SANDIA REPORT

SAND2003-2614
Unlimited Release
Printed August 2003

Acoustic Telemetry

Douglas S. Drumheller and Scott S. Kuszmaul

Prepared by Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550

Sandia is a multiprogram laboratory operated by Sandia Corporation,
a Lockheed Martin Company, for the United States Department of Energy's
National Nuclear Security Administration under Contract DE-AC04-94AL85000.

Sandia National Laboratories

Issued by Sandia National Laboratories, operated for the United States Department of Energy by Sandia Corporation.

Printed in the United States of America. This report has been reproduced directly from the best available copy.

Available to DOE and DOE contractors from
U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831

Telephone: (865)576-8401
Facsimile: (865)576-5728
E-Mail: reports@adonis.osti.gov
Online ordering: http://www.osti.gov/bridge

Available to the public from
U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Rd
Springfield, VA 22161

Telephone: (800)553-6847
Facsimile: (703)605-6900
E-Mail: orders@ntis.fedworld.gov
Online order: http://www.ntis.gov/help/ordermethods.asp?loc=7-4-0#online

SAND2003-2614
Unlimited Release
Printed August 2003

Acoustic Telemetry

by

D. S. Drumheller & Scott S. Kuszmaul

Geothermal Research Department
Sandia National Laboratories
P. O. Box 5800
Albuquerque, NM 87185-1033

Abstract

Broadcasting messages through the earth is a daunting task. Indeed, broadcasting a normal telephone conversion through the earth by wireless means is impossible with todays technology. Most of us don't care, but some do. Industries that drill into the earth need wireless communication to broadcast navigation parameters. This allows them to steer their drill bits. They also need information about the natural formation that they are drilling. Measurements of parameters such as pressure, temperature, and gamma radiation levels can tell them if they have found a valuable resource such as a geothermal reservoir or a stratum bearing natural gas.

Wireless communication methods are available to the drilling industry. Information is broadcast via either pressure waves in the drilling fluid or electromagnetic waves in the earth and well tubing. Data transmission can only travel one way at rates around a few baud. Given that normal Internet telephone modems operate near 20,000 baud, these data rates are truly very slow. Moreover, communication is

often interrupted or permanently blocked by drilling conditions or natural formation properties.

Here we describe a tool that communicates with stress waves traveling through the steel drill pipe and production tubing in the well. It's based on an old idea called *Acoustic Telemetry.* But what we present here is more than an idea. This tool exists, it's drilled several wells, and it works. Currently, it's the first and only acoustic telemetry tool that can withstand the drilling environment. It broadcasts one way over a limited range at much faster rates than existing methods, but we also know how build a system that can communicate both up and down wells of indefinite length.

Contents

List of Figures

Chapter 1

Introduction

This report describes a new system of communication for drilling and production of natural resources. It is called acoustic telemetry. Our acoustic telemetry tool is shown in Fig. 1.1. It can operate in both the drilling and production environments, and it

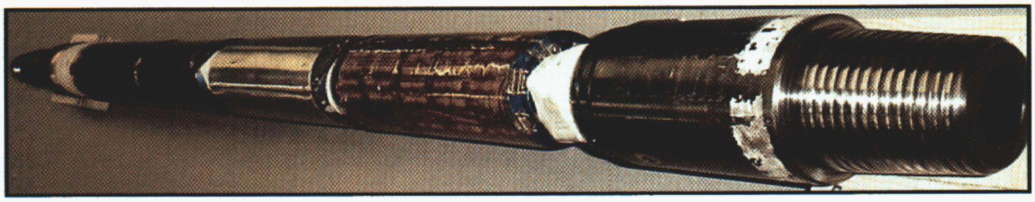

Figure 1.1: The acoustic telemetry tool with the outside pressure housing removed.

measures and broadcasts data from down hole to the surface without wires. You may not be aware of the difficulties of subterranean communications and its importance to the industries that produce oil, gas, and geothermal energy. But even if you are it is worth reviewing these issues in order to explain why acoustic telemetry is important.

1.1 Why telemetry?

Drilling for subterranean resources is virtually a blind process. The driller often does not even know where the drill bit is heading. That's not because it is difficult to determine the direction in which the bit is advancing, but rather because once sensors at the bit do determine the direction it is very difficult and expensive to transmit this information back to the surface. Commonly used means of communication, like radio waves, simply do not work underground. However, drillers have an option to their dilemma. They can use mud-pulse telemetry wherein data are transmitted as an encoded sequence of pressure pulses in the wellbore mud. This option is available to them because large mud pumps are used to continuously circulate this fluid and clean the drill cuttings from the well. The telemetry signals are created at the bottom of the well by periodically choking this flow with a valve to create 500-psi pressure pulses in the mud column. These pulses propagate up the bore of the well to the surface where they are detected by a pressure sensor. This is a simple and often very effective communication system. Its value to the drilling industry can be measured by the revenues it generates for the *measurement-while-drilling* service companies—about $3 billion U.S. dollars annually.

Unfortunately, this service has its limitations. The most obvious limitation is that the communication rates are very slow, about 3 data bits per second or 3 baud. That's more than a thousand times slower then Internet data rates on the poorest of home telephone modems. Mud conditions may also limit or even eliminate the communication signals. For example, in *underbalanced-drilling* operations, nitrogen is injected into the mud creating small bubbles. The presence of the bubbles drastically alters both the absorption and *acoustic impedance*[1] of the mud, blocking all communications. Moreover, even with optimum mud conditions the broadcast ranges are limited because the signal weakens over long distances until it is masked by the ambient noise created by drilling operations. Whereas repeaters are used in other communication systems, such as telephone microwave links, to overcome this range limitation, here using repeaters would require the deployment of additional choke valves into the mud flow path blocking access through the center of the drill string. While the industry has accepted one valve blocking access to the last few feet of the drill string, for various economic and safety reasons it is not willing to accept valves blocking access at higher intermediate points.

1.2 What is acoustic telemetry?

Acoustic telemetry also employs propagating pressure waves to communicate between the bit and the surface. The broadcast carrier frequencies are audible and fall in the middle of the piano keyboard. However, unlike mud pulse telemetry, the waves do not travel through the mud. Instead they propagate in the steel walls of the drill string itself.[2] Therefore the medium of communication is not a viscous liquid but rather an elastic solid, and as we shall see this offers significant advantages. Moreover, the broadcast signals themselves are not created by choking the high energy flow of the mud stream with a valve; instead they are generated by a small, low-power transducer buried inside the wall of pipe. Indeed mud pulse telemetry depends upon a

[1] Acoustic impedance is an important material property. It is discussed later in Section 2.2.

[2] Small amounts of the acoustic energy also travel through the surrounding fluid. Thus you can hear these signals as they pass through free-standing drill pipe.

mechanical system employing flow valves and fans while an acoustic telemetry system is electronic. From the standpoint of reliability and flexibility, this is an important distinction. Solid state electronics are extremely reliable, and different methods of signal encoding and modulation are implemented through software changes and not hardware modifications.

The telemetry system described in this report is comprised of several components. The downhole module contains pressure, temperature, and motion sensors. The tool monitors these sensors, digitizes the information, and stores the measurements in on-board memory. Selected samples of this data are also encoded and broadcast on the acoustic carrier wave. The tool generates this sound wave within the steel drill string by means of a ferroelectric ceramic transducer. After the sound wave propagates to the surface it is detected by an accelerometer. The accelerometer is contained in the surface module of the acoustic telemetry system that is attached directly to the rotating drill string above the rig floor. Here the captured accelerometer signal is digitized and rebroadcast as a radio-frequency signal from the rotating module to a stationary radio antenna, which in turn is connected to a laptop computer. A computer program then decodes the digitized accelerometer signal, extracts the downhole sensor data, and displays the results on the computer screen.

1.3 Applications

Perhaps the strongest appeal of acoustic telemetry is its wide range of potential applications. Unlike mud-pulse telemetry, which only works with high-volume mud flows driven by large surface pumps, acoustic telemetry works in drilling, production, and completion operations. These tools work in all typical types of tubing strings that are hung inside casing or open hole, and they neither obstruct nor depend upon the flow of fluids. Communication is achieved solely with on-board power. We have successfully tested our tools on drill pipe, EUE production tubing, PH6 tubing, and coiled tubing. We have also broadcast telemetry signals through a variety of packers, drill-stem test subs, mud motors, shock subs, gage carriers, and slip joints. While its true that these well components influence the telemetry signals and sometimes reduce the range of the broadcast, it's also true that the effects are often either negligible or even beneficial. What is important to understand is that these well components produce predictable effects that are not disabling. However, acoustic telemetry will not work when transmission is attempted through the cemented casing of a well. Indeed, here the majority of the wave actually travels not in the casing but rather in the cement and natural formation itself. These types of materials are heterogeneous, highly dispersive, and inherently absorptive.

Drilling represents the most severe application with respect to shock and vibration, and our prototype tools are hardened for drilling applications. Indeed they have successfully drilled two wells. Survival of the broadcast transducer during drilling has been a common concern because it is constructed from a class of ferroelectric ceramic called PZT. But neither of our drilling operations resulted in any mechanical or electrical damage to this element, even though we fielded it in commercial operations that encountered difficult drilling.

1.4 History of the acoustic telemetry project

Sandia's acoustic telemetry project was initiated by the Geothermal Research Department in 1986. The initial work focused on physics issues associated with acoustic wave propagation in drill pipe. It was known at that time that the heavy tool joints used on drill pipe affect these signals by blocking certain broadcast frequencies creating what are known as pass bands and stop bands. (See Section 2.3.) These bands exist because drill pipe is constructed by welding heavy tool joints to light tubing, and the acoustic impedance of a tool joint is about 5 times greater than that of a tube. (See Section 2.2.) The initial work focused upon the development of the engineering analysis codes, DAWG©and PUNK 2000©. (See Sections 4.1.1 and 4.1.2.)

Through a rare stroke of luck we also acquired the original field test tapes reported in the U. S. Patent by Cox and Chaney [1]. While Cox and Chaney's original analysis of this data did not demonstrate the existence of the pass bands and stop bands in drill pipe, our routine spectral analysis of the data demonstrated a nearly perfect match to the theory. These results convinced us to design and fabricate a set of telemetry transducers to test drill pipe properties. Simultaneously, we published our analysis of the acoustical properties of drill pipe including comparison to our scale model experiments and the Cox and Chaney data. This drew the attention of several oilfield service companies including Teleco Oilfield Services, the company that first commercialized mud-pulse telemetry. In 1989 Teleco signed a license agreement with Sandia National Laboratories and started their own program to develop a drilling telemetry tool. However, this program came to an end a few years later when Teleco was acquired and absorbed into Baker-Hughes. By that time it was obvious that the original transducer designs were difficult to maintain and not rugged enough.

Consequently, several years later when Baker Oil Tools proposed the development of a production monitoring tool, we were able to design a simpler and more robust telemetry tool for their application. The design met all expectations and demonstrated the ability to broadcast from 6000 ft in a well with EUE production tubing. Extrapolation of these test results indicated that the ultimate range of the tool was about 12,000 ft. Baker Oil Tools licensed this tool but as yet has not commercialized it.

Building upon our success with the production monitoring tool, about 1998 we initiated a program to develop another drilling prototype. We greatly refined the designs and simplified the tool still further. About a year into this development we licensed this tool to Extreme Engineering. Given Extreme's experience we also asked them to harden our design for the drilling environment. The result of their work is an unqualified success. The tools have spent 22 days downhole during 2001-2002 without failure.

We now have a much better understanding of the influence of well conditions on the range of the acoustic telemetry broadcast. We know that repeaters are required for many of the commercial markets. Furthermore, we have the conceptual design for the repeater; however, we still need to develop the robust software associated with autonomous message demodulation, which is a routine but time consuming task.

1.5 Supplemental documents

The acoustic telemetry project has produced a large number of peer-reviewed journal articles, patents, and other supporting documentation such as user guides for the engineering design codes. We shall briefly review these documents now.

1.5.1 Patents

References [2]-[7] list the 8 patents generated by the acoustic telemetry project.[3] A synopsis of these patents follows:

U. S. Patent No. 5,128,901, [2] This is the underlying enabling patent. We describe methods of counteracting signal distortion and dispersion as well as methods of controlling phased arrays of transmitters and detectors.

U. S. Patent No. 5,222,049, [3] We describe a method of constructing a piezoelectric transducer using PZT ceramic. Threaded elements are used to clamp complete rings of ceramics. These were the first transducers used in this project. We successfully deployed them in a 6000-ft well. They were powered with a wireline cable.

U. S. Patent No. 5,703,836, [4] This patent describes an improved transducer design which is easier to assemble and maintain. It combines a split-ring concept with an axial interference fit. We successfully deployed this design on several occasions with a downhole power supply.

[3]Some of these patents were originally printed with Teleco Oilfield Services listed as the assignee; however, that is an error. Sandia National Laboratories is the sole assignee on all patents listed here.

U. S. Patent No. 6,147,932, [5] Our third generation and current transducer design is described in this patent. Like the others, PZT ceramics are mounted on a steel mandril. Here complete rings of ceramic are mounted on a monolithic mandril. We have successfully deployed this system many times including several drilling projects.

U. S. Patent No. 6,188,647 B1, [6] We describe an extension method of assembling our current transducer.

U. S. Patent application, 2003, [7] We explain fundamental issues of sound control in drill strings. Repeaters with greatly expanded spacing, direction transmitters, sound cancelers, and quarter wave transformers are described.

U. S. Patent No. 5,056,067, [8] We describe a simple circuit for controlling a phased arrays of transmitters and detectors.

U. S. Patent No. 5,477,505, [9] We describe methods of selecting drill pipe to greatly extend the broadcast range of acoustic telemetry signals.

U. S. Patent No. 5,274,606, [10] We describe a discrete-component digital circuit to control phased arrays of transmitters and detectors. This patent is no longer supported.

1.5.2 Technical papers

We have published acoustic telemetry articles in peer-reviewed journals, *The Journal of the Acoustical Society of America* and also *Wave Motion*. They are listed in References [11]-[17]. They encompass theory, experiment, and field test studies of the basic physics behind acoustic telemetry. Information about specific telemetry systems are not reported in these works. A synopsis of these articles follows:

Acoustical properties of drill strings, [11] We describe a computer model that calculates an analytic solution for *extensional wave* propagation in drill strings.[4] Results are compared to scale model experiments. We also present an analysis of the field test results in the Cox and Chaney patent [1]. Our theory demonstrates the existence of pass bands and stop bands in the drill string (See Section 2.3.), and our data from both the experiment and field test demonstrate validity of the theory.

[4]This type of wave is often called a *bar wave*. It results from the vibration of the bar in pure one-dimensional axial motion. Here we take the liberty of also referring to this type of wave as an acoustic wave even though that term is normally reserved for sound waves in fluids.

Extensional stress waves..., [12] We expand the theory to allow computations of ferroelectric transducers. Our computations are compared to scale model transducers mounted in brass rods.

Time-domain computations..., [13] The original model, which was derived to model one-dimensional waves in a rectangular system, is expanded to include one-dimensional waves in cylindrical and spherical coordinates.

Coupled extensional and bending motion..., [14] We examine the exchange of energy between extensional waves and bending waves. Drill pipe is not straight. In particular the internal diameter is created by pulling a mandril through the interior as the pipe is hot formed. This forms a spiral hole and a variable wall thickness that causes the pipe to bend laterally when compressed axially. We demonstrate how this action accounts for much of the signal loss observed during acoustic telemetry broadcasts.

Attenuation of sound waves in drill strings, [15] We describe an inexpensive and effective method of measuring signal attenuation in drill strings. Data from measurements in an 8000-ft California well are presented and analyzed with our computer model, DAWG©. This string is composed of pipes with lengths that vary as much as ten percent. We predict that ordering the pipe by length will greatly reduce signal loss.

The propagation of sound waves in drill strings, [16] We offer both qualitative and quantitative confirmation of the predictions of [15]]. Certain frequencies propagate twice as far.

Wave impedances of drill strings..., [17] Drill strings are periodic structures that exhibit pass bands and stop bands. It can be difficult to inject and extract wave energy from the drill string. This is a major issue in the design of broadcast repeaters. If ignored the range of the repeater will be severely reduced. This article describes a solution to this problem. It is the subject of the patent application [7].

1.5.3 Supporting documentation

References [18]-[19] list the following documents:

Wireless telemetry for well production applications, [18] We describe an application of acoustic telemetry to well production monitoring. We successfully fielded a tool in several production wells. We demonstrated wire broadcasts in EUE and PH6 production tubing, as well as light-weight coiled tubing.

The acoustic telemetry experiments..., [19] We used our drilling tool to broadcast in EUE and PH6 production tubing. The effects of transmission through a variety of commonly used production equipment such as packers and gage carriers are reported.

Software Systems Spec..., [20] We describe the architecture and functionality of the Oracle II software.

Communication Spec..., [21] We describe how to alter the behavior of Oracle II via its communication system.

Chapter 2

Physics Issues

Typical drill strings are assemblies of relatively light steel tubes with heavy threaded couplings, called tool joints, that are welded to each end. Each tube with its tool joints at both ends is about 31-ft long. The tube itself is about 29-ft long. A typical tube has a steel cross-section of about 5 in^2. The steel cross-section of the tool joints is about 25 in^2. When screwed together these elements form a slender string thousands of feet long with heavy concentrated masses spaced periodically at 31-foot intervals. We broadcast our acoustical telemetry signals as extensional bar waves through this assembly. The waves cause the string to periodically stretch and contract. The motion is similar to pulling a long slender rod in a tensile testing machine.[1]

Our broadcast wavelengths are about 20-feet long, and every tool joint in the string causes multiple reflections. This causes our broadcast wave energy to disperse and recombine in bizarre patterns resulting in a rich set of wave phenomena. Here we shall discuss the impact of some of these phenomena on our communication system.

2.1 Wave speed

Communication by acoustic telemetry is achieved with a sequence of extensional bar waves propagating through the drill string. It is important to know the speed of propagation of these waves. This is most easily understood by first considering how waves propagate through a long slender rod of uniform diameter.

If a slender uniform rod is stretched we know that the axial stress in the rod is proportional to the axial strain, and the proportionality or stiffness constant is called Young's Modulus E. (For steel E = 207 GPa.) The mass density of the rod is ρ.

[1]Here our discussion is focused on drill strings, but you should notice that production tubing, be it EUE or PH6 tubing, also has threaded couplings that produce the effects discussed here.

(For steel $\rho = 7.89$ Mg/m^3.) These two quantities give the speed of the wave c. It is

$$c = \sqrt{E/\rho}. \tag{2.1}$$

(For steel $c = 5130$ m/s.)[2] Typical drilling loads and the stresses they cause have negligible affect on the values of E and ρ. Consequently the wave speed c in a uniform rod is a constant and independent of these loads.

