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RAYTHEON DOWNHOLE INFORMATION SYSTEM

Electromagnetic Borehole Measurements While
Drilling System. Final Report

By
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March 1978

Work Performed Under Contract No. EY-76-C-02-2816

MASTER

Raytheon Company
Advanced Development Laboratory
Wayland, Massachusetts

U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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FINAL REPORT

March 1978

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Prepared for

Department of Energy

Division of Geothermal Energy

Prepared By

Raytheon Company
Advanced Development Laboratory
Wayland, Massachusetts 01778

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(Previous Study Title "Electromagnetic Lithospheric Information System For Geothermal Drilling")

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ABSTRACT

This report describes the Raytheon Downhole Information System (RDIS), a real time electromagnetic borehole measurements while drilling system, applicable to oil, gas, and geothermal drilling. It communicates in both directions through the earth in a single hop at a downlink data rate of 3 bps and uplink rates dependent on depth - typically 6 bits/second at 10,000 ft. and 2 bits/second at 15,000 ft.; electromagnetic signal transmission time of approximately .1 second. Downhole hardware for communications, sensors, and power are packaged in three 30 ft. subs. Downhole hardware can be developed to permit operation in a 275°C geothermal environment.

A cost analysis is included that predicts RDIS service could be economically priced at approximately \$1000/day. Commercial availability depends primarily on proof of capability by demonstration in a working drilling well. The most significant portions of needed hardware are available at Raytheon. Follow-on to this D.O.E. study should be implementation of a demonstration at a drilling site.

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EXECUTIVE SUMMARY

A real time borehole measurement while drilling (MWD) system is required by the drilling industry for improved economy and safety in drilling. The major competing technologies include: insulated conductor, acoustic, mud pressure pulse, and electromagnetic. Insulated conductor appears to be the most attractive solution in terms of technical capability (data rate, data transmission time, no power supply downhole). However, after many years of development, the independent hardwire cable approach has not proved operationally successful and the drill pipe imbedded conductor approach is not economically attractive. Acoustic methods have yet to prove technically feasible for deep earth transmission. At the present time, mud pressure pulse has a notable lead in development. However, successful development of an electromagnetic system will offer increased capabilities including, higher data rate; lower transmission time; two way communication; operational flexibility in adjusting data rate as a function of depth, data requirements, and emergency signal requirements; transmission capability while adding pipe; and use in air drilling (no mud) applications.

Raytheon initiated its company funded development of an electromagnetic MWD system, the Raytheon Downhole Information System (RDIS), as a potential commercial outgrowth of its successful work in the 1960's with military applications of electromagnetic transmission through the earth. Raytheon's MWD electromagnetic system operates by transmission through the earth; it does not use the drill pipe and/or casing.

The work reported herein was funded by D. O. E. (formerly ERDA) initially to study the system application to geothermal drilling; later, the contract scope was modified to include updating our work on application to oil and gas drilling.

This study substantiates that an electromagnetic system to operate in a geothermal environment of 275°C can be developed. During the geothermal study phase, the system configuration followed our earlier work which depended on the use of repeaters in the drill string for communication upward at nominal separation of 1000 meters (variable in operational usage). Data rate was conservatively

estimated at 2/3 bits per second for this configuration due primarily to attenuation caused by cased wells where the signal must pass through the well casing at each repeater. Our later work in updating application to oil well drilling has achieved a major breakthrough in system capability - namely the elimination of repeaters in the drill string combined with a higher data rate capability. The principal design change which permits single-hop communication is the use of a boron epoxy wrapped non electrically conductive antenna cannister (instead of previous metal) for our downhole transmitting and receiving antenna. Advantages include reduced cost, higher reliability, less equipment on site, and easier handling during tripping.

The current Raytheon system capability includes a downlink data rate of 3 bits/second (greater capability if needed) and an uplink data rate dependent on depth such as 6 bits/second at 10000 ft. and 2 bps at 15000 ft. Potential for higher data rate depends on the need for more empirical electromagnetic noise data from a system operating downhole. Signal transmission time to the surface is .1 second. Our cost analysis predicts that RDIS service could be economically priced at approximately \$1000/day.

RDIS surface hardware includes transmitter and receiver electronics, transmitter antenna loop and receiver antenna solenoids on the earth's surface, and data processing and display. Most of the electronics equipment is in a truck. The only components on the drilling rig platform are for data display for drilling control and emergencies. Downhole hardware is located just above the drill bit. It includes the bottom telemetry terminal (electronics, antenna, batteries) and the sensor equipment, all mounted in three 30 foot subs. (See Figure 1-4).

Commercial availability of the Raytheon electromagnetic system depends primarily on a proof of capability by demonstration in a working drilling well. As part of Raytheon's in-house development program, the most significant portions of the needed hardware are available including the appropriate cannister (sub) which has been mechanically tested for supporting such a demonstration in a drilling string environment. Therefore, the follow-on to this D.O.E. study should be implementation of a hardware demonstration at a drilling site.

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RAYTHEON DOWNHOLE INFORMATION SYSTEM

FINAL REPORT

1.0 INTRODUCTION

This report describes the Raytheon Downhole Information System (RDIS) which promises to substantially reduce the cost of drilling oil, gas, and geothermal wells.

The system consists of a downhole sensor package located just above the drill bit in a normal drill string, a telemetry link in the drill string, and a well-head data management and control system located at the drill rig.

The RDIS downhole sensor package collects data on local temperature, pressure, drilling dynamics and rock lithology. The telemetry transmits this information to the surface where it is used by the data management and control system to assist the driller in continuous drilling optimization, thus improving drilling rate and reducing costs. In addition, the system provides continuous monitoring to prevent catastrophes such as blow out or loss of drill bits or pipe down hole.

Two versions of the RDIS have been configured. One of these, developed for geothermal applications where downhole temperatures of 275°C may be expected, includes a number of electrical repeaters in the drill string in addition to bottom and surface communication terminals. The other, developed under a change of scope to include oil well applications, requires only the bottom and surface terminals. This simplification is achievable because oil drilling normally takes place in a cooler downhole environment, permitting the reliable use of higher power batteries and electronics components downhole with state-of-the-art components. The body of this report contains a detailed discussion of the oil well telemetry system. The geothermal version has been detailed in the Interim Report. For the sake of completeness, the geothermal telemetry system discussion is reproduced herein as Appendix A.

1.1 Background

The efficiency of current drilling operations is hampered since there are only two primary methods for obtaining data; namely, well head sensing and downhole logging. Well head sensors measure parameters in real time, such as drill string turning rate, applied forces and torques, and mud composition and

flow rate. Logging techniques measure many significant downhole parameters, such as temperature, pressure and rock lithology indicators, but measurements cannot be made in real time. In fact the drill string must be removed to accommodate most logging tools.

There is a clear need for a technique to measure downhole parameters in real time to avoid major inaccuracies in extrapolating from real time well-head data and very infrequent logging data. To satisfy this need, the Raytheon approach places an instrumentation package downhole and transmits information up by direct electromagnetic propagation through the earth.

Since 1960, Raytheon has been engaged in research and development concerning the propagation of electromagnetic waves in the earth's crust. In several studies and experiments performed for the Air Force, low data rate communication up to 5 kilometers through the rock strata was demonstrated at locations in New England, upper New York State and Colorado. Additional theoretical work and experiment design has been performed for the Navy.

In 1973, investigations were begun by Raytheon as part of its company funded activities to determine the applicability of lithospheric propagation to oil and gas well drilling telemetry and command/control. These projects included theoretical studies, experiments and design work to establish a feasible technique for rapid transfer of vital information from downhole to the surface.

The approach selected as a result of these efforts is given detailed treatment in the present contract as reported herein. Important studies and experiments performed earlier (leading to the approach selected) examined key electromagnetic propagation and mechanical requirements.

In order to demonstrate feasibility of an integrated design satisfying all electromechanical requirements, a twenty-foot long six-inch diameter stainless steel canister was designed and built to contain the downhole receiver transmitter and batteries. The unit was environmentally tested in an actual drill string under drilling conditions at the University of Tulsa. Figure 1-1 shows the unit with its cover removed. The section in the foreground contains the solenoidal antenna with iron magnetic core. The structure in the background is reserved for electronics and self-contained power supply. The unit is shown being tested under simulated drilling conditions in Figure 1-2, at the University of Tulsa test facility.

Figure 1-1. Breadboard Repeater Module
(Cover Removed)

1-4

Figure 1-2. Simulated Drilling Test Setup

Propagation tests were performed at the Raytheon facility to assess the effect of well casing, an effect of equal importance to the characteristics of the rock strata. Figure 1-3 shows the canister with its stainless steel cover in place and partially inserted into an iron pipe representing well casing. In addition to the above, measurements of surface electromagnetic noise have been performed near an Exxon gas well while it was being drilled at Katy, Texas.

The results of these prior studies and measurements suggest that a downhole information system is feasible and could be quite cost effective. The current project has been undertaken to provide a solid background for development of a system to support drilling operations. In this report, a preliminary version of the commercial development plan follows the technical discussions.

1.2 Objectives

Several key objectives have been addressed:

1. Generate a preliminary design for the telemetry link. It will be designed to propagate directly through the earth, thus eliminating wires and cables which are unreliable in the drilling environment.
2. Generate a preliminary design for a downhole sensor package capable of providing data which will help in speeding up drilling, reducing equipment wear, instantaneously detecting promising oil bearing and geothermal zones, and preventing catastrophes. Together these advantages will contribute to a substantial drilling cost reduction.
3. Generate design approaches and techniques for countering the extreme environmental conditions to be found downhole under geothermal conditions, particularly as they may affect downhole sensors, electronics and power supplies. In addition to the severe pressure and vibration effects of normal drilling, geothermal wells have an extreme temperature environment. The current contract defines a downhole formation temperature of 200°C . Nevertheless, the equipment for geothermal applications will be designed to withstand a more realistic formation temperature of 275°C . Since under normal drilling conditions, the electronics may be cooled by mud flow, the electronics will be designed for full operation at 175°C - 200°C and for storage without damage at 275°C in case of emergency (e.g., mud flow stoppage).

Figure 1-3. Breadboard Repeater Mounted Inside Casing Section

4. Examine a closed loop system configuration combining the sensors and the telemetry with a normal drilling rig to optimize drilling. This closed loop configuration should minimize drilling cost, including prevention of catastrophes.
5. Perform a cost benefits analysis to evaluate the advantages of the closed loop system and determine how the system might be provided for use by the drilling industry on a cost effective basis.
6. Formulate a system development plan. Initial elements of the plan include orderly validation of key engineering parameters and operating drill rig evaluation of prototype hardware. The data obtained will provide the basis for establishing cost/performance values from which the commercial RDIS design will be developed. The overall objective is to obtain commercial benefits to the drilling industry with minimal lead time. Commercial availability of RDIS could occur in 1980, if the plan proposed is followed.

1.3 Downhole Information System

The downhole information system for oil well drilling is displayed in Figure 1-4. This system requires only a bottom and a surface terminal. Another approach, employing repeaters in the drill string, has been designed as well. This design has been configured to withstand the more severe environment of the geothermal well, namely corrosive liquids and a much higher formation temperature. The alternate approach is covered in detail in Appendix A.

As shown in Figure 1-4, the telemetry bottom terminal forms a portion of the drill string just above the drill bit and the sensor package. Recorded data derived from the sensor package is transmitted periodically up to the surface terminal by electromagnetic propagation through the earth. Data is normally sent upon command by the surface terminal.

Emergency information warning of impending disasters such as blow out, loss of circulation or broken drill bits will be sent via the uplink immediately using specially coded "red flag" messages triggered by a compact downhole processor located in the sensor package. The surface microprocessor coordinates well head data management and control and provides access to a remote computer for utilization of drilling optimization programs. The display control console provides the drilling operator with up-to-date information and control capability.

Figure 1-4. Raytheon Downhole Information System (RDIS)

The bottom terminal and sensor/recorder package are designed to be mechanically compatible with the drill string and the downhole assembly. Typically, the terminal would consist of a 30 foot sub for batteries and transmitter, and another of equal length for the antenna. The sensor/recorder and receiver would comprise a third sub of similar size.

1.4 Report Content

The body of this report is divided into five sections, namely:

2.0 DRILLING TELEMETRY SYSTEM

3.0 INSTRUMENTATION PACKAGE DESIGN CONCEPT DEVELOPMENT

4.0 DRILLING CONTROL LOOP DESIGN

5.0 COST BENEFITS ANALYSIS

6.0 RDIS COMMERCIAL DEVELOPMENT PLAN

Their content is briefly summarized below.

1.4.1 Drilling Telemetry System

The system consists of a bottom terminal and a surface terminal. Downhole hardware is designed to withstand anticipated shock, vibration, abrasion and thermal environmental conditions. The bottom terminal consists of three subs, each about 30 feet in length: first for power supply and solid-state transmitter electronics; second for a 28-foot iron cored solenoid antenna; and third for the solid-state receiver, sensors, and recorder.

The surface terminal receiver has several antennas and associated pre-amplifiers located some distance from the drill rig (up to 1000 ft.) to minimize the effects of rig generated noise. Separation of the antennas may be employed to aid in noise cancellation. The transmitter antenna is a large multiturn loop of wire laid along the ground to provide high gain.

The bottom terminal (see Figure 1-4) consists of a command receiver (R), and a transmitter (T), both of which utilize a common antenna. The antenna is a solenoid 28 feet long. It is protected by a non-conducting cover which is resistant to abrasion and shock, but does not shield the electromagnetic signals. The terminal is below the well casing during drilling, thus eliminating attenuation which might accrue if it were enclosed by the casing.

Signals are propagated digitally at extremely low frequencies (approximate range of 1-10 Hz). Bandwidth is equal to carrier frequency. Using four phase PSK modulation, an uplink bit rate of twice the signal bandwidth is achieved. The major bandwidth limitation is carrier attenuation in propagating through the earth. Attenuation is most severe when the earth is quite damp over large regions between the bottom terminal and the surface. For such difficult conditions (average conductivity of 0.1 mho/meter), an uplink rate of 2 bits/sec is quite feasible. For more usual situations where conductivity is an order of magnitude or more lower, 10 bits/second or more is easy to achieve.

A reliable downhole power source is critical to achieving the desired performance. Fortunately for temperatures normally encountered downhole in oil well drilling, conventional batteries are available providing 1.5 watt hours per cubic inch. This capability will provide the desired data rates and satisfy message length constraints for drilling where the bit is changed every 1000 feet of penetration or less.

A design utilizing a 30 foot transmitter/battery sub and a 30 foot antenna sub for the bottom terminal is presented in Section 2.0.

1.4.2 Drilling Sensor Package

A set of ten sensor types including a status monitor has been selected for the sensor package. They are listed along with the quantities measured by each in Table 1-1. The package may be used in a variety of ways depending upon what is known a priori of the local lithology and the expectation of problems at various depths.

The package contains a downhole processor which reduces greatly the amount of data which must be transmitted and which also automatically warns of potential emergency conditions such as blow out, kick, twist-off or bit failure. The depth intervals at which data is taken can be commanded from the surface via the telemetry link. A nominal set of measurement intervals for hard rock drilling sensor protocol is shown in Table 1-1.

The drilling sensor package was originally designed with geothermal drilling application in mind. However, most of the sensors discussed are also applicable to oil and gas well drilling.

Table 1-1

Sensors and Typical Measurement Intervals

Sensor	Measured Quantity	Nominal * Measurement Interval(Ft.)
Laterolog	Resistivity (Log of Ohm-M) (Mud, disturbed, undisturbed formation)	5
Spontaneous Potential (Electric Log)	Vertical component of potential gradient (Mud, disturbed, undisturbed formation)	5
Gamma-Gamma Log	Specific Gravity	5
3D Sonic Log	Transit Time (μ -sec)(compression, shear, and mud wave)	5
Directional Sensor	Drift Angle Inclination Angle	30 30
Thermistor	Temperature of mud (Deg °C)	5
Pressure Transducer	Mud pressure (PSI) (a) Across drill string (b) Inside drill string	30 30
Strain Gages	Force/Torque on drill bit (a) Mean axial (lb) (b) 1 σ Axial (lb) (c) Mean torsional (Ft- lb) (d) 1 σ Torsional (Ft- lb)	30 30 30 30
Acceleration Acoustic	Drilling/Drill bit status	30
System Status Monitor	Sensor Package Status	30

* Controllable by command from surface.

1.4.3 Drilling Control Loop Design

In Section 4 the overall system is described in some detail. Particular attention is given to the Wellhead Data Management and Control System (WEDMACS) which is not treated elsewhere. The heart of the WEDMACS is a microcomputer which interfaces with all the other units. Most important of these are (1) the graphics display unit, which provides information to the drilling operator and through its keyboard allows him to exercise control, (2) the remote computer, through which sophisticated advice can be obtained by the operator, and (3) the surface and downhole information systems which provide basic information on drilling progress.

1.4.4 Cost Benefits Analysis

A case study has been performed to provide a comparative estimate of RDIS benefits in drilling a 15,000 foot hole in a moderately hard rock producing zone. This well would take about three months to drill and would cost about \$1.2 M. Net benefits per hole based on "learning curve" improvements should amount to at least \$296,000 or about 24% of the unassisted well drilling cost.

1.4.5 RDIS Preliminary Development Plan

A preliminary plan to provide 10 RDIS commercial systems for operational field deployment within 40 months after contract award (ACA) has been generated. The preliminary development plan has been structured to provide key demonstrations and milestones for management evaluation of RDIS technical and economic performance levels as the development cycle proceeds. Development is to proceed in three phases.

During Phase I, RDIS hardware is evaluated in an operating drill rig under reduced environmental and mechanical stress conditions. Brassboard (B/B) level equipment is used throughout.

Phase II, which is initiated on successful completion of the B/B system tests, consists of the development, test, and field demonstration of a complete fully qualified RDIS prototype system. This system will operate reliably under the realistic environment associated with deep holes in oil bearing formations. A three month interval is allocated at the end of Phase II for field demonstrations to potential customers of the prototype RDIS system at one or more selected drilling sites.

Phase III, commercial systems deployment, is initiated upon prototype checkout. The commercial systems, having been produced on the assembly line, will differ from the prototype system only in the fabrication technique employed.

2.0 DRILLING TELEMETRY SYSTEM

The telemetry system is the major element of the Raytheon Downhole Information System. It provides two way digital communication between the drill rig at the surface and the drill bit and sensor unit downhole. The communications hardware consists of a topside receiver, transmitter, and associated antennas, and a bottom terminal consisting of a receiver, transmitter, and common antenna, all mounted in the drill string just above the drill bit.

Although its operation is similar to that of the repeater system described in the Interim Report, the telemetry design presented in this section has several unique features and advantages. No repeaters are used or needed between the downhole and surface locations. Eliminating of repeaters reduces system cost, provides for higher reliability, and insures easier handling during tripping.

The design features a downhole antenna mounted in a 30 foot drill string section which is rugged and adequately protected against downhole abrasion conditions while enclosed in a non electrically conducting cover. The use of wound boron fibers stabilized with epoxy permits electromagnetic transmissions without the severe attenuation penalties imposed by eddy currents flowing in a solid metal cover. Because this source of attenuation has been eliminated, propagation can take place between surface and downhole directly through the earth at a quite satisfactory data rate. A second major source of attenuation has also been eliminated, namely the iron well casing, since the bottom terminal will normally be below the casing during drilling operations.

