INTERN EXPERIENCE WITH
GETTY OIL COMPANY - LAFAYETTE ONSHORE AREA

An Internship Report

by

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ABSTRACT

Intern Experience with

Getty Oil Company - Lafayette Onshore Area. (August 1982)

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This report describes the author's internship at Getty Oil Company - Lafayette Onshore Area from August, 1981 through July, 1982. The purpose of the internship was to allow the author to become familiar with drilling and production operations in southern Louisiana as currently practiced by the industry.

During the internship, the author held the position of Operations Engineer and was assigned to the Lafayette Area engineering staff. Primary responsibilities included drilling an 18,000-ft exploratory well, monitoring production from an established field, and organizing a corrosion control program for the Area. These activities gave the author, a mechanical engineer, the opportunity to develop technical skills in an engineering discipline other than the one in which he was educated.

The author feels that the internship was successful in satisfying the final objectives and that it provided invaluable experience and insight into petroleum exploration and production operations.

ACKNOWLEDGEMENTS

The author would like to thank all those who contributed to making the internship a meaningful experience.

A special thanks goes to the management and staff of Getty Oil Company - Southern Exploration and Production Division for permission to publish this report and for their cooperation and accommodations in allowing the author to return to Texas A&M on a temporary assignment. The author would especially like to thank the following persons: Mr. F.J. Hoffman, Division Engineering Manager, Mr. H.R. Andrew, New Orleans District Production Manager, Mr. W.D. Cornelius. District Engineer, Mr. D.A. Nichols, Superintendent - Lafayette Onshore Area, and Mr. C.A. Rohan, Area Engineer.

The author also extends his gratitude to the members of the faculty of Texas A&M University who served on his committe; Dr. M. Henriksen, P.E., Advisor and Chairman, Dr. R.M. Alexander, P.E., Dr. C.F. Kettleborough, P.E., Dr. T.A. Parish, P.E., Dr. A. Mahajan, and Dr. L.C. Shine. A special thanks goes to Dr. C. A. Rodenberger without whose guidance and encouragement the author would not have entered the Doctor of Engineering program.

Others deserving recognition include Mrs. Kathy Shearer for her assistance in administrative matters with the University and Miss Terri Derouen for her many hours spent typing this report.

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CHAPTER I

INTRODUCTION

Purpose of the Report

This report describes the internship experience of Robert Magee Shivers III with Getty Oil Company - Lafayette Onshore Area from August 10, 1981 until July 7, 1982. The primary purpose of the report is to insure that the objectives of the internship have been met.

Content and Organization of the Report

Nearly all engineering activity conducted at the Area level in Getty Oil Company would be properly classified as petroleum engineering related, whereas the author's formal educational background is in mechanical engineering. In order for the author to perform his job satisfactorily as a member of the Area engineering staff, it was necessary for him to obtain a rudimentary working knowledge of certain petroleum engineering principles and practices. This was accomplished both through self study and through attendance of various schools offered in-house by Getty. The purpose of this report is not to present an in depth study of any particular phase of petroleum engineering, but rather to give an overall description of both the engineering responsibilities and the involvement of other technical and non-technical persons within the Getty organization in drilling and production operations. The text

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This report follows the general style and format of the Journal of Petroleum Technology.

of this report is written in such a manner as to be easily understood by engineers in disciplines other than petroleum engineering.

Chapter II briefly outlines the internship activities. Chapter III of the report briefly describes the organization of Getty Oil Company from the Corporate level down to the Area level. The bulk of the text can be grouped into three sections: 1) Drilling - Chapters IV-VI, 2) Production - Chapter VII, and 3) Special Projects - Chapter VIII. Summary and conclusions for the report are included in Chapter IX.

CHAPTER II

DESCRIPTION OF INTERNSHIP

During the internship the author held the position of Junior Petroleum Engineer and was assigned to the Area engineering staff. The job description for this position is included in Appendix A. Mr. C.A. Rohan, the Area Engineer, served as internship supervisor and headed the Area engineering staff. Mr. Rohan reports to Mr. D.A. Nichols, the Area Superintendent. Engineering responsibilities can be grouped into three broad categories: 1) Drilling, 2) Production, and 3) Special Projects. In contrast to other production organizations where engineers are specialized according to drilling, production, reservoir, corrosion, etc., the Area engineering staffs for Getty Oil Company are composed of general practitioners. Each engineer in the Area office is expected to familiarize himself not only with the engineering calculations and planning involved in the previously mentioned categories, but also to be able to assist in their operations. To this end, time spent in the field is equally important to time spent in the office. Specific projects assigned to the author during the internship were:

1. Drilling - plan and assist in drilling of the Jeanerette Lumber and Shingle Company #1. This was an 18,000-ft exploratory well drilled near Morgan City, Louisiana.

2. Production - responsibility for production of Erath field. This field consisted of two gas wells and four oil wells which produced on artificial lift. Also, production duties included establishing a corrosion control plan for the Lafayette Onshore Area.

3. Special Projects - special projects were assigned from time to time by the Area Engineer and the Area Superintendent.

Each of these responsibilities and a general discussion of the involvement of other people within the organization at each stage of development is included in Chapters III-VIII of this report.

A copy of the formal internship objectives is included in Appendix A.

CHAPTER III

GETTY OIL COMPANY - ORGANIZATION AND RESPONSIBILITIES

Getty Oil Company - General

Getty is a major integrated petroleum company engaged in searching for and producing crude oil and natural gas and in transporting, refining, and marketing petroleum and petroleum products.

Getty's domestic reserves are located in Texas, Louisiana, and other Gulf Coast states, the Gulf of Mexico, onshore Alaska and California, and in the midcontinent and Rocky Mountain states.[1] The company's foreign reserves are in Algeria, the Arabian Gulf, Canada, Colombia, the Mediterranean Sea, the Saudi Arabia-Kuwait Partitioned Neutral Zone, and the North Sea.

In 1981, the company was ranked as the 23rd largest industrial corporation and the 15th largest oil company in the United States with sales of over $13 billion and net income of $856 million.[2] At year end the company had over 19,000 employees including those at its subsidiaries.

The company has five petroleum exploration and production divisions: Southern, Central, Western, International and Canadian.

Southern Exploration and Production Division

The Southern Division is responsible for petroleum activities in the eastern portion of Texas, in Alaska, and in 24 states in the Gulf Coast, southeastern and eastern regions of the country. The division is also responsible for domestic offshore activities in the Gulf of Mexico, in Alaskan waters, and off the east and west coasts of the United States.

The division functions primarily as a financial and budgetary office and maintains headquarters in Houston, Texas.

Three district offices answer to the Southern Division: Houston, New Orleans, and Offshore. Organization charts for the Southern Division, New Orleans District, and Lafayette Onshore Area are shown in Figs. 1-4.

New Orleans District

The New Orleans District is responsible for production and exploration operations in the southern half of Louisiana, Mississippi, Alabama, and in other eastern states. The District consists of an exploration staff, production staff, financial planning, administrative, unitization, and environmental and safety groups. The exploration staff, headed by the District Exploration Manager, is composed of exploratory geologists, development geologists, geophysicists, and landmen. The Production Department, headed by the District Production Manager, consists of an engineering staff which is supervised by the District Engineer, and a District Operations Superintendent who is responsible for the operations of three Area offices, Lafayette, Mobile, and Venice. The District engineering staff is divided into reservoir and petroleum engineering groups, headed by the lead reservoir and lead production engineer, respectively. The three Area offices are each headed by an Area Superintendent.

Lafayette Onshore Area

The Lafayette Onshore Area is responsible for oil and gas production in 39 south Louisiana parishes and in the state territorial waters. The Area has approximately 21 producing fields and over 120 wells. Average production is 800 BPD of crude oil and condensate, 600 BPD natural gas liquids, and 20-25 MMCFPD of natural gas. Fields are scattered throughout southern Louisiana from Beauregard Parish in the west to Terrebonne Parish in the southeast. The largest single field is the Hollywood field located in the city of Houma, Louisiana. This field accounts for over 75% of gas production and 70% of condensate and NGL production for the entire Area.

The Lafayette Onshore Area was organized in November, 1980. Previously, south Louisiana production had been supervised by the Mobile Area office. During all of 1981 and the spring of 1982, the Lafayette Area was involved in an active exploratory and development drilling program in an effort to increase production and reserves.

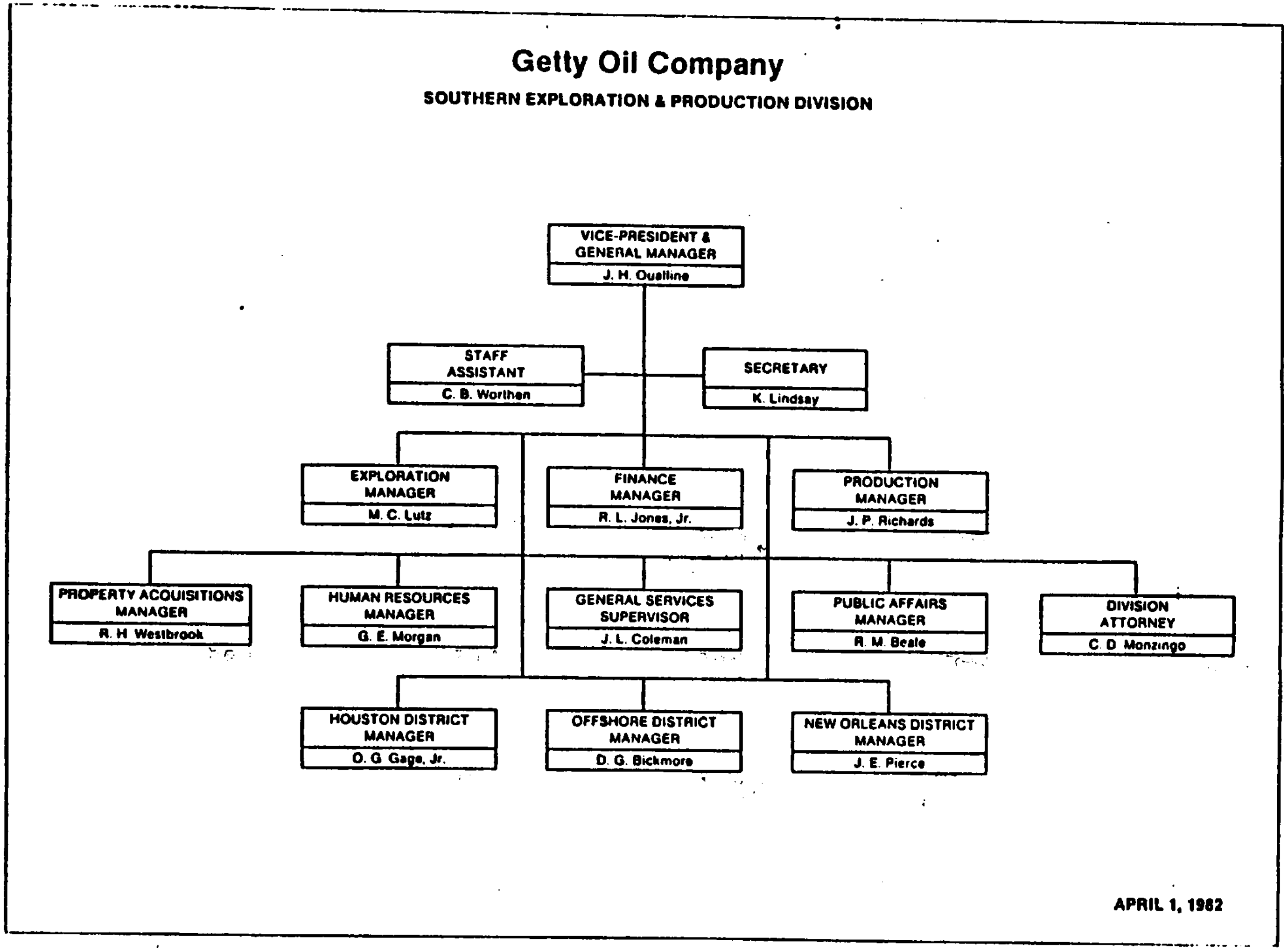

Fig. 1--Organization Chart - Southern Division.