Now recall that the drill string is not a uniform rod at all. In fact the presence of the heavy tool joints add mass to the drill string without greatly increasing the stiffness; that is, they effectively increase ρ without increasing E. This causes the wave speed to drop. Unfortunately, the situation is far more complicated than that, and a detailed analysis of the wave speed of a drill string shows that c depends upon the frequency of the wave. This analysis [11] shows that c is still relatively constant for frequencies below 100 Hz. Indeed for commonly used steel drill strings, $c = 4800$ m/s for frequencies below 100 Hz. For higher frequencies c drops even lower and then rises again. This will be described in greater detail in Section 2.3.

The frequency dependence of c is very important because communication can only be achieved by broadcasting over a range or *band* of frequencies. Even turning on and off a "single-frequency beacon" much like a Morse Code signal generates a continuous band of frequencies. Thus different parts of our communication messages travel at different speeds.[3] Furthermore if we broadcast a wave packet containing waves with numerous closely grouped frequencies, the packet itself will propagate at a speed which is slower than the individual waves that make up the group. For example, at 625 Hz the *group velocity* of the drill string is about 3500 m/s. As we pointed out, indeed drill strings and production tubing present us with a rich set of wave physics.

2.2 Acoustic impedance

The concept of electrical impedance is broadly understood and accepted by the technical community. We understand that it represents the ratio of voltage to current.

[2] If you look up the speed of sound for steel in a textbook, you will find it listed as 5900 m/s. This is the speed of a wave in a very large block of material. This wave speed is greater than c because the stiffness of a large block in uniaxial strain is greater than E and involves the determination of an additional parameter called Poisson's ratio.

[3] The dependence of c on frequency is called *dispersion*. Dispersion is not unique to either acoustic waves or drill strings. Indeed it caused grave problems with the first transatlantic telegraph cable. Here Morse code signs dispersed to an unrecognizable form as they crossed the Atlantic. In fact we know that the 3 Hz components of the signal took almost a quarter second longer to cross than the 12 Hz components. This was not understood at the time and the cable was damaged when the operators raised the line voltage to "improve" communication.

We also know that it is important to match the impedances of different circuit elements to insure the efficient transfer of power between them. However, when we turn our attention to wave phenomena the counterpart of electrical impedance, which is wave impedance, is often ignored because its importance is not understood. But it is important because sound has power just like electricity, and the effectiveness of a communication system hinges on the effective use of power.

To understand wave impedance you might consider what happens when you speak to a friend. First consider that your voice travels as a wave from your mouth to your friend's ear at a speed of 345 m/s; that is, it travels at Mach 1, the speed of a fast airplane. As it travels through the air it causes the pressure in the air to change. It also causes the air to move slightly. The pressures and air velocities are very small else your friend would be knocked over by your voice. The ratio of the pressure over the air velocity is called the wave impedance of air. Analysis shows that this ratio is also equal to the density of air, 1.2 kg/m^3, times the speed of sound, 345 m/s.

Now consider that sound travels through both air and water. Your friend's ear has amazing sensitivity to sound waves in air, but it has almost no detection capability in water. You can't speak to your friend underwater because the wave impedance of water is about 5000 times greater than that of air. Indeed, this impedance mismatch prevents both your voice and your ears from working effectively underwater. To hear underwater sounds you need a hydrophone. The wave impedance of a hydrophone is matched to that of water, and with it you can even hear whales talk.

Now let's look at our acoustic telemetry system. We want to talk and listen inside steel. The wave impedance of steel is about 35 times greater than water. Thus our broadcast sources and detectors must be very stiff to produce high forces with little motion. Because we are communicating through a series of slender tubes with finite cross-sectional area, we actually need to use a slightly different definition of wave impedance, which represents the ratio of the total axial force F in the tube over the axial velocity v. Thus the wave impedance z is equal to the product of the density, wave speed, and the cross-sectional area in the wall of the steel tube,

$$z = \rho c A, \tag{2.2}$$

so that

$$F = zv. \tag{2.3}$$

Here you can see what happens at each of the tool joints in the drill string. As the wave moves from the tube into the tool joint the area A changes from 5 in^2 to 25 in^2. Thus the impedance changes by a factor of 5, which blocks most of the wave energy and causes a wave reflection. This is the basic mechanism that results in the frequency dependent wave speed that we discussed in the previous section.[4]

[4] As a classical "thought experiment" we might suppose for a moment that we could use aluminum

Equation 2.2 is the primary reason we use transducers made of lead-zirconate-titanate (PZT) ferroelectric ceramic. PZT has a slightly higher density than steel and a slightly lower wave speed. A large range of cross-sectional areas including single element disks with diameters greater than 5 inches are available at economical prices. Consequently it is a straight-forward task to design PZT transducers that are impedance matched to the steel drill string.[5] Equation 2.2 also explains why our designs do not employ resonating elements. The traditional transducer design task usually involves transducer elements with z's that are greater than the wave medium as, for example, when we are driving sound into water with PZT elements. Thus resonating systems are used to lower the effective z of the PZT transducer and bring it to a match with the water. Resonance is not used for the acoustic telemetry system because we already have an ideal match in impedance.

2.3 Stop bands and pass bands

Both drill-pipe and production-tubing strings employ threaded couplings at approximately 31-ft intervals. Thus when we broadcast a message along the string the wave will encounter a periodically spaced array of impedance mismatches, which will result in a virtually innumerable set of reflections. At first we might conclude that the reflections will completely block the wave, but this is not quite true. Some waves will be blocked, but other waves will get through. The frequency of the wave will determine what happens. The results of an analysis of the wave speed of a typical 5-in drill string is shown in Figure 2.1, and the corresponding results for $2\frac{7}{8}$-in EUE production tubing are shown in Figure 2.2. These are plots of the speed of the wave versus frequency. In both cases we illustrate two wave speeds. We use a dashed line to illustrate the *phase velocity*, and we use a solid line to illustrate the *group velocity*. We'll explain the differences in these wave velocities in a moment, but first we notice shaded bands of frequencies in which the velocities are not plotted. These are called *stop bands*. Communication is impossible at these frequencies because drill strings and production tubing block these waves. We identify the stop bands by number. For example 500 Hz is in the second stop band of the drill pipe. Pass bands exist

tool joints. Because the quantity ρc for aluminum is about one quarter of steel, we could easily alter A to make the z of the aluminum tool joint equal the z of the steel tube. In such a case the waves would travel through the tool joints undisturbed—at least until the drill string fell apart.

[5]The magnetostrictive material Terfenol is often marketed as a superior material for this application because its unconstrained motion is much greater than PZT. This fact is irrelevant for our application. Terfenol is more compliant than either PZT or steel, it is more expensive, and it is difficult to fabricate into transducers with suitable values of A. The z's of Terfenol transducers fall well below the z of steel. Indeed it is better suited to underwater applications. The efficiencies of the electrical power systems used to drive Terfenol are also well below that of PZT systems.

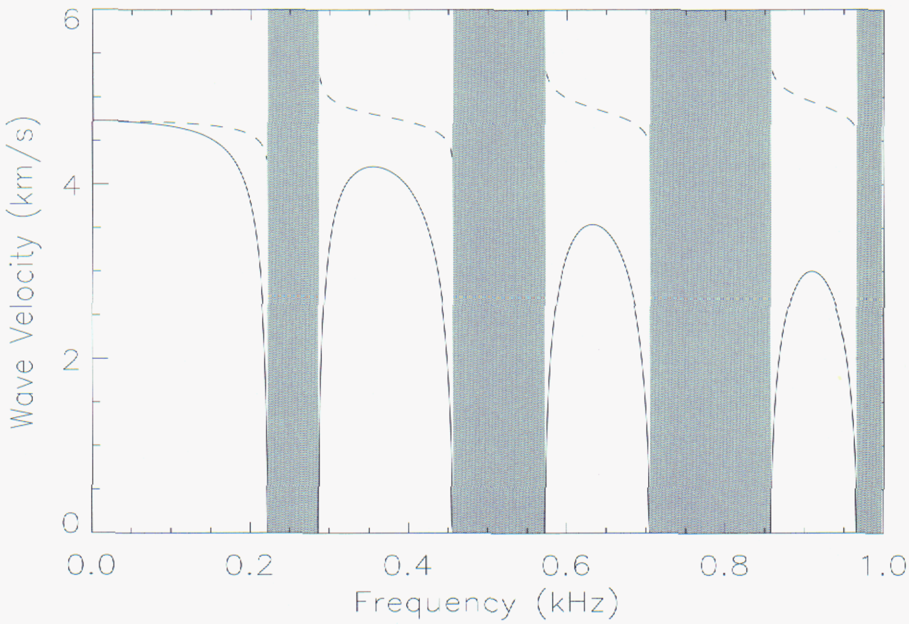

Figure 2.1: Pass bands and stop bands of drill pipe. The group velocity (—) and the phase velocity (- - -) are illustrated only within the pass bands.

between the stop bands. Notice that communication in the drill pipe is possible at 625 Hz because this frequency is located in the third pass band.

Single-frequency waves travel at the phase velocity. Packets, which contain groups of waves with a narrow range of frequencies, travel at the group velocity. We show such a packet in Figure 2.3. This is field-test data obtained from an accelerometer mounted on the EUE production tubing near the surface flange of a gas well. The signal was broadcast from 6000-feet downhole by one of our telemetry tools. Notice that the duration of the packet is a few seconds. The frequencies in the packet are in a 100-Hz band centered at 1200 Hz. Thus this packet travels in the fifth pass band of the production tubing. The individual wave oscillations are so tightly spaced that they cannot be separately resolved in this plot. The packet travels at the group velocity and the waves inside travel at the phase velocity. Moreover examination of Figure 2.2 shows that the packet travels somewhat under 5 km/s while each of the waves in the packet travel above 5 km/s. No doubt this might seem counterintuitive to you. However, as this wave packet travels up the production string the waves inside that first appear at the back of the packet, *move forward through it, and disappear* at the front.

Now you might ask what happens if we form a wave packet with frequencies

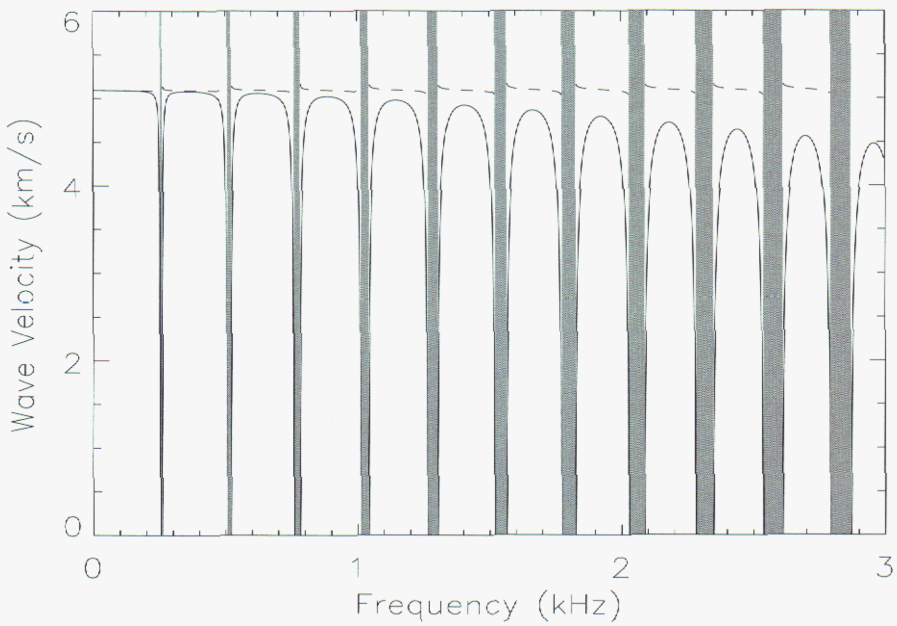

Figure 2.2: Pass bands and stop bands of EUE production tubing. The group velocity (—) and the phase velocity (- - -) are illustrated only within the pass bands.

centered near the edge of a pass band where the group velocity is zero? In this case the waves within the packet still move at approximately 5 km/s, but the packet stands still. This is a common phenomenon called *standing-wave resonance*. Pianists create standing waves in the strings of their instruments by striking the keys. While the vibration of an individual piano string appears to be fixed in space and not to travel up and down the length of the piano, it's actually a stationary wave packet composed of individual waves traveling rapidly along the string.

While its interesting to talk about the theory of sound waves in drill strings and production tubing, we might question the relevance of this theory to real situations. One way to actually *see* pass bands and stop bands in these tubing strings is to take a wireline truck to a well, ask the operator to lower a very small back-off charge down the tubing, and detonate it deep in the well. The discharge will create a wave packet containing a very wide range of frequencies. It will immediately propagate up the tubing to the surface where we can detect it with an accelerometer. By using a Fourier transform analysis, we can separate and display the amplitudes of each of the waves in the packet. The measured amplitudes for such a field test is compared to the theoretical locations of the stop bands in Figure 2.4. The comparison illustrates the agreement for the first 11 pass bands of the tubing. We point out that these results

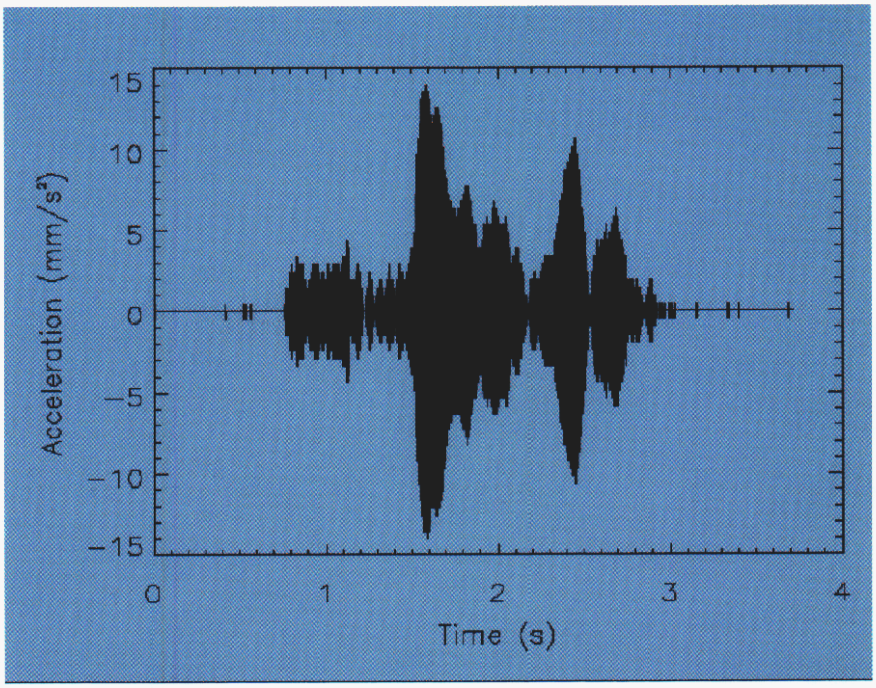

Figure 2.3: A wave packet in EUE production tubing. This packet contains all frequencies between 1150 Hz and 1250 Hz.

were obtained from under a cow pasture in Texas using commercial grade production tubing. Had this data been obtained from carefully controlled experiments under optimum conditions, this level of agreement between theory and experiment would not be considered good—it would be considered astonishing. Indeed the locations of the pass bands are clearly confirmed. The varying amplitudes of the measured signal components reflect the different amplitudes created by the detonation. The speed at which the packet propagates confirms the theoretical estimates of the group velocities.

Data of this quality has been obtained in numerous field tests. It is one indication that the physics analysis and the associated engineering codes that we have developed for acoustic telemetry are exceedingly useful and important tools for designing and predicting the behavior of the telemetry system and its components.

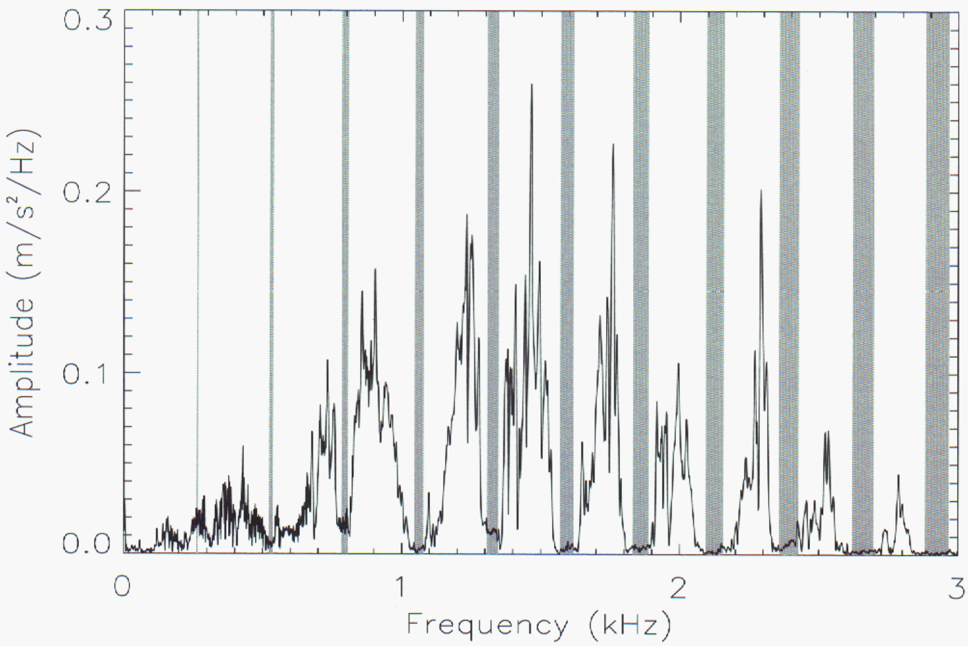

Figure 2.4: Field tests results that support the existence of pass bands in EUE production tubing. The solid line is the spectral analysis of the accelerometer measurement. The shaded areas indicate the theoretical locations of the stop bands.

2.4 Energy and efficiency

The amount of electrical energy that can be generated downhole is very limited—on the order of 100 watts.[6] Indeed the commercial success of mud pulse telemetry is strongly dependent on the fact that the energy in the telemetry pulses comes from the mud pumps at the surface. Downhole electrical energy is only required to open and close the valve that chokes the mud flow. Even so, the data rates are slow partly because higher rates of valve actuation require too much electrical energy. In contrast, acoustic telemetry signals are generated directly by the downhole electrical power supply. This makes the efficient conversion of electrical energy into sound of prime importance.

[6] Electrical generators driven by the mud flow are often employed, but their length is approximately proportional to their generating capacity. Very powerful generators often fail because their long length subjects them to excessive bending.

The energy E in a *simple* propagating wave is [7]

$$E = zv^2. \tag{2.4}$$

Thus if we use the metric MKS system of units, E is given in watts and represents the rate at which wave energy is flowing past a particular point of the pipe. When the pipe has a uniform diameter, z is given by Eq. 2.2. Waves in drill strings and production tubing are *complex* combinations of multiple reflections from the pipe couplings. Consequently we cannot compute z this way. Rather we must refer to [17] to compute z for these strings.

