Part IV

Predicting the Occurrence of Oil and Gas Traps

Introduction

Petroleum exploration methods are largely determined by the target trap type. Some methods are universally applicable. Part IV contains chapters that discuss general exploration methods and methods for locating structural and stratigraphic traps.

In this part

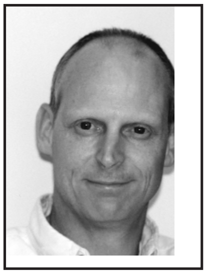
Part IV contains the following chapters.

Chapter 12

Interpreting Seismic Data

by

Christopher L. Liner



Christopher L. Liner

Chris Liner received a B.S. (1978) in geology from the University of Arkansas and an M.S. (1980) in geophysics from The University of Tulsa. In 1980, Liner joined Western Geophysical as a research geophysicist located in London and in 1981 joined Conoco as an exploration geophysicist working midcontinent areas of the United States. After completing his Ph.D. from the Colorado School of Mines (1989), he worked as a research geophysicist with Golden Geophysical in Denver.

Since 1990, he has been on the faculty of the Geosciences Department at The University of Tulsa. He is currently associate professor and is serving as editor of *Geophysics.* Liner is the author of several papers in the areas of seismic processing, wave propagation, and seismic survey design. He is also the author of two books: *Greek Seismology* (1997) and *Elements of 3-D Seismology* (1999). Liner received the Best Poster Paper award at the 1998 SEG Annual Meeting.

Overview

Introduction

A useful analogy can be made between seismic and medical imaging. Not so long ago a mysterious ailment might have meant high-risk exploratory surgery (equivalent to pattern drilling). Wherever possible, surgery today is orthoscopic and highly targeted (equivalent to directional drilling). This is possible because we now have high-quality medical images (equivalent to seismic data) available to guide the surgeon. In this day and age, who would undergo surgery without an X-ray, ultrasound, cat scan, or some kind of medical imaging?

The purpose of both medical imaging and seismic imaging is to reduce risk. In the search for petroleum, seismic imaging reduces risk of many kinds—drilling dry holes, drilling marginal wells, under- or overestimating reserves. Seismic information is a good interpolator between wells. It transfers the detailed information obtained at well locations to the area between wells.

Clearly, a single chapter (or book) cannot cover seismology in detail. This chapter discusses major aspects of the subject from a conceptual standpoint. It focuses on the fundamentals of seismic data, emphasizing interpretion of 3-D seismic data.

In this chapter

This chapter contains the following sections.

Section A
Seismic Primer

Introduction

This section discusses basic concepts of the seismic method. Although the use of 3-D seismic data is the focus of this chapter, many of the concepts discussed apply to 2-D seismic data analysis as well.

In this section

This section contains the following topics.

Phases of a Seismic Project

Introduction

Generally speaking, there are three phases of a seismic project:

- Acquisition
- Processing
- Interpretation

In this chapter we concentrate on interpretation, but it is hard to ignore the importance of the other phases.

Acquisition

A good interpreter knows the basics of seismic survey design and can recognize problems when they arise. Even a well-designed survey can be ruined by sloppy acquisition methods. Common culprits are poor positioning or cabling information (i.e., which receivers are live for which shots).

A 3-D seismic survey is designed to give optimum results for a particular depth interval containing the target(s). If there are design, acquisition, or processing problems, then the data may contain artifacts. These are most commonly seen as map-view amplitude patterns and are called an acquisition footprint. One should avoid footprints because they can mask or confuse geologic patterns in the data.

Processing

Raw seismic data look as much like an image of the earth as a hamburger looks like a cow. An enormous amount of computer and human effort is required to transform raw seismic data into a usable image. Each step involves many user-supplied parameters that can change the result—maybe a little, maybe a lot. In short, processing should rightly be coupled with the interpretation process since the processor makes decisions affecting data quality. However, this is rarely the case because few individuals possess sufficient expertise in both areas.

Getting the most from seismic data

In a perfect world, one person or a small team would design, oversee acquisition, process, and interpret a seismic survey. All too often, an off-the-shelf design is shot by a low-bid contractor, processed with standard flow and parameters, then delivered for interpretation. The company that breaks out of this cycle of mediocrity can expect to pay more but can also achieve a competitive advantage.

Recurring Themes

Introduction

From the broad field of seismology, a few things seem to pop up with regularity. Some of these have been collected here. Keep them in mind when working with seismic data—in particular, 3-D seismic data.

The onion

The knowledge required for working with seismic data is built of several layers like an onion. The figure below illustrates the idea. At the heart of the onion are 1-D seismic concepts like wavelet, convolution, traveltime, and reflection coefficient. All this shows up in the next layer, 2-D seismic, plus arrays, offset, dip, and lateral velocity variation. The next layer, 3-D seismic, includes all of 2-D plus azimuth, bins, and the data volume. Finally, 4-D seismic is time-lapse 3-D, which introduces repeatability, fluid flow, and difference volume.

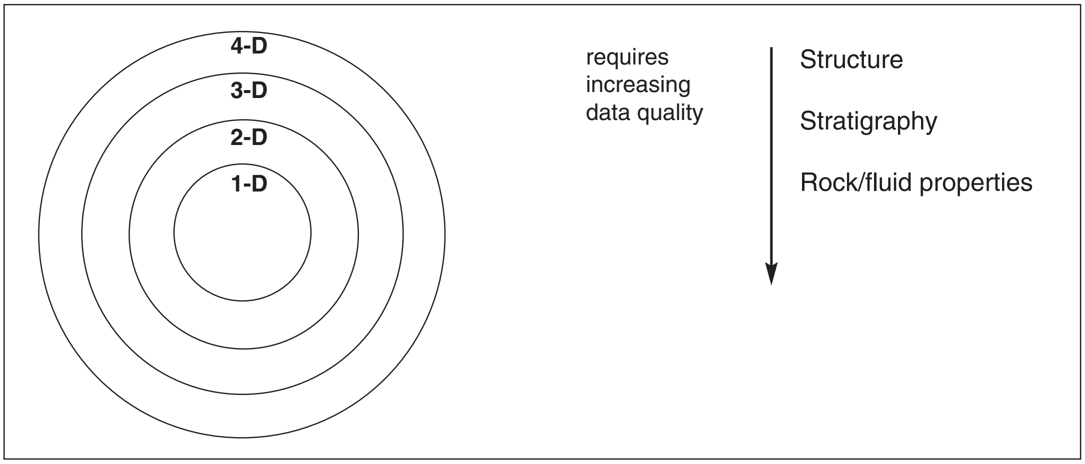


Figure 12–1. From Liner, 1999; courtesy PennWell.

Data quality

The main job for seismic interpretation is to map three things:

1) Structure
2) Stratigraphy
3) Rock/fluid properties

In this order, each task requires increasing data quality. Quality is a nebulous term largely determined at acquisition time by correct survey design and execution. Processing generally has less impact on quality but is still very important.

Echo location

The seismic technique is an echo-location method similar to sonar, radar, and medical ultrasound. A wave is emitted, and it rattles around in the material. Part of it is reflected back. From the part that returns, we attempt to determine what is out there.

Traveltimes and amplitudes

In one sense, seismic data consist of traveltime, amplitude, and waveform information. Structure mapping involves only the traveltimes, stratigraphy involves both traveltime and amplitude, and rock/fluid property information lives in the amplitude and waveform.

Recurring Themes, continued

Edges

If you look at a rock outcrop, you see sandstone, shale, limestone, etc. If you look at seismic data, you see the edges of rock units. The figure below shows the edge effect on a Gulf of Mexico salt dome example. Seismic is, in effect, an edge detection technique. The bigger the velocity and/or density contrast between the rocks, the stronger the edge.

To be fair, seismic impulses respond to much more than just lithology. Any vertical variation in rock property that modifies the velocity or density can potentially generate seismic reflections, including a fluid contact, porosity variation, or shale density change.

