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AN EXPLORATION 3D SEISMIC FIELD TEST PROGRAM IN OSAGE COUNTY, OKLAHOMA

Final Report
October 1998

By
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January 1999

Performed Under Contract No. DE-AC22-94PC91008
(Original Report Number NIPER/BDM-0376)

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ABSTRACT

There has been a substantial decline in both exploratory drilling and seismic field crew activity in the United States over the last 15 years due primarily, to ongoing uncertainties in the price of domestic oil. To reverse this trend and to preserve the entrepreneurial independent operator, the U.S. Department of Energy (DOE) is attempting to encourage hydrocarbon exploration activities in some of the unexplored or under-exploited regions of the United States. This goal is being accomplished by conducting broad regional reviews of potentially prospective areas within the lower 48 states and by studying and developing ways to increase efficiency and lower costs for domestic exploration operations for independent operators, the backbone of the drilling industry within the U.S.

Studies are being conducted on a scale generally unavailable to the smaller independent. The results of this work are being made available to industry and the public, to encourage more aggressive domestic operations in the U.S.

This report will discuss a series of surveys that were conducted in Osage County, Oklahoma, to evaluate state-of-the-art, high-resolution seismic, geochemical, and microbial techniques.

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1.0 INTRODUCTION

The U.S. Department of Energy (DOE) was conducting a series of research programs and field tests at the National Institute for Petroleum and Energy Research (NIPER), in Bartlesville, Oklahoma, managed for DOE by BDM-Oklahoma. This program has recently been moved to the National Petroleum Technology Office (NPTO) in Tulsa, Oklahoma.

The work is designed to encourage petroleum activity within the U.S. (especially activity conducted by smaller independent operators), spur exploration, and increase domestic production. Most of the target independent operators are too small to have their own internal research programs.

The Seismic Field Test Program has been conducted for DOE by BDM Petroleum Technologies. The work was designed to demonstrate the newer capabilities of state-of-the-art 3D techniques for imaging small structures, thin reservoirs, stratigraphic pinchouts, and other subtle traps. The project goal included determining the cost-effectiveness of current survey techniques and procedures as a prospecting tool for the smaller independent geological/geophysical exploration company. DOE had made the decision to determine the capabilities, costs and effectiveness of conducting 3D seismic surveys in a small operator setting and to examine in detail the economics of conducting such a survey. With these objectives in mind, it was initially decided to follow typical small operator practices in the 3D seismic field test.

The Osage County location was chosen, in part, to further the goals of the President's Native American Initiative. This initiative is designed to encourage entrepreneurial activities on tribal reservations and other Native American lands. Osage County is largely Osage tribal land, and has had a long history of shallow oil production. Many of the wells in the area are being operated by small independent companies. An important aspect of the program was the strict adherence in the work to all Osage Tribal Council rules and local environmental regulations.

A Request for Proposal (RFP) for the acquisition and processing of seismic data in Osage County was prepared after studying the petrophysical properties of subsurface formations, using core and wireline logs. This was done to identify optimal field parameters and equipment for the field work.

A series of obstacles (described in Section 2.0, below) had to be overcome before a study area was selected. Eventually, it was determined that the work would be conducted in partnership with DLB Oil and Gas, Inc., of Oklahoma City, one of the independent operators active in the county. Since DLB was planning to conduct a conventional 3D seismic survey, BDM Petroleum Technologies changed plans, and proposed the conduct of a specialized, higher-resolution survey on a portion of the DLB lease acreage. DLB would continue with their plan to shoot a conventional survey over their full lease, while DOE would provide the funds to increase the shot spacing from 110′-bins to 55′-bins (see Section 3.0) over a portion of the lease.

This proved to be a much better program for DOE than the original plan, since by that point, there were already several conventional 3D seismic surveys under way in Osage county, and adding just one more shoot would prove little. Combining a conventional survey with a high-resolution program, on identical acreage and the same survey points, allowed operators to directly compare the benefits to be gained from the tighter spacing and improved parameters.

Ultimately, DLB surveyed a 16.75-mi^2 area in the Bigheart prospect, just northeast of Hominy, Osage County, Oklahoma, using a conventional 110′-bin size. DLB also agreed to shoot a 6.00-mi^2 portion of the total area with a 55′-bin configuration.

Once the data had been processed, BDM interpreted examples of both the 110′- and 55′-data, to identify the improvements available with the higher-resolution information. The dominant structural and tectonic features of the region were mapped, and subtle features were selected for further study on the 55′-bin size survey. Results are discussed in Section 3.0

In addition to the seismic surveys, a geochemical and a microbial survey were conducted in the Osage County study area. These surveys are discussed in Sections 5.0 and 6.0.

2.0 SELECTION OF STUDY AREA

Prior to the start of the 3D seismic program, a series of geologic studies was done to identify good prospects with a high potential for oil or natural gas reserves. The plan was to use one of these features as the study area and to shoot a conventional 3D seismic survey in the area, using parameters typical of a small, independent operator. This program was designed, in part, to increase interest in the region by independents, and to stimulate exploratory activity on Native American lands. The program was almost too successful for its own good.

Information on the potential prospects was conveyed to the Osage tribe, and the BDM publicity office and the Technology Transfer group released information on the program and its goals.

Following this early publicity about the program, several operators, led by a major, Chevron, moved into the county and began obtaining leases from the Osage tribe. They obtained permits for seismic operations covering large portions of the county, including the entire western half of the county, as well as several blocks in the eastern half. As preliminary work progressed on the task, several prospects developed during BDM-Oklahoma work were leased by the tribe to these other operators, bringing revenues to the Osage tribe and providing employment in the area. Ultimately, three major surveys were conducted in the county, as well as several minor studies.

All of the original potential prospects were taken by the time the DOE 3D program was ready to proceed, and several new sites that were developed also were leased by the time BDM approached the tribe for permission to shoot in those areas.

Eventually, an arrangement was negotiated with DLB Oil and Gas, Inc., of Oklahoma City, one of the independent operators that followed Chevron into the county. This arrangement worked out to be a much better test and demonstration project for DOE than the simple, conventional 3D survey that had originally been planned.

DLB had planed to shoot a 16-mi^2 prospect in the Bigheart area, just northeast of Hominy, Osage County, Oklahoma, using a standard set of 3D parameters. BDM Petroleum Technologies personnel revised the original plans for a "conventional" 3D survey, and instead made arrangements with DLB to piggyback a redesigned, much more innovative high-resolution survey on top of the already-planned survey. The high-resolution work was to take place in a 6-mi^2 area in the northwest corner of the DLB prospect. The 3D survey area (see Fig. 2–1) forms an irregularly shaped block in parts of Townships 22 and 23 North, and Ranges 9 and 10 East.

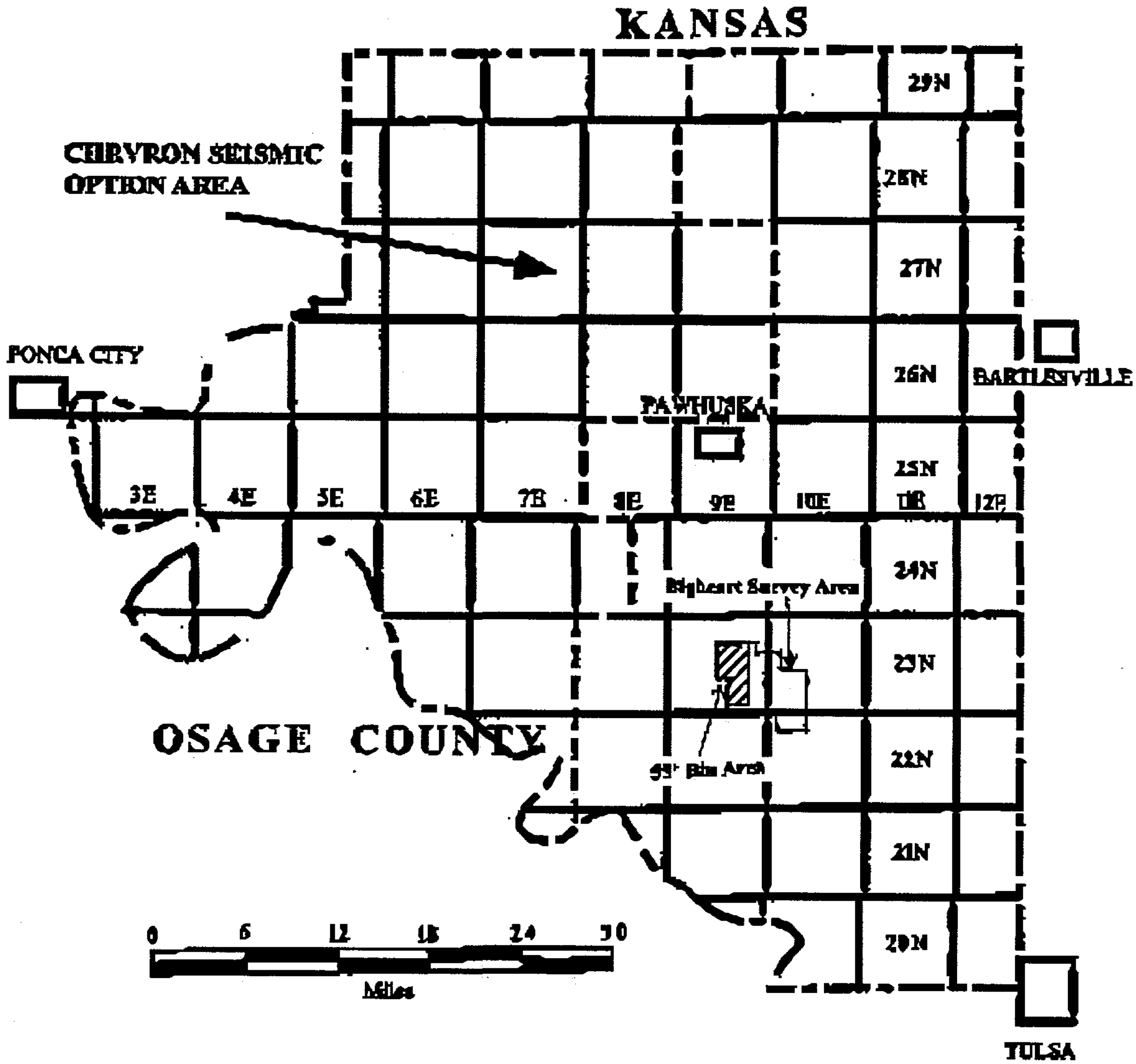

Figure 2–1 Map of the Survey Area in Osage County, Oklahoma.

The new, innovative approach allowed a direct comparison of data quality for the two different bin sizes over precisely the same survey area. The objective became to determine if reducing the bin size from 110-ft to 55-ft, while keeping all remaining field and recording parameters the same, would provide sufficiently improved resolution to justify the extra cost. It was assumed that the high-resolution survey would allow the mapping of subtle geological features, but it was uncertain just how much the imaging capabilities would improve.

The information provided in the following section will demonstrate that the improvement was dramatic. Interpreters will be able to see for themselves, based on the information in this report, which features can be identified at each resolution and which reservoirs would have been missed if only the 110-ft bin survey data had been available.

3.0 SEISMIC SURVEY

As has been discussed above, the objectives of this program evolved as local conditions changed during the conduct of the DOE research work. When the program began, Osage County, Oklahoma, was a backwater area, in terms of the oil industry, with minimal drilling or workover activity for many years. One of the primary objectives of BDM-Oklahoma was to create publicity and technology transfer opportunities.

3.1 Objectives for the 3D Field Test

The BDM Petroleum Technologies program for the 3D field test was designed to develop and demonstrate new and innovative techniques to search for thin, shallow targets using state-of-the-art data acquisition, processing and interpretation technologies, and to identify areas of potential cost savings in the design and implementation of such a survey. Recent technological innovations in 3D seismic technology have made it possible to image subtle geological features in structurally and stratigraphically complex areas that may contain significant accumulations of hydrocarbons.

The 3D seismic field test was designed to accomplish the following seven specific tasks:

1. Design a model field test program using parameters and a scale appropriate for small operators or other independents, including Native American nations
2. Field test the design
3. Test and evaluate the potential of the newest equipment and state-of-the-art parameters to image thin beds and subtle hydrocarbon traps
4. Develop new and innovative seismic interpretation technologies for use in identifying shallow exploration targets
5. Assess the efficiency, effectiveness, and economics of the survey design, processing, and interpretation from the point of view of a typical small operator
6. Transfer the results of the survey to Osage tribal representatives with the objective of encouraging additional energy development on Native American land
7. Transfer information on the innovations in the survey design technology, parameters, and interpretive methodologies to independent operators

3.2 Geologic Setting of the Osage County Study Area

Osage County is located in the north-eastern part of Oklahoma, adjacent to Oklahoma-Kansas border (Figure 3–1). Geologically, the Osage county study area is located on the Northeast Oklahoma platform, immediately east of the Nemaha uplift (see Fig. 3–2). The region is part of the "Cherokee platform" of northeast Oklahoma (referred to as the "Cherokee basin" in Kansas). This southern margin of the North American continent was a tectonically quiet region, generally speaking, throughout the Lower Paleozoic, with slight flexing of the shelf allowing basins to deepen episodically. Sediment influx during the Lower Paleozoic originated from far-distant uplands or local, low-relief islands.

The Osage county region lies to the north of the McAlester basin, a northern extension of the Arkoma basin (see Fig. 3–2). The generally-stable Cherokee shelf was surrounded by the Anadarko basin on the southwest, the Seminole arch on the south, and the Chautauqua arch on the northeast, during the Paleozoic. These tectonic features and activity in the Ozark region, to the east, in Missouri and Arkansas, influenced or controlled depositional patterns and the stratigraphy of Osage County throughout the Lower Paleozoic. The setting changed significantly with the rise of the Nemaha uplift beginning in Mississippian time. At that point, a local sediment source developed, and the Forest City and Salina basins were isolated from each other.

Figure 3–3 depicts a generalized stratigraphic column for the northeastern Oklahoma platform. It shows various strata, including potential source rocks and reservoirs. The Paleozoic sediments lie on top of a highly-irregular, severely eroded Precambrian basement surface, with numerous remnant hills that formed islands in the earliest Paleozoic seas. The section also includes several significant unconformities, including one that formed during the Middle Ordovician, a second representing part of the Silurian-Devonian interval, and a third at the top of the Mississippian.

The total Paleozoic sedimentary thickness ranges from about 2,000 ft., overlying basement highs in the southeastern part of the county, to about 5,000 ft., in the western portions of the county. The basement appears to be extensively faulted and disturbed in the southern portions of the study area. It is deeper, generally unfaulted, and forms a relatively low-relief deep basin in the northern township. Approximately half of the accumulated sedimentary section was deposited during Pennsylvanian time.

There are a total of more than 360 of about 367 reservoirs that produce either oil or natural gas from the Paleozoic formations in Osage County. The bulk of the production comes from the Bartlesville Sandstone, part of the Cherokee Group, of Pennsylvanian age, along with the Ordovician-aged Arbuckle Dolomites.

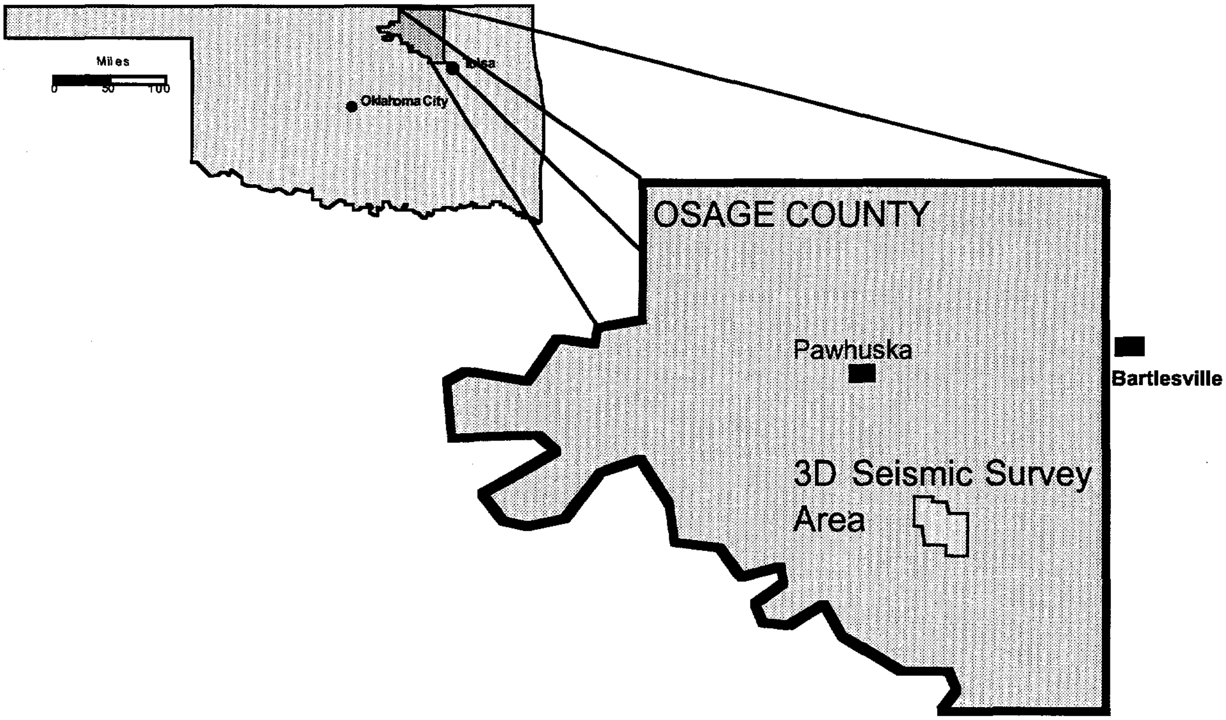

Figure 3–1 Location Map of Osage County and the 3D Seismic Survey Area.

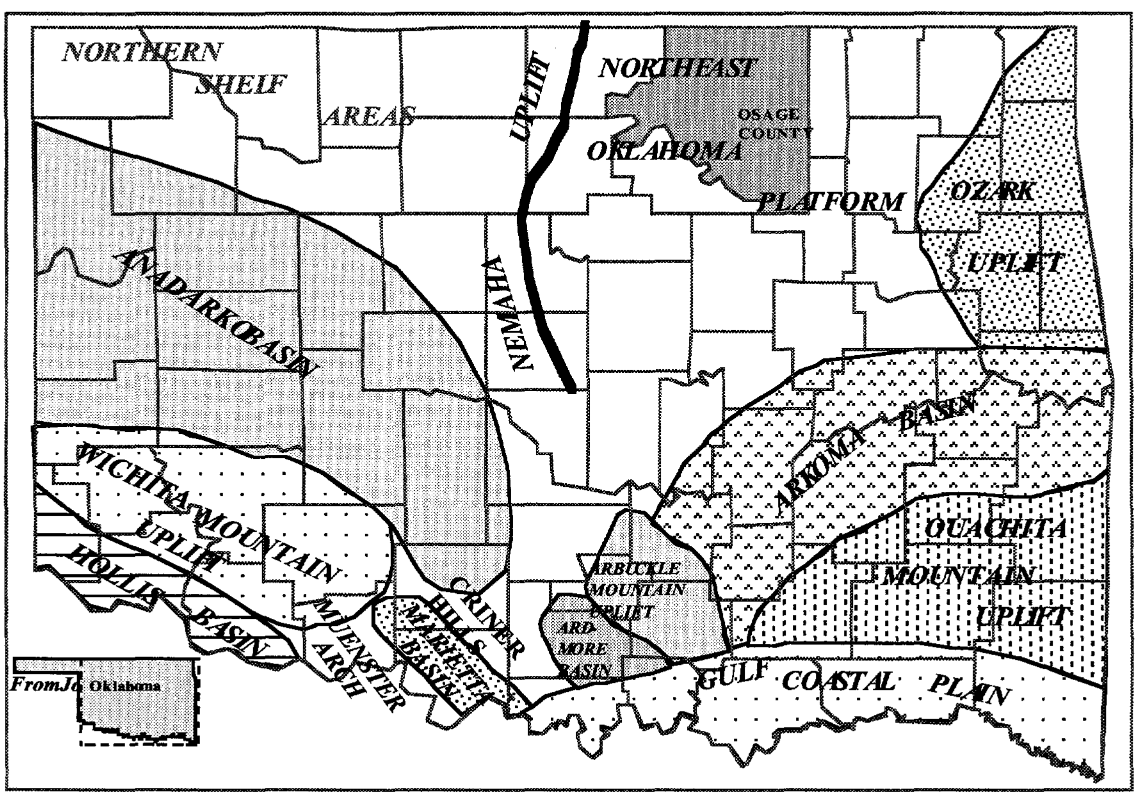

Figure 3–2 Major Geologic Provinces of Oklahoma.