A simple fact can now be stated. If we want to generate a telemetry signal of amplitude v, the electrical energy delivered to a transducer must be greater than E. Our telemetry transducer produces $E = 10$ watts of wave energy. To do this the batteries must deliver 50 watts to the tool. That means the tool produces 40 watts of heating distributed throughout the transducer, the power amplifier, and the battery pack itself. This efficient use of energy is primarily due to the high efficiency of the PZT transducer, the optimization of the power amplifier, and the method of mounting the transducer on the steel mandril. *It is doubtful that any other transducer system could generate more sound with the same amount of electrical energy.*

2.5 Attenuation of acoustic waves

As our communication broadcast travels up the drill string a portion of the energy of this signal will be converted to heat and lost. Eventually the signal will become too weak to detect. We know that the downhole tool can typically radiate 10 watts of energy into a drill string. Consider a situation where for each 1000 feet of propagation up the drill string our communication signal retains only $\frac{1}{4}$ of its remaining energy. Thus after the first 1000 feet only 2.5 watts remains, and after the next 1000 feet only 0.625 watts remains. Here we see that the amount of energy that is lost is proportional to the amount remaining, and thus the amplitude of the communication signal decays exponentially with distance. In such cases the signal decay is quantified with the attenuation factor α, which is normally specified in decibels per distance. We determine α as follows:

$$\alpha = -10\log_{10}(\tfrac{1}{4}) = 6 \text{ dB}/1000 \text{ ft}. \tag{2.5}$$

You will notice that by convention α is computed using the ratio of the energy level. (It can also be computed using the amplitude ratio of the velocity v provided the

[7]People often expect to see the term $\frac{1}{2}$ in the energy expression. However, elastic waves have both potential and kinetic energy components.

factor 10 is replaced with the factor 20. Because energy is proportional to the square of v you will get the same values from this computation.) In this example the signal will weaken by 60 dB's after propagating 10,000 ft. It will then contain 10 μW of energy, which is still easily detected with commercial accelerometers. We can routinely acquire and decode these signal levels in typical production applications, but drilling applications often contain noise levels that mask these signals. This will be discussed in greater detail in Section 2.7.

We know that α depends on a variety of factors. Among them are:

- The frequency of the communication signal.
- The geometry of the pipe.
- The amount of contact between the pipe and wall of the well.
- The density, viscosity, and gelling qualities of the mud.

Indeed, some of these factors such as contact between the pipe and the formation are often difficult if not impossible to quantify. Even if they could be quantified a suitable predictive model for α is not available. However, it is still useful to review the pieces of this puzzle that we do understand.

There are two pipe-geometry effects. They are associated with variations in the individual pipe lengths and the wall thicknesses, respectively. To understand how pipe length influences attenuation you must first recall that the tools joints joining neighboring sections of pipe create stop bands in the drill string. The frequency boundaries of each stop band depend upon the length of the pipes. The higher the stop band frequency the stronger the dependence on the length. In a typical pipe as the length is decreased by about one foot, the fifth pass band, for example, will move up to the frequencies previously occupied by the fifth stop band. Indeed in a drill string with a mixture of pipe lengths the fifth pass band often ceases to exist. Meanwhile, the fourth pass band will be narrowed, but the third will remain relatively unchanged. This effect is discussed in greater detail in [11], [16], and [17]. The influence of wall thickness is more subtle but just as important. While the outside diameter of the finished pipe is relatively straight, the inside hole is not. These hollow pipes are manufactured by a hot-rolling process. As the pipe is rolled to form the outside diameter, a mandril is simultaneously pulled through the center to form the inside diameter. Unfortunately the mandrill usually walks off the centerline in a cork-screw fashion. Thus the internal surface of the finished pipe has a helical shape. The signals we broadcast through this pipe mostly cause axial extension and compression along the centerline of the pipe, but unfortunately, the helical shape of the hole also causes the pipe to bend and twist. In doing so, some of the energy in the broadcast signal is converted into bending and torsional waves. This is often called *mode conversion*. The energy transferred to these new modes is lost and contributes to the total observed attenuation of the tubing string. A detailed analysis of mode conversion between our extensional communication waves and highly dispersive bending waves is given in [14]. It is demonstrated that 3 to 4 dB/1000 ft of attenuation can be attributed to the wall-variation effect.

Contact between the tubular string and the wall of the well occurs because of planned deviation of the well from vertical, because of unplanned doglegs, and because of the natural tendency of the rotating drill to cut a spiral hole into the formation. Moreover when a coiled tubing string is deployed we know that it assumes a spiral shape as it rolls off the storage coil. This causes it to lay against the well casing along its entire length. We usually observe higher attenuation in these situations. Indeed, coiled tubing exhibits higher attenuation than drill pipe despite its lack of tool joints.

The attenuation is also strongly dependent on the frequency. For example, in [16] we reported attenuation of 3.8, 5.7, and 8.5 dB/1000 ft in the second, third, and fourth pass band of a drill string. Indeed, this data suggest that attenuation is approximately proportional to frequency. These results were obtained from measurements of signal attenuation in 5-in drill pipe suspended in a vertical well filled with water. But contrast that against measurements of attenuation in PH6 tubing in a vertical well filled with mud. (See Fig. 2.5.) In this case attenuation decreases as the frequency

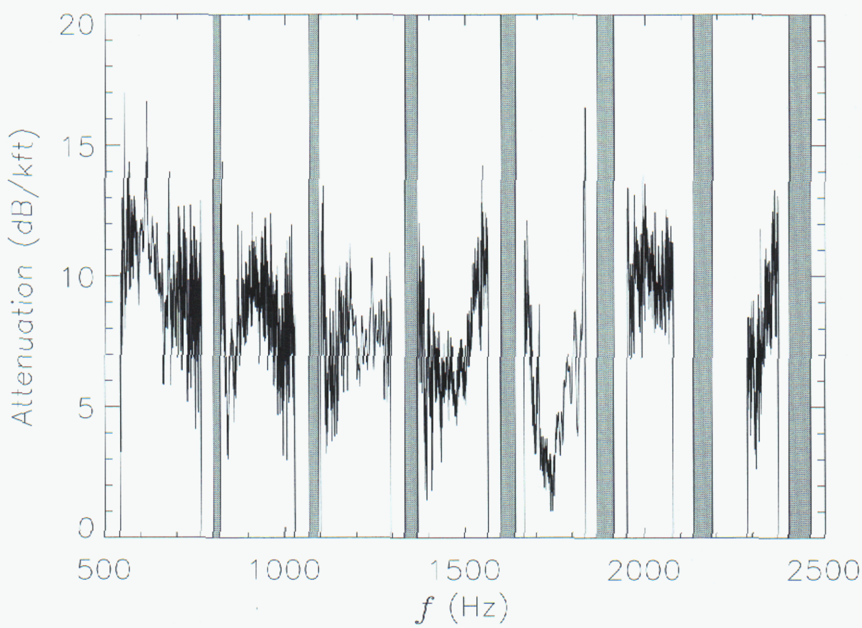

Figure 2.5: *Signal attenuation in PH6 tubing in a vertical mud-filled well.*

increases to 1800 Hz. Attenuation in PH6 and EUE production tubing in a water-filled well also appears to decrease with increasing frequency. Our measurements suggest that placing drilling mud in the well usually increases attenuation in both production tubing and drill pipe. Indeed the effect can be quite pronounced, doubling or tripling the attenuation, after the mud is allowed to gel or setup over a period of several days. When broadcasting in drill pipe we use the third pass band near 625 Hz because the heavy tool joints combined with variations in pipe length severely narrow and eliminate the higher pass bands. However, the light tool joints used in production tubing allow access to higher frequencies, which often have lower attenuation.

While there is no reliable theoretical model for the prediction of the attenuation parameter α, there are two straightforward methods of measuring it. The most obvious method is to deploy our tool and measure the decrease in signal strength as the tool is tripped into the well. This tool makes periodic measurements of its own signal strength, which can be used to calibrate its signal level. The second method is less obvious. Here we deploy a small explosive charge into the well on a wireline. These charges, which are called *backoff shots*, are commonly used in drilling and production applications. We often deploy only a short length of detonator cord or even only the blasting cap itself. When detonated it produces a broad-spectrum and highly repeatable disturbance in the tubing. The resulting waves travel up the tubing string just as a broadcast wave would. Because of their broad frequency spectrum they *light up* all of the pass bands simultaneously. The signal that is recorded with an accelerometer at the surface allows us to measure attenuation in all of the pass bands simultaneously. References [15] and [16] describe this method in detail.

2.6 Directional control of waves

Suppose a long uniform tubular string is suspended in a well with a transducer mounted at the midpoint of the string. When we activate the transducer to broadcast a message to the surface we find that equal amounts of wave energy are broadcast both up and down the pipe. Indeed we have wasted half of the energy of our source unless we can turn the downward traveling wave around and constructively recombine it with the upward traveling wave. This situation is not unique to acoustic telemetry. Home stereo systems suffer from the same problem because loud speakers radiate energy backwards into their cabinets as well as forwards into your living room. Most speaker cabinets are of the *infinite-baffle* type, which capture and absorb the backward-traveling radiation in order to improve sound fidelity. That's part of the reason commercial stereo power amplifiers are so big. In the past *base-reflex* cabinets were also popular. Here the low frequency components of the backward-traveling waves were reflected from the rear of the cabinet, released through a port directly below the speaker cone, and allowed to recombine with the sound radiated directly off the front side of the speaker. This is what gave old *juke boxes* their booming sound quality. While this idea does not lead to a particularly good high-fidelity sound system, it does serve the purpose for our acoustic telemetry system. Indeed if we use a broadcast frequency of $f = 625$ Hz , the wavelength λ in steel will be equal to,

$$\lambda = c/f = 5130/625 \approx 8 \text{ m}. \tag{2.6}$$

Thus when a 2-m long *quarter-wave bar* of steel is placed below the PZT transducer, it will *tune* the transducer by reflecting the back radiation of the transducer and then combining it constructively with the forward radiation. (Often other types of transducer designs require *half-wave bars* instead.) Regardless of patent claims to the contrary, all existing transducer designs suitable for deployment in well tubulars radiate equally in both directions and therefore would benefit from some form of tuning to improve their signal levels.

Unfortunately its also possible to *detune* a transducer. If a *half-wave bar* is attached to the bottom side of a PZT transducer the upward traveling wave will be totally canceled. Again we emphasize that this is not unique to the PZT system. Any type of transducer can be detuned. Said another way, while tuning can only buy us a 6 dB increase in signal strength it can cost us everything in signal loss. While the danger of detuning is evident and easily avoided in this simple illustration, actual bottom-hole assemblies used for drilling and production present a far more complex situation in which our intuition fails. In these situations only an analysis with a code such as DAWG©can tell us if our transducer is properly tuned. Indeed we always analyze the bottom-hole assemblies used in our field tests to ensure proper tuning, but even that approach has its limitations because often the drilling supervisor must quickly change the assembly to a new configuration that might detune it. Drilling must proceed and cannot wait for the machining and assembly of additional parts to tune the system.

There are two ways to fix this situation. Two transducers can be placed into the string and operated as an array with their drive signals set 90 degrees out of phase. (See patent [2].) This two-transducer array will broadcast waves only up the drill string over the entire width of our communication band. Thus the assembly below the array becomes entirely irrelevant. The second method to ensure proper tuning is to employ a *passive reflector*. This is a special arrangement of pipe or *dumb iron* placed directly below a single transducer. Its purpose is to act like a two-sided mirror. It does not allow wave energy to pass, regardless of whether the wave approaches from above or below. It is simple to build and deploy, but for intellectual property reasons we cannot fully describe this device at this time.

2.7 Communication and modulation methods

Drill string and production tubing form a dispersive communication medium. By that we mean that each frequency component of the broadcast signal travels at a different velocity, the phase velocity. (See Fig. 2.1.) Likewise attenuation also changes with frequency. (See Fig. 2.5.) The situation is further complicated by the transducer tuning as well as other constructive and destructive wave interference phenomena.[8] The existence of stop bands and dispersion force us to broadcast in a narrow frequency band, the central 50 Hz of the third pass band. But to compensate for the random variations in interference and attenuation we have not narrowed the band any further. Indeed we actually employ a pass-band sequence of frequency chirps for communication. (See Fig. 2.6.) The illustrated chirp represents a traveling wave

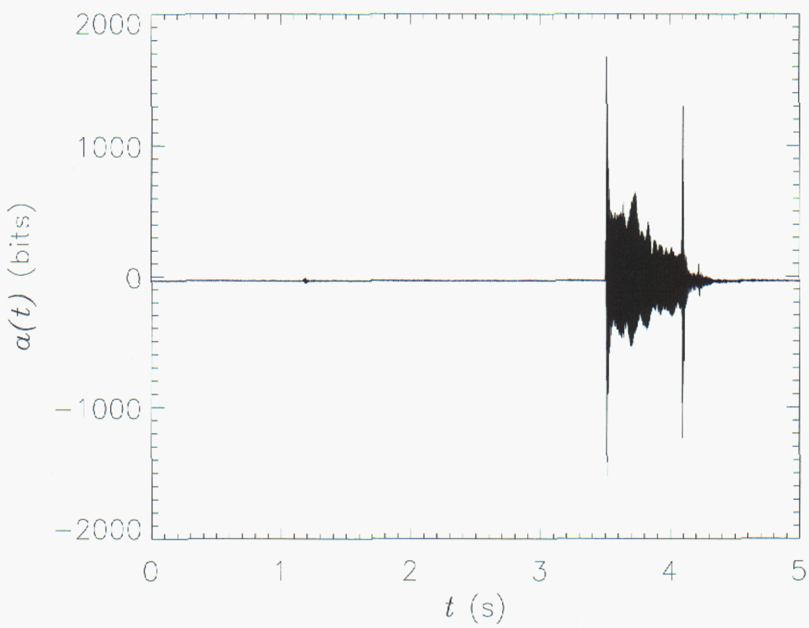

Figure 2.6: A chirp broadcast from downhole through a production-tubing string and received by an accelerometer at the surface.

packet that primarily contains a 50 Hz band of frequencies in the central portion of the third passband. The beginning of the chirp contains the low frequencies. The

[8]Our discussion of tuning and detuning in Section 2.6 is a special example of interference phenomena. We might also expect spurious and random reflections distributed along the length of the well tubing that would also lead to additional wave interference. The apparently random hash in the attenuation plot in Fig. 2.5 probably results from this type of interference.

frequencies increase as time increases. At the time of broadcast the amplitude of this chirp was constant from front to back. Attenuation and interference have altered this. The spikes at the beginning and end of the chirp are due to high frequency transients resulting from the startup and shutdown of the power amplifier. This chirp has traveled through production tubing, which allows these higher frequencies to propagate with lower attenuation than the 600 to 650-Hz frequencies in the main body of the chirp. Clearly, more effective communication could be achieved by tuning the power amplifier to broadcast in a high pass band of the production tubing. (See Sec. 5.2.5 for more discussion of this issue.)

Broadcasts from the tool are divided into a series of time windows or frames. If a chirp appears in a particular frame it represents a binary one bit. If not, it's a zero. The framing rate is adjustable between about 1 to 50 baud. Because we have not incorporated data compression methods in our communication scheme, the framing rate is equal to the communication baud rate. A typical message broadcast by the tool contains an 8-bit sync word, a 16-bit message number, a selectable number of 12-bit data words, and finally a parity bit. Each data word contains a measurement from a selected gage such as a temperature or pressure sensor. Thus if we select only the temperature gage and a framing rate of 10 baud, a period of $(8 + 16 + 12 + 1)/10 = 3.7$ seconds is required to transmit a complete message containing one temperature measurement. Obviously, this is an inefficient communication protocol that we have employed simply to demonstrate the feasibility of this communication system. However, it has several advantages.

Message errors can be detected two ways. First if parity is selected to be odd, the tool broadcasts a parity chirp at the end of the message that ensures that the total number of individual chirps in the broadcast message is an odd number. If the received message contains a even number, there is an error in the interpretation of the received message. The 16-bit message number can also be used to check for errors because it is redundant information. Typically we know what it should be.

Messages are broadcast with energy levels near 10 W. The accelerometers, which receive the broadcast messages, are capable of detecting energy levels down to 10^{-11} W or 120 dB lower. Ambient noise levels are usually far above the detection threshold of the accelerometers. Thus the broadcast range is limited by our ability to detect the message in the presence of noise. Our use of chirps allows us to use digital signal processing methods to improve the signal-to-noise ratio of the message. For example, if the duration of the chirp is Δt seconds and the chirps sweep across a Δf frequency band, the application of a match filter can improve the signal-to-noise ratio by an amount equal to the product $\Delta f \Delta t$. If our tool is set to broadcast 1-s chirps, then $\Delta f \Delta t = 50$, which is a $20 \log_{10}(50) = 34$ dB improvement. If the chirp only lasts 0.1 s, then the match filter will only give 14 dB improvement. Moreover, if half of the chirp frequencies are canceled by interference we might expect only

$20\log_{10}(\Delta f \Delta t) = 20\log_{10}(25\times 0.1) = 8$ dB improvement. This illustrates the classical tradeoff between baud rate, communication bandwidth, and communication range, which holds for acoustic telemetry as well as all other communication systems.

Chapter 3

Prototype Tool—Oracle II

Oracle II is designed to be a drilling tool. It broadcasts communication signals in the third passband of the drill string. The tool is 4.75 inches in diameter and about 5-ft long. (See Fig. 3.1.) The pressure housing of the tool can safely withstand

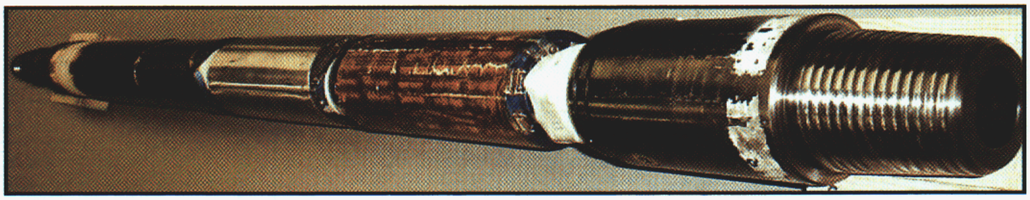

Figure 3.1: The Oracle II prototype telemetry tool. The outside pressure housing has been removed. The ceramic transmitter is at the far end. The brass colored covers house the logic module and the sensor package. The power amplifier lays just behind the logic module. The batteries are at the near end.

5000 psi external pressure while simultaneously transferring the weight on bit and torque from the string above to the drill bit below. The housing contains all the major components of the tool that are mounted around the mandril including the sensor package, power supply, logic module, power amplifier, and acoustic transmitter. Before giving detailed descriptions of the individual components let's see how they function together.

We deploy Oracle II to collect sensor data down hole and broadcast it to the surface as an extensional bar wave propagating through the drill string. The tool draws its operating power from a low-voltage DC battery pack. The data originate as analog electrical signals in the sensor package. The logic module monitors these voltages and digitizes them creating a sequence of binary numbers that represent a history record of each sensor. The logic module then stores these records in memory.