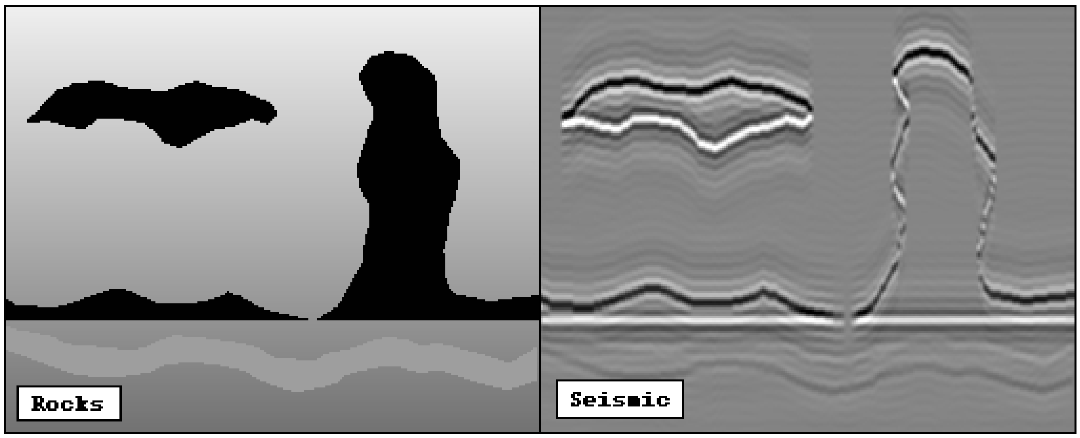


Figure 12–2. From Liner, 1999; courtesy PennWell.

Event tracking

A key part of the interpretation process for 3-D seismic data is event tracking. To picture this, think of the 3-D seismic data volume as a block of vanilla ice cream with chocolate streaks. Tracking means we follow a streak into the cube and find out where it goes—this is structure mapping. We also keep track of how dark the chocolate is as we follow it—this is amplitude mapping.

Computer limitations

Available computer speed and memory impose severe limitations on the use of advanced 3-D seismic processing. Current hardware is sufficient for the interpretation process, but the software can be complicated and expensive ($5,000–$180,000).

3-D Seismic: The Data Cube

Introduction

Seismic prospecting has been around since the 1920s and was almost exclusively two-dimensional until the mid-1980s. Three-dimensional techniques were experimented with as early as the 1940s but did not progress far until digital processing became common in the 1970s. Current worldwide seismic effort is estimated to be over 50% 3-D, and the percentage is growing rapidly. This would apply to dollar volume and/or acquisition effort. International (non-U.S.) seismic prospecting could be as high as 75% 3-D. We live in a 3-D world and now understand that 2-D seismic data is prone to many pitfalls and problems. A great advance of the last 25 years has been the development of the 3-D seismic technique, which has much more risk-reducing information content than an equivalent amount of 2-D seismic.

3-D advantages

What is the attraction of 3-D? Why do you want a 3-D survey rather than a (less expensive) grid of 2-D seismic lines? A 3-D seismic survey has many advantages over a 2-D line or a grid of 2-D lines—even a dense one. [A 2-D grid is considered dense if the line spacing is less than about 1/4 mile (1,320 ft; 400 m).] The advantages of 3-D include the following:

- True structural dip (2-D may give apparent dip)
- More and better stratigraphic information
- Map view of reservoir properties
- Much better areal mapping of fault patterns and connections and delineation of reservoir blocks
- Better lateral resolution (2-D suffers from a cross-line smearing, or Fresnel zone, problem)

Data sets

A 3-D seismic data set is a “cube” or volume of data; a 2-D seismic data set, on the other hand, is a panel of data. To interpret the 3-D data we need to investigate the interior of the cube. This is done almost universally on a computer due to the massive amounts of data involved. A 3-D data set can range in size from a few tens of megabytes to several gigabytes—the equivalent of a library of information.

Data volume concept

To understand the concept of a volume of data, think of a room. Imagine the room divided up into points, each, say, one foot apart. Any particular point will have an (x,y,z) coordinate and a data value. The coordinate is the distance from a particular corner of the ceiling. We choose the ceiling so that z points down into the room. At any given point the data value is, say, the temperature, so we have temperature as a function of (x,y,z). As we move around the room to other points, the temperature changes—high near incandescent lights and low near a glass of ice water.

A 3-D seismic data volume is like the room-temperature example except for two changes:

- The vertical axis is vertical reflection time, not depth.
- The data values are seismic amplitudes rather than temperature.

3-D Seismic: The Data Cube, continued

3-D data set example

Let's take our example a step further. Think of a 3-D seismic data set as a box full of numbers, each number representing a measurement (amplitude, for example). Each number has an *(x,y,z)* position in the box. For any point in the middle of the box, three planes pass through it parallel to the top, front, and side of the box.

The figure below illustrates 3-D data from north Texas. It measures about 1.5 mi^2 across the top. Figure 12–3A shows three views for a point in the middle of the box. The dark and light bands in the sections are related to rock boundaries. Keep in mind that seismic techniques detect edges. Figure 12–3B is a different view. It is a cube display with vertical and horizontal slices to show what is inside the data.

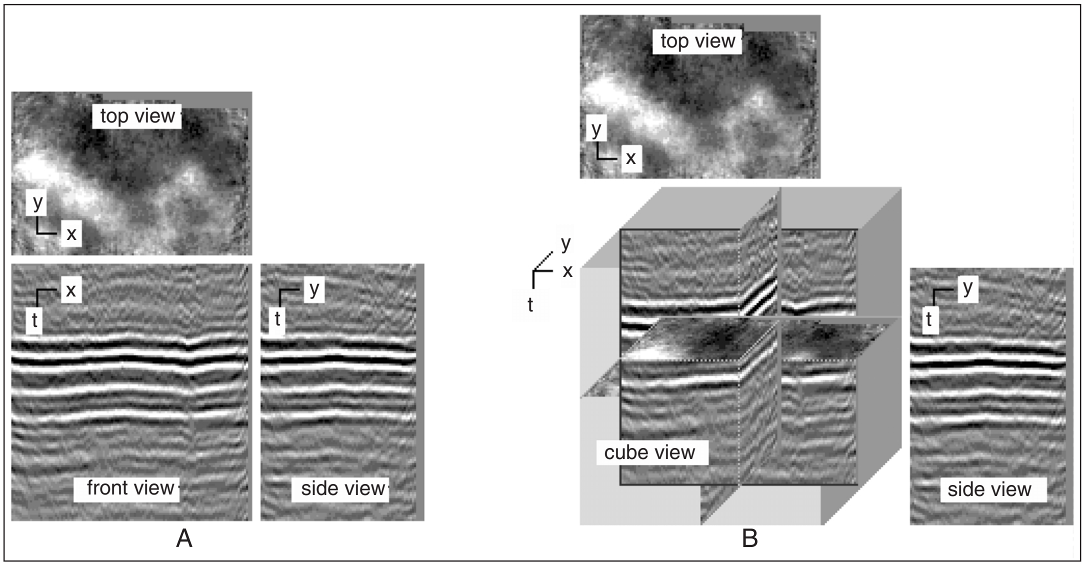


Figure 12–3. From Liner, 1999; courtesy PennWell.

Components of a 3-D Seismic Survey

Midpoints

To transmit energy into the subsurface, a shot is fired on the earth's surface. Many seismic receivers record the resulting echoes from underlying strata. Each receiver records the echoes in a trace called a **prestack trace.** Each prestack trace has a source and receiver coordinate, but the trace is plotted at the point halfway between the source and receiver pair, called the midpoint. The seismic method is designed so several prestack traces have the same midpoint.

Bins

For 2-D seismic, the prestack traces are sorted into groups associated with one midpoint on the earth's surface. The 3-D seismic data are sorted into discrete areas called bins. All actual midpoints that fall into the bin area belong to that bin. In effect, a grid is laid over the actual midpoints. Each bin has an in-line and cross-line dimension. The fold of each bin is the number of traces captured by that bin. Through the stacking process, all traces within a bin are summed to create a single stack trace, greatly improving signal quality.

