, once in the source line direction, once in the receiver line direction. The result, if properly achieved, would be a 3-D migration[1] that would truly collapse the Fresnel zone down to a single point (Fig. 5.3). The application of 3-D migration accurately repositions reflection energy to its true subsurface location. Transects through a properly migrated 3-D seismic volume will only show features that are truly in the plane of the section. As such, a vertical transect through a 3-D seismic volume is a better, more accurate image than an equivalent 2-D seismic transect.

Migration performed on the data prior to stacking ("pre-stack" migration) is becoming increasingly commonplace, but the relatively high cost of this work prevents many companies from exploiting it. Similarly, this discussion has dealt with migration in the time domain. If a good velocity model for an area can be constructed, it is possible to migrate in the depth domain, producing a data volume that has a vertical axis in depth units (feet/meters) rather than in time. Again, although this type of processing is becoming more commonplace, it is not yet standard practice. Accordingly, we will focus on time migrated data in the remainder of this course.

Eaton et al. (1997) noted that most reflection seismic processing is geared towards enhancing continuous features such as bedding. However, in crystalline terranes scattering effects from localized bodies should be of paramount importance. Unmigrated 3-D seismic volumes may therefore be of greater interest in the mining industry than migrated volumes since they can help interpreters to recognize scattering anomalies (diffractions) that might be produced by features such as ore bodies.

THE 3-D SEISMIC DATA VOLUME

Once the data have been processed, the result is a digital data set that represents a volume of seismic data (Fig. 5.4). Each bin in a 3-D seismic volume (having x and y dimensions that are defined primarily by data acquisition operations, see Figs. 5.1, 5.2) is represented by a single seismic trace conceptually centered in the middle of the bin. Each trace in turn is divided into equal increments in the z direction that define the sampling interval. For petroleum exploration purposes, the sampling interval is typically 2 ms or 4 ms. The result is that the 3-D seismic volume may be thought of as a series of

[1] Although 3-D migration was originally a two step procedure as described here, one step 3-D migration is becoming more commonplace.

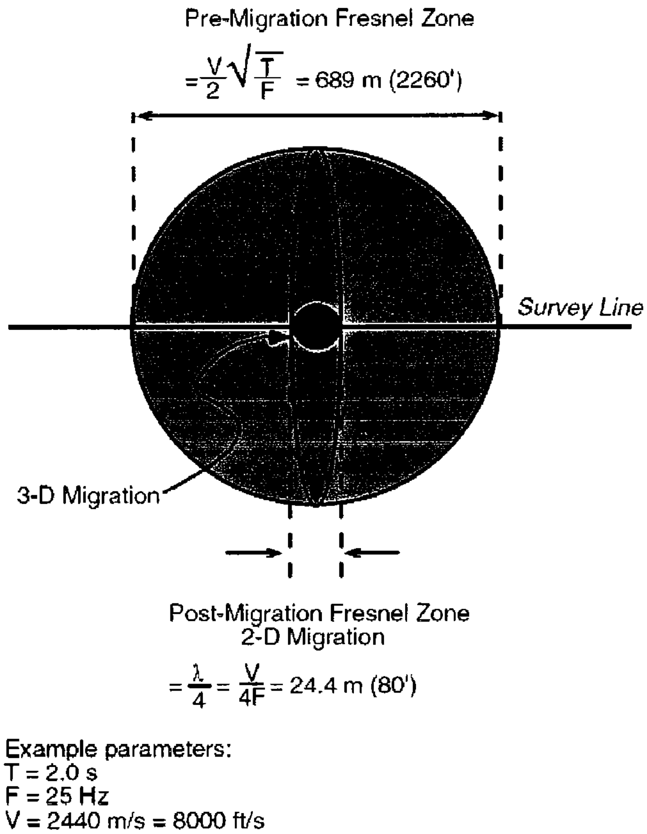


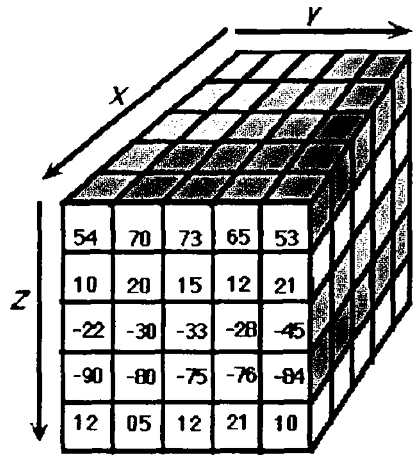
Figure 5.3. How 2-D and 3-D migration affect the size of the Fresnel zone. Based on Brown (1999).

cubes, or voxels ("volume element" - a term analogous to the 2-D pixels of remote sensing), each of which stores a particular amplitude value. Each voxel then is associated with four pieces of information: the x,y and z location and the amplitude value.

Using modern computer graphics capabilities, it is possible to visualize and interpret the seismic data in a variety of ways (Fig. 5.5). The 3-D seismic data volume is stored in digital (binary) format on disk. The types of displays that can be generated depend on the software and hardware capabilities of the interpreter, but generally can be grouped into a few distinct categories that will be discussed next.

Vertical Transects

Vertical transects through a 3-D seismic volume (Figs. 5.5a-d, 5.6a) look analogous to 2-D seismic profiles. In fact, some of the transects we have seen so far (Figs. 3.9 and 4.8) were actually transects extracted from 3-D seismic volumes. These transects differ from 2-D lines in that their location and orientation are decided by the interpreter in an interactive manner, rather than being constrained by the original seismic survey line orientation as is the case for 2-D data. Since the data are stored digitally, the interpreter can also zoom in on small portions of the seismic data, or zoom out to see the larger structural and stratigraphic framework. Most software packages allow the user to



XY Grid: Bin size (e.g., 30 x 30m)

Z Increment: Sample rate (e.g., 2 or 4 ms)

Amplitude Range:
8 bit - 127-> - 128
16 bit - 32767 -> -32768
32 bit - 2147483647 -> - 2147483648

Figure 5.4. The 3-D seismic volume concept. The data consist of vertical traces, "columns" in the figure, each of which represents a specific surface area or "bin". Each bin is centered on a midpoint (Figs. 5.1, 5.2). In the Z direction, each trace has been digitally sampled according to the user-defined sampling rate. The x, y, and z increments define a series of box-like "voxels" each of which stores a single amplitude value. When viewing the data, we look either at wiggle traces or variable density displays (side and top of the cube) rather than the digital amplitude values themselves. Modified from Hart (1999b).

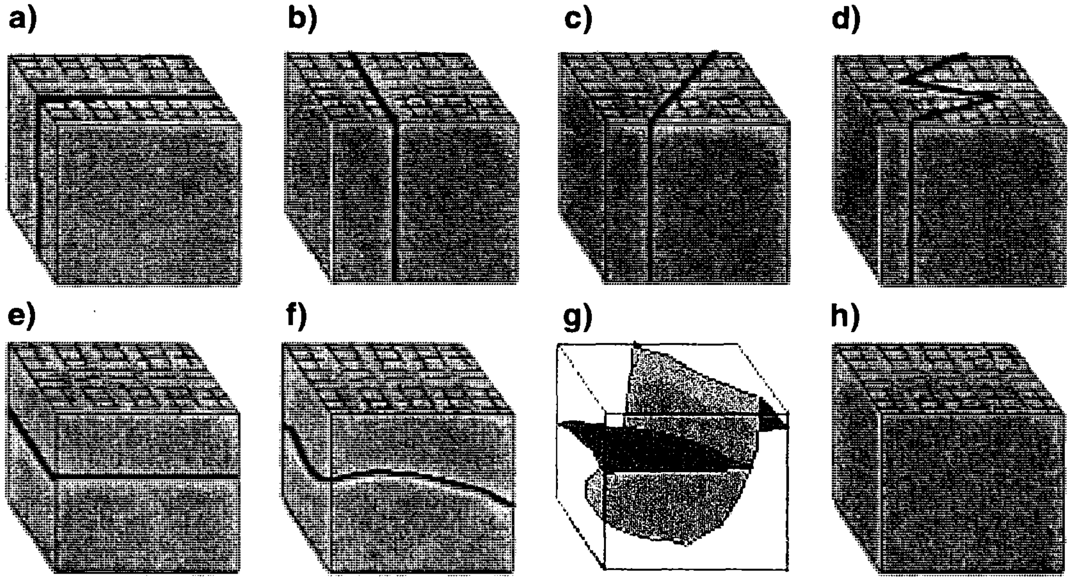


Figure 5.5. Schematic representation of different types of 3-D seismic displays that can be viewed during an interpretation. a) inline/line (orientation of receivers in a land survey), b) trace/crossline (orientation of sources in a land survey), c) arbitrary line, d) zig-zag/multipanel display, e) time slice, f) horizon slice, g) perspective view, and h) cube display. Modified from Hart (1999b).

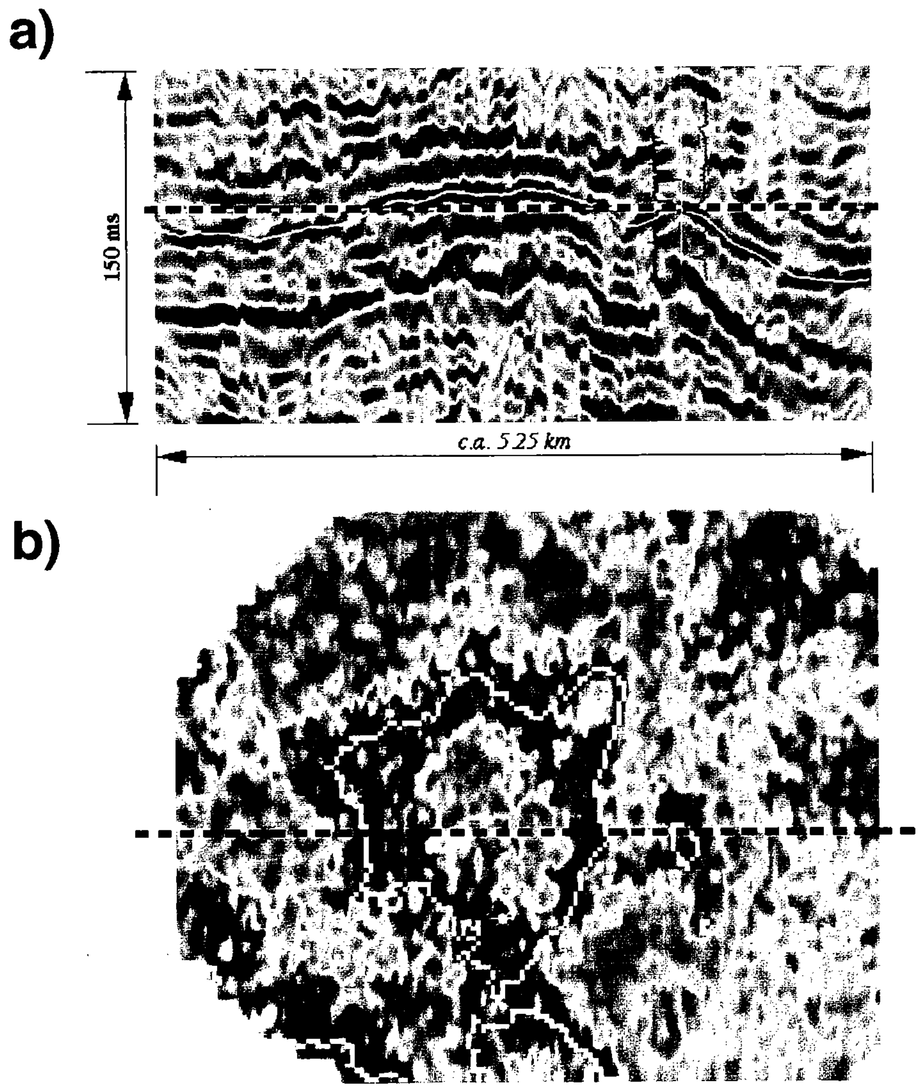


Figure 5.6. a) Vertical transect through 3-D seismic volume showing Ordovician carbonate buildup from the Williston Basin. Top of buildup shown by white horizon. Well at right shows gamma ray (left) and sonic (right) logs. Dashed line shows level of time slice shown in 5.6b. b) Time slice through 3-D seismic volume showing outline of top of the carbonate buildup (white line). Note presence of several stuctural culminations. Dashed line shows location of transect shown in 5.6a. Horizontal scale identical for both images.

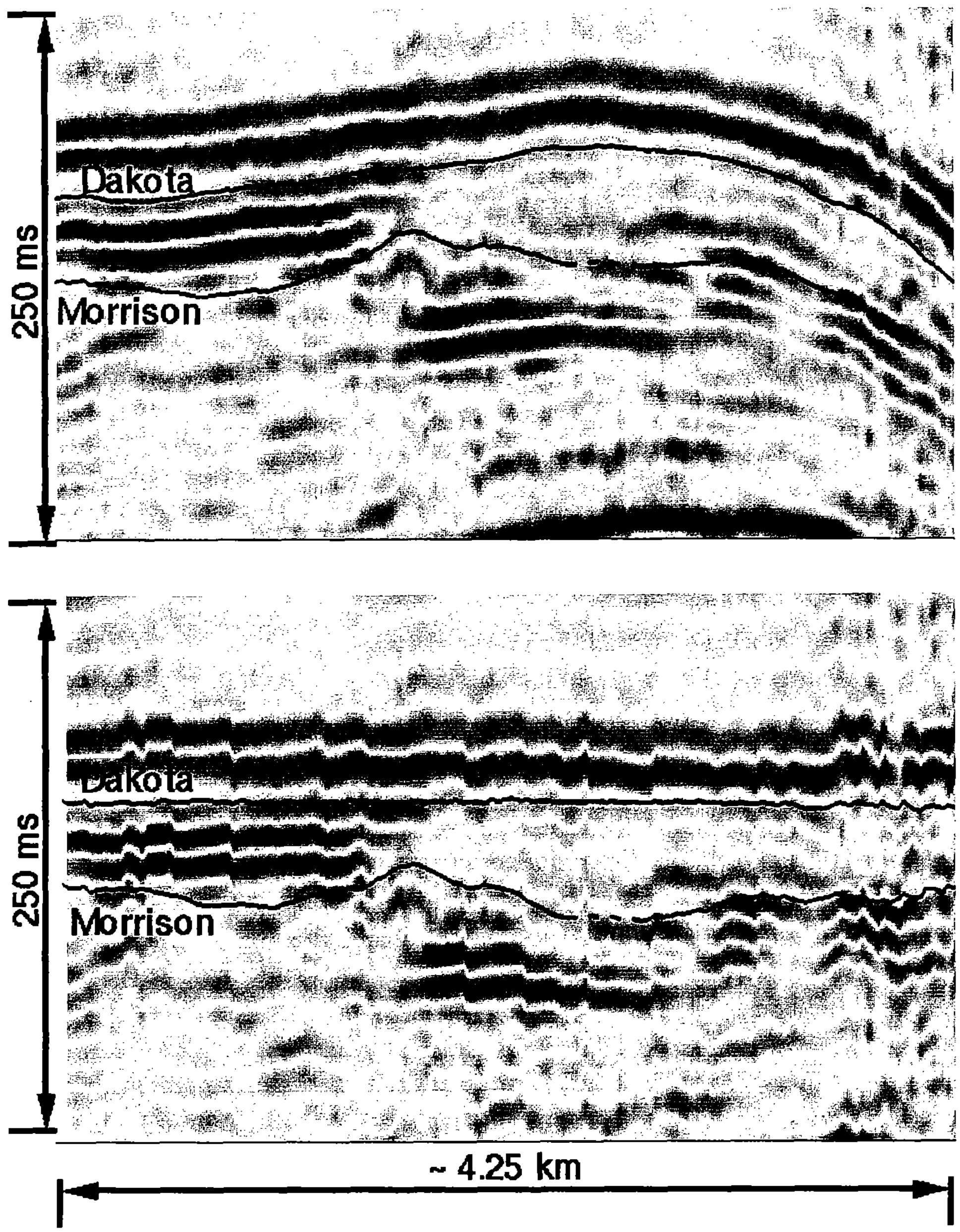


Figure 5.7. The upper image shows the current structural configuration of the top and base ("Morrison" pick) of the Cretaceous Dakota Formation in an area of the San Juan Basin. The strata have been folded by Laramide (early Tertiary) tectonism. By flattening on the Dakota pick, the true geometry of the unconformity at the base of the unit (top of Morrison) becomes more readily visible.

display vertical transects: a) in the inline or line direction (usually this is the orientation of the source locations in the 3-D acquisition program), b) in the crossline or trace direction (the orientation of the receiver lines), and c) arbitrary lines that represent transects through the data in any direction decided upon by the interpreter. The arbitrary line may consist of a single transect or a series of continuous transects that zigzag their way through the data set (sometimes called a multipanel display; Fig. 5.5d). Arbitrary lines are used when the interpreter wishes to view the true geometry of structural or stratigraphic features that are oriented obliquely to the line or trace orientation (see below) or when wishing to integrate borehole log information from more than one well with the seismic data. With vertical transects, the data can be flattened on a selected horizon to more clearly view true stratigraphic relationships in areas that have been structurally deformed (Fig. 5.7). This latter process is akin to using a formation top or log pick as a datum to construct a stratigraphic cross-section (using well logs or outcrops) rather than generating a structural cross-section.

Horizontal Sections

These displays, known as time slices, represent a slice through the data at a given TWT (constant z coordinate) through the data (Figs. 5.5e, 5.6b). Note that because rock velocity varies laterally, a time slice does not necessarily represent a constant subsurface depth. The display is somewhat analogous to a geologic map. The difference is that, instead of viewing how stratigraphic units intersect the ground surface (which may or may not be planar), the interpreter sees how the seismic manifestation of the stratigraphy intersects an arbitrarily selected constant time below the seismic datum. In both cases however, the thickness of any given stratigraphic unit on the display (map) is a function of the stratigraphic dip (for a constant thickness, a less steeply dipping bed/reflection will appear wider; Fig. 5.8) and thickness/frequency of the stratigraphic unit.

Although Brown (1999) and others recommended using time slices for horizon interpretation, most interpreters tend to concentrate their use of these displays on interpreting faults - especially where stratigraphic dips are small (i.e., relatively undeformed basins). The utility of time slices for horizon interpretation is greatest when beds have a pronounced dip. In this case, horizon mapping on time slices can be a quick way of generating time structure maps for those horizons. With the advent of automatic horizon tracking and interfacing of seismic interpretation with mapping packages (see below), time structure maps can, in most circumstances, be generated just as readily by basing most interpretation on vertical sections.

Horizon/Fault and Map Displays

These displays show characteristics of horizons or faults that have been interpreted in a seismic volume. They allow the interpreter to view spatial relationships in two dimensions. Time structure of an interpreted horizon (showing locations of faults, folds and structural dips) is perhaps the most commonly viewed display (Figure 5.9). If desired, the interpreter can interactively adjust the color scale bar to detect structural relationships (e.g., areas with subtle closure that could act as hydrocarbon traps) that might otherwise be overlooked.

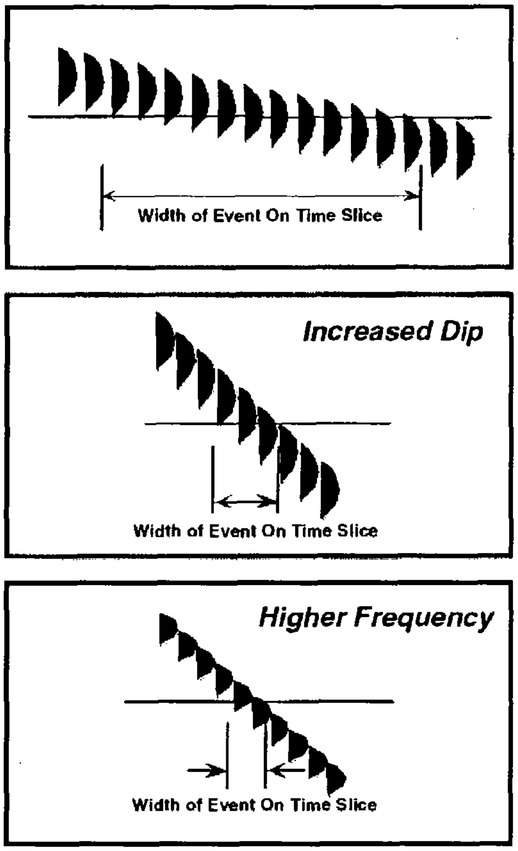


Figure 5.8. Schematic diagram illustrating the effects of stratigraphic dip (top and center image) and reflection frequency (center and bottom image) on the width of a reflection viewed on a time slice. Based on Brown (1999).

In many areas, the seismic amplitudes associated with particular stratigraphic horizons may be of significance (e.g., Enachescu, 1993). For example, 'bright spots' are associated with hydrocarbon accumulations in some areas, and interpreters will examine map displays of the amplitude of seismic horizons to look for stratigraphic or structural features that might be hydrocarbon traps. Displays of horizon amplitudes are sometimes called horizon slices (Fig. 5.5f). Channel sandstones and other stratigraphic features may also, under some circumstances, be identified using seismic amplitudes (e.g., Hardage et al., 1994; Brown, 1999). In some settings it may be desirable to superimpose structural contours onto amplitude displays (Fig. 5.10).

Bouvier et al. (1989) present an example of the use of fault slices to examine fault sealing capabilities of Tertiary faults in the Niger Delta area. Fault slices are generated by extracting amplitudes along a surface that is parallel to a fault plane, then projecting those data onto a vertical surface. By generating fault slices in both the hanging wall and footwall, the juxtaposition of lithologies across the fault can be assessed. In this way, it might be possible to judge whether a fault is a barrier to fluid flow (e.g., sand on shale contact) or not (e.g., sand on sand) along the entire fault plane.

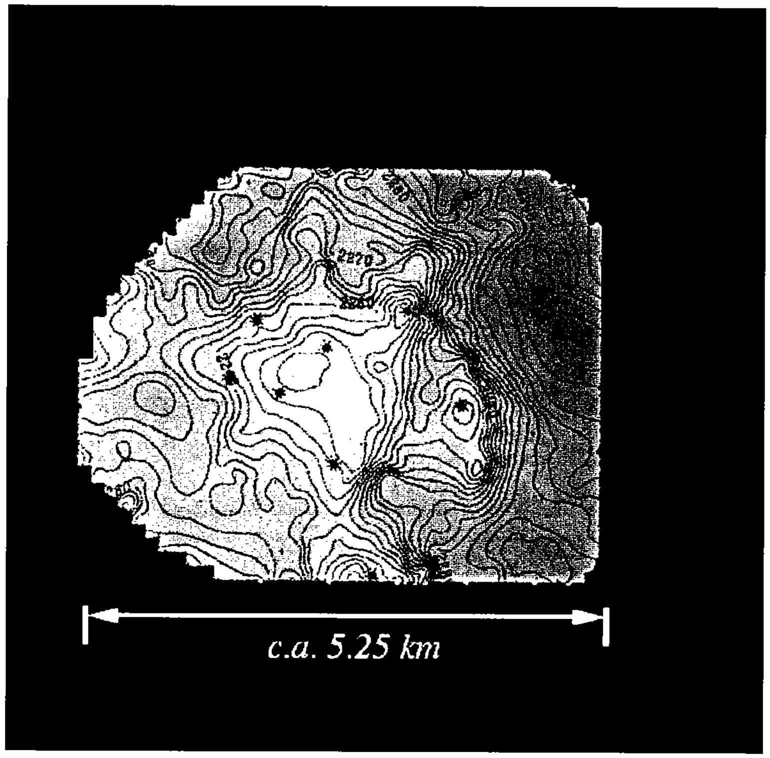


Figure 5.9. Time structure map of top of Williston Basin carbonate buildup shown in Fig. 5.6. Contours in milliseconds (ms) two-way traveltime (TWT). The level of structural detail shown is much greater than could be mapped using well control (star symbols) alone.