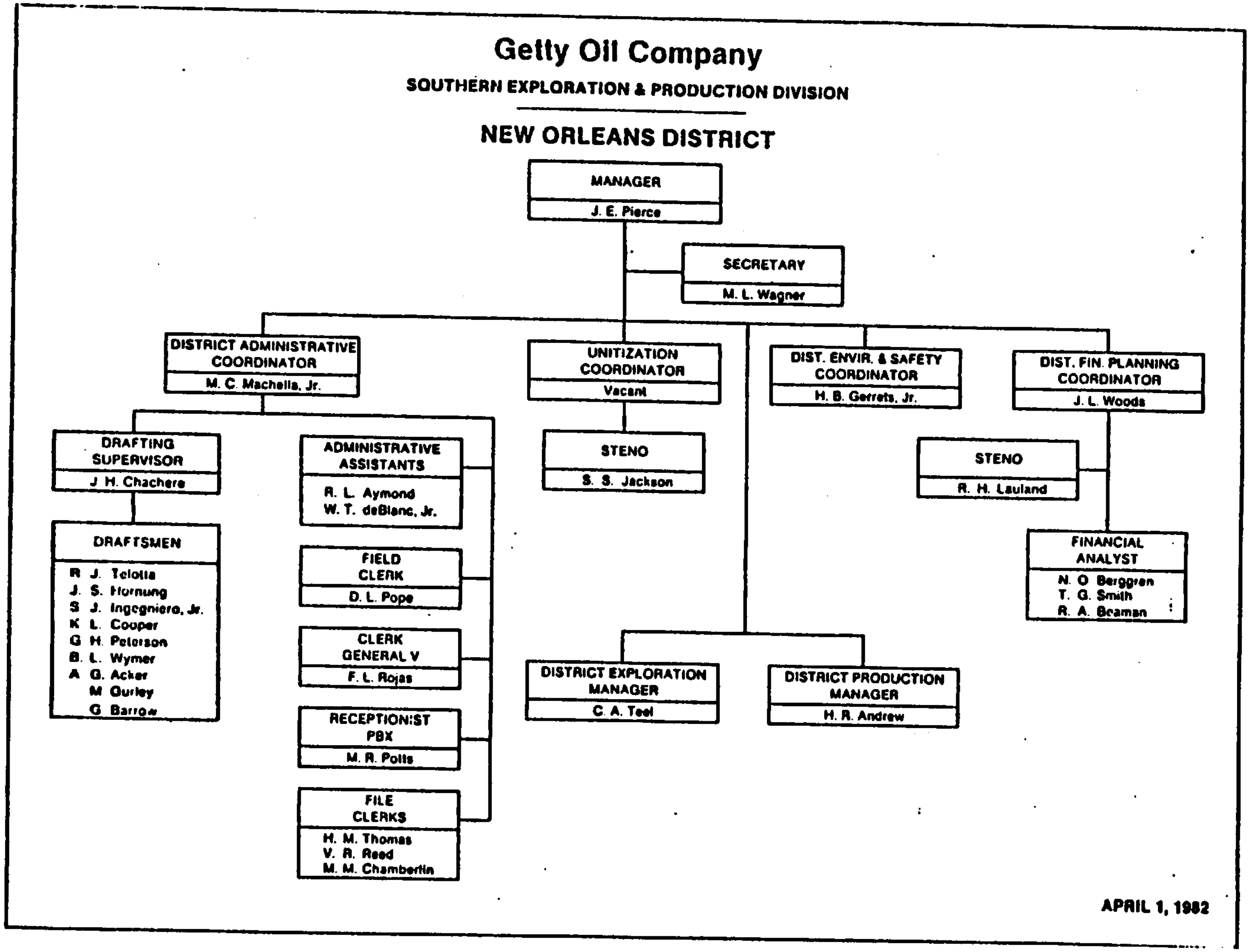

Fig. 2--Organization Chart - New Orleans District.

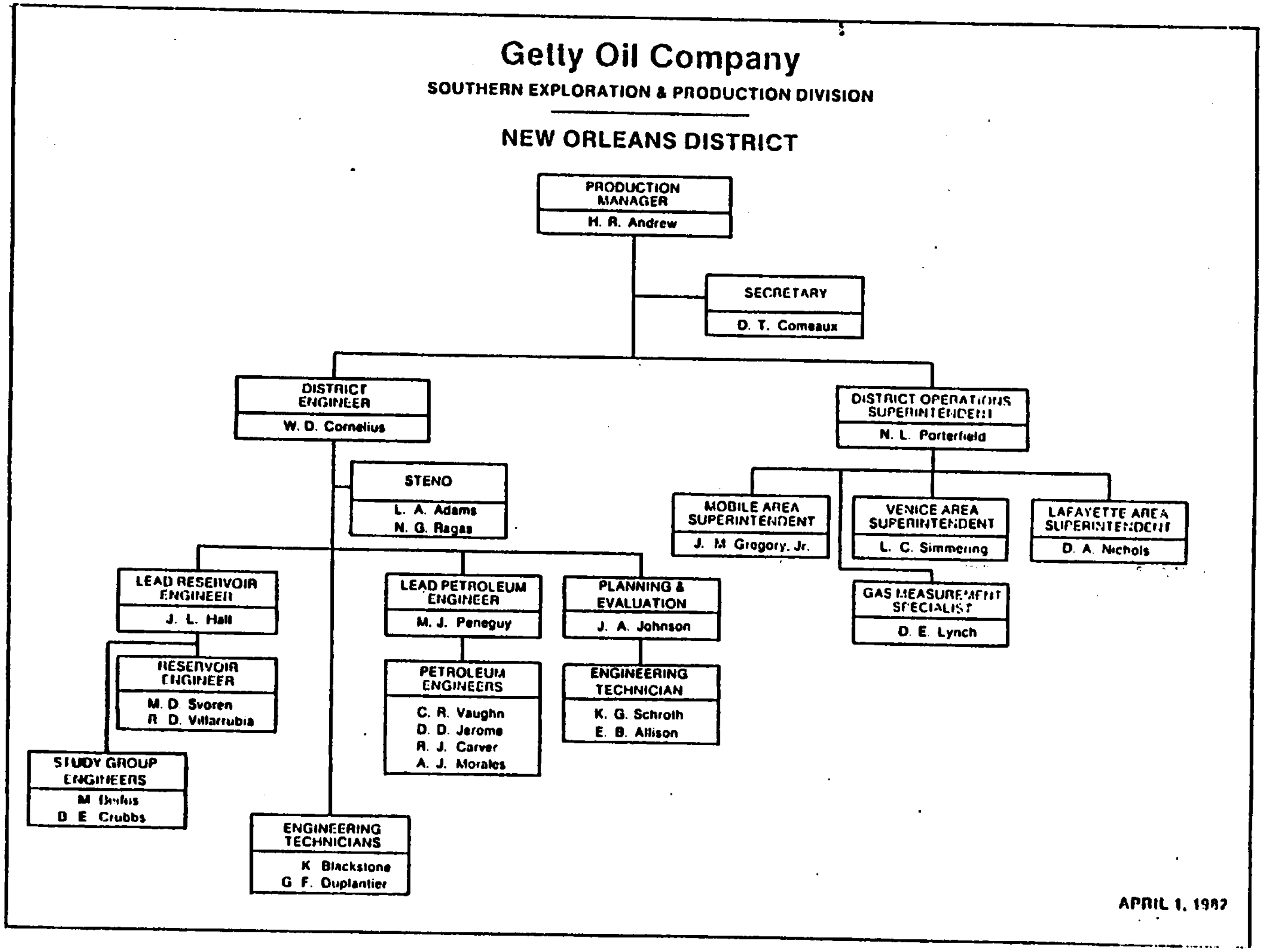

Fig. 3--Organization Chart - New Orleans District Production Department.

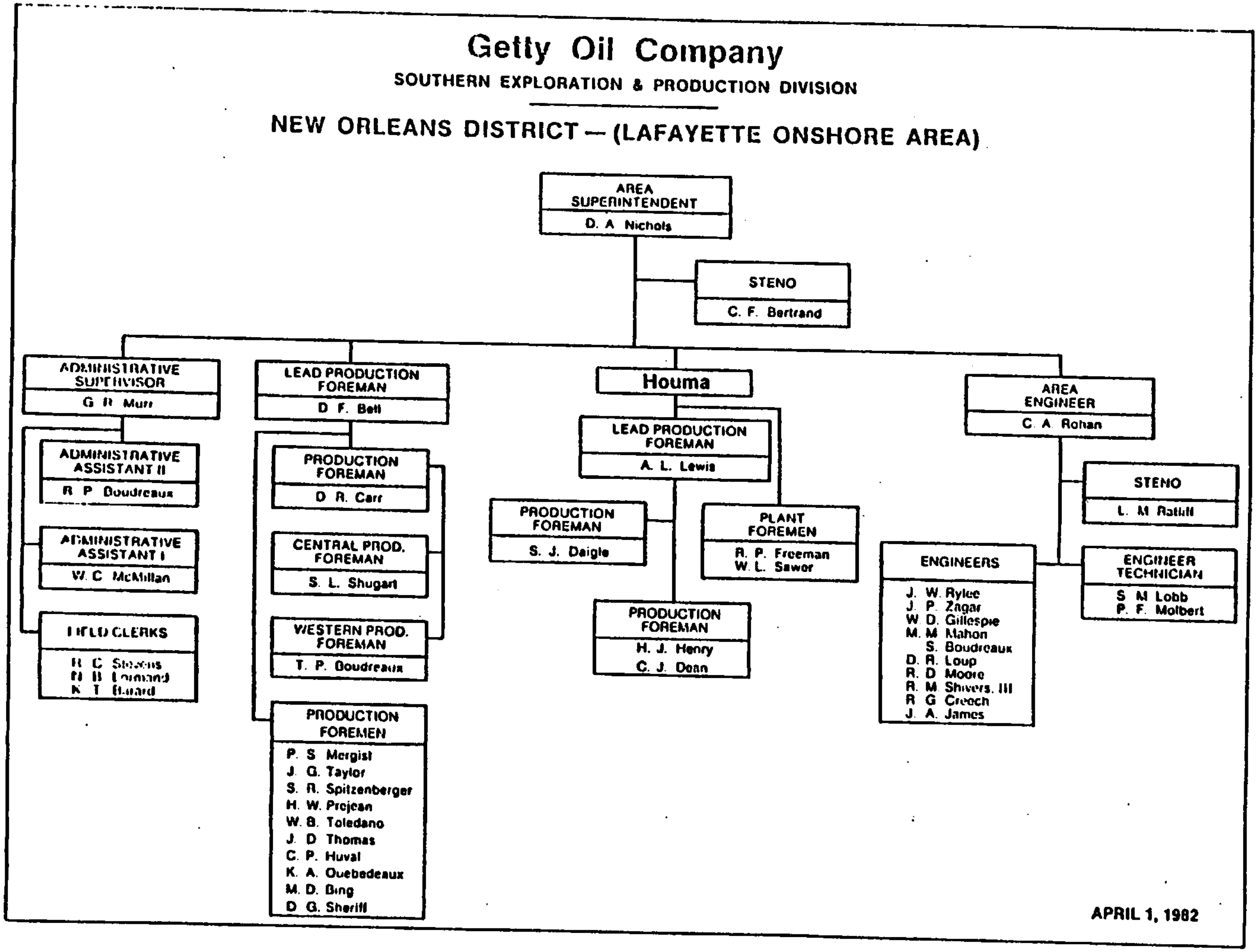

Fig. 4--Organization Chart - Lafayette Area.