The figure below illustrates the bin concept. The actual midpoints for a well-designed and executed survey will show natural clustering (A). On this cloud of midpoints we impose a grid of bins, each bin capturing all traces whose midpoints lie in it (B). After processing (stacking, migration, etc.), there is one trace at the center of each bin (C). These are the poststack data traces we interpret.

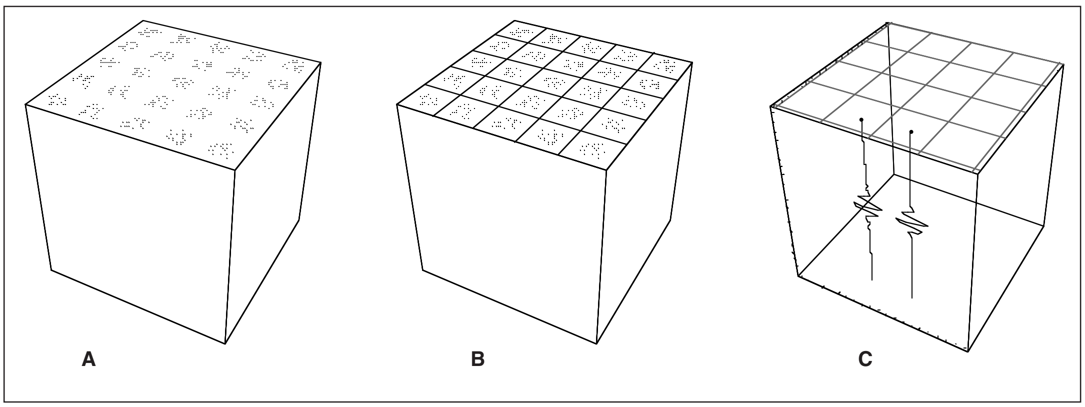


Figure 12–4. From Liner, 1999; courtesy PennWell.

3-D Seismic Data Views

Vertical slices

As it arrives on tape from the processor, 3-D seismic data are organized into lines composed of traces. In the computer these are all merged into a dense cube of data. The data cube can be sectioned, or sliced, in several ways. Vertical cuts through the data cube are called **lines** or **sections.** For marine surveys, in-line is the direction of boat movement (parallel to receivers) and cross-line is perpendicular to boat movement. For land surveys, there is no uniform definition of in-line and cross-line. A vertical section that is neither in-line nor cross-line is an arbitrary line and may be very irregular in map view as needed to pass through locations of interest.

The figure below shows how the vertical slices are labeled, depending on their orientation.

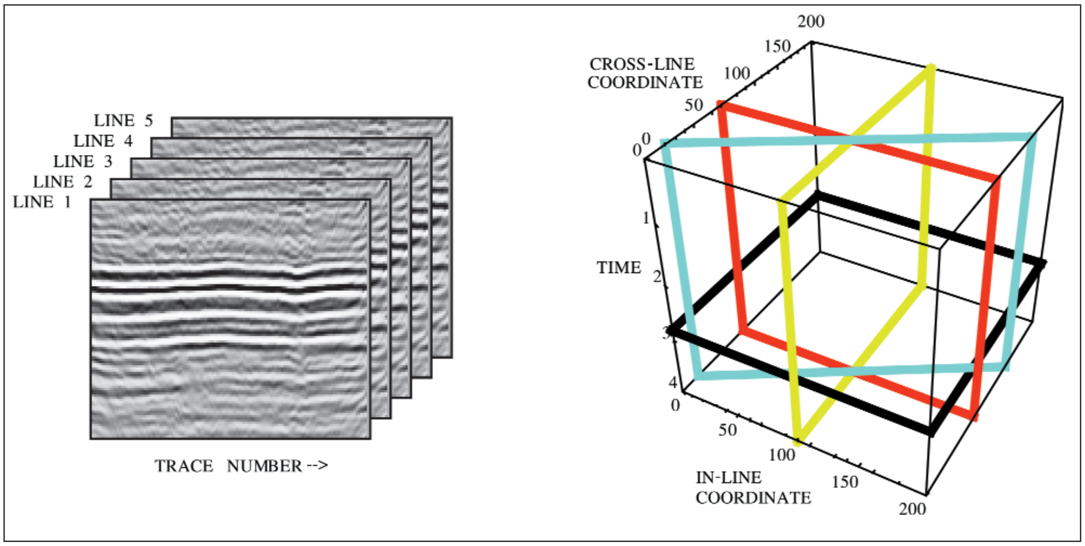


Figure 12–5. From Liner, 1999; courtesy PennWell.

Horizontal slices

Horizontal or subhorizontal cuts through a seismic data cube are called slices. As illustrated in Figure 12–5 above, horizontal slices can be

- Time slices (horizontal cuts of a time cube)
- Depth slices (horizontal cuts of a depth cube)
- Horizon slices (from tracking)
- Fault slices

Depth slices are only available if the data delivered from the processor are converted to depth. Fault slices require very high-quality data with clear, mappable fault surfaces. Both are rarely encountered.

Section B

Identifying Seismic Events

Introduction

Models of seismic data help us identify seismic events or reflections stratigraphically. The model is a hypothetical seismic trace called a synthetic seismogram and is generated from sonic and density logs. In this section we review the method of modeling and identifying seismic events.

In this section

This section contains the following topics.

Building a Stratigraphic Model

Introduction

The problem addressed in seismic modeling, or simulation, is calculating the seismic response (traveltime and amplitude) for a given stratigraphic model. The stratigraphic model consists of those physical properties that influence seismic wave propagation—typically compressional wave speed, shear wave speed, and mass density. This set of parameters can describe the simplest possible solid, called an isotropic elastic solid. For some purposes, it is sufficient to consider the earth as an acoustic (fluid) medium characterized by only two parameters: sound speed (v) and mass density (ρ). Seismic reflections are generated where there is a contrast in impedance (which is the product of velocity and density).

Velocity data sources

Depth-dependent velocity and density models are needed to identify events or to create a synthetic seismogram. Velocity information can come from a variety of sources. Here is a list, in order of preference:

- Vertical seismic profile (VSP)
- Sonic with checkshots
- Sonic without checkshots
- Checkshots only

VSPs

A vertical seismic profile (VSP) yields the best connection between geologic horizons and seismic events. It is recorded by using a source at the surface and many receiver locations down a wellbore, or vice versa. The receivers record full traces for interpretation. The receiver spacing is usually 10 ft. This gives actual traveltimes from the surface to points in the earth, and it is the best and most direct method of associating seismic events with geological horizons. The kind of VSP shown in Figure 12–6 (produced by commercial software) is often called a zero-offset VSP, meaning that only a single source position is used as close to the wellhead as possible. It is relatively inexpensive. There are also multioffset and multiazimuth VSPs, which use many source locations. These are much more expensive and sometimes are useful for local, high-resolution imaging. However, a zero-offset VSP is sufficient for event identification and 3-D seismic calibration.

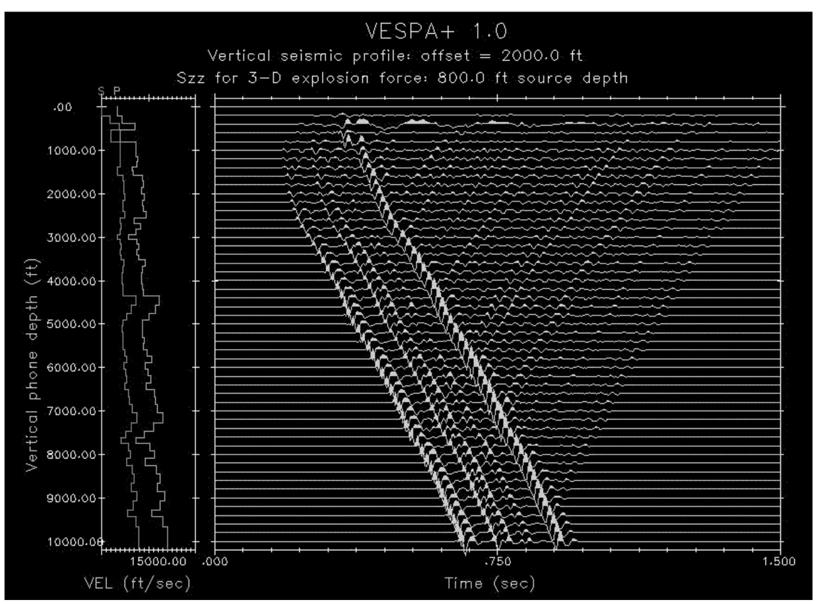


Figure 12–6. Courtesy Landmark Graphics.