Messages, which are intended for broadcast to the surface, are also constructed from portions of these records. The logic module also controls the power amplifier. The job of the amplifier is to generate an oscillating high-voltage drive signal using the low-voltage DC battery pack. The logic module uses the power amplifier to construct the chirp sequence discussed in Sec. 2.7. The acoustic transmitter is connected directly to the high-voltage output of the amplifier and produces the vibrations in the drill string that propagate to the surface.

3.1 PZT transducer

The job of the PZT transducer is to produce extensional bar waves in the steel drill string. Thin rings of the ferroelectric ceramic PZT are used to do this. PZT is a lead titanate zirconate compound, which exhibits a piezoelectric effect; that is, it expands and contracts in response to an applied electric field. We use one of the denser and harder compounds often designated as PZT-8. The rings are stacked together into what is commonly called a *sandwich* transducer. We then place hollow brass cylinders on each end so that the effective thermal expansion of the ceramic and brass combination is equal to that of steel. We then mount this assembly on a hollow steel mandril where the ceramic transmitter is held in place under an axial compressive load of approximately 50,000 lbs. (See Fig. 3.2.) A 2-in diameter hole runs horizontally through the center of the mandril. When the outside pressure housing is in place, the outside diameter of the tool is 4.75 in. Construction of the PZT transducer is relatively routine. Mounting it on the mandril is not. The methods we employ are discussed in our patents. This transducer is driven with an oscillating signal that often exceeds 1000 V peak-to-peak. The ceramic behaves like a capacitor with a phase angle of approximately 89 degrees. More than half of its electrical resistance is due to the radiation of acoustic energy into the drill string. As we discussed in Sec. 2.2 it is important to match the mechanical impedance of the transducer to the mandril and the drill string. It is equally important to match its electrical impedance to that of the power amplifier. Because this device is capacitive, the amplifier must be inductive.

3.2 Power systems

Management of electrical power is a crucial element of the Oracle II system. Effectively converting electrical power into acoustic broadcast energy determines system efficiency and signal strength. The acoustic output of the PZT transducer is directly related to the amplitude of the oscillating high-voltage drive signal. Because we use

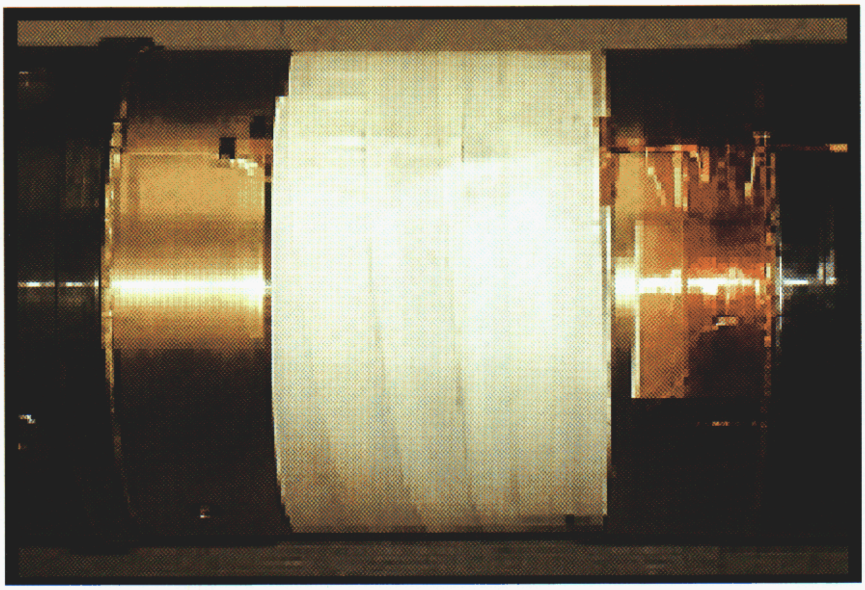

Figure 3.2: A PZT transducer mounted on a steel mandril. The brass rings provide compensation for thermal expansion. Tape covers the ferroelectric ceramic.

drive signals that exceed 1000 V peak-to-peak the transducer drive currents exceed 40-A peak. Users must follow safety procedures to mitigate the hazards of these high voltages and currents as well as the high energies stored in the capacitor bank.

We have separated the Oracle II power system into components that provide regulated power to the electronics and components that generate the high-voltage signal to drive the transducer. System electronics require regulated +5-V and +10-V power supplies. We use a capacitor bank, power amplifier circuit, and transformer to generate the oscillating high-voltage drive signal from a low-voltage DC battery pack. Of course when we test the high-voltage drive the secondary coil of the transformer must be connected to the transducer. Because the transducer is capacitive, the amplifier circuit must be inductive. In fact the secondary coil and the transducer form a classical series tank circuit that exhibits resonance within the frequency band of the chirp.

System power is supplied by a single battery pack with separate low voltage and high voltage outputs. (See Fig. 3.3.) These individual outputs prevent the high current demands required of the high-voltage system from affecting the low-voltage reference grounds of the electronics systems. The individual grounds for both systems are joined on the power amplifier board at a low sensitivity ground node. Battery

Figure 3.3: Battery Pack for the Oracle II prototype telemetry tool.

packs are inserted in the annular space between the mandril and the tool cover. Because of this space limitation we use battery packs with either *AA or C* size cells.[1] A minimum number of cells are required to achieve the high voltage requirement of the transformer primary whereas the maximum number cells is limited by the space allocated for the battery pack. The Oracle II AA-size battery pack has 72 cells and C-size battery pack has 40 cells.

The high voltage battery pack delivers on average 50 watts to the tool during an acoustic chirp. The battery voltage usually drops during the generation of an acoustic chirp because the battery current reaches or exceeds the specified maximum pulse discharge limit. This may result in problems with internal fuses and degraded lifetimes of some primary lithium batteries.

The low voltage battery pack delivers on average less than 0.5 W to the electronics. The +5-V electronics consume the most current with an average current draw of 50 mA. This relatively high current exists because we selected parts that could be upgraded to high temperature ratings. Initially we believed that the low voltage

[1] We use a 5.3-inch diameter cover to house the *C* cell pack.

battery pack would be the limiting factor in the predicted 100-hour operating time of Oracle II. However, our field-testing revealed that the high voltage pack is the limiting source failing after 50 hours of use. We speculate that the high-voltage current pulses, which exceed the maximum discharge limit, cause this degraded lifetime.

We also use a bank of capacitors to store energy and assist the battery pack to generate the acoustic chirp. The capacitor bank and battery pack outputs are wired in parallel to the primary of the transformer. We have not current limited either source. The capacitor bank stores 3.5 J of energy, which is a shock hazard. A message transmission, which is a sequence of acoustic chirps, causes the capacitor bank to undergo a series of charge and discharge cycles for each chirp. The battery pack charges the capacitor bank between each chirp and both the capacitor bank and battery pack provide current during a chirp.

The capacitor bank is also inserted in the gap between the mandril and the tool cover. It has almost 4 mF of capacitance, which is adequate to sustain the short chirps used in communication rates at 20 baud or faster, but it has insufficient charge capacity to generate the longer duration chirps used for slow communication baud rates. In many of our field tests we used 2 baud communication rates, which requires 10 times the capacitance and an additional allotment of physical space in the tool.

Now that we have reviewed the energy sources let's look at how we create the high-voltage drive signal. The power amplifier circuit board contains the functionality to convert the micro-controller square wave signal into a sequence of thin pulses used to modulate the transformer primary coil. These pulses are used to switch battery and capacitor bank power into the transformer primary, which then pumps the tank circuit formed by the secondary coil and the transducer.

The transformer itself is wound on a gapped toroid. (See Fig. 3.4.) The primary

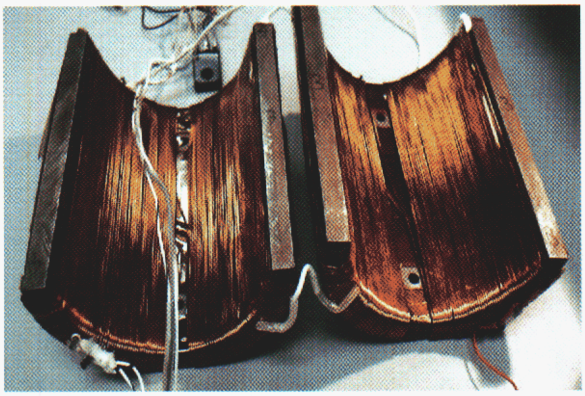

Figure 3.4: Transformer halves for the Oracle II prototype telemetry tool.

halves of the transformer are wired in parallel whereas the secondary halves are wired in series. The power amplifier impedance is matched to the transducer by adjusting the gaps between the transformer halves.

3.3 Logic systems

The Oracle II system functionality is implemented using a micro-controller with associated memory and peripheral support logic. Our design was driven by the need to field an adaptable system architecture that supported acoustic telemetry research and development. To satisfy this goal the sensor selection, message timing, and communication parameters are software adjustable. Moreover our design facilitates upgrading to high temperature rated electronics because we have used low temperature rated electronic components that have equivalent Silicon-On-Insulator high temperature rated Honeywell components. This temperature constraint was a limiting factor on micro-controller speed and bus width, memory size, system power consumption, and interface options. Due to these restrictions, our final logic system design is very straightforward considering the available functions on Oracle II.

Oracle II operates as an autonomous state-machine that schedules events based on configuration parameters downloaded during programming. System features and corresponding event sequencing are fixed at startup and cannot be altered during operation. Selected portions of the test data that the system acquires from its sensor can be acoustically transmitted in real-time, but the complete test data set is stored in memory. This stored data can be serially uploaded after recovery from the test well and halting the system.

The system is controlled by an 8-bit Intel micro-controller running at 12 MHz. Program code is approximately 18 kbytes and resides in a 32-K E^2PROM. Program variables, configuration parameters, and sensor data recorded are stored in 2 each 32-K static RAMs. Communication is performed over an RS-232 port at 9600 baud. The complete logic system for Oracle II is located on a single printed circuit board.

3.4 Sensors

Oracle II contains twelve sensor channels, which are all configured as inputs. We have connected temperature, pressure, voltage monitors, and vibration sensors to nine of these channels. The three spare inputs are reserved for future system expansion. The logic module records the analog input voltages from the sensors, digitizes the signals, and stores the measurements in on-board memory. Tool operators can select which sensors to monitor, how often they will be recorded into memory, and what data will be acoustically transmitted.

Sensor sampling rates and sensor analog resolution are predetermined quantities based on system hardware. Each recorded sensor measurement is actually the average of 32 samples taken at a rate of 4196 Hz, which you may notice is an unusual sampling rate. This rate is based on measurements of the combined hardware and software processing time as well as constraints of our frequency domain analysis.

A 12-bit analog-to-digital converter digitizes all sensor measurements into 4096 step levels. Individual sensor transfer functions translate the digitized sensor information into physical units. The total analog input range is 10 V. This results in an incremental resolution of 2.44 mV. This is not to say that we have an accuracy of 2.44 mV, but rather the smallest incremental change that hardware can detect is 2.44 mV. We did not perform an error study to determine sources of random and systematic errors, nor did we calibrate the system. However by averaging 32 samples we have reduced system noise by a factor of approximately 1/6. By and large the Oracle II measurement scheme can be considered an 11-bit system. This implies that the *ideal system resolutions* given for each sensor should be doubled when making critical measurements.

Oracle II system temperature is monitored to identify if the maximum temperature limit is exceeded. Our system contains electronics that have a commercial grade rating of 85°C. Temperature sensors are mounted on the circuit boards and on the mandril. Temperature differences between two locations give an indication of temperature gradients in the tool. As much as 4°C difference have occurred as the tool is tripped at a fast pace into the well with the circuit board temperature sensor lagging behind the mandril sensor. The circuit board temperature sensor has an ideal system resolution of 0.25°C and the mandril mounted temperature sensor has a 1.2°C ideal system resolution.

The Oracle II system also monitors borehole pressure either in the interior hole of the tool or the surrounding annulus between the tool and the wall of the well. The downhole pressure is a combination of the static pressure due to the column of fluid and the dynamic pressure due to mud pumps at the surface. The pressure housing of the tool can safely withstand 5000 psi external pressure. An absolute pressure transducer from Paine is mounted in a pressure port and the wiring is potted to protect against vibration. (See Fig. 3.5.) This system performs quite well. For example during one drill stem test it detected a 1200 psi drop in pressure that occurred in less than ten seconds as the drill-stem transitioned out of a large hydrostatic pressurization. Indeed, the pressure log that Oracle II recorded was identical to the standard oilfield data logger that was also deployed on this drill stem test. The pressure sensor has an ideal system resolution of 4.7 psi and an operating pressure range of 10,000 psi.

Drill string vibrations are monitored by the Oracle II accelerometers. These vibrations result both from actual acoustic broadcasts as well as environmental drilling noise. Both 5-G and 50-G accelerometers from Analog Devices are mounted on the

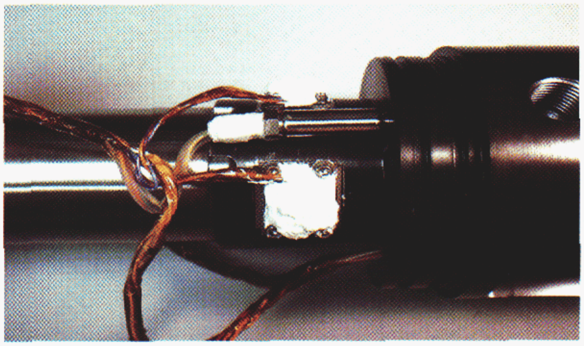

Figure 3.5: Paine pressure sensor mounted on the mandril.

mandril. The 50-G accelerometer is sampled only during an acoustic transmission whereas the 5-G accelerometer is programmed to capture environmental noise. Typically an average accelerometer output level is computed and stored by the system, but we also have the capability to record short acceleration history snapshot that can be analyzed by the LabVIEW™ based Tool Setup Code to determine the frequency spectrum of our messages and the downhole drilling environment. The 5-G accelerometer has an ideal system resolution of 10 mG and the 50-G accelerometer has an ideal system resolution of 64 mG.

The Oracle II system also monitors the battery voltage and high voltage output of the transformer secondary coil. Indeed, recording of the high voltage battery output has permitted real-time determination of system fault conditions caused by low battery levels while the system was still at the bottom of the well.

3.5 Pressure housing

The functions of the pressure housing are:

- To withstand external pressures resulting from the well fluids.
- To transmit drill torque and weight to the bit.
- To transmit acoustic telemetry broadcasts.

We have achieved these goals with the current design. The tool has drilled several commercial wells. Neither the housing nor the internal components were damaged.

3.5.1 Design Considerations

While the ceramic elements of the transmitter have high compressive strength, they are not as strong as steel. Even so they must be in intimate mechanical contact with the steel mandril and pressure housing in order to produce and broadcast acoustic signals. Designs that allow the broadcast to get out of the transducer and into the drill string must necessarily allow disturbances from drilling to get back into the transmitter.[2] That means the transducer elements, be they PZT or any other material, must withstand drilling loads. For this reason we employed a design in which the clamping action of the mandril on the PZT ceramics is achieved without a threaded connection. We also choose a design in which the outer pressure housing is used to transmit a major portion of both torsional and bending loads.

3.5.2 Fabrication/Testing

The patents [5] and [6] contain a detailed description of our method for mounting the ceramic transducer on the mandril. Before assembling the prototype tools, we tested this assembly procedure using a special fixture. (See Fig. 3.6.) The fixture was comprised of a special hollow mandril with a single large shoulder cut into it at about its half point. This mandril had a tapered oilfield thread at the bottom, which allowed it to be screwed to the hydraulic fixture. A long rod was placed inside the mandril before it was actually screwed onto the fixture. After assembly the ram of the hydraulic cylinder was extended to push the rod against the upper end cap of the mandril and thereby stretch the mandril axially along its entire length. Next, a hollow brass cylinder, which was used in place of the PZT transducer was placed over the top of the mandril and allowed to rest against its shoulder. Then another hollow cylinder called the anvil was heated and placed over the mandril and allowed to rest on top of the brass cylinder. As the anvil cooled it shrank to an interference fit on the mandril. Then the hydraulic ram was released to allow the mandril to contract axially and squeeze the brass cylinder between the anvil and the shoulder of the mandril. Usually this resulted in insufficient compression of the brass cylinder. When this happened the mandril was stretched again, shimming strips were placed between the brass and the anvil, and the mandril was released again. This step always resulted in a proper compression load on the brass cylinder.

During assembly of Oracle II we used this method to over compress the PZT transducer. Indeed, in the last step in assembling the tool we partially stretched the

[2] For example, U. S. Patent 5,128,902 by Spinnler puts forward the idea that a soft disk can be placed between the transducer and the mandril and that the thickness of this disk can be adjusted to let disturbances travel out of the ceramics without allowing damaging disturbances to travel in. We know of no way of doing that unless the disk yields before the ceramics do. Yielding of the disk, which is an issue of its strength and not its stiffness, would of course permanently deform the material and open a gap between the transducer and the mandril and thereby eliminate the ability of the transducer to broadcast messages. Often people confuse the stiffness of a material with its strength. Indeed neither is a soft material necessarily a weak material nor a stiff material a strong one.

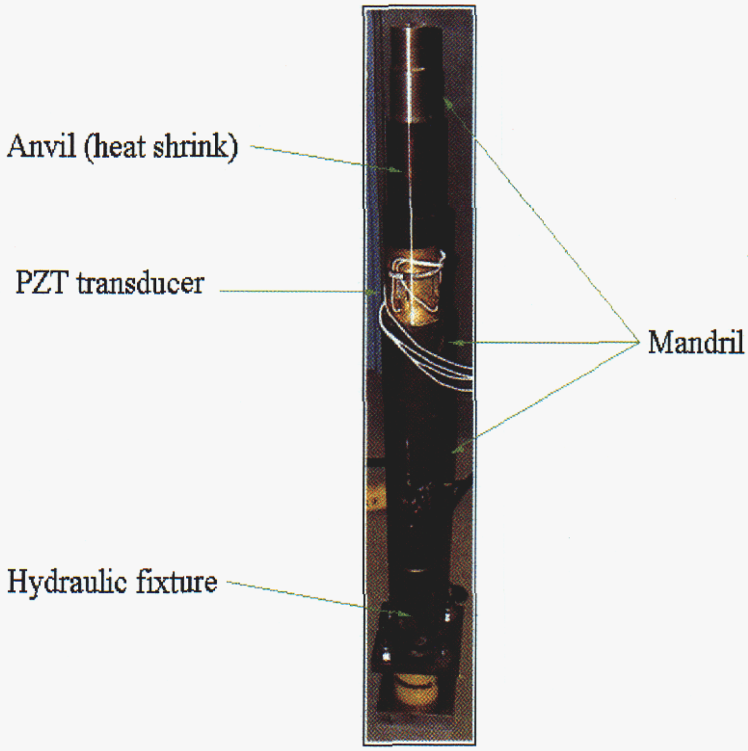

Figure 3.6: Test fixture for heat shrink assembly of the anvil to the mandril.

mandril with the outer pressure housing. This placed the outer housing into compression and increased the stiffness and loading carrying capability of the entire tool. The system is designed so that the final load on the PZT transducer is independent of the assembly torques. Indeed, the rig crew cannot twist or over compress the transducer as they screw Oracle II into the bottom-hole assembly

3.5.3 Hardening

The remaining components that required mounting on the mandril were the sensors, circuit boards, power-supply transformer and heat shield, and battery packs. We contracted Extreme Engineering of Calgary Canada to harden the mounting of these components. Vibration absorbing encapsulation of components and careful stress relieving of wired connections were employed throughout. During field trials these tools were repeatedly subjected to harsh drilling environments for extended periods.