CHAPTER IV

PROSPECT EVALUATION AND BUDGETING

Origin of Drilling Prospects

Most wells originate with a drilling prospect. This is a proposal to drill based on geological interpretation and preliminary economic analysis. Geologists are assigned to certain geographical areas or "trends" in the case of exploration geologists or to an already existing field(s) in the case of development geologists. The geologist uses logs from other wells or "offsets" drilled in a particular area, in conjunction with geophysical data, in order to try to interpret the subsurface geology of an area and to identify geological structures which are likely to contain hydrocarbons.

A geological structure thought to contain oil or gas is called a prospect. In their various stages of development prospects are classified as either Class I, Class II or Class III.

A Class III prospect is one that is still in the formative stage. At this point it is usually little more than an idea or "lead," possibly with some preliminary geological or geophysical interpretation.

A prospect becomes Class II after all geophysical data has been gathered and interpreted, and the geologist has completed his subsurface geological work by mapping the structure as best as he can. At this point, a request for a cost estimate is usually submitted to the Area production office having jurisdiction over the region where the prospect is located. Once a well cost estimate has been obtained, an economic analysis is performed by running a General Exploratory Evaluation Program or GEEP program.

The GEEP program analyzes economics by assigning risk factors to the four major ingredients that make up a commercial reservoir. These four components are:

1. Structure - a structure must be present to form a trap in which hydrocarbons can accumulate over geologic time. This may be a fault, a stratigraphic trap, an anticline, or other feature. The probability assigned to this is a geological judgment based on the quality of geophysical data and the degree of subsurface geological control available in the area. In practice, this probability is usually less than 50%.

2. Reservoir - a permeable reservoir or sand must be present in order to be able to produce any hydrocarbons which accumulate in the trap. If the objective zone is composed of erratically deposited deltaic sands, such as the Planulina Trend, then this probability will be low.

3. Porosity - even if a trap and a sand are present for the hydrocarbon to accumulate, the sand must have some amount of porosity or pore volume in order to contain significant amounts of oil or gas. This factor is usually more critical in the tight sands found in hard rock country. Miocene Age sands in south Louisiana are usually assigned a probability of 80-90% for porosity unless they are extremely deep.

4. Hydrocarbons - if a trap and a sand with porosity are discovered, then there is still uncertainty as to whether hydrocarbons will be present. Theoretically, hydrocarbons are generated through decay of

organic matter. This matter is invariably present, so this factor is assigned a probability of 90-100%.

After all geophysical and geological work and preliminary economic analysis has been completed, the land secion, an operating group of the Exploration Department, will obtain leases to the mineral rights over an area ideally large enough to include any possible productive zones on the structure of interest. The leases typically last for three years. In south Louisiana it is common practice to pay bonus money up front for the lease, plus an annual rental fee equal to the bonus at the end of each year until drilling begins.

After mapping the structure, running all economic analysis, and obtaining a secure land position, a Class II prospect becomes a Class I prospect. At this point the prospect should be ready to drill from an exploration standpoint.

Preparation and Approval of Drilling Budget

Over a period of months, many Class I drilling prospects may be inventoried in the Exploration Department. The ones that the District feels are most promising are grouped together and submitted to the Division office as the proposed drilling budget for the upcoming year. The Division will cull the list of prospects and submit the remaining package to the Corporate office. Corporate headquarters will impose budgetary constraints which will possibly reduce the number of prospects even more. Once a group of prospects has obtained corporate approval, they become the proposed drilling budget for the next year. This budget is, however, only tentative. Capital outlays may be revised upward or downward to reflect the current economic outlook. Some capital expenditures may be diverted away from internal or "company operated" wells in order to buy interest in prospects generated by other companies or "outside operated" wells. For this reason, wells scheduled to be drilled in the immediate future must be resubmitted every three months on the Quarterly Drilling Budget. After the wells for the upcoming quarter have been approved, they are ready to be turned over to the Production Department to be drilled.

Well Prognosis Forms

An approved drilling well is first routed from the Exploration Department to the Production Department in the form of a WP-0 (well prognosis) form. This is a letter of intent to drill a well. It will contain basic information such as surface location, proposed depth, objective sands, etc. This letter will be routed through the District Production Manager to the Area office. Once there, the well will be assigned to a particular engineer who will usually be responsible for the well from initial planning to plugging or completion. The following forms will be prepared by the engineer:

1. WP-1 - contains detailed information as to surface location, elevation, and access to highways, railroads, towns, etc.

2. WP-3 - summarizes casing program, cement program, and mud program to be used for the well.

3. WP-4 - contains detailed information on tubular goods. Size, weight, grade, quantity, types of connection, and design factors are included.

The following forms will be prepared at the district level.

4. WP-2 - prepared by the Exploration Department. Contains specific geological information such as depths of significant formations and the logging program for the well.

5. WP-5 - summarizes information from WP-1 through WP-4.

6. WP-9 - condenses information from WP-5 and includes information such as required investment, working interest, present worth, payout, and expected rate of return from the proposed well.

Government Permits

Before actual drilling can begin, certain permits must be obtained from federal, state, and local government agencies. The District office is responsible for securing all drilling permits.

On the federal level, the most common permit is one issued by the Corps of Engineers. This permit is required whenever any construction, dredging, or drilling is undertaken in a federally designated wetlands area. Other special permits may be necessary if drilling is to be conducted on wildlife refuges or in wilderness areas.

At the state level, all wells drilled in Louisiana must file for a permit with the Office of Conservation of the State Department of Natural Resources. When this permit is issued, a serial number will be assigned to the well which will serve as a permanent identification number.

At the local level, permits must sometimes be obtained from the Parish Police Jury (equivalent to County Commissions in Texas) when the wellsite is located on wetlands.

CHAPTER V

WELL PLANNING

Introduction

All drilling cost estimates are generated in the Area by the engineering staff at the request of the District office. Cost estimates are usually worked up at the request of a geologist who needs the figure for preliminary economic analysis of a drilling prospect, or the estimate can be done at the request of the Production Department when the prospect has gone through more stages of approval and is being proposed as part of the drilling budget. In the first case, the cost estimate is usually just a reasonable "ballpark" figure derived from a minimum of engineering analysis. In the latter case, the cost estimate will be used to prepare an actual AFE (Authorization for Expenditures) and the engineer strives to estimate costs within $\pm$ 5%.

Regardless of the degree of precision of the estimate, there are certain basic procedures the engineer must follow in order to generate the cost. The engineer must estimate the mud weight required at each depth, select casing sizes and setting depths, design the casing, decide what type of mud will be used, and estimate how many days it will take to drill the well. During the internship, the author had to learn these procedures in order to plan the Jeanerette Lumber and Shingle Co. #1 well and to prepare various other cost estimates requested by geologists in the District office. A discussion and explanation of these procedures follows.

Offset Information

A request for a cost estimate will contain, as a minimum, the surface location of the well, the objective formation, the proposed depth, and a list of other wells drilled in the area that can be used for references. Sometimes, a contour map of a particular sand, a profile map illustrating major faults, and depth correlations of significant formations will also be included.

Wells previously drilled in the immediate vicinity, or "offsets," are of great interest to the engineer because they provide the best available data on pore pressure and potential drilling problems. The engineer should obtain copies of the logs from these wells, whatever drilling records are available, and if possible, talk to other operators who have drilled in the area before. Acquisition of offset information will provide the foundation on which the entire well program is based and its importance cannot be overemphasized.

Estimating Pore Pressures

Once copies of the logs from offset wells have been obtained, the engineer is prepared to make a quantitative estimation of pore pressure. This is defined as the hydrostatic pressure of the fluid in the pore space of the formation and is usually expressed in the equivalent pound per gallon mud weight which would be required to equal that pressure at depth. Mud density is actually an indication of average pressure gradient rather than absolute pressure. For example, normally pressured sands have different hydrostatic pressures depending on their depth, but they all have a 0.465 psi/ft or 9 ppg gradient. Thus, all normally pressured sands regardless of depth can be controlled with a 9 ppg density mud.

Pore pressures can be calculated from log data by plotting formation resistivity, conductivity, bulk density or sonic transit time versus depth on semilog paper. The data will plot as a straight line in the normally pressured sections of the hole. This defines the "normal trend line." In abnormally pressured sections the data will deviate from this normal trend. Empirical graphs and overlays are available which provide a quantitative estimate of pore pressure based on the ratio of the actual value to the normal trend value of whatever parameter is being plotted. The engineer should verify these esimated pore pressures by analyzing drilling records to determine what mud weight was actually used to drill the well.

A plot of pore pressure and estimated mud weight for the Jeanerette Lumber and Shingle Co. #1 well is included in Appendix B.

Selecting Casing Size and Setting Depths

Once an accurate pore pressure plot has been drawn, the engineer is prepared to select the casing sizes and setting depths. This is referred to as the well program. Choosing setting depths is largely a matter of engineering analysis and knowing where problem formations are anticipated. Selecting casing sizes is mainly a matter of judgment and experience. The well program is probably the most important single item in determining not only the cost of a well, but whether the well can be drilled successfully. Casing set too shallow can result in failure to control kicks because of inadequate fracture gradients and can leave troublesome formations exposed causing numerous drilling problems. Casing set too deep represents wasted time and money required to drill the hole and purchase additional pipe. Casing with too small a diameter restricts one's options to set additional casing or drilling liners and can result in inability to reach total depth with a hole large enough to log or complete it. Casing with too large of a diameter leads to problems in obtaining adequate pressure control and results in tremendous extra costs involved in drilling extra large holes and running entire additional casing strings.

Three basic well programs have gained acceptance by Getty for south Louisiana drilling. These well programs provide the flexibility needed to drill almost any hole and are commonly used by many operators. The well programs are described below:

CASE I - Shallow Hole

16"	Conductor pipe
10 3/4"	Surface casing set in 14 3/4" hole
7-7 5/8"	Intermediate casing set in 9 7/8" hole
6-6 1/2"	Hole drilled to T.D. (Total Depth)

CASE II - Medium Hole

20"	Conductor pipe
13 3/8"	Surface casing set in 17 1/2" hole
9 5/8"	Intermediate casing set in 12 1/4" hole
7-7 5/8"	Optional drilling liner set in 8 1/2" hole
6-6 1/2"	Hole drilled to T.D.

CASE III - Deep Hole

30"	Conductor pipe
20"	Surface casing set in 26" hole
13 3/8"	Intermediate casing set in 17 1/2" hole
9 5/8"	Intermediate casing set in 12 1/4" hole
7-7 5/8"	Optional drilling liner set in 8 1/2" hole
6-6 1/2"	Hole drilled to T.D.