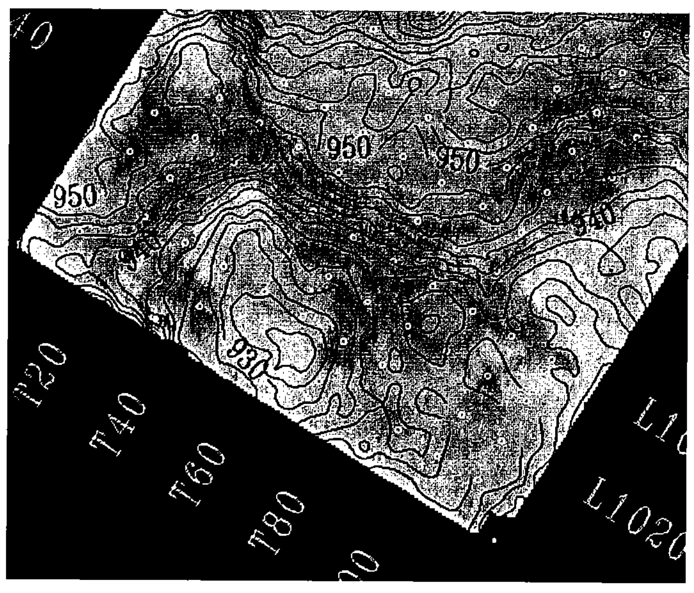


Figure 5.10. Time structural contours (ms TWT) of Entrada horizon, a Jurassic aeolian deposit from the San Juan Basin, superimposed on horizon amplitudes (horizon slice). Lower amplitudes shown in lighter gray. The horizon dims on structural highs, as predicted for productive Entrada buildups. Seismic map is approximately 3.5 km along lower left boundary.

Although strictly not related to one horizon, map displays are also employed to view thickness, in time (isochron) or depth (isopach) units, between two stratigraphic horizons. Other "interval attributes", such as the maximum amplitude between two horizons, may also be viewed and interpreted in this fashion. These and other interval attribute analyses are sometimes employed in a 'quick look' fashion to identify stratigraphic configurations or rock properties elements that warrant detailed investigation. Horizon attributes (Chapter 6) are also viewed in map views.

Perspective Displays

This type of display (Fig. 5.5g, 5.11) is used to show horizons, faults and well data as 3-D perspective views that may be rotated to help the interpreter assess spatial relationships in 3-D. Additionally, they may be employed to quality check interpretations; for example, to ensure that horizon or fault picks are physically plausible (i.e., they do not intersect in impossible ways). With some interpretation packages it may be possible to superimpose 'attributes' such as seismic amplitude, isochrons (thickness, in time units), etc. on top of the 3-D surface to more easily evaluate, for example, possible relationships between amplitudes and structure. Illumination angles and opacity might also be adjusted to help detect subtle structural trends (Fig. 5.11).

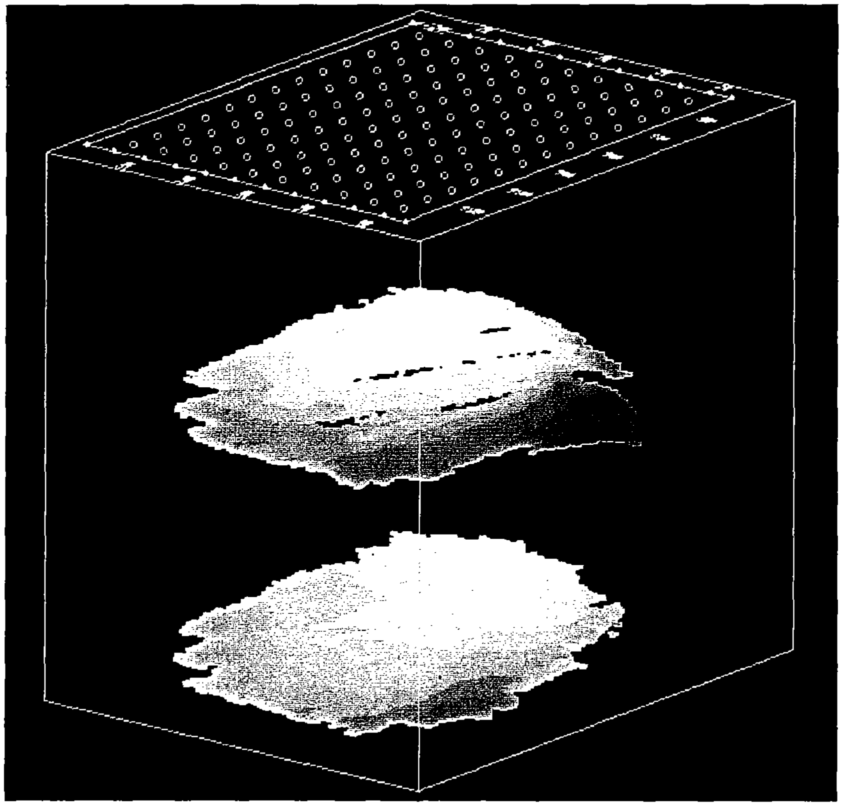
Cube Displays

This type of display (Fig. 5.5h, 5.12) allows the interpreter to view the seismic data as a volume. By scrolling through the data cube (front to back, side to side, and top to bottom), the interpreter can quickly get an intuitive feel for the broad scale stratigraphic and structural configuration of a study area before beginning detailed interpretation. Scrolling through the data can also help him/her to make picks where the data are ambiguous. Interpretations (fault and horizon) can be made on the faces of the data cube. The data may be 'clipped' in various ways to visualize specific aspects of the data set that will assist in the interpretation.

Most cube displays show the faces of the data volume, while data behind those faces remain out of sight. Voxel rendering technologies allow the interpreter to make specific ranges of amplitudes transparent, leaving only narrow ranges of amplitudes visible (Kidd, 1999). The objective is to facilitate the viewing and interpretation of subsurface features that have specific amplitude characteristics. This type of display can be especially useful, for example, when planning a deviated wellbore so that it penetrates multiple pay zones that manifest themselves as "bright spots" (amplitude anomalies) at distinct stratigraphic levels. Kidd (1999) showed how voxel rendering can be used to identify stratigraphic and structural features (Fig. 5.13).

Combination Displays

Some software applications allow several different types of data and interpretations to be visualized together (Fig. 5.14). For example, an interpreter may wish to examine well paths, interpreted horizons and some seismic data together. As is the case with the other types of displays, the objective is to visualize the geology,



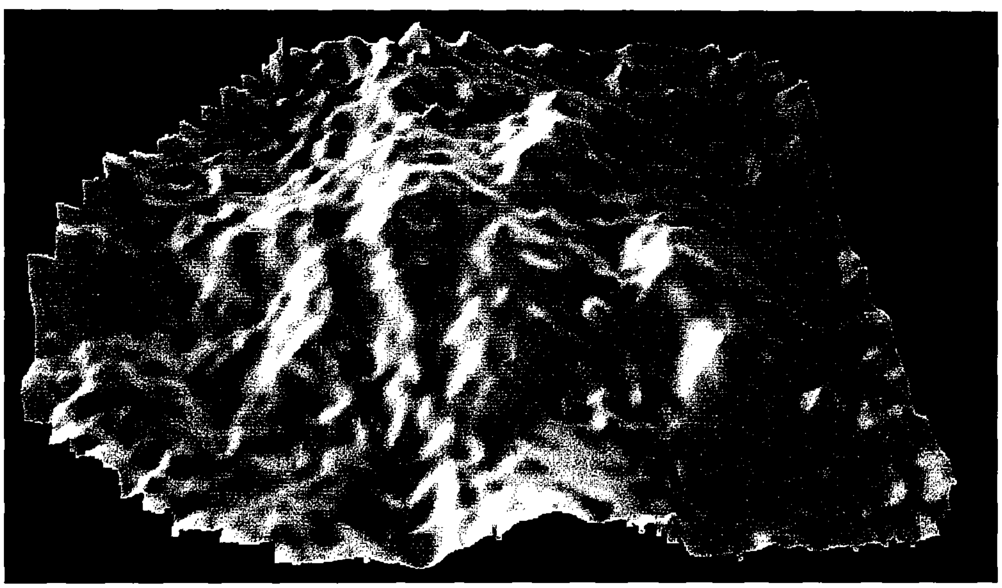


Figure 5.11. Two different perspective views. The upper image shows Cretaceous (top) and Pennsylvanian (base) horizons that have different structural configurations at the two levels. Gray tones show relative elevation at each level. Area is approximately 4.5 x 4 km. The lower image shows the top of the carbonate buildup seen in Figs. 5.6 and 5.9. In this case the illumination has been adjusted to be primarily from the west (left), revealing structural trends that may not be apparent in the time structure map (Fig. 5.9). The two images were produced using different software packages that have different capabilities.

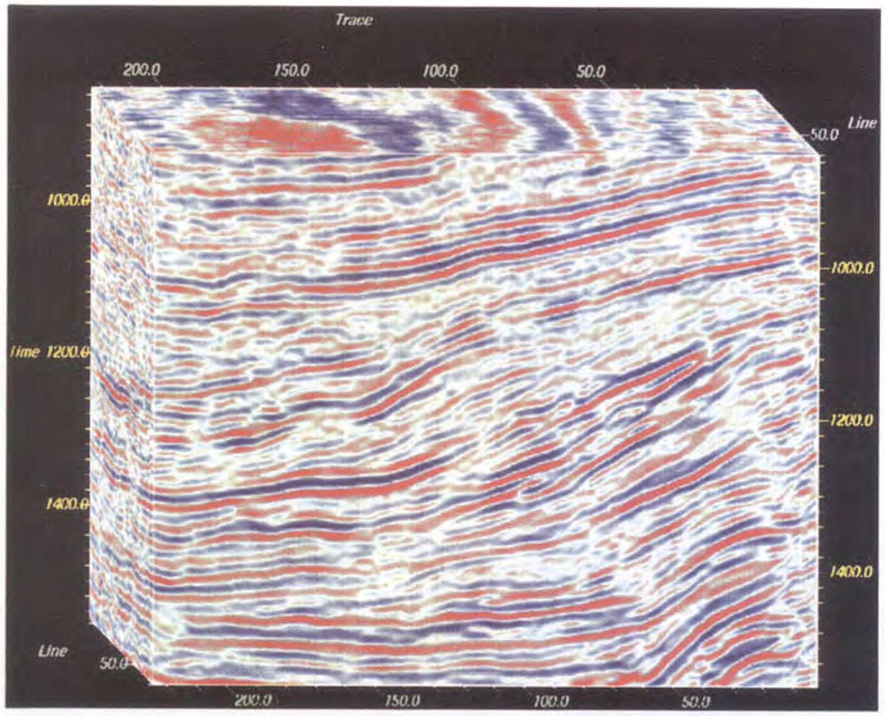


Figure 5.12. Sample cube display. Data show prograding Permian shelf margin from the Delaware Basin. By interactively scrolling through the data (side to side, front to back, top to bottom) the interpreter can quickly assess changes in stratigraphic or structural style throughout the data volume.

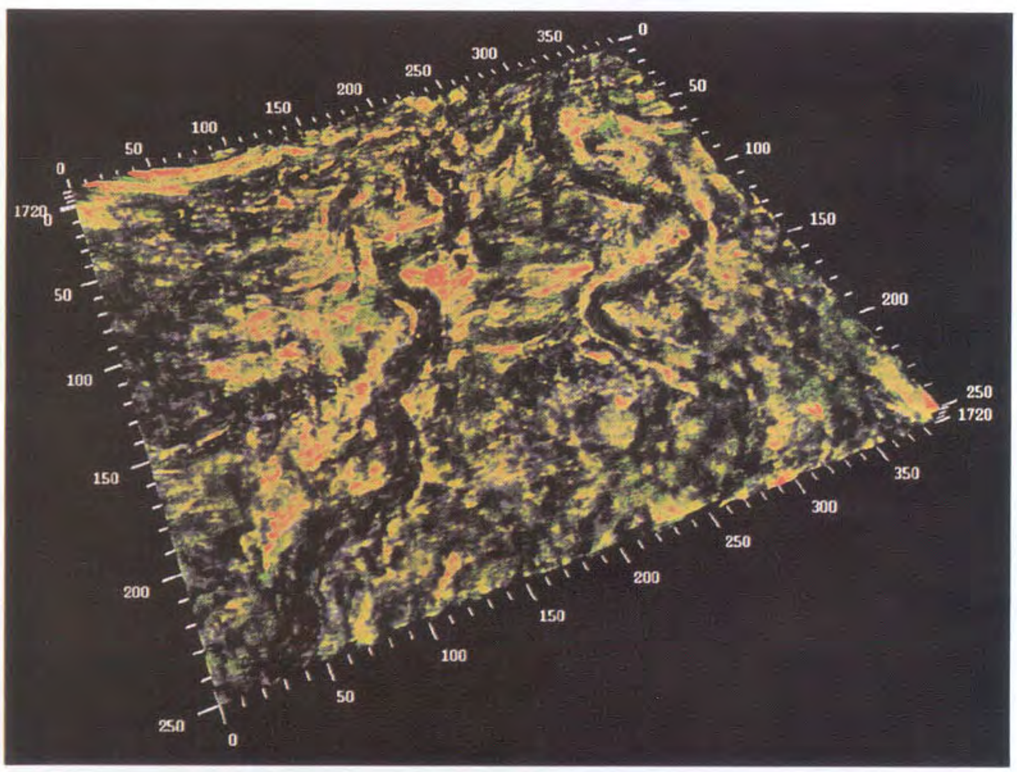


Figure 5.13. Voxel display showing sinuous channels. This type of volume visualization can reveal spectacular images of stratigraphic features (if they are present!). From Kidd (1999).

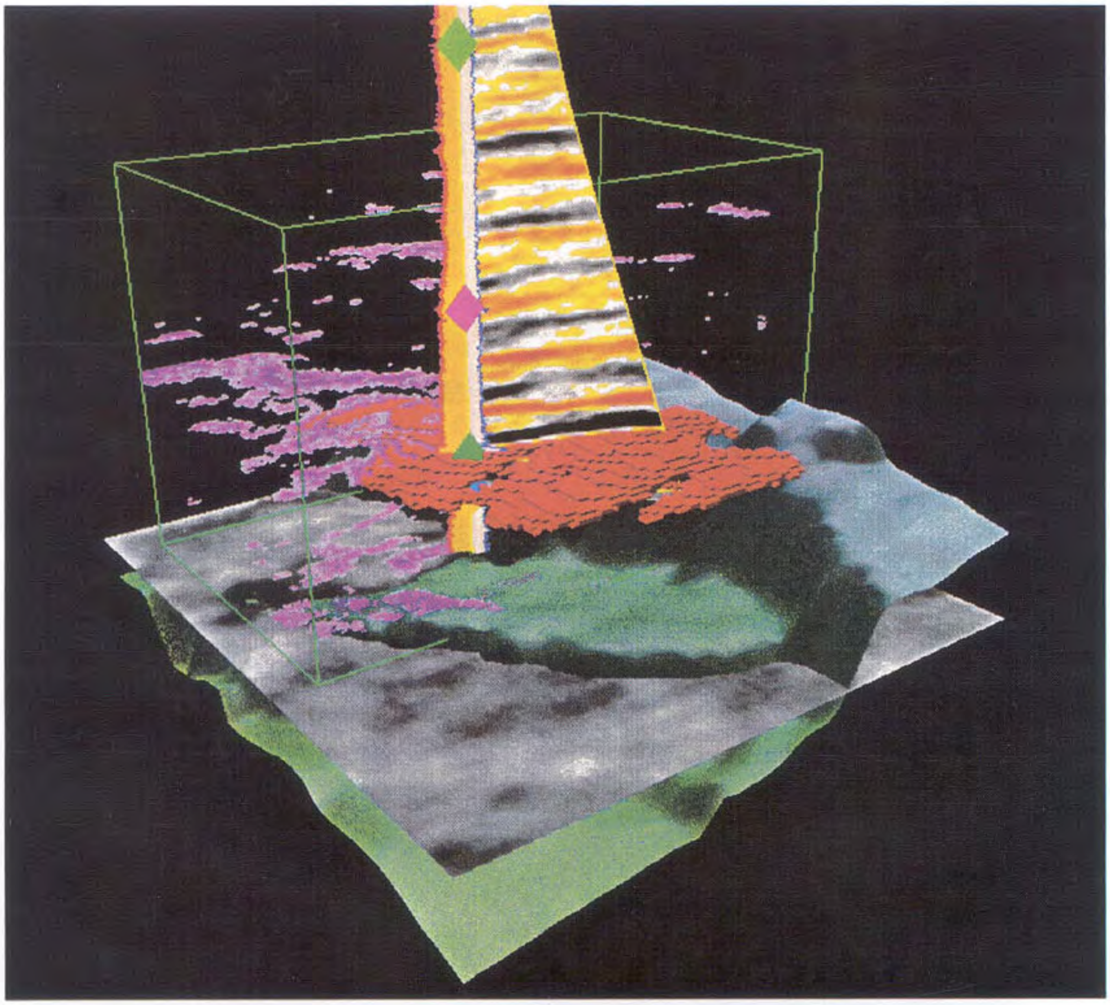


Figure 5.14. Combination display showing interpreted horizon (green), a time slice (grey), two voxel "clouds" (magenta and red) a wellbore with digital logs (diamonds are geologic markers) and a portion of seismic data. This type of display can help the interpretation team, engineers, management, investors or others to quickly grasp subsurface spatial relationships. Image courtesy of GeoQuest.

engineering and other types of data in 3-D so that spatial relationships, potential interpretation errors, or other potentially significant features can be evaluated. Another important component is that these displays help the interpreter to present his/her results to others (e.g., co-workers, management, investors) who have not been active in the interpretation process, but who will be making decisions (e.g., to drill or not) based upon the interpretation results.

Virtual reality technologies are being explored that allow the interpreter to view the data in 3-D or even to "enter" the seismic volume (Dorn, 1998). The idea is that these visualization technologies will help the interpretation team to see the 3-D complexities of the subsurface in three dimensions, allowing better interpretations and better decisions to be made. At the moment, application of these technologies is limited to situations where project economics make the expense practical.

SUMMARY

This chapter has highlighted three significant advantages of 3-D seismic data over 2-D seismic or other data types. These are:

- Complete (or nearly so, given the bin size) subsurface coverage of the 3-D survey area. This allows stratigraphic and structural features to be continuously mapped, without making the interpreter "guess" about how they should be correlated as would need to be done when working with 2-D seismic or log data (Chapter 4).
- 3-D migration. This processing step, when properly achieved, repositions reflected energy to its correct subsurface location. The result is a seismic volume that accurately portrays the subsurface location of stratigraphic and structural features. Note that pre-stack depth migration may need to be performed in areas of complex geology or subsurface velocity regimes (e.g, adjacent to, or below, salt domes, thrust belts).
- Flexibility of data display. With 2-D seismic data the interpreter is constrained to looking at the seismic lines in the manner in which they were acquired. The 3-D seismic volume (combined with appropriate software) allows the interpreter to interactively choose how to view the data and interpretations. In this way he/she is able to optimize the display in order to view and interpret stratigraphic or structural features of interest.

For all of these advantages, the limitations of the seismic method must be remembered. These include:

- The data are, most commonly, in the time domain. This leaves open the possibility that velocity artifacts might distort true subsurface structure (e.g., Fig. 4.9). Even depth-migrated data are only as accurate as the velocity model that went into their construction.

- Limits on resolution (vertical and lateral) need to be appreciated in order to determine whether the data will allow the interpreter to actually see the features of interest (Chapter 2).
- The non-uniqueness of the seismic method. Changes in amplitude (or other attributes) can be produced by a variety of factors, such as changes in fluid content, porosity, bed thickness or even data acquisition parameters. As such, it is typically not possible to predict lithology, porosity, fluid content, etc. by looking at amplitude data alone.
- Seismic data cannot find resources (gas, oil, water, ore bodies etc.) where they do not exist. "Failure" of an interpretation program to find such commodities does not necessarily imply that the methodology is lacking.

To combat these limitations, it should be remembered that seismic interpretation is part science and part artistry. A good interpreter needs to be able to integrate data and concepts from a wide variety of sources (Fig. 1.2) and apply liberal amounts of intuition (typically gained from experience both with the rocks/sediments being studied and the software being applied). This integrative interpretation procedure is discussed in the next chapter.

"Failed" 3-D seismic surveys are those that do not provide answers, or provide wrong answers, to the questions that were originally posed. This can be the result if the surveys were collected and/or processed improperly. As such, it is important for the interpreter, data processor and acquisition people to be in close communication during all phases of the project in order to assure that the right questions are being asked and answered. Note too that the existence of 3-D data coverage over an area does not necessarily imply that it is not worth collecting another 3-D data set over that area. It could be that acquisition parameters of the original survey were incorrect for the new project. For example, the original survey might have been after deep targets and the frequency content is insufficient to resolve shallow thin beds. Perhaps the bin size was too great in the original survey. In areas of complex geology, the acquisition design for the first survey may not have been optimal.

No mention has been made so far about when and where to collect 3-D seismic data. Ideally, as academicians, petroleum geologists, environmental consultants, etc., we could collect data volumes everywhere and anywhere. Unfortunately, the technology is expensive and we need to make choices. Some insights from the petroleum industry are instructive.

To begin, we need a reason for collecting a 3-D seismic survey in a particular location. There is no point collecting some data just to see "what's there". Hydrocarbon accumulations, ore bodies, aquifers, etc. are not homogeneously distributed throughout the Earth. 3-D seismic technology will not find these resources if they do not exist. We need to have done our geologic homework to make sure that there is something about the structural or stratigraphic complexity of a particular subsurface location that can be effectively addressed with 3-D seismic methods.

"Effectively" in the last sentence is defined via cost-benefit analyses. For example, if we want information about shallow reservoirs and have abundant well control, we may choose not to collect 3-D seismic data because the cost of acquiring shallow data is high, the cost of drilling wells is low (i.e., the cost of a mistake is low) and the available well control could be sufficient for us to make adequate maps. On the other hand, the deeper the target is, and the more stratigraphically and structurally complex an area is, the greater the need for collecting 3-D seismic data. The cost of a 3-D seismic survey may be less than the cost of a dry hole (e.g., Hart et al., 1996) and, perplexingly, in these cases a 3-D seismic "success" could mean that a well was not drilled. How these cost-benefit analyses will play out in other fields (e.g., mining, environmental) remains to be seen.

Furthermore, there are places where it is difficult (if not impossible) to collect good quality seismic data, 3-D or otherwise. This can be the case, for example, where surface geologic conditions prevent the efficient transfer of acoustic energy from the energy source to the ground or from the ground to the receivers (geophones), or where ambient noise is high and consequently the signal-to-noise ratio of the seismic data is low. In these cases, implementation of a successful 3-D seismic program may not be possible, and other technologies may need to be employed.

One of the criteria we should consider when working with 3-D seismic data is whether other subsurface data types are available for the area, and whether they can be integrated into the interpretation. In Chapter 1 we saw that we need to integrate other data types in order to reap maximum benefit from the 3-D seismic data. Well logs provide important "ground truth" that constrains our interpretations of ambiguous seismic data. As such, in the petroleum industry most 3-D seismic surveys are collected around existing producing wells (although larger companies are collecting increasing amounts of 3-D data for exploration purposes). The availability of other data types should be a consideration when 3-D seismic technology (or, for that matter, 3-D GPR) is being considered for any type of project.

CHAPTER 6: INTERPRETING 3-D SEISMIC DATA

As mentioned in Chapter 1, and elsewhere in this work, the 3-D seismic interpretation does not rely solely on seismic data. Instead, good interpreters (or good *interpretation teams*) try to integrate as many other types of data as possible into their interpretations. This might include well log data, production data, pressure data, and other types of geologic, geophysical and engineering data. The idea is to make the interpretation as robust as possible. That is, an interpretation that explains the seismic observations, but does not agree with what is known about the geology or production data, needs to be rejected. Multidisciplinary skills and approaches are required in order to maximize the return on the investment made in collecting and processing the data (Hart, 1997). This represents a significant change from the times when geophysicists alone were responsible for looking at, and interpreting, seismic data.