There were no failures of any of these components including the PZT transducer.

3.6 Acquisition systems

The telemetry broadcast travels up either the drill string or the production string as a sequence of extensional bar waves in the steel tubing. It can be detected by attaching an accelerometer directly to the tubing. If the tubing is stationary a cable can be directly connected to power the accelerometer and collect the vibration data. The acquired signal can then be filtered, digitized, and stored on a computer disk. Alternatively, if the tubing is rotating the data can be filtered, digitized, and stored in a "flash" memory card that is housed in a portable unit small enough to attach directly to the rotating string. This unit, called the *Data Logger*, has an obvious disadvantage in that we can only access and decode the data by stopping rotation of the string and removing the flash memory card. In contrast the *Surface Receiver* employs an RF link to radio the data to a remote stationary computer. We can use any of these three methods to monitor the acoustic broadcast and convert it into a digital sequence that represents the raw analog signal containing our modulated information from Oracle II at the bottom of the well. We demodulate this signal to extract the message with a computer code called BABEL©. (See Sec. 4.2.1.) Let's now examine each of these three alternative acquisition systems in detail.

3.6.1 Hardwire connection

We monitor the acoustic broadcasts my strapping a Wilcoxon 728 piezoelectric accelerometer to the side of the tubing string. (See Fig. 3.7.) This is a high-quality, 10-G, instrumentation accelerometer with about 66 dB dynamic range. Its response is flat from 5 Hz to 3 kHz. Its resonant frequency is above 10 kHz. We attach a Model P702 power supply and signal conditioning unit to the accelerometer. The 44-dB dynamic range of this amplifier is smaller than the accelerometer, but it has three gain settings of 1, 10, and 100. The output of the amplifier is an analog signal representing the axial acceleration of the tubing string. This equipment serves for virtually all of the field applications in which the tubing string does not rotate; that is, at a gain of 1, the high-noise applications rarely saturate these instruments, and even the most quiet applications will generally not allow gain levels above 100. Indeed, at gain 100 it is sometimes possible to hear the airborne conversation of the rig crew when the digitized signals are played back through an audio system.

Before we digitize the analog signal we run it through a Precision Filters EL8 low-pass filter. This standard procedure avoids anti-aliasing the frequency components of the accelerometer signal. This filter blocks frequencies above 2 kHz by more than

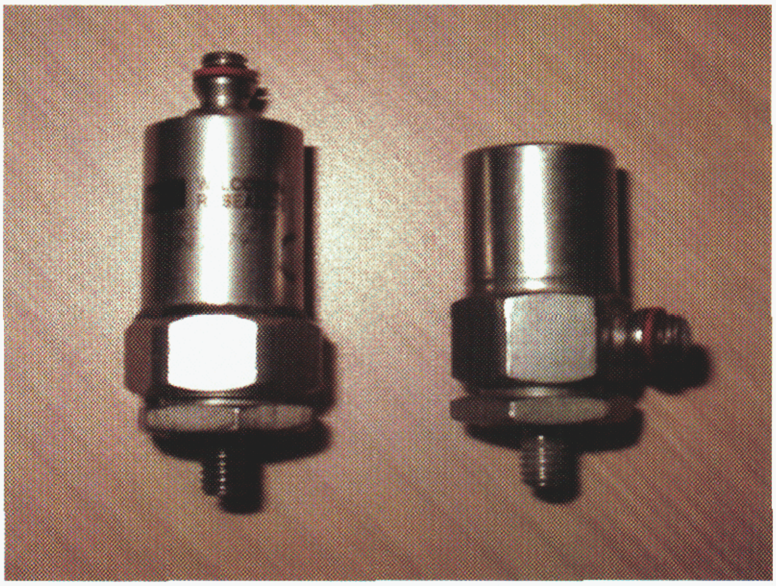

Figure 3.7: Two Wilcoxon accelerometers with top and side connections.

96 dB so that they will not be aliased by a 16-bit digitizer. The output of the filter is then fed into our digitizer and sampled at 8192 Hz. The output of the digitizer is parsed into a sequence of files, which are given names like a00000000.bin, a00000001.bin, etc. Each file, which typically contains 5 seconds of data, is then stored on a computer disk as an archive.

3.6.2 Data logger

If the tubing is rotating we cannot use a hardwire connection. One alternative is to use the Data Logger, which stores the digitized data on a flash memory card. (See Fig. 3.8.) The disadvantage here is that data can only be examined after stopping the rotating tubing string, removing the flash card, and downloading the data onto the PC. To eliminate this inconvenience the Surface Receiver was developed. However, prior to this point the Data Logger was developed and deployed to collect data from rotating strings for noise analysis.

We contracted Extreme Engineering of Calgary, Canada to implement the Data Logger concept. To expedite development time and reduce costs the design used commercially available parts wherever possible. The Data Logger is housed in two watertight protective cases that are fastened together with hose clamps. One case contains the Wilcoxon amplifier with battery and an accelerometer mounted on a piece of steel channel. The other case includes a commercially available data logger module, industry standard Compact Flash memory card, and a custom circuit board

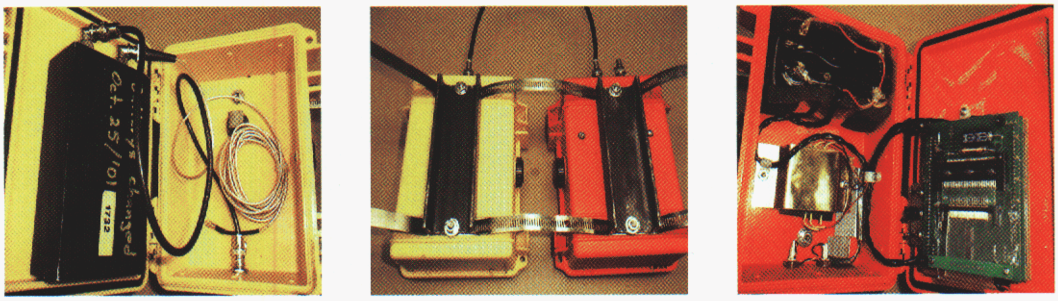

Figure 3.8: The Data Logger contains the Wilcoxon amplifier (left) and the flash memory system (right). The accelerometer is mounted externally directly in the tubing.

with an anti-aliasing filter and 16-bit analog-to-digital convertor. Also inside this case are the batteries that permit wireless Data Logger operation.

Once started, the Data Logger acquires 16-bit accelerometer data at 8192 Hz and stores the samples in the Compact Flash memory card until the memory is full. Continuous collection of data on a single channel for approximately three hours is possible when using a 192 Mbyte capacity Compact Flash memory card.

To access the data you must remove the Data Logger from the tubing string, open it, turn it off, and pull out the Compact Flash memory card. Then we use an adapter cable to connect the card to a PC and collect the Windows formatted data. Next we demodulate the acoustic broadcast data to extract the message information with a computer code called BABEL©. (See Sec. 4.2.1.)

3.6.3 Surface receiver

The surface receiver is the optimum method for extracting data off a rotating string in that it enables collection of *near* real-time data at remote locations far away from rig floor activity. (See Fig. 3.9.) We drafted the system requirements and contracted Extreme Engineering of Calgary, Canada to design and assemble two systems. The design has been successfully evaluated and field-tested. At present, Extreme Engineering offers the Surface Receiver as a commercial product.

The complete Surface Receiver system can be separated into the components that are attached to the rotating string on the rig floor, the *Rig System*, and those located at a remote location, the *Rig Monitor*. The Rig System provides signal conditioning and conversion as well as signal processing and transmission capability. Its location on the rig floor imposed design restrictions associated with intrinsic safety, temperature and moisture exposure, and limited battery power for RF communications. The Rig Monitor receives data from the Rig System and transfer it to files on the PC.

Figure 3.9: The surface receiver contains the accelerometer, low-pass filter, digitizer, and RF data link.

The Rig Monitor is usually located in a trailer, which afforded more design flexibility associated with an indoor-setting such as minimal safety concerns, stable temperature, and access to electrical outlets.

The mechanical packaging of the Rig System fulfilled several objectives. Among them are:

- Rigid attachment of the accelerometers.
- Shock and vibration proof containers.
- Class 1, Division 2 containment, including internal antenna.
- Easy attachment/detachment to differing pipe diameters.
- Minimal interference with rig floor activity.

Indeed, some of these goals such as the Class 1, Division 2 requirement mandated novel implementation of individual gas-tight sealed bays linked together through rugged conduit.

Rig System electrical components are housed in four bays that include the battery, antenna, processor, and accelerometer bays. These components filter the signal, digitize two channels of accelerometer data, and transmit the digital data via the RF link. Accelerometer data is sampled at 9009 Hz per channel, stored *temporarily*, and then broadcast over the RF link. You will notice that the unusual sample rate is an artifact of available system clock rates. We use an embedded PC running on a Linux based operating system for Rig System control. We use a second processor for gathering analog-to-digital conversions.

Rig System power is provided by analog and digital power supplies and associated battery packs. Battery pack capacity permits constant collection and transmission of data for approximately 24 hours. The RF communication link is based on the wireless local area network protocol IEEE 802.11. The link is established using a commercially available wireless card and a custom designed 2.4 GHz patch antenna. Even at transmission distances beyond 100 feet we have not experienced any RF communication problems such as multi-path interference caused by the rig structure.

The Rig Monitor hardware is all commercially available and consists of a Windows 2000 based laptop computer, RF modem PCMCIA-style PC card, and external antenna. Custom designed software stores the data received over the IEEE 802.11 link for analysis and for audio playback through the PC sound system. The software also monitors the Rig Systems hardware status and will alert the operator to out-of-limit conditions.

The Rig Monitor was not intended to perform data display nor decoding of the stored binary files. Here again, we use the demodulation capabilities of BABEL©to extract the message information. Indeed, with this configuration we can witness changes to downhole parameters such as pressure and temperature in *near* real-time from the comfort of a logging trailer. The delay between the downhole data measurement and when that data is viewed is comprised of the downhole and surface data processing times, the wave propagation delay of the drill string, and wireless data buffering and transmission delay. For that reason we refer to this data as *near* real-time.

Chapter 4

Software

We have developed two classes of computer codes—engineering codes and application codes. The engineering codes are the analysis tools we use to design and model the performance of the acoustic telemetry system. They model the generation, propagation, and detection of extensional bar waves in the tubing strings. We use the application codes to deploy the tool in the field. They control Oracle II and the surface data acquisition and demodulation system.

4.1 Engineering codes

There are two engineering codes. The first engineering code, DAWG©, is a FORTRAN analysis routine, which generates a solution to user-specified input. The output of DAWG© is a set of binary data files that are stored on the user disk. The second engineering code, PUNK 2000©, is a graphics routine, which reads and displays these stored data as well as other experimental data.

4.1.1 System analysis—DAWG©

The code DAWG© is based on the algorithm described in [12]. Additional descriptions of this algorithm may be found in the books [22] and [23]. Upon startup DAWG© requests the name of the file containing the geometry of a tubular string with telemetry transmitters and receivers. (See Fig. 4.1.) You can also specify a variety of electrical filters in the transmitter and receiver circuits. The algorithm in DAWG© then computes an analytical time-domain solution to this input.

This code models piezoelectric ceramics as well as strain gages, accelerometers, and other motion sensors. It was used to design Oracle II. We also use it to optimize the bottom-hole assembly and maximize the broadcast signal strength. DAWG©

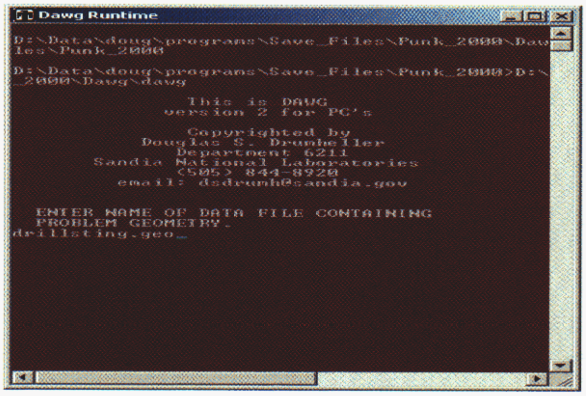

Figure 4.1: DAWG© is the system analysis code.

can also read experimental voltage records and use them as source signals to drive the PZT transducer. Alternatively, DAWG© has its own internal signal generator to create impulse spikes, harmonic wave packets, step waves, as well as other wave forms.

Moreover it is possible to model very complex systems such as phased transducer arrays and the circuits that drive them. Indeed we can also generate a wave with a PZT transmitter array that will propagate past an accelerometer array and then feed the output of the accelerometer array back to the PZT transmitter array that produced the wave in the first place. Such feedback often causes instabilities in the solution, which are not artifacts of the calculation but rather represent a true physical system instability. The system can be stabilized with proper processing of the feedback signal. DAWG© accepts input representing digital signal processing filters to stabilize the system. We have successfully designed stable feedback systems with DAWG© and verified the results with experiment.

4.1.2 Graphics display—PUNK 2000©

PUNK 2000© displays the output generated by DAWG©. (See Fig. 4.2.) You can compare different sets of calculations either to each other or to experimental data. PUNK 2000© also has a *movie* capability where you can watch the profile of the material motion as the wave propagates through the problem geometry. You can also execute and display Fourier transforms of the gage history records. For example, if the PZT transmitter at the bottom of a drill string is driven by an impulse, the Fourier transform of the record from an accelerometer at the top of the drill string will reveal the passband-stopband structure of the drill string. This works because an impulse contains equal amounts of all frequencies. The unequal frequency levels in

Figure 4.2: PUNK 2000© is the graphics postprocessor for the system analysis code, DAWG©.

these results are due to the selective frequency response of the PZT transmitter, the geometry of the bottom-hole assembly, the drill string itself, and the accelerometer. Indeed this is the analytical counterpart of the Texas-cow-pasture experiment we describe in Sec. 2.3.

4.2 Applications codes

There are three application codes. BABEL© is the real-time user interface that displays the raw acoustic broadcast. It demodulates the broadcast message, reports message errors, and displays history plots of the sensor readings. The embedded tool application code resides in the memory of Oracle II. The tool setup application provides the user interface to configure the embedded tool application code.

4.2.1 Demodulation—BABEL©

When Oracle II is deployed in a well, BABEL© provides the interface between the user and the incoming acoustic data files from either the surface receiver, the data logger, or the hardwired connection to the accelerometer. (See Fig. 4.4.) After startup BABEL© watches the PC user disk. As acoustic data files appear on the disk BABEL© reads and displays them. (See Fig. 4.5.) The sequence of frequency chirps

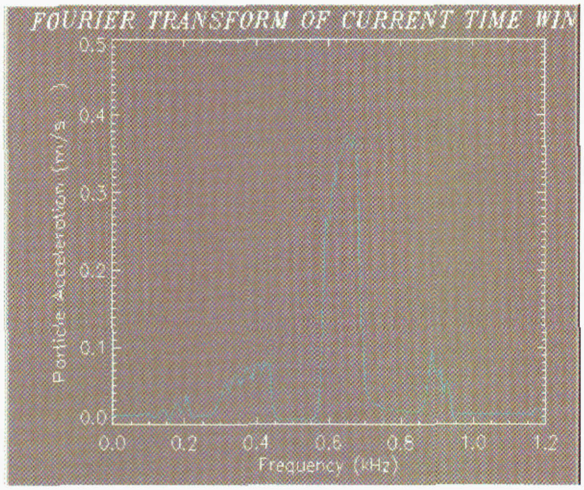

Figure 4.3: The Fourier transform of an impulse wave after it has propagated up a drill string.

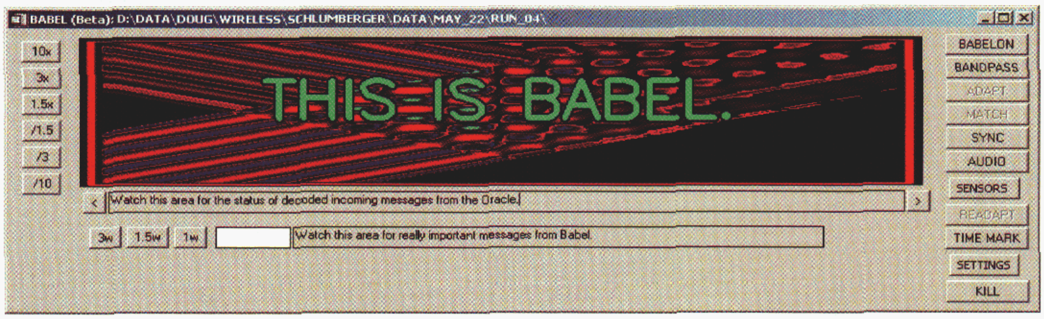

Figure 4.4: BABEL© demodulates the acoustic broadcast and displays the down-hole data.

represents the ones and zeros of the binary encoded message. BABEL© contains sets of digital filters that the user can select to improve the signal-to-noise ratio. The filtered message is automatically demodulated, and the histories for each of the active down-hole sensors are displayed on the screen. They are also written to individual ASCII files that are automatically updated as each new data point is obtained. These ASCII data files are easily accessed by other display software.

4.2.2 Tool application—Embedded

The embedded tool application code resides in the E^{2}PROM memory of Oracle II and provides system functionality in conjunction with the micro-controller. We've partitioned system tasks into six *objects* and numerous supporting modules [20]. Each

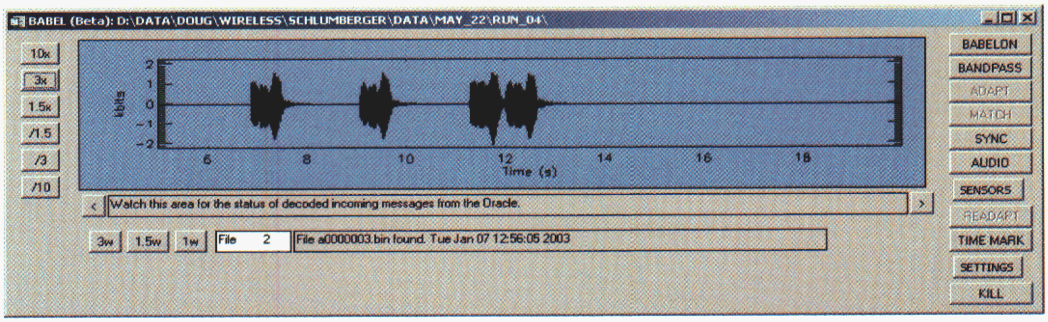

Figure 4.5: Raw acoustic data flowing into BABEL©.

object has a state machine framework and synchronizes its operation with the other objects by means of event handling. Supporting modules, which are not based on a state machine model, send events to these objects. The events themselves carry no information but rather are only indicators that some action has occurred. The Object Communication Model shows the communication paths for the six objects in our system. (See Fig. 4.6.) The objects are represented by ovals, supporting modulus are represented by boxes, data flow paths are represented by solid lines, and event paths are represented by dotted lines.