Velocities from sonic logs

Velocities can be acquired from sonic logs with or without a checkshot survey. A checkshot survey is like a baby VSP. The receivers are sparsely located down the well, usually on key geologic boundaries. Also, the information recovered is limited to arrival time (a number), unlike the full trace a VSP gives. The checkshots help correct for any drift in a sonic log due to missing log intervals or hole problems. This makes the calculated traveltimes more reliable. One can obtain good velocity data from sonic logs without checkshots. However, if there are any hole integrity problems, significant errors can exist in the sonic data. If a sonic log is not available, very coarse velocity data can be obtained from a checkshot survey with only 5 or 6 traveltimes per well.

Velocity from density

Density information also contributes to creation of a synthetic seismogram. Density can be estimated from sonic data, but independent density information from a neutron density log is preferred.

Synthetic Seismograms

Introduction

Once a stratigraphic model has been built using velocities and densities, a synthetic seismogram (or synthetic) can be constructed to identify seismic reflections. A synthetic seismogram is the fundamental link between well data and seismic data, and it is the main tool (along with a VSP, if available) that allows geological picks to be associated with reflections in the seismic data. As discussed, if a VSP is available for a particular well, a synthetic is not needed. The VSP directly measures both time and depth to a formation of interest.

Creating a synthetic seismogram

Usually synthetic seismograms are created using specialized software. The user may be unaware of the process that creates them. The table below lists the steps necessary to create a synthetic seismogram manually.

Step	Action
1	Edit the sonic and density logs for bad intervals.
2	Calculate vertical reflection times.
3	Calculate reflection coefficients, R_0.
4	Combine the last two items to create a reflection coefficient time series.
5	Convolve the reflection coefficient series with the wavelet.

Reflection coefficient

The normal-incidence reflection coefficient for a rock contact is an important quantity. Sheriff (1984) defines it as "the ratio of the amplitude of the displacement of a reflected wave to that of the incident wave." Mathematically, reflection coefficient can be expressed as

$$R_0 = \frac{(\rho_2 v_2 - \rho_1 v_1)}{(\rho_2 v_2 + \rho_1 v_1)}$$

where:

ρ = rock density
v = rock velocity
1 = parameters above the interface
2 = parameters below the interface

Convolutional model

The final simulated seismic trace can be summarized by the convolutional model:

$$T(t) = R_0(t) * w(t) + n(t)$$

where:

$T(t)$ = seismic trace
$R_0(t)$ = reflection coefficient series (spikes)
$*$ = convolution
$w(t)$ = wavelet
$n(t)$ = noise

Convolutional model (continued)

This model of the seismic trace assumes many things, including removal of all amplitude effects except R_0. The job of seismic data processors is to deliver data to the interpreter in a form consistent with the convolutional model, but it is hard to get it right.

Example synthetic seismogram

The figure below shows a simple synthetic seismogram. We can see most of the components that go into the creation of a synthetic seismogram—the velocity model, reflection coefficient series, individual wavelets, synthetic trace, and simulated stack section (lower plot). The velocity model is from north-central Oklahoma. The density model is not shown.

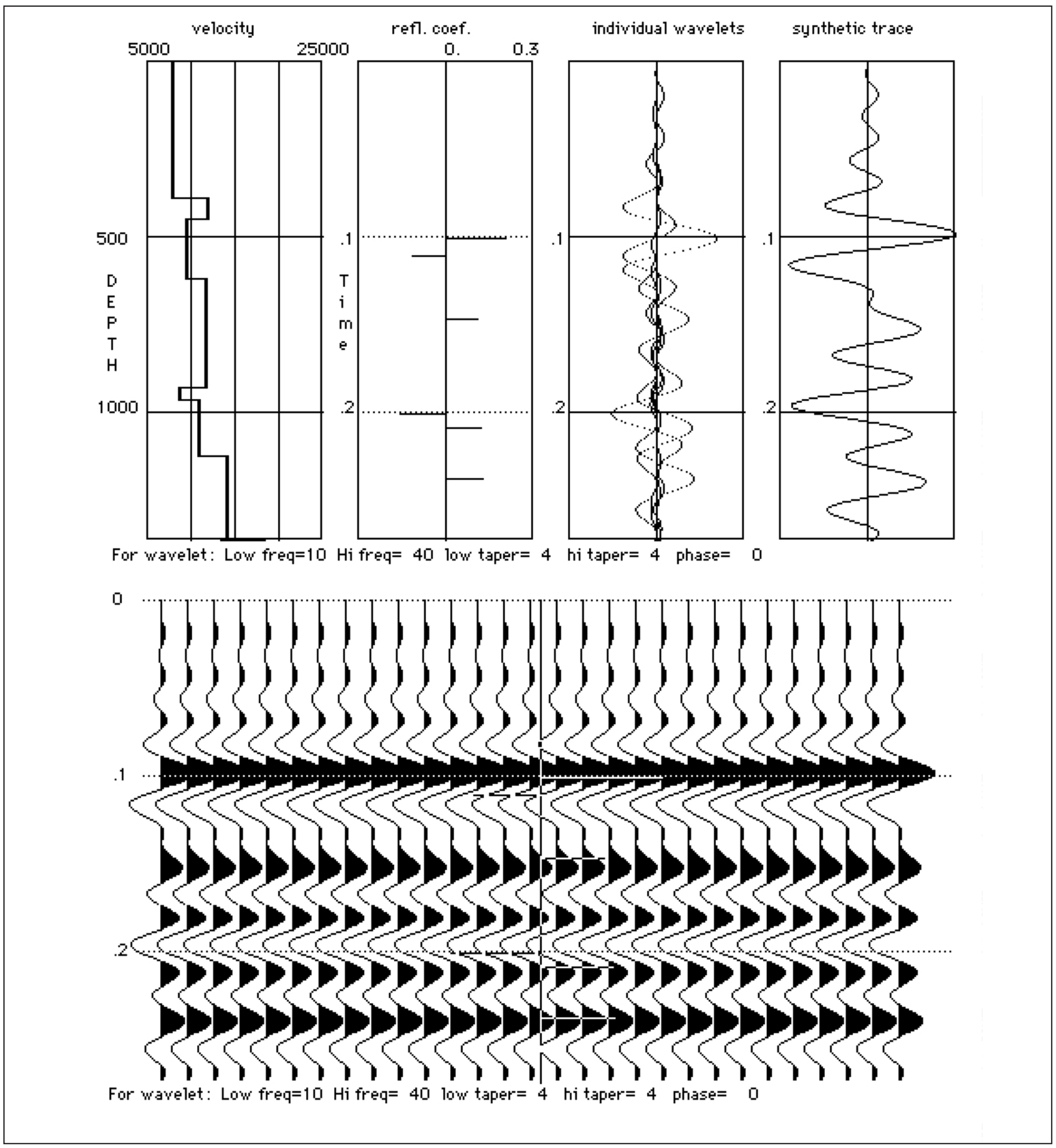


Figure 12–7. From software by S. Hill, Conoco.

Matching Synthetics to Data

Introduction

The goal of using a synthetic seismogram is to match stratigraphy as seen in well logs or outcrops to seismic field data. The field data need to have been migrated, since only then does the time axis represent vertical traveltime, which is calculated from sonic log measurements.

The matching process

The matching process involves simulating a seismic trace from well logs and user parameters (waveform, frequency, phase), then manually aligning the simulated trace with the field trace(s) in the vicinity of the well. This is normally done over some limited interval in the well, probably centered on the reservoir target. If the fit is not good enough, then the parameters are changed (updated) and another comparison is made. This continues until a match is achieved. It can be a tedious and time-consuming job, particularly for large projects involving many wells. But if not done properly, it is possible to incorrectly associate seismic events and geological horizons.