The classifications "Shallow, Medium, and Deep" are very subjective. Case I well programs have been used on wells as deep as 16,000 ft. Much depends on how much offset information is available. Generally, the less information available, the more of a tendency to go with a larger well program. The tradeoff is between extra costs and uncertainty about reaching the planned total depth. Usually, Case I is used for wells 12,000 ft and less, Case II for wells 12,000-18,000 ft, and Case III for wells 18,000+ ft.

In the case of the Jeanerette Lumber and Shingle Co. #1 excellent offset information was available. A well had been drilled to 15,200 ft less than 300 ft away, and well logs and daily drilling reports were available. Pressure transition zones and problem formations could be predicted almost to the foot. The projected total depth of the well was 18,000 ft and had there been no offsets for several miles, a Case III type well program may have been selected. However, due to the quantity and quality of offset information, a Case II well program was selected and proved to be successful. This well program was $1-2 million cheaper than the deep hole program, illustrating the critical importance of good offset information when planning a cost effective drilling program. For specific weights, grades, and setting depths, refer to Appendix B.

Designing Casing

Once nominal casing sizes (outside diameters) and setting depths have been selected, some design criteria must be adopted to select the necessary burst, collapse, and tension capabilities of each casing string. Casing is usually the most costly single item in a well, therefore it should command much attention to proper sizing. Casing strings with inadequate burst strengths can endanger lives and property if they fail while trying to control a kick (a controlled influx of formation fluid into the hole). Casing with inadequate collapse strength can result in a junked hole and cause the well to be sidetracked or redrilled. Casing with inadequate tensile strength poses moderate danger to personnel and can seriously jeopardize the well if it parts downhole.

Getty does not have a standardized casing design philosophy but does provide guidelines for design factors. Design factors used in the Southern Division are as follows:

Burst - 1.25

Collapse - .9-1.0

Tension - 1.6

Each of these design factors are to be applied to the joint and pipe body properties listed in various vendor catalogues. Pipe body properties for burst and collapse are calculated according to empirical formulae established by API. Joint properties must be obtained from vendor data. All pipe body properties are based on the minimum yield strength of the particular grade of steel used.

One of the more commonly used casing design theories is the "Maximum Load" concept. With this concept, maximum surface pressure is selected as the rated working pressure of the blow out preventers and maximum pressure at the casing shoe is the injection pressure. Injection pressure is defined as the pressure required to fracture the formation at the bottom of the casing and pump into it. This can be easily calculated from fracture gradient charts available for the Gulf Coast. A gas gradient curve is drawn upwards from the injection pressure at the casing shoe and a mud gradient curve is drawn downwards from the maximum surface pressure on top. The two gradient lines will intersect somewhere in the middle of the casing string. A line representing the "backup" or collapse loading from the formation pressure outside of the casing is then superimposed onto the mud and gas gradient lines to yield the final design curve for burst loading. A collapse loading line is derived from superimposing a mud backup inside the casing upon a line representing the collapse loading of the heaviest conceivable fluid outside the casing. Usually this will be the mud weight the casing is set in. Tension is designed for by simply calculating the bouyant weight of the casing string and comparing it against the rated pipe body yield or joint strength, whichever is weaker. Since the burst, collapse, and tension loads will vary continuously with depth, a casing string made up of hundreds of different weights, grades, and joint types could ideally be selected to fully optimize the properties of the string and minimize costs. As a matter of practicality however, casing strings are usually limited to a maximum of three different casing types. Strings more complex than this tend to pose tremendous logistical problems at the wellsite when trying to insure that everything is run in the hole in the correct order. Also, one runs the risk that a few joints will be run out of place, damaging the design integrity of the entire casing string.

This general design philosophy can be applied, with minor modifications as to its assumption, to analyze and design surface casing, intermediate casing, liners, and production casing. A wellbore schematic showing the casing selected for the Jeanerette Lumber and Shingle Co. #1 is included in Appendix B.

Selecting Bit Types and Sizes

The bit is the business end of the drill string. While drilling operations are in progress, attention should be focused on the optimum weight, rotary speed, and pump pressure necessary to optimize bit runs and minimize cost per foot. The drilling engineer preparing a detailed cost estimate must make some prediction as to what type of bits will be used in which portions of the hole and how they will perform. Bit performance (i.e., rate of penetration) is generally more significant than bit cost because it will ultimately determine how many days will be required to drill the well. The total cost for all bits used is usually less than 3% of the total well cost, but daily rig time and other rental costs usually represent over 40% of the well cost. Thus a relatively small amount of money spent on bits governs a significant portion of well costs through their performance.

Bits used by Getty for south Louisiana drilling invariably consist of either tri-cone roller type bits or diamond bits. The tri-cone bits come with either mill tooth or tungsten carbide insert cutting structures, and either journal bearings or roller bearings. Mill tooth bits are used at shallower depths where formations are relatively soft and uncompacted. The mill tooth bits will usually drill faster than the insert bits, but the cutting structure is not as durable. The trade off is between faster penetration but shorter bit life with the mill tooths and slower penetration but much more time on bottom with the insert bits. The economic criteria used to compare bit runs and judge which type is optimal is "cost per foot," defined as follows:

$$\$/\mathrm{FT} = \frac{\text{Bit Costs + Hourly Costs x (Drilling Time + Trip Time)}}{\text{Number of Feet Drilled}}$$

Both rig costs and daily rentals should be included in the hourly cost figure. At shallower depths, mill tooth bits will usually prove to be the most economical, but at deeper depths, when trip times become longer, the insert bits will become cheaper.

In some cases, diamond bits will drill faster than insert bits and will usually last twice as long. For this reason, diamond bit runs are very common below depths of 12,000-15,000 ft.

Bits are manufactured in certain standard sizes, most of which correspond roughly to the inside diameter of common casing strings. For example, 12 1/4" bits are usually used when drilling out from 13 3/8" casing and 8 1/2" bits are used after 9 5/8" casing has been set. If extremely heavy walled casing is selected, there may not be enough clearance to pass a standard size bit through it. Nonstandard size bits can be specially ordered, but delivery times can be several months.

In the well planning stage the engineer, usually with the aid of a bit company representative, analyzes the logs and bit records of offset wells in order to prepare a bit program and estimate drilling times. Bit records contain the best information available for bit performance in a particular area, but in their raw form they fail to take into account differences in weight, rotary speed, degree of hydrostatic overbalance or underbalance, hydraulics, sand content of the mud, and other things that can affect bit performance. Some of these discrepancies can be eliminated by normalizing the weight, rotary speed, and mud weights for each bit run to some common value.

Usually, a bit recommendation is requested from a service company when a formal cost estimate is being prepared. The bit recommendation will include copies of bit records and logs from offset wells. The engineer will review the recommendation with the service company, make whatever changes are necessary, and incorporate it into the drilling prognosis as a guideline for the drilling foreman on the rig.

A copy of the bit recommendation for the Jeanerette Lumber and Shingle Co. #1 is included in Appendix B.

Mud Program

The drilling fluid or "mud" is the heart of the drilling operation. It has several functions, but the main ones are to remove cuttings from the hole, control formation pressures to keep the well from blowing out, cool and in some cases lubricate the bit, and to prevent the wall of the hole from caving in. Nearly all muds used by Getty in south Louisiana are dispersed water based muds. Due to their high temperature stability, oil base muds are sometimes used by other operators when drilling extremely deep (20,000+ ft) holes if bottom hole temperatures exceed 350°F.

The potential mud bill for a well usually ranges from $100,000 to $1,000,000 depending on what mud weight is required and how long the mud will have to be maintained. The major cost items in a mud system are listed below:

1. Weighting agents - usually barium sulfate ($BaSO_4$) or "barite." This material has a specific gravity of 4.2 and is used as a weighting agent in both water base and oil base muds up to densities of 21 ppg.

2. Viscosifiers - usually active clays such as bentonite. These materials are added to the mud to provide sufficient viscosity to remove cuttings from the hole and to provide a base for an impermeable "filter cake" which is deposited across the face of any permeable formation to prevent loss of circulation.

3. Dispersants - organic compounds added to the mud to reduce viscosity. Dispersants must be used in heavy muds in order to render the fluid pumpable without excessive circulation pressures.

4. Caustic Soda - Sodium hydroxide (NaOH) is added to mud to raise the pH in order to enhance the performance of dispersants and inhibit corrosion of the drill string. Water based muds usually have a pH of 10.5-12.0.

5. Filtrate loss controllers - additives such as lignite that act to seal the filter cake by physically plugging up minute pore spaces in order to render it impermeable.

When planning a well, an engineer usually has neither the time nor expertise to prepare a comprehensive mud program on his own. Typically, the engineer will outline the desired properties such as density, viscosity, and water loss at each casing setting depth, and submit the information to a service company for a detailed list of necessary products to be added and an estimated total cost. The engineer must utilize offset information as best as possible to pinpoint potential drilling problems which will affect the mud. For example, if normally pressured sands will be exposed while drilling with moderately weighted muds (12-14 ppg), then a low water loss will be required to prevent excessive filter cake buildup. Or, if extremely sensitive shales will be encountered, then inhibitors or maybe even an oil base mud will be needed. Either of these possibilities can add hundreds of thousands of dollars to the cost of the mud. Mud company personnel are usually familiar with what additives will be necessary to combat specific problems, but it is the engineer's responsibility to thoroughly research all offset information and provide them with pertinent details.

A copy of the mud program selected for the Jeanerette Lumber and Shingle Co. #1 is included in Appendix B. As an illustration of the sensitivity of mud costs to unforeseen problems, the mud cost for this well was estimated at $450-500,000 by the technical staff of a reputable major mud company. Due to problems encountered in obtaining a low water loss before setting 9 5/8" casing and problems with carbonates from limey shales encountered at deeper depths, the actual mud cost exceeded $800,000.

Drill String and Bottom Hole Assembly Design

Bottom hole assembly is defined as the bit sub, drill collars, stabilizers, drilling jars, heavyweight drill pipe, and other downhole tools that are run below the drill pipe at the bottom of the drill string. The two main functions of the bottom hole assembly are to provide weight to apply to the bit and to control hole deviation.

In order for the bit to drill, a certain amount of weight must be applied to it. It is not desirable to apply this weight with the drill pipe, because running the relatively flexible drill stem in compression would buckle it, setting up stress reversals as it is rotated, which would lead to fatigue failures. For this reason drill collars, extremely heavy walled joints of pipe, are run to provide adequate weight with a safety factor of 1.15 so that the drill pipe is always in tension. There has been some controversy in the industry as to how to calculate the actual effect of bouyancy on the drill collars. Papers have been written which advocate the use of the so called "pressure area" or "force area" method of calculating available bit weight as opposed to the application of a simple bouyancy factor. One of the author's first assignments after beginning the internship was to research this problem and submit an explanation of which theory was correct. A complete discussion of this work is included in Chapter VIII of this report and in Appendix E. To calculate the available bit weight, Getty simply multiplies the air weight of the drill collars times the bouyancy factor for the mud weight in the hole and divides by 1.15 to allow for errors in weight indicator readings.

$$ABW = \frac{\text{Bouyancy Factor x Air Wt. of Collars}}{1.15}$$

The second purpose of the bottom hole assembly is to control hole deviation. Under the application of weight the bit tends to drill at some angle other than vertical. This tendency can be controlled by the selective placement of stabilizers in the collar string to either construct a "pendulum assembly" or "packed hole assembly." The factors affecting stabilizer placement are discussed fully in the "Bottom Hole Assembly Report" included in Appendix D of the paper.