Even though we've implemented the Oracle II system in the language C and not C++, we use the object paradigm throughout our code. Objects realized from a global template yield highly regular system architecture. Supporting modules are classes implemented in C to provide constructors for their instances, class variables, and methods for operating on instances. A main loop distributes cooperative multitasking control between the objects. A maximum of 10 ms of processing time is issued to any one object before another object can take over to prevent one object from dominating the processing time and to generate predictable time behavior. An interrupt structure has been implemented to assign priority to those functions that are time critical such as the chirp generation. Virtual timers help with system timing chores by creating events to synchronize objects. The Oracle II system does not have a real time clock.

4.2.3 Tool setup—LabVIEW™

Operation of the Oracle II software system is based on configuration commands and data storage instructions. The LabVIEW™ based Tool Setup program provides the user interface to the Oracle II hardware system. (See Fig. 4.7.) The embedded tool application program and the LabVIEW™ tool setup program enable you to select desired features. These programs adhere to a common communication format. Refer to [21] for message protocol syntax, Oracle II command semantics, individual control

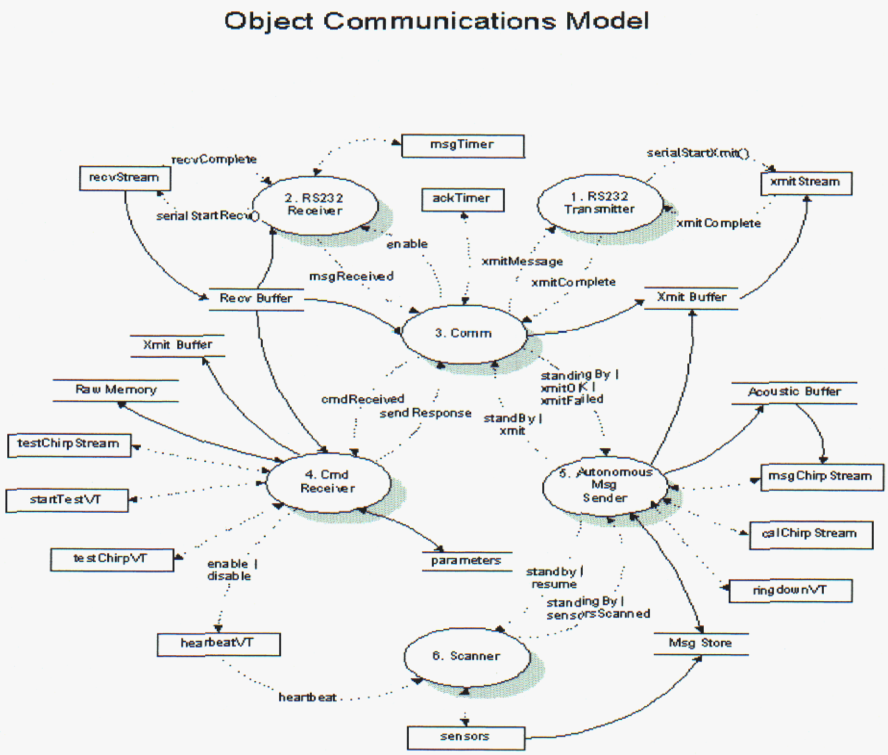

Figure 4.6: Embedded code Object Communications Model.

parameters, and State-Of-Health (SOH) field formats. The embedded tool application code must first be installed and running before Oracle II can be configured with the preferred operating behavior. You can then select a set of configuration parameters from the LabVIEW™ tool setup program, verify that the application program is running, connect the computer to Oracle II via the RS-232 interface, download the configuration into the tool, and disconnect the RS-232 interface. The Oracle II system is then ready for deployment.

When you attach accelerometers directly to a stationary drill string, you can use the LabVIEW™ tool to acquire the analog acoustic signal and generate the binary files required by BABEL©. Moreover you can run BABEL© concurrently to display and demodulate the acoustic signal and then place the interpreted sensor data into ASCII files.

The LabVIEW™ tool also has post test capability to upload, display, and archive test data through the RS-232 interface. You can then view graphical displays of the test data including Fourier transforms of accelerometer measurements. Just as with BABEL© you can also write this information into ASCII files that are readily accessed

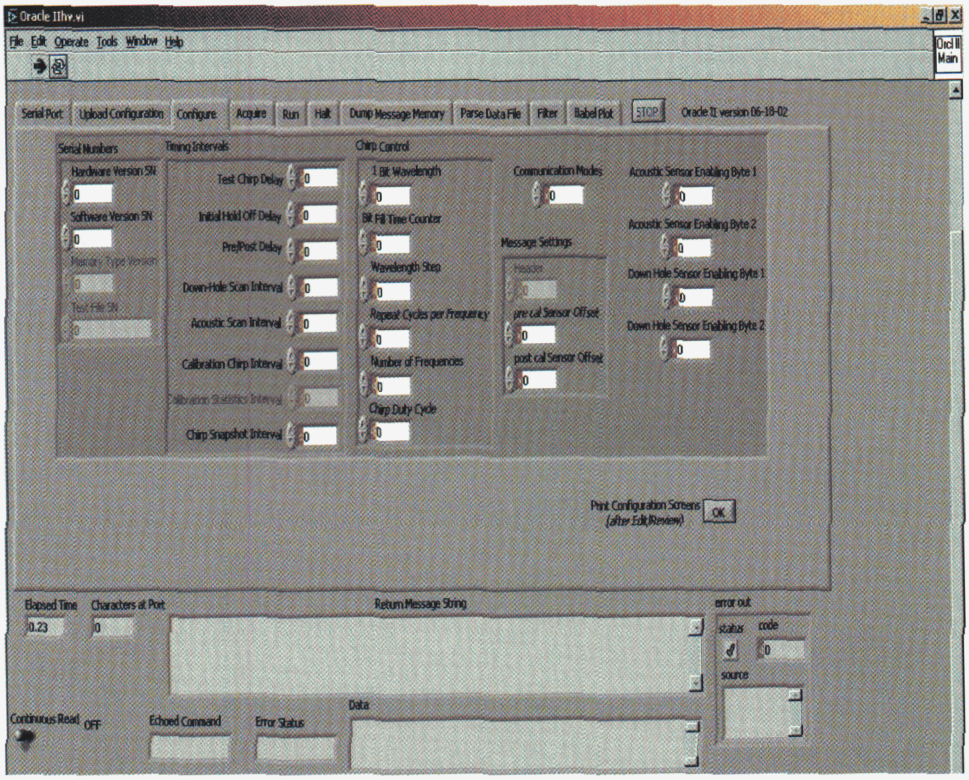

Figure 4.7: LabVIEW™ implemented Oracle II Tool Setup Program front panel.

by many commercial spreadsheet and graphics software packages. The LabVIEW™ tool can even view the ASCII files written by BABEL©.

Chapter 5

Testing and Results

Our extensive testing program can be divided into two categories–component integration, which includes full-scale tests using a 1400-ft drill string deployed horizontally across a work site at Sandia National Laboratories, and field testing, which includes remote operations at both drilling and production sites. Many tests were completed with the assistance of our licensees. To protect proprietary interests, we do not report detailed results here.

5.1 System integration and surface testing

Managing electrical power and converting it into acoustic broadcast power was our foremost concern during the final integration of the system components. We have achieved 20% efficiency in the conversion of battery power into acoustic energy radiated from Oracle II into the drill string. This required the careful laboratory adjustment of the electrical impedance of the power amplifier to the impedance of the PZT transmitter. Moreover measurement of this efficiency also required the use of the 1400-ft surface drill string.

5.1.1 Laboratory

We performed a comprehensive functionality test of every subsystem prior to final integration. Our checkout consisted of experiments to verify the design. Results were recorded manually. Due to the small number of subsystems, we did not develop automatic testing capabilities. Also, we did not subject the electrical subsystems to environmental testing; however as part of our system-hardening contract with Extreme Engineering, we had the vibration, structural, and pressure capabilities of the subsystems analyzed.

We placed major emphasis on validating system software, verifying data acquisition channels, and characterizing system power in a controlled laboratory setting. We used system circuit boards setup on a bench top to integrate communications between the Embedded Tool application code and the LabVIEW™ Tool setup code. We injected known test patterns to authenticate the data acquired by the system. Manufacturer's sensor specifications were used to generate sensor transfer functions to convert the recorded data in to physical units. Most of our time was spent testing and adjusting the system power management. We recorded both voltage and current profiles for the low and high voltage power supplies during both system idle and active states. As previously stated, the proper timing of current flow from the battery pack and capacitor bank to the transformer primary coil is critical for the efficient conversion of electrical power in to acoustical power.

You will also recall that careful laboratory matching of the electrical impedance transformer secondary coil to the load impedance of the PZT transducer is necessary to the overall system efficiency. We accomplished this by adjusting the transformer gap using an impedance analyzer to facilitate this process.

5.1.2 Full-scale tests at Orpheus

The Orpheus Site contains 1400-ft strings of 5-in drill pipe and $2\frac{7}{8}$-EUE production tubing. (See Fig. 5.1.) Typically we mount a transmitter at one end and clamp accelerometers at intermediate locations along the entire length of the string. Waves broadcast by the transmitter attenuate about 6 dB as they travel the entire length of the drill-pipe string. They reflect off the far end and return as echoes after losing another 6 dB. Accelerometer measurements of these waves provide us with an accurate indication of the total wave energy radiated by the transmitter. We compare this to the power drawn from the battery pack to evaluate the efficiency of the transmitter system. Orpheus has also been used to test a variety of tuning devices that enhance the output of the transmitter and that also eliminate reflections at transition points between drill collars, drill pipes, and kellys. (See Section 6.)

At Orpheus we can also test the entire communication system from the acquisition of data by Oracle II to the demodulation and display of the sensor histories on the PC with BABEL©. Using other transmitters we can playback recorded drilling noise and inject it into the string to mask the telemetry signal. This provides us an opportunity to test and optimize new signal processing algorithms and modulation techniques.

5.1.3 Mobile laboratory

Our mobile laboratory contains a sophisticated data acquisition system. (See Fig. 5.2.) When it is not in the field we use the mobile laboratory for system development and

Figure 5.1: The Orpheus test site. On the left an accelerometer is mounted on a block that is temporarily strapped to the drill string. On the right the transmitter is mounted on the end of the 1400-ft long string. In this image a string of production tube also appears to the right of the drill pipe.

integration studies at Orpheus. This has allowed us to accelerate our field testing program by minimizing the differences between the *home* and *field* environments. Although fielding Oracle II requires only a PC and the back of a pickup truck, testing over several days or weeks often requires routine servicing of the tools, which can be accomplished effectively in the field with this facility.

5.2 Field testing

Our tools are not delicate laboratory apparatus, but rather robust field-tested equipment. In September 2001 they were placed into service starting at the PITS facility in Alberta Canada. During the next year they saw approximately 24 days of field service in harsh drilling and production environments. What follows is a brief summary of the field tests with a general description of the results. At this time analysis

Figure 5.2: The Mobile Laboratory.

of much of these data is still incomplete.

5.2.1 PITS

The Petroleum Industry Training Service (PITS) operates the Nisku Training Center at Nisku, Alberta Canada. We deployed both Oracle II tools in their 1-km well over a two-day period. (See Fig. 5.3.) The following list of bottom-hole assemblies were

Figure 5.3: The PITS Site.

used in these tests:

1. Transmitter mounted directly to drill string.
2. Transmitter mounted below a shock sub.

3. Transmitter mounted below a mudmotor and jars.

No drill bit was used, instead a short bullnose was placed below the transmitter. Four drill collars, with approximately a 5.5-in outside diameter, were placed above the tool. Nominal 16.6 lb/ft drill pipe was used above the collars. The well was filled with water, and tests were run with and without rotation of the drill string.

Measured signal attenuation levels were low, about 3.5 dB/1000 ft, but noise levels caused by rotation of the drill string were the highest of all of our field tests. Rotation off bottom at 60 RPM produced noise levels within the acoustic transmission band that were comparable to acoustic broadcast levels. This well was completely cased, and the combination of being water filled and cased might have contributed to these high levels. Also the rig, which had been donated to the training center was old and exhibited high vibration levels. We estimated the effect of the shock sub, jars, and mudmotor, rented from Weatherford, on the broadcast signal by comparing the measured levels using configurations #2 and #3 against the measurements using bottom-hole configuration #1. Only minor changes were noted. Moreover, rotation of the tool with the mudmotor had little effect on the noise levels.

5.2.2 EOG

The next field test was at an Entec Oil and Gas (EOG) project in eastern Alberta. (See Fig. 5.4.) Oracle II was deployed directly above a PDC drill bit. Seven sections of

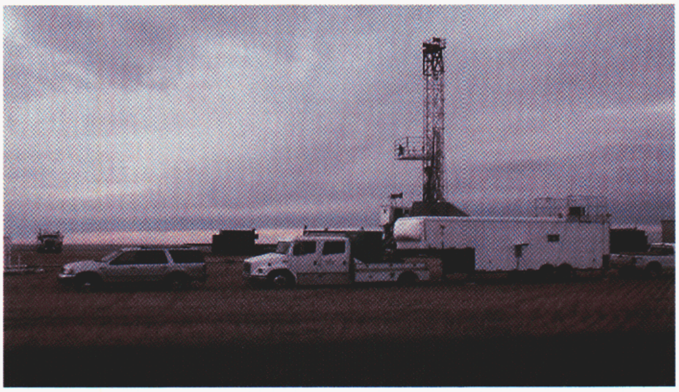

Figure 5.4: The EOG Site.

heavy weight drill pipe were deployed above the tool. This was followed by $3\frac{1}{2}$-in drill pipe. This string was rotated from the surface at 180 RPM and used to drill a 764-m gas well. The surface receiver was not available for this test, and space constraints limited our use of the data logger. However, we did obtain some data during rotation, and at midpoint and target depth operations were halted for several minutes to allow us to acquire data with a hardwired connection. Broadcast signals were detectable under all observation conditions. Signal attenuation was approximately 8 to 10 dB per thousand feet. Noise levels were lower than those measured while rotating off bottom at the PITS facility. Because this was the first deployment of Oracle II under drilling conditions[1] we performed a complete inspection of the recovered tool. This included a detailed impedance measurement of the ceramic transducer. No damage was evident at that time and none has become evident since.

5.2.3 Rivercrossing tests

Extreme Engineering of Calgary, Canada holds a license to our acoustic telemetry technology. They have deployed one of our telemetry tools in three different drilling projects. Each was a rivercrossing application where relatively large diameter horizontal boreholes are drilled under rivers and lakes for utility line emplacements. (See Figs. 5.5 and 5.6.) Oracle II's capability to measure bore-hole pressure at the bit is particularly important to prevent breaching of drilling fluids to lake and stream beds with subsequent damage to spawning sites for native fish. In these projects the drill bit returned to the surface on the opposite side of the lake or river. This allowed for careful and simultaneous measurement of broadcast levels both at the transmitter as well as back at the drill rig. It also allowed measurements of the influence on signal strength due to different modifications of the bottom-hole assembly. These tests demonstrated the strong commercial potential for this technology to rivercrossing applications.

5.2.4 Drillstem tests

Baker Oil Tools also holds a commercial license to this technology. The drill stem test is one of their potential commercial applications. A drill stem test is often performed between the drilling and completion phases of the well. Typically the drill string is used to deploy the drill-stem test equipment with a set of packers. Oracle II was deployed between the packer assembly in a well in the Tri-City area in Alberta. (See Fig. 5.7.) The broadcast successfully traveled back to the surface through both the

[1]We believe this to be the first deployment of any acoustic telemetry system under drilling conditions.

Figure 5.5: The Grand Prairie Site.

packers and the drill-stem test tool. Baker also conducted followup tests at the Baker Beta Site near Tulsa Oklahoma. The influence of mud conditions, in particular the extent of gelling, on signal strength were studied.

5.2.5 Oil production

During May 2002 we executed a series of tests at the Rocky Mountain Oilfield Test Center in Wyoming. Oracle II was deployed on two types of production tubing: 9.3 lb/ft EUE and 12.9 lb/ft PH6. Both vertical and deviated wells were used. Because very light collars are used to join the sections of production tubing together, production tubing exhibits high frequency pass bands. From previous experience we knew that these pass bands have lower attenuation than the 625 Hz broadcast band used in drill pipe. Fortunately our tools periodically broadcast a calibration tone burst that scatters energy into these higher-frequency side bands. We made use of this fact to examine the attenuation in production tubing at these higher frequencies. (See Fig. 5.8.) Indeed, we were able to monitor data transmission in these bands to provide real-time temperature and pressure readings from the bottom of the wells,

Figure 5.6: The Vulcan Crossing.

which ranged up to 5000 ft in depth.

As an example of the success of the decoding process in these tests, consider the on-board temperature log recorded by Oracle II during a trip into a vertical well. The tool was run to 4500 ft on PH6 tubing. Then it was pulled back to 3000 ft and gel was injected into the well. The log is shown in Figure 5.9 where the solid line is the on-board data recovered after the test. The individual diamonds are the data broadcast in real time by Oracle II. While the telemetry messages were broadcast continuously throughout the test, we were only capable of acquiring them while the tubing was stationary using a hard-wired connection to the accelerometer.

You will note that during the first 6 hours as we ran the tool into the well the temperature increased. On the trip into the well 9 stops were made to allow us to attach the accelerometer and acquire the telemetry broadcast. The plateau at 3 hours into the test corresponds to the noon hour of that day. At 6 hours into the test the tool was pulled back to 3000 ft and the gel equipment was rigged. Starting at 8 hours gel was injected into the well, and the accelerometer was connected nearly continuously for two hours. The Oracle II broadcasts provide nearly uninterrupted real-time data

Figure 5.7: Clockwise from top left: The Tri-City drill-stem test site, real-time data acquisition in a warm trailer, and starting and stopping the tool in freezing central Alberta.

acquisition during this period. The two exceptions occurred at 8.65 hours when the accelerometer amplifier batteries where replaced and at 9.25 hours where the accelerometer was briefly removed. During this period 150 telemetry messages were received, and 13, usually transmitted during pumping operations, were rejected by BABEL©due either to parity or to message number errors. The remaining data shown on the plot represent "accepted" telemetry signals collected both in quiet and noisy pumping stages of this test.