Problems with matching

In practice, synthetic seismograms are rarely a perfect match to field data. There are many reasons for this.

- **Frequency**—Sonic logging operates in the kilohertz frequency range (high frequency, short wavelength), while seismic data are typically 10–90 Hz (low frequency, long wavelength). This means the sonic log is influenced by a tiny volume of rock compared to a seismic wave passing the borehole.
- **Anisotropy**—Sonic logs measure velocity in the vertical direction, while seismic waves travel at significant angles away from the vertical. If anisotropy is present (and it usually is), then velocity depends on the direction the wave is traveling. It is not uncommon to see a 10–15% difference between horizontal and vertical velocities.
- **Hole**—Sonic logging is sensitive to washouts and other hole problems, while long-wavelength seismic waves are not.
- **Wavelet**—The user is required to specify the wavelet, and it is very easy to get it wrong. Some advanced software products can scan the data and attempt to extract the wavelet. But these scanners involve many user parameters.

Identifying Reflectors

Introduction

Whether using VSP, synthetic seismogram, or log overlay, the final step is to compare the object to seismic traces in the vicinity of the well and find a fit.

Example

In the figure below, a sonic log has been converted to time and velocity. Note that the time axis on the seismic section and the converted sonic log are linear, while the depth tick marks on the sonic are nonlinear. The geological horizons annotated on the sonic log are located via the depth tics from picks on other logs (electric, gamma ray, etc.). It is important to realize that a sonic log never goes to the surface; there is always a gap for the surface casing. So we do not expect time zero on the converted log to fit at time zero on the seismic section. In practice, the log is placed over the seismic section and shifted vertically until we are satisfied with the fit.

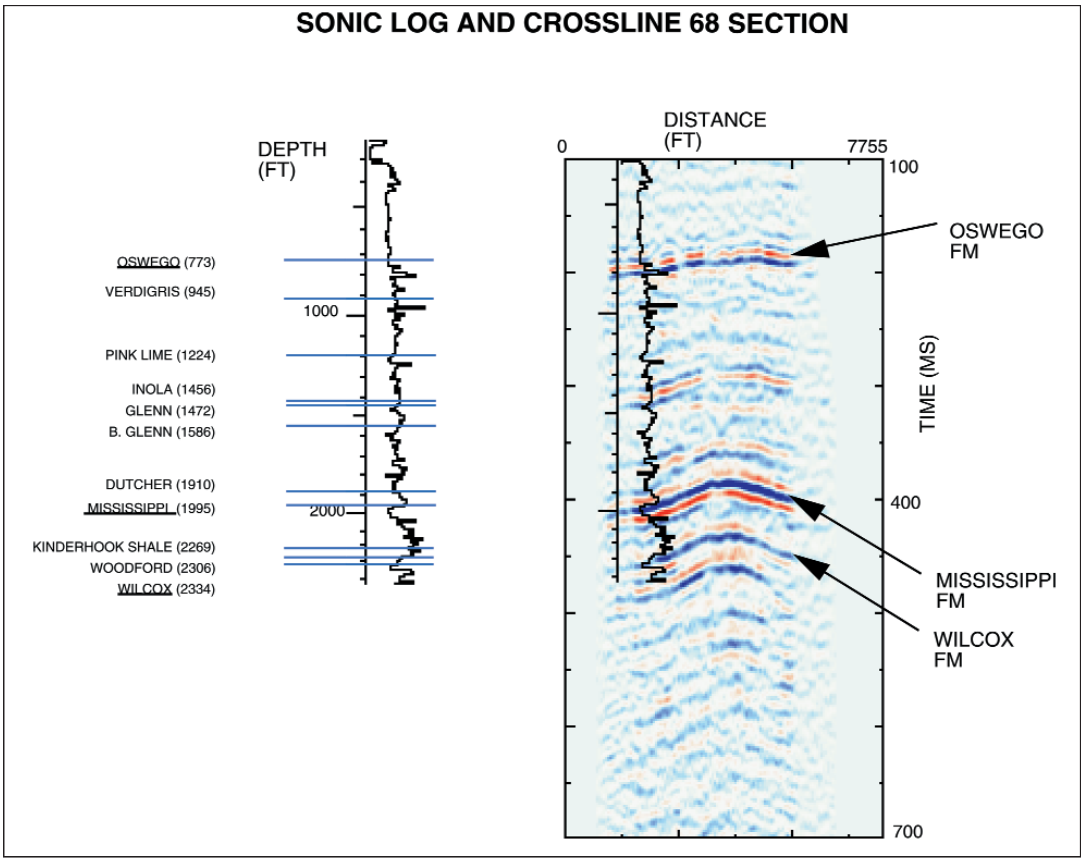


Figure 12–8. From Liner, 1999; courtesy PennWell.

Section C
Interpreting Structure

Introduction

Seismic interpretation has evolved significantly over the last 20 years or so (Wilson, 1984; Matteini and Salvador, 1986; Brown, 1992, 1999). Some changes are related to computer technology, while others are geophysical or geological advances. However, the basic goal of seismic interpretation has not altered: to identify likely hydrocarbon accumulations and reduce risk associated with drilling. This begins with structural mapping based on seismic plus well control. The product is $z(x,y)$, a depth value at each point inside the survey area.

This section reviews the classic techniques of mapping structure using seismic data.

In this section

This section contains the following topics.

Mapping Structure with Seismic Data

Introduction

Whether doing 2-D or 3-D seismic interpretation, the tasks are fundamentally the same. The work can sometimes be done by hand for 2-D data (paper sections and manual contouring of maps) but virtually requires computer assistance for 3-D data. The recipes described on the pages that follow apply to hand or computer work.

Four basic techniques

There are four basic techniques for getting structure from seismic data (the names are not standard).

Technique	Description
Classic	Mapping a surface of interest (from data) using average velocities
Modified Classic	Mapping a surface of interest using a densely drilled shallow horizon, avoiding the weathering layer at the earth's surface
Migrated Depth	Mapping an area using a 3-D seismic data cube with the vertical axis converted to depth (commonly used in complex areas but needs manual tweaking to match well control to seismic data)
Volumetric Depth Conversion	Mapping an area using migrated seismic data (with time axis) converted to a depth cube using a $v(x,y,z)$ velocity model

Preparing Seismic Data for Mapping

Introduction

Before seismic data can be used in maps, they must be checked for quality; they must have reflectors identified for key geologic horizons, which should be tracked throughout the data grid; and key sections must be interpreted structurally.

Example data set

The example given in this section is a small 3-D data set from the Glenn Pool field in northeastern Oklahoma. The target is the Ordovician Wilcox Formation. The interpretation was done using a system called Cubic.

Procedure

Follow the steps listed below to make a classic structural seismic interpretation.

Step	Action
1	Preview data for quality and consistency with acquisition and processing reports.
2	Make structure contour maps for key horizons using well control only.
3	Identify online wells with velocity control.
4	Compute a synthetic seismogram for each online well with a sonic or density log.
5	Associate reflectors at each online well with stratigraphic horizons using VSP, synthetic seismogram, or time-stretched logs.
6	Interpret seismic data using color identifiers (tracking) by extending reflection events across the entire survey area.
7	Mark faults and key structural details.

Step 1: Preview data

Preview seismic data for quality and consistency using acquisition and processing reports that come with the data. Note any geological conditions that might cause the interpretation method listed in the procedure to fail. As shown in Figure 12–9A, each 3-D seismic survey has a unique outline of live traces or image area. Use the outline of the image area with the processing report and well spots (Figure 12–9B) to confirm correct orientation of the survey. This might sound silly, but it is very easy to get the orientation wrong since there are many ways to orient a cube.