Deviation in most wells drilled in South Louisiana can be effectively controlled with a 60-ft pendulum assembly. This type of hook up was used successfully from surface to total depth in the Jeanerette Lumber and Shingle Co. #1 well as outlined in the drilling book in Appendix B.

Hydraulics

The jet bit was first introduced in the early 1950's. Instead of a conventional watercourse through which mud was circulated at a comparatively low velocity through the center of the bit, the circulating fluid was forced to flow through small nozzles or "jets" on the outside of the bit. Fluid passing through these jets is accelerated to velocities of several hundred feet per second and the force of the stream is aimed between two adjacent cones, toward the bottom of the hole. This improves the performance of the bit for two reasons:

1. As the jet stream passes between cones, it tends to knock off sticky cuttings which can ball up on the cones and prevent the teeth from penetrating into the formation.

2. As the high velocity fluid impinges upon the bottom of the hole, it tends to wash away cuttings as soon as they are cut away from the formation. This prevents them from being "redrilled" and slowing the bit down. Also, in soft formations the force of the jets will actually destroy the rock and directly increase penetration rate.

In rotary drilling, the term hydraulics refers to selecting the optimum pump pressure, flow-rate, and nozzle size in order to achieve the most efficient bottom hole cleaning capability. Efficient hole cleaning is essential for two reasons:

1. It improves the rate of penetration.

2. It facilitates the detection of changes in pore pressure by monitoring drilling parameters.

Hydraulics programs should follow one of two design philosophies:

1. Maximum Hydraulic Horsepower, or

2. Maximum Jet Impact Force.

Maximum hydraulic horsepower at the bit is obtained by selecting nozzle sizes such that approximately 65% of the total pressure drop in the circulating system occurs at the bit.[3] Maximum jet impact force is obtained by sizing nozzles for a 48% pressure drop across the bit. In order to size jets for a particular bit run, one merely has to:

1. Select the pump pressure that will be used,

2. Assume a flowrate, and

3. Calculate circulation pressure losses in the surface equipment, drill pipe and collars, and annulus and

4. Calculate the pressure drop across the bit and corresponding nozzle size.

This is an iterative process that is repeated until the desired pressure loss at the bit is achieved. The surface pressure selected should be the maximum pressure that the mud pumps can feasibly produce. In order to minimize downtime due to repairs, this pressure will usually be less than the manufacturer's rated working pressure. Running maximum surface pressure will insure that the most energy per unit volume is being put into the circulating fluid.

In the well planning stage the engineer should have a fairly accurate estimate of the mud weights that will be used at each depth of the hole. Pump pressure can be assumed to be 2,700-3,000 psi. With this information, a guideline for jet sizes for each bit run can be prepared. The only other major consideration is the actual flowrate and the resulting annular velocity. Annular velocities which are too high will result in excessive annular pressure losses which will increase the chance of lost circulation. Also, it is possible for velocities to become high enough to induce a turbulent flow regime in the annulus. This can cause severe hole erosion problems. Annular velocities that are too low may not provide adequate lifting capacity to remove cuttings, especially at lower mud densities and viscosities. These factors can best be analyzed during the actual drilling of the well when specific rheological data on the mud is available, but some planning should be done prior to this. The maximum hydraulic horsepower design method results in lower circulation rates than the maximum jet impact method. Since it requires a higher pressure loss at the bit, circulation pressure losses must be minimized by lowering the flowrate. For this reason, hydraulic horsepower programs should be used when drilling surface holes and usually after 9 5/8" casing has been set in order to reduce annular friction pressure losses. These pressure losses, also referred to as equivalent circulating density or ECD, may cause lost circulation while drilling the very porous permeable sands found at shallow depths. After a long string of casing has been set, the ECD needs to be controlled because small clearances create a restricted flow area and even a small pressure drop per foot becomes significant when compounded over several thousand feet.

Cost Estimating and Scheduling

Before money can be allocated to drill a well, an Authorization For Expenditures or AFE must be approved by the appropriate authority level. The AFE budgets a certain amount of money for the project for which it is specifically written. All invoices related to that project will reference the AFE number for the project and will be charged against the AFE. If the amount appropriate for the project by the AFE is overspent, then a supplement must be approved for the project to continue.

The engineer assigned to a well is responsible for preparing the drilling AFE. He must estimate, as accurately as possible, the costs of all tangible and intangible items related to drilling the well and allow a reasonable amount for contingencies such as fishing jobs. In order to monitor costs and schedule on a daily basis while drilling, the engineer will also prepare a graph representing estimated days required to drill to each depth and amount of money required to drill to each depth.

In preparing the AFE, the engineer is effectively writing a budget for the well. Major items to be included are:

1. Tubulars
2. Drilling day work
3. Drilling fluid
4. Tool rentals and bits
5. Location costs
6. Well logging services
7. Cementing services

Tubular costs can be estimated easily and accurately once the casing and tubing strings have been designed. Prices for particular pipe and connections are published by various supply companies and are readily available. Unless a drastic change occurs in the price of tubular goods the actual cost and estimated costs should agree $\pm$ 10%.

Although there have been some recent trends away from it, the vast majority of drilling contractors work their rigs on a straight "day rate" for which they are paid a fixed amount, specified by contract, for every day the rig is operational. Certain allowances are made for downtime, but generally this fee is not contingent upon drilling a certain amount of hole or any other factor. However, while the daily cost of the rig is easily ascertained, the total number of days required to drill the well is an engineering judgment. Offset wells are analyzed to serve as indicators of how much time is required to drill each interval of the well, and onto this allowances must be made for logging, running casing, and special problems such as lost circulation and fishing. A total daily cost is estimated and the cost of the tubulars, logging, and cementing services necessary at each casing setting point are known. With this data, a cost versus depth curve will be constructed to monitor the gross budget of the well while drilling.

Drilling fluid costs are difficult to estimate accurately on wells that require drilling with weighted muds for extended periods of time. The density and volume of mud required at depth can be predicted fairly well, and thus the cost to build the mud system is known. However, the rheological properties of the mud tend to deteriorate with time and require constant maintenance. The type of formation encountered can have a tremendous effect on the cost of maintaining the mud system. Calcareous shales can cause viscosities to increase, abnormal temperatures can cause stability problems, long sections of permeable sands can result in excessive dehydration of the mud downhole, and extremely water sensitive shales can necessitate inhibitors or even a switch to oil base muds. Total mud costs tend to be higher than originally estimated and should be budgeted liberally. On the Jeanerette Lumber and Shingle Co. #1, mud cost was estimated at $500,000, budgeted at $600,000 and actually turned out to be over $800,000.

Rentals and bit costs are made up of the dozens of incidental items, large and small, that are required to drill but are not customarily furnished by the drilling contractor. These items include such things as heavyweight drill pipe, drill collars, pumps, drilling instrumentation, mud cleaners, centrifuges, certain size BOPs, miscellaneous valves and fittings, drill bits, and many other things. It is impractical to itemize the cost of each of these in an effort to estimate their total cost. Usually, a percentage of the day rate for the rig based on experience is sufficient. While the cost of each one of these items is small, their total cost can be 10-20% of the total well cost.

Wellsite preparation costs must be estimated with the location of the actual wellsite in mind. If the wellsite is on well drained ground with close access to an all weather road, then the cost to prepare the location will be relatively low. Low ground requiring extensive filling, remote locations that need long access roads, or soft ground requiring piling to support the weight of the rig are just a few factors which can drive up the cost of a location.

The type of logs to be run on a well are specified by the Exploration Department. The logging program depends on the nature of well and the amount of offset data available. Usually, exploratory wells will require more frequent logging runs and more comprehensive logging programs. This is attributable to two factors. One is that from an operations standpoint, it is essential that one not drill off unexpectedly into a zone of high pressure. Even the most severe pressure transition zones usually give some warning as they are being drilled unless they are entered by suddenly crossing a fault. In areas where little offset well control is available, or where faulting is suspected in the region of a transition zone, frequent logging runs should be planned. The electric log will yield data that can be used by the geologist for geological correlation and by the engineer to quantitatively predict pore pressure and indicate the development of a pressure transition zone.

The second reason for more frequent logging runs on exploratory wells is that the well is being drilled into unknown and relatively unpredictable geological territory. If problems such as a kick or lost circulation caused a hole to have to be abandoned after drilling for several thousand feet without running a log, then valuable information is lost. In this situation it is not known if any commercial sands were drilled through, and the information could only be had by the costly process of sidetracking and redrilling the hole. Had logging runs been made prior to the well being lost, then positive data would be available as to the presence or absence of hydrocarbons, thus greatly simplifying the decision of whether the well should be redrilled. In the case of the Jeanerette Lumber and Shingle Co. #1, logging runs were made at 500-ft intervals after drilling to 16,000 ft.

Other than the number of times the well is logged, the main factors determining the cost of the logging program are the types of logs to be run and the downhole environment to which the logging tools must be subjected. Logging programs can consist of any combination of tools from a simple induction or electric log to a full suite of logs which includes electric logs, sonic logs, gamma ray, neutron-density logs, dipmeter, and sidewall cores. A full suite of logs is expensive because of both direct logging charges plus the rig time which is lost. A full suite usually requires at least three separate wire line runs and can take from 12 to 48 hours depending on the amount of hole to be logged. Mechanically, the logging tools are affected by both heat and temperature. In very deep wells (20,000± ft) bottom hole pressures can exceed 20,000 psi and bottom hole temperature may be over 400°F. These conditions will require special logging tools which are much more expensive than conventional tools.

Logging charges are not especially difficult to budget for. Downhole environments can be predicted well enough to determine whether special logging tools will be required, and by coordinating with the geologist and reviewing offset drilling records, a reasonable estimate can be made of the number of logging runs required. Once this information has been gathered, a wireline services company representative can be consulted to provide a detailed cost estimate.

Cementing costs are affected by two main components, the volume and composition of cement slurry used and the cost to transport the cement to the wellsite and pump it downhole.

The composition of the cement slurry is affected by the density required, pumping time, and the bottom hole temperature. Slurry density may be varied from 12.5-16.5 ppg simply by changing the water content. Densities outside this range require special light weight slurries or dense weighting additives. The volume of slurry required is determined by the size of the hole drilled, the size casing set in the hole, and the amount of hole enlargement due to erosion or washouts. If the slurry volume is large, long pumping times may be required to mix and displace the cement and retarders may be required to delay thickening of the cement. Certain types of cement may require accelerators to promote hardening at low temperatures. Bottom hole temperatures in excess of

230°F will require addition of silica flour to provide the slurry with long term temperature stability.

If the wellsite is an inland drilling barge, then a marine cementing unit may be necessary to perform the job of transporting, mixing, and displacing the cement.

In the cost estimating phase of drilling the well, the engineer should furnish a cementing services representative with estimated cement volumes required, expected cement densities, bottom hole temperatures, and any special logistical problems associated with the job. In the cost estimate the engineer should include money necessary for cementing in case the well is to be plugged and abandoned. If all the data pertinent to cementing is estimated with nominal precision, then actual cementing cost should rarely exceed the budgeted amount.

In summary, an AFE represents a multimillion dollar budget and must be thoroughly planned. If the estimated well cost is too low, then marginally economical wells may appear as good investments. If well costs are estimated too high, then good prospects will be made to appear uneconomical. An engineer, whether performing a "rough" cost estimate or an actual AFE has a responsibility to investigate every aspect of drilling the well as thoroughly as possible in order for management to make intelligent decisions when preparing annual and quarterly drilling budgets.