Not only has the philosophy of the interpretation process changed, the mechanics of the process have also changed. The use of interactive workstations to view and interpret seismic data (Chapter 5) has dramatically improved productivity. Interpreters can now play "what if" games more rapidly (this might be done when the seismic data are ambiguous). Automation of some tasks is now possible. The interpreter can view his/her data in ways that were not possible when working with paper images. New data can quickly be incorporated into the interpretation process to update or revise existing interpretations. Different vintages of seismic data, perhaps including multiple 2-D and 3-D data sets, can be merged and viewed as if they represent a single continuous data set. The results can be exported in digital format to mapping packages, and "final products" generated in a fraction of the time it took when working with paper (analog) data.

This isn't always a good thing. In the rush to produce results quickly, it may be possible to forget some of the basic assumptions or principles one needs to keep in mind when interpreting seismic data, 3-D or otherwise. An interpreter needs to keep the fundamentals of geology and the seismic method in mind. The images one can generate from a workstation during a 3-D seismic interpretation can be powerful, especially when presented in color. As an interpreter, or as a person viewing somebody else's interpretation, one should always be interested in observing how well the interpretations fit the data, and not just what the interpretations mean or imply. Quality control must be exercised at all stages of the interpretation.

In the same way that there are many steps in common between 3-D seismic and 2-D seismic processing, the 2-D and 3-D interpretation processes share many of the same steps[1]. One begins by building a database of reports and other types of data. As much of the data as possible will be converted to digital form, for direct integration into the seismic interpretation process. Next, the interpreter will scan through the data to get a feel for data quality, broad scale stratigraphic and structural setting, etc. Cube displays are particularly well suited for this task. By scrolling through the data cube, within a few

[1] It is worth pointing out that much 2-D seismic interpretation is being done on computers nowadays. The interpretation packages have many things in common with 3-D interpretation packages.

minutes the interpreter can have a good feel for the structural and stratigraphic variability he/she is likely to encounter during the interpretation. As noted at the end of Chapter 4, the interpreter needs to be able to define the project objectives and balance the need to examine specific intervals versus undertaking a "complete" interpretation. By focusing too much on a specific stratigraphic interval, it is possible to miss the large-scale controls on deposition or structural development. Conversely, it is possible to spend too much time looking at large-scale features and not enough on the details. How the interpreter should balance his/her efforts will vary from project to project and, unfortunately, there are no universally accepted guidelines.

The type of interpretation software that is being used will also influence the interpretation workflow. Different packages have different capabilities although, like word processing software, most have many of the same applications. However, workstation-based packages offer more viewing flexibility and can handle larger data sets than PC-based packages. Even within workstation-based packages there are differences in that some have improved graphics capabilities that allow the interpreter to view the data as it exists in the subsurface (i.e., in true 3-D).

As with other subsurface studies, the principal objectives of a 3-D seismic survey are definition of subsurface stratigraphy, structure and rock physical properties. Most such data sets are collected from areas of existing production, so that some subsurface control (e.g., wireline logs, cores, and engineering data) exists already. Having this information 'up front' allows the interpretation team members to better leverage the massive amounts of data available to them in the 3-D seismic volume. The establishment of development drilling plans (finding infill and step out drilling sites), is a common application of 3-D seismic, although most interpreters will also use the data for exploration purposes (e.g., looking for other, as yet unproductive, stratigraphic intervals; Hart, 1997). There is increasing use of 3-D seismic data, particularly by large companies, as a purely exploration tool.

STRATIGRAPHIC INTERPRETATION

Having familiarized himself/herself with the available information, the interpreter needs to begin picking horizons in the seismic data. This might be done through the analysis of VSPs or synthetics. One immediate advantage of working with 3-D seismic data is that it is generally possible to compare a synthetic or VSP directly to the seismic trace that corresponds directly to the well location. With 2-D data, wells are often located at various distances to the side of seismic lines. The interpreter then needs to hope that the structure and stratigraphy do not change significantly between the location of the well and seismic data. This is not always the case, and even differences of a few tens of meters can be significant in structurally or stratigraphically complex areas. In this case the tie between the synthetic and the seismic data can be relatively poor, leading to ambiguities in the horizon interpretation process.

Once the key stratigraphic horizons have been defined, they need to be picked throughout the 3-D volume. A modest size 3-D seismic survey might consist of 100 lines

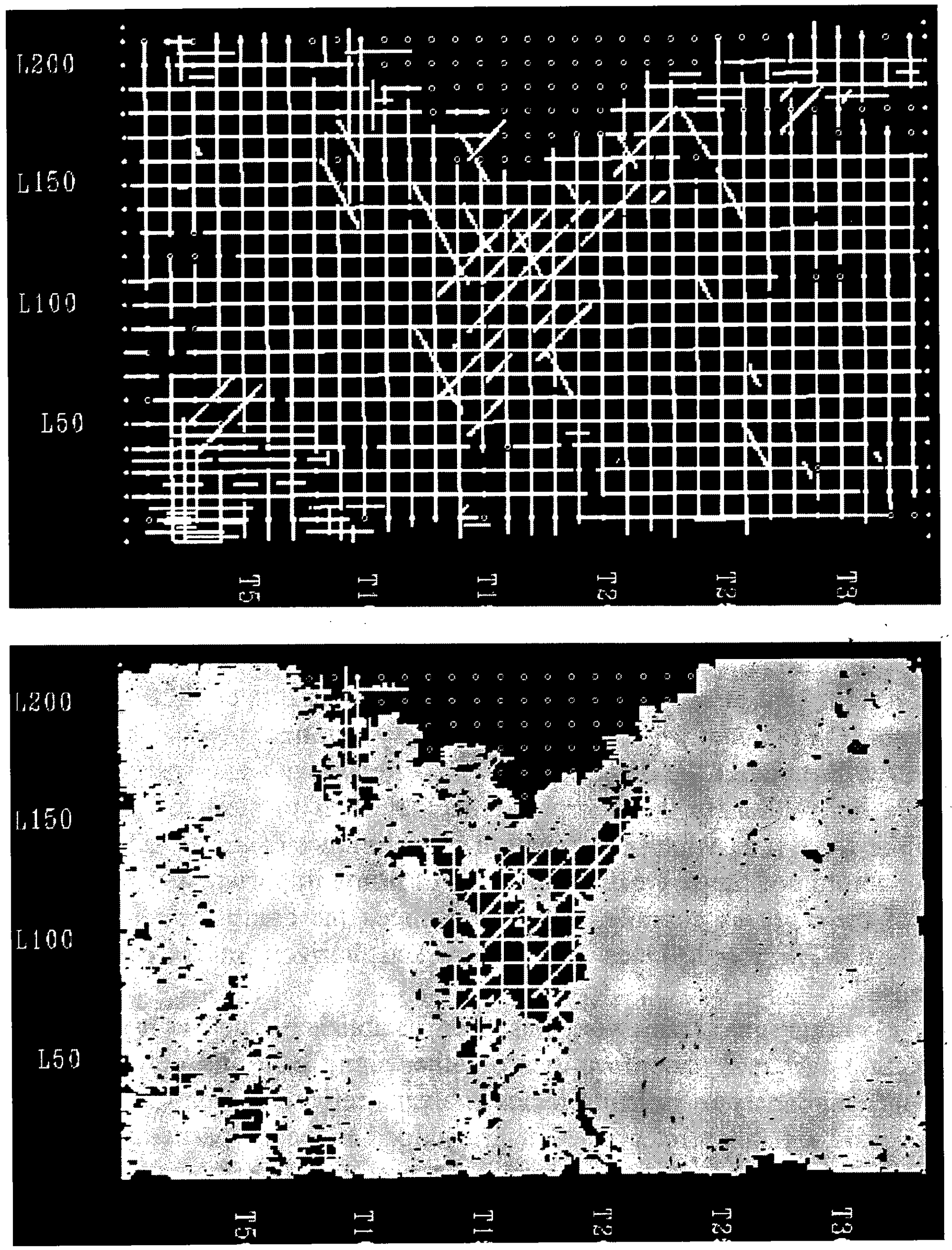


Figure 6.1. Horizon autotracking. The seed grid (top) was picked as completely as possible on a regular grid of ten lines by ten traces. It was not possible to pick the horizon in some areas because of data quality and stratigraphic complexity. Arbitrary lines (diagonal) and more closely spaced picks were subsequently used to help fill in some of the gaps (the large area in the upper middle is an area of no data (overlain by a lake). The lower image shows the initial results of the autotracking (gray tones show time structure). Most of the survey area is filled in, except for some "problem areas". The interpreter will need to go back to these areas and try to fill them in, either by adding more seed lines, by changing the autotracking parameters, or by manually making the pick through those areas. Area is approximately 3 x 5 km. With good quality data, it is typically possible to autotrack a horizon pick through a larger area than this with a sparser grid of seedpoints (in exceptional cases, a single input line may suffice). For all cases, the interpreter will need to view the autotracking results in vertical transects, perspective displays, and by other means to ensure that the autotracking algorithm has performed properly. Data from the Permian Basin.

by 100 traces (some larger marine surveys can be 2000 lines by 3000 traces; Dorn, 1998). This means 10,000 traces for which a horizon should be defined (provided that it is continuous throughout the survey area). Picking a horizon on this number of traces can be an extremely laborious task, and so 3-D seismic interpretation packages generally have means of automatically picking (or autotracking) horizons.

The general idea of autotracking is that the user will provide a series of "seed points", usually an intersecting grid of picks (Fig. 6.1). The grid might be picked on every tenth line in both the line and trace orientations and so resemble the 2-D data grid shown in Figure 4.4. Given these seed points and user-defined parameters for the autotracking, the software will attempt to follow the horizon (a peak, trough or zero crossing) throughout the seismic data volume (Figure 6.1).

The usefulness of autotracking depends on several factors. First, the continuity of the horizon is important. A horizon that is broken by many faults or a stratigraphically discontinuous surface will be hard to autotrack. It will also be difficult to autotrack a horizon through noisy (i.e., poor quality) seismic data. Second, the reflection character is important. A reflection that parallels and has a high amplitude contrast with its neighbors will be relatively easy to autotrack, whereas one should expect trouble when downlap, onlap, etc. (Fig. 4.5) cause reflections to bifurcate or join. Finally, as a time saver, autotracking should be employed with as few seed lines as possible. It makes no sense to pick a tight grid of seed lines for an "easy" horizon that could be picked from a single seed line. On the contrary, some horizons defy autotracking and may need to be picked manually throughout the data volume. Experience with autotracking software is the only guide that will help the interpreter decide when to stop picking and let the computer do the work (i.e., which combination of techniques to use to get the best result in the shortest amount of time). Quality control is of prime importance. Let the computer do as much of the work as possible, but *always* check the computer's results with the following question in mind: Does the autotracked horizon make geophysical and geological sense?

Once a stratigraphic framework has been established, such as by defining and mapping flooding surfaces, unconformities or other significant and definable horizons, detailed stratigraphic analyses (seismic facies analysis, reflection character analysis; Fig. 4.6) are conducted on those intervals that are judged to be of particular stratigraphic importance. Clinoforms, channels, parasequences, reef complexes or other stratigraphic entities are studied using conventional seismic stratigraphic criteria and integrating all available log, core and biostratigraphic data (Fig. 6.2). Where line or trace orientations are oblique to stratigraphic trends, arbitrary lines through a seismic volume need to be selected to examine the true longitudinal and cross-sectional geometries of clinoforms, channels and other features.

With most software packages, it is possible to superimpose wireline logs directly over the seismic data in vertical transects in order to help merge geologic (logs) and geophysical (seismic) data and concepts (Figs. 5.6a, 6.3). Depending on the types of logs employed, these displays can help to guide correlations from well to well, identify facies associations or stratal surfaces, identify fluid contacts, etc.

Horizon slices can be thought of as approximations of paleodepositional surfaces (Dorn, 1998). Along with time slices, they can be used to help the interpreter to identify and map features such as fluvial channels, sinkholes, (e.g., Brown, 1999; Hardage et al.,

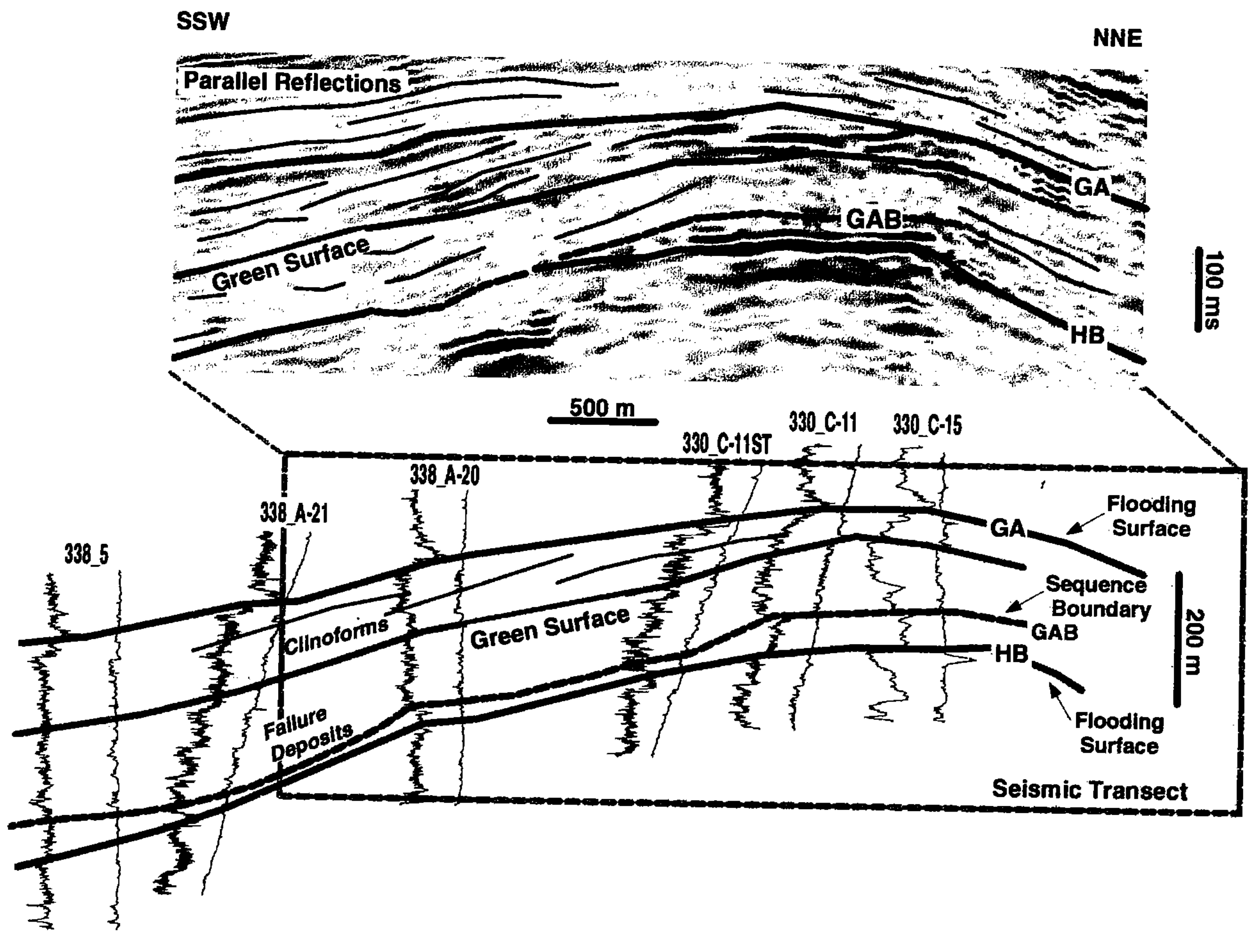


Figure 6.2. North-south 3-D seismic transect (top) and wireline cross-section (bottom) through Pleistocene lowstand deltaic complex from the offshore Gulf of Mexico. Stratal surfaces, reflection configurations, depositional facies and other features of interest have been identified. This type of seismic and log data integration is a powerful tool allows the benefits of both technologies to be exploited. The logs have higher vertical resolution and show lithologies and fluid content. Gamma Ray log facies can be directly related to seismic facies (reflection configuration). The seismic data facilitate stratigraphic correlations between wells. See Fig. 7.7 for location of transect. Modified from Hart et al. (1997).

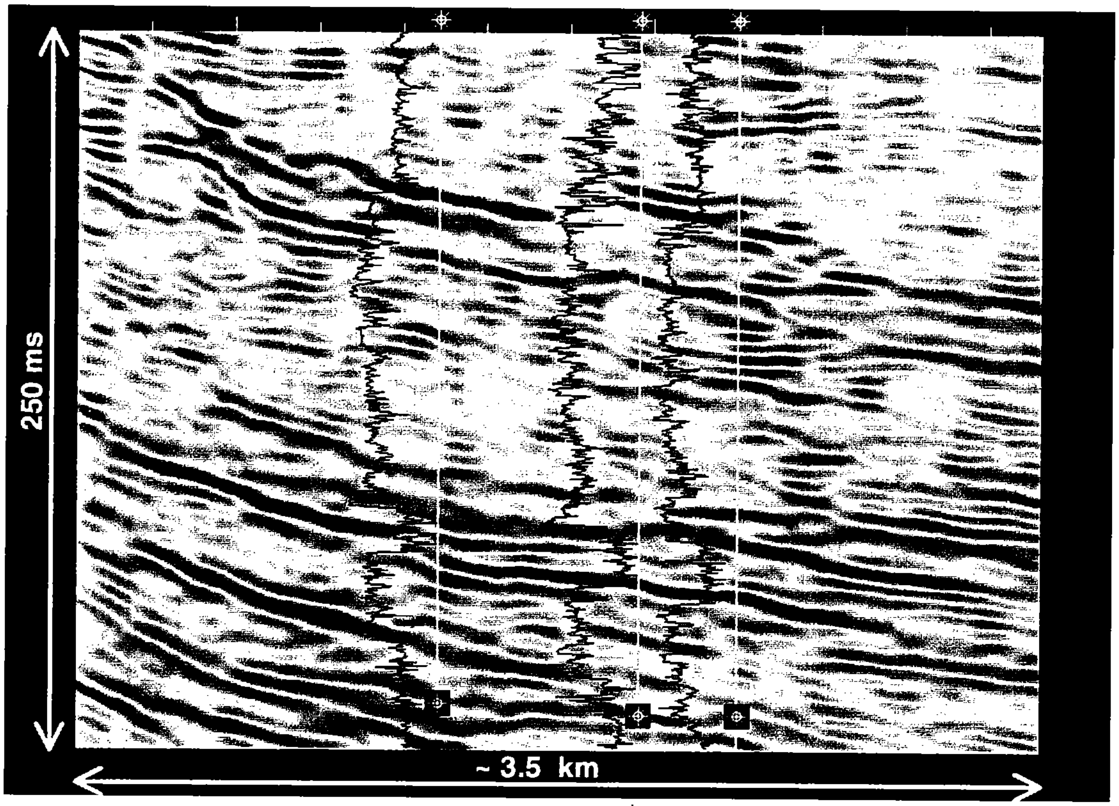


Figure 6.3. Example of a seismic view with well log overlay. Log curve shows Gamma Ray (increasing to right) with true location of wells indicated by vertical white lines. Note good correspondence between lithology contrasts (low GR – clean carbonates, higher GR – dolomitic sandstones and siltstones) and the location of prominent reflections. This type of display, only possible to view once time-depth relationships have been properly established, can be used to help verify picks, both log and seismic. Transect shows basinward (right) progradation of a mixed siliciclastic/carbonate Permian shelf/slope in Delaware Basin. Modified from Hart (1999b).

1994), deltaic lobes (Hart et al., 1997), reefs (Brown, 1991) and even meteorite impact structures (Isaac and Stewart, 1993). In the petroleum industry, knowledge of the distribution of these depositional features can help to identify or predict sedimentary facies distributions, and thus the location of reservoir quality rock or barriers or baffles to subsurface fluid flow that might compartmentalize reservoir.

Typically, vertical transects, time slices, perspective views, voxel visualizations, time structure maps and amplitude displays will be evaluated together to assess a given area (Chapter 5). If the area has been structurally deformed, vertical transects might be flattened on a horizon to more clearly see depositional features (e.g., Fig. 5.7). The key is to exploit the 3-D nature of the seismic data as much as possible, and not to simply rely on interpreting the data as a series of dense 2-D lines. In fact, some software vendors discourage the practice of picking grids of seed lines and instead encourage the picking of horizons on cube or voxel displays. This procedure may be a timesaver for experienced interpreters (especially those who are familiar with the structure and stratigraphy of the study area) but viewing grids of seedlines can help the interpreter to build a stratigraphic and structural framework in his/her own mind.

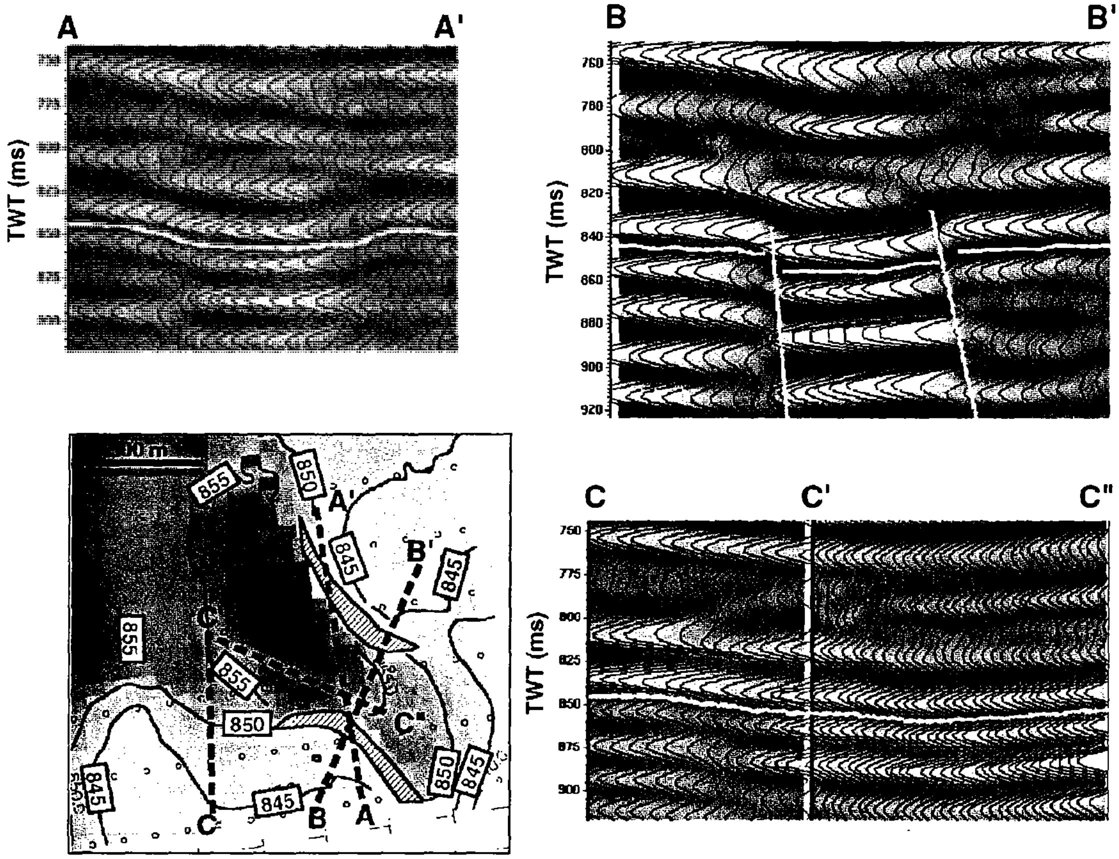


Figure 6.4. Seismic transects across a small graben in New York. See time structure map (ms, TWT) in lower left for line locations. Transect A-A' (top left) is in the line orientation of the survey. It crosses the graben obliquely, and so the bounding faults are not distinct. An arbitrary line, B-B' (top right) is nearly perpendicular to the faults, and so they show up clearly. If any ambiguity exists about the integrity of the horizon pick in the middle of the graben, an arbitrary line can be picked that goes around the tips of the faults (C-C'-C", lower right). This multipanel (zig-zag) line shows stratigraphic continuity from outside to inside the graben, thus verifying the picks. Modified from Hart (1999).