Step 1: Preview data (continued)

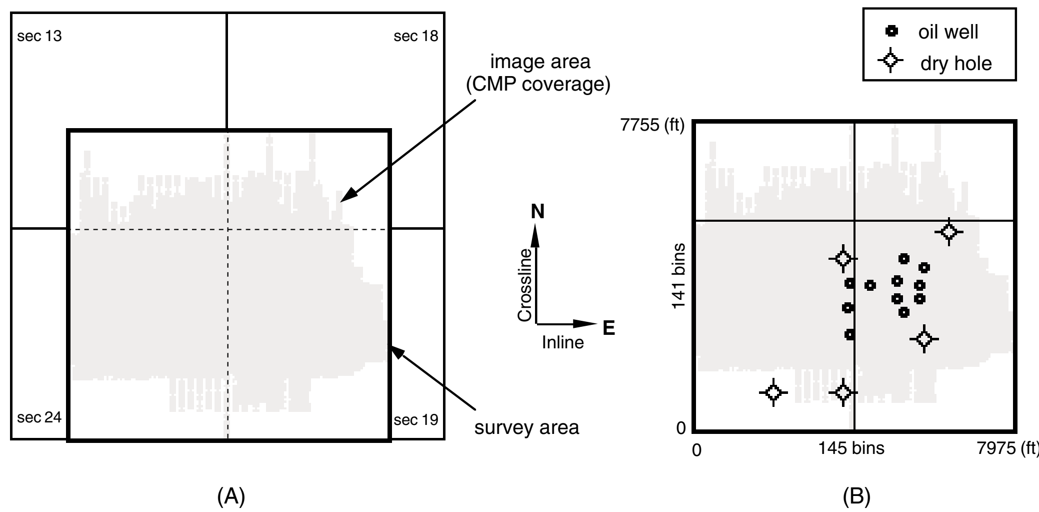


Figure 12–9. From Liner; courtesy PennWell.

Step 2: Create well control maps

A depth structure map should be constructed using all available well control to the horizon of interest. There are many ways of gridding or contouring depth points. Whatever the method, it should also be used in the depth conversion velocity map (next section). The wells-only depth structure map is a useful baseline.

Step 3: Identify wells with velocity control

Identifying online wells with velocity control is a vital point in the seismic mapping process. For a 2-D survey, online wells are located on a seismic line. For a 3-D survey every well in the image area is online. The velocity control can be (in order of preference)

1) Vertical seismic profile (VSP)
2) Sonic log
3) Checkshot survey

Step 4: Compute simulated seismic traces

For each online well with a sonic or density log, we can compute a simulated seismic trace (synthetic seismogram). Another option is to convert sonic log (or velocity, density, velocity * density) to time and directly overlay onto the seismic section being interpreted. Figure 12–8 (from the Glenn Pool survey) shows this approach. For wells with a VSP, a trace is available directly and need not be simulated.

Step 5: Identify stratigraphy of reflectors

Correlate seismic reflectors at each online well with key geological horizons using a VSP or a synthetic seismogram. A checkshot survey can be used as a last resort. Ideally, events should be correlated for every online well.

Preparing Seismic Data for Mapping, continued

Step 6: Track events

Interpret seismic data using color identifiers by extending reflection events across the entire survey area. This process is called tracking—following an event throughout the data volume.

Step 7: Mark faults

Mark faults and other structural details on the seismic sections. If necessary, jump-correlate picked events across faults. When a conflict exists, a well-tie correlation is preferred to seismic jump correlation across faults. The seismic section in the figure below shows a jump correlation. A small panel of data, labeled A, is outlined on the right side of the fault. Two key horizons are marked. The data panel was copied, then moved across the fault and adjusted until a satisfactory fit was made at B. Note the apparently continuous event connecting the yellow dot at A with the blue dot at B. This is a false correlation.

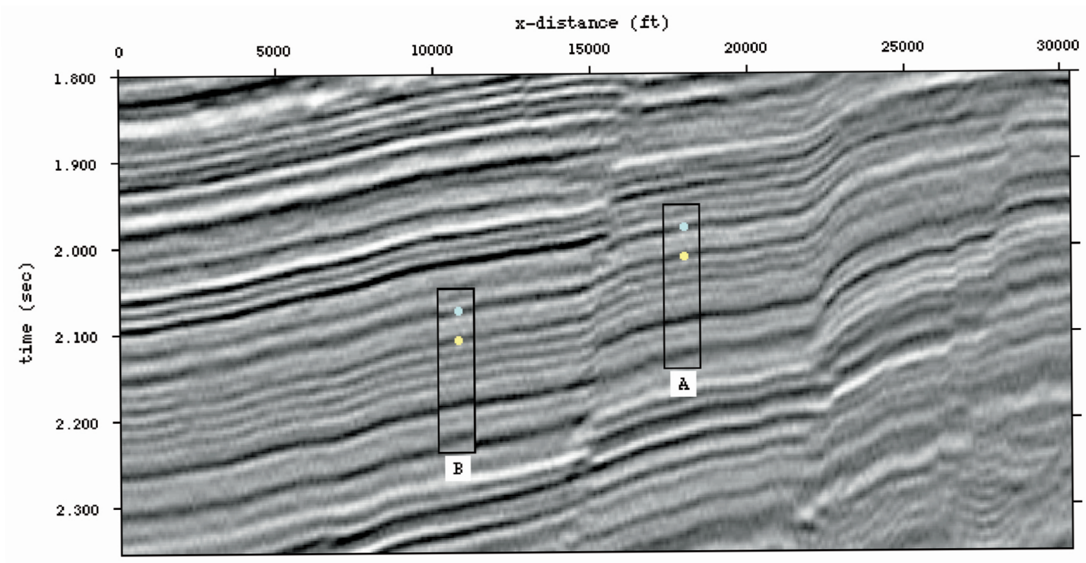


Figure 12–10. From Liner, 1999; courtesy PennWell.

Marking up key sections

Beyond jump correlation, an important part of structural interpretation is to mark up a few key lines in detail. Figure 12–11 shows part of such a marked-up section. Faults are marked in green, with line width denoting relative importance. Sense of throw is indicated as up (U) or down (D). Yellow dots indicate events used to calculate depth and fault throw, while yellow lines are events used for dip calculations. Fault numbers indicate relative age (1 = most recently active, etc.). Red arrows show stratigraphic bed terminations. The arrowhead indicates whether termination is from above or below. For depth, throw, and dip estimates, a simple linear velocity model was used: $v(z) = 5{,}000 + 0.4^*z$, where v is in ft/sec and z is depth in feet. This velocity model is often useful in basins that contain unconsolidated sediments, such as the Gulf of Mexico. The data for Figures 12–10 and 12–11 come from Southeast Asia.