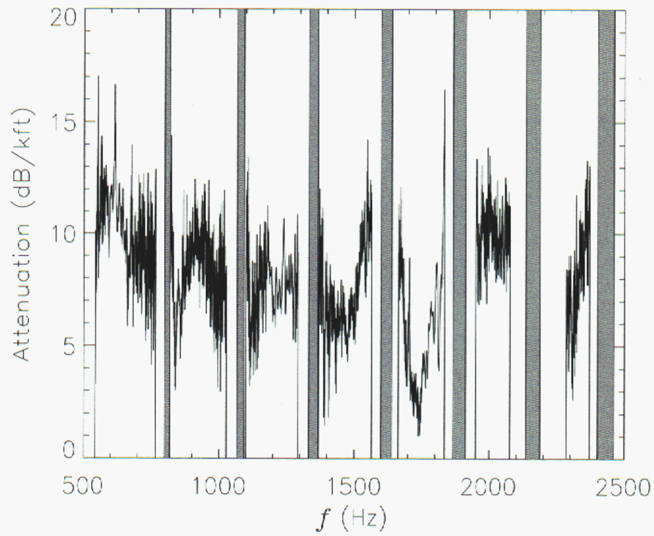

Figure 5.8: Signal attenuation in PH6 tubing hanging in elevators. The calculated stop bands are based upon an estimate of 31.5-ft for the shoulder-to-shoulder tubing length.

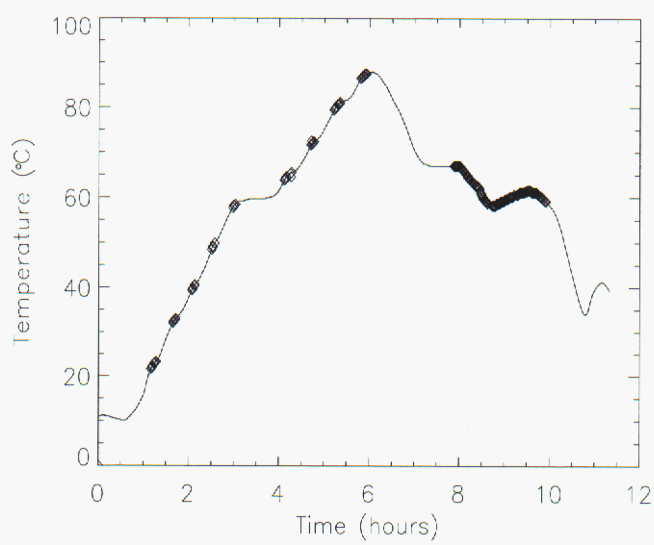

Figure 5.9: The solid line is the on-board data, and the diamonds are the data decoded from the acoustic broadcast.

Chapter 6

New Devices

We have formed two conclusions from the field test results reported in Sec. 5.2. First the combination of attenuation and noise levels limits the useful range of the current telemetry system. That range is about 8,000 to 10,000 ft in production tubing applications, and 3000 to 4000 ft in horizontal rivercrossing applications. The other applications fall between these range limits. We conclude that a *repeater* must be developed to extend the telemetry ranges. Our other conclusion is not so apparent from the discussion. However, our experience shows that we cannot control the geometry of the bottom-hole assembly. Indeed, the driller often makes sudden alterations of this assembly to accommodate changes in drilling conditions. These changes can adversely affect the broadcast signal by detuning the system. Our solution here is to develop a *passive reflector*. The following is a brief discussion of these devices.

6.1 Passive reflector

This device is basically a mirror to acoustic waves. It is built from a combination of different weight tubes joined end to end. The total assembly is approximately 15-ft long. Because it acts as a mirror the transmitter does not *see* and is therefore not influenced by the rest of the bottom-hole assembly below the reflector. We used DAWG©to design the reflector, but we have not built or deployed it. We plan to do so in the near future and will report the results at that time.

6.2 Repeater

Typically people in the drilling industry view the word *repeater* with suspicion. More hardware suggests more complexity and far less reliability. In addition repeaters usually mean more obstructions in the hollow center of the drill string at intermediate depths. In fact, with acoustic telemetry systems use of repeaters afford us the opportunity to greatly reduce the total power consumption of the telemetry system. Indeed, this actually simplifies the total system. Moreover with reduced power consumption it is not necessary to place generators or battery packs into the central hole of the drill string.

Conceptually the repeater is simple. Just use a smaller Oracle II and modify it to receive incoming messages and rebroadcast them up the drill string. Unfortunately it is possible to build a very bad repeater with high error rates and a limited broadcast range. There are two issues here. First we must develop robust autonomous software that reliably demodulates, interpretes, and rebroadcasts messages. Then we must design the repeater to detect very weak incoming signals and rebroadcast very strong outgoing signals. Here we again face the issue of impedance matching our device to the drill string. (See Sec. 2.2.) Without appropriate attention to this detail we can easily cut the effective range of the repeater in half. Detailed discussion of this topic can be found in [17] as well as the patent application [7].

Chapter 7

Licensing

Sandia follows standard business procedures when licensing technology for commercial use. Licenses have already been granted for acoustic telemetry. With one minor exception these licenses are nonexclusive. The intellectual property available for license are the patents discussed in Sec. 1.5.1 and the copyright software discussed in Sec. 4. Of course the two fully-functional Oracle II tools are also available for testing and evaluation of new commercial applications.

Chapter 8

Awards

Extreme Engineering introduced the Extreme Acoustic Telemetry system into the marketplace during 2003. That year Extreme Engineering and Sandia National Laboratories submitted a joint entry for Acoustic Telemetry Technology to the prestigious *R&D 100 Awards* competition. (See Fig. 8.1.) On July 1, 2003, we received the following letter from R&D Magazine:

> **Congratulations!** The XAT (Extreme Acoustic Telemetry) that you submitted in the 2003 R&D 100 Awards program has been selected by the independent judging panel and editors of *R&D Magazine* as one of the 100 *most technologically significant* products introduced into the marketplace over the past year...

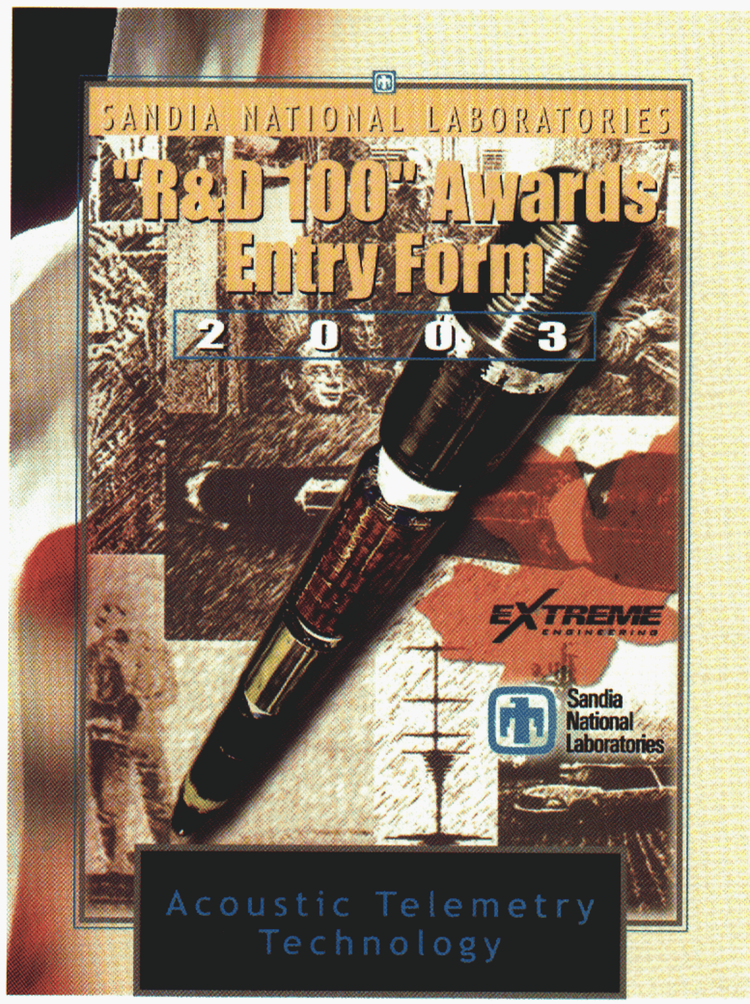

Figure 8.1: The cover of our successful R&D 100 entry form.

Chapter 9

Acknowledgments

Many people helped us. Specifically we wish to thank Luis Mendez and Ed O'Malley of Baker Oil Tools. They helped field the tools for the drill stem tests. Thanks are given to Derek Logan, Paul Camwell, Tony Doph, and Wendel Siemens of Extreme Engineering. They did an exceptional jobs of hardening Oracle II and building the surface receiver. They also assisted at PITS, and EOG. They promoted and ran the rivercrossing tests, and they continue to collaborate in the development of the passive reflector. Derek Logan also closely collaborated in the preparation of the R&D 100 Award entry form. Both Rick Hill and Jim Grossman provided us with programming assistance. Rick did the embedded coding, and Jim did the LabVIEW™ applications. Michael Selph and George Staller assisted with the mechanical design fabrication of Oracle II. T. J. Cook helped with the cover for the R&D 100 Entry Form. Steve Knudsen of Sandia National Laboratories has assisted us for more than a decade. He built the mobile laboratory, helped assemble and test Oracle II, and froze his fingers in Canada. (See Fig. 5.7.)

On the non-technical side, Kevin McMahon served well beyond the call of duty on licensing issues. Finally, as this project began both Jim Dunn, past Manager of the Geothermal Research Division at Sandia National Laboratories and Ted Mock, past Director of the Geothermal Technology Division of the United States Department of Energy, gave us unfailing support and encouragement.

Bibliography

[1] W. H. Cox and P. E. Chaney. Telemetry system. U. S. Patent No. 4,293,936, 1981.

[2] D. S. Drumheller. Acoustical telemetry in a drill string using inverse distortion and echo suppression. U. S. Patent No. 5,128,901, 1991.

[3] D. S. Drumheller. Electromechanical transducer for acoustic telemetry system. U. S. Patent No. 5,222,049, 1991.

[4] D. S. Drumheller. Acoustic transducer. U. S. Patent No. 5,703,836, 1997.

[5] D. S. Drumheller. Acoustic transducer. U. S. Patent No. 6,147,932, 2000.

[6] D. S. Drumheller. Extension method of drillstring component assembly. U. S. Patent No. 6,188,647 B1, 2001.

[7] D. S. Drumheller. Reducing injection loss in drill strings. U. S. Patent application, 2003.

[8] D. S. Drumheller. Analog circuit for controlling acoustic transducer arrays. U. S. Patent No. 5,056,067, 1991.

[9] D. S. Drumheller. Downhole pipe selection for acoustic telemetry. U. S. Patent No. 5,477,505, 1995.

[10] D. S. Drumheller and D. D. Scott. Digital circuit for echo and noise suppression in a drill string. U. S. Patent No. 5,274,606, 1991.

[11] D. S. Drumheller. Acoustical properties of drill strings. *J. Acoustical Society of America*, 85:1048–1064, 1989.

[12] D. S. Drumheller. Extensional stress waves in one-dimensional elastic waveguides. *J. Acoustical Society of America*, 92:3389–3402, 1992.

[13] D. S. Drumheller. Time-domain computations of one-dimensional elastic waves in liquids, solids, and ferroelectric ceramics. *Wave Motion*, 17:63–88, 1993.

[14] D. S. Drumheller. Coupled extensional and bending motion in elastic waveguides. *Wave Motion*, 17:319–327, 1993.

[15] D. S. Drumheller. Attenuation of sound waves in drill strings. *J. Acoustical Society of America*, 94:2387–2396, 1993.

[16] D. S. Drumheller and S. D. Knudsen. The propagation of sound waves in drill strings. *J. Acoustical Society of America*, 97:2116–2125, 1995.

[17] D. S. Drumheller. Wave impedances of drill strings and other periodic media. *J. Acoustical Society of America*, 112:2527–2539, 2002.

[18] D. S. Drumheller S. D. Knudsen and L. E. Mendez. Wireless telemetry for well production applications. Internal Report.

[19] D. S. Drumheller. *The Acoustic Telemetry Experiments at the Rocky Mountain Oilfield Testing Center.* Sandia National Laboratories, Albuquerque, New Mexico 87185, October 2002. SAND2002-3189.

[20] F. Hill, S. S. Kuszmaul, D. S. Drumheller, and S. D. Knudsen. *Software System Specification for Low Temperature Tool Down-hole Electronics.* Sandia National Laboratories, Albuquerque, New Mexico 87185, August 2000.

[21] S. S. Kuszmaul, F. Hill, D. S. Drumheller, and S. D. Knudsen. *Communication Specification for Low Temperature Tool Down-hole Electronics.* Sandia National Laboratories, Albuquerque, New Mexico 87185, November 2001.

[22] D. S. Drumheller. *Introduction to Wave Propagation in Nonlinear Fluids and Solids.* Cambridge University Press, Cambridge, 1998.

[23] A. Bedford and D. S. Drumheller. *Introduction to Elastic Wave Propagation.* Wiley, New York, 1994.

Distribution:

Pierre Bessiere
Vice President - Special Projects
Scientific Drilling
1100 Rankin Road
Houston, TX 77073

Ken Bertagnolli, Ph.D., P.E.
U S Synthetic Corporation
1260 South 1600 West
Orem, UT 84058

Marcel Boucher
ReedHycalog
6501 Navigation
Houston, Texas 77011

Bill Calhoun
ChevronTexaco Drilling Technology Center
2202 Oil Center Court
Houston TX 77073

Louis E. Capuano, Jr.
ThermaSource, Inc.
PO Box 1236
Santa Rosa, CA 95402

Tom Champness
Drill-Cool Systems
627 Williams Street
Bakersfield, CA 93305

Curtis Cheatham
c/o Precision Drilling
363 N. Sam Houston Pkwy. E. Suite 1700
Houston, TX 77060

David Chen
Halliburton Sperry-Sun
Building C
P. O. Box 60070
Houston, TX 77205-0070

Robert I. Clayton
Security DBS
15815 Waverly Road
Houston, TX 77032

John H. Cohen
Maurer Technology Inc.
13135 South Dairy Ashford Rd.
Suite 800
Sugar Land, TX 77478

Ted Clutter
Executive Director
Geothermal Resources Council
PO Box 1350
Davis, CA 95617

Craig H. Cooley, P.E.
Manager, Test and Evaluation
U S Synthetic Corporation
1260 South 1600 West
Orem, UT 84058

Gary J. Collins
Staff Engineer
Drilling Technology
ConocoPhillips
P.O. Box 2197
Houston, TX. 77250-2197

Jim Combs
Geo-Hills Associates
2395 Catamaran Drive
Reno, NV 89509-5731

Dr. George Cooper
UC-Berkeley
595 Evans Hall
Berkeley, CA 94720

Hal B. Curlett, COB/CEO
Deep Heat Energy Corporation
3101-A Big Horn Ave.
Cody, WY 82414

J. David Dowell
ChevronTexaco Exploration
& Production Technology Co.
Floating Drilling
2811 Hayes Road, Room 4121
Houston, TX 77082

Mike Elsayed
University of Southwestern Louisiana
PO Box 44170
Lafayette, LA 70504-4170

Stephen Ernst
Smith Bits - GeoDiamond
16740 Hardy Street
Houston, TX 77205-0068

Prof. Zak Fang, Ph.D.
Department of Metallurgical Engineering
University of Utah
135 South 1460 East, Room 412
Salt Lake City, UT 84112

Coy M. Fielder
Vice President of Technology
Diamond Products International
15955 West Hardy, Suite 300
Houston, TX 77060

Phil Frink
Blade Energy Partners
1415 Halsey Way, Suite 300
Carrollton, TX 75007

Marvin Gearhart
RBI-Gearhart
7601 Will Rogers Blvd.
Fort Worth, TX 76140-6023

Dave Glowka
ENP Capital Resources, Inc.
811 Sussex Drive
Austin, TX 78745

Geir Hareland, Ph.D.
Harcon, Inc.
803 Caine St.
Socorro, NM 87801

Craig Ivie
ReedHycalog
6501 Navigation
Houston, Texas 77011

Allan Jelacic, Physical Scientist
EE-2C/Forrestal Building
U.S. Department of Energy
1000 Independence Ave. SW
Washington, DC 20585

Dennis Kaspereit
Calenergy Operating Company
950 W. Lindsey Road
Calipatria, CA 92233

Buddy King
Noble Engineering
13135 South Dairy Ashford, Suite 800
Sugar Land TX, 77478

Raymond J. LaSala, General Engineer
EE-2C/Forrestal Building
U.S. Department of Energy
1000 Independence Ave. SW
Washington, DC 20585

Roy Ledgerwood, III
Hughes Christensen
9110 Grogan's Mill Road
The Woodlands, TX 77380-3615

Bill Livesay
Livesay Consultants
126 Countrywood Lane
Encinitas, CA 92024-3109

James W. Lovekin
GeoThermex, Inc.
5221 Central Ave., Suite 201
Richmond, CA 94804 USA

Julian Luckett
Geothermal Energy Team
Shell Int'l Exploration
& Production, STV-GE
PO Box 60
2280AB Rijswijk
The Netherlands

Oliver Matthews
Security DBS
15815 Waverly Road
Houston, TX 77032

William C. Maurer, PhD
President
Maurer Technology Inc.
13135 South Dairy Ashford Rd.
Suite 800
Sugar Land, TX 77478

Graham Mensa-Wilmot
Director
Smith Bits - GeoDiamond
16740 Hardy Street
Houston, TX 77032

Nic Nickels
Baker-Hughes INTEQ
2050 West Steele Lane, Suite C-1
Santa Rosa, CA 95403

Dennis L. Nielson
DOSECC, Inc.
423 Wakara Way, Suite 300
Salt Lake City, UT 84108

Paul O. Padgett, P.E.
Vice President of Operations
ProDril Services Incorporated
3101 Big Horn Avenue
Cody, WY 82414-9250

Marshall Pardey
QD Tech, Inc.
4558 South Kayland Circle
Salt Lake City, UT 84117

Michael L. Payne, P.E., Ph.D.
c/o BP
501 Westlake Park Blvd
Houston, Texas 77079

Carlos R. Pereira
ReedHycalog
7211 North Gessner
Houston, TX 77040

Mitchell Pinckard
Noble Engineering & Development Ltd.
13135 South Dairy Ashford, Suite 800
Sugar Land, TX 77478

Gene Pollard
Ocean Drilling Program
1000 Discovery Drive
College Station TX 77840

Wyatt A. Pritchard
Security DBS
15815 Waverly Road
Houston, TX 77032

Jack Pruitt
Security DBS
15815 Waverly Road
Houston, TX 77032

Robert P. Radtke, President
Technology International, Inc.
2103 River Falls Drive
Kingwood, TX 77339-3154

Scott Randolph
Operations Manager
GTI Catoosa Test Facility, Inc.
P.O. Box 1590
Catoosa, OK 74015

Richard Raney
RA-TECH
2800 Fannin Ave.
Midland, TX 79705

Bill Rickard
Resource Group
40201 Sagewood Drive
Palm Desert, CA 92260

Richard Riedel
Technology International, Inc.
70 N Copperknoll Circle
The Woodlands, TX 77381