STRUCTURAL INTERPRETATION

Structural and stratigraphic interpretations necessarily feed off one another and must be conducted somewhat simultaneously. For example, it is not possible to calculate throw on a fault without being able to identify common horizons on either side of the structure. Conversely, to correlate a horizon from one side of a fault to the other, the interpreter needs to understand the fault geometry (normal, reverse, etc.). As with stratigraphic interpretation, vertical transects, time slices and other displays will all be utilized together during the structural interpretation procedure. Faults can be interpreted on both time slices and vertical transects, and the results of interpretation on one display may be viewed and used to guide fault picking on the other. The ability to view arbitrary lines through the seismic volume can, as with stratigraphic interpretation, have a significant beneficial impact on structural interpretations (Fig. 6.4).

As with a stratigraphic interpretation, the structural interpretation begins by identifying the large-scale features, then successively mapping finer details. Faults are generally detectable when the throw is greater than one quarter of the wavelength (Sheriff and Geldart, 1995). Subtle faults that are not easily recognized on vertical transects may sometimes be detected by generating and examining horizon attributes from autotracked horizons (e.g., Bouvier et al., 1987; Dalley et al., 1989). These include the surface's dip and azimuth (i.e., the direction that the surface is pointing, ranging from 0° to 360°; Fig. 6.5), and other properties (Hesthammer and Fossen, 1997; Townsend et al., 1998). Depending on the orientation and dip of the fault with respect to stratigraphic horizons, any particular one of these displays might help to detect subtle structures that have a significant impact on subsurface fluid flow. Careful manipulation of color scales can bring out subtle features that might otherwise go unnoticed.

Coherency attributes (including *Coherence Cube*™ technology) generate a seismic attribute that quantifies the similarity between a given seismic trace and its neighbors (Bahorich and Farmer, 1995; Marfurt et al., 1998). This numerical measure is somewhat analogous to the 'reflection continuity' attribute that seismic interpreters have been employing qualitatively for many years. When the wave shape for a trace in a given time window is similar to that of adjacent traces, as might be expected when the stratigraphy is continuous across an area, the coherence attribute calculated at that position is high. When there are significant differences between traces, as might be expected where the stratigraphy is offset by faulting, the coherency is low. This type of data volume is derived from a conventional 3-D seismic amplitude volume, and may be viewed in the same ways (Fig. 6.6, 6.7). Coherency volumes may, very precisely and quickly, reveal the location of subtle faults that might be otherwise missed.

It should be noted that coherency attributes can also be very useful for detecting stratigraphic features such as channel systems (Fig. 6.8), or reefs. Brown (1999) shows some excellent examples of channels that have been detected using coherency attributes.

Once horizons have been mapped in a 3-D volume, they generally need to be depth converted. If we have collected the data to drill for hydrocarbons, saying that a target is at 1542 ms TWT at a particular location does not really help the engineer to plan a drilling program. The same problem holds for aquifers or other features of interest.

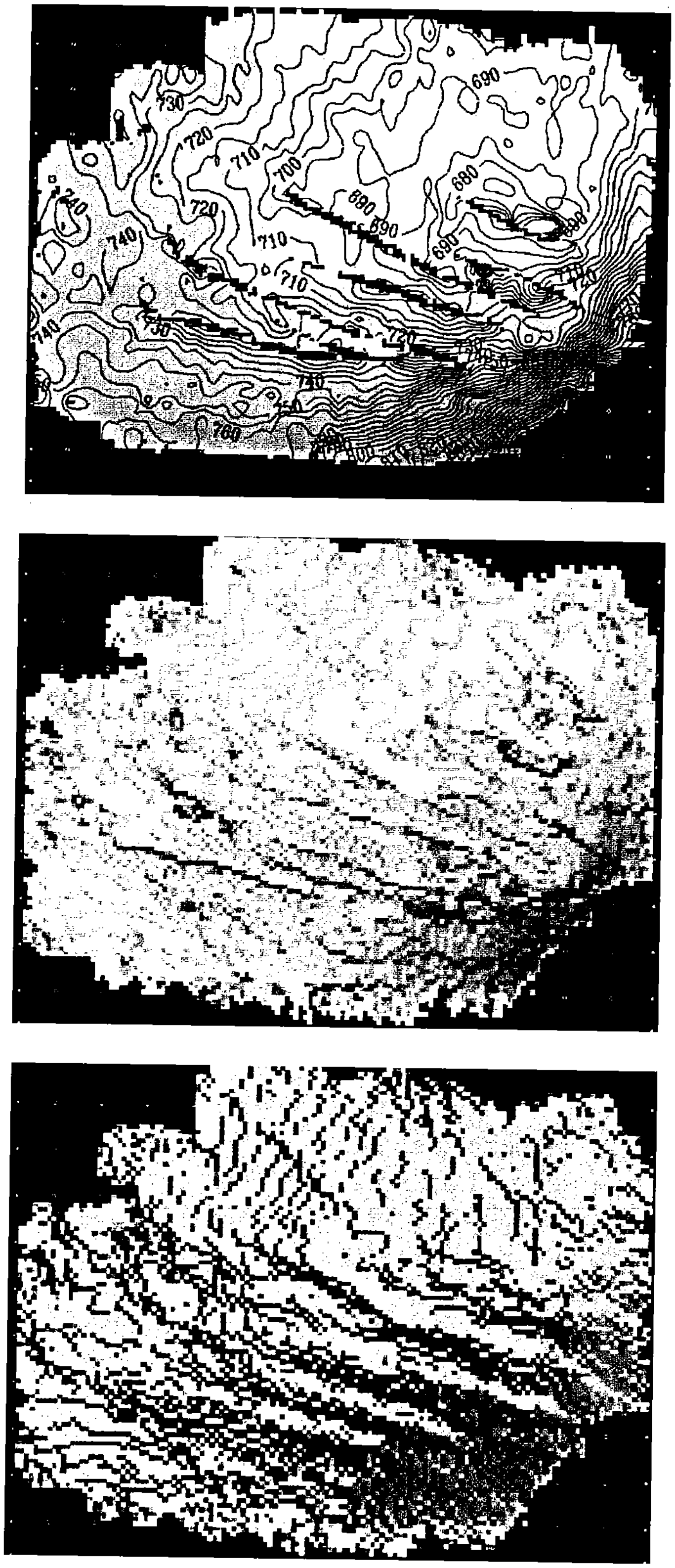


Figure 6.5. The top image shows a time structure map of a horizon. Note fault heave areas where the horizon is no longer present. These faults have been identified using conventional interpretation methods. The middle image shows horizon dip (dark = high dip) and the lower image shows horizon azimuth (illumination from NE). Subtle fault trends are visible in the two lower images that were not visible in the original interpretation (top). Modified from Hart (1999b).

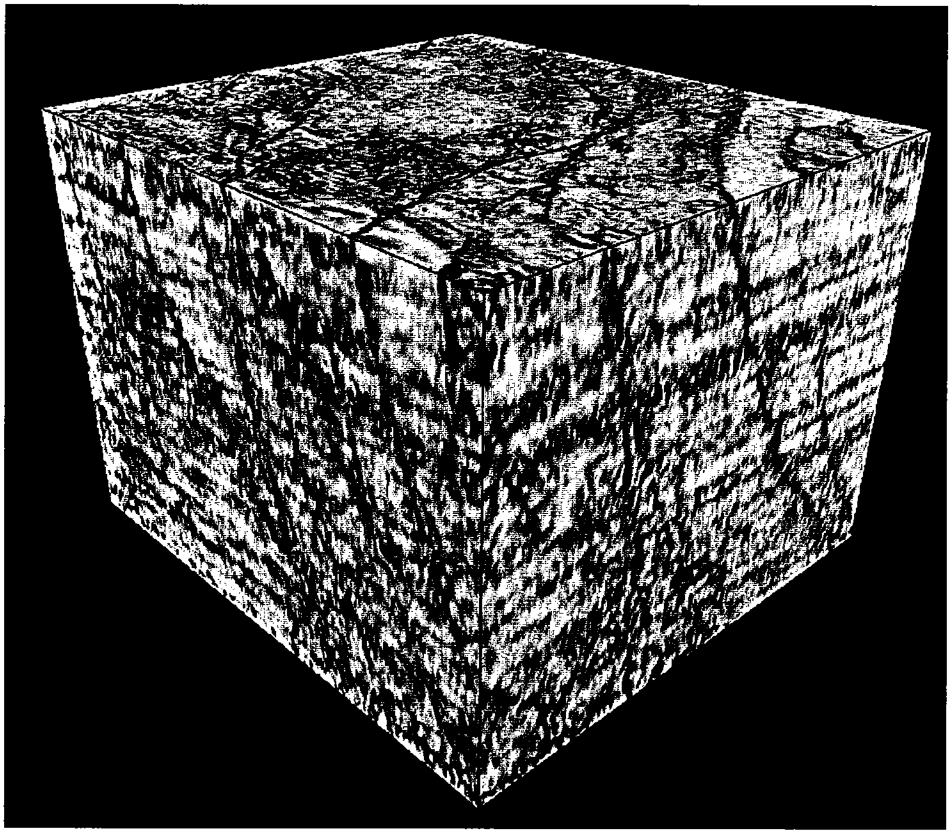


Figure 6.6 Coherency attribute cube showing excellent definition of faults as curvilinear dark features corresponding to low values of the coherency attribute. Note different expression of faults on side, front and top of cube. Figure courtesy of GeoQuest.

However, not only is a time structure map not in meaningful depth units, it could be wrong or misleading if there are velocity problems within the survey area.

There are several ways to depth convert horizons (e.g., geostatistics, depth migration, 3-D velocity model building) but they all require some type of velocity information. One of the simplest methods is to integrate the seismic horizons with well picks to generate time-depth pairs to generate a velocity field (Fig. 6.9). An example of the possible differences that could be present between a time structure and a depth structure map is shown in Figure 6.10.

3-D seismic analyses often result in structure maps that show significant differences when compared to structure maps based on 2-D seismic and/or well control . That these maps truly are more accurate than the original maps has been empirically (and frequently) demonstrated in the petroleum industry by drilling results and by integration with other data types (e.g., Haldorsen and Damsleth, 1993; Brown, 1999).

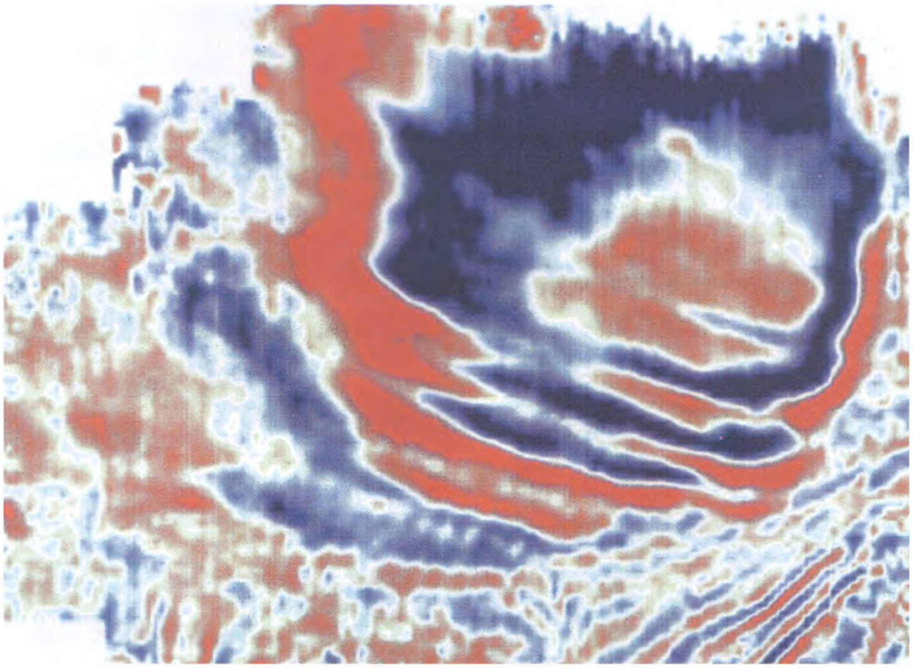


Figure 6.7. Upper image shows a time slice through a 3-D seismic amplitude volume at about the level of the horizon shown in Figure 6.5. Some NW-SE faults are apparent as offsets of reflections. Lower image shows a time slice through a coherency attribute volume at exactly the same level as the upper image. The faults are much more apparent (as low values of coherency, in dark) in this image than in the upper image. Area of both images is approximately 6 x 4.5 km.

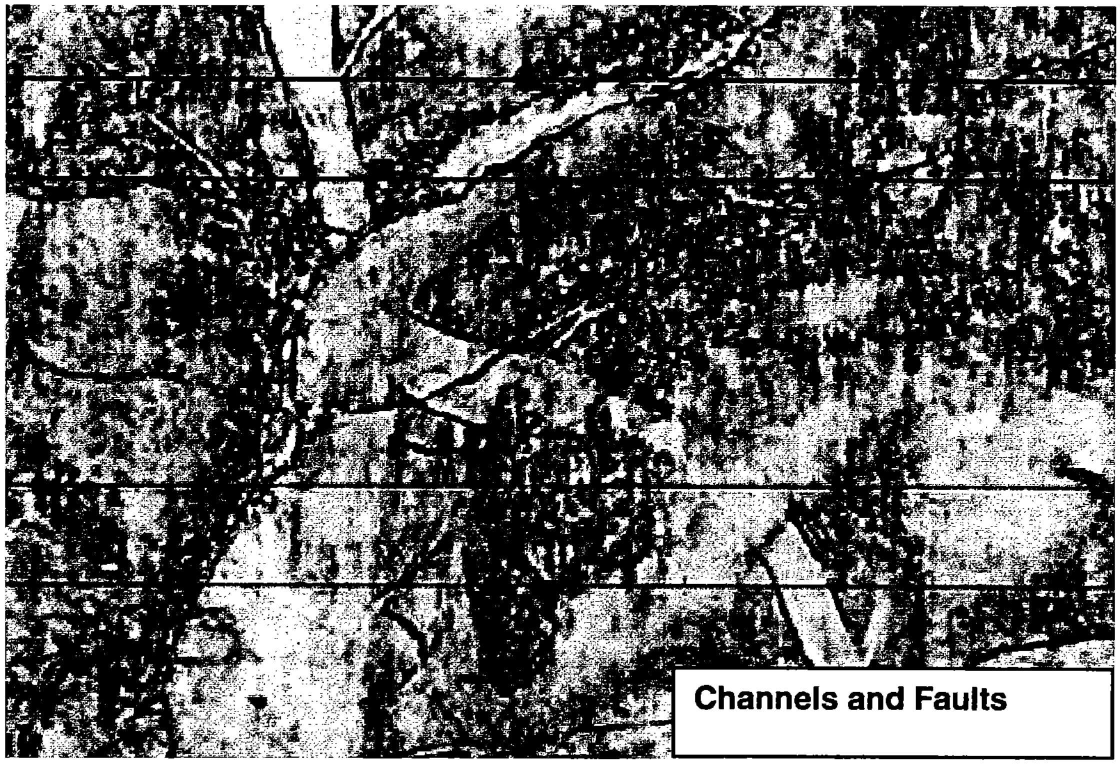


Figure 6.8. Channels and faults visible in a Coherence Cube time slice from the Gulf of Mexico. Figure courtesy of Coherence Technology Corporation

ROCK PROPERTIES FROM 3-D SEISMIC DATA

Once the stratigraphy and structure of an area have been analyzed and mapped, the interpreter may attempt to define rock properties from a seismic volume. The qualitative approach to this was described in Chapter 4, where we discussed how amplitudes, reflection continuity, frequency, etc. were estimated and employed to deduce particular rock/sediment properties. Seismic inversion is a method of directly deriving rock properties (e.g., impedance) from seismic data. However, the results are non-unique and often do not display the resolution needed for a modern seismic interpretation program.

Complex trace attributes, such as amplitude, instantaneous frequency, reflection strength, instantaneous phase and many others (Tanner et al., 1977; Brown, 1996; Fig. 6.11) are currently being analyzed and exploited qualitatively in the hopes that they contain information about the physical properties of the rocks being imaged. The analysis of these attributes is not new (e.g., Tanner and Sheriff, 1977). However, the vigor with which 3-D seismic interpreters are currently deriving and exploiting them (Hart, 1997) is related to: a) the direct way in which large amounts of digital data can be analyzed, and b) the ability to link log-derived physical properties

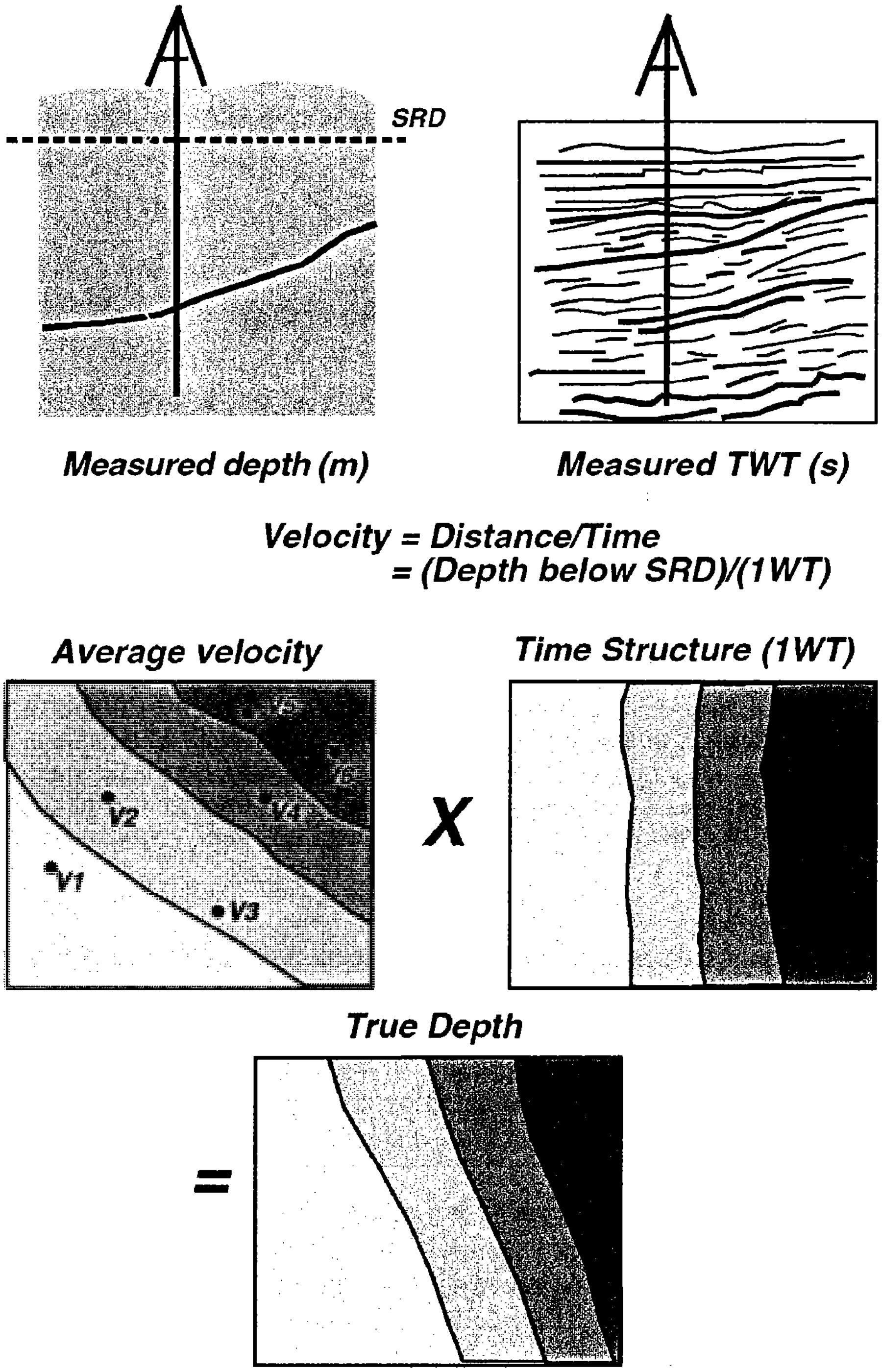


Figure 6.9. Simple depth conversion. At top left, the depth below the seismic reference datum (Chapter 3) to a horizon (formation) is known from well logs. The two-way traveltime to the top of the horizon at the well location is also known from the seismic data (top right). The average velocity from the seismic reference datum to the top of the horizon can be computed by dividing the distance (measured depth) by a one-way traveltime (1WT = TWT/2). Average velocities are derived for all well locations and the results are gridded to produce a velocity map (center left). The velocity map is then multiplied by the time structure (converted to 1WT; center right) to produce a depth map (bottom). The example is deliberately drawn to show slight differences between the time structure and depth structure maps.

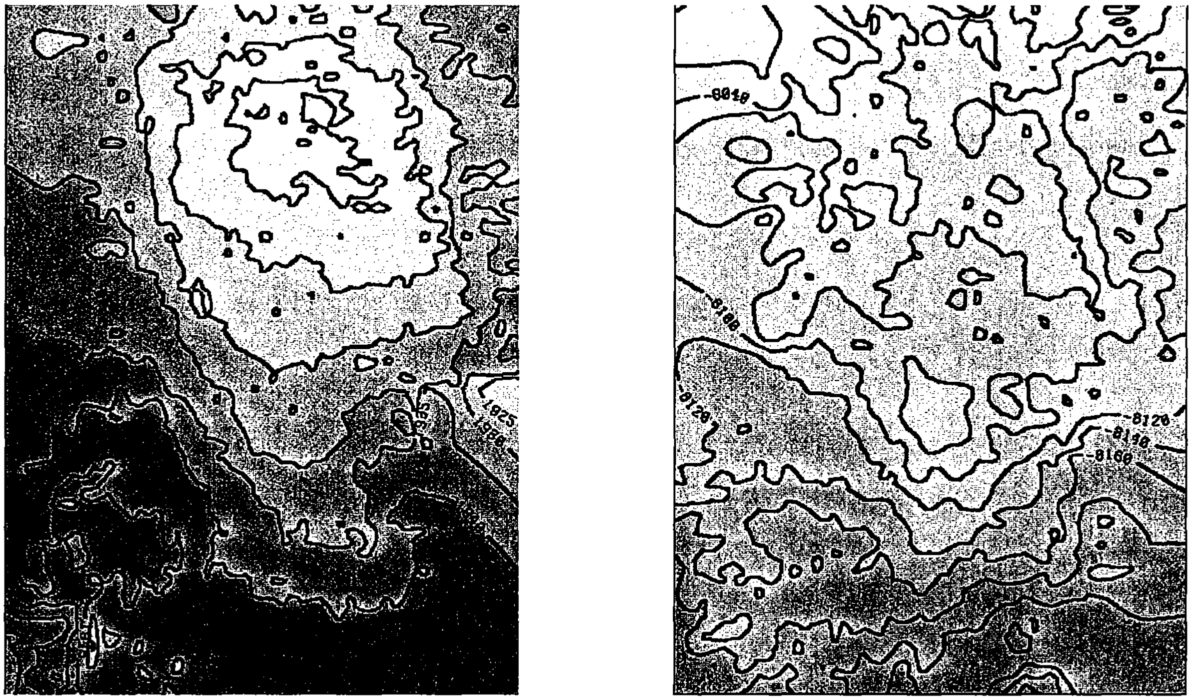


Figure 6.10. On the left is a time structure map (ms TWT) of the top of the Devonian Nisku Formation from the Williston Basin. On the right, the Nisku has been depth converted (subsea elevation in feet) using the procedure outlined in Fig. 6.9. Note the differences that are attributable to surface statics (velocity) problems related to Pleistocene glacial deposits at the surface. The depth-converted horizon was tested and found to be accurate via drilling. Area of both maps is approximately 3 x 5 km.

from individual wells to a specific traces in a spatially continuous 3-D seismic volume.