The basic parameters of the equipment have been defined and a successful drilling demonstration could be shown. A commercial development plan consisting of a proof of concept demonstration followed by prototype development is provided in Section 6.0.

2.1 Telemetry System Requirements

The telemetry system transmits three types of messages:

1. Commands from surface to downhole
2. Sensor information from downhole to surface
3. "Red Flag" emergency data from downhole to surface

Requirements on the first define the downlink and the other two the uplink. Downlink commands would be needed to activate/reprogram the sensor package to send up particular data needed. Uplink sensor information content and "red flag" speed requirements call for a relatively high data rate consistent with mechanical and environmental constraints. The downlink commands would be infrequent and low in data content. Consequently the maximum data rate selected for the uplink would be more than adequate for the downlink.

Limitations on uplink performance are governed by the characteristics of the lithosphere as a transmission medium, by the physical size of the downhole transmitter-antenna configuration, and by the size of the power source downhole. Downlink performance has less constraints since surface power and real estate for the transmitting antenna loop are not as restricted.

Emergency data (e. g., blowout) must be received at the surface as rapidly as possible. Electromagnetic signal transmission time is approximately .1 second. By optimizing the emergency message format as a function of adequate false alarm rate, message transmission time can be minimized. Other sensor data must be received at the surface at the rate that sensor information is expected to change, which is generally a function of the drilling rate.

As is shown in the discussion of the instrumentation package (Section 3.0) only 484 bits are needed to adequately examine each 30 foot layer. Since drilling rates are slow, typically 10 - 20 ft. per hour at depths in moderately hard ground, a rate of 1 bit/second is sufficient to keep well ahead of the need, providing very timely information.

Trade-off studies reported below have been performed to establish a design consisting of 3 canisters downhole; namely the sensor package, an antenna sub and a battery sub. Each is 30 feet long to allow easy manipulation of the units during tripping. For a nominal depth of 15,000 feet an uplink data rate of over 2 bits per second is achieved. Therefore, required transmission time is only 2% of drilling time, based on a need for new sensor data every 30 feet (nominal length of sensor package) and a drilling rate of 10 feet per hour.

2.1.1 Link Elements (See Figure 1-4)

The downlink transmitter is a solid state switching unit which applies pulses to a large loop antenna spread on the ground in the neighborhood of the drilling rig. Signals are received downhole via a solenoid antenna forming a section of the drill string and a solid state receiver located in an adjacent section. The downhole antenna is designed for optimum uplink transmission characteristics and works well also in the receive mode. In fact limitations on received signal to interference ratio downhole are governed only by the noise field ambient downhole and not by receiver internal noise. Internal receiver noise is well below received ambient noise using the downhole antenna as a receiver antenna while it is designed to optimize the uplink.

The uplink transmitter is a solid state unit mounted in the battery sub next to antenna sub. Signals transmitted upward via the solenoid antenna are detected by the surface receiver which utilizes several small solenoids embedded in the earth as receiving antennas. Signals from the several antennas are combined in such a way as to provide maximum cancellation of surface ambient noise.

The sections following discuss in detail the tradeoffs performed to establish design parameters for all critical elements in both the uplink and the downlink.

2.1.2 Downlink Design Tradeoffs

2.1.2.1 Introduction

The downlink antenna system consists of a large circular loop transmitter lying on the ground which generates a magnetic field at the downhole receiver as indicated in Figure 2-1. The vertically oriented downhole receiving antenna will respond to the components of H_r (radial field) and H_θ (transverse field) parallel to the antenna axis. The sum of these parallel components must be of sufficient strength to overcome the receiver noise and thus provide an adequate signal-to-noise ratio. Receiver design considerations dictate that the dominant contribution to receiver noise is ambient magnetic noise; i. e., atmospheric noise attenuated by earth electrical conductivity, rather than receiver thermal noise. Reliable measurements of ULF and ELF atmospheric noise have been made by J. E. Evans in conjunction with the Sanguine project.⁽¹⁾ Typical power spectrum densities of magnetic field parallel to the earth's surface measured in Malta and Saipan are shown in Figures 2-2 and 2-3. Spectral densities are in units of dB referred to one ampere-turn/m- $\sqrt{\text{Hz}}$ (referred to as dBH). Vertical field spectral densities are less than parallel field spectral densities by 10 to 20 dBH. From this data, a moderately high surface vertical magnetic field spectrum density of -115 dBH in a one Hertz bandwidth was taken for the downlink design tradeoffs.

The signal-to-noise ratio at the receiver is derived under the assumption that the ambient noise propagates in earth as a plane electromagnetic wave and the signal magnetic field is generated by a magnetic loop immersed in an infinite homogeneous medium. Ambient noise will decrease with depth due to the shielding effect of the earth. The rate of decay is dependent on the real part of the complex propagation constant for plane wave propagation in lossy medium. The real part or attenuation constant, α , is

$$\alpha = \omega \left(\frac{\mu \epsilon}{2} \right)^{1/2} \left[\left(1 + \frac{\sigma^2}{\omega^2 \epsilon^2} \right)^{1/2} - 1 \right]^{1/2} \quad \text{Nepers per meter (1)}$$

Figure 2-1. Downlink Antenna System.

Figure 2-2. Spectrum of Moderate Level Malta Noise

Figure 2-3. Spectrum of High-Level Saipan Noise

where

ω = radian frequency

μ = magnetic permeability of the medium in henries per meter

ϵ = dielectric constant of the medium in farads per meter

σ = electrical conductivity of the medium in mhos per meter

For typical earth electrical properties, ⁽²⁾ $\frac{\sigma}{\omega\epsilon} \gg 1$ in the frequency range of interest. Therefore

$$\alpha = \left(\frac{\omega\mu\sigma}{2} \right)^{1/2} = 1/\delta \quad (2)$$

where δ is the skin depth of the medium. The ambient noise at the receiver is therefore $\exp(-r/\delta)$ times the moderately high magnetic field noise at the surface.

For frequencies ≤ 10 Hz, D. B. Starkey⁽³⁾ has demonstrated that the magnetic fields in earth generated by a surface loop transmitter are not appreciable modified by the finite conductivity variations and geometry of intervening conducting layers associated with stratification and upper air half space. Correlation of theoretical fields with experimental results show agreement of most amplitude measurements to within 3 dB for 11,000 foot deep well tests in Wyoming where conductivity ranged from 0.25 to 0.0025. Consequently, the magnetic field intensity at the receiver generated by the surface loop transmitter is given by the field intensity components generated by a magnetic dipole immersed in an infinite homogeneous medium. Expressed in spherical coordinates, the complex field components are ⁽⁴⁾

$$H_r = \frac{NI(\pi a^2)}{4\pi r^3} [1 + j\gamma r] [e^{-j\gamma r}] 2 \cos\theta \quad (3)$$

$$H_\theta = \frac{NI(\pi a^2)}{4\pi r^3} [1 + j\gamma r - \gamma^2 r^2] [e^{-j\gamma r}] \sin\theta \quad (4)$$

where N , I , and πa^2 are the transmitting loop antenna turns, current, and area, respectively, and r is the range from the loop center to the receiver. The complex propagation constant, $\gamma = (\omega^2 \mu \epsilon + j \omega \mu \epsilon)^{1/2}$ reduces to $(1-j)/\delta$ for the condition $\sigma \gg \omega \epsilon$. The magnitude squared of the magnetic field components (proportional to field power) can be expressed in terms of skin depth δ or an absorption parameter, Γ , as follows:⁽⁵⁾

$$\begin{aligned} |H_r|^2 &= \left[\frac{NIA}{4\pi r^3} \right]^2 4 \exp(-2r/\delta) [1 + 2r/\delta + 2(r/\delta)^2] \cos^2 \theta \\ &= \left[\frac{NIA}{4\pi r^3} \right]^2 |\Gamma_r|^2 \cos^2 \theta \end{aligned} \quad (5)$$

and

$$\begin{aligned} H_\theta^2 &= \left[\frac{NIA}{4\pi r^3} \right]^2 \exp(-2r/\delta) [1 + 2r/\delta + 2(r/\delta)^2 \\ &\quad + 4(r/\delta)^3 + 4(r/\delta)^4] \sin^2 \theta \\ &= \left[\frac{NIA}{4\pi r^3} \right]^2 |\Gamma_\theta|^2 \sin^2 \theta \end{aligned} \quad (6)$$

Variation of magnetic field intensity with frequency, and the ratio of range to skin depth is illustrated by behavior of the absorption parameters, $|\Gamma_r|$ and $|\Gamma_\theta|$, plotted in Figure 2-4. The absorption parameter is the ratio of the field intensity available in the conducting medium to that which would be available if the medium were nonconducting.

2.1.2.2 Surface Loop Transmitter

The atmospheric noise at the downhole receiver defined as H_{nn} is

Figure 2-4 Absorption Parameter, Γ , Versus Ratio of Range to Skin Depth, r/δ

$$H_{nn} = 10^{-5.75} \sqrt{\Delta f} \exp(-r/\delta) \text{ ampere-turn/meter} \quad (7)$$

where Δf is the bandwidth of the receiver. The moderately high surface spectrum density of -115 dBH in a one Hertz bandwidth is assumed as discussed above in Section 2.1.2.1. For the case of coaxial transmitting and receiving antennas, $\theta = 0^\circ$, the signal-to-noise ratio at the receiver input terminal is derived from equations (5) and (7). Recent field measurements indicate that the loop transmitter could be offset an amount $r \sin \theta = \delta / 5$ (see Figure 2-1) from the coaxial case without a change in the magnitude of the signal magnetic field sensed by the downhole antenna.⁽⁶⁾

The signal-to-noise ratio is

$$\frac{|H_r|^2}{H_{nn}^2} = \text{SNR} = \frac{(NIA)^2 \left[1 + \frac{2r}{\delta} + 2 \left(\frac{r}{\delta} \right)^2 \right]}{(4 \pi^2 r^6) (10^{-11.5} \Delta f)} \quad (8)$$

The required magnetic moment m of the transmitting loop is therefore

$$m = NIA = \frac{\sqrt{\text{SNR}} \cdot \sqrt{f} \cdot 10^{-5.75} \cdot 2 \pi r^3}{\sqrt{1 + \frac{2r}{\delta} + 2 \left(\frac{r}{\delta} \right)^2}} \quad (9)$$

where $\Delta f = f$. The choice of bandwidth equal to frequency f is based on the design requirement of maximizing bandwidth at a given frequency of operation to achieve a maximum bit error rate. This choice implies that the loop Q where $Q = \frac{2 \pi f L}{R}$ is set to unity. At low values of earth electrical conductivity or large skin depths, the earth shielding of surface magnetic noise at the receiver is small and the required magnetic moment is large. Bounds on the magnetic moment have been calculated from equation (9) and range from 10^6 to about 2×10^7 amp-turn-meter² as seen in Figure 2-5. A 12 dB signal-to-noise ratio

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Figure 2-5. Required Loop Magnetic Moment $m = \text{NIA}$.
(r in meters and σ in mhos per meter)

was used and is considered adequate for the proposed downlink system.

The corresponding transmitter power P required to generate a magnetic moment m for a given loop geometry and time constant $\tau = L/R$ is

$$P = I^2 R = \frac{\mu_0 m^2}{\pi^2 a^3 \tau} \left[\ln \left(\frac{8a}{b} \right) - 2 \right] \text{ Watts} \quad (10)$$

The loop dimensions, a , b , are defined in Figure 2-1. The loop self-inductance is approximately ⁽⁷⁾ ($b \ll a$)

$$L = N^2 \mu_0 a \left[\ln \left(\frac{8a}{b} \right) - 2 \right] \text{ Henries} \quad (11)$$

and loop resistance is

$$R = \frac{2\pi a \rho N}{A_c} \text{ Ohms} \quad (12)$$

The magnetic permeability of free space is μ_0 and ρ is the electrical resistivity of the wire used to form the transmitting loop. N is the number of turns and $A_c = \pi b^2$ (wire cross-sectional area).

Power, current, inductance, resistance, and turns have been calculated as a function of loop radius and for time constants of 0.1 and 0.01 seconds using equations (10), (11) and (12), and #10 AWG copper wire. (See Figures 2-6 through 2-8.)

The transmitting loop time constant controls the maximum bit rate which may be employed. Since Q is set to unity, and the bit rate is twice the bandwidth for the quadriphase modulation to be used, the governing relationship is

Figure 2-6. Loop Power and Current Requirement for Maximum Rate of 3.2 Bits/sec, $\tau = 0.1$ sec.

Figure 2-7. Loop Power and Current Requirement for Maximum Rate of 32 bits/sec, $\tau = 0.01$ seconds.

Figure 2-8. Loop Design Parameters.

$b_{\max} = \frac{1}{\pi \tau}$ where $b_{\max}$ is maximum bit rate. Thus a 3.2 bit/sec rate is permitted by a 0.1 second time constant.

Table 2-1 displays parameters extracted* from Figures 2-6 to 2-8 which illustrates the tradeoffs which must be considered in selecting the best transmitting loop design. From Table 2-1 we selected column II as the preferred design configuration with the lowest power requirement of 1700 watts and an adequate data rate of 3.2 bps. The 140 turns of wire for the 150 meter radius loop would be assembled in a cable of several sections with connectors to permit expeditious emplacement.

2.1.3 Uplink Design Tradeoffs

2.1.3.1 Introduction

The downhole transmitting antenna consists of a single winding layer solenoid with ferromagnetic core. The core has a center hole for mud pumping to the drill bit. The structural support for the antenna is provided by a composite material, boron epoxy fibre, wound around the coil to form a high mechanical strength non-electrically conducting cover. A schematic of the antenna cross-section is shown in Figure 2-9.

Figure 2-9 Antenna Cross Section

The nominal length of the transmitting antenna is 8.5 meters. The magnetic moment is $m = NIA_e$ where A_e is defined as the "effective area". The effective area of the antenna is an important design parameter. It is controlled by the magnetic permeability μ of the ferromagnetic core material and the length to

*For magnetic moment (m) = 2×10^7 amp-turn-meter².

Table 2-1

SURFACE TRANSMITTER ALTERNATIVES

	I	II	III	IV
Max Bit Rate (bps)	3.2	3.2	32	32
Loop Radius (m)	100	150	150	200
Power (watts)	5600	1700	17000	7600
Current (amp)	4.4	2	20	11.6
Voltage (volts)	1270	850	850	655
No. Turns	152	140	14	14

diameter ratio of the core. Application of Ampere's Circuital law to the geometry indicated in Figure 2-9 shows that the effective area is approximately

$$A_e \triangleq \mu_a \pi (b'^2 - c^2) + \pi c^2 \quad (13)$$

where c = radius of mud pipe

and b' = radius of ferromagnetic core

The approximate self-inductance of the antenna winding is therefore $L = \mu_0 A_e N^2 / \ell$ where N is the number of turns and ℓ is the physical length of the antenna winding. The magnetic parameter μ_a is defined as the apparent core permeability and may be estimated from design data given in reference (8). Several of these design curves have been reproduced in Figure 2-10. It is clear that for a given length to diameter ratio, $(\ell / 2b')$ a magnetic material of permeability μ need only be chosen to provide a value for apparent permeability corresponding to the knee of the curve when a maximum value of effective area is desired. The limiting value ($\mu \rightarrow \infty$) is ⁽⁹⁾

$$\mu_a = \frac{2(\ell / 2b')^2}{4.02 \log_{10}(\ell / 2b') - 0.92} \quad (14)$$

for $(\ell / 2b') \geq 10$ and solid core.

2.1.3.2 Downhole Coil Transmitter

The magnetic field components generated by the downhole transmitting antenna are given by equations (5) and (6) in the previous section with $A = A_e$ and angle θ defined with respect to the downhole antenna as shown in Figure 1. The results of recent up link field transmission tests ⁽⁶⁾ demonstrate that the measured vertical magnetic field at the surface of the earth seen by a receiving loop antenna remains essentially constant over the buried loop transmitter out to an offset distance of $\delta / 5$, where δ is one plane wave skin depth in the earth.

Figure 2-10. Relation between apparent permeability μ_a and true permeability μ of cylinders having a given ratio of length to diameter.

At an offset distance of one skin depth the magnitude of the vertical magnetic field component is down by only 3 dB. For coaxial or non-coaxial (offset no greater than $\delta/5$) transmitting and receiving antennas, the signal-to-noise ratio at the input terminal of the receiving antenna is

$$\text{SNR} = \frac{|H_r|^2}{H_{nn}^2(0)} \quad (15)$$

where $H_{nn}(0)$ is the surface noise magnetic field in bandwidth Δf and is the same value as used in the downlink design trades ($H_{nn}(0) = 10^{-5.75} \sqrt{\Delta f}$). Therefore

$$\text{SNR} = \frac{(NIA_e)^2 \exp(-2 \frac{r}{\delta}) \left[1 + 2 \frac{r}{\delta} + 2 \left(\frac{r}{\delta} \right)^2 \right]}{(4 \pi^2 r^6) (10^{-11.5} \Delta f)} \quad (16)$$

The transmitter power $I^2 R$ required to generate a given SNR at the surface receiver is determined from a transfer function T defined as $T = |H_r|^2 / I^2 R$ where R is the total resistance of the antenna winding. Expressed in terms of the transmitter coil design parameters, (ignoring core loss)

$$T = \left(\frac{A_e^2 \ell d}{32 \pi^2 \rho b' r^6} \right) \exp \left(-\frac{2r}{\delta} \right) \left[1 + \frac{2r}{\delta} + 2 \left(\frac{r}{\delta} \right)^2 \right] \quad (17)$$

The coil length to diameter ratio is $\ell/2b'$, d is the diameter of the wire used to wind the coil and ρ is the resistivity of the wire. The transmitter power required is therefore

$$P = I^2 R = \frac{H_{nn}^2(0) \text{ SNR}}{T} \quad (18)$$

$$= (10^{-11.5} \Delta f) (\text{SNR}) \left\{ \frac{32 \pi^2 \rho b' r^6 \exp(+2r/\delta)}{A_e^2 \ell d \left[1 + 2\left(\frac{r}{\delta}\right) + 2\left(\frac{r}{\delta}\right)^2 \right]} \right\} \quad (19)$$

Noise cancellation techniques may be used to reduce the amount of power required. (Noise cancellation is discussed in Section 2.2.1) If the noise cancellation factor is defined by C_F ,

$$P = 10^{-11.5} \Delta f \left(\text{SNR}/C_F \right) \left\{ \frac{32 \pi^2 \rho b' r^6 \exp(+2r/\delta)}{A_e^2 \ell d \left[1 + 2\left(\frac{r}{\delta}\right) + 2\left(\frac{r}{\delta}\right)^2 \right]} \right\} \quad (20)$$

The design of a downhole antenna to achieve a surface signal-to-noise ratio is constrained by (1) the bit rate requirement or desired bandwidth, $\Delta f = f$, (2) magnetic core saturation, and (3) geometry. The bit rate or bandwidth requirement implies a unity Q factor for the coil. This requires equality between the winding inductive reactance and total winding resistance at the transmitter frequency. Core loss, represented by a resistance in addition to the winding ohmic resistance, is part of the total winding resistance, but its value is difficult to estimate.