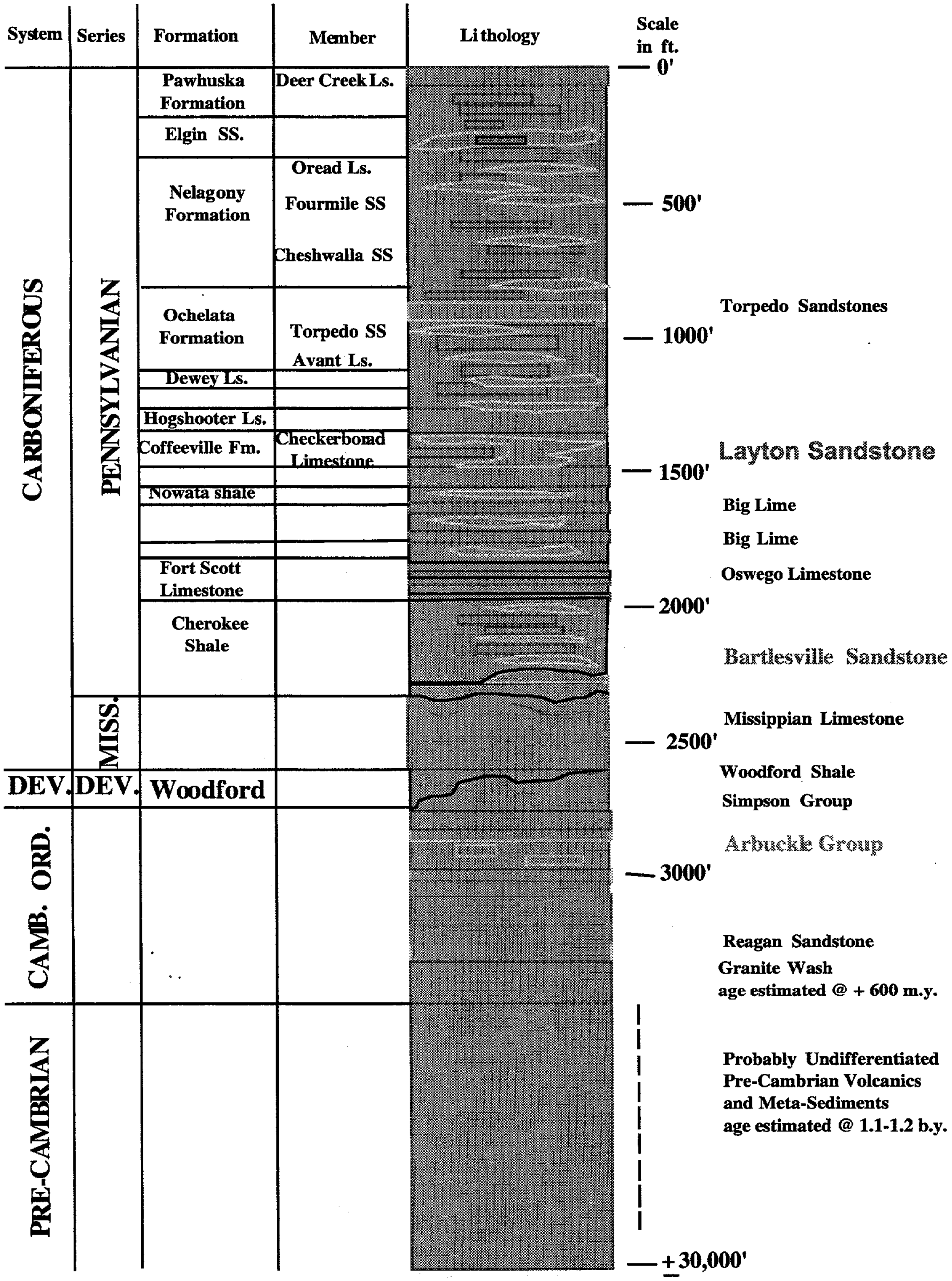

Figure 3–3 Representative Stratigraphic Column for Osage County.

One of the primary objectives of the interpretation work for this project has been to determine the relationships of the various geological factors, including

- structure,
- tectonics, and
- stratigraphy

on oil and gas accumulations in the study area.

A large number of wells have been drilled in the Osage county study area. Most of these are shallow wells, which did not test the deeper formations close to the basement. The integration of information from oil and gas production data from these wells, with structure and tectonics maps generated using the high-resolution seismic data, has provided a new, innovative tool to study the nature of hydrocarbon traps in the area.

After identification of the dominant structural and tectonic trends that have influenced hydrocarbon accumulations in the study area, additional studies were undertaken to identify the relationships between stratigraphically-controlled and structurally-cum-stratigraphically controlled oil and natural gas accumulations in the study area.

3.3 Design of a Model Field Test Program

A detailed investigation was conducted of the most-recent available literature on seismic exploration, to determine the current state-of-the-art and optimal equipment and parameters for the Osage county work. Local petrophysical properties were identified through the study and interpretation of wireline logs from the study area. This helped to identify factors that could affect the resolution of the survey and mapping of geological features in Osage county. The results from this study were used as a guide for the selection of data acquisition and processing parameters for the field test.

Important results from this preliminary study include the following observations and considerations:

- The potential to image vertical detail in sub-surface features is limited owing to the length of the propagating wavelength.
- The maximum resolution, i.e. the ability to recognize the top and the bottom of an interval, is a function of the bandwidth (or the frequency range), the dominant frequency of the seismic signal, and the noise level at the target depth.
- The occurrence of overlapping wavelengths from closely spaced reflectors also limits vertical resolution.
- Higher frequency content and greater bandwidth of the seismic data can contribute to higher vertical resolution.

Therefore, all efforts had to be made during acquisition and processing to obtain the highest possible frequencies and the widest available bandwidth for the seismic wavelet at the target depths.

In light of the shallow depths of most of the Osage county targets and considering that rougher terrain conditions and a greater degree of faulting were present in the southern and southeastern portions of the county, the evidence suggested that the survey data quality should be optimal if frequencies in excess of 80-Hz were to be recorded at the target depths.

3.4 Setup and Testing for the Bigheart 3D Survey

A brief description of the state-of-the-art field equipment and data-acquisition parameters employed in the Osage county 3D survey is given below:

Data Acquisition Layout, Equipment, and Parameters

The following survey specifications, materials, and parameters were used for this survey.

Ground Survey

The X, Y (map location), and Z (elevation) coordinates for the survey points (SP) and geophone placement were identified using a highly sophisticated global positioning system (GPS). The GPS system utilizes multiple navigation satellites. Precise time and position information transmitted by these satellites is used by a GPS ground station and by receivers at the SPs to triangulate a highly-precise location/elevation fix.

The first step for the establishment of the SPs was to set up a base station at a known location. The SPs were then located using remote transceiver units. The remote units and the base station communicated with the satellites simultaneously. A computer calculated the difference between the location reading at the known location of the base station and the unknown locations of the remote SPs. This difference was transmitted to the remote units for correction of their readings. This procedure gave a final corrected XY and elevation reading for each SP, in real time. These readings were stored for later downloading onto the survey computer.

Each GPS satellite continuously transmits its precise position (latitude and longitude, along with elevation above the planet) and the exact start time of the transmission. The GPS receivers acquire this signal. They then measure the interval time between the origin and the receipt of the signal to determine the precise distance between the receiver and the satellite. The process is known as ranging.

The receivers use multiple satellite sources during the positioning procedure. Once each SP has computed ranges for several satellites, its location on the surface of the earth can be determined with extreme accuracy and precision. In theory, as few as three satellite signals will provide a reasonably accurate position. For the accuracy desired for seismic surveys, however, six or seven satellites are generally required. Each of the satellites being utilized should be located a minimum of ten-degrees above the horizon. These standards should allow definition of the position to within approximately one-foot.

Under the best conditions, the DLB survey could receive signals from more than ten satellites. The surveyors kept a close watch on the communication situation, and were ready to suspend operations if the number of signals received dropped below eight. The location accuracy obtained by DLB for the ground survey SP stations was within approximately 15 cm, in most cases.

An ongoing problem for the survey was the fondness of a majority of the local inhabitants, primarily cattle, for the survey ribbons and markers. The ribbons contained starch, which proved to be a delicacy that the cows relished. When the survey crew discovered that many of the markers were disappearing, the surveyors made a special effort to prominently paint the ground, as well as to plant flagging, at each survey point.

The initial, idealized SP and receiver location plan for the Bigheart survey is shown in Figure 3 – 4. The SP vibrator station lines run north to south and are identified as lines SP-100 to SP-257 on the map. Receiver lines run east to west and are identified as lines R-1 to R-133. The initial, idealized SP and receiver location plan for the Bigheart survey is shown in Figure 3-31, NIPER/BDM 0296. The SP vibrator station lines run north to south and are identified as lines SP-100 to SP-257 on the map. Receiver lines run east to west and are identified as lines R-1 to R-133.

As generally happens in the real world, real life circumstances in the field complicated the picture slightly. Although the land is flat and gently rolling across much of the survey area, occasional deep gullies and moderate to large streams complicated access in places. Where such natural obstacles interfered on the ground, the actual receiver and SP locations deviated slightly from the ideal, pre-planned locations. The actual, adjusted survey map is shown in Figure 3–5.

Source Line Information . The SP lines were orientated north-south, with 440-ft line spacing in a staggered "brick" pattern. The SP intervals were 220 ft and 110 ft (for the 110-ft and 55-ft bin sizes, respectively), giving approximately 300 SP/mi^2 for the 110-ft bins and approximately 600 SP/mi^2 for the 55-ft bins. A total of 5,778 points were vibrated in this survey.

Receiver Line Information. The receiver line orientations were east-west, with 440-ft line spacing. The receiver group intervals were 220 ft and 110 ft (for 110-ft and 55-ft bin sizes, respectively), giving approximately 300 receiver points/mi^2 for the 110-ft bins and approximately 600 receiver points/mi^2 for the 55-ft bins.

For a 3D survey, the data-acquisition contractor prepares a paper base map (the so-called map coordinates) which identifies the location of each seismic trace on the earth. A 3D seismic survey has regular grid of bins, so any trace can be identified either by map coordinates or by line/trace coordinates which is prepared by the seismic processor (see Fig.3–7). A seismic processor During the survey, definesa regular grid of lines and traces (sometimes called X-lines or cross-lines) is defined. The traces, or CDP bins, in this reference system are located in pairs of line numbers and trace numbers. Figure 3–5 shows the line/trace coordinates for the 55'-bin and the110'-bin surveys. For the larger 110'-bin survey, the line numbers run from 1 to 264, north to -south, and trace numbers run east to -west, from 1 to 229. For the smaller, 55'-bin survey, line numbers run from 160 to 528 and trace numbers from 1 to 200.

Energy Sources and Parameters

Although dynamite was the most common energy source for seismic surveys for decades, this has changed in recent years, for multiple reasons,

- originally, for reasons of safety,
- then due to environmental considerations,
- and, finally, for technical reasons, especially due to a desire to control frequencies and source signatures,

many modern surveys have switched to Vibroseis technologies.

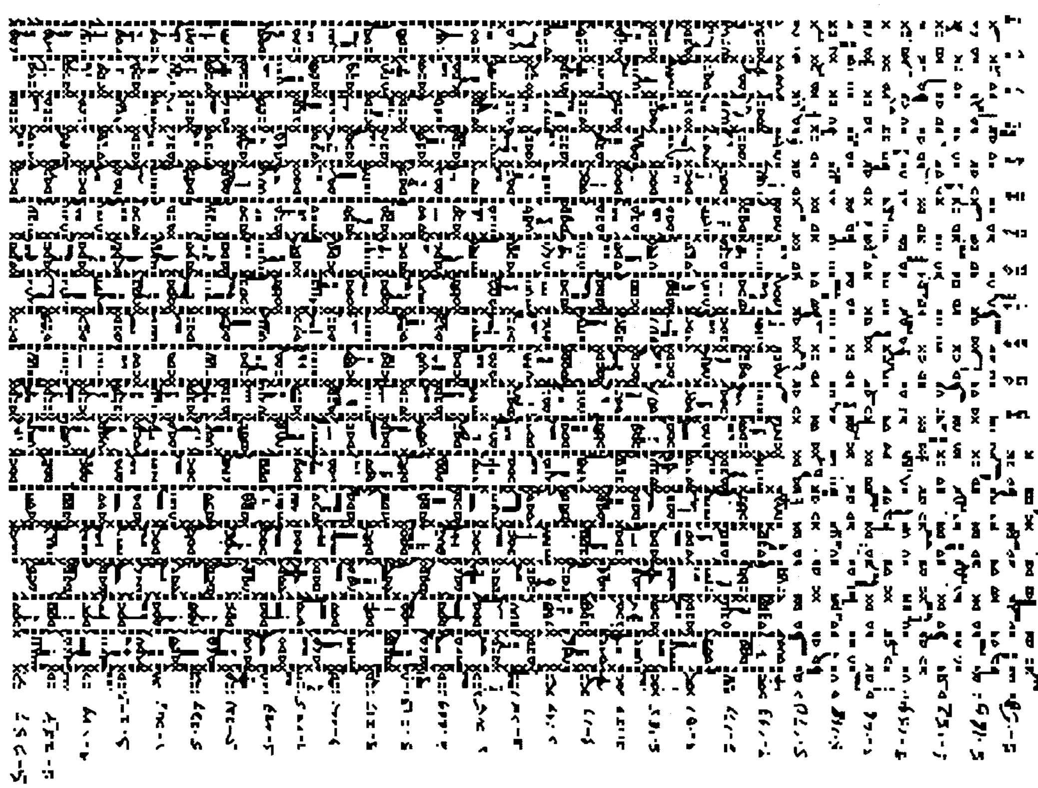

Figure 3–4 Preplanned, Theoretical Receiver and SP Locations for the Bigheart Survey.

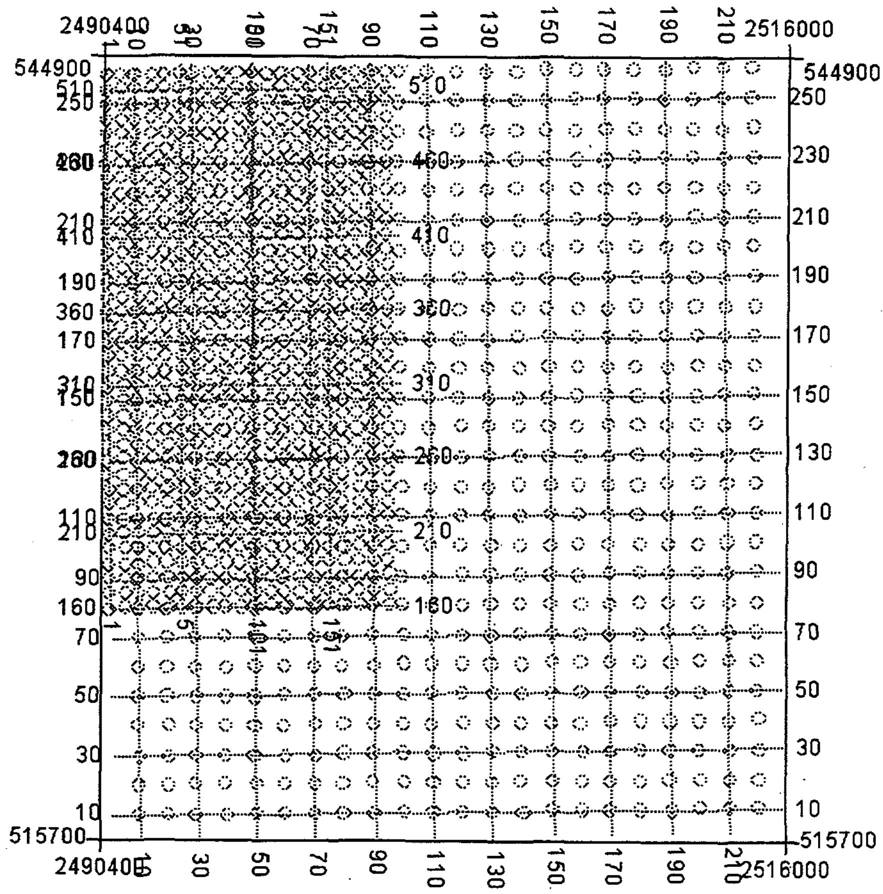

Figure 3–5 **Location Map of Inlines and Crosslines for the 55-ft and 110-ft Bin Data Area in the Osage County 3D Seismic Survey.**

The seismic energy for the Bigheart 3D seismic survey was provided by four relatively light-weight Vibroseis trucks, synchronized in unison, transmitting energy into the ground. Truck size and model were selected for this survey based on

- the depth of the target formations;
- the depth to regional basement;
- terrain;
- soil type, stability, and hardness; and
- environmental considerations.

Seismic energy was transmitted from the trucks into the ground by simultaneous, in-phase, vibrations of baseplates attached beneath the Vibroseis trucks (Anstey 1981).

The peak force, F, exerted by the baseplates on the ground can be defined as:

$$F = \text{Area} \times \text{Pressure}$$

where "Area" represents the area of the baseplate, and "Pressure" equals the peak system pressure.

Two source configurations were used for the recording of the Bigheart Survey,. The first equipment setup incorporated four Mertz Model-22 buggy vibrators, each with a holddown weight of 28,000 lb. The second configuration consisted of two Mertz Model-18 buggy vibrators, each with a holddown weight of 42,000 lb.

The change was incorporated for logistical reasons. It allowed the crew to record more efficiently, by using two sets of trucks, customized to local field conditions. The mix of vehicles permitted access to the rougher parts of the terrain in the prospect. Prior to switching vehicles, testing was conducted to ensure that the amplitude relationship between the two sets would be comparable.

Eight successive vibration sets were transmitted at each SP. Each vibration suite produced a record which was summed automatically with the sum of the previous sweep, until eight sweeps per SP were completed. Each vibrator sweep was eight seconds long, with a listening time of three seconds. After vibrating at each given SP, the trucks moved simultaneously to the next source position.

The frequency bandwidth of the transmitted signals ranged from 30 to 120 Hz. Low-frequency noise turned out to be a significant problem in this survey. Due to the nature of the terrain and the lack of a uniform weathering layer, the use of any type of array canceling would have been difficult. Since this prospect was shallow in nature, it was necessary to protect the integrity of the near traces. Sweep tests were conducted to determine the frequency range of the generated noise and sweep parameters were selected to eliminate as much noise as possible from the final spectrum.

Due to dense vegetative overgrowth in certain areas, and because of the importance of adhering precisely to the surveyed SP locations due to the shallow nature of many of the targets, it was necessary at times to construct pathways for the vibrators. This was done by clearing away the trees and brush with a bulldozer. Due to environmental considerations, attention was paid to ensure that only the necessary dozing would be accomplished. This clearing was necessary to guarantee that SP locations were precise, so that both offset range and distribution would be optimized to achieve the geophysical objectives.

Data-Acquisition Parameters

Shooting PatterN. Nine hundred channels/SP (15 lines X 60 channels per line) were recorded in the portion of the area with the 55-ft bin size. 450 channels/SP (15 lines X 30 channels per line) were recorded in the area with 110-ft bin size.

Pattern dimensions were 6,160 ft north-south and 6,380 ft or 6,490 ft east-west. Recording offsets were 3,190 ft or 3,245 ft inline and 3,080 ft cross-line.

There was roll/on/off.

Data-Sampling Rate and Record Length **.** A 2-ms sample interval and a total record length of 3 s were used.

Fold (Redundancy of Coverage). In the 55-ft bin size portion of the survey, the data were 14 fold at a depth of 1,000 ft, 24 fold at 2,000 ft, and 50 fold at 3,000 ft.

Table 3–1 summarizes the specifications and parameters for the survey.

Table 3–1 Specifications and Parameters for the Osage County 3D Seismic Survey

Source Information	The following parameters were used for the Vibroseis source information:
Line Orientation	North-South
Line Interval	440′ in a staggered, "Brick" pattern
SP Interval	220′ and 110′ (for 110′- and 55′-bin sizes, respectively)
SP/Square Mile	300 (approx.) and 600 (approx.)
Number of SPs	6000 (approx.)
Total Source-Line Miles	202 (approx.)
Number of Source Lines	115
Receiver Information	The following receiver parameters were used:
Line Orientation	East- West
Line Interval	440′
Receiver Interval	220′ and 110′ (for 110′- and 55′-bin sizes, respectively)
Receiver Points per $Mile^2$	300 (approx.) and 600 (approx.)
Number of Receiver Points	7000
Total Receiver-Line Miles	207 (approx.)
Number of Receiver Lines	55

Table 3–1 Specifications and Parameters for the Osage County 3D Seismic Survey (Cont.)

Shooting Pattern	The following shooting pattern was used:
Number of Channels Recorded per SP	900 or 450
Pattern Layout	15 lines x 60 Channels, or
	15 lines x 30 Channels
Pattern Dimensions	N S = 6160′
	E W = 6380′ or 6490′
Recording Offsets	Inline = 3190′ or 3245′
	Crossline = 3080′
Roll/ On/Off	Yes
Data Sampling Rate and Record Length	The following parameters were used for sampling and record length:
The Data were Recorded at a	2ms Sample Interval.
Total Record Lengths were	3 Seconds.

Quality of Recorded Seismic Data

The use of state-of-the-art equipment and a high multiplicity of fold coverage in the Bigheart survey ensured that the recorded data had high fidelity, as well as high resolution.

The fold recorded in the 55′ bin size area varied with depth, and were:

At 1000′	14 Fold
At 2000′	24 Fold
At 3000′	50 Fold

Geophones, Recording Channels, Cables, and Miscellaneous Field Equipment

The selection of good quality geophones is extremely critical when attempting to assemble a high-quality data recording system. DLB used 10-Hz, high-fidelity transducers. The system included strings of six geophones, potted, buried, and covered at each receiver location, for noise reduction. The summed signals received by the six geophones produced the output for each data channel. The I/O System II is capable of simultaneously recording data from 1,008 channels for each SP. Three hundred cables and 1,650 strings of geophones were available for this survey.

Data Recording System.

The field recording at the Bigheart survey was done using an Input/Output (I/O) Data Recording System II. All the requirements for a high-resolution system

- precision (the number of bits digitized by the system was 24),
- low noise levels, and
- high dynamic range (120 decibels)

were eminently satisfied by the I/O System II.

The dynamic range (DR) for a survey, defined by Sheriff (1991) as the ratio of the largest to the smallest recoverable signal, is of particular significance for a high-resolution study. The I/O System II has a DR of 120 dB, which is more than adequate for this type of work, enabling the recording of a maximum-minimum amplitude ratio of about 1 million. This should be eminently adequate for the recording and identification of even very faint signals from subtle geological features.

Recording of the Vibroseis Data

Since a Vibroseis source signal being input to the ground persists for an extended period of time, the reflected signals recorded in the field appear entirely incoherent to the eye. The reflected Vibroseis response is composed of superimposed signals from each of the reflecting horizons. Each reflection should theoretically have approximately the same waveform as the source signal, but the actual wave corresponding to each reflector will be delayed by the amount of time required to travel from the source to the reflecting interface and back.