Seismic amplitudes are the most readily imaged and interpreted attribute (Enachescu, 1993) although other attributes are exploited in a qualitative way as well (e.g., Hardage et al., 1996), either individually or collectively. Non-uniqueness of response (e.g., seismic amplitudes can be affected by changes in porosity, bed thickness, reflector geometry, processing and other variables) should be an important consideration when interpreting such data.

Using a relatively new technique, growing numbers of interpreters are attempting to empirically correlate seismic attributes with reservoir physical properties measured by borehole logs (Schultz et al., 1994). The complex trace attributes, either "instantaneous" values or extracted from "windows" (Fig. 6.12), potentially contain information about the physical properties of the rocks being imaged seismically, but the direct relationship between the rock properties and seismic attributes may be practically impossible to derive from first principles.

The objective is to correlate physical properties, as measured from borehole logs, with seismic attributes derived from the traces that correspond to the boreholes (Fig. 6.13). Once an empirical relationship has been established, it can be used to make predictions about rock properties wherever the input attributes are defined (i.e.,

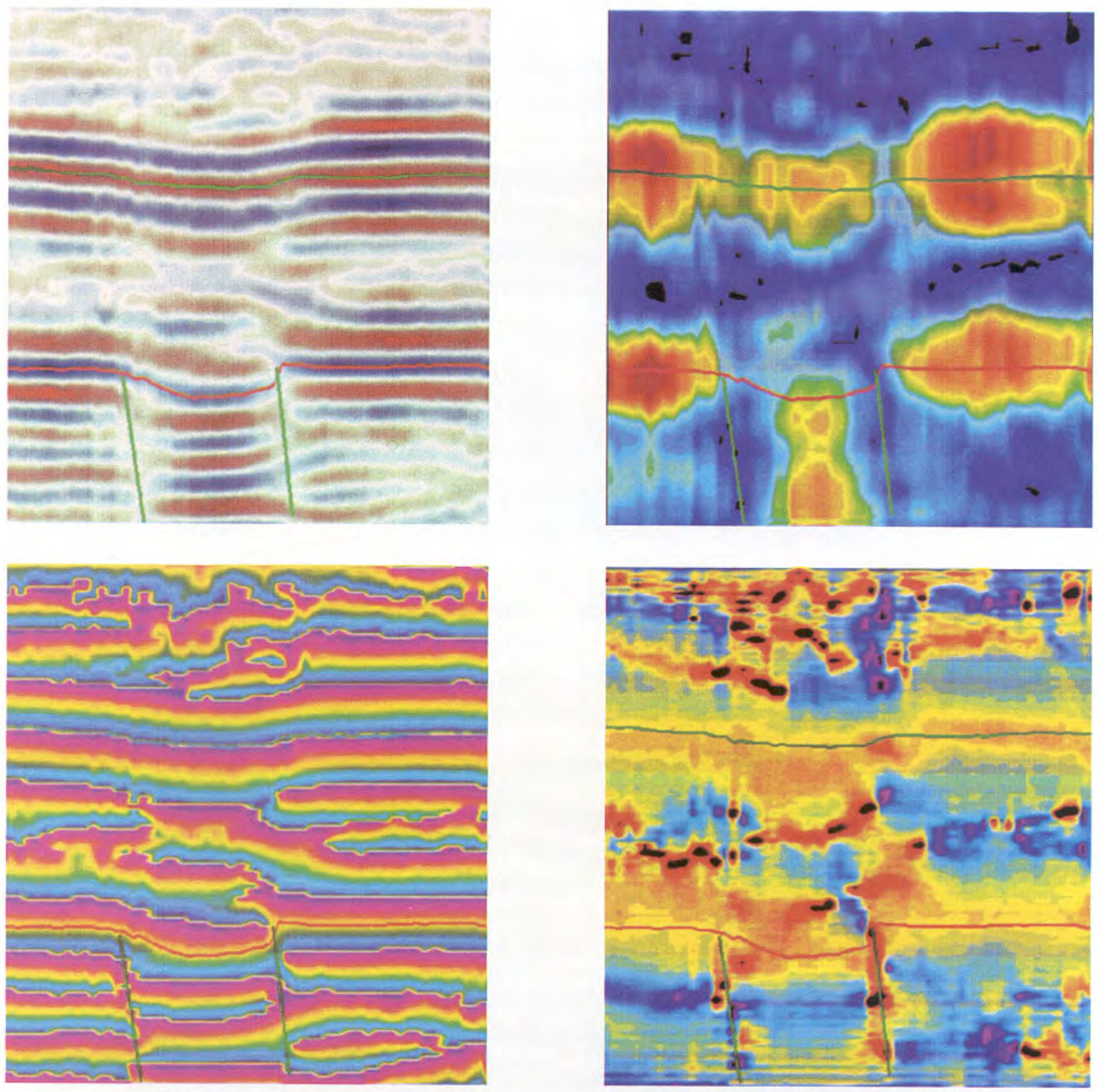


Figure 6.11. Variable area wiggle displays of selected seismic attributes. All images show the same portion of data. Upper left shows variable density amplitude data with two faults (lower two high-angle green lines) and two horizons (green and red). Upper right image shows reflection strength (amplitude independent of phase) version of the data (high reflection strength in dark red, low reflection strength in dark blue). Note subtle changes in reflection strength along horizons that are less obvious in amplitude data. Note that the faults are associated with low reflection strength zones. At lower left is an instantaneous phase (phase independent of amplitude) version of the data (colors represent constant phase). Note that horizons track along a constant phase value (i.e., the picks are good) and that the faults are associated with a slight offset of phase. At lower right is an instantaneous frequency (rate of change of phase) version of the data (high frequencies in purples, low frequencies in red). Note subtle changes in instantaneous frequency along horizons and that the faults are associated with low frequency zones.

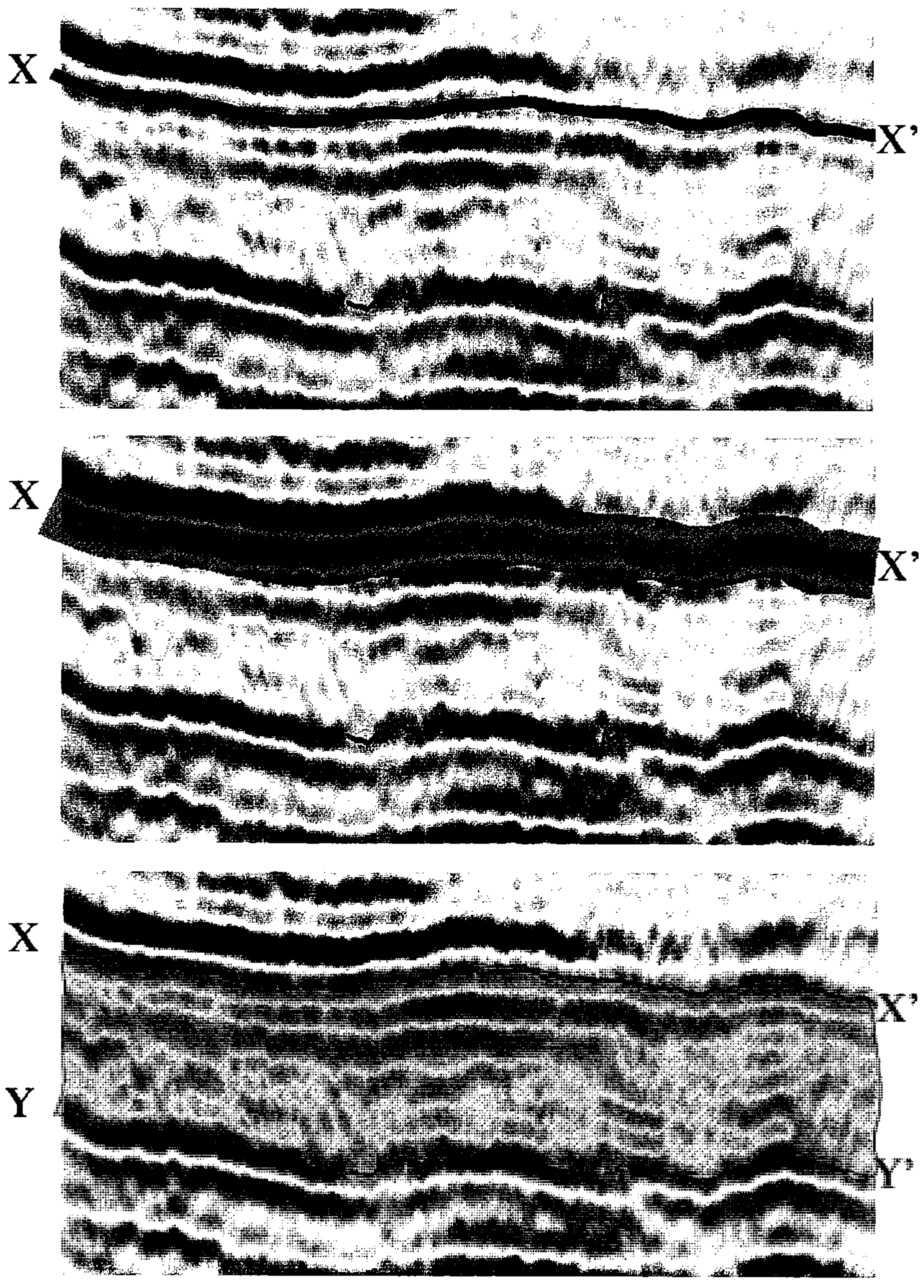


Figure 6.12. Seismic attribute extraction possibilities. At top, "instantaneous" attributes (instantaneous frequency, instantaneous phase, amplitude, horizon dip, etc.) are extracted along a horizon (X-X') that has been picked in the 3-D survey area. In the middle, "interval" attributes (maximum amplitude, average frequency, RMS amplitude, ratio of positive to negative values, etc.) are extracted in a window (gray area) that is centered on the picked horizon (X-X'). Interval attributes can also be extracted from a window that is defined by two horizons (X-X', Y-Y'), as shown in the lower image. Whether an interpreter selects one of these techniques or uses all of them depends upon factors such as project objectives, thickness of the interval being studied, confidence in the well-seismic tie, etc.

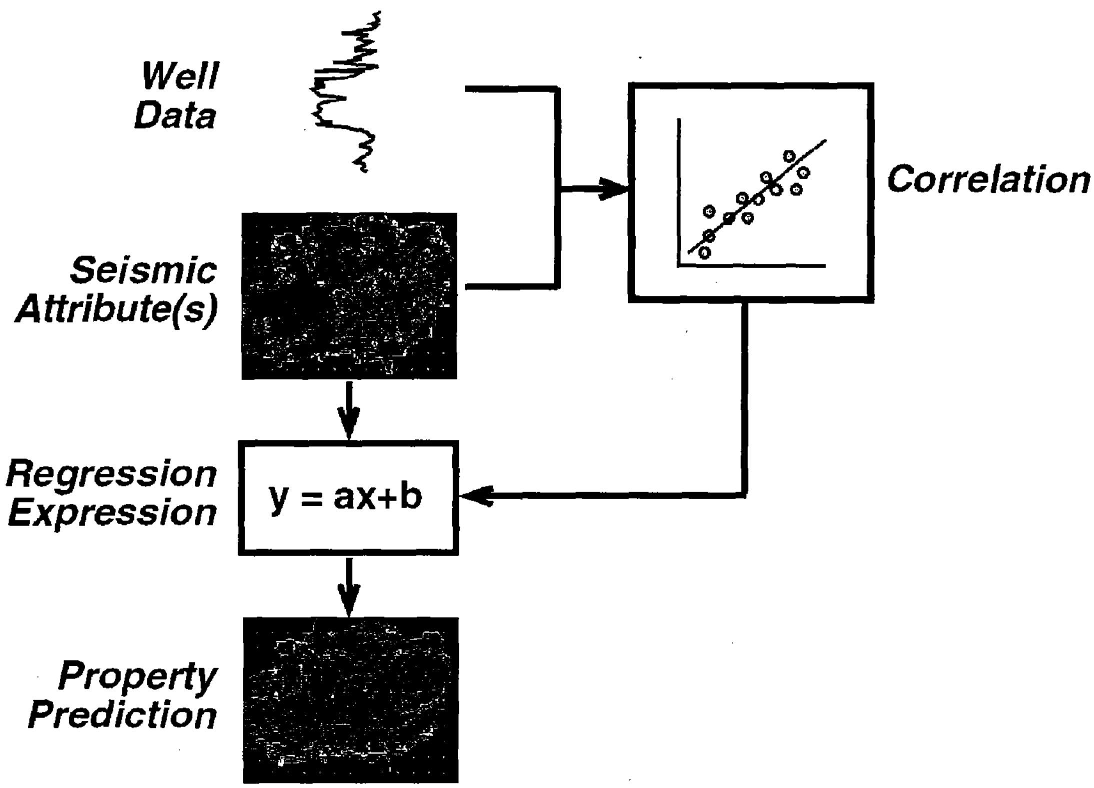


Figure 6.13. Schematic representation of how seismic attributes are extracted from 3-D volumes and combined with log-derived data to make predictions of rock/reservoir properties away from existing wellbores. Well data are used to define the physical property of interest (e.g., net sand, average porosity). The value of selected seismic attributes is extracted at well locations, then the log-based values are correlated against the attributes to look for statistically significant relationships. One or more attributes might be used during the correlation phase, and the correlation might be based on linear regression, neural network analyses or some other procedure. The seismic attributes are then fed into the empirical numerical relationship ("regression expression") to make a prediction of the physical property of interest throughout the 3-D survey area. Modified from Hart (1999a).

throughout the 3-D survey area). In addition to complex trace attributes, horizon attributes (e.g., dip, azimuth), amplitudes, isochrons, structure, velocities (e.g., Grimm et al., 1999) and other quantitative measures derived from the seismic data can all be considered to be "attributes" in these analyses. Different methods are being utilized or developed, including multiple regression, geostatistics and neural networks, first to derive the relationships and then to distribute properties throughout the area of the seismic survey. An example of this methodology will be presented in the next chapter.

Much effort is currently being put into refining these methods (e.g., Hirsche et al., 1997; Russell et al., 1997; Schuelke et al., 1998; Hart and Balch, *in press*) Although attribute studies should form an integral part of a development or exploration program, the results of these analyses must be integrated with the results of geologic, geophysical and engineering analyses (Hart, 1999a). No matter how mathematically rigorous a physical properties prediction might be, it should be rejected if it is not both geologically and geophysically plausible. Pearson and Hart (1999) showed an example of how a

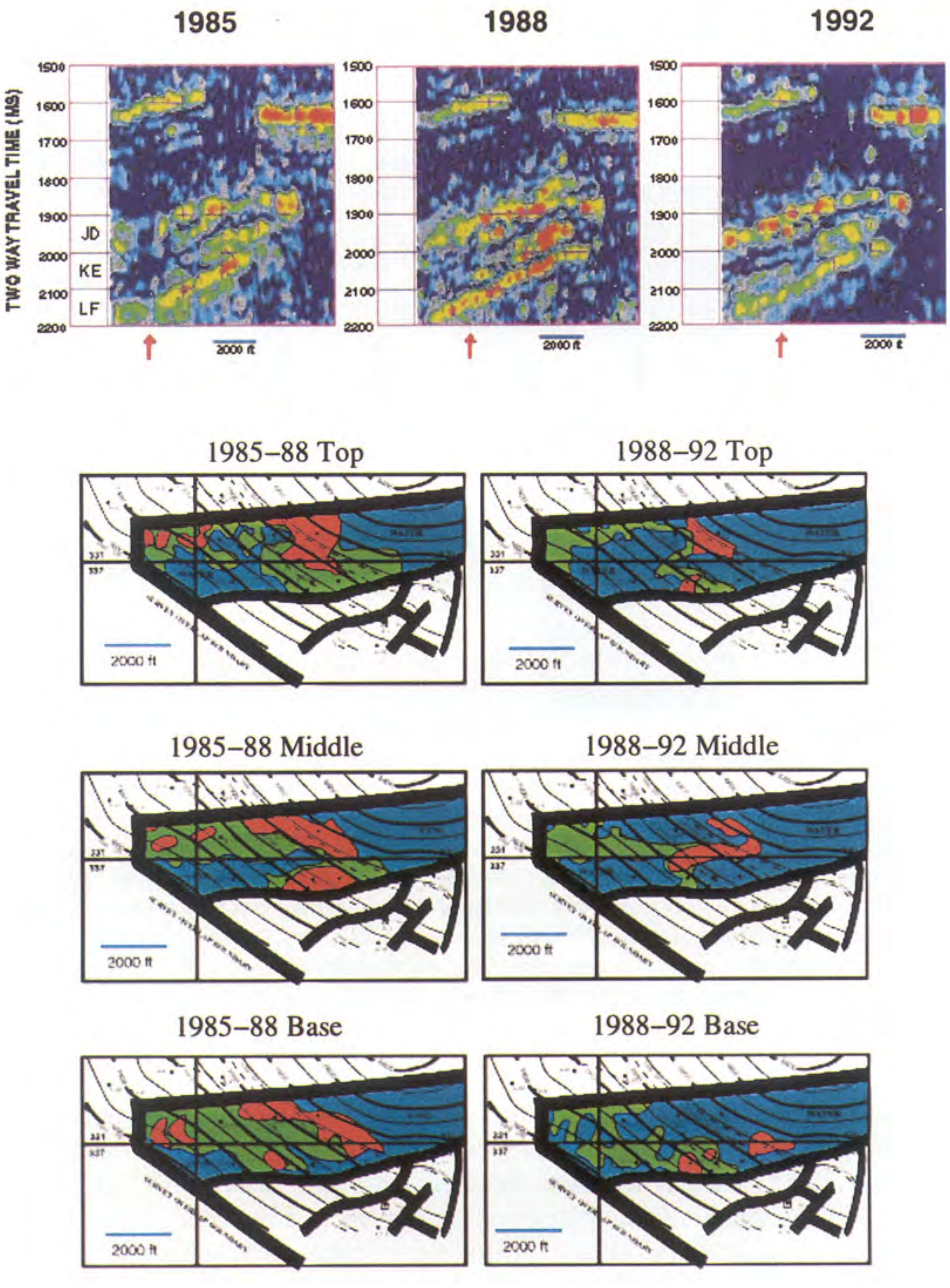


Figure 6.14. Time–lapse monitoring of changes in reservoir pore fluids ("4–D seismic"). The upper image shows a common reflection strength transect (high values in red, low values in blue) through three different vintages of 3–D seismic data. Note the changes at the LF level between images. These changes in reflection strength are due primarily to changes in fluid content in the reservoir, although other factors (e.g., reservoir pressure) also play a role. By analyzing reflection strength at different levels through the reservoir (maps), it is possible to identify gas cap development (red), water–charged intervals (blue) and by–passed oil (green) between surveys. Integration of seismic analyses with geological, petrophysical and engineering data and concepts is critical in these studies. Modified from Anderson et al., (1996). Other approaches to time–lapse monitoring have been developed.

sequence stratigraphic interpretation and attribute-based physical properties prediction can converge toward a common solution.

TIME-LAPSE ("4-D") SEISMIC

Seismic modeling and empirical analyses some years ago demonstrated that it was possible to detect hydrocarbon accumulations in sandstones using seismic amplitudes. The reason is that the presence of oil or gas in the pore spaces of a rock changes the elastic moduli and rock bulk density (Chapter 2) with respect to a similar rock whose pore spaces are filled with water. The effect depends on the circumstances. In places like the offshore Gulf of Mexico, where water-filled reservoir sands (unconsolidated) are slower and less dense than the encasing shales, putting hydrocarbons in the pore space causes the sands to become even slower and less dense than the shales. As a result, the acoustic impedance contrast is higher, the reflection coefficient is higher and a stronger amplitude reflection is generated. This is the basis of the "bright spot" technique. Elsewhere (e.g., older rocks), sandstones are faster and denser than the enclosing shales. Replacing some of the water in the pore spaces with hydrocarbons causes a reduction in acoustic impedance contrast and a dimming of amplitudes.

Whatever the effect, changes in the pore-filling fluids of a reservoir due to hydrocarbon production might be detectable using seismic methods because those fluids affect the bulk rock properties that are imaged seismically. By collecting successive seismic data sets over a reservoir, it might be possible to detect or even monitor changes in the composition of pore-filling fluids over time if those changes are associated with detectable changes in fluid properties (e.g., Greaves and Fulp, 1987; Anderson et al., 1996). Ideally, having this capability allows the field management team to monitor reservoir drainage to ensure that all areas are being drained by existing wells. If it is seen that certain areas are not draining, perhaps because the reservoir is compartmentalized by stratigraphic features or faults, new wells can be planned that specifically target those areas.

The feasibility of seismically monitoring fluid flow is evaluated up front, before any decision is made to conduct repeat 3-D seismic surveys. The feasibility study includes work to see what changes in rock properties are likely to occur as a result of changes in fluid content. Also, a realistic geologic model is used as input for seismic modeling. Engineers input data and information regarding the changes in fluid content and fluid contacts in the reservoir.

Not all areas are candidates for time-lapse seismic studies. In some cases (especially less porous older rocks) the feasibility work will conclude that changes in fluid content due to production will not generate enough of a difference in the seismic response to be effectively monitored. However, the changes in fluid content are not the only important variable. Changes in reservoir pressure and temperature also need to be considered, as they too will affect the rock properties. In some cases these effects can be monitored seismically.

OTHER TECHNIQUES

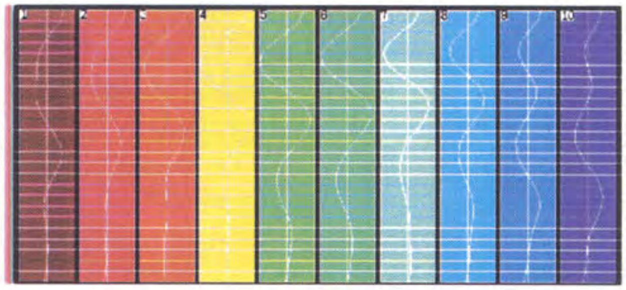
The field of 3-D seismic technology is evolving rapidly and much of the development of new technologies is occurring in the private sector. Several companies have proprietary packages that, for a fee, may be used to process or analyze 3-D seismic volumes. For example, one such company processes 3-D volumes to produce cubes that display the location of "gas chimneys" (i.e., vertically migrating gas; Meldahl et al., 1999), the location of which might be important for sea-floor stability considerations or hydrocarbon prospecting.

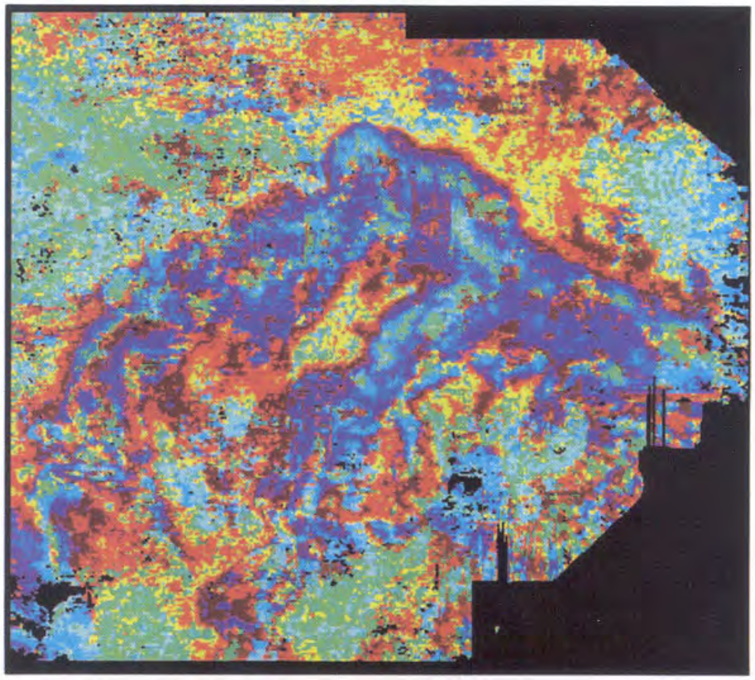
One tool that is showing considerable promise for detecting stratigraphic features uses subtle changes in waveform shape ("seismic facies") within a user-defined interval (Morice et al., 1996; Poupon et al., 1999). These changes might be due to variability in lithology, bed thickness, porosity or other factors that are related to depositional processes, diagenesis, fluid migration etc. The objective is to use neural networks to map seismic character and assess the variation in signal shape over an interval of interest (e.g., a reservoir). The result is a series of end-member model traces that represent seismic data heterogeneity. Classification maps (e.g., Fig. 6.14) are then computed to show the distribution of similarity between actual seismic data and the models. The results can be striking images of geologic features that are objectively derived from the seismic data. These images and results can be merged, both visually and analytically, with other types of information (Poupon et al., 1999).