Tom Roberts
ReedHycalog
6501 Navigation
Houston, TX 77011

Dr. Leon Robinson
826 Heathcliff Court
Houston, TX 77024

John C. Rowley
Pajarito Enterprises Consulting Services
3 Jemez Lane
Los Alamos, NM 87544

Dan A. Sanchez
US Department of Energy
Albuquerque Office
DOE/AL

Aaron Schen
ReedHycalog
6501 Navigation
Houston, TX 77011

Jim Senger
Diamond Products International
15500 International Plaza Drive
Houston, TX 77032

Gary L. Smith
Conoco, Inc.
Leader, Drilling Technology
Offshore, 1006
P O Box 2197
Houston, TX 77252-2197

Paul Spielman
Coso Operating Co.
PO Box 1690
Inyokern, CA 93527-1690

Cheryl L. Stark
23 126 WL1
501 Westlake Park Blvd
Houston TX 77079-2696

Marc W. Steffen
Calpine, Drilling Manager
10350 Socrates Mine Road
Middletown CA 95461

Bob Swanson
Unocal Corporation
1160 North Dutton Ave
Suite 200
Santa Rosa, CA 95401

Michael E. Utt, P.E.
Technology & Operations Support
Unocal Corporation
14141 Southwest Freeway
Sugar Land, TX 77478-3435

Tommy M. Warren
Director, Research & Development
TESCO Drilling Technology
Rt. 1, Box 130-10
Coweta, OK 74429

David White
Schlumberger Cambridge Research
High Cross,
Madingley Road
Cambridge, CB3 OEL, UK

Bob Worrall
Shell Int'l Exploration and Productio
Research and Technical Services (RTS)
Volmerlaan 8
2280 AB Rijswijk
The Netherlands

Dennis L. Yeager, President
Diamond Oil Well Drilling Co., Inc.
P.O. Box 7843
Midland, TX 79708

Malgorzata B. Ziaja, Ph.D.
Assistant Professor
Montana Tech of
The University of Montana
Petroleum Engineering Department
1300 West Park St.
Butte, MT 59701

Mike Jagoe
General Manager-Contracting Services
Boart Longyear
2340 West 1700 South
P.O. Box 27314
Salt Lake City, Utah 84127-0314

Terje B. Nilsen
Principal Consultant
Nilsen Consulting
7115 W. Tidwell, #102
Houston, TX 77092

Matt W. Carson
Division Patent Counsel
Baker Hughes Inc.
3900 Essex Lane, Suite 1200
Houston, TX 77027

Billy Greeson
Projects Manager
Camco Coiled Tubing Services
P.O. Box 14484
Houston, TX 77221

John A. Victor
Wireline Consultant, Gulf Coast
Camco Products and Services
7275 Grand Boulevard
Houston, TX 77054

Thomas C. Collins
Vice President for Research
Oklahoma State University
203 Whitehurst
Stillwater, Oklahoma 74078-1020

Samuel J. Gauthier
Technical Services Engineer
Camco Coiled Tubing Services
P.O. Bx 14484
Houston, TX 77221

Bruce B. Howell
Drilling Consultant
Turnsteel of Idaho
2625 W. 2000 S.
Rexburg, Idaho 83440

Fritz W. Reuter
12406 Moorcreek Dr.
Houston, TX 77070

Dr. A. L. Podio
Dept. of Petroleum
& Geosystems Engineering
University of Texas at Austin
Austin, TX 78712

Carl F. Boehm, Jr., P.E.
Scientist Engineer
ABB Vetco Gray Inc.
12221 N. Houston Rosslyn Rd.
Houston, TX 77086

Luis Mendez
Product Engineering Director
Inflatabes & Thru Tubing
Baker Oil Tools
P.O. Box 40129
Houston, TX 77240

Lee Nirider
Senior Production Engineer
Marathon Oil Company
P.O. Box 3128
Houston, TX 77253-3128

Gilbert Conort
Product Development Manager
Testing Services
Schlumberger
P.O. Box 1590
Rosharon, TX 77583

Jim Filas
Special Projects
Schlumberger
14910 Airline Road
P.O. Box 1590
Rosharon, TX 77583

Garry Berthiaume
Operations Manager
Lonkar Services Ltd.
8080 Edgar Industrial Crescent
Red Deer, Alberta
Canada T4P 3R3

Masao Tsuge
President
Geothermal Energy Research
and Development
Kyodo Bldg.
11-7, Kabuto-Cho, Nihonbashi
Chuo-Ku, Tokyo 103-0026
JAPAN

Jackie E. Smith, P.E.
Manager, Research & Development
Grant Prideco, L.P.
5301 Polk St., Bldg. 7
Houston, TX 77023

Kazumi Osato, C. E.
Manager(R&D) Department of Technology
Geothermal Energy Research
and Development
Kyodo Bldg.
11-7, Kabuto-Cho, Nihonbashi
Chuo-Ku, Tokyo 103-0026
JAPAN

Satoshi Nakashima
Leader, Marketing
& Business Development Group
Geothermal Energy Research
and Development
Kyodo Bldg.
11-7, Kabuto-Cho, Nihonbashi
Chuo-Ku, Tokyo 103-0026
JAPAN

Tatsuya Sato
Manager, Department of Technology
Geothermal Energy Research
and Development
Kyodo Bldg.
11-7, Kabuto-Cho, Nihonbashi
Chuo-Ku, Tokyo 103-0026
JAPAN

Haruya Nakata, C. E.
Director, General Manager
Dept. of Tec.
Geothermal Energy Research
and Development
Kyodo Bldg.
11-7, Kabuto-Cho, Nihonbashi
Chuo-Ku, Tokyo 103-0026
JAPAN

Takashi Okabe, Dr. Eng., C. E.
Leader, Technology Group
Dept. of Tec.
Geothermal Energy Research
and Development
Kyodo Bldg.
11-7, Kabuto-Cho, Nihonbashi
Chuo-Ku, Tokyo 103-0026
JAPAN

Bjrn N. P. Paulsson, Ph.D.
President
Paulsson Geophyisical Services, Inc.
1090-F South Cypress St.
La Habra, CA 90631-6860

Dean Ueckert
Principal Electrical Engineer
ABB Offshore Systems Inc.
8909 Jackrabbit Rd.
Houston, TX 77095

Andrew Sendyk
Manager, Advanced Technology, DSP
Harris
156 Parkland Green SE
Calgary, AB T2J-3X6
CANADA

Quentin Morgan
Senior Development Engineer
Expro
Phoenix House, Tyseal Base,
Craigshaw Crescent
West Tullos, Aberdeen AB1 4AW
SCOTLAND

Chris Hetmaniak
Sr. Project Engineer
Maurer Engineering Inc.
2916 West T. C. Jester
Houston, TX 77018

Iain Maclean
North Sea Limited
Phoenix House
Craigshaw Crescent
West Tullos, Aberdeen AB1 4AW

Jeff Brami
Research Specialist
Exxon Production Research Company
P.O. Box 2189
Houston, TX 77252-2189

Rich Maxwell
Manager
A & L Underground, Inc.
P.O. Box 878
201 East Loula
Olateh, KS 66051-0878

Derrick R. Dance
Myad Technical Services
#15-3250 Ross Road
Naniamo, B.C.
V9T 254
CANADA

Randy Duncan
Project Superintendent
A & L Underground, Inc.
5602 FM Road 2403
Alvin, TX 77511

Frank Tirpak
President/C.E.O.
Lonkar Services Ltd.
8080 Edgar Industrial Cres.
Red Deer, Alberta
T4P 3R3
CANADA

Gordon Regehr
Instrumentation Technologist
Lonkar Services Ltd.
8080 Edgar Industrial Cres.
Red Deer, Alberta
T4P 3R3
CANADA

Louis E. Capuano Jr.
Drilling engineer
ThermaSource Inc.
725 Farmers Lane
P.O. Box 1236
Santa Rosa, California 95402

Steven Landriault
Manager, Product Development
Research & Development
ABB Vetco Gray Inc.
12221 N. Houston Rosslyn Road
Houston, TX 77086

Brad Boisen
General Manager
Slope Indicator Company
3450 Monte Villa Parkway
P.O. Box 3015
Bothell., WA 98041-3015

Ian Calder
Director, Research and Development
ABB Vetco Gray Inc.
12221 N. Houston Rosslyn Road
Houston, TX 77086

Donald J. Kwapien
Principal Engineer
ABB Power Plant Laboratories
CEP 9026-1203
2000 Day Hill Road
Windsor, CT 06095

Gus Mullins
Mullins & Associates, Inc.
600 Kenrick, B-11
Houston, TX 77060

Bob Joyce
Program Manager
INTEQ
2001 Rankin Road
Houston, TX 77073

Cameron J. Marshall
Project Engineer
Boart Longyear Inc.
P.O. Box 330, 1111 Main St. W.
North Bay, Ontario
P1B 8H6
CANADA

Taigo Wada
Director, Geothermal Energy Center
NEDO
Sunshine 60, 30F
1-1, 3-Chome Higashi-Ikebukuro
Toshima-Ku, Tokyo, 170-6028
JAPAN

Koichi Kawasaki
Project Leader, Geothermal Energy Cen
NEDO
Sunshine 60, 30F
1-1, 3-Chome Higashi-Ikebukuro
Toshima-Ku, Tokyo, 170-6028
JAPAN

Steven P. Rountree
MWD Project Manager
Prime Directional Systems LLC
1125 Hwy 90 East
Broussard, LA 70518

Johnny L. Gent, P.E.
Drilling Engineer
BP America Inc.
501 Westlake Park Blvd.
Houston, TX 77079

Frank Shepard
Sr. Systems Engineer
INTEQ
2001 Rankin Road,
Houston, TX 77073

Gordon R. J. Mackenzie
Product Line Manager
Baker Oil Tools
P.O. Box 40129
Houston, TX 77240-0129

Mark Beattie
Project Team Leader
PathFinder Energy Services, Inc.
15151 Sommermeyer Street
Houston, TX 77041-5332

Elan Yogeswaren
Principal Research Physicist
PathFinder Energy Services, Inc.
15151 Sommermeyer Street
Houston, TX 77041-5332

Dr. Bonnie Valant-Spaight
Research Physicist
PathFinder Energy Services, Inc.
15151 Sommermeyer Street
Houston, TX 77041-5332

Mahendran S. Relton
Project Manager
PathFinder Energy Services, Inc.
15151 Sommermeyer Street
Houston, TX 77041-5332

S. Mark Haugland
Sr. Research Physicist
PathFinder Energy Services, Inc.
15151 Sommermeyer Street
Houston, TX 77041-5332

Richard Meehan
Section Manager
Schlumberger
Sugar Land Product Center
150 Gillingham Lane
MD150-2
Sugar Land, TX 77478

Ricardo Pardey, Ph.D.
Emerging Technologies
PDVSA
Urb. Santa Rosa, sector El Tambor
Los Teques, Edo. Miranda
P.O. Box 76343, Caracas 1070-A
Venezuela

Laurent Prouvost
Product Development Manager Testing
Schlumberger
Well Completions and Productivity
1, rue Henri Becquerel
92140 Clamart
FRANCE

Thomas F. Bailey
Product Line Engineering
Weatherford International, Inc.
11909 Spencer Road (FM 529)
Houston, TX 77041-3011

Tom Tilon
Vice President - Technology
Weatherford International, Inc.
11909 Spencer Road (FM 529)
Houston, TX 77041-3011

Paul A McClure
Operations Director
Target Energy Group
Badentoy Road, Badentoy Park,
Portlethen, Aberdeen, AB12 4YA

Guillermo Aldana
1513 Payne Ave.
Austin, TX 78757

Bill Barham
Consultant
Barham Consulting
2347 Oak Park Road
Glendora, CA 91741

Professor Marc Bedford
6820 Cypress Point N. #23
Austin, TX 78746

Greg Boser
Analog Services
RR 7
Calgary, Alberta T2P 2G7
CANADA

Dr. Paul Camwell
CTO
Extreme Engineering
#8, 6025 - 12 St. SE
Calgary, Alberta T2H 2K1
CANADA

Professor Elmer Hixson
University of Texas
1513 Payne Ave.
Austin, TX 78757

Derek Logan
President
Extreme Engineering
#8, 6025 - 12 St. SE
Calgary, Alberta T2H 2K1
CANADA

Neeraj Magotra
Texas Instruments
12203 Southwest Freeway,
MS718
Stafford, TX 77477

Professor Peter E. Malin
Earth & Ocean Sciences
Duke University
Durham, NC 27708-0235

Richard Ryan
Ryan Energy
3000, 500 - 4 Avenue SW
Calgary, Alberta, Canada T2P 2V6

Edward O'Malley
Baker Oil Tools
9100 Emmott Road
Houston, Texas 77040

Tom Taylor
Earth & Ocean Sciences
Duke University
Durham, NC 27708-0235

Nancy Winfree
Dominca
12111 Ranchitos Rd NE
Albuquerque, NM 87122

Shraga Wolf
Vice Presdent, Technology
Baker Atlas
P.O. Box 1407
Houston, TX 77251-1407

Dave Schmalzer
Argonne National Laboratory
955 L'Enfant Plaza SW, Suite 6000
Washington, DC 20024

John Ziagos
Lawrence Livermore National Laboratory
P.O. Box 808
Livermore, CA 94551-0808

Allen Goland
Brookhaven National Laboratory
P.O. Box 5000, Building 815
Upton, NY 11973-5000

Jim Albright
Los Alamos National Laboratory
P.O. Box 1663, MS D443
Los Alamos, NM 87545

Joanna McFarlane
Oak Ridge National Laboratory
P.O. Box 2008, MS 6181
Oak Ridge, TN 37831-6181

Bruce Reynolds
Idaho National Engineering
and Environmental Laboratory
P.O. Box 1625, MS 2110
Idaho Falls, ID 83415-3710

Norman Goldstein
Lawrence Berkeley National Laboratory
1 Cyclotron Road, 90-1145
Berkeley, CA 94720

Bernie Saffell
Pacific Northwest National Laboratory
P.O. Box 999, MS K5-02
Richland, WA 99352

Larry Myer
Lawrence Berkeley National Laboratory
1 Cyclotron Road, 90-1114
Berkeley, CA 94720

Purna Halder
National Energy Technology Laboratory
One West Third, Ste. 1400
Tulsa, OK 74103

Maria Vargas
National Energy Technology Laboratory
3610 Collins Ferry Rd
Morgantown, WV 26507

Rhonda Lindsey
National Energy Technology Laboratory
Advanced Drilling, Completion
and Stimulation Systems
One West Third, Ste. 1400
Tulsa, OK 74103

David Alleman
National Energy Technology Laboratory
Environmental Research and Analysis
One West Third, Ste. 1400
Tulsa, OK 74103

John Rogers
National Energy Technology Laboratory
P.O. Box 880, MS E06
Morgantown, WV 26507-0880

Jerry Casteel
National Energy Technology Laboratory
Reservoir Life Extension
One West Third, Ste. 1400
Tulsa, OK 74103

Kathy Stirling
National Energy Technology Laboratory
Sr. Project Manager, Process Technology
One West Third, Ste. 1400
Tulsa, OK 74103

Bill Gwilliam
National Energy Technology Laboratory
P.O. Box 880, MS E06
Morgantown, WV 26507-0880

Edith Allison
U.S. Department of Energy
FE-32 FORS Rm. 3E-028
1000 Independence Ave., SW
Washington, DC 20585

Bill Hochheiser
U.S. Department of Energy
FE-32 FORS Rm. 3G-043
1000 Independence Ave., SW
Washington, DC 20585

Louis Capitanio
U.S. Department of Energy
FE-32 FORS
1000 Independence Ave., SW
Washington, DC 20585

Elena Subia-Melchert
U.S. Department of Energy
FE-32 FORS Rm. 3E-028
1000 Independence Ave., SW
Washington, DC 20585

Art Hartstein
U.S. Department of Energy
FE-33 GTN Rm. A-433
19901 Germantown Rd.
Germantown, MD 20874-1290

William J. McDonald, Ph.D.
Vice President, RST Engineering/R&D
Noble Downhole Technology, LTD
13135 S Dairy Ashford
Sugar Land, TX 77478

Brian Wagg
Senior Research Engineer
C-FER Technologies
200 Karl Clark Rd.
Edmonton, AB T6N 1H2

Stephen Hickman
Geophysicist
Earthquake Hazards Team
U.S. Geological Survey
345 Middlefield Road, MS 977
Menlo Park, CA 94025

John Stowell, President
Mount Sopris Instrument
17301 West Colfax Avenue, Suite 255
Golden, CO 80401 USA

Jean-Luc Deltombe
Technical Director
Advanced Logic Technology
Batiment A, route de Niederpallen,
L-8506 Rdange sur Attert - Luxembourg

David M. Lauderdale
I-3 Technologies
13717 Vic Road NE
Albuquerque, NM 87112

Richard Adler
North Star Research Corporation
4421 McLeod, NE, Ste. A
Albuquerque, NM, 87109

Robin Denise Robinson Brown
Baker Oil Tools
9100 Emmott Road
Houston, Texas 77040

Prof J. Kim Vandiver
M.I.T. Room 5-222
Cambridge, MA. 02139

Dr. J. C. Dunn
Cotton Wood Ln
Fort Sumner, NM 88119

Larry Lee, President
Ktech Corporation
2201 Buena Vista SE
Ste 400
Albuquerque, NM87106-4265

Dennis Grady
Applied Research Associates
Southwestern Division
4300 San Mateo Blvd NE
Albuquerque, NM 87110

Leland L. (Roy) Mink
Program Manager
EE-2C/Forrestal Building
U.S. Department of Energy
1000 Independence Ave. SW
Washington, DC 20585

1	MS 9018	Central Technical Files	8945-1
2	MS 0899	Technical Library	9616
1	MS 0114	Kevin McMahon	1304
1	MS 0482	Kent Meeks	2131
1	MS 0986	Ron Franco	2664
1	MS 0741	M. L. Tatro	6200
1	MS 1033	Eddie R. Hoover	6211
1	MS 1033	S. J. Bauer	6211
5	MS 1033	Terrance J. Cook	6211
75	MS 1033	Douglas S. Drumheller	6211
1	MS 1033	J. T. Finger	6211
1	MS 1033	R. D. Jacobson	6211
1	MS 1033	J. A. Henfling	6211
1	MS 1033	Jim Grossman	6211
1	MS 1033	David Raymond	6211
1	MS 1033	Douglas Blankenship	6211
1	MS 1033	R. A. Normann	6211
1	MS 1033	A. J. Mansure	6211
1	MS 1033	J. L. Wise	6211
50	MS 1033	Scott S. Kuszmaul	6211
10	MS 1033	Steve Knudsen	6211
1	MS 1033	Jim Grossman	6211
1	MS 0706	Allan Sattler	6113
1	MS 0751	David Holcomb	6117
1	MS 0751	Rebecca Brannon	6117
1	MS 0719	Jim Pierce	6142
1	MS 0834	Mike Prairie	9112
1	MS 0819	Tim Trucano	9211
1	MS 0415	Brad Godfrey	9811
1	MS 0161	Russell Elliot	11500
1	MS 1159	Michael Selph	15344