The first step in the recording of Vibroseis data is to gather the reflected signals, then to use computers to cross-correlate the input sweeps with the recorded data (Dobrin 1976). The entire length of the sweep must be used in the cross-correlation process. The process is schematically depicted in Figure 3–6 .

During data recording, the operation of the vibrators was controlled by Pelton Advance II electronics and monitored in the recording trucks by VibraSig. Both these software packages represent the current state-of-the-art industry standard for vibrator control.

At the end of each sweep, a detailed report was transmitted to the recording truck. This report provided a graphical display of the average and the maximum phase for each truck. This information was useful to ensure that the trucks stayed within the phase standards set for the prospect, in this particular case, within 5 degrees at all frequencies. The correlation pulse of each truck was also transmitted, to further confirm the zero phase and amplitude spectrum of each sweep. These displays were useful in alerting the operator to any problems, either with a truck or with the coupling of the vibrating pad and the ground surface. In this way, potential problems were detected early and corrected.

Data Quality of the 3D Seismic Data

Due to the judicious combination of precision SP surveying; the careful, informed selection of a Vibroseis energy source and prime-quality equipment; the identification and use of an optimal set of parameters; the use of top-quality, state-of-the-art geophones and recording equipment; and the high multiplicity of fold, the recorded data for the Bigheart survey achieved very high quality resolution, imaging thin beds and subtle features with extremely high fidelity.

3.5 Acquisition of Field Data

Field work for the Bigheart 3D seismic test project began during the late summer of 1996, following several months of delays and roadblocks in the process of selecting a study area, as described in Section 2.0.

The Early Phases of the Survey

The first step for the field work was conduct of the ground survey, to locate the SP and receiver positions. An archaeological survey had to be performed in one portion of the study area. This survey was required because bulldozing was going to be necessary in areas of dense ground cover. Trails had to be cleared for the Vibroseis trucks before they could traverse these areas.

The seismic crew, with equipment, began to arrive at Bigheart during the final week of September, 1996. Field tests for the selection and verification of data acquisition parameters were conducted on October 1 and 2, 1996. These tests included:

- determination of the optimal number of vibrators to be used for obtaining the best possible field records,
- identification of the best frequency bandwidths for the vibrator sweep signal,
- selection of optimal up or down sweep of vibration,
- selection of the slope (dB per octave) of the vibrator sweep signal,
- determination of signal tapers for the optimal input to the given sweeps, and
- synchronization parameters for vibrator sweeps.

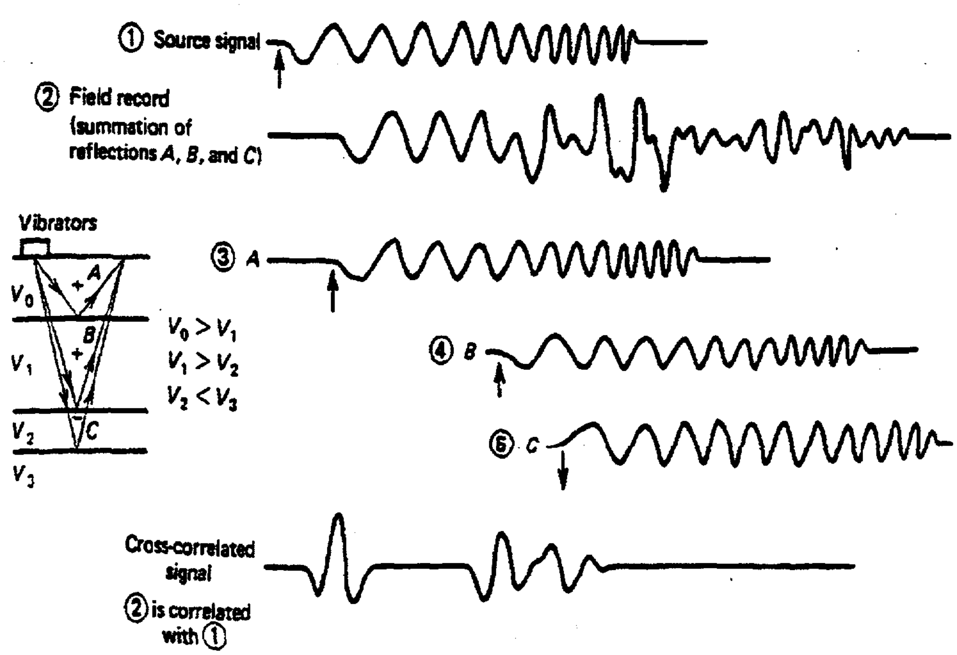

Figure 3–6 Schematic Description of Vibroseis Data Processing.

Difficulties Encountered During the Middle Phase of the Survey

Initially, during the early part of October, rapid progress was made on the survey. Eventually, however, inclement weather conditions began to hinder the program. Frequent rains hit the region during the later part of October and for several days in November.

Even the slight vibrations from raindrops hitting the ground surface at or near geophones can introduce significant amounts of noise into the seismic traces. This type of noise would quickly overwhelm the target subtle signals in a high-resolution survey like this. In addition, if the ground becomes too wet and muddy, significant rutting, sod tear-up, and other environmental damage can be done, and the Vibroseis trucks could get stuck, even with all-terrain, all-wheel drive capabilities. Besides difficulties with equipment movement, source generation in ponded water presents real difficulties, and water-saturated shallow soils have different transmission properties than dry soils.

By mid-November, the soils at Bigheart were thoroughly saturated, and large portions of the rolling landscape were under shallow standing water. Due to the impossible operating conditions in most of the study area, and unsupportable standby charges for idle days, the crew temporarily moved out, to work for another client in a drier part of the company.

Completion of Data Acquisition

Water-saturation conditions in Osage County were so thorough that it took several weeks for the soils to dry out. In addition, the crew was now occupied on a different survey. Field work did not resume until January 17, 1997. From that point on, the survey continued without any major problems until completion on February 19, 1997.

In the eastern section of the prospect, rugged terrain and bare rock outcrops frequently combined to produce poor vibrator-ground coupling. This erratic, often poor, coupling produced less-uniform and frequently weaker transmission of energy into the ground. The problem was minimized, where possible, by applying heavier than normal hold-down weights for the vibrators.

When the field work resumed on January 17, 1997, a Bell 206 helicopter with a 1,000-lb cargo capacity was used for moving lighter-weight equipment and supplies. Using a helicopter, rather than wheeled vehicles, proved to be very efficient, particularly in the rougher parts of the survey area. It also cut down on the land traffic around the prospect, thus minimizing potential damage to the terrain and other environmental problems.

A total of 5,778 points were eventually vibrated.

3.6 Processing of the Seismic Data

At the conclusion of the survey, the field tapes were shipped to GeoTrace Technologies, of Dallas, Texas, for processing. No significant problems were encountered during the processing of the data. The data for the southeastern part of the survey area had some refraction statics problems, but they were overcome satisfactorily.

Important points to note about the processed 3D data include:

- The data from the field tapes were processed to enhance the signal-to-noise ratio by the application of various data-processing routines.
- In processing the data, the seismic reflections are always assumed to be coming from the point midway between the shot and the receiver.
- In 3D surveys, all seismic reflections from within a certain area (called the "bin") are averaged to represent the seismic data from the center of the bin.
- The final, processed seismic data, therefore, represent averaged seismic traces from various bins located throughout the seismic survey area.
- 110′-bin data will involve averaging information from an area four times the size of the bins in a 55′-bin survey.

At each bin location therefore, processing produced a seismic trace sampled at discrete intervals (for example, 2-ms), extending from 0 second to the total length of the record (for example, 5-seconds). The length of the record was determined by the depth of investigation.

Seismic record quality varied from the northwestern part of survey area, where uniformly-rolling pasture land dominated, to the southeastern section of the prospect, where the topography was much more rugged. As would be expected, record quality was found to be better in the areas with uniform terrain. Luckily, data quality was best in the region where the high-resolution survey was conducted (see Fig. 3–5).

The final stacked and migrated seismic data, ready for interpretation, were received in by BDM Petroleum Technologies in Bartlesville during the last week of May and the first week of June, 1997.

3.7 Preparation for Interpretation of the Seismic Data

When the data were returned from GeoTrace, they were prepared for interpretation at BDM Petroleum Technologies.

Loading of the 3D Seismic Data onto Personal Computers

The processed seismic data from GeoTrace were loaded onto personal computers for interpretation. The procedures for loading the seismic data were fairly straightforward, but precautions must be taken to ensure that the computer to be used has adequate disc storage space.

The interpretation was done using 3dPAK for Windows, a software program developed by Seismic Micro Technology, of Houston, Texas. This program has been developed to run on a desktop personal computer with a minimum of 16 MbMB of Ram and a math co-processor. About 600-Mb of storage space was required for the data alone for the 55-foot and 110-foot bin size surveys in Osage County.

At BDM Petroleum Technologies, the data were loaded onto Pentium Pro computers with 6 Giga bytes of hard-drive space and 64 MBb of RAM. The programs have been running smoothly on these computers. Occasional minor glitches or problems during the data interpretation phase caused only temporary setbacks. Problems could be circumvented by following alternative procedures. It should be mentioned that such minor problems crop up in almost any software package that involves complex mathematical manipulations with large volumes of data.

Generation of Synthetic Seismograms

The first step in the interpretation of data in any seismic survey is the identification of the various reflections on the seismic section. This correlation of seismic reflections with geology is best done with the help of synthetic seismograms generated from sonic and density logs. The procedure used for the identification of reflectors in this study is discussed below. It is best to use synthetics generated from multiple wells.

For the Bigheart survey, various well logs (primarily gamma ray, density, sonic, neutron and resistivity/induction logs) were collected from the log library maintained by the Bureau of Indian Affairs at Pawhuska and the Oklahoma Well log library at Tulsa. In addition to well logs, production data and well completion reports were also collected.

14 sonic logs from the study area were digitized. ProMAX seismic processing software, loaded on a BDM Petroleum Technologies SunSparc 20 Workstation, was used to generate synthetic seismograms for these wells. The synthetic seismogram from the Millsap #1 well, which was extensively used in our studies, is shown in Figure 3–7.

Note that an accurate generation of reflection coefficients requires the input of density values. but since density logs were not available for the Millsap well, a pseudo bulk density profile was generated, using the sonic log. The wavelets selected for convolution with the reflected series to generate a synthetic can be a Ricker, Ormbsby or Klauder wavelet. Each of the different types of wavelets require different specifications, depending upon the number of frequency values needed to define that type of wavelet.

Various techniques were experimented with for the generation of synthetics. Note that the synthetic (see Fig. 3–7) generated with a 100Hz Ricker wavelet (where 100 Hz is the central frequency of the Ricker wavelet) shows much finer stratigraphic detail than a synthetic generated using a 40 Hz signal (see Fig. 3–8).

Several stratigraphic units of interest, including producing formations (such as the Bartlesville Sandstone and the Arbuckle dolomites) and distinctive marker beds (like the Woodford Shale) were identified on the logs (see Fig. 3–9). This made it easy to identify the same features on the seismic sections where the lines pass through the wells from which the synthetic seismograms were generated.

These seismic reflectors were mapped along in-lines and crosslines, forming a closed loop to ensure that the starting and the ending reflectors matched. An example of inlines and crosslines cross-lines from the seismic data cube for the Bigheart survey is shown in Figure 3–10.

Interpretation

Once the data were loaded, and the synthetics had been generated, a series of conventional and innovative approaches were taken in the interpretation phase of the work.

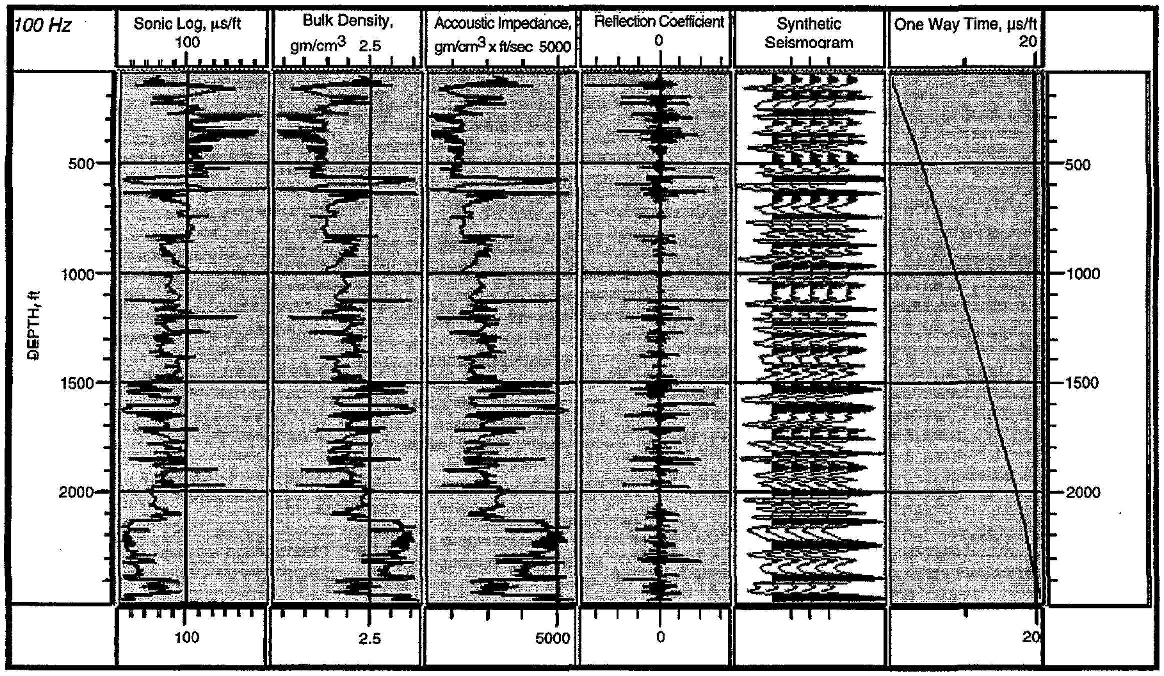

Figure 3–7 **Synthetic Seismogram of the Millsap #1 Well Generated Using a 100-Hz Ricker Wavelet.**

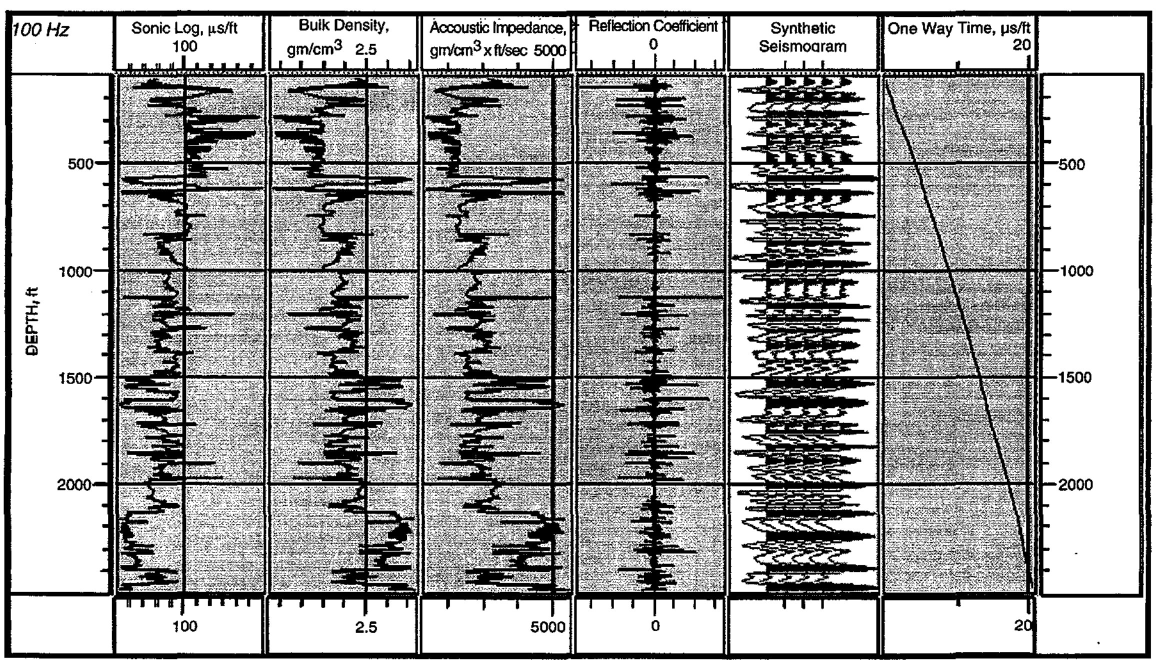

Figure 3–8 **Synthetic Seismogram of the Millsap #1 Well Generated Using a 40-Hz Ricker Wavelet.**

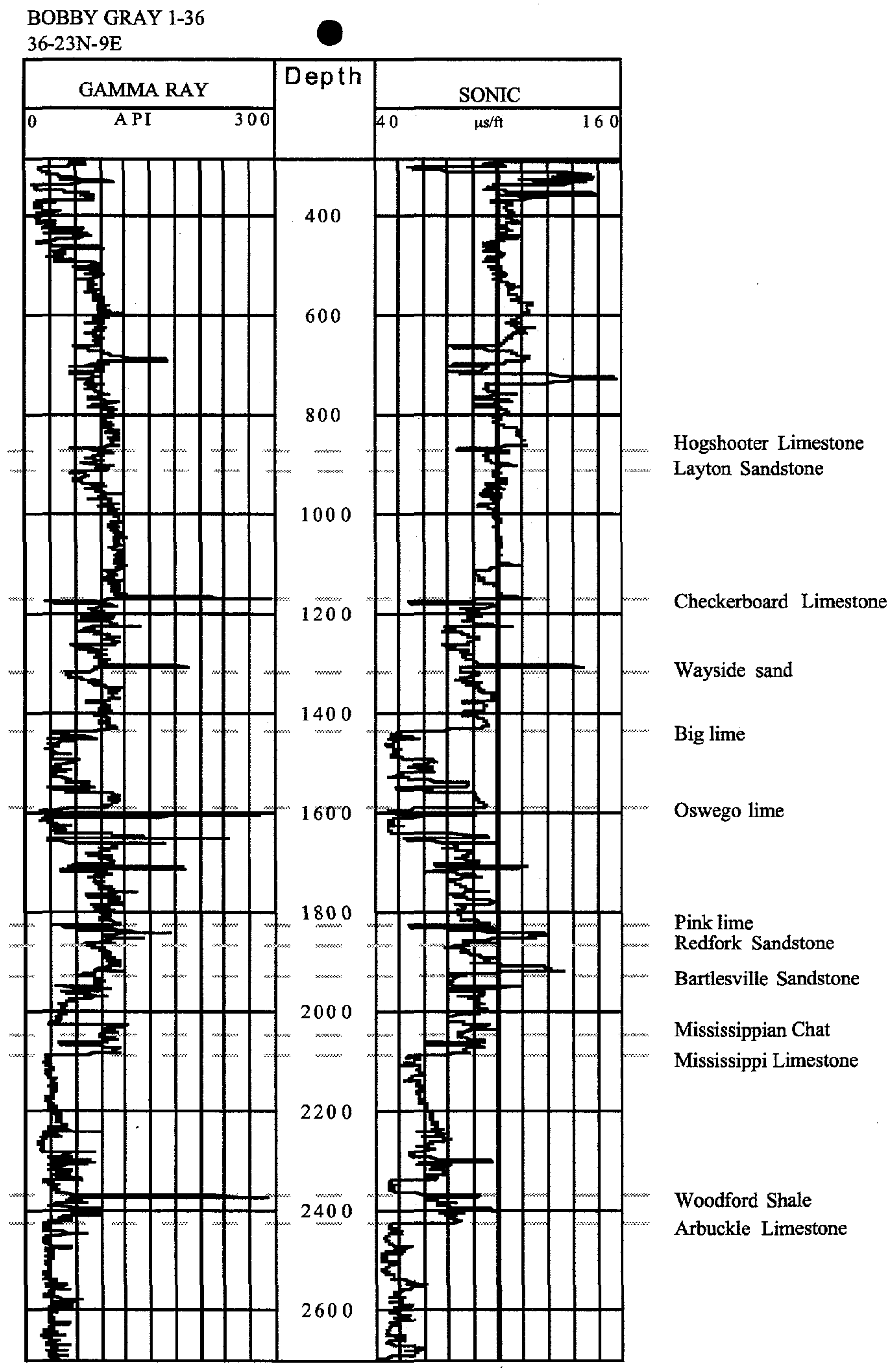

Figure 3–9 Representative Sonic and Gamma Ray Logs Showing the Tops of the Important Reflectors.