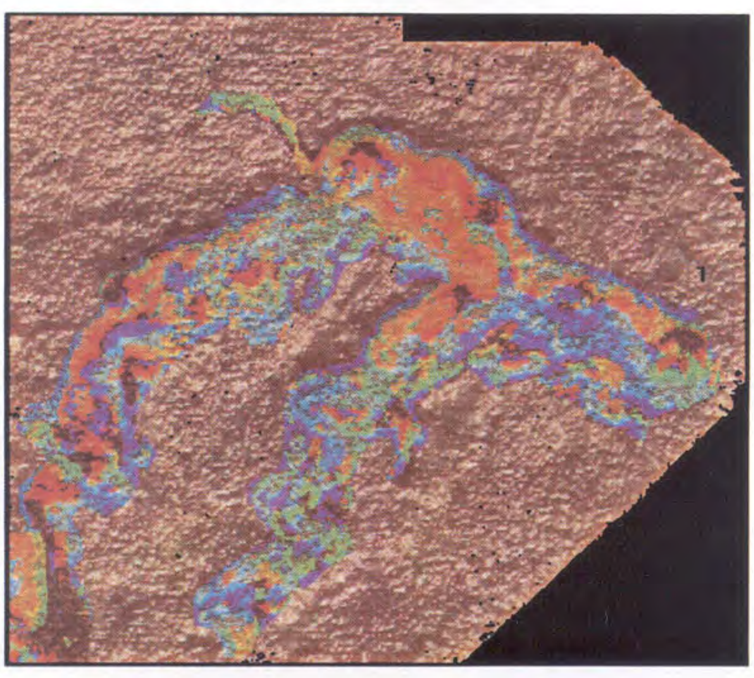
POSTSCRIPT

Many of the interpretation tools and techniques that are used routinely nowadays were not available only a few years ago (see changes in Brown's AAPG Memoir 42 between 1991, 1994 and 1999). Dorn (1998) for example, discussed the use of virtual reality rooms that allow the seismic interpretation team to become "immersed" in the data. Although this particular technology is currently not widely used, it seems clear that advances in visualization technologies will play an important role in the future of seismic interpretation. This is a positive trend, in that the interpreter will be allowed to view the subsurface the way that it actually exists: in 3-D. The caveat is that geologists need to keep actively involved in the process, in order to make sure that the subsurface reality

Figure 6.15 (opposite). Automated seismic facies classification in the Oligocene Frio Formation of south Texas. The upper image shows ten color coded "end member" seismic traces that were identified by an unsupervised neural network as being present at the Frio level in the seismic survey area. The middle image shows the spatial distribution of the seismic facies. Two eastward (right) flowing rivers are present. Further analysis of this image can help the interpreter to identify sedimentary features such as point bars, levee deposit, channel fills, spits and mouth bars, overbank deposits, etc. In the lowe image, the seismic facies have been superimposed on a dip map of the horizon of interest. The result approximates a paleo-geomorphologic map of the depositional system. Survey area approximately 114 km^2. Images courtesy of Flagship Geo.







(i.e., the *geology*) does not get left out.

The interpretation flow described in this chapter has been developed in the petroleum industry. However, the approach has definite applicability to the environmental industry and, possibly, the mining industry (should 3-D seismic prove to be a worthwhile technology in that discipline). Typically in the petroleum industry, a 3-D seismic interpretation is not viewed so much as a 'final product', but as a 'work in progress' that is to be updated and revised as new data become available through drilling. Integration of all available data types helps the interpreter to constrain the possible subsurface stratigraphy, structure and rock properties. However, the non-uniqueness of the seismic method is something that continues to be a problem, whether one is working with 3-D or 2-D seismic data. We have an ambiguous, incomplete picture of the subsurface with 3-D seismic data, but it is by far the best picture that we can hope for and advances in technology are making that picture better every year.

CHAPTER 7: SELECTED CASE STUDIES

INTRODUCTION

Until this point, we have dealt with 3-D seismic in the abstract sense, i.e., the focus has been on general principles rather than on concrete examples of what types of things that the technology can accomplish. This chapter will present selected case studies that illustrate some accomplishments (and limitations) of 3-D interpretations. The studies are drawn from projects that the author has worked on personally. Brown (1999) and Weimer and Davis (1996) present many other excellent case studies that illustrate other uses of the technology, interpretation approaches and concepts that are not presented here. Two other good sources are *The Leading Edge* and *First Break*. *Geophysics* has had some good case studies lately, including a few that dealt with shallow, high-resolution ("environmental") surveys. Trade magazines (*World Oil*, *Oil and Gas Journal*, etc.) also publish case studies.

Locations of the study areas are provided in Figure 7.1. The first case study deals with a small 3-D seismic survey collected in central New York. It shows some of the limitations that one can run into when working with a limited data set. Next, the offshore Gulf of Mexico is the scene for a multidisciplinary study of how depositional features control production from Pleistocene shelf margin deltas. The structural geology of that same area is the focus of the third case study. This work discusses the three-dimensional evolution of a growth fault array and shows how 3-D seismic data can be exploited to study structural problems. Finally, we will visit a small oil field in southern Alabama to look at how seismic attributes may be employed to derive reservoir physical properties.

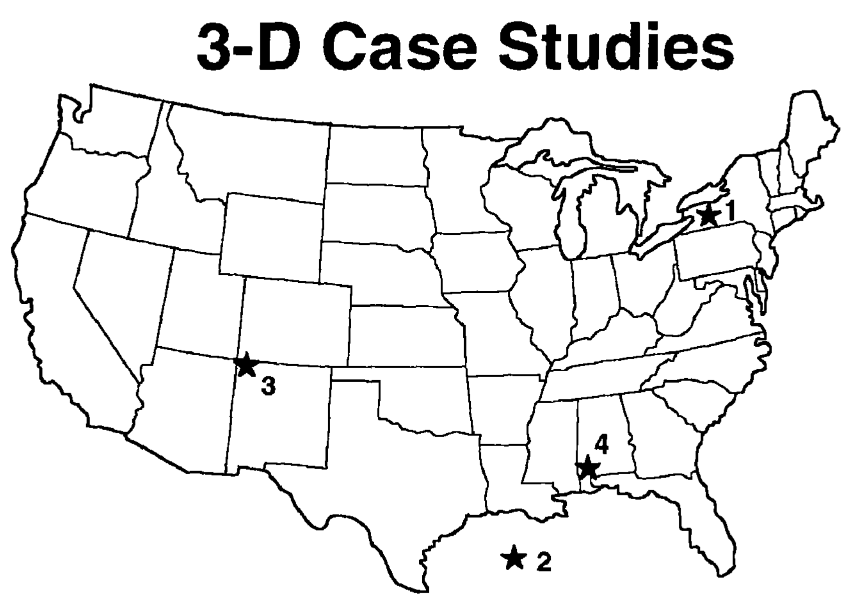


Figure 7.1. Location of case studies described in this chapter.

WYOMING COUNTY, NY

This case study is based on analyses of the first 3-D seismic data collected from New York. Partial results were presented in Hart et al. (1996). The objectives were twofold: a) to evaluate the possibility that a Cambro-Ordovician subcrop play being chased in Ohio could be extended into New York, and b) to test the usefulness of 3-D seismic for finding and exploiting those reservoirs.

The 3-D seismic survey was small, 7 km^2 (2.7 square miles). The location had been picked based on interpretation of a non-regular grid of 2-D seismic profiles (Fig. 7.2a) and the results of a well drilled to test a structure defined during the 2-D seismic interpretation. The well tested some gas, but quickly watered out and was completed in a naturally fractured interval just above the unconformity. That well was the only well in the area of the 3-D survey that penetrated the target horizon, although there were several wells in and around the 3-D survey area which penetrated shallower horizons. One synthetic was available for a well located some distance away from the study area (Fig. 7.3). The hope was that this synthetic would allow a good enough character match to be able to pick the 3-D seismic data. Fortunately, this seemed to be the case. No check-shot data were available from the study area.

The 2-D seismic interpretation concluded that the basic structure at the Cambrian level had a SW-NE trend (Fig. 7.2a), since this conformed with the structure that could be mapped at higher levels where well control was abundant. When mapped with 3-D seismic however, the Knox Unconformity had a dominant NW-SE trend (Fig. 7.2b) that was completely unexpected. This trend was associated with faulting (Fig. 6.4) below the unconformity. Hart et al. (1996) concluded that the faults were associated with the reactivation of NW-striking Proterozoic wrench faults that were reactivated during the Middle Ordovician tectonic activity that generated the Knox Unconformity. These structures were later buried (Figs. 7.4, 7.5).

Unfortunately, no structural closure was found in the 3-D study area. A well was drilled however in the northern part of the study area, structurally higher than the only other well to reach the Cambrian in the survey area, and it did produce gas although not at the rates originally hoped for. The structural complexity imaged at the unconformity level suggests that similar play opportunities may be present in New York as in Ohio. This result was previously undemonstrated.

This case study demonstrates a "limited" success based on qualitative interpretation of 3-D seismic data. The principal factors that could have contributed to greater success would have been: a) a larger 3-D survey area that might have been able to find structural closure. Seeing more of the picture might have allowed better definition of stratigraphic features that are important in Ohio, and b) more data that could be integrated into the interpretation. With only one well, it was impossible to link seismic attributes with well properties (Chapter 6) or production data and so establish what type of seismic character needs to be looked for in the data. This theme is explored in the next case study.

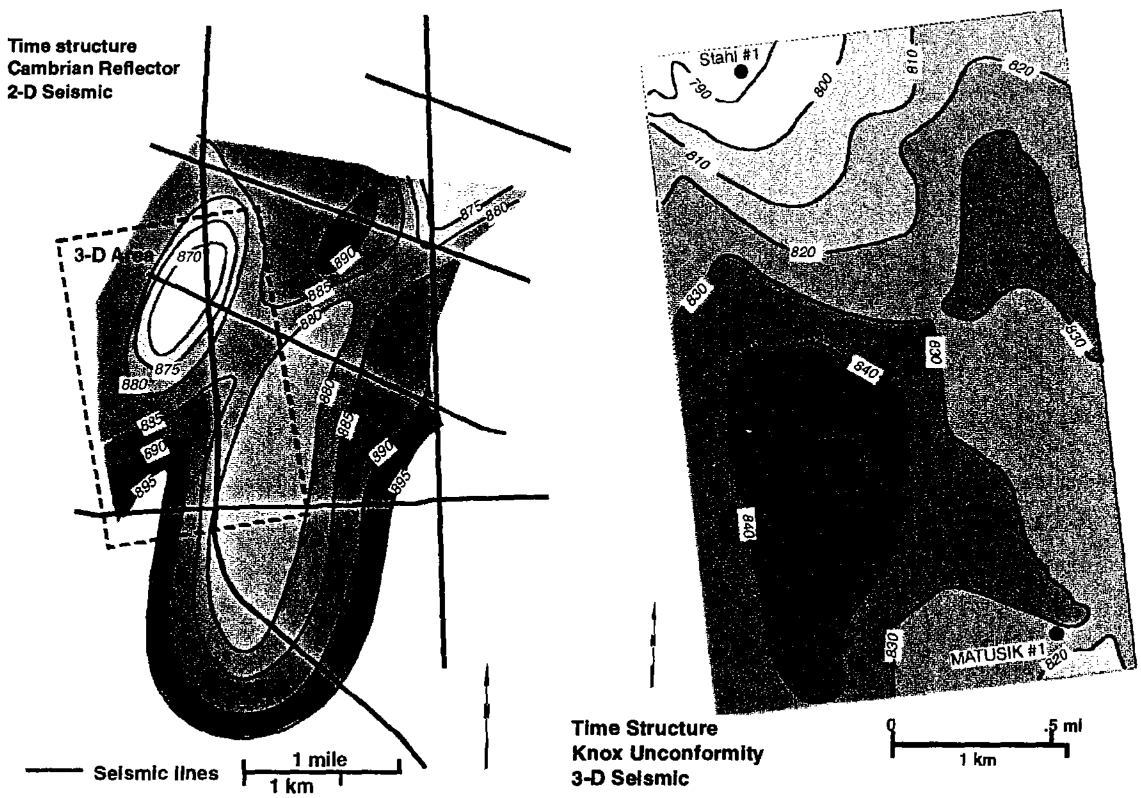


Figure 7.2. a) Time structure map (ms TWT) on top of "near Cambrian" reflection based upon an irregular grid of 2-D seismic lines. The data were interpreted to show a NE-SW structural strike in order to conform to known structure (from well control) at shallow depths. Note outline of 3-D seismic survey area b) Time structure map (ms TWT) on Knox Unconformity (close to reflection shown in 7.2.a) based on mapping with 3-D seismic data. Note the NW-SE trend at this level that was missed using the grid of 2-D lines. The Matusik #1 well, drilled to reach the crest of the structure based on the 2-D mapping, narrowly missed hitting a small graben.

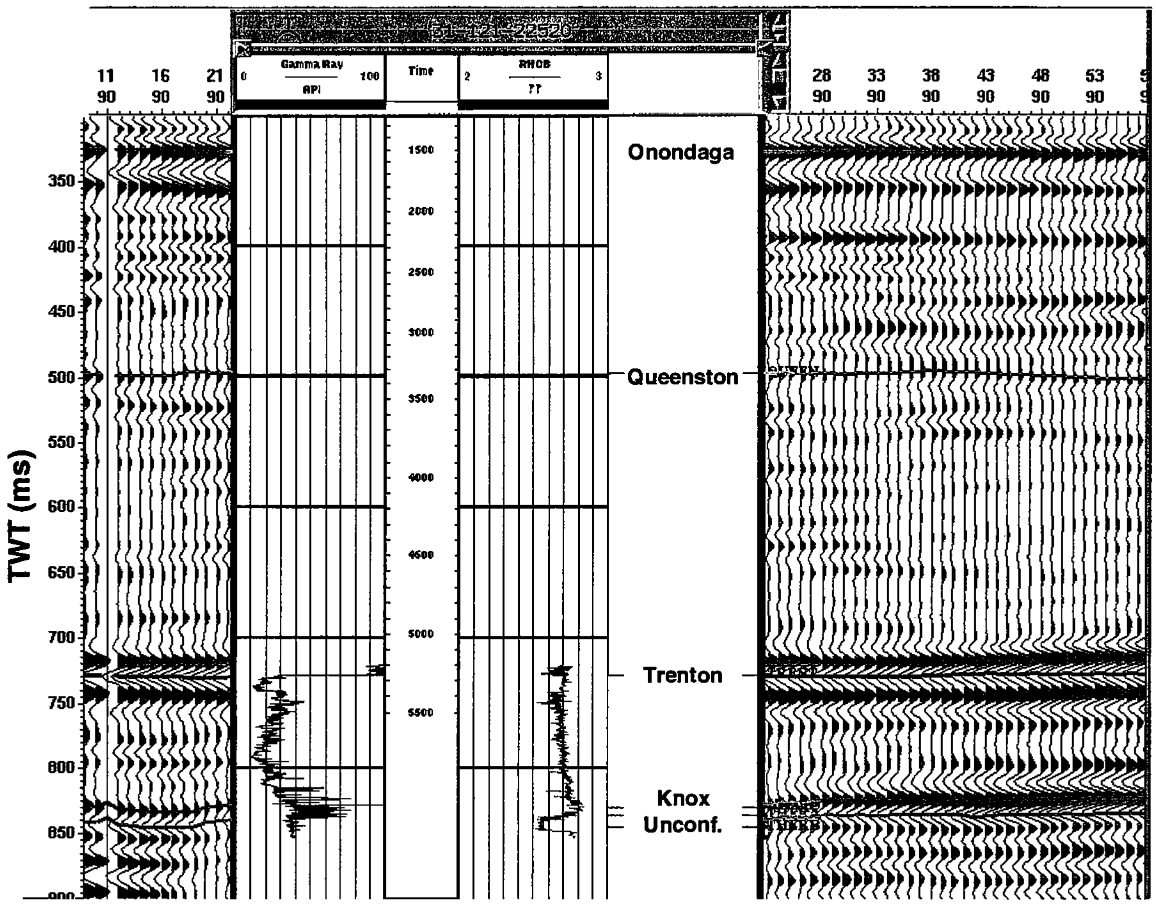


Figure 7.3. Well tie at the Matusik #1 location. Image shows variable area wiggle display of seismic data with digital well log data (gamma ray – left, density – center, log picks, right) inserted at well location. Upper log picks (Onondaga and Queenston) made from log data that were not digitized. In the absence of a check shot survey for this project, the well picks were tied to seismic reflections (based on knowledge of their seismic character in nearby areas) to create an "artificial" time-depth survey.

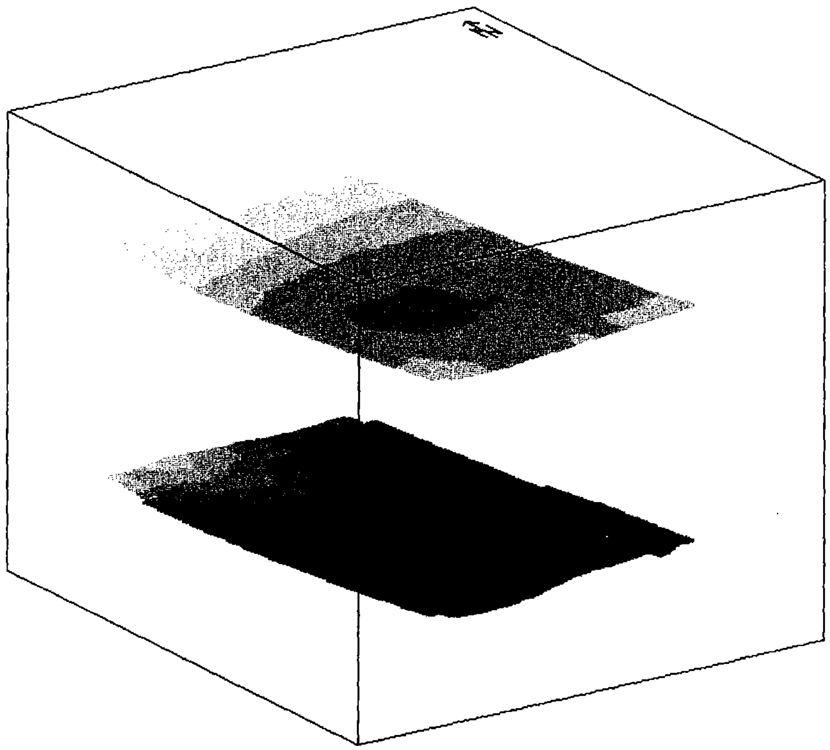


Figure 7.4. Perspective diagram of Onondaga (upper) and Knox Unconformity (lower) time structure horizons. Gray tones indicate relative structure at each horizon (dark = deep). Note how NW-SE structural trend at Knox level is absent at the Onondaga level.

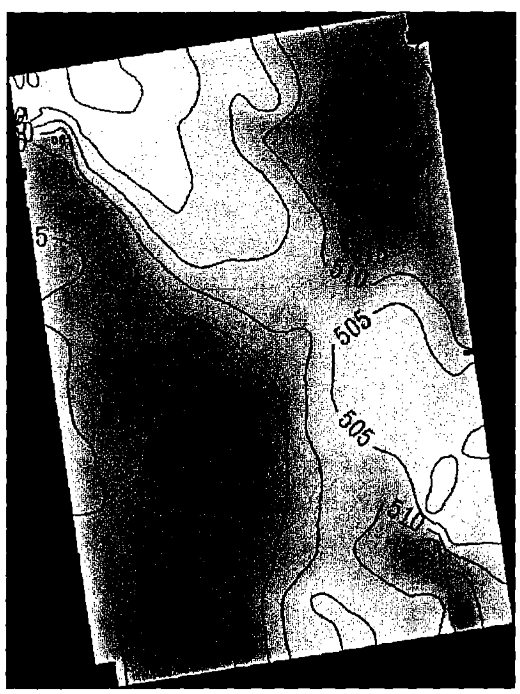


Figure 7.5. Isochron map (ms TWT) of Onondaga-Knox Unconformity interval. The presence of thin areas (light gray) over structural highs at the Unconformity level suggests that the deep structure was buried by Onondaga time.

PLEISTOCENE LOWSTAND DELTA, OFFSHORE GULF OF MEXICO

The second case study provided a much larger data set to work with: over 200 km^2 (74 square miles) of 3-D seismic data and over 1500 digital logs from about 200 wells. The location is the Eugene Island Block 330 Field of the offshore Gulf of Mexico (Fig. 7.1). Production in this field is from several stacked lowstand basinal and deltaic sands (generally unconsolidated) that have been folded and faulted. The uppermost sand, the GA Sand (Fig. 7.6), was chosen for detailed analysis. Full results are presented by Hart et al. (1997).

Log analysis provided both gamma ray log facies that could be used to identify depositional environments and the physical properties of the units. In this area, the reservoir sands are slower and less dense than the surrounding shales. The presence of gas or oil (the oil contains dissolved gas under *in situ* conditions) in the sands makes them even slower and less dense than the surrounding shales (see also Chapter 6), enhancing the acoustic impedance contrast between the two lithologies. As such, hydrocarbons can be imaged as *bright spots* (high amplitude reflections).

Synthetics were used to tie the well data to the seismic. Several check-shot surveys were also available, helping to account for velocity variations in the study area. Once the logs and seismic had been tied, the top of the GA sand and other significant horizons were identified and mapped throughout the study area. Integration with fault mapping allowed structure maps to be generated (Fig. 7.7). The most significant reflections were generated by flooding surfaces, also the most prominent lithologic boundaries, although downlap surfaces and unconformities were also identified (Figs. 6.2, 7.8). These seismic sequence analyses and seismic facies analyses were integrated with well log data to define the major paleogeographic elements and a depositional history. Deposition was controlled or influenced by syn-depositional structural development, autocyclic lobe switching, mass failures and changes of relative sea level.

A major concern here was that depositional features (such as mouth bar sands or interdistributary littoral sands) or faults could be compartmentalizing reservoirs and, thus, existing wells might not be adequately draining them. Amplitude maps extracted from the top of the GA sand showed the disposition of potential hydrocarbon reservoirs (Fig. 7.8a). Both faults and stratigraphic features were seen to compartmentalize the reservoir and new drilling opportunities were identified (Sibley and Mastoris, 1994). In fact, the graph presented in Figure 1.1 was derived for a portion of this study area. Time-lapse seismic work described by Anderson et al. (1996) was also from this field, albeit for a different reservoir level.

This study demonstrates a "classic" example of the use of 3-D seismic. Abundant seismic and other data types could be integrated into the interpretation. Production had already been established in the study area and so the seismic character of the intervals of interest could be established fairly easily. Direct hydrocarbon indicators (the bright spots) allowed definition and delineation of oil-charged sands. The structural and stratigraphic complexities were significant and could not be adequately mapped using well data and/or 2-D seismic data.