For a given winding cross-sectional geometry (see Figure 2-9) and fixed values of f , C_F , SNR , ρ , σ , r and μ (frequency, noise cancellation factor, signal-to-noise-ratio, winding resistivity, earth average conductivity, depth and ferromagnetic core material permeability, respectively) the length of the antenna will control both the maximum permissible power to avoid core magnetic field saturation and maximum possible effective area. Short antennas (<5 meters) require large transmitting power and are difficult to saturate. Long antennas (>20 m) require considerably less transmitter power and saturate at much lower power levels as compared to short antennas. The value of magnetic field

intensity within the core material is approximately $H = NI/\ell$ from Ampere's Circuital law. The corresponding magnetic flux density B is therefore $NI\mu_a/\ell$. If the saturation magnetic field for a particular ferromagnetic core material is defined as B_{SAT} , the winding current that will produce this value of internal magnetic field is approximately

$$I_{SAT} = B_{SAT} \ell / \mu_a N \quad (21)$$

The average power dissipated in the antenna winding corresponding to this value of current is

$$P_{SAT} = (B_{SAT} \ell / \mu_a N)^2 R \quad (22)$$

A unique value of antenna length ℓ may be determined from equations (20) and (22) for the condition $P_{SAT} = P$.

Using the above relationships and applying reasonable performance criteria and physical and environmental constraints, a computer analysis was performed for optimizing a practical coil design. Results are listed in Table 2-2. Physical dimensions of the antenna are established to provide a unit of size comparable to a standard 30 foot drill pipe section. The received signal-to-noise ratio at the surface will guarantee an easily detectable signal. The surface magnetic noise level of -115 dBH/Hz and the earth conductivity of 0.01 mhos/meter are conservative estimates in terms of their effect on propagation from downhole to surface.

Considering the core saturation effects in the antenna and the earth propagation attenuation (which increases with frequency) a maximum frequency and bit rate is possible at each depth for the coil design chosen. At 15,000 foot depth the maximum frequency is 1.1 Hz (2.2 bits/sec); at 20000 feet it is 0.3 Hz (0.6 bits/sec).

To achieve the proper bandwidth a series resistance must be added to the antenna coil so that the effective Q is approximately unity. This will insure a bandwidth equal to the carrier frequency. In operation the value of the series resistance would be changed by a simple switch at increments of depth. Typically adjustments every 1000 feet would be sufficient. Thus the switching could be made between each trip, as the downhole unit is brought to the surface in order

Table 2-2

DOWNHOLE ANTENNA PARAMETERS

PERFORMANCE CRITERIA

Surface SNR 12 dB

Noise Cancellation Factor (C_F) 30 dB

ENVIRONMENTAL CONSTRAINTS

Average Earth Conductivity (σ) 0.01 mhos/meter

Surface Magnetic Noise -115 dBH/Hz

PHYSICAL CONSTRAINTS AND DESIGN PARAMETERS

Coil Length (ℓ) 8.5 meters

#10 AWG Wire Diam. (d) 0.259 cm

Copper Wire Resistivity (ρ) 1.724×10^{-6} ohm-cm

Rel. Permeability of Core Material (μ) 4000

Apparent Core Permeability (μ_a) variable (see Fig. 10)

Achievable Saturation Flux Density of Core 22,000 gauss

Mud Pipe Diameter ($2c$) 7.62 cm

Single Layer Winding Diameter ($2b'$) 14.4 cm

Number of Turns ($N = \ell/d$) 3282

to change the worn drill bit. The coil winding resistance is 4.9 ohms. To achieve the desired Q, series resistance added would be 106 ohms at 15000 feet and 21 ohms at 20000 feet.

2.1.4 Bottom Terminal Design Considerations

2.1.4.1 Boron Epoxy Wrapped Antenna Canister

A significant signal loss occurs if the outer canister cover surrounding the antenna is metallic. This loss is caused by the generation of eddy currents. Such loss can be reduced to an insignificant level by using a cover combination of boron epoxy non-conductive material for structural strength with a slotted thin outer coating of wear protection material such as tungsten carbide. The following discussion describes a nominal design.

The non-conducting antenna canister to avoid shielding losses and provide mechanical strength is constructed as shown in Figure 2-11. The ends of the drill string section have standard drilling pipe thread and are connected by the 2.5 inch I.D. and 3.0 inch O.D. steel tube which carries the drilling mud through the string section. The ends are long enough to accommodate the tools required to make up the drill string. Outside the mud tube are packed longitudinal sections of iron. These sections are wound with a conductor which is enclosed by a dense epoxy. Between the two tapered transition sections is a .475" thick layer of boron fiber epoxy. The boron fibers are wound in helical fashion ($\approx 45^\circ$ pitch angle). One half of the fibers are wound into a left screw - the other half into a right screw, in alternating layers. The boron fiber epoxy is covered by a thin (1/16" or less) layer of tungsten carbide to give wear protection. The tungsten carbide layer is slotted to avoid shielding losses.

The canister has been designed to withstand simultaneously:

Torque = 132,000 in lbs.

Bending moment = 96,000 in lbs.

Axial load = + 30,000 lbs. (tension)

- 210,000 lbs. (compression)

While exposed to the loads shown, the drill string is able to support typical pressures occurring simultaneously in the mud (e.g., internal 17,200 psi and external 15200 psi at 15,000 ft. and 23,000 psi internal and 21,000 psi external at 20000 ft.).

Figure 2-11. Boron Epoxy Antenna Canister.

2.1.4.2 Batteries

Temperature conditions in deep oil wells have been investigated. It has been found that ambient temperatures up to 350°F may sometimes be encountered, i. e., 177°C . A survey of batteries potentially available within the next year or two has been conducted. No conventional secondary batteries capable of meeting downhole temperatures above 100°C were found to be currently available. Based on current information, it is concluded that primary batteries with an energy density of 1.5 watt-hrs per cubic inch for the downhole battery package should be achievable for near term demonstration of bottom terminal design and performance. This density factor has, therefore, been assumed for the prototype design reported in Section 2.2.

In the prototype design, about 5184 cubic inches of battery compartment has been allocated. (A 27 feet length compartment with 16 square inch cross-section.) A sketch of the battery compartment is shown in Figure 2.2-M, Section 2.2. Using 1.5 watt-hrs per cubic inch for battery energy density gives 7776 watt-hours of available energy. For the 8.5 meter length, 15000 foot depth antenna design described in Section 2.2, the operating frequency of 1.1 Hz corresponds to 2.2 bits per second of information transmission. The total power required is 3240 watts at 5.4 amperes and 600 volts. The time to transmit 16000 bits, corresponding to an increment in depth of 1000 feet, is approximately 2 hours. This is based on 480 bits per 30 foot increment transmitted for 1000 ft which is assumed drilling distance before drilling bit is changed. Then batteries can also be changed. The battery system would need to supply to the 15000 foot depth antenna 6480 watt-hours of energy at 5.4 amperes and 600 volts which is well within the capability (7776 watt-hours) of the battery system to provide.

2.2 Telemetry System Design

The telemetry system consists of a surface terminal and bottom terminal. Key factors in the design of each have been described above in Sections 2.1.2, 2.1.3, and 2.1.4 which present electromagnetic tradeoff results for both uplink and downlink as well as critical electromechanical considerations affecting the bottom terminal. The following discusses the resulting design and the anticipated performance.

2.2.1 Surface Terminal - Design and Performance

The surface terminal, shown in Figure 2-12, consists of a solid state transmitter and receiver each connected to its own antenna system. The transmitter accepts commands from the microprocessor in the Wellhead Data Management and Control System (WEDMACS - discussed in Section 4.0) and sends messages in four phase PSK modulation at extremely low frequencies for interpretation by the downhole sensor package. Messages would direct the sensor package to gather certain data and/or to transmit selected information on the uplink. The receiver accepts four phase PSK signals and sends them to the WEDMACS microprocessor for interpretation. These signals could be normal data transmission or emergency "red flag" messages warning of such things as impending blowout or broken drill bit conditions.

To transmit a sufficiently strong signal downhole to 20,000 feet, the transmitting antenna will be a large multiple loop of wire laid on the ground. Loop diameter will be approximately 300 meters ($\approx$ 1000 feet). Power required is 1700 watts with a current of 2 amperes and voltage of 850 volts. Data rate for the down link is 3 bits/second. The surface receiver antennas consist of several small solenoids arranged to achieve cancellation of much of the ambient noise. Each antenna will be imbedded in the ground at shallow depth (approximately one foot) to guarantee mechanical stability. Each antenna contains its own pre-amplifier to establish a low noise figure. Amplified signals are sent to the cancellation receiver where they are processed to reject ambient noise. Cancellation should be possible because the ambient noise is expected to be somewhat correlated over a large area. Correlation is much poorer for the signals from downhole since they stem from essentially a point source. Cancellation achievable is estimated to be about 30 dB.

Figure 2-12. Surface Terminal.

2.2.2 Bottom Terminal Design

The Bottom Terminal unit is a major portion of the self-contained down-hole information unit illustrated in Figure 2-13. The complete down-hole assembly consists of three sections each of which are approximately 30 feet long and 7 inches outside diameter. The bottom communication terminal consists of the antenna section and the transmitter/battery section, and the receiver portion of the instrumentation/receiver section, which also houses the sensor package. The instrumentation/receiver section is located nearest the bottom of the drill string. Next is the antenna section followed by the transmitter/battery section. These sections are designed to withstand loads imposed during well drilling operations. The loads include torque, axial loads, bending, pressure and those forces which occur when the sections are "made-up" or "broken-out" of the drill string.

The sections are joined to each other and to the drill string by standard A. P. I. pin and box threaded tool joints. Electrical interconnections will be accomplished by a rigid multi-conductor jumper bar which is bolted into aligned recesses and plugs into sealed mating receptacles which are located in the adjoining section ends. These recesses are located during fabrication by using matched master pin and box tool joint gages which are properly torqued into the section ends.

2.2.2.1 Instrumentation/Receiver

The instrumentation/receiver section is configured as shown in Figure 2-13. The outer tube with its threaded end fittings is the primary structural member. Electronics are mounted in a pressure housing which in turn is supported within the outer tube by three longitudinal struts and also by support rings. Mud flows downward through the annulus formed by the space between the electronics housing and the outer tube.

2.2.2.2 Antenna

The antenna section is configured as shown in Figure 2-13. The mud tube is welded at each end to thick wall threaded end fittings. Core iron is located around the mud tube and the coil is wound around this core. The antenna cover is the primary load carrying member and consists of thick wall non-conductive composite made of alternately left and right hand helically wound boron filaments

Figure 2-13. Bottom Terminal Unit.

and epoxy. A slotted hard metallic coating with an electrical gap (avoids shielding losses) the length of the antenna surrounds the composite antenna cover to protect it from abrasion damage.

2.2.2.3 Transmitter/Battery

The transmitter/battery section is shown in Figure 2-13. To provide an internal form factor suitable for housing batteries, a dual mud tube configuration is used. Dual mud tubes with suitable end fittings and bracketry form an inner tube assembly which supports the batteries and transmitter electronics. A heavy wall tube internally threaded at one end and attached to a thick wall threaded end fitting on the other end form the outer tube assembly which is the primary structural load carrying member and is also the outer pressure housing for the batteries and transmitter electronics. The outer and inner tube assemblies are fitted with seals and a threaded connection which is torqued to remain tight in down-hole use.

2.2.3 Uplink Telemetry System Performance

System and performance parameters are listed in Table 2-3.

The nominal design is configured for a depth of 15,000 ft. The data transmission parameters shown apply at that depth. It has been assumed that the trip depth is typically 1000 feet, i. e., the average drill bit will survive for an incremental penetration of 1000 feet. During this interval, a total of 16,000 bits will be transmitted, approximately 484 bits per 30 foot drill pipe section (see Sec 3.0 for a discussion of information content). For each 30 feet of penetration, approximately four minutes will be used for transmission. It may be desirable to stop drilling during this period but theoretical considerations related to interference with the communications channel indicate that uplink communication and drilling can proceed simultaneously.

Red flag (emergency messages) are transmitted in only 8 seconds. This represents primarily the time to generate a 16 bit message at 2 bits per second. Propagation time for the beginning of the message to arrive at the surface from downhole is negligible. The propagation delay is approximately 0.1 second for a very conservative case, where unusually high earth conductivity is assumed. The 16 bit length is selected to minimize false alarms due to bit errors. If the

leading bits are used to tag a blowout message, and operational procedures permit initiating blowout prevention procedures on the possibility of some false alarms, the 8 seconds can be reduced to a few seconds.

Table 2-4 estimates performance at depths other than the nominal. Because of the increased attenuation with depth, data rate will be reduced at greater depths than 15000 ft. At these depths, the drilling penetration rate is generally slower, particularly in harder rock and more difficult downhole environments. Therefore, slower data rate, when compared with the slower drilling rate, is sufficient. It should also be recognized that signal transmission time is approximately .1 second. Therefore, emergency messages (e.g., blowout, broken drill bit), with a minimal message length of bits, could be transmitted in reasonable time, dependent on false alarm acceptability.

Table 2-3

Uplink Telemetry System Parameters And Performance**Environment**

Nominal Depth	15,000 feet
Pressure	> 17,000 PSI
Formation Temperature	177°C (350°F)
Average Conductivity (σ)	$10^{-2} + 10^{-4}$ mho/meter
Vibration/Shock	$\leq 8g$

Data Transmission

484 bits per 30 ft. penetration	
Average Trip Conditions (drill bit life)	
Penetration Increment	1000 ft.
Total Data Transmission	16,000 bits
Nominal Data Rate	2 bits/sec
Nominal Message Time	4 minutes
(per 30 ft. penetration)	
Red Flag (16 bits)	8 seconds

Nominal Design

Antenna Sub	30 ft.
Power Supply Sub	
Length	30 feet
Energy Storage	~7.8 kilowatt hours
Receiver (in 30 ft. Instrumentation Sub)	1 ft. Section

Table 2-4

Uplink Performance With Depth

Red Flag Time Secs.	Depth (ft.)	Data Rate Bits/Second	Power (Watts)	Message Time (484 bits) (minutes)	Typical** Penetration Rate (ft/hr)	Percent Trans- mission Time
1.6	10,000	6	2180*	1.3	20	1.5%
	12,000	4	2900*	2.0		
	14,000	3.6	5220	2.2		
7.3	15,000	2.2	3190	3.7	10	2.1%
	16,000	1.8	2610	4.5		
	17,000	1.3	1890	6.2		
	18,000	1.0	1450	8.1		
	19,000	0.7	1020	11.5		
27	20,000	.6	870	13.4	6	4.5%

*At 10,000 to 12,000 foot depths, excessive battery voltage (>1 kv) dictated a reduction in battery power required for transmission.

** Source: "Drilling For Energy Resources", National Resource Council.

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3.0 INSTRUMENTATION PACKAGE DESIGN CONCEPT DEVELOPMENT

The downhole instrumentation concept is dictated by type of real time drilling data needed, development feasibility, and instrumentation package on-site cost. Reported in this section are definition of the instrumentation package measurement requirements, specification of the instrumentation package operational and environmental requirements and development of the overall electrical/mechanical design concept.

3.1 Benefits Accruing from Real-Time Downhole Instrumentation

The Raytheon Downhole Information System (RDIS) is in competition with existing practices. It is helpful to review the status quo of drilling data collection techniques. Current operational drilling data is obtainable through two primary mechanisms: well head sensing and downhole logging. Real-time data is available only for the well head parameters. These include the various forces and turning rates applied to the top of the drill string and the flow rate, state variables, and compositional parameters associated with the mud streams. Downhole conditions are inferred by extrapolation of well head data within a predictive framework based on a priori lithology, complex physics and mechanics of the currently operating drill string configuration, and drilling history to date. On the other hand, logging techniques provide direct measurement of downhole conditions, but only after drilling has taken place.

The principal weaknesses of existing data collection techniques are twofold. First, the extrapolations used to estimate conditions at the drill bit are somewhat inaccurate. This results from the attenuation of mechanical forces along the drill string and because of the high level of mechanical noise introduced by contact of the drill string with the hole boundary and mud streams. This is particularly acute for the higher frequency components of the signal, as related to drill bit instabilities (bouncing, rifling) and rapidly occurring phenomena (blowouts, kicks, or bit failure). Direct downhole measurements related to these phenomena can provide data which are now available. Second, direct measurement of downhole formation parameters now requires that the drilling operation cease while the logging tools are employed. Thus, logging is doubly expensive in that not only are costs incurred in the form of fees paid

to the logging company but capital costs (and some O & M) are incurred even though the drilling equipment is inactive.

In order to develop an appropriate set of measurement requirements for the downhole instrumentation package, it is convenient to consider the benefits within three categories. These are prevention of catastrophic events, optimization of the drilling operation, and determination of formation lithology. The first category exploits the real-time capability of RDIS. The second category exploits the downhole location of the RDIS as it removes the spatial extrapolation requirement and improves knowledge of conditions at the drill bit face. The third category reduces the amount of independent logging required, therefore reducing associated costs.

When the measurement requirements have been ranked by benefits returned, it is necessary to configure an instrumentation set sufficient to satisfy the measurement requirements. Because feasibility of the instrumentation is essential, it is imperative that the components of the instrumentation set be derivable from known logging tools and techniques.

3.1.1 Catastrophe Prevention

Use of the RDIS can alleviate or prevent two types of catastrophes beyond what can be accomplished with current technology. These are recognition of blowouts before the blowout pressure wave reaches the top of the hole and impending or actual failure of the drill bit.

3.1.1.1 Blowout Recognition

Blowout is the result of an imbalance between the hydrostatic pressure in the drilling mud and the ambient formation pressure. When the ambient formation pressure is the greater and the supply of formation fluid/gases are sufficient, the drilling mud can be forced out of the hole.

The downhole instrumentation telemetry concept, which can permit recognition of blowout conditions prior to the time that blowout effects are felt at the top of hole, allows timely application of blowout prevention techniques. This capability is not available today and represents a potential benefit associated with the RDIS concept.

Blowout recognition can proceed based upon measurements of the following state variables:

- 1) The rate of change of pressure in the mud (will increase rapidly).
- 2) Absolute pressure difference across drill string wall (may even change sign).
- 3) Mud sonic propagation characteristics (increased attenuation, decreased speed).
- 4) Mud conductivity (will change rapidly and, probably, irreversible).
- 5) Exterior temperature discontinuities (will increase).

The magnitude of the above quantities can be used to recognize the extent, size and type of blowout. Thus the drilling operator, based on the situation existing and measured at the bottom of the hole, can make a decision as to the timing and degree of blowout preventor techniques to be applied.