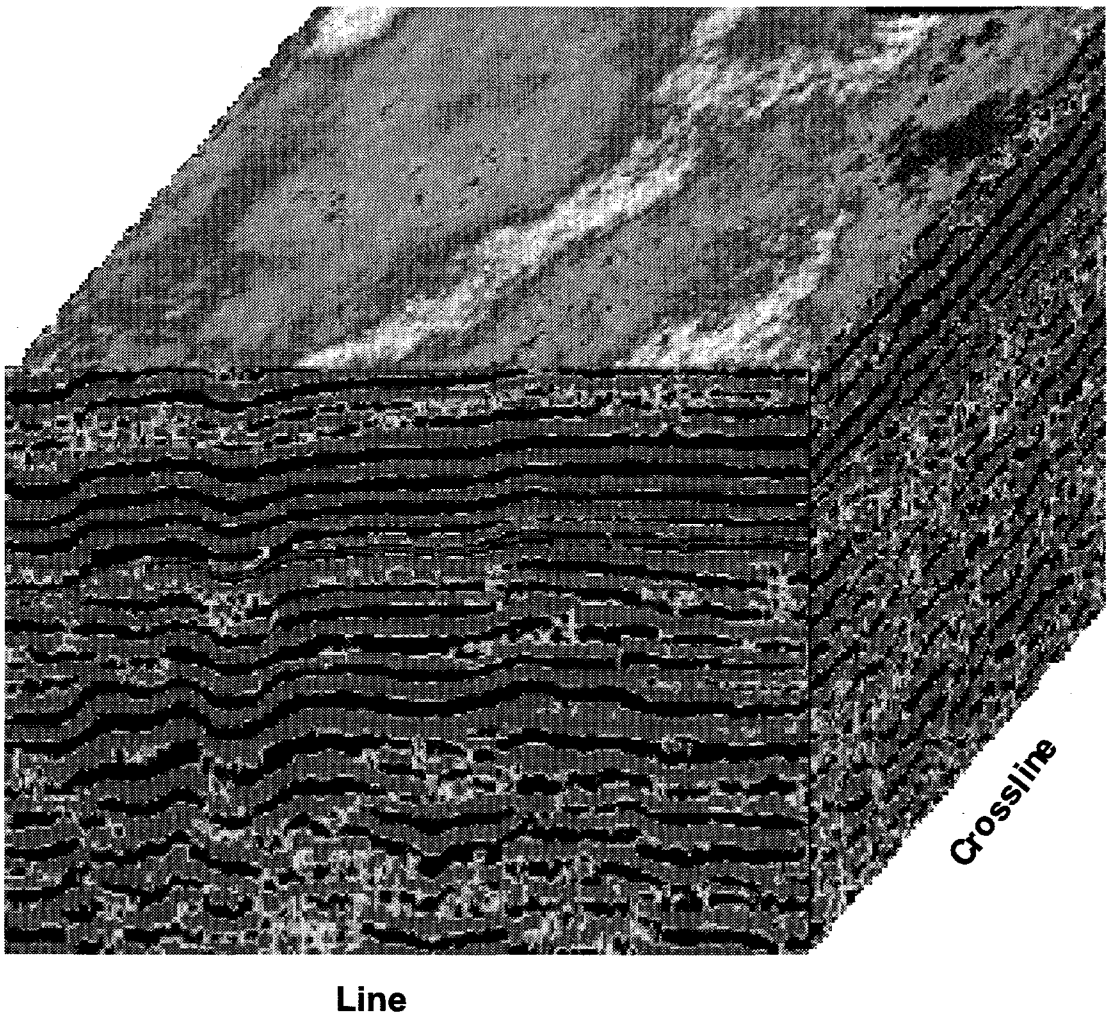

Figure 3–10 3D Seismic Data Cube from the Bigheart Area.

Identification of the Bartlesville Sandstone Reflector

In this part of Oklahoma, the Pennsylvanian-age Bartlesville Sandstone has been an extremely prolific producer of oil and natural gas. Figures 3–3 and 3–9 show the location of the Bartlesville sandstone within the stratigraphic column, along with the sonic and gamma-ray signatures of this reservoir for the Bobby Gray #-1-36 well.

After identification of the top of the Bartlesville sandstone on the synthetic seismograms, the structure of the sandstone was mapped (see Fig. 3–11) across the 110′-bin size area.

The trends identified on the Bartlesville map explain the locations of many of the old oil fields scattered across the study area. Most of the abandoned wells and still-active strippers were drilled in areas with good Bartlesville sand development.

Identification of the Layton Sandstone Reflector

A second common drilling target in the study area has been the Layton sandstone. This unit was also mapped from the seismic data. Figure 3–12 shows the geologic structure at the level of the Layton sandstone. The contours have been drawn at 2-msec intervals.

3.8 Detailed Investigations of the Seismic Data

For the identification of new potential reservoirs, the interpretation work by BDM Petroleum Technologies began with a "bottom up" approach, looking at the basement, including deep structure and faulting trends, to identify how fundamental tectonics and relief on the initial Paleozoic depositional surface influenced sedimentary patterns and the stratigraphy in the region.

Basement Structure and Tectonics

The seismic data from the entire 16.75 mile^2 110′-bin survey area in Osage county were interpreted to generate a structure map for the top of the seismic basement reflector. The two-way reflection times to the top of the basement reflector were obtained by extrapolating the two-way times at one of the deeper wells (the Millsap #1) that penetrated the top of the Ordovician-aged Arbuckle formation. The reflector times were cross-checked against sonic logs from other wells in the survey area.

In extrapolating the two-way times, the first strong, consistent reflector below the Arbuckle was assumed to represent the return from the top of seismic basement. Contours on the top of the seismic basement surface, drawn at 5-ms intervals, and the major faults that have cut the basement, are shown in Figure 3–13.

The identification and mapping of seismic basement was relatively simple in the north and central parts of the study area. This is because:

- the basement reflector in this area is generally quite strong, and
- there has been relatively little tectonic activity that has disturbed the basement in this area.

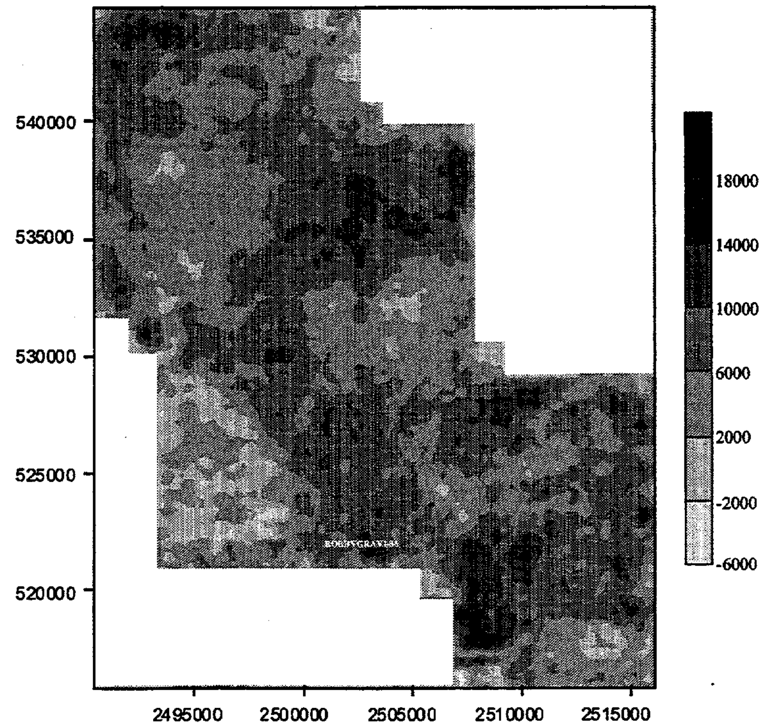

Figure 3–11 Amplitude Map of the Bartlesville Sandstone.

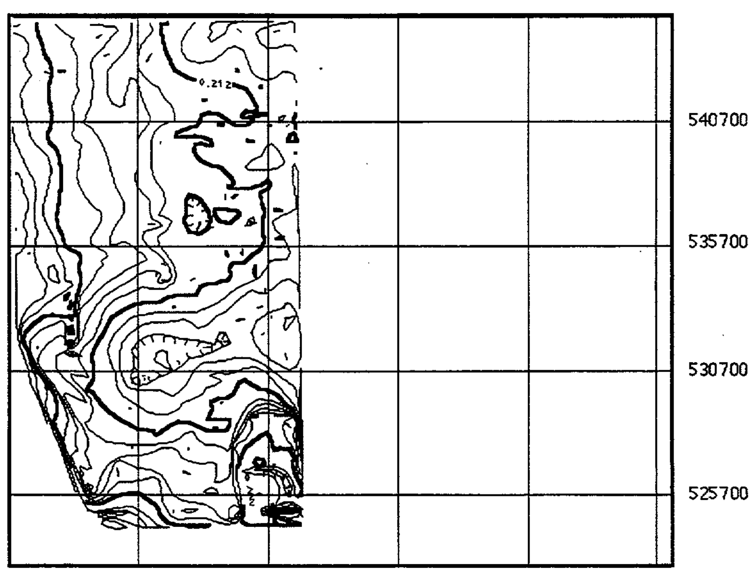

Figure 3–12 Structural Contours on the Top of the Layton Sandstone.

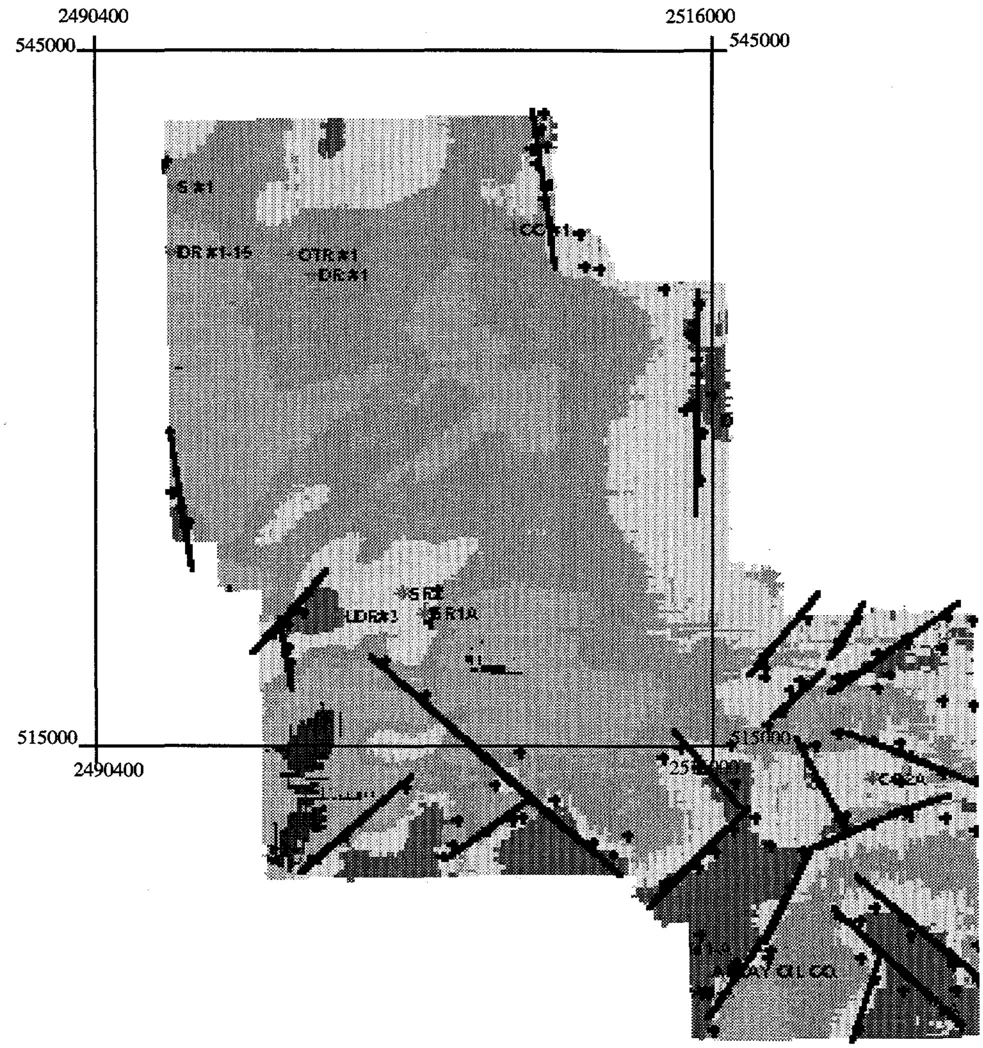

Figure 3–13 Interpreted Seismic Basement Time Map, with Overlay of Faulting.

In the southern and southeastern parts of the study area, however, the identification and correlation for the seismic basement reflector is much more difficult. This is due to the much larger number of faults that cross that area. Figure 3–13 shows the faults that affected the basement surface in that region. The fault traces have been superimposed on the structure map. As can be seen on this map, two directions of faulting predominate in the study area:

- one trending northwest-southeast,
- the other trending northeast-southwest.

Fracture and Lineament Studies

Information on surface and subsurface lineaments and fractures was interpreted by BDM Petroleum Technologies personnel, using satellite images and aerial photographs of the Osage County study area (see Section 4.0). The results from this work was carefully integrated with the seismic interpretation studies, in a multi-disciplinary, synergistic approach.

Two sets of fracture and lineament trends were identified by the remote-sensing study, one aligned NW-SE and the other, NE-SW. There was an almost perfect coincidence between these features within the shallow sediments and at the surface, and fault trends seen in the seismic basement on the seismic interpretations (see Fig. 3–14).

The apparent strong correlation in this region between basement faulting and shallow fractures and lineaments suggests the possibility that the basement fault system has been reactivated multiple times. These faults appear to have propagated upward, all the way to the surface.

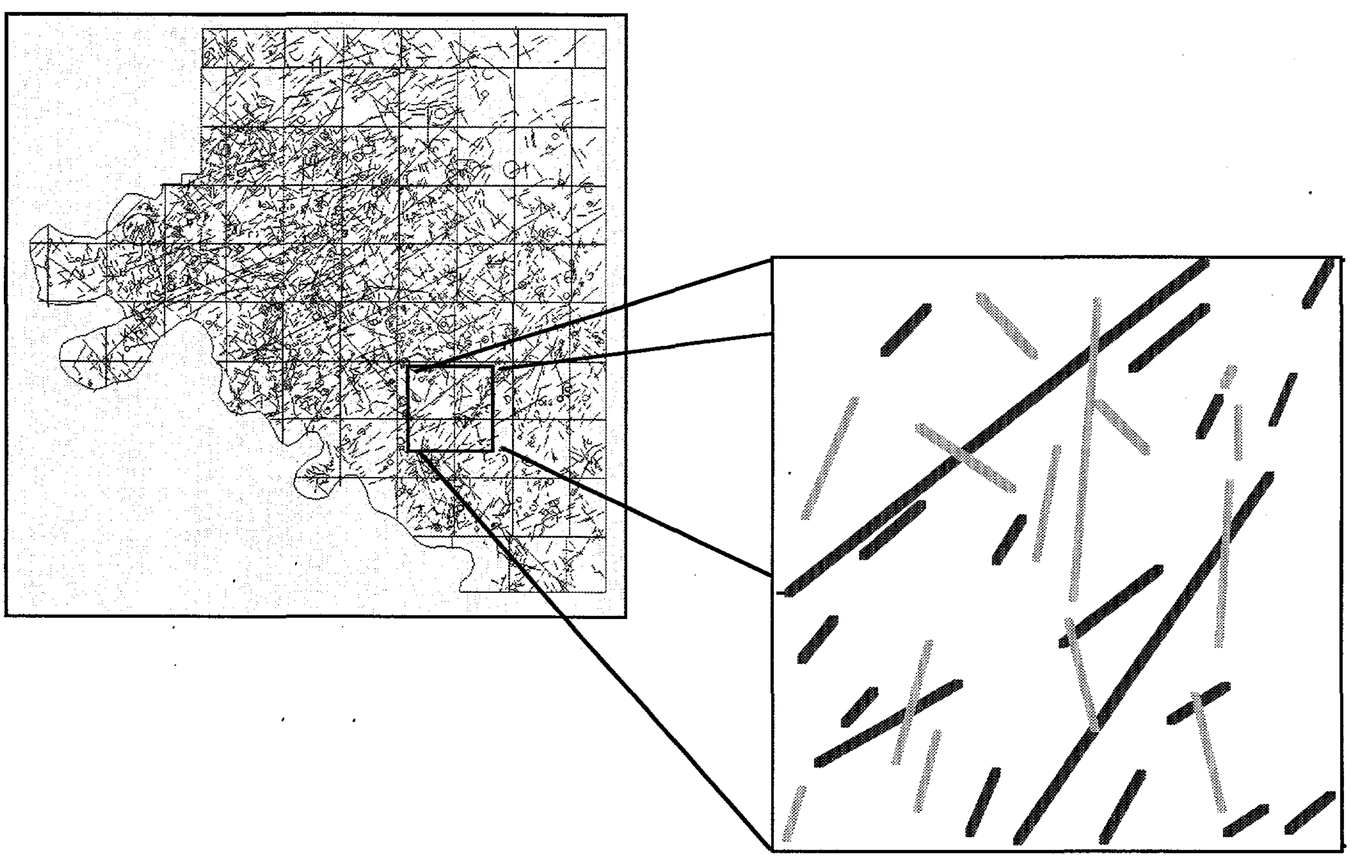

Figure 3–14 Osage County Surface Fracture and Lineament Patterns.

This evidence strongly supports initial observations (NIPER/BDM-0223, March 1995), by BDM Petroleum Technologies personnel, of a strong association between shallow/surface linear features and subsurface oil and gas traps in northeastern Oklahoma. Similar associations were found in the Oklahoma Panhandle, and the Denver and Forest City Basins. It has been postulated that the fault systems have acted as loci for the development of oil and natural gas reservoirs in areas with good seal development. The accumulations apparently form in secondary porosity traps.

Observations on Structual Control of Hydrocarbon Accumulations

As has been mentioned above, the Layton sandstone was an early target for conventional seismic mapping. It soon became a favorite target for more-sophisticated, specialized studies. Figure 3–12 shows the geologic structure at the level of the Layton sandstone.

Regional structure contours indicate that the formation is generally monoclinal in the northern part of the study area, where several commercial-sized hydrocarbon accumulations have been identified. Field 1, Figure 3–15 , is typical of one of these Layton fields. While there is a general, gentle easterly dip of about 70 ft/mi. across the northern portion of the study area, a close examination of the contours around the areas where gas accumulations have been encountered (see Fig. 3–12) indicates that a series of minor flexures in the contours can be seen. This pattern suggests the possibility that there may be minor structural influence on some of the stratigraphic accumulations.

Mapping of a Layton Channel Sandstone

Results of attempts to map meandering Layton sandstone channels, using the 55′- and 110′-data, respectively, are shown in Figures 3–16 and 3–17, respectively. The results from this work included some of the most dramatic results from this project. The original work was done using a color display on a computer monitor. A wide range of color options and varying cutoff values were available. For publication purposes, gray scale displays had to be used.

The 110′-data (see Fig. 3–17) shows very little of interest. Some generalized, formless areas of higher amplitude could be distinguished, but there was no single feature that jumped off the screen, or geologic sense to be made from the display. It would be expected that the 55′-bin data will provide a much better resolution. This is due to the fact that the 110′ survey averages data over an area four times as large as the 55′ survey.

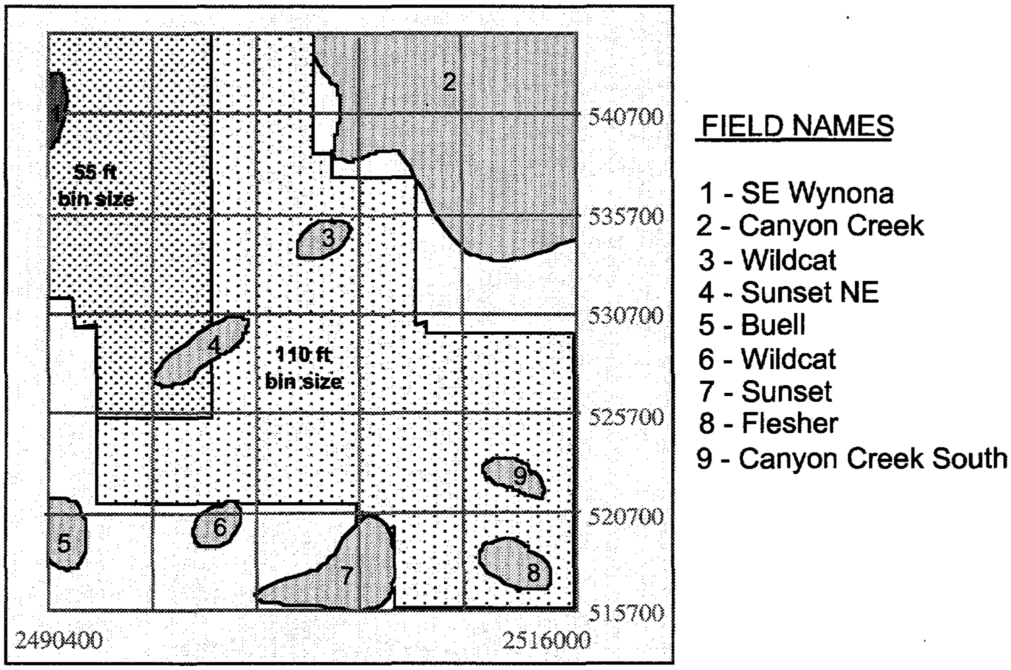

Figure 3–15 Oil and Gas Fields in the Osage County 3D Survey Area.