Preparation and Content of Drilling Prognosis and Report Books

After all preliminary engineering analysis and cost estimating has been done, the engineer will gather all data and operating instructions relevant to drilling the well in the drilling prognosis book. This book will contain a discussion of the drilling program, the geological program, bit recommendations and hydraulics, a copy of the recommended mud programs and cement programs, and a description of wellhead equipment to be used on the well.

The morning report book will contain forms necessary for reporting daily drilling information such as depth footage made, shale density, pore pressure, description of formation, bit weight and rotary speed, pump pressure and flowrate, a summary of operations for the previous 24 hours, mud properties, and daily costs and total costs to date. Also, reports for specialized services such as logging, BOP testing, casing caliper logs, bottom hole assembly inspections, and deviation surveys will be included.

A copy of both the prognosis and report book is maintained at the wellsite and in the office. The prognosis serves as a master "blueprint" outlining how to drill the well and the report book facilitates daily monitoring of drilling progress and serves as a permanent record of drilling operations.

CHAPTER VI

DRILLING OPERATIONS

Personnel Assignments and Responsibilities

The actual drilling of a well involves many different people at different levels within the Getty organization. While budgeting, prospect selection, and AFE supplementing involve persons at both Division and Corporate levels, all matters pertaining to drilling operations are confined to the District and Area offices.

The Area office is where most of the direct supervision of drilling is located. Persons involved at the Area level include the drilling foremen, the engineer, the Lead Foreman and Area Engineer, and the Area Superintendent. Usually, two drilling foremen are assigned to a well. They remain at the wellsite 24 hours a day and work a rotating schedule, usually five days on and five days off. The foremen are directly responsible for all operations at the the wellsite. They report to the Lead Foreman in the office. The engineer assigned to drill the well spends the majority of his time in the office with occasional trips to the well to assist in supervising critical operations such as logging and running casing. The engineer is responsible for monitoring the overall time schedule and budget for the well and for making possible recommendations to cut costs, speed up the drilling, avoid potential problems, etc. The engineer reports to the Area Engineer. The Area Engineer and Lead Foreman report to the Area Superintendent. Most operating decisions related to drilling and production operations are made by the Area Superintendent or his subordinates.

At the district level, persons involved directly in operations include the District Production Manager and the District Operations Superintendent. The District Exploration Manager, lead exploration or development geologist, and the geologist who initially worked up the drilling prospect are also indirectly involved. The District Operations Superintendent is directly responsible for all drilling operations in the District, and is involved in all major operating decisions. During drilling, geologists continuously monitor what formations are being encountered by reviewing electric logs, mud logs, and paleontological analysis of formation samples, and correlate the data with offset wells. They coordinate with production personnel to advise when problem formations may be encountered or when all potential pay zones have been encountered and further drilling is not warranted.

In the case of the Jeanerette Lumber and Shingle Co. #1, paleontology indicated that a deep water depositional environment had been encountered at 17,000 ft. This formation and those below it would not be expected to contain any commercial reservoirs, therefore drilling was stopped short of the planned depth of 18,000 ft. Thus, coordination and communication between the Exploration and Production Departments saved drilling an additional 1,000 ft of hole at a cost of approximately $600,000.

Daily Monitoring of Drilling Operations

The engineer should review all information contained on the morning report sheet to ascertain whether drilling parameters fall within acceptable ranges and whether drilling is proceeding on schedule and within the budget. The depth versus days and cost versus depth curves provide an easily visualized graphical respresentation of this. Other things the engineer should review are whether:

1. Sufficient weight and rotary speed are being run on the bit to obtain an acceptable rate of penetration;

2. Pump pressure and circulation rates are providing good bottom hole cleaning and cuttings removal; and

3. Critical mud properties such as density, viscosity, and water loss are being maintained within acceptable ranges.

If possible, the engineer should coordinate with the geologist and keep the drilling foreman informed as to when problem intervals may be expected such as zones of abnormally high pressure, porous sands or fractured limestones which may cause lost circulation, or water sensitive shales that may require special mud additives to prevent excessive hydration and sloughing. However, in many instances offset drilling records and geological information will not be detailed enough to provide advanced warning of these problems.

In the case of the Jeanerette Lumber and Shingle Co. #1, geological correlation with a nearby offset well was used to pinpoint zones of potential lost circulation and a severe pressure transition zone. This interval had caused enough problems to prevent the offset well from reaching its proposed depth, but by preparing for it with a special bottom hole assembly and mud properties to prevent kicks, lost circulation, and sticking, the interval was drilled with no major problems.

Selection of Bits

Wells in south Louisiana are invariably spudded with mill tooth bits, and these types of bits are used to drill soft formations for the first several thousand feet of the well. Although these bits do not have the durability of tungsten carbide insert bits (25-35 hours vs. 80-120 hours), they are cheaper on a cost per foot basis because they drill fast enough to offset the extra time spent tripping. However, at a certain depth, a breakeven point will occur where insert bits and mill tooth bits will have the same cost per foot. Below this depth, insert bits or diamond bits will be more economical than the mill tooths.

The engineer should calculate and plot cost per foot for each mill tooth bit run until a trend line can be established which will allow him to predict the performance of the next bit. Bit runs from offset bit records may be plotted to generate a cost per foot trend line for insert bits. The engineer may then predict the optimum point to switch to insert or diamond bits and advise the drilling foreman.

Also, whereas the engineer has already made an outline of the optimum hydraulics program for each bit run, he should review the actual rheological properties of the drilling fluid and any limitations of the fluid handling equipment on the rig to make any modifications necessary to the selection of nozzle sizes, pump pressure, etc.

Bottom Hole Assembly, Drill String, and Casing Inspection

Tubular goods such as drill pipe, drill collars, and casing represent the fundamental mechanical components of drilling. As with anything mechanical, they must be occasionally inspected and repaired. The importance of this cannot be overemphasized. If a tool joint on a piece of drill pipe fails to create a tight seal, then a washout will occur. This involves at the least, a time consuming trip to locate the washout or if not noticed soon enough, this tool joint may fail, resulting in a fishing job to retrieve the pipe left in hole. Drill collars must be inspected for the same reasons. Due to their stiffness and the fact they are often rotated in a buckled mode, (and thus subjected to continuous stress reversals which lead to fatigue), they are even more susceptible to connection failure than the drill pipe. Another factor to consider is the degree of dogleg severity to which the drill string is subjected, especially in a directional hole. As the drill string is rotated inside casing, it tends to wear a hole in the casing wherever there is contact. An undetected hole in a string of casing can jeopardize the entire well if it results in failure to be able to control pressure during a kick. For these reasons, the drill pipe, drill collars, stabilizers and in-situ casing must be regularly inspected.

Drill pipe will normally be inspected by x-ray, eddy current, ultrasonic, and/or black light methods before the well is drilled. Normally, it will not need another inspection while drilling the well. Responsibility for drill pipe inspection is generally left to the drilling contractor.

Drill collars and stabilizers need much more frequent inspections. The engineer should establish a recommended inspection schedule for the entire bottom hole assembly and include it as part of the well prognosis. Typically, a schedule may call for black light and ultrasonic inspection every 90-110 rotating hours when drilling 12 1/4" hole and every 140-150 hours while drilling 8 1/2" hole.

The Lafayette Onshore Area has a standing policy that casing shall be pressure tested to 80% of its rated burst or 4,000 psi maximum after being initially set, and a casing caliper log will be run every 14 drilling days thereafter to detect any worn spots.

Well Logging

Logging runs are necessary before each string of casing is set to evaluate any unlogged open hole. More frequent logging runs may be desirable as discussed in Chapter V of this report. The engineer and geologist should be present at the wellsite to discuss what types of logs will be necessary. As a minimum, an induction log along with an SP (spontaneous potential), gamma ray, and sonic logging tools should be run. These can all be run simultaneously. Additionally, in an exploratory well, the geologist will usually request a dipmeter in order to help evaluate the geological structure being drilled. If the induction log does not indicate any commercial reservoirs, then neutron density logs and side wall cores will probably not be run.

Running and Cementing Casing

Casing setting depths are estimated in the well planning stage but the engineer must look at well data to select the actual setting depth. Considerations include:

1. What is the fracture gradient at the previous casing shoe?
2. What mud weight is expected to drill the subsequent formations?

3. What margin of safety is required between the actual mud weight and the fracture gradient of the previous casing shoe?

4. Fracture gradients and mud weight constraints notwithstanding, are there any problem formation which need to be "put behind pipe"?

In most cases, Getty likes to maintain at least a 1.0 ppg safety margin between mud weight and frac gradient. Thus, if the fracture gradient of a string of 13 3/8" casing set a 6,000 ft is 15 ppg, then a string of 9 5/8" casing should be run and set before reaching formations which require a 14 ppg mud to control. Safety margins are especially critical when drilling into a transition zone and only a string of relatively shallow surface casing has been set. If an unexpectedly high pressure sand is encountered and causes a kick, the formation at the casing shoe may be broken down and allow fluid to flow uncontrollably from a lower sand to an upper sand. This is liable to cause the drill string to become stuck and result in an extensive fishing job or possibly even a junked hole.

From the time the casing setting depth has been reached until the casing is run and cemented in place, constant well-site supervision is necessary. Because this is considered a critical operation, the engineer is usually present at the rig to assist and relieve the drilling foreman. The engineer should review all logs with the geologist to determine if any sands appear to contain hydrocarbons and to help establish geological correlation with other wells in the area. The engineer should also consult with the cementing company and update them on required cement volumes, densities, rheological properties, and bottom hole temperatures in order to determine if any modifications of the proposed cement slurry are necessary.

Completion and Abandonment Operations

After a well has been drilled to total depth and logged, it will either be completed or plugged and abandoned, depending on whether commercial deposits of oil and gas are found.

Completion costs may range from several hundred thousand to several million dollars depending on the depth of the well, pressure that must be controlled, whether continuous corrosion treatment will be required for H_2S or CO_2 and other factors that will dictate design of the completion casing and tubing. Also, several days or weeks of rig time will be required to run the completion. Even more money will be required to build surface facilities to process the well stream. Thus, even if hydrocarbons are discovered, the reservoir may not be large enough to warrant spending the extra money required to complete the well.

In this case, the well will be abandoned according to the regulations of the State Department of Conservation. These regulations are rather extensive, but basically they require that:

1. Any perforated intervals be isolated from each other with cement plugs;

2. That a cement plug be placed at the shoe of the lowest string of casing if production casing is not run;

3. That cement plugs be set to isolate any exposed fresh water sands from possible contamination by salt water sands; and

4. That a plug be set near the surface and all casing be cut and pulled "2 ft below plow depth."[4]

CHAPTER VII

PRODUCTION

Introduction

Production refers to all activities related to lifting oil and gas out of a reservoir after a well has been drilled and completed. Engineering aspects of this broad field include design of artifical lift systems, reservoir stimulation techniques such as fireflooding and waterflooding, prevention of downhole and surface corrosion, economic analysis of recompletion prospects and dozens of other topics. In addition to learning the technical aspects of all of these procedures, the engineer assigned to the Area engineering staff is expected to familiarize himself with the operational activities associated with each. Most production activities undertaken in the Lafayette Onshore Area are concerned with the 1) analysis, design and supervision of recompletions, 2) efficient operation of gas lift systems, and 3) downhole chemical treatment for corrosion.