3.1.1.2 Detection of Impending Drill Bit Failure

At the present time, the drilling plan, the current penetration rate, the calculated torque and axial pressure applied to the drill bit, and hole history to date are used to determine when a drill bit should be changed. In general, two errors may be made during this decision making process. The first is changing the drill bit before its useful drilling lifetime is exhausted. This results in more frequent extractions of the drill string than are necessary. The second is the use of a drill bit beyond its effective lifetime. This will result in lower penetration rates and in the possibility that significant pieces of the drill bit may actually remain in the hole, requiring fishing expeditions. While neither decision-making error is truly catastrophic, both involve considerable expense.

Downhole instrumentation can monitor the state of wear on the drill bit by measurement of the acoustic waves created both by the action of the drill bit on the formation and by the bearings and other moving parts associated with the drill bit. In addition to the acoustic measurements, acceleration and vibration measurements will be made. Analysis of the resulting data can allow the operator to evaluate the likelihood of pending drill bit failure and to evaluate the drilling efficiency of the existing drill bit/formation/torque/bit-loading combination.

3.1.2 Drilling Operation Optimization

The art of obtaining maximum drilling efficiency in terms of penetration rate has been well established. It is based on the level of experience of operating personnel, control of the overall drill configuration, the drilling plan and the hole history. AMOCO in particular has developed a set of drilling optimization computer programs which correlate the above factors to provide a timely recommended drilling configuration.

Use of the RDIS can improve the current level of drilling optimization in two areas: It can provide real-time data and it can improve the accuracy with which downhole conditions are known. Based on inputs from the drilling industry and a survey of available literature, the following dynamic variables have been identified as being of importance to drilling optimization:

- bit wear state
- power, torque and bearing load applied to the drill bit
- bit mud pressure differential
- bit dynamics
- directional data
- lithology (covered separately in Section 3.1.3)

3.1.2.1 Bit Wear State

The rate of rotation and bearing pressure applied to the drill bit control both the rate of penetration into the formation and the wear rate of the drill bit. The relationship between these parameters is determined by, among other things, the current state of wear of the drill bit. By directly measuring drill wear state (using measured data as described in Section 3.1.1.2) this relationship can be exploited to strike an appropriate balance between penetration rate and bit life.

3.1.2.2 Applied Bit Stresses

The RDIS allows direct measurement of forces applied to the bit at the bottom of the hole through use of strain gauges. These conditions can be most accurately determined at the bottom of the hole. Since it is known that these

quantities are used in the existing drill bit optimization programs, it is felt that more accurate measurement of this data can improve their performance.

An additional benefit is the identification of high rotational friction conditions existing at an intermediate depth between the bit and the well-head. Timely knowledge of this phenomena can help to avoid twist-off conditions and the subsequent expense of fishing expeditions and/or lost downhole equipment below the break point.

3.1.2.3 Mud Pressure Measurements

Mud dynamics and control are important to monitoring an efficient and safe drilling operation. In addition to the blowout/kick implications mentioned in Section 3.1.1, accurate mud pressure measurements within and across the drill string can also support improved drilling efficiency.

Pressure drop across the drill bit jets is available directly through measurement of differential pressure across the drill string wall. This pressure drop is in turn related both to the mud Reynolds number as it flows under the drill bit and flushes chips away from the cutting surface and to the wet state of the jets themselves.

Annular mud pressure control is needed to maintain a balanced pressure condition, which can increase penetration rates (without increasing bit wear rates) by a factor of three or more. Real time correlation of the acoustic sensor output (which detects the plastic cutting noise associated with over-balanced conditions and the brittle cutting noise associated with balanced conditions), mud annulus pressure observations and formation density measurements, and control of the mud flow throttling orifice and the mud density can be combined to obtain balanced drilling benefits in a systematic fashion.

3.1.2.4 Bit Dynamics

When stress levels and rotation rates applied to the drill bit and/or mud mechanics are selected incorrectly, the drill bit may begin to exhibit undesirable dynamic instabilities. Bouncing is, as the name implies, a pogo action of the drill string; the bit bounces up and down against the face of the rock where it is being drilled. A second instability is called rifling; the bit rattles around the hole and leaves grooves in the hole which are similar to the rifling

lands in a gun barrel. Both phenomena are considered undesirable because they tend to increase bit and bottom assembly wear and decrease penetration rate. The corrective action to be taken is to modify drill speed, bearing weight or mud dynamics. Measurement of the accelerations and vibrations existing in the drill string near the bit can be used to diagnose when these undesirable conditions occur and corresponding adjustments can be made.

3.1.2.5 Directional Data

Although not specifically related to the optimization of drilling through the rock with regard to speed, correct hole trajectory is an important parameter in the drilling operation. The key parameters to be measured here are the inclination of the drilling direction with respect to vertical and the direction—i. e., north, east, south or west, in which the drift is occurring. Corrective action to restore verticality consists of increasing drill speed and decreasing bit weight from the surface.

When directional drilling is being done (as in hot dry rock projects), accurate determination of the actual position of the hole is essential. Use of the RDIS can result in real-time position measurement, thus providing a better method for directional drilling without requiring long pauses in the drilling operation to run wireline surveys or other special purpose logs.

3.1.3 Lithology

The range of rock types likely to be encountered in drilling geothermal wells is very large. The rocks that have been drilled already for geothermal power include both sedimentary and igneous rocks. Metamorphic rocks should also be included in the range of rocks because (1) the sedimentary rocks have really been metamorphosed (albeit to a low grade) and (2) the sequence of rocks penetrated in drilling current geothermal prospects includes metamorphic rocks. It is anticipated, therefore, that continued exploration and development of geothermal areas in the United States, as well as elsewhere, will involve the drilling of holes through sedimentary, igneous, and metamorphic rocks.

The physical properties of rocks are controlled by the following factors:

- (1) rock type (igneous, sedimentary, metamorphic, and the sub-divisions within these broad groups),
- (2) microcracks (relative volume, pressures at which the cracks close, connectivity, tortuosity, and so on),
- (3) fluids that fill the open cracks (proportion of the void space filled with fluid, relative proportion of gas and liquid composition),
- (4) total porosity,
- (5) pressure (lithostatic pressure, pore fluid pressure), and
- (6) temperature.

Fortunately, not every factor has equal weight with respect to each property. As an example, consider the velocity of compressional waves (V_p). Figure 3-1 shows the variation of V_p with pressure as measured in the laboratory on a small, dry sample of Westerly (RI) granite. At low pressures, below 1 to 2 kb, the property changes rapidly with pressure. At higher pressures, above 1 to 2 kb, the property changes slowly with pressures. Above 2 kb, the change is due to the variation with pressure of the properties of the constituent minerals of which the rock is composed. The large changes at low pressures, however, are due to the presence of microcracks in the sample. If no microcracks had been present in the sample, then the velocity would be that shown by the dashed curve -- a linear extrapolation of the high pressure portion of the curve. If the microcracks had been completely filled with water (and the pressure in the water maintained constant at 1 bar), then the velocity would be that shown by the dotted portion. The composition of the fluid (provided that it is mainly water) has relatively little effect on the value of V_p , but may have very large effects on other properties (e.g., electrical resistivity).

Knowledge of several parameters as a sample of depth, obtained in real-time or in near-real time, appears to be potentially important in the drilling of geothermal wells.

Figure 3-1. Compressional Wave Velocity Variation with Pressure

3. 1. 3. 1 Geophysical Parameters

In the drilling and exploration for geothermal energy, the parameters that are needed are the following (with the numbers indicating the priority): (1) temperature, (2) permeability, (3) total porosity, and (4) pore pressure. Unfortunately, while drilling is in progress, only mud temperature can be measured directly. In order to obtain values for the other three parameters, a set of related parameters are to be measured while drilling is in progress, for the purpose of estimating the values of the parameters that are really desired. The table below lists the parameters to be measured. The variation with depth of the parameters in the table can be inverted, given suitable functional relations, to yield the variation of the desired parameters.

Geophysical Parameters To Be Measured During Drilling

Temperature
Electrical resistivity
Velocity of Compressional Waves
Shear Wave Velocity
Density

Temperature

Temperature is obviously the single most important parameter with which to characterize a geothermal system. The higher the temperature, the more desirable the geothermal reservoir. A precision of 1.0°F is sufficient to assess the heat stored in the reservoir.

The required spatial resolution for the temperature measurement is five feet. This resolution would be adequate for the construction of a temperature-depth log. Furthermore, temperatures in a drilling well are unlikely to change significantly over such an interval.

Electrical Resistivity

The electrical resistivity of rocks depends chiefly on the content of microcracks and the composition of the fluids contained in the microcracks. It is mainly independent of the composition of the minerals--but important exceptions in geothermal areas are the clay minerals.

Measurement of the electrical resistivity during drilling is important for several reasons. First, the initial assessment of a geothermal field is often based on a single set of geophysical measurements; namely, electrical conductivity surveys. Such surveys are made in the early phases of exploration for a geothermal reservoir. They are conducted from the surface of the earth. Measurements of apparent electrical resistivity as a function of horizontal distance, or alternatively as a function of frequency at fixed distances, are interpreted by the geophysical practitioners in terms of the variation of gross electrical conductivity with depth in the earth. The inversion of the data is difficult and the models are rather poorly constrained. Hence, direct and continuous monitoring of electrical conductivity with depth in the borehole may lead to significantly improved interpretations of the original geophysical data while the well is being drilled. Such improved interpretations of the geophysical data could lead to drastic revisions of the projected total depth to completion for the drilling phase.

Second, the variation of electrical resistivity with depth may yield important estimates of the variation of permeability with depth. The best estimate of permeability is likely to come from the combined analysis of electrical resistivity,

velocity of compressional waves, and velocity of shear waves. Nonetheless, if only the electrical resistivity data were available, and experience in a particular region had shown that large variations of resistivity were associated with large variations in permeability, then one would obviously use such variations to predict the permeability.

Third, low values of electrical resistivity are expected to be important for geothermal production because they are likely to be related to high values of permeability. A high value of permeability may be due to the presence of natural cracks in the rocks. It may also be produced in the rocks by artificial stimulation (such as hydrofrac, acid injection, etc.). The identification of such zones that may be suitable, during the drilling operations, may be significant for the production of geothermal energy. Variations over short distances (say, a few feet) of 2 or even 3 orders of magnitude may occur. The identification of the depths at which such changes occur is very important and may affect significantly the estimates of the value of a particular zone within a well.

Problems in normal logging of electrical resistivity have occurred due to mud penetration of the walls during the drilling because of the relatively high conductivity of the mud. Significant differences in electrical resistivity have been noted between measurements taken immediately after drilling and measurements taken a few weeks later. Making measurements during drilling therefore would improve upon the accuracy of such measurements since the mud has not yet had a change to significantly penetrate the formation.

The maximum spatial resolution desired for the measurement of electrical resistivity is 5 feet. This spatial resolution is based on the observation that rather thin zones of high permeability are sometimes highly significant in geothermal energy. Hence, the determination of the precise location of the top and bottom of such zones is important.

Velocity of Compressional Waves

The velocity of compressional waves in rocks depends on the composition of the minerals, the microcracks present, the presence of pore fluids, pressure, porosity, and temperature. It is believed that there is considerable value in

measuring V_P during the drilling operations for the following reasons: (1) Such variables as rock type can be determined independently and in near-real-time by the analysis of the drill cuttings brought to the surface in the drilling operation. Or they may be known ahead of time through independent geologic studies of the region. (2) Variation of compressional velocity with the permeability can be related empirically and in many instances provides an excellent indicator of the presence of microcracks and hence of regions of high permeability. (3) When used in conjunction with other parameters, it is an excellent indicator of the presence of microcracks and constrains values of crack porosity and permeability.

The range of compressional velocities for igneous and sedimentary rocks is almost an order of magnitude (1 - 8 km/sec) although the variation within a single borehole is unlikely to be that large. Considerable work has been done on the various effects on the V_P due to pressure, temperature, mineralogy, cracks pore fluid pressure, and so on. That work has been considered as background for the simple statement of the range of compressional velocities.

Summarizing such considerations, the intrinsic properties of the main minerals that compose igneous and sedimentary rocks cover the range from about 5 to 8 km/sec. Clays may be as low as 1-1/2 to 2 km/sec. The effect of pressure on the intrinsic property, over the range of pressures likely to be encountered in drilling geothermal holes in the next two decades, is nil. The effect of temperature is likely to be no greater than a few percent of the intrinsic value. For example, a temperature of 200°C decreases the velocity of a dunite 1.8%, a granite 1.6%, a particular sandstone 6%, and a limestone 3.5%.

The effects of microcracks on compressional velocity, at atmospheric pressure, could be as great as a factor of 2 or 3, but is unlikely to be so large for rock in situ. Based on laboratory investigations, it is judged that the effect in situ will probably not exceed 20 or 30%, though in cases it may be as large as 100%. The effect of microcracks is to reduce the velocity of compressional waves.

Shear Wave Velocity

The additional information that is provided by simultaneous measurement of shear wave velocity is great. From the two velocities (and the mass density), we

can calculate all of the elastic properties of the rock: compressibility, Young's modulus, shear modulus, bulk modulus, and Poisson's ratio. Furthermore, we can obtain a rather good estimate of the crack porosity and therefore the permeability. The shear velocity is a function of mineralogy, crack content, pressure, temperature, and porosity. The intrinsic velocity is largely determined by rock type and completely determined by the mineralogy. It is largely insensitive to the effect of lithostatic pressure, at least over the range to be encountered in drilling geothermal wells. It is affected by temperature to about the same extent as velocity of compressional waves; namely, a few percent at temperatures to 200-300°C. The shear velocity of the rock is affected greatly by the content of the microcracks present, but is largely independent of the presence or absence of water within the cracks.

Formation Density

Formation density is useful in estimating rock mechanical parameters (Young's and shear moduli, bulk compressibility, and Poisson's ratio) from sonic propagation velocity measurements. These mechanical parameters are, in turn, useful for selection of the downhole drilling assembly configuration, for the optimization of the drilling operation, and in the evaluation of fracturing potential. Formation density, when correlated with bottoms up data, can provide an independent estimate of in situ porosity.

3.1.4 Minimal Instrumentation Set

Based upon the measurement requirements described in the previous sections, a set of instrumentation with associated measurement ranges and accuracies has been selected. There are nine different types of instruments that will be included within the instrumentation package, namely (1) laterolog-spontaneous potential log, (2) gamma-gamma log, (3) sonic log, (4) directional sensor, (5) temperature sensor, (6) mud pressure sensors, (7) strain gauges, (8) acceleration acoustic sensors, and (9) microprocessor. They are discussed separately below.

Laterolog

The laterolog is basically a multiple electrode version of the conventional ohmmeter. Its function is to measure the true bulk resistance (or conductivity) in three distinct regions. The three regions are:

- 1) The mud in the annulus between the drill pipe and the formation wall;
- 2) The portion of the formation immediately adjacent to the hole which has been disturbed either by the process of the drill bit penetrating it or by infusion of mud; and,
- 3) The undisturbed formation which surrounds the disturbed formation zone.

The multiple electrodes of the laterolog are distributed along the axis of the drill string. By measuring the resistance between electrodes, the bulk resistance of the surrounding medium can be obtained. As a rough rule of thumb, the zone whose resistance is being measured is radially displaced from the axis of the drill string by approximately the spacing between electrodes. By using multiple electrodes along the instrumentation package, it is possible to estimate the resistance of all three zones of interest. Commercially available laterologs are not intended to work in conjunction with a drill string; rather they are lowered down the hole separately. They typically have electrodes which are mounted on mechanical arms which extend to contact the formation wall. This would be unacceptable for RDIS application because the rotating drill string would soon cause mechanical failure of the protuberances. However, it is possible to coat the outside of the instrumentation canister with insulation/plastic and bond the electrodes over the dielectric surface. The electrodes themselves then would have to be sufficiently mechanically strong to resist the wearing forces which will be exerted against the outside of the canister. Currently commercially available units are quoted as being operational in temperatures up to 260°C . The measurement range is 10^0 to 10^{+6} ohm-meters with an accuracy of $\pm 12\%$.

Spontaneous Potential

A quantity known as the spontaneous potential is defined as the voltage potential between an electrode on the surface of the ground and electrode located downhole. By operating the laterolog in its converse mode - forcing the current flowing in the electrodes to zero and measuring the voltage on the electrodes - it is possible to measure the vertical gradient of the spontaneous potential. Integration of this vertical gradient can then be used to estimate the spontaneous potential itself. The principal use of spontaneous potential is in the definition of layering between different strata of rock. Galvanic interfaces are easily identifiable through their spontaneous potential discontinuities. Thus the same instrument can be used for two applications. The measurement range is $\pm 30\text{ mv/m}$ with an accuracy of $\pm 1\text{ mv/m}$.

Gamma-Gamma Log

The gamma-gamma log contains a gamma source and a beam forming mechanism which directs the rays out into the formation. The gamma rays are scattered by the electrons contained within the surrounding medium. The magnitude of the scattering is directly proportional to electron number density. The electron density is in turn equal to the proton number density within the medium because the formation is presumed to be neutrally charged. Since the anticipated ratio of neutrons to protons in typically encountered formation is reasonably constant, a direct mass density estimate may be made. Using a directional receiver beam or an array of directional receiver beams to estimate the amount of scattering at different radial distances from the gamma source, the gamma-gamma log can estimate the distribution of electron densities radially outwards from the instrumentation canister. This distribution precisely tracks the mass density. The effective range of the gamma-gamma log is limited to less than thirty feet. However, it appears to offer the only real-time direct measurement of density and must be included within the instrumentation set. Gamma-gamma logs are currently commercially available for operation at temperatures up to 205°C. The measurement covers a specific gravity range of 1.8 to 2.2 with an accuracy of 0.027. This range should sufficiently handle the rock types for geothermal drilling.

Sonic Log

The sonic log is basically a small sonar-type device. An appropriate transducer is used to launch sound waves from the drill string through the mud out into the surrounding formation. Using multiple receivers spread along the axis of the drill string, the speed of the shear and compression wave components can be estimated. Knowing the mass density of the formation from the gamma-gamma log, formation mechanical properties can be deduced. These include Young's modulus, Poisson's ratio and the shear modulus. If a priori or topside information is available on the elastic moduli of formation, that a priori formation may be used in conjunction with the speed of sound data to estimate the porosity of the rock. At the present time, commercially available sonic logs are quoted as being available for temperatures up to 205°C. It should be remembered that this device is fairly complex including as it does transmitter, receivers, and signal processing equipment. Of all of the various instrumentation techniques, this particular one will

probably exhibit the highest degree of sensitivity to ambient temperature; however, it is well within the capability of present technology. The measurement range is 250-1500 μ s with an accuracy of $\pm 10 \mu$ s.

Directional Sensor

The directional sensor has two functions, drift angle and inclination angle. Direction sensors are commercially available now and are used routinely in logging operations. In order to determine the drift direction of the hole it is necessary to make reference either to a stable platform or to some external directional reference. Magnetic north is customarily used as an external reference. One of the major weaknesses of using the magnetic reference for drift direction is that it will not function within a casing. This may not be a serious problem in RDIS because of the fact that it is unlikely that the casing will be installed at a depth very close to the drill bit (recall that the instrumentation cannister occupies a position in the drill string which is within one or two drilling collar sections of the drill bit itself). To determine inclination angle, a mechanical gravity vector sensor will be used. The drift angle measurement range is 0 - 360° and the inclination angle measurement range is 0 - 90°. Both have an accuracy of $\pm 0.12^\circ$.