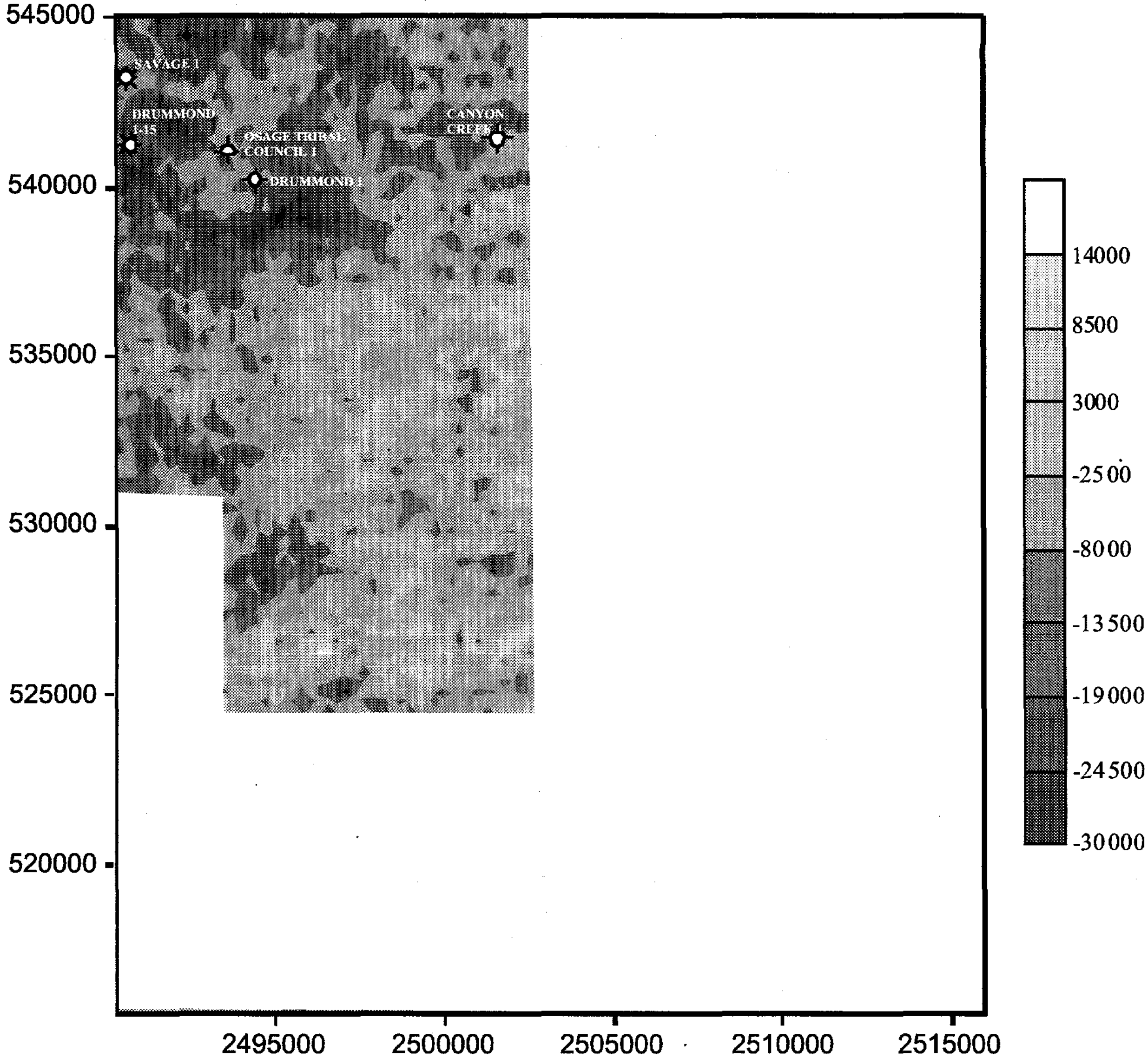

Figure 3–16 Seismic Amplitude of Layton Sandtsone, using 55-ft bin data.

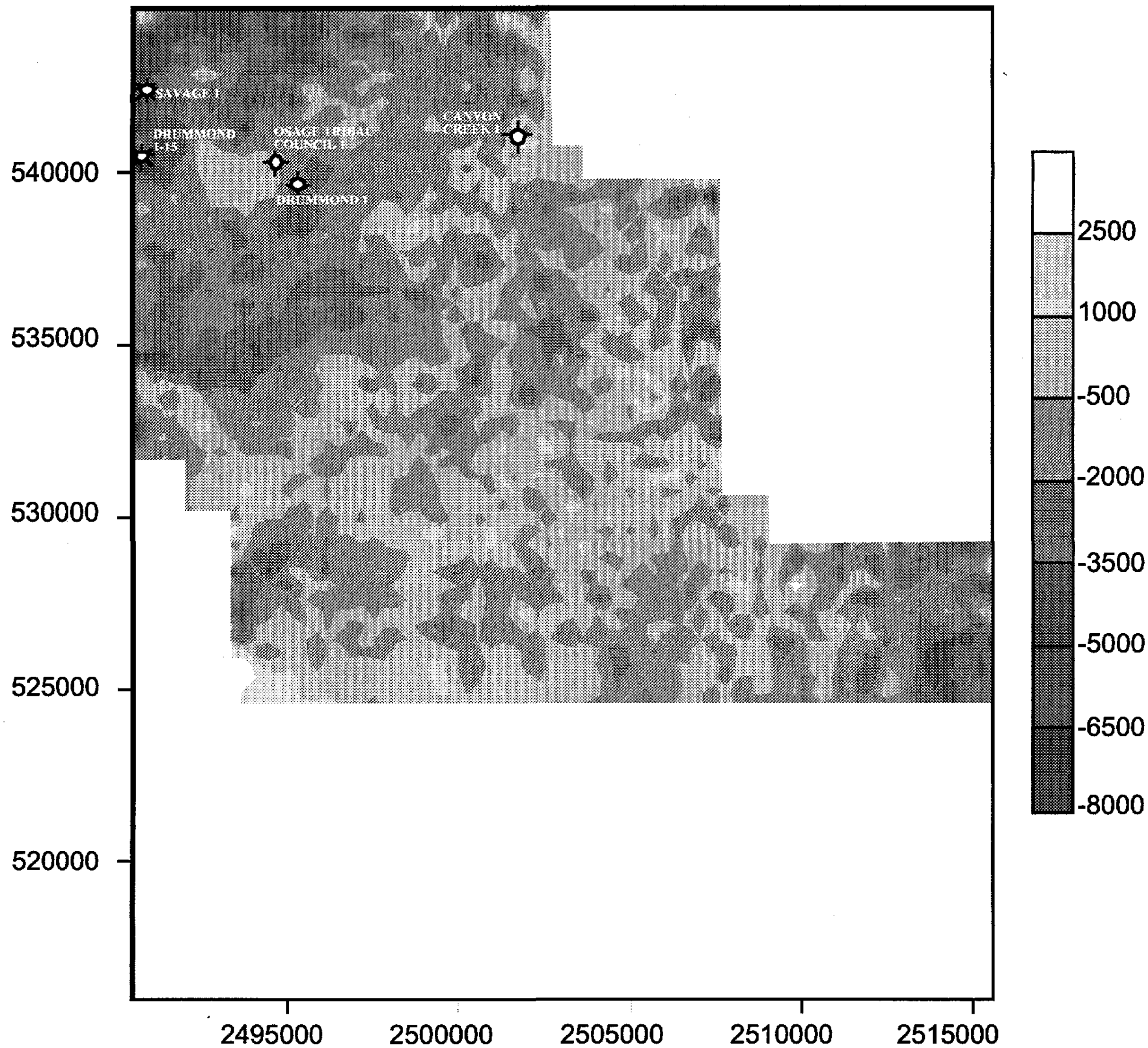

Figure 3–17 Seismic Amplitude of Layton Sandstone, using 110-ft bin data.

The change from the 110′- to the 55′-display was dramatic, a key finding of the research. When the 55′-bin data was initially displayed, the change was startling. With the higher resolution, the course of a meandering channel could be delineated (see Fig. 3–16). Varying the cutoff levels on the color display made it possible to increase the resolution still further. Ultimately, bends in the channel, and an overbank splay deposit were identified. The shape of the splay stood out. Comparison of this 55′ plot and results from the Geo-Microbial Technologies microbial survey (see Section 6.0 and Appendix) show an extremely interesting correlation, suggesting that the splay, and part of the adjacent channel sand may be natural gas-saturated.

On the gray-scale representation, the darker shades indicate regions with higher-amplitude seismic responses. These typically reflect from areas where the sandstone is thick and relatively clean. The areas with lighter shades represent lower-amplitude features, the surrounding muddy floodplain. In a carefully prepared color display, the facies of the meandering streams, including the main channel, as well as the overbank splay deposit could be identified.

Seismic amplitudes appear to provide an excellent indicator of petrophysical properties within the Layton sandstone on the 55'-bin size data. Clean sand development can be identified in the area of the gas-productive Drummond #1-15 well. The reflector on the 55'-data there clearly shows high-amplitude seismic responses, compared to those seen in the area of the dry wells Osage Tribal Council #1 and Drummond #1, where the Layton is clayey and has much poorer petrophysical properties, in terms of reservoir quality.

3.9 Innovative 3D Seismic Interpretation Techniques

Several innovative approaches were taken to the interpretation of the Bigheart survey.

Methodologies for the Detection of Lateral Variations in Fluid Saturation

Multiple innovative, sophisticated studies were undertaken of the characteristics of the seismic waves from this survey, as part of this study.

Innovative Studies to Track a Thin Gas Sand in Osage County

The value and potential of using high-resolution seismic data as an exploration tool was tested by tracking a thin gas-saturated sand in Osage County from a productive to an unproductive area. The sand under investigation was the Pennsylvanian-age Layton sand, encountered at a depth of approximately 1100'. The Layton has widespread distribution in Osage county, and produces oil and gas in various parts of the county. The objective of this investigation was to determine if there was a systematic way which could be developed to explore for the type of subtle stratigraphic features which are known to occur within units like the Layton. Small pools within units like the Layton contain significant quantities of oil and natural gas at shallow depths.

Although the Layton sand reaches thickness of 30'-40', in places, in the Drummond #1-15 well, located in Section 15, the gas-saturated zone is only about 18' thick. The density/neutron log for this well clearly shows a "gas effect" crossover through the gas-saturated portion of this sand. In this zone, the density curve gives very low readings, and crosses the neutron curve. The density curve shows these low-density values because the effective density of a gas-saturated sandstone is very low, compared to the same sandstone when the rock is solid or is filled with a denser liquid, like water or oil.

The neutron curve shows higher values in a gas-filled reservoir, because there are comparatively fewer hydrogen atoms in a gas-saturated sandstone, compared to a water saturated sandstone. This allows emitted neutrons to travel further away from the source and closer to the detector before they encounter a hydrogen atom. High neutron readings on the log are the result. In the case of a water-saturated sand, gamma emission occurs closer to the source, due to the many collisions with the hydrogen atoms; thus, fewer neutrons reach the detector.

About a mile to the east of the Drummond #1-15 well, the Layton sandstone becomes shaley. In that area, the sandstone no longer shows the gas effect, because the open porosity has become clogged, filled with clay or shale. With the porosity filled, the sandstone has a relatively high density.

Figure 3–18 shows a series of density-log-derived porosities along an east-west section from the Drummond #1-15, where the Layton sandstone is clean, with good porosity development, to the Drummond #1 and Canyon Creek #1, where the Layton pore spaces are clogged with clay. The gamma ray logs from wells 1 the Drummond #1-15 and Osage Tribal Council #1 2 (Well Osage Tribal) show a "dirty" sandstone, , shown in sections 14 and 15 of Figure3–18 clearly indicating that the Layton, which is clean in the Drummond #1-15, has become much shalier to the east.

The exercise for the 3D seismic program became a test to determine if the saturation change in the thin gas sand could be detected from lateral variations in the character of the seismic reflector at the Layton level, such as a consistent amplitude change across the gas sand, from a reservoir area to a "dirty" area.

Amplitude Studies of the Layton Sandstone

The Layton sandstone varied from gas-filled and productive to clay-filled at various points across the study area.

Figure 3–18 shows survey Line 460 as it passes through the Drummond 1-15 well and wells 1 (the Drummond well) and 2 (Well Osage Tribal) in sections 14 and 15. Figure 3–19 shows a portion of Line 452 of the survey, from SP 1 to SP 78, between Times 0.19 sec and 0.35 sec. The traces shown include the reflector for the Layton sandstone (at Time approximately 0.225), as it passes from the gas-saturated portions of the reservoir to clayey parts. To the west (the left side of the figure, Traces 1-22) east, gas saturations are high in the Layton. The section clearly demonstrates high amplitudes in areas where the saturation of gas is high.

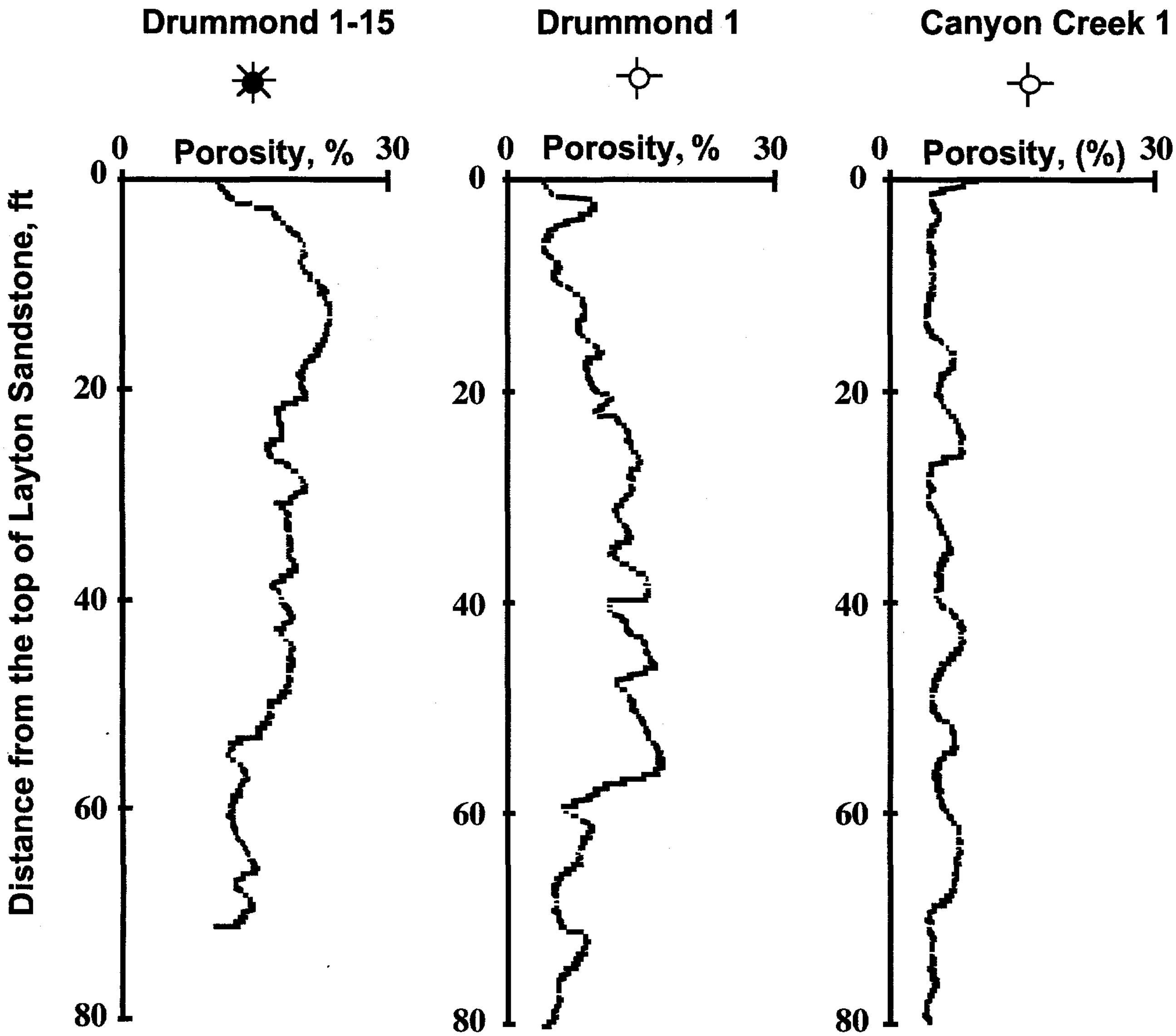

Figure 3–18 Log-Derived Porosity Profiles for Gas-Saturated and Dry Areas.

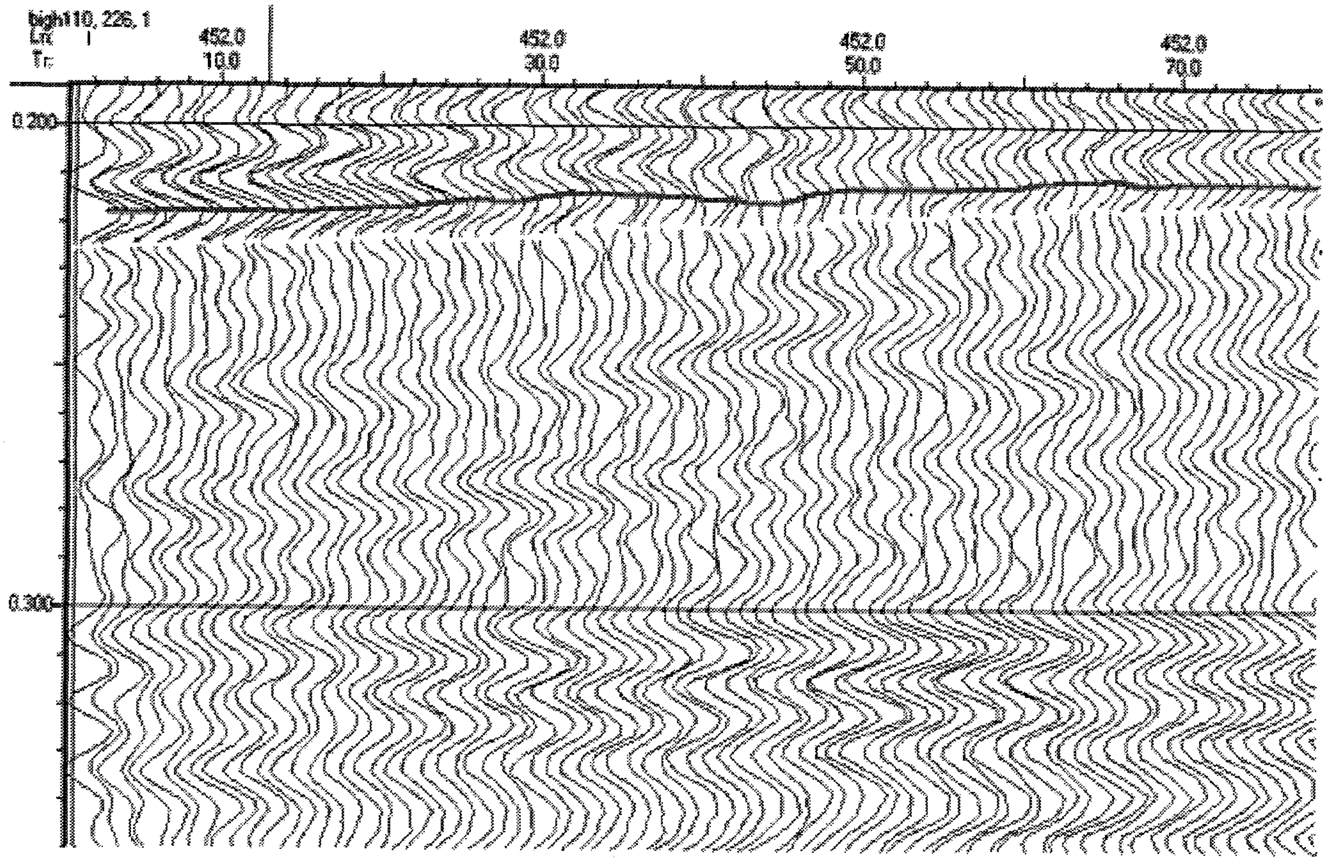

Figure 3–19 **Wiggle Trace Display of the Western Portion of the Seismic Section along Line 452.**

In other areas, (beginning around Trace 42, and extending to the east [right] to Trace 781-10) the amplitude is much lower. In areas where wells did not encounter any significant gas-saturation values or accumulations the seismic reflector amplitude values are quite low.

Exactly this same effect has been reported repeatedly in the literature. One example is a case study by GeoQquest International (1981). The GeoQquest study involved an Upper Tertiary gas sand which was about 40′ thick. The sand was encased in shale. The enclosing shales had high sonic velocities relative to the gas sand. While the top and the bottom reflection events for the Upper Tertiary gas sand could not be seen on a seismic section because the frequencies were not sufficiently high, a sharp increase in negative seismic amplitudes could be seen at the top of the gas sand. This increase was due to the low acoustic impedance of the gas-saturated sand. The same effect is believed to be observed in the seismic section of Line 460. Several other, similar case histories have been reported in the literature.

It was concluded that amplitude analyses could be one of the best tools described in this study.

Figure 3–20 shows how the high-amplitude negative reflection is generated by the gas-saturated Layton sandstone. As seismic waves pass through the high-velocity Hogshooter formation, they impinge upon the Hogshooter-Layton interface. The compressional energy is reflected as a rarefied signal due to the lower acoustic impedance of the gas-saturated Layton sand, compared to the Hogshooter. In other words, the signal from the Hogshooter-Layton contact will be reflected as a trough (see calculations below).

$$R = A_r \;/\; A_i = (\text{rho}_2\, V_2 - \text{rho}_1\, V_1) \;/\; (\text{rho}_2\, V_2 + \text{rho}_1\, V_1)$$

where:

- A_r and A_i are the amplitudes of the reflected and the incident seismic waves, respectively,
- rho_1 and V_1 are the density and the velocity in the Hogshooter limestome formation, and
- rho_2 and V_2 are the density and velocity in the Layton sandstone (which may be gas-filled in one part of the field, and clay-filled in another).

For a typical case, rho_1 and V_1 may be 2.65 gm/cc and 16000'/sec, respectively, and rho_2 and V_2, for the gas-filled sandstone, 2.20 gm/cc and 8000'/sec, respectively, and for the clay-filled case, 2.50 gm/cc and 12000'/sec, respectively.

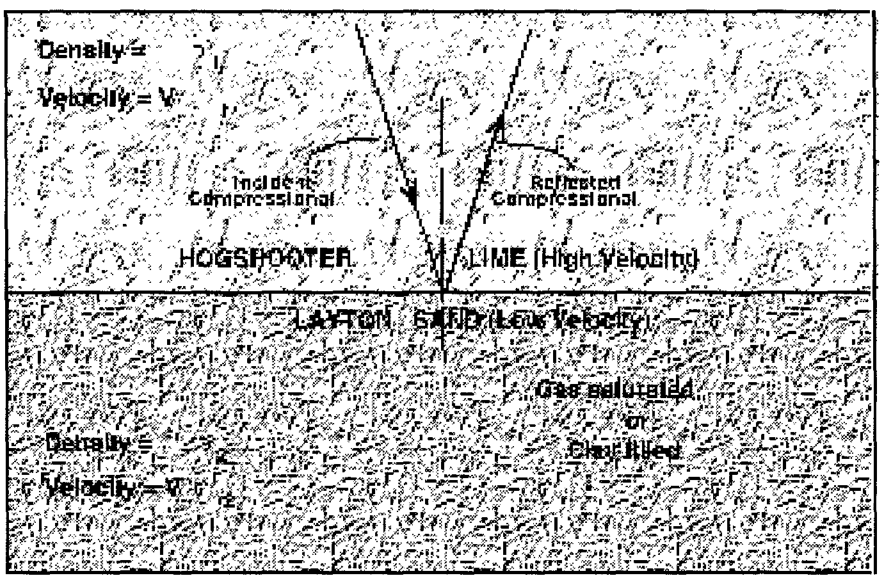

Figure 3–20 Mechanism for the Generation of High-Amplitude Negative Reflections from the Layton Sandstone.