Field Assignments and Responsibilities

Responsibility for the producing fields within the Area is divided up among the entire engineering staff. Each engineer is expected to monitor production rates, revenue, and expenses for his fields to insure that each well is operating profitably. The engineer should study the geological structure of his fields and become familiar with reservoir data such as remaining reserves, type of drive for the sand, production history, aerial extent, location of major faults, bottom hole pressures, unit boundaries, lease lines, etc. for both producing intervals and commercial sands that have not been yet produced.

Recompletion Evaluations

When the formation that a well is completed in has been produced beyond its economic limit or has been depleted, then a recompletion to another potentially productive sand is necessary to restore the well to production. If no such sands exist, the well will usually be plugged and abandoned.

After a well has been drilled, assuming commercial reserves have been found, it is customary oilfield practice to begin production from the deepest reservoir. This practice allows lower depleted zones to be isolated with cement or mechanical plugs as higher zones are brought into production. This also eliminates the need to remove such things as packers, parted tubing, lost tools or any other irretrievable junk in the hole.

The engineer is responsible for investigating and researching the candidate sand for a recompletion to help management determine whether the recompletion will be a profitable investment for the company. The production history of the sand that the well is presently completed in should first be analyzed to determine if a recompletion is necessary. For example, wells will often cease to produce from a gas reservoir when formation water flows into the wellbore and bottom hole pressure is insufficient to overcome the resulting hydrostatic head. The well can sometimes be restored to production by "squeezing off" the existing perforations with cement and reperforating the extreme upper part of the sand in an effort to stop the influx of water.

If it has been determined that the present sand can not be economically restored to production, then a recompletion is in order. The reserves of oil and/or gas of the zone to be recompleted in should be estimated as accurately as possible. This will require the services of a development geologist who will use offset wells, sysmic data, etc. to "map" the sand in order to determine its aerial extent and thickness. The District reservoir engineering staff may then be consulted to estimate the amount of reserves in the sand using either a volumetric or material balance approach. Usually, this work will be done shortly after the well is drilled, but may need revision in the light of such things as a more refined geological interpretation of the structure or revelations as to the performance of a reservoir based on production history.

After reserve figures have been assigned to the sand and a contour map has been drawn, then the engineer should look at all wells in the field to determine if the well under consideration is located in a good position to drain the reservoir. Reservoirs are not generally level but have high and low areas depending on the influence of the local subsurface geology. Generally, the best place to drain the reservoir is from a well(s) located near the highest point or "updip." This will tend to delay the production of any water present in the sand since water, being more dense than gas and oil, tends to segregate in the reservoir and accumulate in low places.

The well under consideration might be located near the hydrocarbon-water interface in the reservoir and could "water out" after producing for a short time. For the same amount of money spent it would be wiser to recomplete a well that was more favorably located on the structure (i.e., updip).

Estimating recompletion costs is similar to estimating drilling cost. Unless a thru-tubing recompletion is possible, a rig will be required along with various rental tools. A workover fluid to control the well, wireline services to perforate and possibly log the well, and cementing services will be required to isolate the lower part of the wellbore with cement plugs. Additional things for the engineer to consider when estimating recompletion costs are 1) how much of the existing wellbore must be cleaned out and what will it cost and 2) do previously run cement bond logs indicate that it will be necessary to "block squeeze" above or below the recompletion sand in order to isolate nearby water sands. These operations can add tremendously to the cost of a recompletion and are easily overlooked.

Once the cost of the recompletion has been determined, then the revenue that is expected to be generated as a result of this investment should be estimated. This will be determined by the production rate of the oil, gas, or condensate and the product price per bbl or MCF. Theoretically, knowing the reservoir pressure, permeability of the sand, viscosity of the produced fluids, pressure loss characteristics of the perforated interval, tubing and flowline pressure losses, and any special constraints on flowing wellhead pressure, the actual rate at which the well will flow could be calculated. All of this information is usually either known or can be predicted within reasonable engineering tolerances, but this approach to estimating production rates is rarely used for routine recompletions. A more common method is to look at production rates from similar wells and assume a decline rate. After production schedules for the well have been estimated, current selling prices for oil and gas can be easily ascertained. Factors complicating future price estimates include special tax considerations such as effects of the Federal Excise Tax on oil, NGPA gas price regulations, state severance taxes, inflation, and projections as to what future free market price will prevail. It is not the engineer's responsibility to make projections on the future price of oil and gas for the purpose of economic analysis. Escalation factors for these prices are furnished by Corporate and Division financial planning groups.

After initial investment costs and expected gross revenues and tax liabilities have been established, all operating expenses related to producing the well need to be estimated. Typical operating costs include the cost to operate an artificial lift system, cost to compress the flow of gas from a low pressure gas well to sales line pressure, cost of corrosion treatment for the well, and cost to dispose of any salt water produced by the well.

Economic analysis of recompletions and other production investments is facilitated by the Petroleum Economics of PECON program. This is an in-house computer program used to analyze development drilling prospects, recompletion prospects, etc. Given certain guidelines the PECON program will automaticaly calculate production schedules, federal tax liabilities, and apply escalation factors to product prices. The program will calculate the net present value and expected rate of return for the project. The program also has features which allow risk factors to be applied to such things as size of reserves, dry hole probability, amount of investment required, product prices, reservoir pressures, water saturation, etc. The program incorporates the risk factor into the economic analysis via a Monte Carlo simulation technique.

Included in Appendix B is a recompletion evaluation for the C. Richard #2 well in N. Erath field. Many of the topics discussed in regard to the PECON study are illustrated in this proposal.

Corrosion Control

Oilfield corrosion can be grouped into two broad categories 1) downhole corrosion and 2) surface corrosion. Corrosion can occur downhole in wells due to the presence of saltwater, H_2S, CO_2, and certain bacteria. Temperatures ranging upwards of 400°F and pressures in excess of 20,000 psi can enhance the corrosive nature of these in extremely deep, hot wells. On the surface, buried flowlines, saltwater holding tanks, and production processing vessels are susceptible to corrosion. Almost all oilfield corrosion is electrochemical in nature. The most common method of treatment for downhole problems is with chemical inhibitors designed to place a protective film on the walls of any steel exposed to the well stream and block the formation of local electrolytic cells. For protection of surface equipment, cathodic protection systems consisting of anode ground beds and/or rectifiers are employed to inhibit electrolytic corrosion.

One of the author's assignments during the internship was to organize a corrosion control plan for the Area. This consisted of obtaining corrosion treatment recommendations from service companies and setting up a regular schedule of treatment for all producing and saltwater disposal wells. Treatments consist of corrosion inhibitors, scale inhibitors, and bactericides. Effectiveness of the treatment program for each well is monitored through iron counts and corrosion coupons. All wells in the Area are treated over a period of three months and the treating program is reviewed at a quarterly corrosion meeting to determine whether more or less inhibitor is needed for each well based on the results of monitoring.

CHAPTER VIII

SPECIAL PROJECTS

Introduction

During the internship, a number of special projects requiring a mechanical engineering emphasis were assigned to the author. Discussions of the analysis and results of two of the special projects are included below.

Effect of Bouyancy and Hydrostatic Pressure on Drill Collar Weight

In 1949, M.F. Hawkins and N. Lamont introduced a concept called the "pressure area" or "force area" method of calculating the effect of hydrostatic forces on drill strings.[5] As commonly applied, this method will correctly predict the overall bouyant force on a drill string submerged in a drilling fluid, but leads to totally erroneous conclusions as to the number of drill collars required to counteract the bouyant force. The primary consideration here is that the drill string should never be run in compression, as this can cause the drill pipe to buckle and lead to fatigue failures. Therefore, a sufficient number of drill collars must be run to supply all necessary drilling weight on the bit and still leave the drill pipe in tension.

The force area principle is not an extremely difficult concept. It simply states that the net effect of bouyancy may be calculated by multiplying hydrostatic pressures by the exposed cross sectional areas that they act upon. Pressures acting upon exposed areas facing downward result in upward forces and pressures acting upon exposed areas facing upward result in downward forces. Normally, drill collars have a larger diameter than drill pipe. Thus, an "exposed area" facing upward is present at the drill collar-drill pipe interface. The drill pipe has some cross sectional area that covers the top of the drill collar string and blocks off hydrostatic pressure from acting downward on part of the drill collar cross sectional area. Meanwhile, the full cross sectional area of the drill collars is exposed to pressure acting upward at the bottom. Following this line of reasoning, the following proof can be developed.

EXAMPLE I

Let:

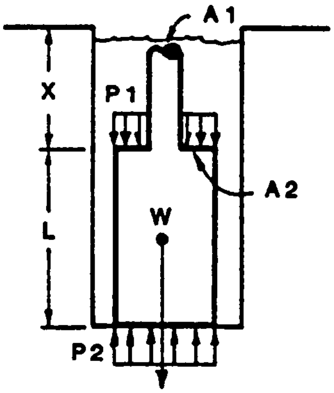

Fig. 5--Drill string schematic.

A_1 = cross sectional area of drill pipe
A_2 = cross sectional area of drill collars
x = depth to drill pipe drill collar interface
L = length of drill collar string
S = density of fluid drill string is submerged in
P_1 = $S(x)$ = hydrostatic pressure at the top of the drill collar string
P_2 = $S(x+L)$ = hydrostatic pressure at the bottom of the drill collar string
W = air weight of drill collars
W_b = bouyant weight of drill collars

The compressive stress in the drill string at depth x is required to be zero in order to prevent buckling. Summing forces, the following equations can be written.

$$W_b = W + P_1 (A_2 - A_1) - P_2(A_2)$$

$$= W + Sx (A_2 - A_1) - S(x+L) A_2$$

setting $W_b = 0$, and solving for x gives

$$x = W/SA_1 - LA_2/A_1$$

This is the method used in the pressure area method proposed by Hawkins and Lamont. This is tantamount to saying that if the drill string-drill collar interface is lowered to the depth specified by x, then the weight of the collars will be zero. Therefore, any weight applied to the bit will place the drill string in compression. This is intuitively known not to be true. The fallacy of this example of the pressure area method is that it fails to consider all of the forces. The axial compression stress in the drill pipe does not have to be zero in order to prevent buckling. Since at any depth, the radial compressive stress is equal to the hydrostatic pressure of the drilling fluid, then the axial compressive stress can take on any value up to and including the magnitude of the radial compressive stress before an elastic instability can occur and cause buckling. If the forces acting on the drill collar string are rewritten assuming that the compressive stress in the drill pipe at the drill pipe-drill collar interface is equal to the hydrostatic pressure at depth x, the following equations can be developed.

$$
\begin{aligned}
W_b &= W + P_1(A_z - A_1) + P_1A_1 - P_2A_2 \\
&= W + Sx(A_2 - A_1) + SxA_1 - S(x+L)A_2 \\
&= W - SLA_2
\end{aligned}
$$

This says that the bouyant weight of the drill collars is independent of depth and is equal to the "air weight" of the drill collars minus the weight of the fluid that the collars displace. This is the basic law of bouyancy stated by Archimedes over 2,000 years ago and is the correct method to be used in calculating bouyant drill collar weight. Examples illustrating this in more detail are shown in the report included in Appendix E.

Bottom Hole Assembly Report

The purpose of the bottom hole assembly is to provide sufficient weight to the bit in order to drill at an acceptable rate of penetration and to control the tendency of the bit to drill a hole at some angle of deviation from vertical.