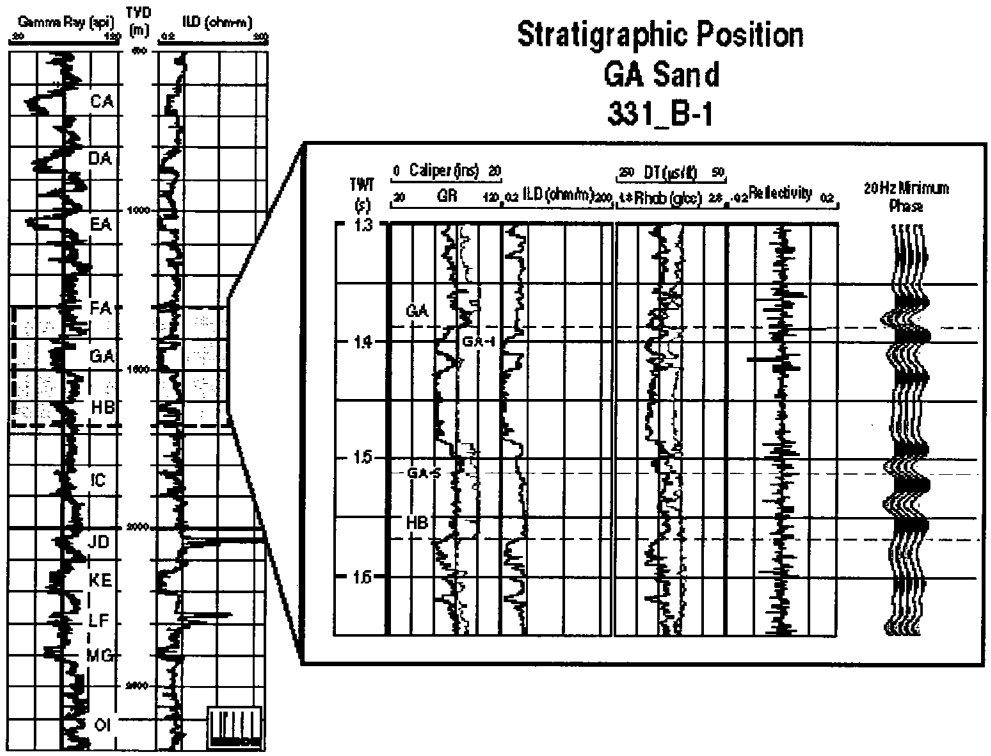


Figure 7.6. Log-based summary stratigraphy of Eugene Island (EI) Block 330 area showing stratigraphic location of GA Sand. Inset shows detailed character of logs in GA interval and a synthetic seismogram for this well that was used to help tie it to the seismic data using available check shot data. Modified from Hart et al. (1997).

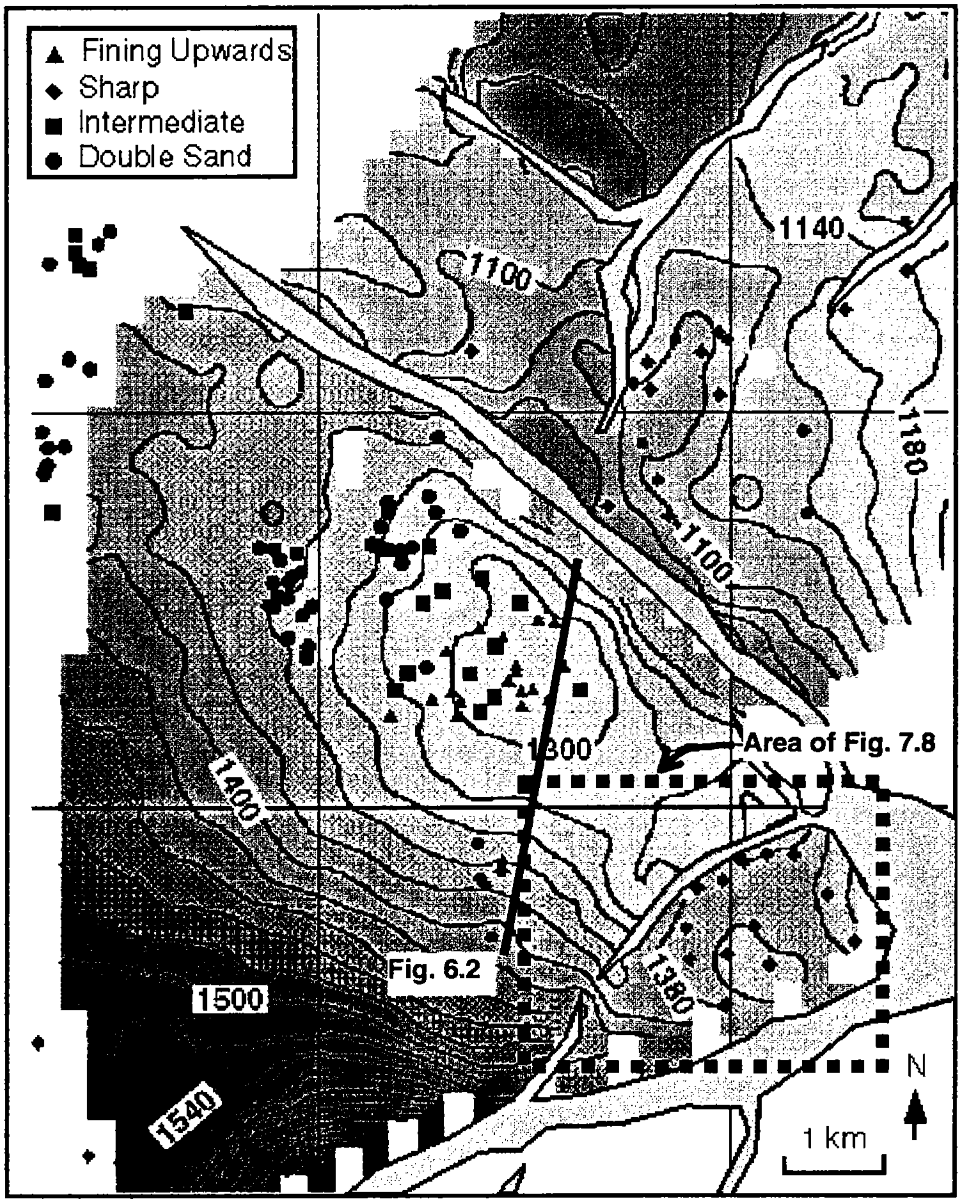


Figure 7.7. Depth converted structure map (contours in meters below sea level) of top of GA sand in the Eugene Island Block 330 area. Depth conversion was completed using a velocity grid derived from check shot surveys. A rollover anticline with 4-way dip closure (a "dome") is present in the center of the image. Well symbols show wireline log facies for all wells that penetrate the GA sand (but not all wells produce from this level), and the distribution of facies indicates that the dome was present during deposition of the sand. Irregular gray polygons show fault network at this stratigraphic level (see Rowan et al., 1998, for analysis of the fault network). Dashed area shows approximate location of Fig. 7.8; line shows approximate location of Fig. 6.2. Modified from Hart et al. (1997).

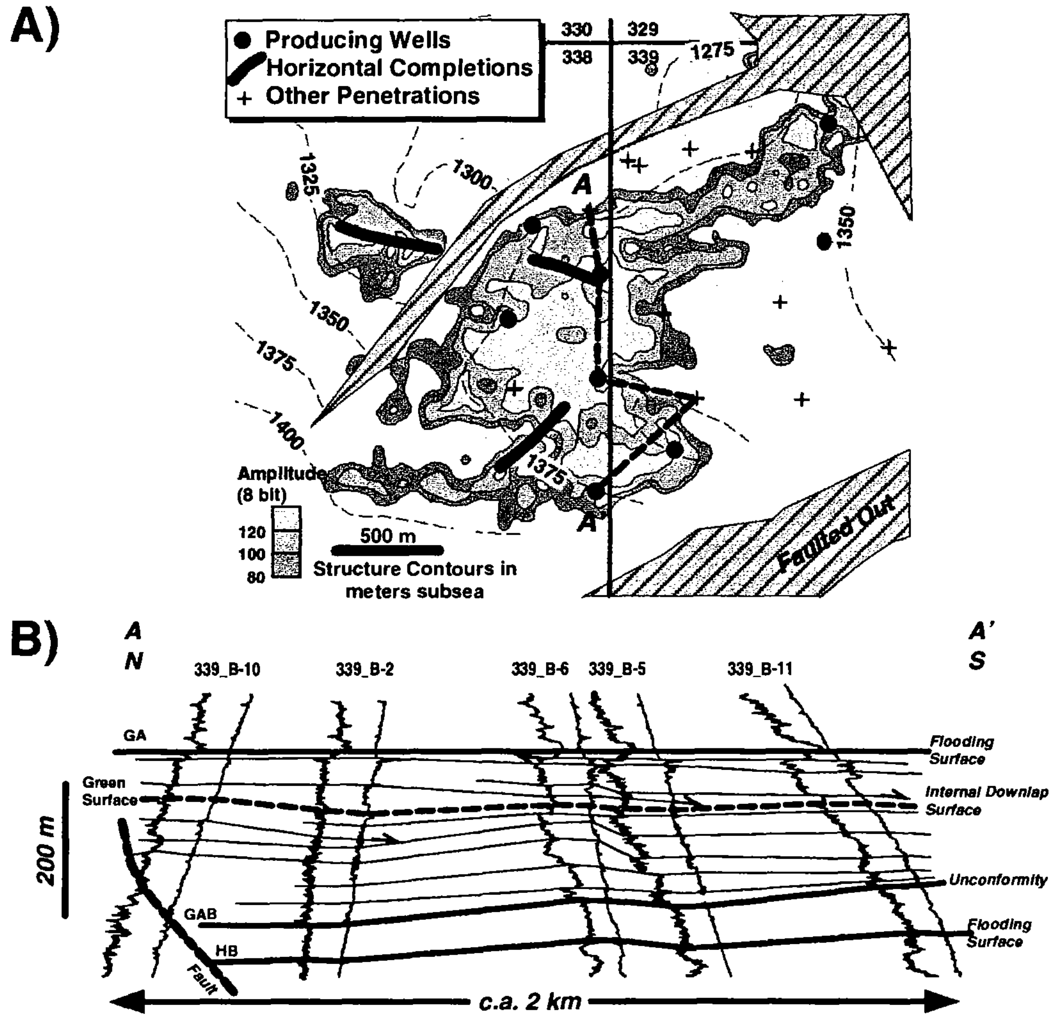


Figure 7.8. A) High-amplitude regions associated with the top of the GA sand in a portion of the EI 330 field area (see Fig. 7.7 for location). High-amplitude areas strike approximately east-west and are interpreted as hydrocarbon-charged, shore-parallel interdistributary sandbodies. A stratigraphic cross section through this area (B) shows that the GA sand consists of a prograding (to the south) deltaic succession that has at least two oil-water contacts (in the 339_B-2 well). As described by Sibley and Mastoris (1994), reservoir compartmentalization in this area by stratigraphic and structural features was leading to inefficient drainage. As such, costly horizontal wells were drilled to target bypassed pay and increase production. Figure 1.1 shows the effects of targeted drilling on production from this area (other production is obtained from stratigraphically lower sands). Modified from Hart et al. (1997).

REVITALIZING AN OLD GAS FIELD – UTE DOME

As illustrated in Figure 1.1, 3-D seismic data have been successfully used to rejuvenate declining oil and gas fields. This is because these data, when properly integrated with other data types, may allow field operators to image and map stratigraphic and structural features that can act as barriers to fluid flow. In this way they can locate and target "bypassed pay" (i.e., portions of the reservoir that will remain undrained with existing wells) and optimize recovery programs.

One such example is Ute Dome Field in northwestern New Mexico (Fig. 7.1). Production from the Cretaceous Dakota Formation (at approximately 700 m depth below surface) was established in 1921 at Ute Dome. Production from the Pennsylvanian Paradox Group (at approximately 2400 m depth below surface) was subsequently established in 1948. Tezak (1978a,b) summarized what was known about the field in the late 1970s. By the end of 1996 the Dakota had produced approximately 19 BCF of gas, and the Paradox had produced nearly 92 BCF of gas.

The Dakota is a stratigraphically and structurally complex unit that, in a broad sense, records the transgression of this area during the mid-Cretaceous (Coniacian). At Ute Dome, the lower part of the formation consists of non-marine channel sandstones and associated fine-grained coastal plain deposits, whereas the upper portion of the Dakota consists of paralic/marine sandstones interbedded with marine shale as a series of backstepping parasequences. These two different depositional settings can be recognized on gamma ray logs by curve shape. Integration of log and production data shows that the lower, fluvial sandstones are the most productive Dakota facies at Ute Dome.

Structurally, the Dakota has been deformed into an asymmetric dome that has been broken by NW-SE striking normal faults. Several of these faults continue to the surface and have been mapped in the Upper Cretaceous Mesaverde Group. Figure 7.9 shows how structural interpretations of this level have changed since the acquisition of the 3-D seismic survey. The 3-D seismic-based map was derived primarily from mapping with vertical transects through the amplitude volume and time slices through a coherency attribute volume (Fig. 6.7). This work showed that there are more faults and their locations are somewhat different than originally mapped (a common 3-D interpretation result).

This complex structure has academic interest (Ralser and Hart, 1999) but is also important from a production standpoint. The faults combine with the discontinuous nature of the fluvial sands to compartmentalize the reservoir in a very complex fashion. As such, understanding the structure at the Dakota level is one part of the problem. One must also, however, be able to predict the distribution of fluvial sandstones. Unfortunately, the frequency content of the seismic data is not adequate for mapping individual sandstones (Fig. 7.10). As a result, mapping of individual fluvial sandstones was based primarily on log correlations, guided in places by 3-D mapping results such as isochron maps (Fig. 7.11).

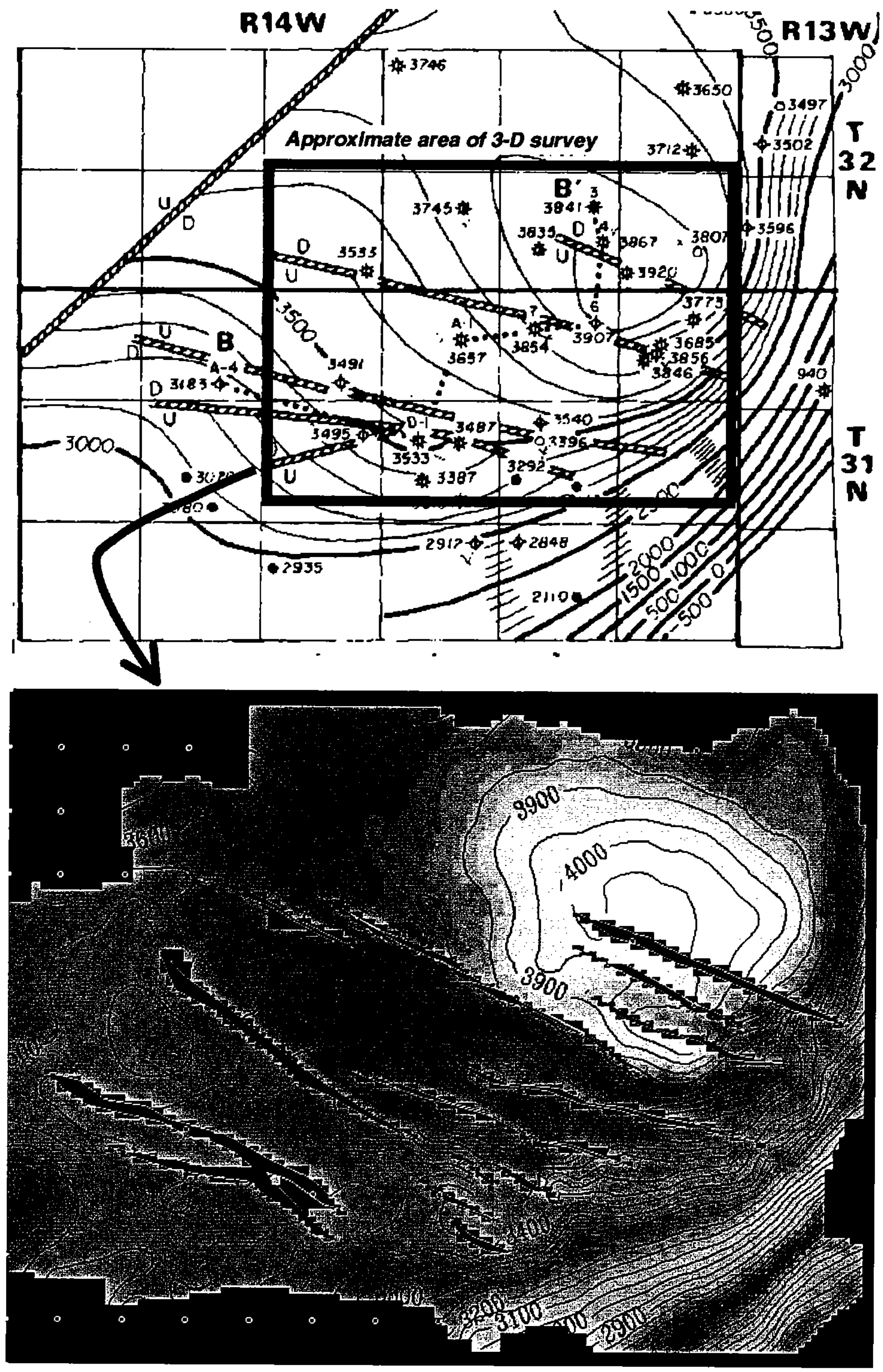


Figure 7.9. Two different versions of a structure map for the Dakota Formation at Ute Dome Field. The upper image is from Tezak (1978a) and shows the structure as mapped in the late 1970s. 3-D seismic data were acquired in the early 1990s and were used along with well data to generate a more accurate map of the Dakota (below) in this field. Note the differences in the numbers of faults, their lengths, and locations. Structure contours are in feet above sea level in both cases. Area is approximately 6 x 4.5 km.

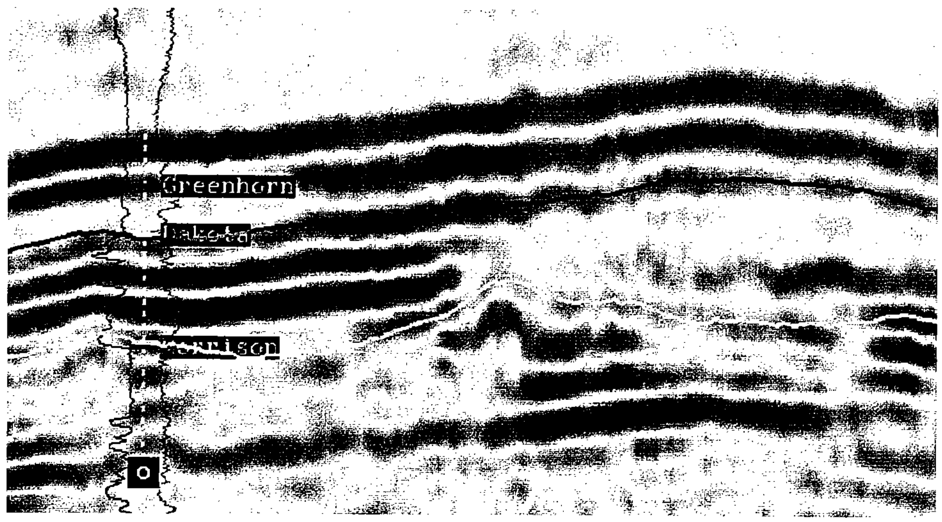


Figure 7.10. Approximately northwest (left) – southeast (right) seismic transect through the Dakota Formation at Ute Dome Field. This arbitrary transect was selected to avoid going across any faults. On left is a well with logs (gamma ray – left, resistivity – right) and marked picks. The level of stratigraphic detail visible in the well logs is greater than that which is seen in the seismic data. Note the relief at the unconformity at the base of the unit (see also Fig. 5.8).

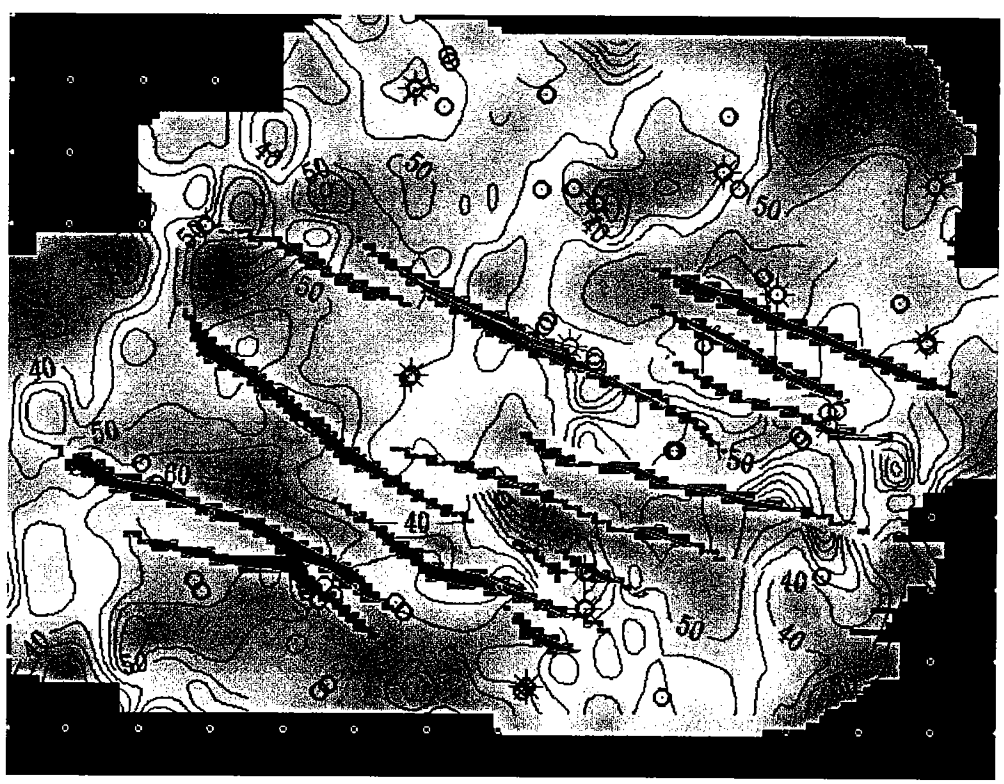


Figure 7.11. Isochron map of the Dakota at Ute Dome. Contours in milliseconds TWT. SW-NE thickness trends are associated with relief on the unconformity at the base of the formation (e.g., Figs. 5.7, 7.10). Other thickness changes are present where the unit has been affected by faulting. Locally, faulting has structurally thinned the formation by faulting out part of the section. Area is approximately 6 x 4.5 km.

Like the first case study presented in this chapter, there are differences between the deep and shallow structure at Ute Dome (Fig. 5.11). There are also lithologic differences between the two levels. At Ute Dome, the Pennsylvanian Paradox group consists of carbonates (mostly limestone) with some evaporites. These rocks were deposited in an outer shelf or penesaline environment and have less stratigraphic variability than the Dakota Formation. The Paradox Group is characterized by low matrix permeability at Ute Dome.

Rocks of the Paradox Group have been folded and faulted but in a different manner than the overlying Dakota Formation (Fig. 7.12). The shape of the dome is different, and faults at this level have less offset and different locations and orientations than faults at the Dakota level. SW-NE striking reverse faults are present along the eastern margin of the survey area (Fig. 7.12, 7.13, 7.14). The throw on these faults decreases up-section (i.e., blind thrusts), such that in the upper part of the Paradox Group they appear to represent simple folding over the underlying faults (Figs. 7.12, 7.13). There are also some down-to-the-southwest normal faults that strike NW-SE but these are not connected to the faults at the Dakota level. Faults and flexures at the Paradox level are evident in dip maps (Fig. 7.14). Comparison of dip maps and gas production from this interval shows that there is good correspondence between these two variables (Fig. 7.14), suggesting that fracture permeability enhances production from these low-permeability carbonates.