For the gas-producing areas, therefore, the reflection coefficient R is given by:

$$R = (2.20x8000 - 2.65x16000) / (2.20x8000 + 2.65x16000) = -0.5616$$

This implies that for such a medium, an incident wave with a peak amplitude = one unit will generate a reflected trough, with an negative amplitude = -0.5616 unit. The negative sign in the reflection coefficient "R," in the equation, implies a 180^0 phase shift.

It should be noted that because the Layton is such a thin sandstone unit (the zone with clean, high-porosity sands is only about 16′ thick), the top and the bottom of the formation will not be resolvable by a seismic reflected pulse. Nevertheless, it will be possible to identify a distinct negative excursion in the seismic wavelet from the target zone, due to the impedance contrast at the Hogshooter-Layton interface.

The amplitude of the negative reflection will be an indicator of the decrease in the velocity within the Layton sandstone. The velocity will decrease as gas saturations increase. Good petrophysical properties of the reservoir (a combination of high porosities and/or high saturation of the reservoir pore space with a low-velocity fluid, like gas) will contribute to an increased negative amplitude.

Statistical Time-Series Analysis of Amplitude Data

The characteristics of the entire seismic wave shape were studied, in addition to the studies of amplitudes at isolated points, already described. The powerful technique of Time Series Analysis was applied to the Osage County data.

Time Series and Spectra. All observed data can be classified as either deterministic or random. Deterministic data are those that can be described by an explicit mathematical relationship. Random data can be described only in terms of probability statements and statistical averages. The theory of time-series analysis deals with the measurement of products and properties of stochastic or random processes.

The yield from 70 consecutive batches (see Fig. 3–21) is a stochastic process because it fluctuates in a manner that makes it impossible to predict exactly the value of the next batch. Although future values for the batches cannot be predicted exactly, a forecast can be made of these future values, based on certain specific average properties of the Time Series. These are derived from statistical laws and models.

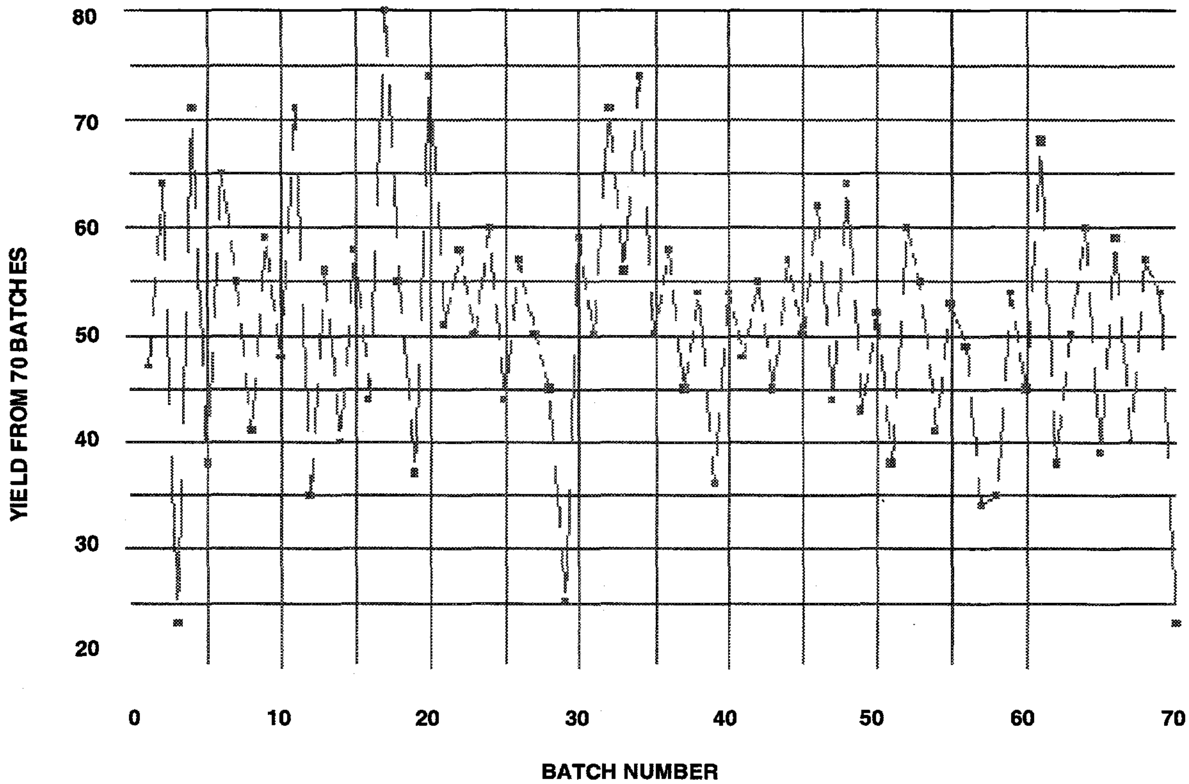

Figure 3–21 Fluctuating Yields from 70 Consecutive Batches.

A stochastic process may be adequately described by the lower moments (mean variance and covariance function, along with the Fourier Transform of the covariance function, the power spectrum) of its probability distribution functions. In other words, the stochastic process may be adequately described by means of a model containing a few parameters which may be estimated from the data.

Spectral Analysis of a Time Series. Spectral analysis brings together two very important theoretical approaches:

- the statistical analysis of Time Series, and
- the method of Fourier analysis.

Of the many branches of science and engineering where this powerful data analysis technique has found applications, its use in the development of information technology is, probably, the most significant.

The mathematical techniques of Fourier series analysis have found widespread applications because of the ease with which most periodic and aperiodic functions may be represented for further analysis by Fourier series. For instance, the Time Series S(t), which is an aperiodic function of time t, may be represented by the following Fourier integral (Jenkins and Watt 1968):

$$S(t) = \int_{-\infty}^{\infty} S(f)e^{j2\pi ft}\,df$$

where S(f) is the Fourier transformation of function S(t) from time domain, t, to frequency domain, f.

This equation implies that any function of time (or distance) may be obtained by the juxtaposition of all possible Fourier frequency components into which the Time Series has been divided.

Power Spectrum. If the Time Series xt consists of a mixture of several cosine waves with frequencies f_i and amplitude a_i, then the variance of the series σ^2 is given by (Jenkins and Watts, 1968):

$$\sigma^2 = \sum_i \tfrac{1}{2} a_i^2$$

This equation implies that if x_t can be regarded as being made up of a mixture of cosine waves, its variance can be decomposed into components of average power or variance $1/2\ a_i^2$ at the various frequencies, f_i.

In a stationary Time Series, S(t), the variance of the corresponding stochastic process may be decomposed into contributions at a continuous range of frequencies, f_i,

$$\sigma^2 = \int_{-\infty}^{\infty} \tau(f)\,df$$

where $\tau(f)$ is called the power spectrum of the stochastic process.

The power spectrum is an approximate measure of the average power or variance in the frequency band f to f + δf.

Development of the Computer Program, SPECBDM, for Spectral Analysis of Geophysical Data. Time Series Analysis decomposes each reflected pulse into its Fourier components and then allows study of the character of the pulse as a function of its frequency content. A computer program called "SPECBDM " was developed at BDM Petroleum Technologies, as discussed below. This program can be used for spectral analysis of a Time Series, and for the computation of various statistical parameters in the frequency domain from the Time Series. The parameters include the Power Spectrum. The Power Spectrum is essentially the frequency distribution of the square of the Fourier amplitudes.

Suppose the digital data x_t, t = 1,2,3, … N correspond to the value of the signal x(t) at intervals Δ. In this case, it has been shown (Jenkins and Watts 1968) that the smoothed spectral estimates t(f) are given by

$$\tau(f) = \Delta \sum_{k=-(L-1)}^{L-1} W(K) C_x(k) e^{-j2\pi fk\Delta}$$

where L = length of each subgroup into which the Time Series has been divided.

This is done to produce spectral estimates that have smaller variances than the original series.

As an example, suppose that the original Time Series had 400 datapoints (N = 400). Instead of computing the spectra for all the 400 values at once, the single series will be split into several subsets, say, k = 8 series of length N/k = 50. Then, a sample spectra is evaluated for each subseries. The mean of the eight sample spectra, at a frequency, f, will give the smoothed spectral estimates.

For a discrete series, the auto-correlation function, $C_x(k)$ can be computed as follows:

$$C_x(k) = \frac{1}{N} \sum_{k=-(L-1)}^{L-1} (x_t - \overline{x})(x_{t+k} - \overline{x})$$

where — (N — 1) is equal to or less than k is equal to or less than (N — 1).

The generated auto-correlation function is then multiplied by the lag window function, W(k). This is done in order to reduce the large swings in the generated power-spectral estimates. The new function generated is then Fourier transformed to obtain unbiased spectral estimates (Jenkins and Watts 1968).

SPECBDM uses a filter to remove any trends from the data so that the Time Series will be truly stationary. It then proceeds to calculate the power spectra of the gravity and the magnetic series. It also computes a few other statistical parameters (such as the phase spectra) which may be useful for interpretation of gravity and magnetic data.

Computation of a Test Power Spectrum of a Time Series. Before attempting to compute the power spectra of the geophysical data of a gravity and a magnetic profile, the program SPECBDM was tried on some known random series, such as the one shown in Figure 3–21. The fluctuating yield from the 70 consecutive batches 46, NIPER/BDM- was a random process, so there was no way to predict what the value of the next batch would be, nor was any underlying trend discernible from this plot.

The computer program first calculated the auto-correlation function from the output values of the batches (see Fig. 3–22), up to a certain lag, at which point the computed auto-correlation value became close to zero. The derived auto-correlation function was then multiplied by a "lag window" function (Tukey's window in this case) in order to obtain an unbiased estimate of the power spectrum as a function of the frequency (in cycles per second). The computed power spectrum (see Fig. 3–23) showed significantly high power at higher frequencies, compared to those at lower frequencies. The spectrum also showed three distinct humps at frequencies of 0.08, 0.3, and 0.38 cps, indicating the possible presence of trends at those frequencies.

Application of SPECBDM in Osage County. Several Time Series were generated for data from Osage County by digitizing the seismic reflected waveforms at regular increments of time in gas-saturated and clayey portions of the subject Layton sandstone reservoir. The porosity profile across the Layton sand in the gas-saturated portion of the reservoir (see Fig. 3–18) was also digitized to generate a Time Series of the log profile.

Figure 3–24 shows the computed power spectra from two reflected pulses from the gas-saturated area (near the Drummond #1-15) compared with the spectrum from the porosity profile. The spectra for the two pulses are very similar. Both show rapid attenuation of power to approximately 0.2 cycles/sec. Above that frequency, the power increases very little.

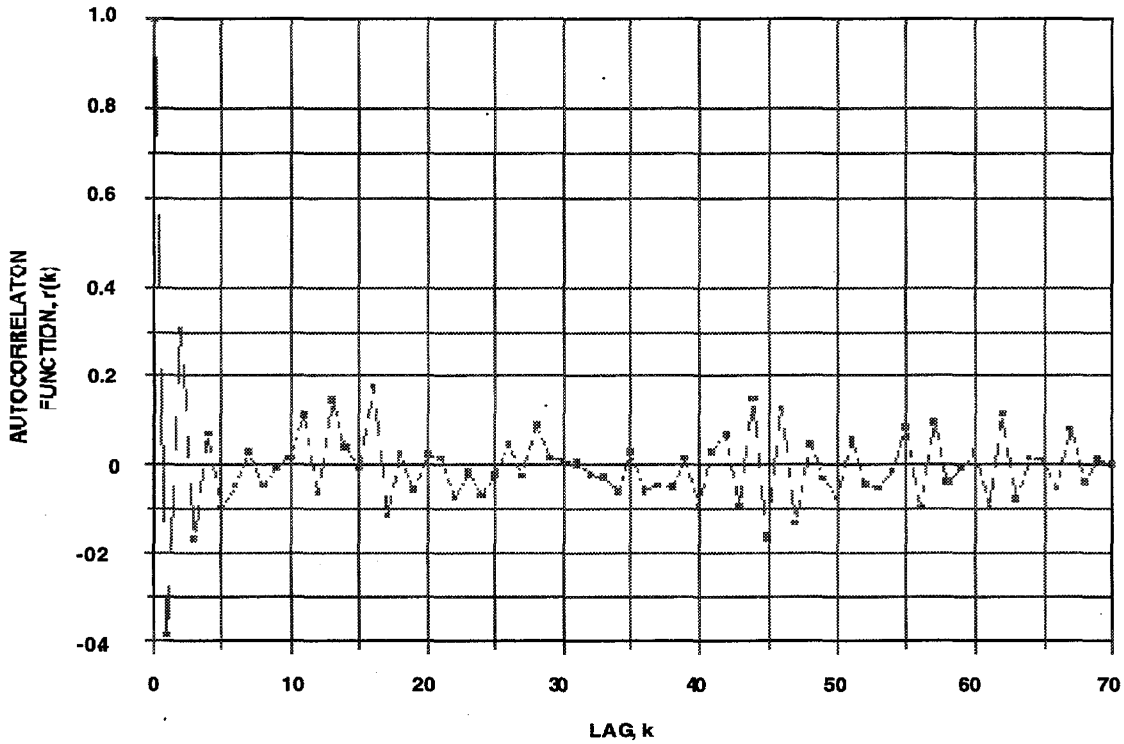

Figure 3–22 Autocorrelation Computation of the Batch Data.

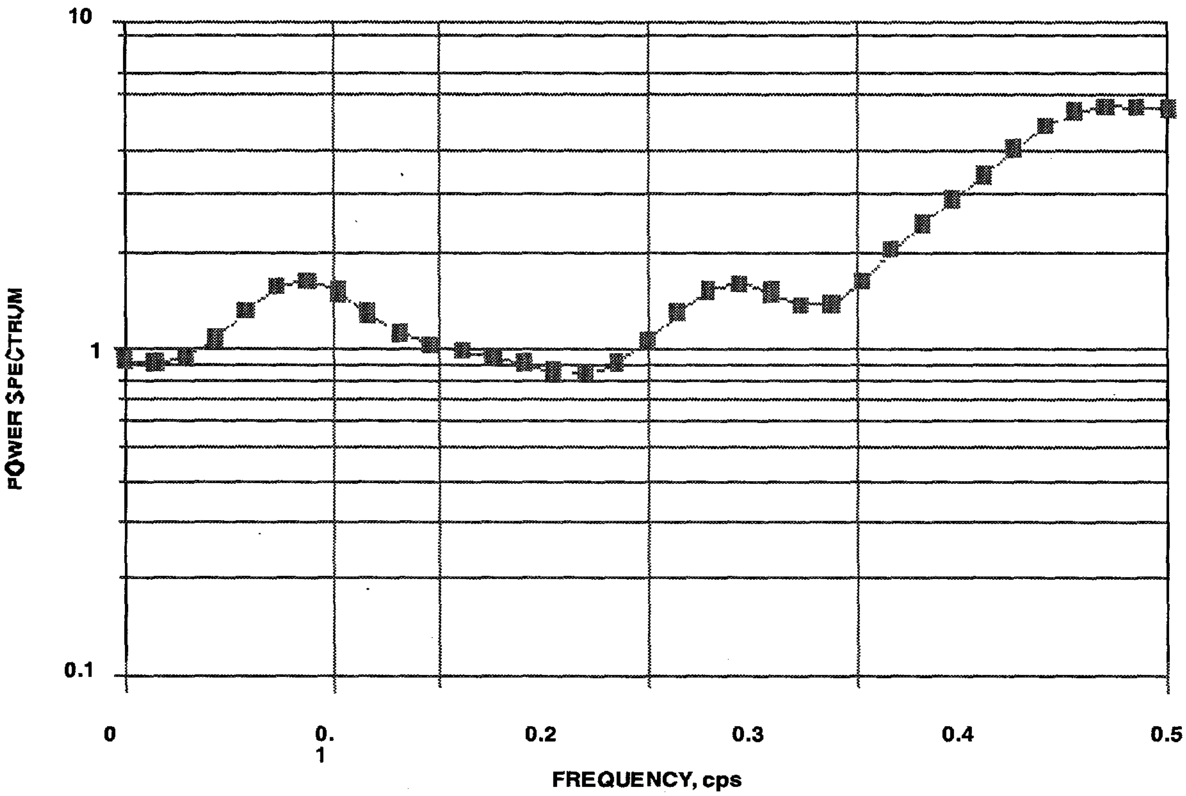

Figure 3–23 Power Spectrum of the Batch Data.

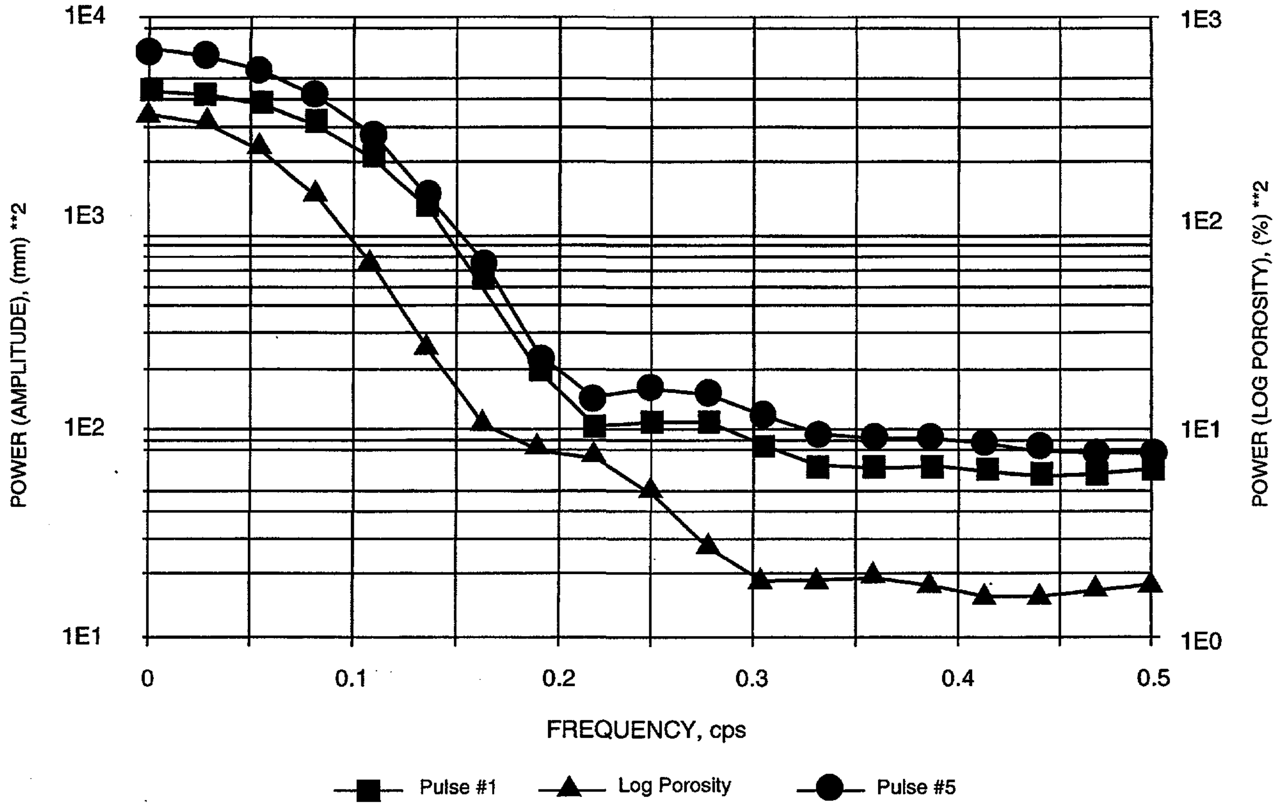

Figure 3–24 Power Spectra of Seismic Amplitudes of Two Seismic Pulses vs Log Porosity from the Gas-Producing Part of the Layton Sandstone.