Temperature Sensor

A thermistor is used as a temperature sensor. Thermistors are now available which are totally satisfactory for use within the operating temperature envelope. The temperature of the mud is to be measured with a measurement range of 10 - 300°C and an accuracy of $\pm 0.3^\circ\text{C}$.

Mud Pressure Sensors

A pressure transducer will be used to measure mud pressure across the drill string and inside the drill string. There are currently devices available which can be used in geothermal downhole environments. The measurement range across the drill string is 0 - 3000 psi; inside the drill string the absolute hydrostatic pressure range is 0 - 30,000 psi. The resolution in both cases will be ± 25 psi.

Strain Gauges

Strain gauges will be used to monitor the forces applied to the drill bit by measuring the stress levels in the drill string immediately above the drill bit assembly. Several types of commercially available strain sensors are suitable for use in the downhole environment.

Four quantities are measured by the strain gauge. The mean axial stress and 1σ axial stress are measured in pounds from 0 to 100,000 with a precision of 500 pounds. The mean torsional and 1σ torsional torque are measured in foot-pounds from 0 to 20,000 with a precision of 300 foot-pounds.

Acceleration/Acoustic Sensors

Acceleration sensors will be used to monitor acoustic and vibrational phenomena associated with the rotating drill bit. Commercially available sensing units are suitable for use in the downhole environment.

Microprocessor For Downhole Control and Data Management

The sensor package contains a microprocessor which controls its measurement protocol. Thus, the protocol can be modified using the surface/downhole command link. For example, if the drilling platform operator decides that measurements of temperature are needed more frequently than previously programmed, the system can be reprogrammed to increase the frequency of measurements.

This downhole control system is also used for data management, downhole communications coordination, data storage and sensor data preprocessing which is necessary downhole. The downhole control system is used for the very important Red Flag transmission. This is an indication of some special problem such as a blowout or some special formation of interest. This flag can be used to indicate an area which should be logged continuously instead of periodically or to indicate the need for initiation of emergency safety measures.

3.1.5 Data Block Structure

Based on the foregoing, a typical data block structure (see Table 3-1) has been derived. The indicated data structure applies for the average drilling

Table 3-1. Typical Block Structure

TYPICAL MESSAGE STRUCTURE

SENSOR	MEASURED QUANTITY	NOMINAL MEASUREMENT INTERVAL (FT)	MEASUREMENT RANGE	MEASUREMENT ACCURACY	NO. BITS PER DATUM	NO. BITS PER 30 FOOT DRILL PIPE
LATEROLOG	RESISTIVITY (LOG OF OHM-M) (MUD, DISTURBED, UN-DISTURBED FORMATION)	5	10^0 TO 10^{+6} OHM-METERS	$\pm 12\%$	6	108
SPONTANEOUS POTENTIAL (ELECTRIC LOG)	Z COMPONENT OF POTENTIAL GRADIENT (MUD, DISTURBED, UN-DISTURBED FORMATION)	5	± 30 mv/m	± 1 mv/m	6	108
$\gamma - \gamma$ LOG	SPECIFIC GRAVITY	5	1.8 - 2.2	0.027	4	24
3D SONIC LOG (2.5 METER SPACING)	TRANSIT TIME (μ -SEC) (COMPRESSION, SHEAR, AND MUD WAVE)	5	250 - 1500 μ s (1.7 - 10 KM/SEC)	± 10 μ s	6	108
DIRECTIONAL SENSOR	DRIFT ANGLE	30	0-360	$\pm .12$ DEG	11	11
	INCLINATION ANGLE	30	0-90	$\pm .12$ DEG	9	9
THERMISTOR	TEMPERATURE OF MUD (DEG $^{\circ}$ F)	5	10-300 $^{\circ}$ C	$\pm .5^{\circ}$ F	9	54
PRESSURE TRANSDUCER	MUD PRESSURE (PSI)					
	a) ACROSS DRILL STRING	30	0-3000	± 25 PSI	6	6
	b) INSIDE DRILL STRING	30	0-30,000	± 25 PSI	9	10
STRAIN GAGES	FORCE/TORQUE ON DRILL BIT					
	a) MEAN AXIAL (LB)	30	0-100,000	± 500 LB	7	7
	b) 1σ AXIAL (LB)	30	0-100,000	± 500 LB	7	7
	c) MEAN TORSIONAL (LB-FT)	30	0-20,000	± 300 LB FT	5	5
	d) 1σ TORSIONAL (LB-FT)	30	0-20,000	± 300 LB FT	5	5
ACCELERATION/ACOUSTIC SYSTEM STATUS MONITOR	DRILLING/DRILL BIT STATUS	30	(6 INDEPENDENT STATES)		6	6
	SENSOR PACKAGE STATUS	30	(16 INDEPENDENT STATES)		16	16

TOTAL NUMBER OF BITS FOR
A FULL DATA TRANSMISSION =

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environment where monitoring of the various sensor outputs is intended without particular emphasis on logging. When a zone of interest is encountered, the command (Type I) link may be used to cause more frequent sampling intervals via the downhole microprocessor for particular sensors. Comments on some of the sensor accuracies and resolutions in Table 3-1 are given below.

The limit to electrical resistivity and potential gradient resolution is on the order of one foot, the diameter of the drill hole. Measurement accuracies are constrained to be compatible with estimated capabilities associated with high temperature electronics assuming no complex techniques are employed. It should be noted that these measurement precisions match or exceed those obtained with current logging practices.

The $\gamma - \gamma$ log accuracy/range parameters were chosen to be consistent with current logging techniques. Resolution of density variation along the axis of the hole is limited to the radial distance. For example, density of the formation at a radius of three feet from the center of the hole should not be sampled more frequently than once every three feet in depth.

The 3-D sonic log accuracy requirements are consistent with today's standard practices. It should be noted that a microprocessor whose component technology is analogous to that tested as described in Section 2.2.2 is required to compress the 3-D sonic log natural output bandwidth to the indicated level.

Directional sensor drift and inclination angle measurement accuracies reflect current needs in this area. It is estimated that inclination angle accuracy, using current state-of-the-art in accelerometer technology, will be sufficient to the need. Drift (i. e., azimuth) angle measurements relative to the earth's magnetic field are also feasible within current state-of-the-art. However, in order to obtain the absolute accuracy required, bias corrections reflecting the uncertainty of the earth's magnetic field with depth must be applied if 0.12° drift uncertainty is to be accomplished. Without such bias corrections, the accuracy of the drift angle is estimated to be $\pm 1^\circ$ under normal conditions, and lower in the vicinity of magnetic anomalies. Directional data may be taken as often as desired along the length of the hole.

The thermistor, pressure, and strain measurement accuracies are all within the competence of off-the-shelf sensor hardware today. Although higher precisions could be obtained, it is judged that the stated levels will be sufficient for evaluation of geothermal formations and geothermal well drilling operations. For example, it is accepted that a well kick, to be of a significant nature, will exhibit a pressure discontinuity of at least 30 psi in the outer annulus mud pressure. Similarly, a kick which escalates into a blow out usually exceeds 100 psi with regard to annulus mud pressure. Balanced drilling usually requires that annulus mud pressure be maintained within 50 to 300 psi of the formation pressure if penetration rate benefits are to be obtained. The stated pressure measurement accuracies satisfy all of the operational requirements mentioned above.

The acceleration/acoustic sensor is intended to identify critical drilling modes and conditions. First, drilling dynamic motions (bouncing, rifling) are to be identified, so that appropriate corrective action (rotation rate, bit weight and/or mud flow rate modification) can be taken. Second, bit wear status/bearing wear-failure conditions are to be identified, so that "green" bits are not pulled nor are worn bits to be used to destruction (which causes "fishing" expeditions). Thirdly, it is desired to ascertain whether brittle or plastic cutting modes (which laboratory tests have shown to be the causal phenomena associated with the increased penetration rates observed during balanced drilling) are in operation during the drilling process. Since the output of the acoustic sensor will be wide-band (0-1000 Hz), it is anticipated that spectral criteria can be defined, based on experience gained over the first few years of operation. These criteria will be inserted as masks within the downhole processor against which the acoustic data may be tested. The results of these tests will be sent up within the typical telemetry block as status bits.

3.2 Instrumentation System Design

Mechanical integrity is a high priority objective to all elements of the geothermal lithospheric link telemetry system. Because the most severe pressures and temperature occur at the deeper depths and because the highest vibration/shock levels occur at the face of the drill bit, it is reasonable to assume that the instrumentation package being located in the portion of the drill string nearest to

the bit will be operating under the worst case mechanical stress level. Wideband Mechanical Stress Data⁽¹⁾ has been recorded for the bit weight, torque, bending moments, and accelerations at the drill collar just above the bit in wells about 5000 feet deep.

The nominal bit weight in these wells was 30,000 lb. with peaks 3.5 times as high. The nominal bit weight in a 15,000 foot well will be 60,000 lb. with peaks of 210,000 lb. It is expected that moments and accelerations will vary with bit weight. The forces, moments and acceleration outlined for the 15,000 foot well below, reflect twice those measured in the 5000 foot wells.

- a. Bit Weight - Nominal - 60,000 lb.
Peak - 210,000 lb.
- b. Torque - 10,600 ft. lb.
- c. Bending Moment - 8,000 ft. lb.
- d. Axial Accelerations - 8 g's
- e. Angular Accelerations - 600 rad/sec²
- f. Radial Accelerations - 8 g's

A candidate load carrying member (see Figure 3-2) has been checked for stresses as a result of the bit weight, moments and mud pressure. The outside mud pressure is 15,200 psi while the mud pressure inside the instrumentation package is 17,200 psi.

Using the standard drill collar steel AS14145H at Brinell hardness of 285-341 (115,000 psi yield strength), it is recommended that the outer tube be 6.75 in. O.D. by 6.00 in I.D. The maximum stress (principal stress axis) in the tube is 50,000 psi. In order to take maximum advantage of the mud convection cooling, it was decided to house the electronics in an inner coaxial tube. The (mud) coolant circulates between the inner and outer tubes. Using a 5.25 in. O.D. by 4.0 inch I.D. electronic housing and assuming the electronics housing has no internal support and is at one atmosphere pressure, the (hoop) stress is 92,000 psi compression. Both inner and outer tubes exhibit peak stress loads

(1) "Research Tool Shows What Happens Downhole," Ferguson, The Oil and Gas Journal, 8 January 1968.

- AXIAL LOAD - 60K # NOMINAL, 210K # PEAK
- TORQUE - 11,000 FT-LBS
- BENDING - 8,000 FT-LBS
- ACCELERATION - 8 G'S
- HYDROSTATIC PRESSURE - 17,000 PSI
(ASSUMES 12" NOMINAL HOLE AT 15,000 FT IN HARD ROCK)

SATISFIED BY: - 6.75 OD x 6.00 ID TUBE
 - MATERIAL IS STEEL, A514145H,A
 STANDARD DRILL COLLAR MATERIAL & SIZE

5 1/2 x 4 1/4 ELECTRONICS HOUSING

Figure 3-2. Mechanical Environment (At Drill Bit)

within the yield strength of the material. In the event that a shock absorbing sub exists between the drill bit and instrumentation package, the peak loads will be less than the 210,000 lbs. used in the stress calculations and a greater safety factor results.

Figures 3-3 and 3-4 show a design concept for the instrumentation package utilizing the above analysis. Approximately 3700 cubic inches are available internally for packaging of the instrumentation and associated prime power assuming an outer envelope constraint consistent with the 6.75 inch by 30 foot drilling collar. The electronics housing is supported longitudinally by an end cap-detente ring combination. Lateral supports (not shown) are spaced at 120° intervals within the electronics housing-load carrying collar annulus. Downward flowing mud also flows in this annulus.

The instrumentation modules are packed axially within the electronics housing. Interlocking center pins within the modules provide a continuous axial support for longitudinal restraint. Lateral restraint is provided by a shock absorbing sleeve between the electronics modules and the interior cylindrical surface of the electronics housing. Cabling channels are provided for wiring harnesses from module to module. The volumetric budget is:

Prime power (1 Kw-Hr @ 1 watt-hr/in ³)	1000 in ³
Instrumentation electronics	900 in ³
Data processing and telemetry interface	300 in ³
Growth (50%)	1100 in ³
Mechanical support and wiring harness	<u>100 in³</u>
	3400 in ³

Figure 3-3. Mechanical Design Concept

Figure 3-4. Instrumentation Packaging Concept

4.0 DRILLING CONTROL LOOP DESIGN

Drilling expertise is currently very much of an art depending greatly upon the accumulated experience of the operators and their expert consultants. Consequently, it is apparent that no completely automated computer control system is advisable at this time. Rather, precise operational data and operational recommendations should be provided to the operator (including his expert advisors as needed) for his decision and actions. In effect, this makes the operator a part of the control loop, as illustrated in Figure 4-1. As shown, he can request any information needed and also can exercise the optimization programs resident in the remote computer. The on-site microprocessor controls the flow of information among the various units.

As in the normal drilling rig, the operator can exercise control at well top by adjusting hook load, which directly affects weight on bit, and by adjusting mud flow rate and drill string rotary speed. He also can gradually change mud properties and periodically change the bit type. He may also initiate blow out protection measures through the blow out preventer stack.

In addition, he may request information from any source via the console and microprocessor, including the downhole sensor package, on-site storage or the remote computer. For example, when the operator requests drilling recommendations from the remote computer via the console, the microprocessor automatically provides the computer with the request and relevant stored data. It then routes the recommendations back to the display console. The operator may also exercise downhole commands via the link if desired. A typical example of this would be a packer device inserted downhole for assistance in blow out protection and capable of responding to a telemetered command.

Lists of data and parameters handled by the closed loop drilling system are given in Tables 4-1 through 4-5.

4.1 Wellhead Data Management and Control System (WEDMACS)

The Well Head Data Management and Control System (WEDMACS) comprises the console, microprocessor and recording equipment at well head, as indicated in Figure 4-1. It integrates and displays all types of data, namely, well top data, well bottom data and stored and recently recorded information. It further derives

Figure 4-1. Closed Loop Drilling System

Table 4-1

Key Drilling Data And Parameters Displayed To Operator

● **Key Drilling Parameters**

Bit conditions - wear, dynamics
Power, torque and bit weight applied to drill bit
Mud pressure differential across bit
Downhole temperature
Directional data
Penetration rate (average and instantaneous)
Rotary speed
Mud flow rate
Mud properties
Mud flow rates (in, out)
Choke hydraulic pressure
Pipe rotational friction (wellhead - drill bit)
Equipment status
Current logging data

● **Key Drilling Data**

Hole history to date (past drilling parameters)
Downhole configuration (bit, drill collars, subs, etc.)
Drilling plan
Logging data to date
Records for nearby wells

Table 4-2

Display/Control Commands And Information Requests

- Downhole Sensor Measurement Program
- Execution Request For Remote Computer Processing
- Request For Data Dump to Remote Computer
- Entry/Storage of Daily Drilling Reports
- Hard Copy of Displayed Information
- Recall/Display of Drilling Data/Parameters
- Clear Red Flag Condition
- Equipment Calibration/Test (RDIS Operator only)

Table 4-3

Well Head Data Inputs

- **Drill bit depth**
- **Penetration rate**
- **Hook weight**
- **Estimated bit weight**
- **Torque on drill string**
- **Drilling table rpm**
- **Mud density and other properties**
- **Input mud pressure (at kelly)**
- **Output mud pressure (at choke)**
- **Input mud flow rate**
- **Output mud flow rate**
- **Input mud temperature**
- **Output mud temperature**
- **Gas shows at mud exit**

Table 4-4
Downhole Data (1)

- Laterolog - Bulk Resistivity/Conductivity of
 1. Mud
 2. Mud formation interface
 3. Formation
- Spontaneous Potential
- Gamma - log - rock density distribution
- Sonic log - hole diameter and rock porosity
- Magnetic and gravitational directional sensors
- Pressure sensor
- Temperature sensor
- Strain gauges - forces and torques at drill bit
- Accelerometers - acoustical and vibrational phenomena
- Red flag
- System status monitor message
- Error detection/correction codes

(1) Complete typical message structure discussed in Section 3.0.

Table 4-5

Downhole Commands

Downhole RDIS Commands

- **Sensor Measurement Commands**
- **Red Flag Limit Set**
- **Repeater Telemetry Synchronization Signal**
- **Repeater Bandwidth/Frequency Control**
- **System Self-Test Commands**

Downhole Assembly Commands

- **Reconfiguration Commands (e.g., Directional Drill, Packer, Pyrotechnics, etc.)**

and displays key drilling parameters, recommendations for further data to be taken, and red flag catastrophe warnings. It provides situation data to the operator as requested via the console. Red flag and data requests are displayed on the console immediately, however, for operator action. Tape recorded data can be formatted to assist the operator in semi-automatic generation of the daily drilling report. See Figure 4-2 for a functional block diagram of this WEDMACS.

4.1.1 Microcomputer

The heart of the WEDMACS is the microcomputer, which by way of example is specified as a Raytheon RP-16. This machine interfaces with all of the components of the system. The major tasks performed by the RP-16 are as follows:

1. Coordinate the input and output of data from the system based on operator specified information.
2. Command the MUX and A/D to read and convert the wellhead data periodically. The periodicity is operator specified but typically would be every twenty seconds. This data would be time tagged and stored on the magnetic tape cassette. The time tag and the decisions on when to poll the wellhead data are based on inputs from a digital clock.
3. Continuously check for the receipt of a red flag from the downhole sensor. If so, declare the existence of a red flag situation and activate the kick alarm.
4. Accept operator inputs concerning automatic transmission of downhole commands. Such an input might specify that measurements A, B, and C are to be made and stored by the downhole sensor every n feet. The RP-16 would determine when the n feet had been drilled (by looking at the depth gauge input from the wellhead data) and then automatically forward the proper commands to the downhole transmitter.
5. Read unformatted digital data sent from the downhole sensor via the lithospheric link upon operator command. This data will be decoded by the RP-16. This decoding can be performed since the RP-16 had

Figure 4-2. Well Head Data Management and Control System (WEDMACS)

previously formatted and forwarded the command word which resulted in the transmission. The command word would request specific results in a specific order. The uplinked data will be formatted into 16-bit words and stored on the magnetic tape cassette.

6. Read the uplinked sensor data and extract the sensor system status word. The state of this word will be used to drive the sensor status display panel which will report on the condition of the sensor package.
7. Upon operator command, forward the data stored on the magnetic tape cassette and operator assisted daily drilling report to a remote computer via a telephone in the acoustic coupler. The complete transmittal of one day's data and the daily drilling report will consume less than 6 minutes.
8. Upon operator command, implement conversational mode between graphics terminal and remote computer to exercise drilling optimization programs. This mode will provide key drilling parameter information to the operator via the terminal for his use in controlling the drilling.
9. Accept operator keyboard entries from the graphics display terminal and either act on them or pass the data to the remote computer, depending on the mode of operation specified by the operator.