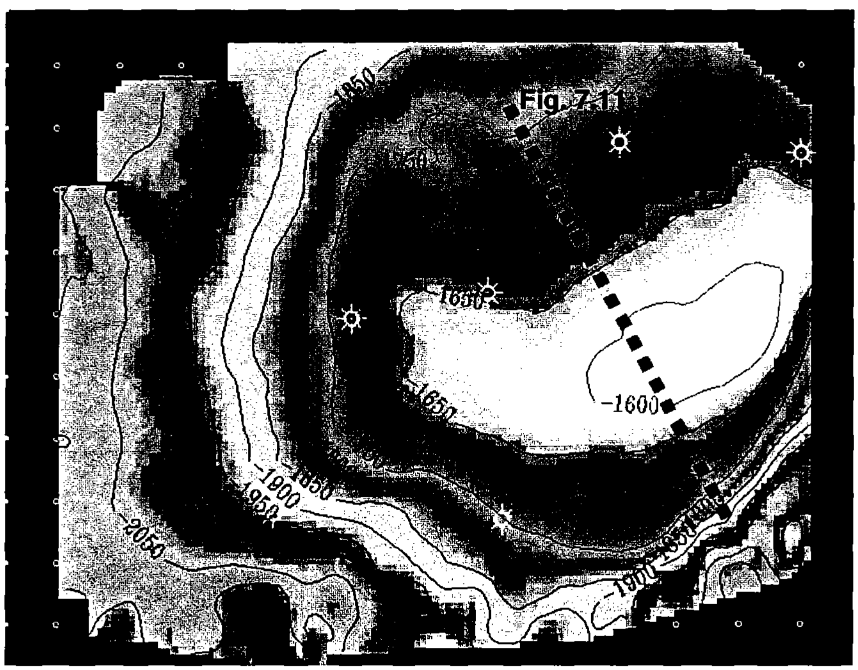


Figure 7.12. Depth converted structure map of the Desert Creek Formation of the Paradox Group at Ute Dome (elevation in feet). The crest of the dome is somewhat southeast of the crest of the dome at the Dakota level (see Fig. 7.9). Also, the prominent NW-SE striking growth faults at the Dakota level are not present at this level. Symbols show location of wells that penetrate and produce from Pennsylvanian rocks. Area is approximately 6 x 4.5 km.

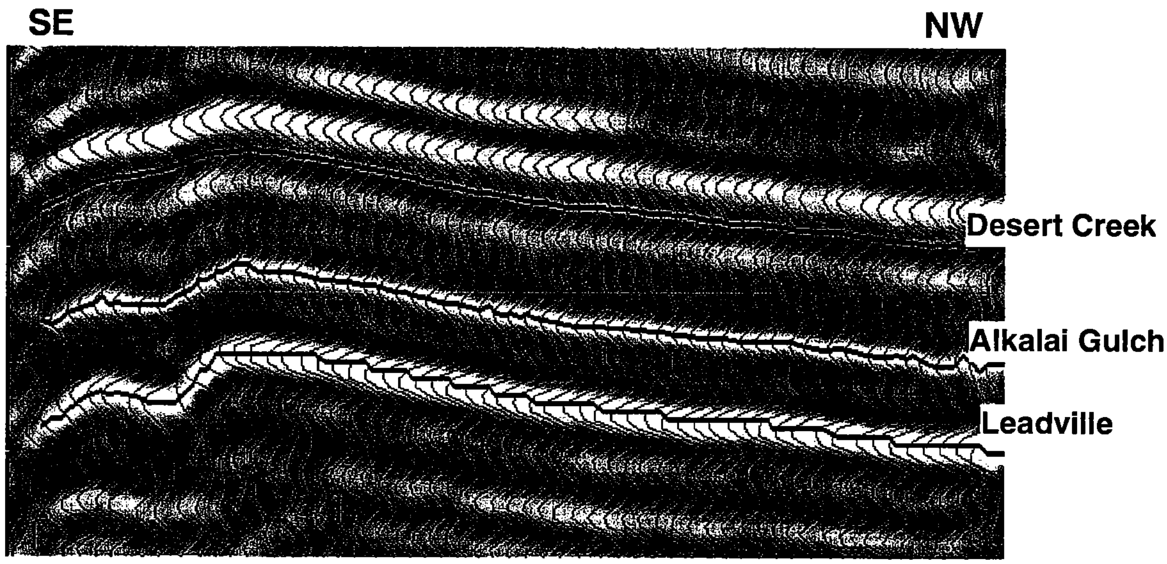


Figure 7.13. Arbitrary transect through Ute Dome 3-D seismic volume showing character of reverse faults at the Paradox level. Reverse fault on left offsets Mississippian Leadville limestone (and underlying horizons) and also offsets Alkalai Gulch cycle of the Paradox. The Desert Creek horizon (near the top of the Paradox, time structure shown in Fig. 7.12) appears to be only flexed over the fault. The transect is a variable density display (black-white color bar) with wiggle trace overlay. See Fig. 7.12 for line location.

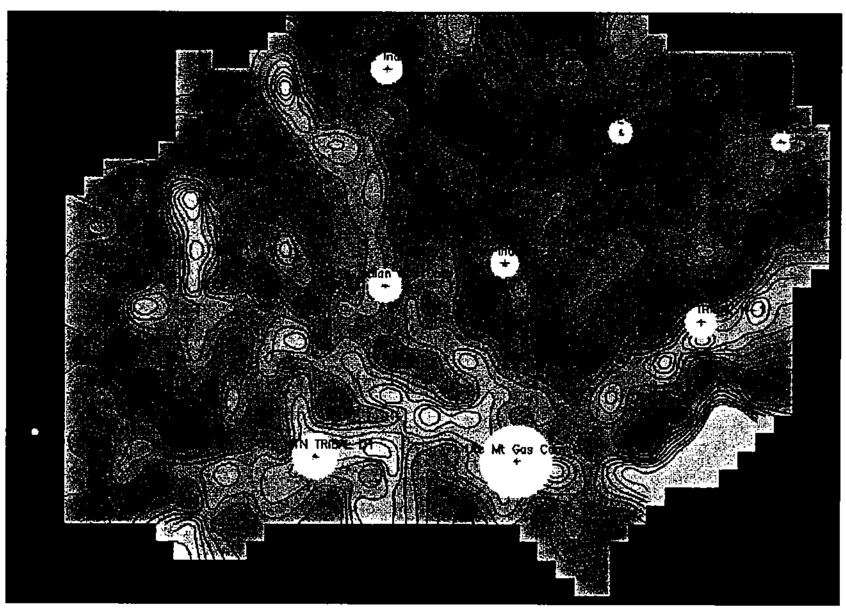


Figure 7.14. Contour map of dip of Alkalai Gulch horizon (higher dips in light grays) with "bubble plot" overlay of gas production from the Paradox Group. The high dip areas show SW-NE and NW-SE trends that indicate locations of reverse faults and normal faults (respectively). The size of the production bubbles is proportional to the best year's production from that well - a simple, but non-definitive measure of well performance and (hopefully) subsurface geologic conditions. Using this and other production measures, it can be seen that the best producing wells (e.g., 1 Ute Mt. Gas Com M, Ute MNT Tribal D 1) are located on high dip areas that are probably associated with increased fracture density.

The analyses at Ute Dome demonstrated the types of differences that can be present between two productive stratigraphic levels in the same field. The Dakota level is a "conventional" clastic reservoir (i.e., matrix permeability and porosity are relatively high) that is compartmentalized by stratigraphic features (channels) and faults. Channel sandstones high up on structure are the primary drilling targets, and faults are to be avoided. On the other hand, carbonates of the Paradox Group form a fractured "tight" (i.e., low permeability) gas reservoir. Fault or flexure zones form the best producing areas and should be targeted by drilling. In both cases, analyses of 3-D seismic data augmented by analyses of geologic and engineering data helped field operators to locate new drilling targets and help to increase production from this old field.

RESERVOIR PROPERTIES FROM SEISMIC ATTRIBUTES

The final case study comes from southern Alabama (Fig. 7.1). Here the problem was to find infill drilling possibilities, possibly only one well, in a small oil field. The target formation was the Jurassic Smackover Formation. The database consisted of approximately 17.5 square miles (45 km^2) of 3-D seismic data, logs for ten wells and a single check-shot survey (Fig. 7.15). Hart and Balch (2000) gave a full description of the project.

In the study area, the Smackover Formation forms a carbonate buildup on a horseshoe-shaped paleobasement ridge. Porosity is developed in the lower part of the formation over the ridges. Off structure, the Smackover overlies the siliciclastic Norphlet Formation and is thought to be non-porous. Above the Smackover, anhydrite of the Buckner Member of the Haynesville Formation thins over the underlying structural highs. These evaporites are in turn overlain by siliciclastics of the main body of the Haynesville (Fig. 7.16).

Previous mapping results of the structure at the top of the Smackover were inconsistent. The structure maps produced by different workers looked different. As such, there was a need to map the structure using 3-D seismic data to see if there were undrilled structural highs that could be possible drilling targets. A 2-D geologic model of the field stratigraphy was constructed, then used as input into a seismic modeling package to see the expected seismic response. Good fit between the model results and the seismic data allowed the principal horizons to be identified and then picked in the seismic data (Fig. 7.17). The time structure map was then depth converted using a velocity map derived from time-depth pairs generated at each well location (c.f., Fig. 6.9).

The Smackover structure map showed three areas of structural closure (Fig. 7.18). Only one well in the field penetrated the crest of a structure, the rest were all sub-optimally located.

There were undrilled structures present in the field, but did they have the porosity needed to make them potential drilling targets? To answer this question, it was decided to use seismic attributes to define the thickness of the porous zone. Fifty-five attributes (reflection strength, average amplitude, isochrons, etc.) were derived from the 3-D seismic data. The thickness of the porous zone (derived from well logs) was correlated against the value of each attribute in the bin that corresponded to the well location.

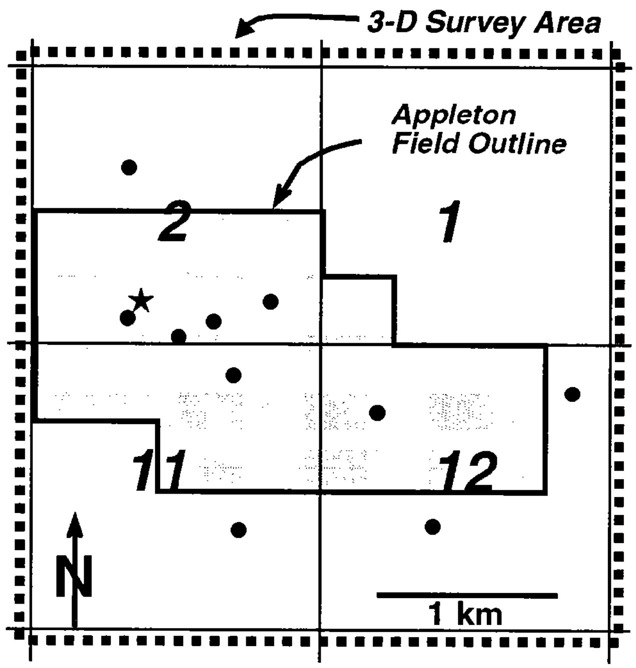


Figure 7.15. Database for study. Dotted box shows outline of 3-D survey area. Dots show well locations. Star shows location of well drilled following study. Numbers (1, 2, 11, 12) refer to section numbers. Polygon shows outline of Appleton Field. Modified from Hart and Balch (*in press*).

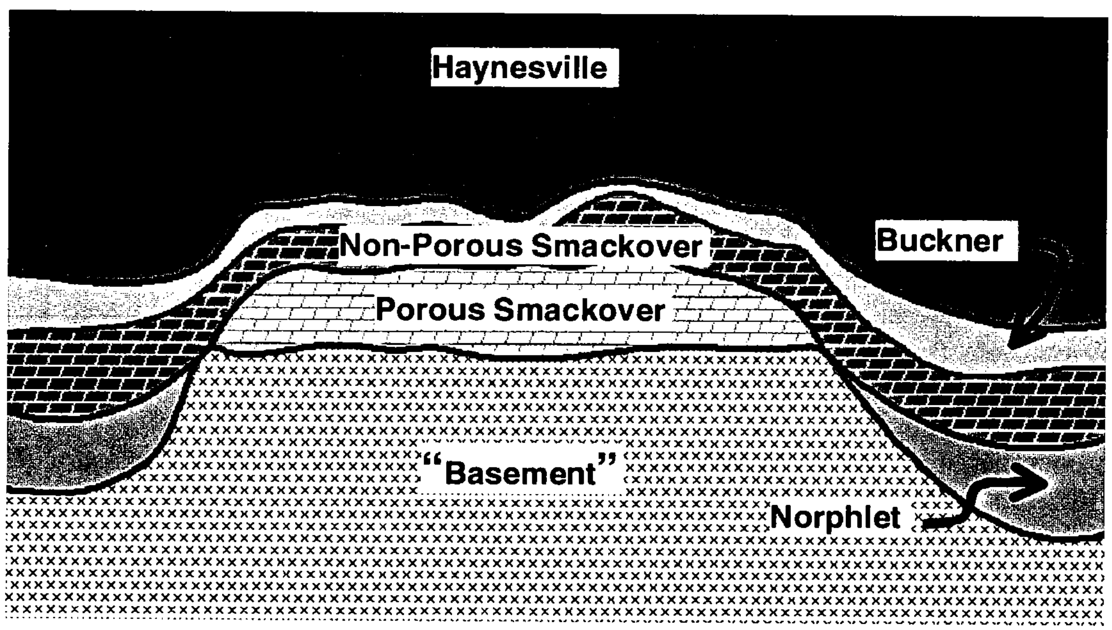


Figure 7.16. Geologic model of strike section across carbonate buildup at Appleton Field. A basement ridge is flanked by siliciclastic sediments of the Norphlet Fm. Porous dolomites of the Smackover Fm. are developed on the crest of the ridge, whereas non-porous carbonates of the Smackover are found on the flanks of the structure and above the porous units on the ridge crest. The Buckner Anhydrite everywhere overlies the Smackover, and the siliciclastic Haynesville caps the succession. Adapted from Hart and Balch (*in press*).

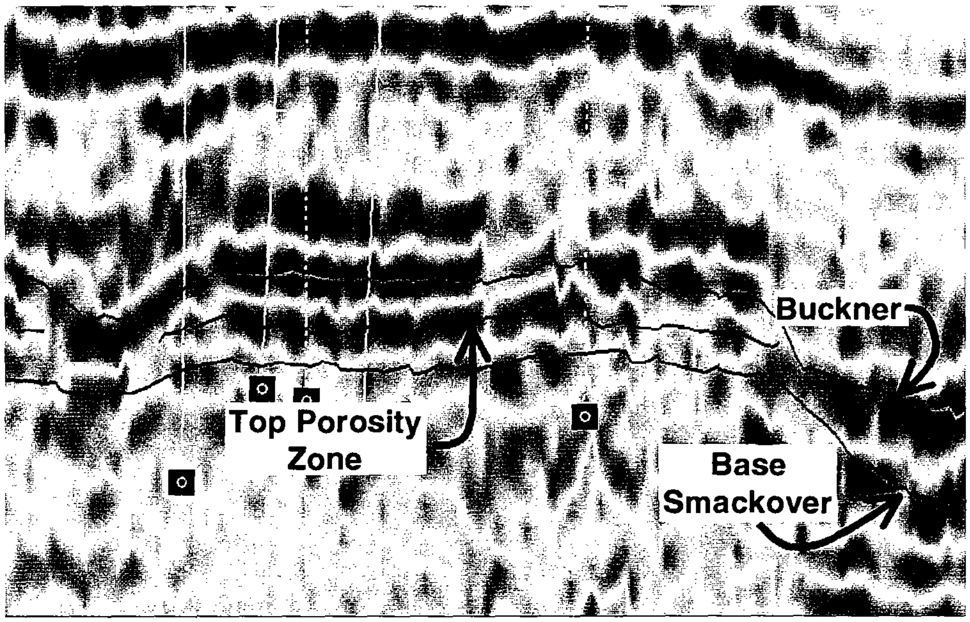


Figure 7.17. Arbitrary transect through 3-D seismic volume along crest of main carbonate buildup at Appleton Field. Transect approximately corresponds to geologic model shown in Fig. 7.14. The principal reflections are: a) the Buckner (Buckner and the top of the Smackover constructively interfere to form a single peak), b) the top of the porosity zone in the Smackover, and c) the base of the Smackover.

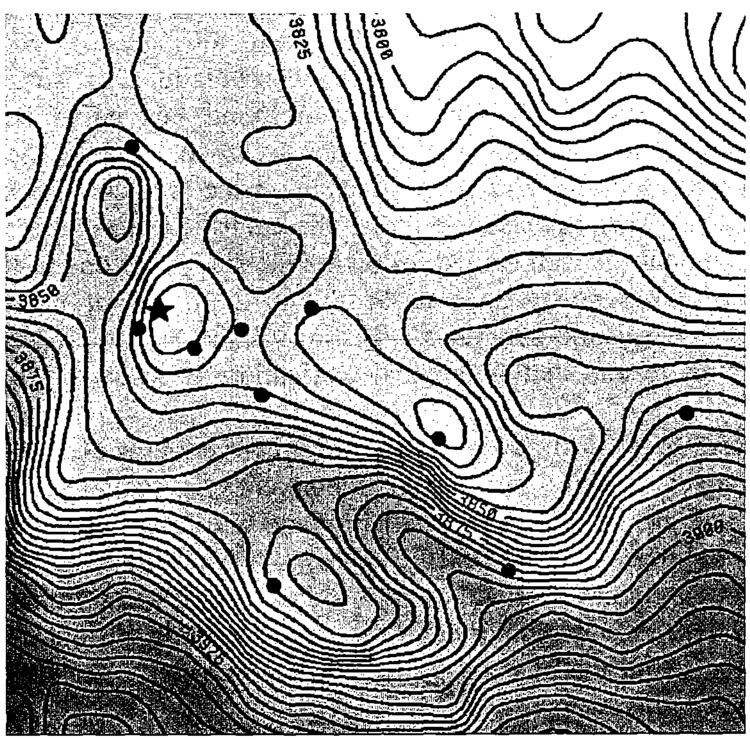


Figure 7.18. Depth-converted structure map of the Buckner (contours in meters below sea level. Dots indicate well locations. Star shows location of well drilled following study. Area shown is approximately 6.5 x 6.5 km (dotted box in Fig. 7.15).

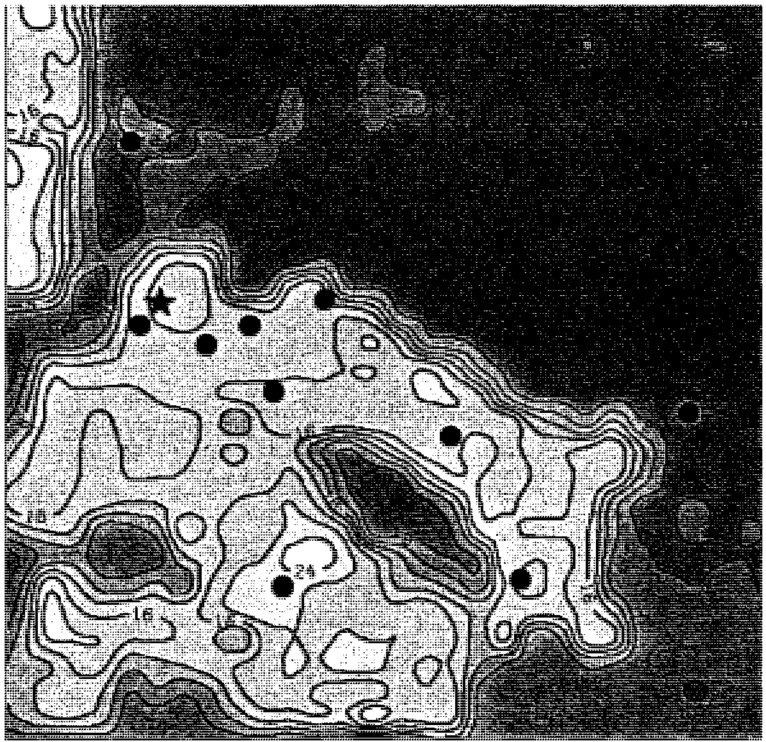


Figure 7.19. Map of predicted thickness of the porosity zone (in meters) at Appleton Field. Dots show well locations. Star shows location of well drilled following study. Area shown is approximately 6.5 x 6.5 km (dotted box in Fig. 7.15).

Correlation coefficients were derived for each attribute-log combination (simple regression analysis), as well as for various combinations of attributes (multivariate regression). In the end, three attributes were found that could be used together to adequately predict the thickness of the porous zone. Once the relationship was determined, it was used to derive a map that shows the predicted thickness of the porous zone (Fig. 7.19). This map showed that the undrilled structures should have good porosity development. A well drilled following the study into one of the structures found the thickness of the porosity zone to be within 2 m (6') of the thickness that was predicted based on seismic attributes. Testing of the attribute-based prediction using seismic modeling results and geological evaluation is presented by Hart and Balch (2000).

This case study illustrates one of the exciting new uses of 3-D seismic in the field of reservoir characterization. Increasingly, companies are looking to improve production by finding oil and gas in existing fields that would not get produced from existing wells. A qualitative approach can be used for cases where there are direct hydrocarbon indicators (e.g., case study #2), although in other cases a more quantitative approach is required. Research groups are perfecting means to exploit seismic attributes in order to gain information about the physical properties of reservoirs, and so better plan drilling and recovery programs.

CHAPTER 8: SUMMARY

The material presented in this course has illustrated uses of 3-D seismic to define subsurface structure, stratigraphy and rock properties. We have touched briefly on the physical basis of the seismic method, how seismic data (2-D and 3-D) are acquired and processed, the advantages of 3-D seismic over other methods, interpretation techniques, and looked at some case studies where 3-D seismic technology has been applied. No two-day short course can make a participant an expert in this or any other field. Furthermore, hands-on experience with 3-D seismic data on a powerful computer will be needed to truly grasp the speed and power of the technology. However, participants in this course should now be in a position to understand the "hows and whys", and so be in a better position to: a) determine whether 3-D seismic technology is right for them in a given project, b) evaluate the results of a 3-D seismic interpretation, and c) by tracking down references provided in these notes, know where to go for more information.

Most of the focus in this course has been on petroleum applications of 3-D seismic technology, because that is where the technology has been developed. It remains to be demonstrated that this petroleum industry approach can be adapted to "academic" branches of the earth science. It also remains to be seen whether certain techniques (e.g., seismic attribute studies) can be adapted to the study of 3-D GPR data. However, if a geoscience project aims to define subsurface structure, stratigraphy or rock properties, 3-D seismic methods stand an above average chance of being able to help solve these fundamental and applied problems – provided that good quality data can be acquired. The primary impediment to expanding the use of 3-D to fields outside of the petroleum industry seems to be cost. In this regard, it will be interesting to see if more cost-effective data acquisition techniques can be developed in the next few years for environmental or other purposes.

One of the underlying themes of this course has been that integration of data and concepts from different disciplines is needed in order to best utilize and extract the wealth of information that is present in a 3-D seismic survey. Geology and geophysics are (usually) the two principle disciplines involved and, as noted several times earlier in this course, a good interpreter (or interpretation team) needs to apply expertise in both of these fields. Hopefully the cultural and communications gaps that sometimes exist between geologists and geophysicists will continue to shrink as the emphasis on goal-oriented problem solving increases.

The technologies being utilized for collecting and analyzing 3-D seismic data are evolving rapidly. Processing techniques are improving to the point that the images visible in 3-D data appear to truly represent geologic features. On the interpretation side however, increasing emphasis is being put on technological advances such as visualization applications, time-lapse monitoring and artificial intelligence applications. In our technology driven society, these advances often appear to overshadow the need to apply stratigraphic expertise to the interpretation. At the same time, seismic methods are not commonly taught to, or learned by, stratigraphers. As such, there is real potential that the stratigraphic information in 3-D seismic volumes is being under-exploited. This is to the detriment of both the end users of the interpretation and the stratigraphy community.

It is my hope that this course will help geologists (in particular stratigraphers) to become more active players in the 3-D seismic game.

Technology, such as the 3-D seismic interpretation tools described in this volume, is an "enabler" that helps people to achieve goals. Technology cannot tell us what to look for, but it can help us to look for things once we have defined what it is we are searching. Powerful technology in the absence of meaningful ideas to test is wasted. The truly remarkable work that is done with 3-D seismic data is accomplished by people who understand that technical excellence and insights in geology, combined with a good understanding of the seismic method, are required to reap the full rewards of working with the technology.

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