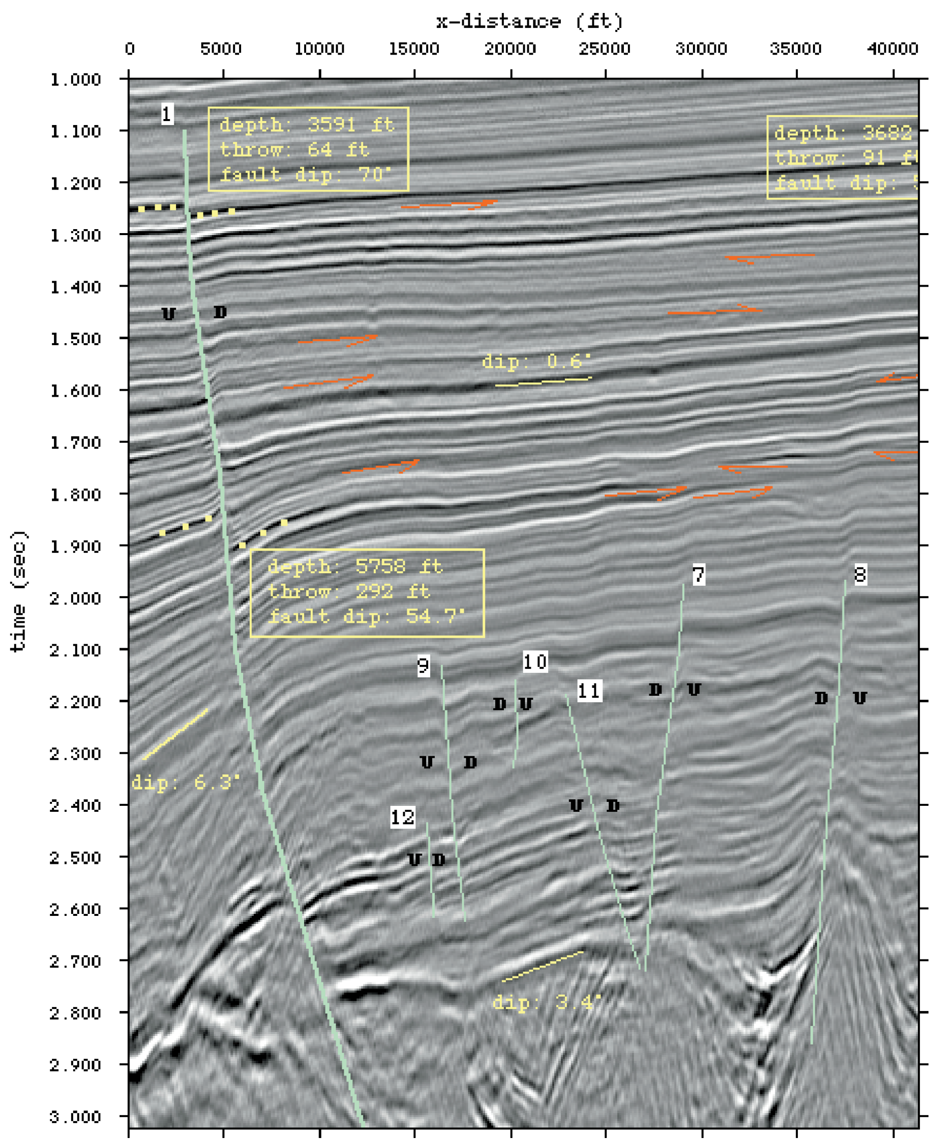


Figure 12–11. From Liner, 1999; courtesy PennWell.

Creating an Integrated Structure Map

Introduction

Below is a recipe for making a classic integrated structure map from seismic data and well control. It is based on mapping one horizon at a time and must be repeated for each horizon of interest. It may not work in areas with severe static problems (i.e., lots of topography or a rapidly changing weathered layer such as glacial till). It also fails when there are extreme lateral velocity variations in the subsurface (subsalt, subthrust, etc.). When it works, this method gives a map which, by definition, matches every well exactly. It uses seismic time structure to interpolate between wells and extrapolate beyond them.

Procedure

Follow the steps listed below for each seismic event to be mapped.

Step	Action
1	Make structure contour maps for key horizons using well control only.
2	Pick seismic horizons.
3	Calculate depth conversion velocity at locations where both well and seismic time picks exist.
4	Convert time to depth by multiplying the time structure map and the depth conversion velocity map.
5	Contour the integrated structure map, keeping in mind the structure map made earlier from well data only.

Step 1: Map structure from well data

Post well depths to key horizons and contour structure maps for key horizons using well control only. These well maps of structure should guide you when making structure maps that integrate both well and seismic data. Comparing this map with the final time structure map gives a good feel for the additional information supplied by the 3-D seismic section.

Creating an Integrated Structure Map, continued

Step 2: Pick seismic horizons

For 2-D data, only the traveltime to each event of interest is recorded with its coordinate along the line $t(x)$. For 3-D data, both traveltime and amplitude at each (x,y) are available from the seismic data cube, $t(x,y)$ and $a(x,y)$. The traveltimes form a time structure map, and the amplitudes are a horizon slice. Figure 12–12A shows a representative line from the Glenn Pool data volume with sonic overlay and tracked events. Horizon amplitude and time structure maps for the Wilcox are shown in Figures 12–12B,C.

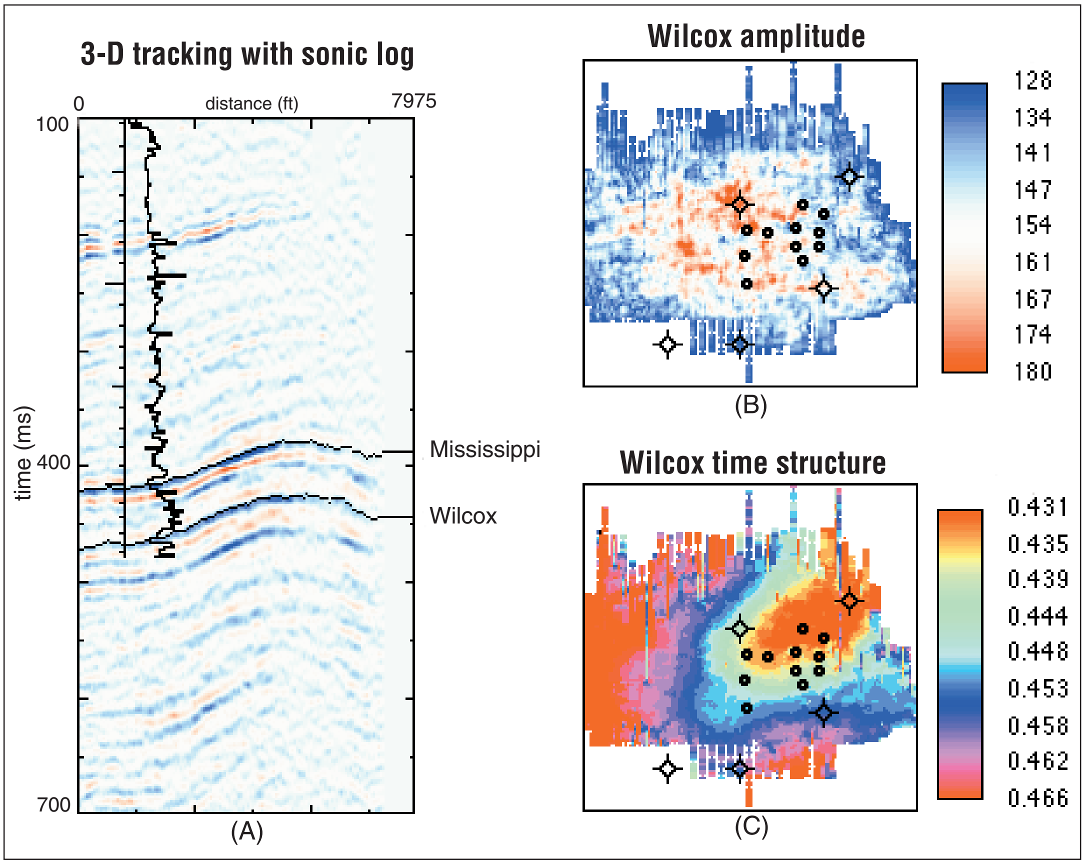


Figure 12–12. From Liner, 1999; courtesy PennWell.

Step 3: Calculate depth conversion velocity

Calculate depth conversion velocity at locations where both well and seismic time picks exist. The wells used as control do not need velocity or density logs but must penetrate the event of interest. The event depth z (measured from seismic datum) is known from well control, and the vertical reflection time t is known from the previous item. The depth conversion velocity is given by

$$v = \frac{2z}{t}$$

Depth conversion velocities are posted to a map and contoured or gridded to create $v(x,y)$.

Creating an Integrated Structure Map, continued

Step 3: Calculate depth conversion velocity (continued)

The figure below shows a hypothetical well with important reference points as well the average velocity map for the Wilcox Formation in the Glenn Pool survey. This map has a fairly strong lateral velocity gradient, i.e., the velocity changes from about 11,400 ft/s for velocity (NE) to 10,200 ft/s (SW) in the space of just over a mile. When this occurs, time structure and depth structure can be significantly different.