4. 1. 2 Graphics Display Terminal And Remote Computer

The other major component of the WEDMACS is the graphics display terminal with keyboard and hard copy unit. This serves as the display and control console shown in Figure 4-1. It allows the operator to command the WEDMACS and to converse with the remote computer. The remote computer is not a part of WEDMACS but it is an integral part of the overall drilling system. Computer programs in the remote computer will "optimize" drilling parameters based on operator inputs and data sent from WEDMACS. The remote computer can generate daily drilling reports automatically based on inputs from WEDMACS. The remote computer can file and sort data upon operator command and ship back to WEDMACS data to be displayed graphically.

4. 1. 3 Cost Estimate For WEDMACS

To provide information to be used in the Cost Benefits Analysis of Section 5. 0, preliminary cost estimates have been made for the WEDMACS. It was assumed that all of the system is capital equipment except for the remote computer which is used on a rental basis. The production cost of WEDMACS electronics hardware and display equipment is estimated to be \$25K.

5.0 COST BENEFIT ANALYSIS

A case study was performed for the Interim Report based on the geothermal repeater system configuration which is described in the Appendix. This case study provided an estimate of RDIS benefits associated with drilling a moderately deep (15000 ft.) hole into a geothermal producing zone. A cost model was developed to define RDIS rental rates in an operational environment. A rental rate of \$1038 per day was derived including maintenance and replacement of RDIS hardware, transportation/logistics of supporting RDIS operations at continental U. S. drilling sites, on-site RDIS operating personnel, general/administrative expenses, and rental company profits. The case study demonstrated well drilling cost reduction of as much as 24% when the RDIS is used plus additional benefits which are difficult to assign cost savings until there is operational experience in use.

Based on the new non-repeater system configuration for oil well drilling described in this final report, this cost analysis is considered more conservative and valid for the following reasons. The hardware costs (see Table 5-5) included 9 downhole average terminal and repeaters for \$10K each equal to \$90K. We now have one downhole transmitter and receiver with no repeaters. This significant hardware reduction cost (and associated maintenance) is only partially offset by the increased cost due to following: downhole terminal including 3 cannisters vs. previous 2; boron epoxy special antenna cannister vs. previous all metal, and increased downhole transmitter power supply with more primary batteries with associated replacement costs. Therefore, the cost benefit analysis is repeated herewith with our confidence that it can be considered more conservative in its conclusions.

It is also appropriate to quote from a recent study done for ERDA. Reference "Borehole Measurements While Drilling - Systems and Activities" by Maurer Engineering Inc., dated June 1977; page iii. "Market analysis indicates pricing potential on the order of \$1000 - \$2000/day for the directional services and perhaps \$2000 - \$4000/day for drilling efficiency measurements". We expect that we could price an electromagnetic system providing both directional and drilling efficiency services in the lower range of \$1000 - \$2000/day.

5.1 Typical Geothermal Well

To provide a quantitative base for examining cost savings, the parameters of a typical geothermal well have been established. The well depth is 15,000 feet and the drilling rate while making hole is estimated at 12 ft. per hour, based on the assumption of moderately hard rock. Parameters selected have been obtained from knowledgeable representatives of the drilling industry. They are listed in Table 5-1. Total cost to drill this well is \$1.232 million.

5.2 Improvements With Downhole Information System

Based on consultation with drilling experts, it has been estimated that improvements (Table 5-2) can be realized based upon the information provided through the link by the downhole instrumentation.⁽¹⁾ Improved knowledge of the lithology as well as detailed information on bit motion, downhole environment and instantaneous torques and forces in the drill string will result in reduced time for making hole, increased bit life, reduced bit costs, reduced trip time, and reduced mud costs. The need for independent logging and angle deviation measurements will be essentially eliminated since the instrumentation package automatically records much logging data.

5.3 Cost Comparison⁽²⁾

Drilling time and cost parameters for a typical 15,000 foot well have been combined with the savings estimates of Table 5-2 to define RDIS benefits (see Table 5-3). Total savings per well during the initial year of RDIS availability are estimated as \$83K or 7% of the cost without RDIS. After RDIS experience has been gained, five years later, savings for the typical well should increase to \$296K or 24%. This is the typical "learning curve" improvement experienced in many industries.

A key factor in producing the savings is reduction in time on site which results from more efficient drilling. Time on site with a mature system will be reduced from 96 to 67 days. Another interesting parameter is the break-even link rental. This is the link rental cost for which net benefits (decreased

⁽¹⁾ See Section 3.1 for full technical discussion of benefits.

⁽²⁾ All costs are in 1976 dollars.

**Table 5-1. Typical Geothermal Well
(Without Downhole Information System)**

•	WELL DEPTH - 15,000 FT			
•	AVERAGE DRILL RATE (MAKING HOLE) 12 FT PER HOUR			
•	TIME ALLOCATIONS - HOURS			
	MAKING HOLE	1250	CONNECT	80
	TRIPPING	450	LOGGING	80
	RIG UP, TEAR DOWN	150	ANG DEV MEAS	20
	SET CASING	120	MAINTENANCE	150
	• TOTAL 2300 HRS (96) DAYS			
•	RIG RENTAL AND CONTINUOUS SERVICE			
	\$ 9K PER DAY			
•	MATERIALS AND INTERMITTANT SERVICES			
	DRILL BITS	60K	LOGGING	18K
	CASING	200K	ANG DEV MEAS	10K
	MUD	80K		
	• TOTAL \$ 368K			
•	TOTAL COST	\$1232K		

Table 5-2. Impact of RDIS on Drilling Costs

	<u>WITHIN FIRST YEAR</u>	<u>AFTER FIVE YEARS</u>
• <u>REDUCES</u> MAKING HOLE TIME	10%	30%
• <u>REDUCES</u> BIT COST, TRIP TIME	20%	50%
• <u>REDUCES</u> MUD COST	20%	50%
• <u>ELIMINATES</u> LOGGING	-	-
• <u>ELIMINATES</u> ANGLE DEVIATION MEASUREMENTS	-	-
• <u>ADDS</u> RENTAL COST - INFO SYS	\$ 1038/DAY	\$ 1038/DAY
• <u>ADDS</u> LINK TRANSMISSION TIME	42 HRS	42 HRS

Table 5-3. Tangible Benefits⁽¹⁾ of RDIS

Case Study: 15, 000 Foot Well Into Moderately Hard Formation

Time Allocations (Hrs)	Current Practices	With RDIS Technology	
		New Technology	Mature Technology
• Making hole	1250	1125	875
• Tripping	450	360	225
• Rig up/Tear down	150	150	150
• Set casing	120	120	120
• Connect	80	80	80
• Logging	80	0	0
• Angle deviation meas.	20	0	0
• Maintenance	150	135	105
• RDIS operation	<u>0</u>	<u>42</u>	<u>42</u>
Total Time	2300 Hrs (96 days)	2012 (84 days)	1597 (67 days)
Rig Rental & Continuous Service Costs @ \$9000/day	\$864K	\$ 756K	\$ 603K
Materials and Intermittent Services			
• Drill bits	\$60K	\$ 48K	\$ 30K
• Casing	\$200K	\$ 200K	\$ 200K
• Mud	\$80K	\$ 64K	\$ 40K
• Logging	\$18K	0	0
• Angle deviation meas.	<u>\$10K</u>	<u>0</u>	<u>0</u>
Total Cost	\$1232K	\$1068K	\$ 873K
Gross Benefits		\$ 164K (13%)	\$ 359K (29%)
RDIS Days on Site		78 days	60 days
RDIS Rental @ \$1038/day		\$ 81 K	\$ 63 K
Net Benefits		\$ 83K (7%)	\$ 296 K (24%)
Break Even Rental Rate		\$2102/day	\$5983/day

⁽¹⁾ All costs assume 1976 dollars.

drilling costs plus RDIS charges) would be zero. The amounts given, \$2102 per day within the first year, and \$5983 per day after five years, are much higher than the actual estimated rental cost, \$1038 per day. This implies that the RDIS system has the advantage of costing considerably less than it is worth to the driller.

Beyond those specific quantifiable elements addressed in Table 5-3, substantial additional benefits to the geothermal community result directly from RDIS availability. These are summarized in Table 5-4.

5.4 Estimated Link Rental Cost

The link rental cost has been estimated as indicated in Tables 5-5 and 5-6. For this analysis, all development and other non-recurring charges have been excluded. Thus, the results give the costs for continuing the rental service once it has been started. The analysis is based on a deep, wet, cased well requiring 13 repeater stations. ⁽³⁾

The manufacturing or purchase cost of each item of hardware has been estimated based on the preliminary hardware configuration. Taking a conservative approach, the downhole equipment is assumed to last for only one year because of the rugged geothermal environment. The topside equipment useful lifetime is estimated at four years. The average number of repeaters (including the bottom terminal) which must be on hand at the well is nine.

Prorating over the useful equipment life, the downhole equipment costs \$120,000 per year of operation. Topside equipment replacement cost is \$14,000 per year. To find the charges which must be made to the driller, additional factors must be added:

Interest on money	10%
Annual inflation rate	10%
Down Time (% of time equipment is not in use because of maintenance requirements or scheduling difficulties)	25%
Administrative and profit (G & A plus fee)	25%

⁽³⁾ Most wells (e. g., GT-2) would require less than 13 repeater stations.

Table 5-4. Additional Benefits of RDIS

- **Less Environmental Impact**
 - More effective blow out avoidance/control
 - Better control/knowledge of mud pollution into formation
 - Smaller number of "dry" holes
- **More Rapid Growth of Geothermal Energy Sources**
 - Reduced resource exploitation cost
 - Wider range of geothermal resources fall into "exploitable" category
 - More accurate downhole data speeds geothermal drilling learning curve
 - More accurate downhole data allows wider range of geothermal well completion techniques and higher proportion of geothermal producers to total wells drilled
- **Enhanced Reconfigurable Downhole Assembly Technology**
 - Directional drilling control and feedback
 - Chain bit control/monitor
 - Packer control/monitor
 - Real time monitoring of cementing operations

Table 5-5. Hardware Costs

EQUIPMENT MANUFACTURE AND PURCHASE		(\$K)
(EXCLUDES NON-RECURRING CHARGES)		
DOWN HOLE (1 YEAR)		120 (PER YEAR)
TERMINAL AND REPEATERS-9 AVERAGE	90	
AT \$10K EACH		
SENSOR PACKAGE	<u>30</u>	
	120	
TOPSIDE (4 YEARS)		14 (PER YEAR)
WELL HEAD PROCESSING	25	
XMTR, RCVR, DECODER, ANTENNA	16	
VAN	<u>15</u>	
	56	
INTEREST AND INFLATION	(20%)	26
25% DOWN TIME		54
G & A PLUS FEE (25%)		<u>54</u>
TOTAL		\$268 K PER YEAR
• HARDWARE RENTAL CHARGE: \$734/DAY		

Table 5-6. Estimated Link Rental Cost

•	HARDWARE RENTAL		\$ 734 PER DAY
•	LABOR AND DATA PROCESSING	\$ PER DAY	
	2 SPECIALISTS AT \$1500/MONTH	100	
	1 TECHNICIAN (20 HRS/WK AT \$8/HR)	23	
	OVERHEAD ON LABOR (60%)	74	
	REMOTE COMPUTER CHARGES	20	
	G & A PLUS FEE (25%)	<u>54</u>	
			\$ 271 PER DAY
•	TRANSPORTATION		
	\$3000 FOR 90 DAYS		\$ 33 PER DAY
	<u>TOTAL RENTAL COST</u>		<u>\$1,038 PER DAY</u>

The resulting equipment related portion of the rental charge is therefore \$268,000 per year or \$734 per day.

Table 5-6 combines the above results with labor, data processing and transportation cost estimates. Labor rates quoted are somewhat higher than are found currently in the drilling and logging industries for skilled personnel. As shown, total rental cost comes to \$1038 per day.

5.5 Catastrophe Avoidance Savings

The above analysis demonstrates that considerable benefits may be expected during routine drilling. It has not addressed the many other benefits listed in Table 5-4. Of particular interest are the cost savings due to prevention of catastrophic events.

Catastrophic events include blow outs from high pressure and pieces of broken drill bit which must be fished out. If not controlled in time, a blow out can be very dangerous and very costly due to destruction of equipment and harm to personnel. Fishing expeditions for drill bit pieces can consume considerable time over which drilling is held up. These items are difficult to quantify but they have a significant cost impact. The downhole sensors will provide timely warning to trigger prevention measures resulting in very great savings.

6.0 RDIS COMMERCIAL DEVELOPMENT PLAN

In the Interim Report a commercial development plan was presented for a geothermal repeater system configuration as described in the Appendix. That plan is revised herewith to reflect the new single hop system configuration for application in oil well drilling. The initial introduction of this system into oil well drilling makes good commercial sense for assuring its availability at a reasonable cost to geothermal drilling. Since the oil (and gas) drilling market in the near future is anticipated to remain much larger than geothermal, acceptance in that market will permit more attractive pricing for geothermal application.

Commercial acceptance of RDIS is obviously dependent on proof of its telemetry capability in a drilling operation. A variety of sensors exist for measuring downhole data; however due to the slow progress of developing a commercial telemetry link, there has not been significant packaging development of the available sensors for use downhole in conjunction with a telemetry system. (One publicized example of an operational configuration is Teleco, Inc. development of a mud pulse telemetry system combined with a directional sensor.) In the development plan presented herein, a final choice has not been made of downhole sensors to be included in the Instrumentation section of the hardware. As a minimum, we would anticipate directional, temperature, acceleration, and pressure sensors.

A preliminary plan to provide 10 RDIS systems for operational field deployment within 40 months after Phase I contract award (ACA) has been generated. During Phase I, RDIS hardware is evaluated in an operating drill rig under moderate temperature and mechanical stress conditions. Brassboard (B/B) level equipment is used throughout. Phase II, which is initiated on successful completion of the B/B tests, consists of the development, test, and field demonstration of a complete fully qualified RDIS prototype system. This system will operate under the full mechanical/thermal environment. A three month interval is allocated at the end of Phase II for field demonstration to potential customers of the prototype RDIS system at one or more selected drilling sites. Phase III, commercial systems deployment, is initiated upon prototype checkout and demonstration.

The preliminary development plan has been structured to provide key demonstrations and milestones for management evaluation of RDIS technical and economic performance levels as the development cycle proceeds.

The first key decision (9 months ACA) in the development plan is whether to proceed with full prototype RDIS design. At this point in the program, key system elements will have been tested at the B/B level in the field to establish their performance parameters. Available engineering test data will include surface and downhole electromagnetic noise environment under static, mud flowing, and making hole conditions, signal propagation phenomena in both cased and uncased holes, and brassboard hardware mechanical and electrical performance levels at moderate (5000 feet, 150°C) stress levels. Since the prototype RDIS is to exhibit full system performance levels, certain subsystems (e.g., prime power source, power amplifier components, structural shell) will require further moderate level development. Therefore, vendor evaluation is conducted to identify any prototype RDIS development problems and to define courses of action alleviating undue schedule/performance risk prior to the decision point.

The second key management decision (21 months ACA) is whether to commit resources to production tooling and assembly line infrastructure and to buy long lead items associated with production of commercial units. Data on which this decision is made will include, at a minimum, demonstrations and test results from fully qualified prototype units under actual operational conditions, full prototype design documentation, complete cost estimates (including bids from qualified vendors for production quantities of required hardware), and a strong positive indication of the user market.

During the period while the initial commercial system is being produced, the prototype RDIS will be used for additional demonstration purposes to show the tangible and intangible cost benefits. Upon completion of the first commercial system, the prototype hardware will be reworked as required for delivery as the second commercial system.

6.1 Phase I: Brassboard RDIS Hardware Proof of Principle Test

Phase I is designed to provide low cost/low risk RDIS hardware and to validate the RDIS design approach through a series of field tests. Existing

Raytheon owned hardware will make up a major fraction of the equipment needed for "proof of principal" testing. This equipment will be of brassboard (B/B) character, designed for electrical performance at reduced environmental stress levels. Packaging constraints and long term reliability requirements will be relaxed to allow greater flexibility in electrical performance and to minimize costs associated with the rework and/or in-field modifications normally associated with initial field trials.

The topside transmitter consists of a commercial (10 KW) cycloconverter mounted in the same truck trailer used for previous experiments and a transmitting topside antenna consisting of a 30 meter diameter ten turn loop of insulated wire. The receiving antenna system will consist of the transmitting antenna and three similar antennas. Each antenna will be connected to a receiver front end (preamplifier, 60 Hz notch filter, multiplexed A/D converter) and received signals will be processed to remove natural and drill rig induced noise. A Raytheon type 703 minicomputer (with 16K words of memory and a 1 μ s cycle time) will simulate digital processing techniques envisioned for the commercial grade systems. The minicomputer will also be used to simulate the WEDMACS system, including topside transmitter control and other WEDMACS functional requirements, so that the topside system performance can be demonstrated.

Since all of the above equipment either exists from Raytheon's previous in-house development program or is readily obtainable from standard sources, it is anticipated that these subsystems will be available for integration and field testing at Raytheon's Wayland facility early in Phase I. Noise cancellation digital processing algorithms will be tested for application at the RDIS frequency band and the techniques for conducting validation demonstration at the drilling site will be established.

The existing Raytheon owned terminal will be modified for operation at the RDIS frequency and at the (brassboard) 150°C temperature goal. Some sensor electronics will be included for minimal measurements since Phase I emphasis is on proof of telemetry capability. This brassboard bottom terminal will also contain some diagnostics and data recording electronics to provide a built-in test (BITE) function for the downhole electronics. The mechanical configuration of this terminal is shown in Figures 1-1, 1-2, and 1-3. This brassboard hardware

has been qualified (testing performed at drilling laboratory at University of Tulsa) to 5000 ft. depth at 150°C.

Following subsystem checkout at Raytheon's Wayland facility, the brass-board RDIS system will be shipped to the field for proof of principal testing. The noise cancellation receiver will be activated and performance in the vicinity of the drill rig will be checked. Surface transmitter/bottom terminal/sensor performance will then be checked with the bottom terminal located on the surface. The downhole equipment will then be lowered into the well to permit measurement of downhole noise and to check out communication link performance under static (i. e., non-drilling) conditions at various depths. These tests will be repeated when mud is circulating (but the drill string is not rotating) and when both circulation and rotation are in progress. Following these demonstrations, the mechanical integrity of the system will be demonstrated by leaving the downhole equipment in the drill string while making hole. Data collected will be transmitted to the simulated WEDMACS system. This received data will be displayed and stored on the appropriate Raytheon 703 peripheral units for later comparison when the drill string is pulled with the (identical) data stored downhole on the bottom terminal recorder.

6.2 Phase II: Prototype RDIS System Development and Demonstration

Phase II includes the fabrication, test, and demonstration of a complete RDIS system at the prototype level. On-site prototype system level checkout is followed by the formal prototype system demonstrations to potential RDIS users and other interested parties.

During the RDIS prototype development, full working drawings and related documentation will be generated, vendors evaluated, and cost data established to support the production of commercial units. This information, along with positive user market indications and successful prototype performance are all required for the decision to proceed with full commercial development.