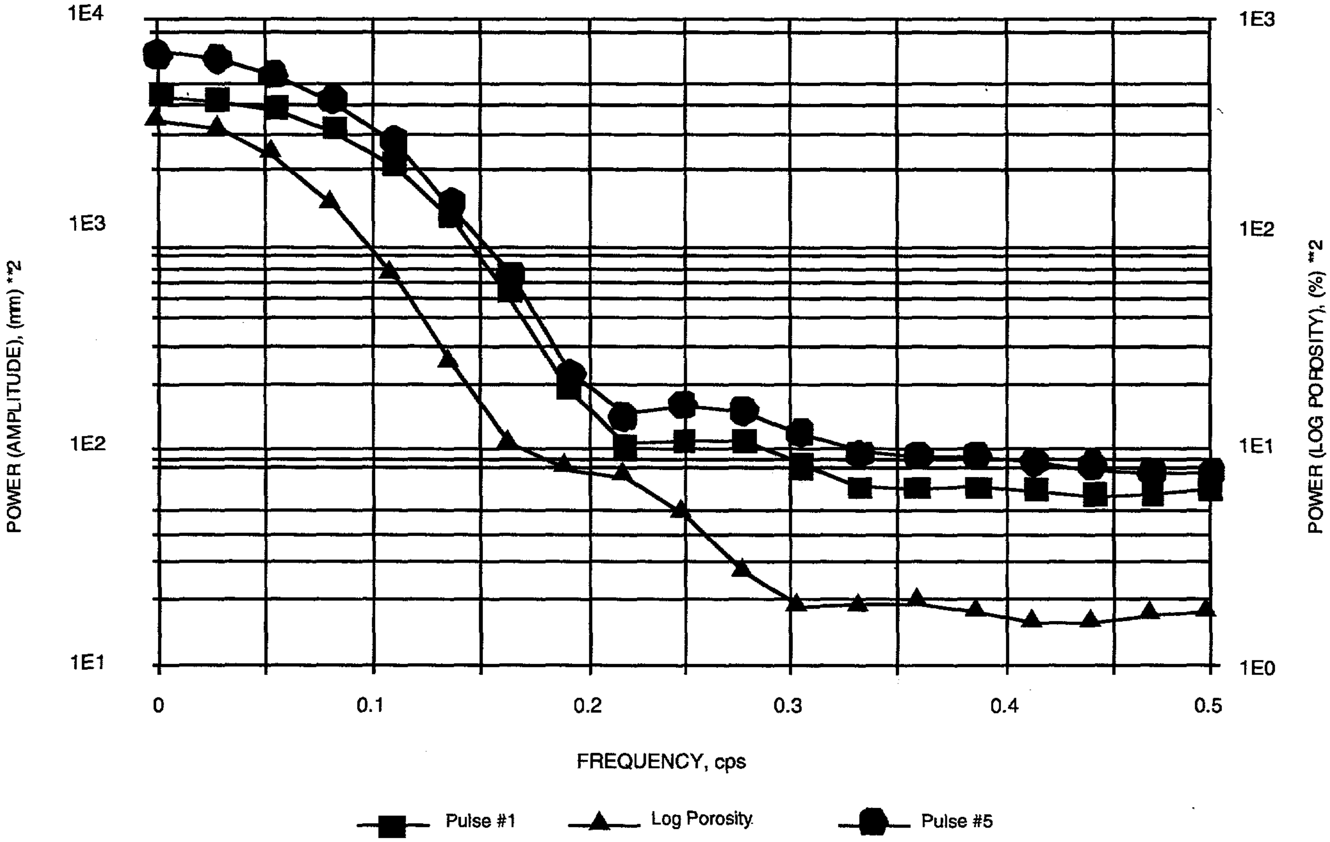

Figure 3–25 Power Spectra of Seismic Amplitudes of Three Seismic Pulses vs Log Porosity from the Clayey, Non-productive Part of the Layton Sandstone.

The spectrum of the log profile has very similar characteristics to the reflected pulse spectra, indicating that the porosity in the reservoir is, at least partially, influencing the reflected pulse shape. In the unproductive, dry parts of the field, (see Fig.3–25) the spectra for pulses 1 and 2 appear to be very similar to each other, but the spectrum of the third pulse is quite distinctive, and is probably an aberration, representing a highly-localized anomalous area. Alternatively, it could be a result of noisy traces.

In Figure 3–25 the spectrum of log porosity (from the gas-saturated area) does not show as good a correlation as that seen in Figure 3–24. If the spectra of pulses 1 and 2 are assumed to be representative of an unproductive area, then a comparison of these spectra with the spectrum from a gas-saturated area (see Fig. 3–24) indicates that the attenuation of power with frequency is relatively more gradual in the non-productive, dry areas.

A sharp drop in power at lower frequencies seems to be characteristic of clean, gas-filled portions of a reservoir. As the relative gas-saturation of a reservoir unit increases, the sharpness of the power attenuation theoretically should increase, because the impedance contrast across the interface between the reservoir unit and the enclosing units should also increase.

A careful examination of the waveform of the reflected signals across the region where the Layton gas sand is productive was quite instructive. Studies around locationsTrace Location 1, where the sand is clayey and non-productive (To the east [right] of Traces 48 in) (see Fi. 3–19), already had indicated that there was a variation in amplitude over the gas-bearing portion of the sandstone. In addition, it was found that there was a change in the wave shape. This change was apparently due to a damping of the reflected pulse. This damping was probably caused by a reduction in porosity and attendant increase in velocity (see Fig. 3–26).

An increase in clay content (and an associated decrease in porosity) can be detected on the gamma ray logs in the Osage Tribal Council #1 and#1 and Drummond #1 wells #2 on (for the well locations, (see Fig. 3–16) in the non-productive portions of the reservoir. Filling of the pore spaces with clay and a reduction in gas content will also increase sonic velocities in the sand, and hence will affect the shape of the reflected pulse. Density-log-derived porosities for the productive, gas-saturated; and the clayey, non-productive parts of the Layton reservoir are shown in Figure 3–18.

The shapes of the reflected seismic wave should be affected by porosity variations within the sand, as indicated by the porosity profiles shown in Figure 3–18 .

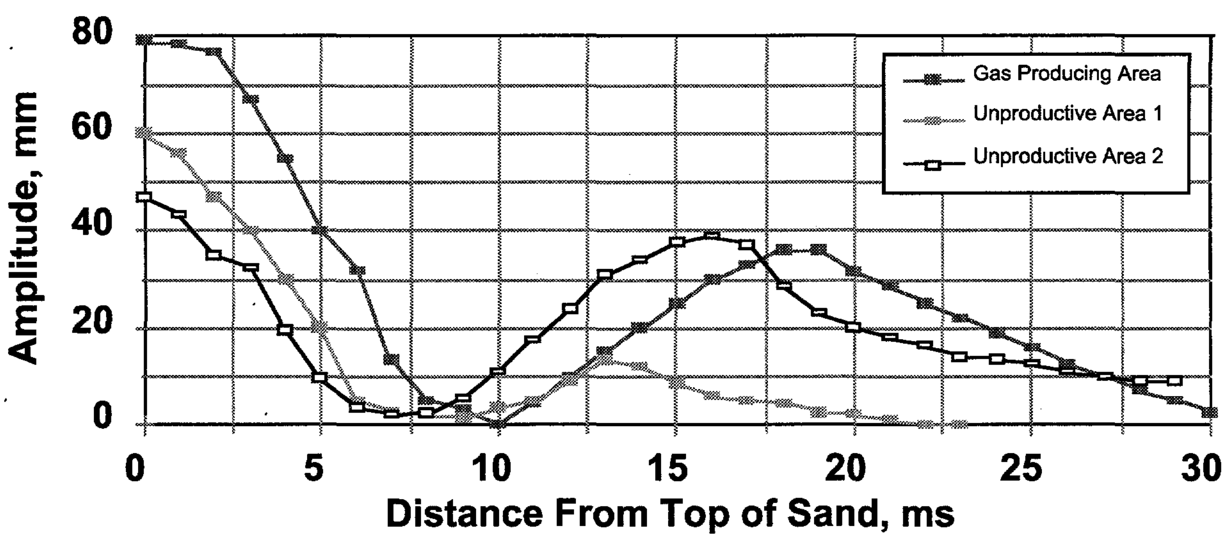

Figure 3–26 Wave Shapes of the Layton Reflector in the Gas-Saturated and Non-Productive Areas.

Utilization of the Display of Color to Emphasize Seismic Amplitude for the Identification of Subtle Features

While interpreting the Osage County 3D seismic data, it was found that the 3D seismic interpretation software provided powerful display and data manipulation tools. Techniques made available with the seismic data interpretation software can greatly help in the investigation of subtle variations of structure and stratigraphy.

One example comes from the ability to adjust the color range of the display, to emphasize and analyze amplitude information contained in the seismic data. Key aspects of color include:

- amplitude variations represented by color gradations may be very useful in studying stratigraphic changes,
- adjusting the screen display of the seismic section by boosting or reducing the amplitude level can help significantly in the mapping of subtle geological features.

As one example, boosting the amplitudes on a seismic section quite often helped in the identification and reliable mapping of fault traces.

Detection and mapping of small faults. Two small faults can be clearly seen on the 55′-bin data along Line 516 at Time 0.44-seconds, Traces 128 and 132 (see Fig. 3–27). A 40-foot displacement of the topmost bed can clearly be observed, and the faults can be traced down to the basement. A third fault, at Time 0.50 seconds, Trace 86 dips to the west (toward the lower Trace numbers).

The same degree of detail does not show up on the 110′-bin data at those same locations. The 110′ line shown in Figure 3–28 does not clearly image the two separate faults along the right half of the line. Because of the averaging effect over a greater distance on the 110′ line, the displacements are not indicated by sharp breaks, as they are in the 55′-bin data. The fault on the left half of the line also has a very different aspect on the 110′ line.

The 55′-data has a sharper imaging capability not only because of the effect of averaging, but also because it appears to contain a larger percentage of higher frequencies.

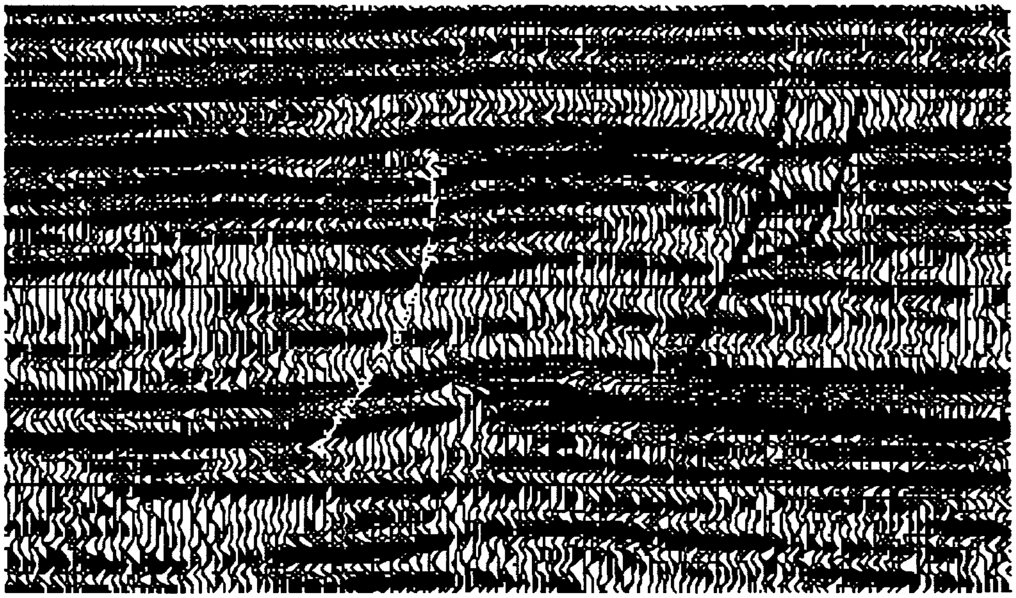

Figure 3–27 The Higher Resolution of the 55-ft-Bin Data is Demonstrated by the Mapability of Three Small Faults.

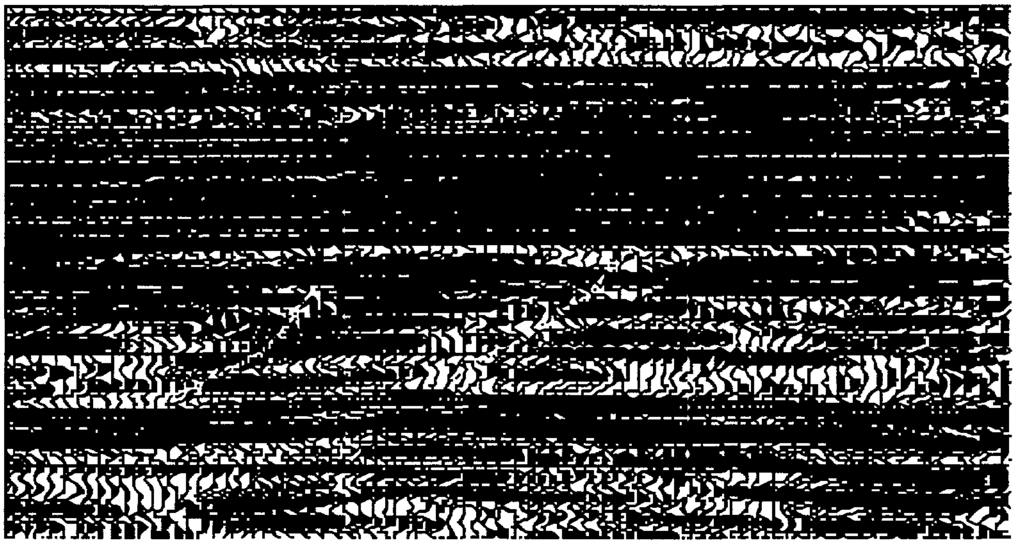

Figure 3–28 The Lower Resolution of the 110-ft Bin Data is Demonstrated by the Mapability of Only Two of the Three Small Faults Seen in Figure 3–27.

3.10 Conclusions

3D Seismic Survey Costs

Once all the charges for the Bigheart survey were billed and paid, the following cost figures were identified:

- Acquisition costs for the 110′ bin area averaged $37,000 per square mile.
- Acquisition costs for the 55′ bin area averaged $50, 000 per square mile.
- Processing costs for the data were $2,500 per square mile.

Analysis of Costs. The cost of the Bigheart survey proved to be higher than anticipated. There were several reasons for this. These included:

- Highly-unusual inclement weather conditions hit Oklahoma during the months of October and November, 1996. This adverse weather may have been an early side effect of a record El Niño, that began around the time that the survey was being conducted. The weather problems resulted in the crew sitting idle for 24 days at a rate of $10,000 per day.
- When work resumed after the weather shut-down, several measures were adopted to make up for the lost work period. A large amount of time was recouped by requisitioning a helicopter crew for transport, to improve maneuverability in muddy conditions. The helicopter both speeded up field movement and was environmentally-friendly, ultimately reducing damage costs and restoration fees. However, the rental costs were substantial.

3D Survey Cost Reduction Measures. Possible measures to reduce costs in future surveys would include the following:

- Selection of an optimal, or at least more-favorable time window for running seismic surveys to avoid very bad weather conditions. Consuting regional climatic tables and long-term weather forecasts can help to ensure that the field work is being planned for a time period with a reasonable prospect for satisfactory weather conditions. The prudent operator should also ensure that there is an opportunity to complete the survey before seasonal changes will bring work to a halt.
- Conducting a detailed assessment of the terrain conditions during the initial elevation survey to evaluate the accessibility of the vibroseis trucks to the various survey locations. This can reduce data acquisition time by increasing the total number of points vibrated per day.
- When possible, the roughest part of the survey terrain should be completed first, if there are high chances that the weather will be deteriorating later in the survey season.

The Relationship between Structure, Tectonics, and Oil and Gas Accumulations

The known locations of commercial accumulations of oil and gas in the study area in Osage County are shown in Figure 3–15. A comparison of the basement structure map (see Fig. 3–13) with the map of hydrocarbon accumulations reveals the following:

- The locations of the major hydrocarbon accumulations discovered thus far in the study area appear to have been largely influenced or controlled by basement structure. A strong correlation exists between the areas with major oil and natural gas accumulations and prominent basement highs.
- In addition, the major oil and gas accumulations in the region are associated with faults, with the dominant orientations of these faults being southeast-northwest or southwest-northeast.
- Although basement structure appears to influence the depositional patterns and thicknesses of some formations, especially the deepest units, other stratigraphic accumulations (including the Layton sandstone) do not appear to be strongly influenced by basement structure. Some of these units appear to be located along the flanks of the basement highs.

A Comparative Study of the Imaging Capabilities of 55′- and 110′-Bin Size Data

A larger bin size involves the averaging of information over a larger area, so it is obvious that the 110′-bin data will be "smoother" compared to the 55′-bin data, and lacking in detail. 110′-bins involve averaging data over an area four times the size of 55′-bins.

The crucial questions are:

- How much variability is present in the 55′-data?
- Can this variability be meaningfully interpreted to provide additional information on subtle geological features?
- Does this additional information have relevance for oil and gas exploration?

Key observations on the relative usefulness of the 55′- and 110′-data sets are discussed below, using seismic sections from several different areas.

It has been observed that boosting the relative amplitudes of the seismic data may help in mapping fault traces. This was shown on two lines, as described above. The fault interpretation procedure benefited from the ability to use boosted amplitude data.

The versatility of the 3D seismic interpretation package allows viewing of seismic data emphasizing different attributes of the data. Vertical and horizontal sections can be obtained directly from the 3D seismic data cube, for very detailed interpretation and integration with geology.

The 55′-bin data appear to contain higher frequencies, compared to the 110′-bin data, and consequently, subtle structural and stratigraphic features are imaged better in the 55′-bin data.

It is worthy of note that if data are collected at a 55′ bin size, then it is relatively easy to generate 110′-bin data simply by averaging data over a larger area, but the inverse, that is, obtaining 55′ -bin resolution from data acquired with a 110′-bin, is not possible.

To summarize, imaging subtle geological features in depositional environments such as the platform deposits in Osage County, where there are rapid changes in lithology and facies, high-resolution 55′-data will certainly be more useful than 110′-data.

For certain other depositional environments that involve imaging of larger-scale features, 110′ -bin data may be adequate. 110′-data may even prove to be more useful in certain instances where the objective is to map the dominant structural trends without being affected by interfering noise from small geological features.

Comparison of the Seismic Features with Results from the Geochemical and Microbial Surveys

Finally, once the seismic interpretation was completed, maps prepared from the seismic data were compared with results obtained from a surface geochemical and a microbial survey of the study area. These two studies are described in the next two chapters. The coincidence of a large anomaly identified by the microbial survey and a channel sand identified on the 55′-bin size data is striking.

4.0 REMOTE-SENSING ANALYSIS

The objective of the remote-sensing and lineament analysis in Osage County was to review and test the ease-of-use and effectiveness of the FRAC-EXPLORE Version 2.0 software package (Guo et al. 1996a), developed by BDM Petroleum Technologies personnel for use as a tool for oil and natural gas exploration.

Version 2.0 of this program has been refined and upgraded to allow remote sensing analysis for fracture zones, in areas where secondary fracture porosity can form or enhance the quality of oil and gas reservoirs. The program was designed to work in a rapid manner, and at very low cost, for the small, independent operator.

4.1 Project Description

Several significant accomplishments were made in the development and testing of the remote sensing and surface fracture analysis software during the Osage County work. These include:

- the completion of FRAC-EXPLORE Version 2.0, a comprehensive user-friendly computer software package applying remote sensing data and surface lineament and fracture analysis for oil and gas exploration
- the completion of an extensive statistical analysis of surface lineaments and fractures for identifying the probability functions of natural fracture characteristics for stochastic simulation of subsurface fault systems
- the demonstration of these new techniques, methodologies, and software packages at various professional meetings.

4.2 Software Improvements

FRAC-EXPLORE Version 2.0 is based on a quantitative methodology developed in 1995 (Guo et al. 1995). The first version of FRAC-EXPLORE was completed in July 1996 (Guo et al. 1996a). To increase the calculation efficiency of and to add new capabilities to the software, the second version of FRAC-EXPLORE was completed in December 1997, with significant improvements over the first version.

The following upgrade improvements were made during the conversion from Version 1.0 to 2.0:

- The Graphical User Interface (GUI) was improved for consistency and clarity
- All variables were explicitly defined to reduce memory requirements

- The "Save Graphics" menu from the Version 1.0 was modified to be more user-friendly
- Color legends were added to most graphics outputs, to assist in anomaly interpretation
- A new form was added for anomaly displays, using mixed types of structural indicators
- Visual Basic 5.0 was used to recompile the software

In part, as a result of these improvements, FRAC-EXPLORE Version 2.0 runs at least 21 times faster than FRAC-EXPLORE 1.0.

4.3 Statistical Analysis of Surface Lineaments And Fractures

Satellite images and aerial photos of the study area were collected (Guo et al. 1996b). Surface lineaments and fractures were mapped, digitized, and statistically analyzed in order to obtain the probability distribution functions of natural fractures for characterizing subsurface fault systems.

The orientations and lengths of identified surface linear features were calculated using the digitized coordinates of the two end points of each individual linear. The lengths and spacing data for the surface linear features within each individual set were obtained using an analytical sampling technique.

Statistical analyses were then performed to find the best-fit probability-distribution functions for the

- orientation,
- length, and
- spacing

of each data set. Twenty-five hypothesized probability distribution functions were used to fit each data set. A chi-square goodness-of-fit test was used to rank the significance of each fit. A distribution which provided the lowest chi-square goodness-of-fit value was considered the best-fit distribution.

The following procedures were performed for the statistical analysis of surface lineament and fracture characteristics:

- A rose diagram analysis to identify the number of subsets in a surface lineament and/or fracture system.
- A filtering analysis for partitioning each surface-fracture system into subsets.

- A sampling analysis for the collection of surface-fracture spacing data using a new analytical technique.
- A best-fit analysis for the gathering of distribution functions for surface lineament and/or fracture orientation, length, and spacing.

4.4 Conclusions

The following conclusions were obtained from the extensive remote-sensing statistical analysis:

- Natural fracture orientations are best described by triangular and normal distributions, followed by logistic, chi-square, and PearsonV distributions. Triangular and normal distributions are, by far, the most significant distributions for characterizing natural fracture orientation data.
- Natural fracture lengths are best described by PearsonVI and PearsonV distributions. Other favorable distribution functions for characterizing natural fracture length data include extreme-value, lognormal2, lognormal, loglogistic, logistic, and triangular distributions.
- Natural fracture spacing data are best described statistically by lognormal2 and PearsonVI distributions followed by lognormal, inverse Gaussian, Weibull, exponential, and PearsonV distributions.
- The probability-distribution functions utilized to identify and characterize natural fracture systems, based on analysis of surface lineaments and fractures, can also be used for stochastic simulations of subsurface fault systems. This allows delineation and quantification of basement-fault-controlled oil and gas traps, based on studies of satellite images and aerial photos.