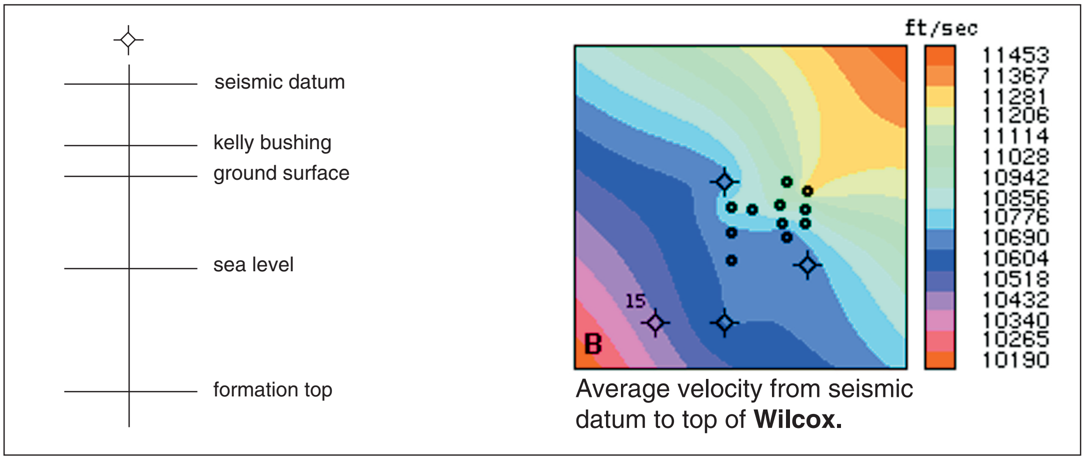


Figure 12–13. From Liner, 1999; courtesy PennWell.

Step 4: Convert time to depth

Convert time to depth by multiplying the time structure map and the depth conversion velocity map, i.e.,

$$z(x,y) = \frac{v(x,y)*t(x,y)}{2}$$

The factor of one-half is necessary because the times are two-way vertical times and we only want the one-way depth. The figure below shows the process and result for the Glenn Pool Wilcox horizon.

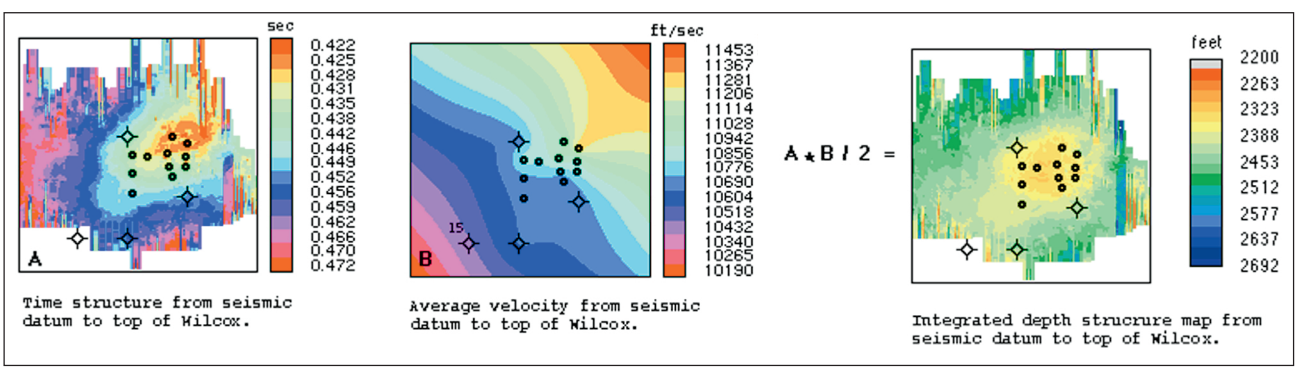


Figure 12–14. From Liner, 1999; courtesy PennWell.

Step 5: Contour map

Contour or grid the integrated structure map with the same technique used for the wells-only depth map. This allows head-to-head comparison (Figure 12–16).

Integrated map

The final product *z(x,y)* is called an integrated structure map. It honors all well-control depth points (by definition) and uses the seismic events to interpolate between these points. The figure below is a comparison of the first depth map from well control only and the seismic plus well integrated depth map.

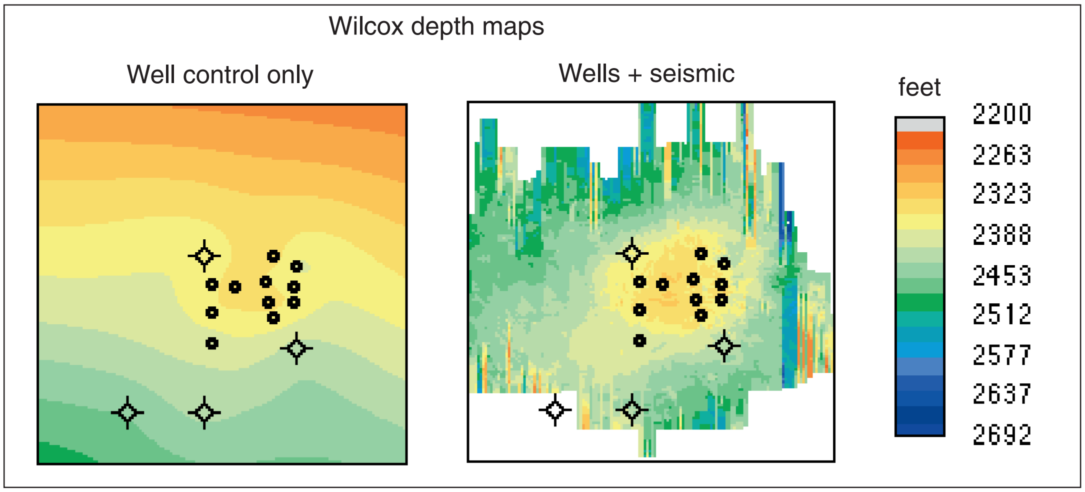


Figure 12–15. From Liner, 1999; courtesy PennWell.

Figure 12–16 is a zoom of the central area in the maps in Figure 12–15. Map A uses well control only, and map B uses well control plus seismic interpretation.

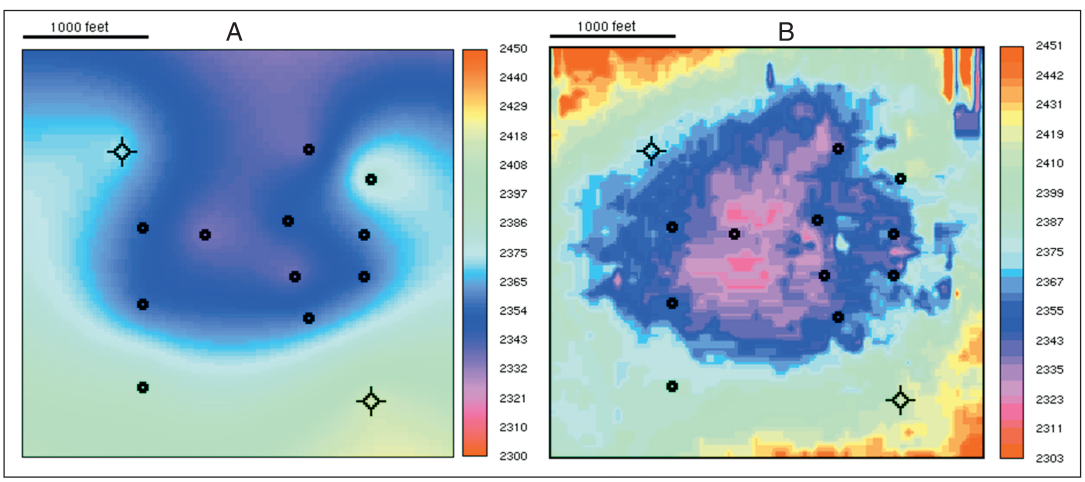


Figure 12–16. From Liner, 1999; courtesy PennWell.

Creating an Integrated Structure Map, continued

Conclusion

The mapping process described here can give useful results in many situations. However, the following cares should be considered:

- Strong lateral velocity variations may require depth migration and direct output to a depth cube.
- Existence of dense, shallow well control might allow depth mapping from a shallow seismic event. This minimizes the effect of topography and near-surface velocity problems.

Many depth conversion techniques should be available to the interpreter, since each is appropriate for commonly encountered problems. Each has strengths and weaknesses. Ultimately, however, structure maps should be delivered in depth, not time. Only then can the information be a useful guide to drilling decisions.

Section D

References

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