6.3 Phase III: Commercial RDIS System Deployment

Successful system level checkout of a full prototype system will initiate tooling for commercial hardware. Commercial systems will be electrically and mechanically identical to the prototype system except for minor variations required by the manufacturing process.

The first commercial system will be completely new. The second system will be the demonstration prototype reworked slightly to match the final commercial design. Subsequent systems will be produced at increasing frequency until a rate of one RDIS per month is reached. Each commercial system will receive a month of checkout before delivery. Training of field personnel will be initiated early and will continue throughout Phase III to insure adequate support for the commercial system.

6.4 Schedule

Phase I Proof of Principle testing will be performed in first 9 months. Phase II Prototype Development and Demonstration is planned for the next 12 months. Phase III Commercial Development commitment is assumed at the end of the Phase II demonstration period. In addition, during Phase II production preparation will have been completed other than tooling and parts procurement. The first commercial system is planned for 29 months after start of Phase I and a total of 10 commercial systems by the 40 months from start of Phase I. At that time the production rate capability is 1 system a month.

Appendix A

GEOTHERMAL DRILLING TELEMETRY SYSTEM

A geothermal telemetry system was described in the Interim Report. It included an environmental requirement of 275°C. formation temperature. This system employs repeaters at intervals in the drill string; lower power than the oil drilling configuration in the bottom transmitter; does not use a non metallic cover for the downhole transmitting antenna; and includes a total of two subs for all the downhole electronics.

For sake of completeness, the geothermal version is reproduced herewith from the Interim Report with minor corrections and the deletion of Section 2.5, "Alternate Repeater Design for Uncased Wells Only". The system described in this final report in Section 2 provides a better configuration for uncased wells as well as cased wells.

Figure A-i is also repeated on the following page from the Interim Report. It shows the basic system configuration for the following discussion with an example set of operating parameters for a nominal 15000 ft. depth.

Figure A-i Geothermal Repeater Configuration.

2.0 GEOTHERMAL DRILLING TELEMETRY SYSTEM

The telemetry system is a major component of the Raytheon Downhole Information System. It provides the digital communication channels which serve as conduits for control signals from the surface to well drilling equipment downhole and for sensor data from downhole sensors to the surface. The communications hardware (see Figure 2-1) consists of a topside receiver and transmitter, a series of repeaters spaced along the drill string, and a bottom terminal. Propagation and hardware design analyses have been carried out which establish system performance and hardware design requirements.

A telemetry system design has been defined which meets the data link, propagation, and mechanical integrity requirements. This design is consistent with technology levels appropriate to the development program discussed in Section 6.0, RDIS Preliminary Commercial Development Plan. During Phase I of the development cycle, conclusions reached during the engineering feasibility analysis can be validated.

2.1 Definition Of Hardware Systems Requirements

Referring to Figure 2-2, there are three types of lithospheric links utilized in the communication system. The requirements placed on the hardware elements must insure that digital data will be passed through each link uncontaminated by false information regardless of the electromagnetic noise background and any power losses incurred along the path.

2.1.1 Link Categorization

The Type I link shown in Figure 2-2 extends from a signal transmitter on the surface to all downhole hardware elements. This link would be used for reconfiguration of the downhole assembly and for system self-test. Typical examples of reconfiguration might include commands to downhole sensors relating to instrument readout program modifications desired by wellhead personnel and commands to sophisticated (e. g., directional drilling) downhole hardware. Self-test commands might typically task the system to pass a pre-established data set from the bottom terminal to the surface receiver in order to check out link integrity or call for various instrumentation package internal voltage calibration levels. The Type I links might also be employed to initialize, resynchronize, or otherwise align the internal clocking within the time multiplexed repeaters along the drill string.

Because the Type I link transmitter is provided with essentially unlimited prime power (the availability of AC mains associated with a typical drilling operation is assumed) and is unconstrained with respect to size and weight, maintenance of sufficient signal strength to assure error-free reception of commands poses no serious question of feasibility but is rather a matter of implementation. The technology for the generation of electrical power from AC mains is well developed for frequencies of interest (1-30 Hz) and need not be addressed further. The transmitting antenna can consist of a number of satisfactory configurations. A typical configuration consists of several turns of heavy gauge insulated wire arrayed in a 100 meter diameter circle buried a few inches below the earth's surface. Local iron or metallic structures will not significantly affect antenna performance.

The Type II links pose the most stringent problems. These links extend from each repeater to the repeater located immediately above. Since the bottom terminal is identical to a repeater except for an interface with the sensor package, the link from bottom terminal to repeater #1 is also Type II. These links are used to relay data from downhole to the topmost repeater station. Information carried would include digital data from downhole sensors and information as to the status of the downhole instrumentation package.

The hardware associated with Type II links will consist of a series of repeaters. It is intended that each of the repeaters will be self contained, with internal prime power, receiver, signal processing, time division multiplex, transmitter, and antenna. It is desired that each relay station be self sufficient and mechanically equivalent to a piece of drill string, so that there is minimal technology impact on standard drilling practices/hardware. The relay station is housed in a stainless steel canister approximately 7 inches in diameter by 30 feet long. The volumetric restriction imposed by this requirement both limits prime power availability and forces the antenna to be electrically small. Both of these factors limit the maximum allowable spacing ("hop length") between relay stations. An additional factor - the presence of steel well casing - will affect those relay stations within the cased portion of a well. The attenuation of the signal as it traverses the casing further limits the hop length.

Figure 2-1. Raytheon Downhole Information System (RDIS)

Figure 2-2. Three Types of Lithospheric Links

The Type III link which extends from the topmost repeater to the surface is of relatively moderate difficulty. It carries the same information as the Type II link. The transmitter end, being part of a repeater, suffers the same power and attenuation restraints as a Type II link. However, the surface receiving terminal can utilize special antennas and digital processing to discriminate against rig generated and atmospheric originated background noise. The Type III link receiver will therefore be more sensitive than the Type II link receiver. Application of directional receiver signal processing techniques will more than compensate for the anticipated higher noise levels occurring at the surface, where there is no earth overburden to produce shielding of atmospheric generated noise.

Because of the physical effects described above, it is clear that a design satisfying Type II link requirements will be sufficient to satisfy Type I and Type III requirements. Hence, if feasibility can be shown for the Type II link, the feasibility of Type I/III links is not in question.

2.1.2 Propagation Requirements

The requirements for successful propagation of data appropriate to the underground repeater-to-underground-repeater path are derived by consideration of the ambient noise levels at the receiving station, the degree to which the signal levels must exceed noise for fault-free data transmission, the propagation loss from transmitter to receiver, and the effective transmitter strength.

Electromagnetic noise occurring at the receiving end of an underground path originates in the atmosphere and is attenuated as it travels from the earth's surface to the receiver site. Noise intensity with vertical magnetic polarization (to which the receiver is sensitive) has been measured by several different experimenters at various points on the earth's surface. For the frequency range of interest (1 to 30 Hz), it is reasonable to assume that this noise level will not exceed, at the earth surface and at 1 Hz, -115 dBH (decibels relative to a field strength of 1 ampere turn per meter) in a 1 Hz bandwidth and -155 dBH, still in 1 Hz bandwidth, at 30 Hz. Most of the analysis described is developed at the 1 Hz frequency since the hole casing and metallic cover losses are prohibitive at higher frequencies.

Ambient noise will decrease with depth due to the shielding effect of the earth. The rate at which ambient noise decays with depth is dependent upon the real part of the propagation constant, α .

$$\alpha = \omega \left(\frac{\mu \epsilon}{2} \right)^{1/2} \left[\left(1 + \frac{\sigma^2}{\omega^2 \epsilon^2} \right)^{1/2} - 1 \right]^{1/2}$$

where

α = attenuation constant (nepers/meter)

ω = signal frequency (radians/second)

μ = permeability of the medium (henrys/meter)

ϵ = permittivity of the medium (farads/meter)

σ = conductivity of the medium (mhos/meter)

For typical⁽¹⁾ local earth conditions, where $\left(\frac{\sigma}{\omega \epsilon} \right) \gg 1$, it is found that a simpler expression for the attenuation constant is appropriate.

$$\alpha = \left(\frac{\omega \mu \sigma}{2} \right)^{1/2} \text{ nepers/meter}$$

Converting this expression to a more convenient set of units and using the surface noise level of -115 dBH, the subsurface noise level can be predicted from the expression given below:

$$\rho_N = \left[-115 - .0174 (\mu_r \sigma f)^{1/2} z \right] \text{ dB}$$

where

μ_r = relative permeability of earth

σ = conductivity of earth (mhos/meter)

f = signal frequency in Hz

z = depth in meters

ρ_N = noise density in dB relative to 1 ampere turn/meter/Hz

(1) Conductivity between 10^0 and 10^{-6} , permittivity between 10^{-10} and 10^{-11} , and frequencies less than 100 Hz.

The ambient signal level in the vicinity of a relay receiver is a function of the transmitter strength, the spacing between transmitter and receiver and the electromagnetic characteristics of the intervening earth. The expression used to calculate ambient signal strength is given below:

$$S_{AS} = 20 \log_{10} \left[\frac{M(1 + 2\beta R + \beta^2 R^2)^{1/2}}{2\pi R^3} e^{-\beta R} \right] \quad \text{dBH}$$

where

S_{AS} is the ambient signal strength (dB relative to 1 ampere turn per meter)

M = transmitter source strength (ampere turns-meters squared)

β = α , the attenuation constant in nepers/meter $\left(= \sqrt{\frac{\omega \mu \sigma}{2}} \right)$

R = the range between transmitter and receiver in meters

The requirement for reliable transmission of data can be shown to be a function of the signal-to-noise power ratio (SNR) at the receiving station. The telemetry links use 4-phase PSK modulation, so the expression for the bit error rate is:

$$P_{BE} = \frac{1}{2} \operatorname{erfc} \left\{ \sqrt{\frac{\text{SNR}}{2}} \left[1 - \frac{1}{4} \operatorname{erfc} \sqrt{\frac{\text{SNR}}{2}} \right] \right\}$$

where

P_{BE} = the probability that a data bit is received incorrectly

erfc is the complementary error function

SNR is the signal-to-noise power ratio

In order to define an acceptable level for P_{BE} , it is necessary to make several assumptions as to operational factors. Telemetry data is sent from down-hole at 30 ft. intervals as the hole is drilled. For typical (10-15 ft/hr)*drilling rates, a block of telemetry data will be transferred approximately 10 times per day. Each block of telemetry data will contain an error code (e. g. parity check) so that if a bit error occurs during transmission, the wellhead system can request the block be sent again. Since the transmission time for a block of data is not long, it is not inappropriate that repeat transmission requests be required occasionally, say once or twice a day. Based on a 400 bit block length and 12

*Hard rock

repeater stations (12 Type II links), this allowable 15% error rate transforms to the requirement that the probability of a single bit error over a single hop not exceed 3×10^{-5} . Using the equation above, this in turn becomes a requirement that the SNR not fall below 12 dB. Using the previously defined relation for ambient noise density as a function of depth, the required ambient signal level is seen to be:

$$S_{REQ} = -103 - 0.0174 (\mu_r \sigma f)^{1/2} z + 10 \log_{10} BW \quad \text{dBH}$$

where

S_{REQ} = required ambient signal level (in dB relative to one ampere turn per meter (1 AT/meter))

BW = signal bandwidth in Hz

and other parameters are as previously defined.

Because of the special noise rejection receiving antenna used at the surface, it is clear that the topmost repeater can be placed at a depth equal to or greater than the spacing between repeaters. Therefore, a reasonable choice for z is R , the hop length. The equations for S_{AS} and S_{REQ} can be combined to yield a relation for the required transmitter strength, m , as a function of: R , the range between repeaters; BW the bandwidth of the link; f , the signal frequency; and (μ, σ) , the earth's electromagnetic characteristics.

2.1.3 Test Results

Tests were conducted using a breadboard repeater transmitter with the following characteristics:

Number of turns (N_T) = 624

Effective area (Ae_T) = 1.8 m^2

Signal current (I_T) = 3.75 amps (rms)

$M = (N_T Ae_T I_T) = 4212 \text{ ampere turns (meter)}^2$

No casing effects were included in this test.

The ranges at which the tests were conducted were 60 and 84 meters. Measured signal strengths (S_{AS}) were -50.2 and -59.2 dBH, respectively. The signal frequency was 1 Hz. The experimental accuracy is ± 0.5 dB.

Using the previous relation (Section 2.1.2) for S_{AS} , and assuming a conductivity of 0.1 mho/meter and permeability of 4×10^{-7} henry/meter, the predicted signal strengths are -50.2 and -58.7 dBH, in good agreement with the experimental observations.

2.2 Geothermal Link High Temperature Electronics Performance

The high formation temperature (275°C) in which a geothermal drilling system operates poses problems to both functional electronics and to prime power sources within the telemetry stations and instrumentation package.

2.2.1 High Temperature Environment

Computer analyses were performed to estimate the ambient temperature downhole. Typical results (Figure 2-3) indicated that the drilling mud will serve as an effective forced convection coolant, limiting the temperature rise to approximately 60% of the formation temperature relative to the wellhead. For example, if the wellhead mud temperature is 20°C, the mud temperature will increase to a maximum of 173°C for a 15,000 foot hole with a 275°C formation, temperature at bottom, i. e. the mud temperature rise ($173^\circ\text{C} - 20^\circ\text{C} = 153^\circ\text{C}$) is 60% of the change ($275^\circ\text{C} - 20^\circ\text{C} = 255^\circ\text{C}$) in the formation temperature. This analysis presumes that drilling (and mud circulation) has been in progress long enough for a quasi steady state condition to pertain and is adequate for normal making hole operation. During shut-in intervals, the downhole mud will approach formation temperatures asymptotically. The time constant⁽¹⁾ approximates several tens of hours for the rise to formation temperature. Three bottoms up time intervals will elapse before mud temperatures decay to the steady state values from a hot hole.

The thermal conditions in which the geothermal link and instrumentation equipment must survive is thus a dual environment. During mud circulation, the equipment must withstand (and operate under) a 175°C to 200°C environment. If the well is shut in for any significant length of time (longer than a few hours), the equipment must withstand near formation temperatures. Fortunately, the latter high temperature environment can be a storage (as opposed to operational) requirement insofar as the link electronics is concerned.

(1) "Steady State & Transient Wellbore Temperature During Drilling", Wm. J. McDonald, Maurer Engineering Inc., Houston, Texas, ERDA E(10-1)-1546, 20 May 1976.

Brief circulation pauses (such as will occur when adding pipe) will not cause temperatures to deviate significantly from the steady state values.

2.2.2 Component Performance Under Thermal Stress

Sandia Laboratories ⁽¹⁾ was visited to review their technical findings related to the performance of passive electronics components under thermal stress to the 300°C levels. The results are summarized in Table 2-1. It is clear that the thermal performance of passive components is adequate for all anticipated applications except those requiring extremely high precision. The only high precision circuitry in the telemetry link relates to timing and synchronization of the repeater stations.

Precision circuit requirements can be met through oven control, temperature compensation, or resynchronization. All the indicated solutions are feasible within the context of off-the-shelf electronics. The (oven) controlled temperature clock is a brute force approach requiring minimal design effort. A minor penalty is a small (~5%) increase in prime power required to supply the oven heaters. This increase in prime power is mitigated by the fact that it diminishes to zero when the ambient temperature is highest which is when the prime power is most difficult to obtain. Temperature compensation of clock circuits is an alternate approach which involves more extensive design engineering but does not increase prime power required. It is a standard technique which has been used extensively for other applications and which does not increase technical risk associated with the system. In the particular application at hand, the topside transmitter can also be used to resynchronize the repeater clocks on an as-needed basis. If it should prove desirable, this operational mode can be used to relax clock accuracy requirements.

Sandia also reported limited results in the area of simple low power active components. Their conclusions in this area are that MOSFET transistors exhibit the least degradation (i. e. leakage currents) at 300°C and that small scale COSMOS integrated circuits (IC's) may show promise.

(1) D. W. Palmer, G. L. Krauss, "275°C Microcircuitry: Resistors, Capacitors, Conductors, Substrates, and Bonding." SAND76-0611, Sandia Laboratories, Albuquerque, N. M., Dec. 1976.

Since digital integrated circuitry is required for proper telemetry link repeater stations, it was decided to run an experiment to verify this class of componentry. A medium scale integration integrated circuit (a full divide-by-ten with decimal decoding) was selected for testing as being typical of the most complex electronics component required in the system. Complementary metal oxide (COSMOS) integrated circuit technology was chosen for the test, since it consumes the least power and can operate at derated voltages, both qualities being desirable for high temperature operation.

Figure 2-4 shows the test setup block diagram and Figure 2-5 shows the test apparatus. Full monitoring of power supply, signal drive, and output waveform/functional integrity were provided under simulated overloading conditions. The thermal control/monitor unit provides for accurate monitoring of ambient temperatures up to 400°C. Operating voltages were derated to 5 volts during the test.

Testing demonstrated short time operating capability at the 275° to 300°C level. Device degradation occurred at the 300°C to 325°C level. Failure was non-catastrophic in that removal of bias at the elevated temperature resulted in self-healing.

Electrical and microscopic tests in Raytheon's Reliability Analysis Laboratory of the functional and non-functional integrated circuits indicated that out-of-specification operation was caused by saturating FET channel currents. This was a result of undesired surface channeling in the metal oxide insulator underlying the gate, a phenomenon anticipated at the 300°C temperatures encountered during the operating test. This phenomenon will not occur during the non-operating state, so that storage at the 275°C ambient formation temperature will not harm the devices. Operating at 200°C (or below) should not cause saturating channel current effects.

Life tests were conducted (on a sample of only two devices) at 200°C to test the conclusion. At the 200 hour mark, no device performance degradation has been observed.

Based on the above testing and analysis program, results are sufficiently promising to suggest that medium scale digital integrated circuits can be used in the electronics design provided that bias is removed when ambient temperature exceeds 200°C. Additional testing of different components in the actual circuit configuration will be required to demonstrate this conclusion definitively.

Figure 2-3. Coolant Temperature (Mud)
6.5" O. D., 5.5" I. D. Pipe

Table 2-1. Thermal Performance
Passive Elements

- o Capacitors (To .01 μ f)
+2% - 0°C to 300°C
- o Capacitors (To 1 μ f)
+2% - 0°C to 300°C
Small Increase in Leakage
- o Capacitors (To 33 μ f)
-50% (0°C to 250°C)
- o Resistors
+2% (0°C to 300°C)

Conclusion: Satisfactory for Low Q
(≤ 10) Circuits

Figure 2-4. MSI Thermal Testing Apparatus

2-12

A-14

Figure 2-5. Component Thermal Performance Evaluation Apparatus

In summary, all required low powered electronic functions can be met at the design ambient temperature of 175 - 200°C encountered in drilling geothermal formations at temperatures of up to 275°C. Furthermore, electronic functional performance requirements can be met without exceeding either packaging volume or prime power constraints applicable to more moderate temperature environments.

2.2.3 High Power Electronic Performance Under High Temperature Environments

Because of the low carrier frequencies (1 Hz) involved, the transmitter power amplifier runs at low speed compared to usual electronic amplifier operating conditions. Thus, a simple switching circuit can satisfy the system requirements.