4.5 Presentations at Professional Meetings

The following presentations were made at various professional meetings to transfer the new methodologies, techniques, and software developed for oil and gas exploration using remote sensing data and surface fracture analysis:

- Guo, G.: "A New Methodology and Computer Software for Delineating Oil and Gas Reservoirs Using Surface Lineament and Fracture Analysis," SPE 38125 presented at the 1997 SPE Petroleum Computer Conference, Dallas, Texas, 8-11 June.
- Guo, G., George, S.A., and Lindsey, R.P.: "A New Methodology for Delineating Hydrocarbon Reservoirs Using Remote Sensing Data and Surface Fracture Analysis," presented at the 1997 AAPG Annual Meeting, Dallas, Texas, 6-9 April.
- Guo, G., George, S.A., and Lindsey, R.P.: "Statistical Analysis of Surface Lineaments and Fractures for Characterizing Naturally Fractured Reservoirs," 4RC-052 presented

at the 4th International Reservoir Characterization Conference, Houston, Texas, 2-4 March 1997.

- Guo, G., George, S.A., and Lindsey, R.P.: "Applications of Surface Lineaments and Fractures for Optimal Horizontal Well Drilling and Production Potential Estimation," SPE 37150 presented in the 1996 SPE International Conference on Horizontal Well Technology, Calgary, Alberta, Canada, 18-20 November.

4.6 Summary

The completion of FRAC-EXPLORE Version 2.0, and its user's manual has provided a comprehensive, user-friendly computer software package for the small, independent operator. Explorationists and development geologists will be able to apply remote-sensing data and surface lineament and fracture analysis in the search for secondary fracture porosity, increasing the potential for successful, commercial-levels of oil and natural gas production.

5.0 GEOCHEMICAL SURVEY

BDM Petroleum Technologies also conducted a geochemical survey in the Osage County study area. Samples were collected of surface soils and tested for a series of marker chemicals.

5.1 Objectives

The surface geochemical survey at the Bigheart site in Osage County was designed to complement the high-resolution seismic survey. The objective was to examine several surface geochemical techniques that could be used for locating oil or gas seeps. The methodology applied was one that could be employed by independents with limited budgets and personnel. To this end, both the sample collection and analytical techniques had to be inexpensive.

Samples were collected within one foot of the surface rather than at depths of 5—25 ft, which tend to be typical of other, commonly-used methods. The plan to collect extremely shallow samples also eliminated integrated soil-gas methods in which a gas absorber would be placed in the ground for a period of time and then collected at a later date.

A fringe benefit of the survey methodologies used in Osage County was that they were essentially non-invasive. This makes them useful in environmentally-sensitive areas or in other regions where disturbances of the ground is undesirable.

To further reduce the cost, the techniques designed did not require extensive expertise in soil science for sample collection. This was desirable because many independents and their staffs do not have formal training in this area, and there is generally a lack of budget money for this type of training in most small companies.

5.2 Survey Location

Figure 5–1 is a map of the survey area, located approximately 8 mi. northeast of Hominy, Oklahoma.

The high-resolution 3D seismic study area was planned to cover 6 mi^2; however, to provide adequate fold at the edges, the seismic lines actually extended over approximately 7.25 mi^2. This same area was the target of the surface geochemical survey.

The seismic survey was designed to collect data using grid lines with a 440-ft spacing. Survey points were located every 110-ft along these grid lines. Each of the survey points was located using a global positioning system (GPS) system. Survey points are accurate to within 15 cm when multiple benchmarks and satellites are used. Figure 5–2 shows the original layout that was planned for the seismic grid.

East-west lines (the rows with Xs on the map) are numbered R-1, R-3, R-5, etc., beginning with the northernmost line. The easternmost point on each line is numbered 100, with the sequence increasing to the west. The westernmost point on each row is 257.

The row at the top of Figure 5–2 is R-17. Geochemical samples were taken at the intersection of the grid lines, with 12 sample points per mile. Occasionally, ponds, creeks or other physical features interfered with the normal sampling and the collection had to be done at a point slightly off the normal grid.

The layout of the actual survey differed somewhat from the planned survey because of dense woods (which blocked satellite reception), gullies, creeks, ponds, and the occasional near-coincidence of a convenient fence line. Figure 5–3 shows the deviation from the planned grid.

5.3 Sampling Procedure

Three types of samples were collected at each grid point:

1. Approximately one-half of a 1-quart polyethylene storage bag of soil was collected from within the top 1—1.5 inches of the surface using a small (Army-style) trenching shovel. Reasonable attempts were made to exclude organic matter, such as large roots and grass (raw or cow-processed). This sample was collected for iodine and magnetic susceptibility analysis.

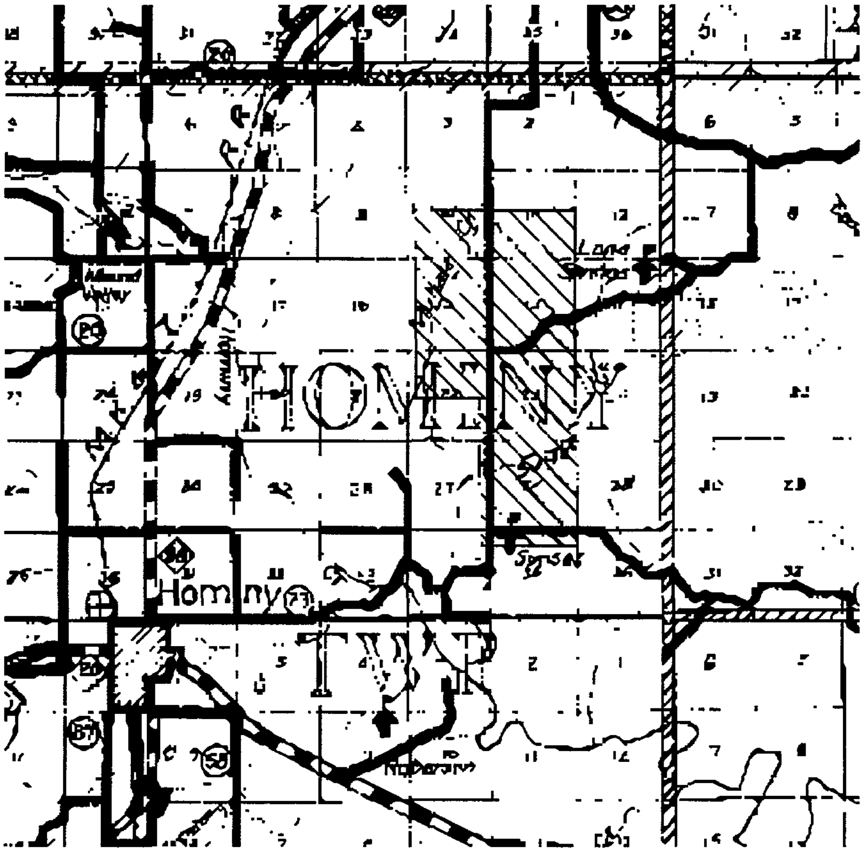

Figure 5–1 Location of Surface Geochemical and High-Resolution 3D Seismic Surveys.

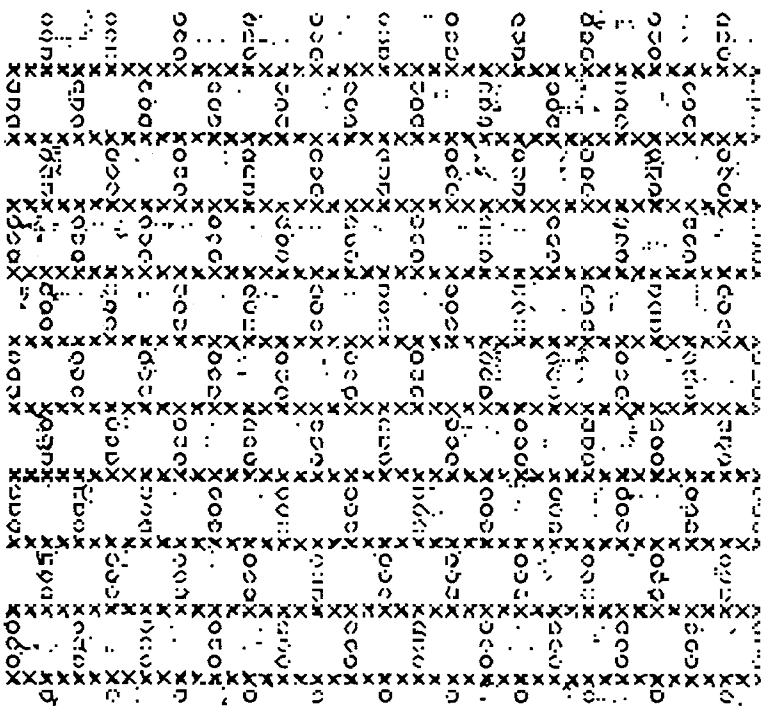

Figure 5–2 Survey Area Showing Planned 440′ Grid and 110′ Intermediate SPs.

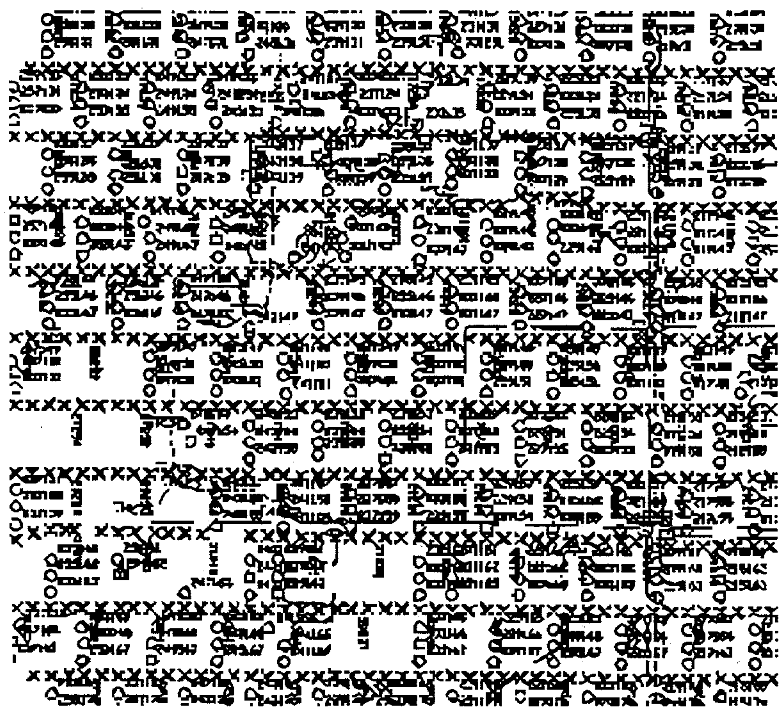

Figure 5–3 Actual Survey, Showing the Same Area as Figure 5–2.

2. A 6-inch long ↔ 0.75-inch diameter soil plug was taken with a standard soil sampler. The bottom 4 inches were collected in a 1-inch-diameter ↔ 4-inch-long polyethylene vial with a snap cap. The lids were taped after a few unsnapped. These samples were collected for pH analysis.
3. After the first 6 inches of sample were taken with the soil sampler, each hole was reentered and a second 6-inch sample was retrieved (6—12 inches below the ground surface). This second soil plug was placed in a 1-inch-diameter ↔ 8-inch-long Pyrex test tube. The test tube was sealed with a Neoprene stopper, which was taped to the test tube to prevent accidental removal or loss. These stoppers had been predrilled with a 0.25-inch hole and sealed with a 0.25-inch diameter glass bead. This sample was intended for soil gas analysis.

Occasionally, the deeper or both soil plugs could not be collected because of rock or hardpan. Under those conditions, a composite sample was sometimes taken (for example, two samples were collected between 6 and 9 inch depth). A duplicate sample set was collected at about every 30th sample site, to check on reproducibility.

5.4 Sampling Rate

The sampling rate varied, depending on field conditions and various obstacles encountered. Under ideal conditions, once the sampling technique was established, an experienced team of two could collect the standard three samples at a site and walk to the next site in 8 min., across normal, open ground. This essentially represents a minimum sampling time. If the sample locations had not been pre-surveyed and marked, the sample-collection rate would have decreased markedly, with considerable time being added for the identification of sample location. Rough terrain slowed work substantially, and the 8-min rate required experience, full dedication, and diligence by all team members.

In addition to the primary batch of 3,000 samples collected over the survey area, the geochemical survey team collected a small series of additional samples to evaluate the local reproducibility, time dependence, spatial consistency, and temperature dependence of the data.

5.5 Results

Iodine Survey

The iodine survey showed two strong anomalies, and possibly a third one. These anomalies appeared as normal levels of iodine at the center and a ring, or partial rings (arcs), of unusually high values surrounding this center. The iodine values in these rings were more than 1.5 standard deviations above background levels.

In addition, if one considers the locations where the iodine values have a standard deviation greater than —1.0 (low values), there are conspicuous "holes" in the iodine map where anomalies exist.

The mean iodine value for the field was 2.82 ppm with a standard deviation of 1.90 ppm.

pH Survey

The raw pH data did not readily reveal any anomalous areas. However, upon using a mild 2D smoothing routine, anomalies could easily be seen. These appeared as areas of low pH, with a surrounding ring of high pH. These high pH areas were in turn surrounded by still another zone of low pH values.

The pH anomalies are centered on the same area as the iodine anomalies. The weakest iodine anomaly is more evident in the pH survey.

The average pH of the survey area is 5.00 with a standard deviation of 0.68.

Magnetic Susceptibility Survey

The data showed several areas of elevated magnetic susceptibility readings. An area with old production in the southern part of the survey had scattered high readings within an abandoned oil field.

In the area to the west of the center of the project area where the pH and iodine surveys had identified anomalies, the magnetic susceptibility showed a feature, although it was not directly on top of the pH and iodine anomalies.

The anomaly identified by the other methodologies in the northeast quadrant of the project area is also difficult to identify using magnetic susceptibility.

In general, magnetic susceptibility anomalies were more diffuse and less easily recognizable than for the other two surveys. The magnetic susceptibility values averaged 163 with a standard deviation of 70.

Interferences

In general, cultural features seemed to create little interference with the geochemical levels.

Cultivated fields of winter wheat, maize, and Bermuda grass did not seem to correlate with any anomalous iodine or pH values. There was also no observed correlation with streambeds.

The only apparent interference occurred along a gravel road adjacent to row R-85. pH values along this road were unusually high, possibly because of lime applied to the road.

A few abandoned oil wells exist within one anomaly. Although several dry holes exist within the survey area, none are within any of the anomalies identified here.

6.0 MICROBIAL SURVEY

As part of the overall BDM Petroleum Technologies integrated, multidisciplinary effort, Geo-Microbial Technologies (GMT), of Ochelata, Oklahoma, was sub-contracted to conduct an independent microbial survey over the same Osage county study area. This study and interpretation was totally isolated from all work performed by BDM, and the results were held as separate, confidential data until the seismic and geochemical surveys had been completed. The process and results of the survey are contained in the Appendix as a separate volume, prepared by GMT.

The GMT microbial survey used the common GPS stations and collected their samples at the same identical points as the seismic and geochemical studies.

GMT collected their samples in a rapid, efficient manner, during a period of good weather. The results proved to be quite interesting. Sample collection over an old oil field showed little of interest. This is what microbial experts would expect if the old fields had been efficiently and relatively-thoroughly depleted by years of production.

The most distinctive anomaly identified by GMT was large in amplitude and had a distinctive shape. It was located in the northern portion of the study area, and generally coincided with a possible channel sand that showed up on the 55′-bin size seismic data. This feature could not be distinguished on the 110′ data.

The results of the GMT survey nicely compliment the high-resolution seismic survey, demonstrating the synergistic value of using multiple techniques in a lease or prospect area.

Several features of possible interest can be seen on the 55-foot seismic survey. The GMT survey also shows more than one relative "high." However, when the two studies are combined, only one area stands out as a prime target. Not only do the two techniques concur as to a potential target, but they appear to agree on the general overall configuration of the possible prospect area.

It should be recognized that this study has only been conducted in one lease area. Additional tests need to be conducted if industry is to confirm and rely upon the combination of high-resolution seismic and microbial techniques.

7.0 SUMMARY

7.1 The Seismic Survey

The 3D seismic survey program was designed to:

- Demonstrate the value of modern, state-of-the-art, high-resolution seismic surveys,
- Develop and test ways of improving efficiency and lowering costs for such surveys, and to
- Increase interest in the study area, part of the Osage nation tribal lands.

The program was extremely successful in demonstrating the value of high-resolution surveys and in developing innovative techniques and interpretive methodologies. The results of the research are described below.

Extremely unusual weather conditions for Oklahoma during data collection drove the costs of this survey up. Nonetheless, several recommendations have been made to cut costs on future field work.

The program objective to increase interest in the study area was almost too successful in its mission to stimulate development on Native American lands. Pre-survey news releases and other publicity generated by the BDM Technology Transfer team in connection with the DOE program greatly increased interest in the region, and the initial potential survey areas were all leased to companies, including Chevron and smaller independents by the time the program was ready to proceed. This made it very difficult for BDM to find an open study area with any decent potential for possible reservoir development.

Ultimately, the survey was piggy-backed in cooperation with a survey planned by DLB Oil and Gas, Inc., an independent operator from Oklahoma City, on DLB-leased acreage. DLB completed its planned "conventional" survey, with the study area shot at high-resolution.

Two software programs, SPECBDM and FRAC-EXPLORE, developed by BDM Petroleum Technologies personnel during the conduct of this DOE program, were used to great effect in the Osage County 3D survey work. FRAC-EXPLORE was designed to conduct a local or regional interpretation of faulting and lineament trends, clues to basement structure, and a valuable tool for oil and natural gas exploration. SPECBDM is a highly-sophisticated geophysical program, designed for spectral analysis of a Time Series, and for the computation of various statistical parameters in the frequency domain from the Time Series. This program will expand the range of tools available to the seismic interpreter for use in high-resolution surveys.

Key observations and findings of the seismic interpretation and analysis include:

- Seimic survey planners should pay attention to regional climatic data and norms, as well as long-range weather forecasts before commencement of large-sized surveys. Stand-by expenses on surveys delayed by inclement weather can have a major impact on the overall survey costs, should weather conditions deteriorate for a prolonged period during field operations. Although there is a great reluctance to temporarily suspend data-gathering operations and release a crew, this may be the best course of action if unusual weather conditions, like an El Niño event, set in during conduct of the survey.
- The superior imaging capabilities of the high-resolution seismic data obtained with the 55′-bin configuration have significantly improved the ability to conduct detailed investigations of subtle structural and stratigraphic features. Multiple seismic attributes, like amplitude, frequency, phase, and interval velocity hold the keys to such investigations.
- Where subtle geological features dominate the section, as in the platform deposits of Osage County, with rapid changes in lithology and facies, the high-resolution 55′ data will provide significantly-sharper images, allowing much better interpretation opportunities in exploration for the subtle trap.
- The amplitude spectra of the reflected seismic pulses show subtle, but distinct, definitive variations from dry areas to the productive portions of the field. An amplitude map clearly delineates a thin, meandering Layton sandstone channel. Drilling has shown that this channel is only about 18′ thick.
- The log-porosity spectrum has a distinct correlation with the spectra of the reflected pulses in gas-saturated areas, strongly indicating that porosity is controlling the shape of the reflected waves. Spectral analysis of the reflected wave shape, therefore, can provide a means for identifying clean, gas-saturated portions within the field. Additional theoretical studies and modeling of the acoustic-impedance contrast of reservoirs with various gas saturations, encased in rocks of varying sonic velocities, would be very useful to develop rules to use for the identification of gas-saturated zones.
- The average sonic transit time is 189 microseconds/ft in typical formation water (20% NaCl), 238 microseconds/ft in oil, and 626 microseconds/ft in natural gas (methane). Thus, it is theoretically quite difficult to distinguish most oil-filled from most water-filled reservoirs, but natural gas accumulations can have a highly distinctive seismic signature. However, in actual practice, many oil reservoirs have associated natural gas saturations which can sharply lower the effective sonic velocities in those reservoirs. The Layton sandstone is gas-saturated in portions of the study area. It was possible to identify reservoir-quality Layton in the 55-foot bin size survey, and distinguish those areas from clay-filled portions of the Layton, even though the unit is quite thin. The pay zone typically has a thickness of only about 18′. For thicker gas-filled sandstones,

with higher saturations, the spectrum should provide a much sharper contrast vs. the spectra from unproductive areas.

- A regional fracture/lineament study was conducted for Osage County and the surrounding area. The basement in the study area is cut by two dominant sets of faults. These faults could also be distinguished on the seismic data. Seismic mapping showed one trend running NE-SW and the other trending NW-SE. These two fault sets agree remarkably well with the directions of surface fractures and lineaments mapped from satellite images and aerial photographs using the BDM-developed FRAC-EXPLORE software package. Oil and gas producing trends were found to be associated with basement faulting, as observed by earlier researchers.
- Precision mapping using the high-resolution seismic data has made it possible to study the relationships between oil and natural gas accumulations and local tectonics, structure, and the stratigraphy of the reservoir rocks. It was demonstrated that a strong correlation exists between basement structure and faulting and the major oil and natural gas accumulations in the study area. Seismic amplitude studies will be an effective tool for delineating gas-saturated reservoirs and to identify areas of good- and poor-quality sandstone development.

7.2 The Geochemical Survey

The geochemical survey was designed to test the effectiveness and synergy of using multiple surface soil tests to look for specific geochemical markers. These included:

- Iodine,
- pH, and
- Magnetic susceptibility

The samples were collected quickly, efficiently, and inexpensively, by non-specialized personnel, without preliminary expensive training. The laboratory analysis phase was conducted rapidly and was low-cost.

The survey identified several anomalous areas.

7.3 The Microbial Survey

The microbial survey was conducted by GMT personnel. Sample collecting in the field was extremely fast and efficient. The details of the survey and its techniques are described in the Appendix.

Older productive areas did not stand out in the survey. This would be expected if those fields had been largely depleted. A strong positive anomaly did show up in the GMT survey in the same area as an apparent river channel imaged with the 55-foot bin-size seismic data. The agreement in location and configuration between the seismic data and GMT data was *highly* intriguing.

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APPENDIX 1
THE GEO-MICROBIAL TECHNOLOGIES FINAL REPORT