Silicon Controlled Rectifiers (SCR) have been tested⁽¹⁾ by Monsanto and others to temperatures of 500°C. These devices were of an experimental type and would require extensive technology development before becoming commercially available. Hence, they are typical of the level of performance obtainable ten years from now. Current off-the-shelf SCR technology indicates that such devices can operate with case temperatures of 200°C provided sufficient power derating is observed. Since the principal difficulty is withstanding voltage in the off state, a combination of power and voltage derating can provide acceptable performance at the 175°C to 200°C temperature environment anticipated. Bread-board amplifier testing is required to demonstrate this capability.

Although solid state amplifier design techniques are attractive from the standpoint of compactness and lack of moving parts, hybrid designs can also perform satisfactorily. Commercially available electromechanical relays with sufficient power handling capability, precision, and speed exist within the desired packaging form factor, and are rugged enough to survive the downhole mechanical environment. Their temperature range does not allow 200°C operation

(1) "Gallium Phosphide High-Temperature Electroluminescent p-n-p-n Switches & Controlled Rectifiers," D. L. Keune, M. G. Craford, A. H. Herzog, and B. J. Fitzpatrick, Monsanto Company, St. Louis, Missouri, J. Applied Physics, Vol. 43, No. 8, August 1972.

because of the insulating coating (enamel) used on the magnetic windings. By modifying the insulation to a higher temperature material (Teflon, for example), relays can be used at the required 200°C level.

In summary, suitable designs are available for the high power electronic functions using either commercial off-the-shelf components for a solid state approach or modified electromechanical relays. It is anticipated that improvements in solid state technology will allow smaller, more compact, and lower cost solid state power amplifiers.

2.3 Prime Power Sources

Approximately one kWh of energy will be required for each electronic canister at a peak power level of 250 watts. A volume of 1000 in³ has been allocated for this use within the packaging design. A survey was made to establish those power sources best suited to the environment or most likely to be capable of extension to the hostile environmental conditions of geothermal wells. A list was made of the power sources which could have a practical value without the problem of temperature. The sources on this list were then further analyzed in the light of the hostile environment. Manufacturers and researchers were contacted. The power sources studied are:

- Primary battery
- Conventional secondary battery
- Molten electrolyte battery
- Flywheel/generator
- Compressed gas/turbine/generator
- Fuel cell
- Mud turbine/generator

In summary, there are a number of promising sources but further development is needed for the geothermal application. For critical experiments, a primary cell could be quickly adapted for near term desired temperature (200°C) and energy density. A low cost prime power system will require six months to one year development. Table 2-2 summarizes several promising immediate and near term approaches. These include primary batteries, a molten electrolyte secondary battery, a H₂/O₂ fuel cell and a mud turbine generator. These and less promising techniques mentioned above are discussed in the sections following.

Table 2-2. Near-Term Electrical Power Sources for High Temperature Environment

POWER SOURCE	CAPABILITY	DELIVERY
Silver Oxide-Zinc Primary Cell	1 Watt-Hr/In ³ 200°C	3 Months to a Prototype Model
Mercuric Oxide Cadmium Primary Cell	1 Watt-Hr/In ³ 150°C	3 Months to a Prototype Model
Lithium-Ferrosulfide Secondary Cell	2 Watt-Hr/In ³ 400°C	3 Months (2 Yrs From Now) to a Prototype
Hydrogen-Oxygen Fuel Cell	5 Watt-Hr/In ³ 200°C	6 Months to a Prototype Model
Mud Motor/Generator	10 kW (Peak) 10 ft Long 200°C	1 Year to a Prototype Model

2. 3. 1 Primary Battery

These batteries use existing technology. They are not rechargeable and therefore do not require recharging facilities. Their throw-away nature impacts both direct cost and operational logistics. The batteries which fall in this category are carbon-zinc, mercuric oxide-zinc, silver oxide-zinc, manganese-zinc and lithium-organic electrolyte. They have varying temperature capabilities and energy densities.

One cell which approaches the 200°C requirement is a silver oxide-zinc cell rated to 170°C in a custom design by Mallory Battery Company. It has been tested to 200°C and delivered energy at 20% of its capability at room temperature. Another cell which has been tested beyond 100°C is a mercuric oxide-cadmium cell by Eagle-Picher Industries. This cell has been tested at 150°C. The energy density of both cells at highest temperature tested is about one watt hour per cubic inch.

2. 3. 2 Conventional Secondary Battery

These batteries also use existing technology. They are rechargeable for many hundreds of cycles. They would require a wellhead recharging facility. The batteries which fall in this category are lead-acid, nickel-iron, nickel-cadmium, silver oxide-cadmium, and nickel-zinc. No off-the-shelf units were found to have been tested or are expected to be operational at temperatures over 100°C.

2. 3. 3 Molten Electrolyte Batteries

The development of molten electrolyte batteries is in process. A number of designs have been demonstrated in laboratories. They are perhaps two years away from availability for field demonstration. In contrast to the more familiar batteries, the molten electrolyte battery requires high temperatures to maintain the electrolyte in the molten state. The energy density is excellent and they are rechargeable.

The reason for requiring the electrolyte (which is a true* electrolyte and solid at room temperature) to be molten is to permit the cell to be reversible,

* A true electrolyte is ionized in its natural state and need not be placed in an aqueous solution to ionize.

i. e., rechargeable. The lithium/iron sulfide battery operates at a temperature of 400°C and has a LiCl/KCl electrolyte. This is a case where the 200°C bore hole temperature is not hot enough. Because of this, the battery would require insulation, preheating, and possibly some of its energy used to make up for heat loss through the insulation. When the battery is in use, internal losses generally provide sufficient heat to maintain 400°C. However, when idle for long periods, some of the battery's energy is used for self-heating.

For an electric car application, the cost has been projected as \$20 to \$30 per kWh. Useful lifetimes excess of 250 cycles (3 years if recharged every 4 days) can be anticipated. Energy density (for 1 kWh and larger batteries) is predicted to be in the range of 2 watt-hr per cubic inch and 80 watt-hr per pound.

2. 3. 4 Flywheel/Generator

The space available in the drill string is in a form which precludes an efficient flywheel design. The energy density available from a most efficient design would be approximately one-fifth that of the primary batteries described above. The high temperature and vibration environment would raise lubrication and bearing problems which would further degrade efficiency.

2. 3. 5 Compressed Gas/Turbine/Generator

The necessity of high speed shaft rotation in this mechanization coupled with the high temperature environment would raise lubrication and bearing problems. In addition, at a storage pressure of 10,000 psi, the stored energy density is in the range of 3×10^{-5} watt-hr/cu. in. The efficiency of conversion to electrical energy would further reduce this value. This mechanization is orders of magnitude poorer below that obtainable with batteries.

2. 3. 6 Fuel Cell

Most of the electrical power in the world is generated by heat engines utilizing the heat from the combustion of fossil fuels, subject to Carnot cycle limitation. Couples are not limited by the heat cycle and will convert at high efficiencies. When the solid active electrode materials are replaced by reducible and oxidizable gases continuously fed from outside sources, the system becomes a fuel cell. The approximate thermal conversion efficiency of a fuel cell is 60 - 85%.

A typical system is the hydrogen-oxygen couple with the highest theoretical output (1, 620 watt-hr/lb of active reactants). An H_2 , O_2 fuel cell utilizing a phosphoric (H_3PO_4) acid electrolyte is estimated to be capable of operation at $200^\circ C$. Operation is continuous as long as fuel and oxygen are supplied, and in most instances the fuel supply settings remain unchanged after operation is started. Hydrogen and oxygen diffuse through the electrodes to the electrolyte interface, where they remain as absorbed gas phases until the electrochemical reactions take place.

The byproduct of the hydrogen-oxygen fuel cell is water, formed at the cathode in amounts corresponding to the combined weight of oxygen and hydrogen consumed. The open-circuit voltage reaches a maximum of about 1.12 volts.

Cell reaction $O_2 + 2H_2 \rightarrow 2H_2O$

Cathode reaction $O_2 + 4H^+ + 4e \rightarrow 2H_2O$

Anode reaction $2H_2 - 4e \rightarrow 4H^+$

Hydrogen ions produced at the anode yield electrons to the circuit and pass to the electrolyte which gives up hydrogen ions at the cathode to maintain neutrality. The hydrogen ions obtain free electrons from the circuit and combine with oxygen at the cathode to form H_2O .

The hydrogen and oxygen required are stored in cylinders. Assuming a 75% conversion efficiency, approximately one pound of fuel would be required for the 1 kWh requirement.

The space available in a drill string represents a decidedly different form factor than is typically required. However, sources estimate that a fuel cell (with fuel) to meet the requirement could be designed into a three foot section of drill string or less. It is estimated that the fuel cell cost would be in the range of \$1000. The fuel cost (H_2 , O_2) is less than \$10 per pound. The life would be in excess of 1000 operating hours. It is further estimated that a six-month development period would be required to package and proof test the technology.

2.3.7 Mud Turbine Power Source

The mud flowing down the center of the drill string at a rate of 300 gallons per minute represents a potential source of shaft power far greater than the 150 watt requirement of the communication system repeaters. Typical mud flow

prime power exceeds 500 hydraulic horsepower (375 kilowatts). Currently available is the Dyna Drill, a mud turbine unit which could be adapted for generator application. This unit is currently rated for 120° - 150°C. It is reported that a modified version of the standard unit is capable of operating in the 175° to 200°C range. The Dyna Drill consists of a Moyno pump gear box and associated drill string adapters. The Moyno pump is well adapted to pumping viscous liquids because its multiple dams prevent slip and produce pressure rises of several hundred lb/sq. in. Because of its configuration, the pump is also well suited for installation in cylindrical piping.

To obtain electrical power, the mud turbine (Moyno pump) shaft would be coupled to a brushless alternator. The alternator would produce an AC voltage which would be rectified and filtered to provide DC. A brushless alternator would eliminate the need for slip rings and associated problems.

Present technology would permit design of an alternator to operate to 200°C with a life of 6000 operating hours. Following a development period, a mud turbine/generator could be available which was capable of operation to 200°C. Design for operation at higher temperatures is difficult to predict at this time.

Teleco, Inc. has developed a mud turbine/generator in conjunction with their mud pulse system for oilwell drilling. Temperature limit for geothermal is unknown.

2.4 Repeater Station Example Design and Performance Levels

The general approach taken during the design definition process was to optimize performance within a mechanical envelope consistent with a 30 foot long by 6 3/4 inch diameter envelope. First, the outer cover was sized to withstand anticipated mechanical stresses. Next, volumes were assigned to functional electronics and the prime power source. The remaining volume was used for the antenna. Effective transmitter source strength and receiver sensitivity were estimated and used as inputs for a computerized telemetry system optimization program.

Two applications - the ERDA GT2 geothermal hole (9600 ft. total depth) and a hypothetical 15,000 foot hole into hot rock - were considered. The result of the analysis was that three repeaters and one bottom terminal would be needed to achieve downhole telemetry for the GT2 case, and five repeaters and one bottom terminal would be required for the 15,000 foot hole. The analysis provided for a suitable safety factor in excess signal level to provide a margin against field degradation effects anticipated under actual operational conditions.

2.4.1 Example Repeater Mechanical Design

An analysis has been performed for the instrumentation/sensor package mechanical design and is described in Section 3.2. Since this hardware, being nearly adjacent to the bit, will undergo stresses more severe than those existing in the drill string, the instrumentation package mechanical design criteria have been used to establish the repeater mechanical design parameters.

The repeater design consists of an outer cover, or canister, with threaded connections at either end to mate with the drill string pipe sections. The 30 foot long canister is 6 3/4 inch outer diameter (OD) and 6 inches inner diameter (ID). The lower end of the canister contains the electronics and prime power. The upper end of the canister contains the antenna.

The electronics and prime power hardware are contained in a steel housing with an OD of 5 1/4 inches and an ID of 4 1/4 inches. The volumetric budget within the housing is shown in Table 2-3 below.

Table 2-3. Repeater Electronics Volumetric Budget

1000 watt-hr prime power	1000 cubic inches
Low power electronics	200 cubic inches
High power electronics	<u>50</u> cubic inches
Total electronics & prime pwr.	1250 cubic inches

The electronics housing, which has an overall length of 110 inches (including endcaps) provides a useable internal volume of 1650 cubic inches, for a growth factor of 32%. Approximately 10 inches of the 30 foot repeater are required for the mechanical connection threads between the repeater station and neighboring pieces of drill string. The remaining 240 (= 360-110-10) inches are used for the antenna. The antenna assembly (which is 5 3/4 inches in diameter and 20 feet long including its end connections) consists of a 1/8 inch wall, 2 inch ID pipe for down flowing mud, a spiral wrapped magnetic core out to a diameter of 5 1/2 inches, and 2000 turns of #10 teflon insulated copper wire wound over the core. The antenna assembly is filled with oil. This allows equalization of the antenna's internal hydrostatic pressure with the downward flowing mud pressure without

contamination of the antenna assembly with mud and without placing a high strength bursting requirement on the mud conduit.

2.4.2 Example Repeater Electronic Design

The effective magnetic moment (source strength) of the transmitter is the product of the antenna effective area, the number of turns, and the current flowing in the turns. The antenna area is calculated from the expression:

$$A_e = \frac{\pi l^3}{\left[\log_e \left(\frac{l}{a} \right) - 1 \right]} \cdot \frac{1}{\left[1 + \frac{2(l/a)^2}{3\mu_r \log_e \left(\frac{l}{a} - 1 \right)} \right]}$$

where:

- A_e = area of the antenna in (meters)²
- l = antenna half length in meters = 3.1 meters
- a = antenna radius in meters = .072 meters
- μ_r = average relative permeability of the magnetic core = 4000

Evaluating the expression,

$$A_e = 9.9 \text{ m}^2$$

The (non-magnetic) steel canister acts as a resistive shorted turn. This effect results in a reduced effective area and as an increased antenna resistance. After taking these phenomena into account,

$$A_e = 2.0 \text{ m}^2$$

There are 2000 turns of wire on the magnetic core. The wire resistance is 3Ω. Based on prototype tests, the effect of magnetic core loss and the canister resistance combine with the copper loss to provide an antenna input resistance of 15 Ω.

The transmitter was sized on prime power source constraints. The repeater non-transmitter electronics consume approximately 2.5 watts under high temperature (worst case) conditions. For a typical four day operational period, the non-transmitter electrical usage will be 250 watt-hr, leaving 750 watt-hr. for the transmitter. The transmitter will operate for less than 3.3 hours

during a four day operational period, which limits transmitter input power to 225 watts. Approximately 170 watts (75%) of the DC input power will be delivered to the antenna for an antenna current of 3.4 amps rms.

The magnetic moment of the transmitted signal is thus:

$$M = N A e I = (2000)(2.0)(3.4) = 13,600 \text{ ampere} - \text{turn} - \text{meters squared.}$$

The 3 dB bandwidth of the antenna system is 1.0 Hz.

The receiver noise figure is 8 dB, typical of MOSFET receiver front end performance at the 200°C, 1 to 30 Hz design condition. Using the antenna effective area of 2.0 m^2 and effective length of 3m, this front end noise figure transforms to an equivalent ambient noise level of -147 dBH/Hz.

A time division multiplex approach is used to move data from lower repeaters to higher repeaters. Each repeater (as controlled by its internal clock) cycles through a receive mode, a transmit mode, and an inhibit mode. Thus, while a repeater is receiving a signal from the adjacent lower repeater, the adjacent upper repeater is in the inhibit mode neither transmitting nor receiving. The nearest (interfering) transmitting receiver is thus two "hops" away. Since a two hop transmission results in a signal weaker by 18 dB than a single hop transmission and a 12 dB minimum signal-to-noise ratio is maintained on the primary path, data bit errors are prevented. An example of the time division multiplex approach is shown in Figure 2-6. The peak data rate is twice the bandwidth for the four phase PSK modulation used. Since the transmitting duty cycle is $1/3$, the average data rate is $2/3$ the bandwidth.

The repeater electronics (see Figure 2-7) include receiving and transmitting circuits which share the same solenoid antenna. After preamplification, filtering and limiting, the received signal is applied to the input of a digital correlator. The correlator samples the limiter output at a rate of 12 samples per carrier cycle and compares each block of stored data with replicas of the red flag and data command sequences to detect commands and determine carrier phase. The timing circuit generates the proper transmitter carrier and gate signals. When the proper preconditions for transmitting a data block are met, the transmitter is gated on and the antenna is switched to the power amplifier output. The transmitter then transmits the block of data stored in the correlator memory. Since

Figure 2-6. Relaying Between Repeaters

Figure 2-7. Repeater Block Diagram

the correlator has oversampled the input data, the transmitter demodulates the correlator samples into the 2 bit/carrier cycle digital code before retransmission.

2.4.3 Example System Performance

Example system capabilities were examined using a computer simulation to test performance in the ERDA sponsored GT2 hole drilled near Los Alamos, New Mexico. Based on the logging data available from the Los Alamos Scientific Laboratory (LASL) report⁽¹⁾, a model of the earth's electromagnetic physical parameters from ground level to the ultimate depth of 2925 meters was constructed. It was found that three repeaters and a bottom terminal would be required to satisfy link signal strength and data integrity requirements. The minimum signal-to-noise ratio at the repeater stations was 15.7 dB, considerably in excess of the required 12 dB. Table 2-4 below summarizes significant results.

Note that the highest repeater (at a depth of 842 meters) is located below the casing which extends only to 800 meters. Therefore, the casing (for this hole) did not affect link performance.

A second test case was run assuming GT2 had been drilled to a final depth of 15,000 feet. As before, the effects of casing may be ignored. A moderately wet earth (conductivity of .0033 mho/meter) was assumed for the unlogged portion. Results are shown in Table 2-5 below. The number of repeaters required is five. Note that a minimum SNR of 14 dB, a power safety factor of 2 dB, is maintained over all links. Also note the effect of the lithospheric shielding of atmospheric noise, resulting in longer hop lengths at the lower depths.

Table 2-4. Example System Performance in GT2 Hole

Link #	Link Type	Depth of Receiver (meters)	Depth of Transmitter (meters)	Signal to Noise Ratio	Average Conductivity (mho/mtrs)	Hop Length (meters)
1	III(*)	0	842	15.7	.0504	842
2	II	842	1505	15.7	.0353	663
3	II	1505	2200	15.7	.0051	695
4	II	2200	2927	15.7	.0026	727

(*) Type III link assumes 10 dB noise cancellation available at surface receiver.

Table 2-5. Example System Performance in 15,000 foot Hole

Link #	Link Type	Depth of Receiver (meters)	Depth of Transmitter (meters)	Signal to Noise Ratio	Average Conductivity over link (mho/meter)	Hop Length (meters)
1	III(*)	0	897	14 dB	.0482	897
2	II	897	1608	14 dB	.0023	711
3	II	1608	2353	14 dB	.0054	745
4	II	2353	3134	14 dB	.0026	781
5	II	3134	3947	14 dB	.0033	813
6	II	3947	4794	14 dB	.0033	847

(*) Type III link assumes 10 dB noise cancellation obtainable at surface receiver.