The optimum arrangement of drill collars and stabilizers necessary to control hole deviation was the subject of some controversy and confusion at the Lafayette Onshore Area at the time the internship was begun. As part of a special assignment from the Area Superintendent, Mr. D.A. Nichols, the author, was charged with the responsibility of researching the literature and talking to other operators in order to present an explanation of the fundamentals of bottom hole assembly mechanics and make formal recommendations as to what types of bottom hole assemblies should be run in various situations. The results of this work can be found in the bottom hole assembly report included in Appendix D.

CHAPTER IX
SUMMARY AND CONCLUSIONS

Introduction

This report described the internship experience of Robert Magee Shivers III with Getty Oil Company - Lafayette Onshore Area from August 10, 1981 until July 7, 1982.

During the internship, the author was assigned to the Area engineering staff under the direction of Mr. C.A. Rohan, the internship supervisor. While serving in that capacity, the author's duties consisted primarily of petroleum engineering related activities and included assignments in drilling, production, corrosion, and special projects. As a staff engineer, the author had no official supervisory responsibilities, but was expected to coordinate with and advise field personnel to insure that projects with which he was directly involved were completed on schedule and within budget.

As a mechanical engineer, the internship provided the opportunity for the author to practice in a different engineering discipline. The author feels that while the lack of any formal petroleum engineering training did not cause any serious problems in drilling related activities, it was somewhat of a handicap in performing production and reservoir engineering related work. Although this handicap was overcome to some degree by self study on the author's part, previous training in the fundamentals of well log analysis, reservoir engineering, and petroleum geology would have been very helpful.

A brief summary of the principal intern activities and their contribution towards meeting the goals of the internship follows.

Drilling Activities

A large part of the internship involved the planning and drilling of the Jeanerette Lumber and Shingle Co. #1 well. This was an 18,000-ft exploratory well involving a budget of over six million dollars. This project required the author to consult and coordinate with persons in the New Orleans District from geologists to drilling foremen. The well was drilled to a final depth of 17,000 ft four days ahead of schedule and $100,000 under the amount budgeted for that depth and should be considerd a success both from an engineering and an operations standpoint.

Production Activities

The author's primary responsibilities in this area were the production of the North Erath field and organizing a corrosion control program for the Lafayette Area.

During the internship, gas production in Erath declined approximately 75% with the loss of the C. Richard well #2 - Champagne Sand Unit. A recompletion to a lower zone was proposed to restore production and at the time the report was written it was being reviewed by the District.

A corrosion control plan was organized and turned over to the production foremen for implementation.

Special Projects

Special projects completed during the internship included the reports on bouyancy and bottom hole assemblies. The results of the bottom hole assembly report were incorporated into the Area drilling policy and will become a permanent part of the Area drilling manual.

Conclusions

The author feels that the intern goals set for drilling were met with great success and that production and special projects goals were met adequately. Goals set for becoming familiar with the non-technical aspects of activity at the Area and District levels were attained primarily through contacts with those persons who were knowledgeable in that area rather than by actual working experience.

Overall, the author feels that the intership was a success and would recommend a similar assignment to any engineer interested in working in the exploration and production of petroleum.

REFERENCES

1. Getty Oil Company - 1982 Annual Report to Stockholders.

2. *Fortune* Magazine - May 3, 1982, p. 260.

3. Moore, Preston L., "Drilling Practices Manual," p. 258.

4. "Handbook for the Oil and Gas Industry," Dec. 1981, 6th Edition, 2nd Supplement, Statewide Order #29-B, p. 29-B-30, para. j.

5. Hawkins, Murray F., and Lamont, Norman, "The Axial Stresses in Drill Stems," Drilling and Mud Production Practice, API, 1949, p. 358-89.

APPENDIX A

INTERNSHIP OBJECTIVES AND JOB DESCRIPTION

FINAL INTERNSHIP OBJECTIVES
ROBERT M. SHIVERS

I. Observe overall organization of the Southern Exploration and Production Division, and its subdivisions and how they function as a part of Getty Oil Company.

A. Layfayette Area Office

1. Become familiar with preparation of daily, weekly, monthly, quarterly, and annual reports; their content, distribution, and purpose.

2. Become familiar with responsibilities of field personnel, production and drilling foremen, engineering staff, and administration.

B. New Orleans District Office

1. Become familiar with responsibilities of District Engineering Staff.

2. Become familiar with preparation of quarterly drilling budget.

II. Work continually as an integral part of the Area engineering staff, performing routine drilling and production duties, as well as working on special projects as directed by the Area Engineer and/or Area Superintendent.

A. Drilling

1. Become familiar with drilling operations through on-the-rig training and assisting in planning and troubleshooting wells with other engineers.

2. Plan and assist in supervising drilling of East American Island Prospect to include cost, scheduling, well program, and coordination of support services.

B. Production

1. Provide engineering support for operations of Erath Field, including surface equipment, wells, and reservoirs.

2. Coordinate with District reservoir engineering staff to initiate joint study of Erath Field to determine reserves in place, production alternatives, and economic limits for EBSU and other wells.

C. Special Projects

1. Complete study on Bottom Hole Assembly recommendations.

2. Develop corrosion control plan for the Area.

3. Investigate increase in burst strength resulting from cementing concentric strings of casing together.

RMS/lr
11-23-81

GETTY OIL COMPANY
JOB DESCRIPTION

CODE 34 -23.3-00

NOTE: IF ADDITIONAL SPACE IS NEEDED USE A BLANK SHEET

TITLE and LOCATION

JOB TITLE		
Junior Petroleum Engineer	☑ EXEMPT	☐ NON-EXEMPT

LOCATION	DEPARTMENT	SUB-DEPARTMENT
District or Area	Production	
SECTION	**UNIT**	**EVALUATION**
Engineering		

BASIC FUNCTION

To assist in performing petroleum engineering work on a District or Area staff.

DUTIES AND RESPONSIBILITIES

Assist in conducting appraisals of oil and gas producing properties for possible purchase or sale by Company.

Estimate oil and gas reserves on newly developed properties and assist in making performance revisions to reserves of old producing properties.

Make economic analyses of capital investment opportunities within the District.

Assist in adopting engineering and production problems for processing on electronic computers.

Assist in planning drilling and workover programs on development wells.

Analyze well logs and recommend intervals for completion in development wells or recompletions.

Furnish engineering planning and advice in conducting such field operations as well stimulations, squeeze cementing, installation of artificial lift, lease facilities and other production equipment.

Assist in the preparation and compilation of engineering reports, budgets, and engineering statistics.

Assist in conducting corrosion mitigation program in the District with particular emphasis on obtaining and analyzing field data.

Assist in the design of surface and subsurface equipment installations in connection with the production of oil and gas and conducting of pressure maintenance programs.

Getty

Getty Oil Company Post Office Box 51000, Lafayette, Louisiana 70505 • Telephone: (318) 235-0957
Telecopy: (318) 233-9803

Lafayette Onshore Area, New Orleans District
Southern Exploration and Production Division

July 29, 1982

Texas A & M University
Mechanical Engineering Department
College Station, Texas 77843-3123

Attention: Dr. M. Henriksen

Re: Internship Report for
R. M. Shivers, III, a
candidate for the degree of
Doctor of Engineering

Dr. Henriksen:

Robert Shivers has concluded his internship with Getty Oil Company as a staff engineer in the Lafayette Area. During his internship, Mr. Shivers has been involved in all phases of our drilling and production activities in South Louisiana.

It is our opinion that Mr. Shivers has made valuable contributions to our work effort. His expertise in mechanical engineering was called upon on a number of ocassions to help resolve problems encountered in our field operations.

Mr. Shivers has the ability to develop into a competent engineer and should be capable of applying advanced engineering principles to field applications. He also possesses the ability to manage other employees, plan and execute all phases of work.

Getty feels that the current internship program offered by Texas A & M should develop into an extremely effective program to develop highly technical engineers that can apply their knowledge to existing and future field applications.

It has been a pleasure to participate in this program.

Sincerely,

GETTY OIL COMPANY

Don A. Nichols
Area Superintendent

DAN/CAR/cfb

APPENDIX B

JEANERETTE LUMBER AND SHINGLE COMPANY WELL #1
DRILLING PROGNOSIS

JEANERETTE LUMBER & SHINGLE #1

The Jeanerette Lumber & Shingle #1 prospect is to be drilled as a test of the lower Miocene Sands, specifically the 1st, 2nd, and 3rd Planulina Sands. Proposed depth is 18,000 ft. Estimated drilling time is 116 days at a cost of about $6.14 Million.

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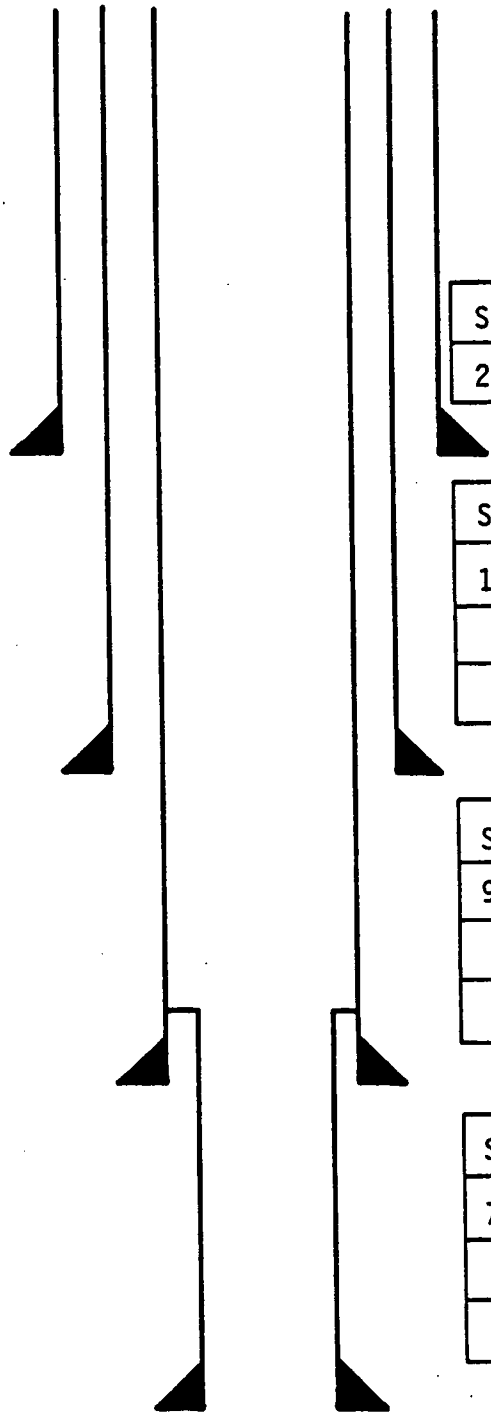


CASING SIZE 20"

DEPTH

PROPOSED 200' ACTUAL 168'

SIZE	Wt.	GRADE
20" Drive Pipe		

HOLE SIZE 17-1/2"

CASING SIZE 13-3/8"

DEPTH

PROPOSED 6000' ACTUAL 6035'

SIZE	Wt.	GRADE
13-3/8	72#	N-80

HOLE SIZE 12-1/4"

CASING SIZE 9-5/8"

DEPTH

PROPOSED 14,000' ACTUAL 13,970'

SIZE	Wt.	GRADE
9-5/8	53.5#	S-95

HOLE SIZE 8-1/2"

CASING SIZE 7-5/8"

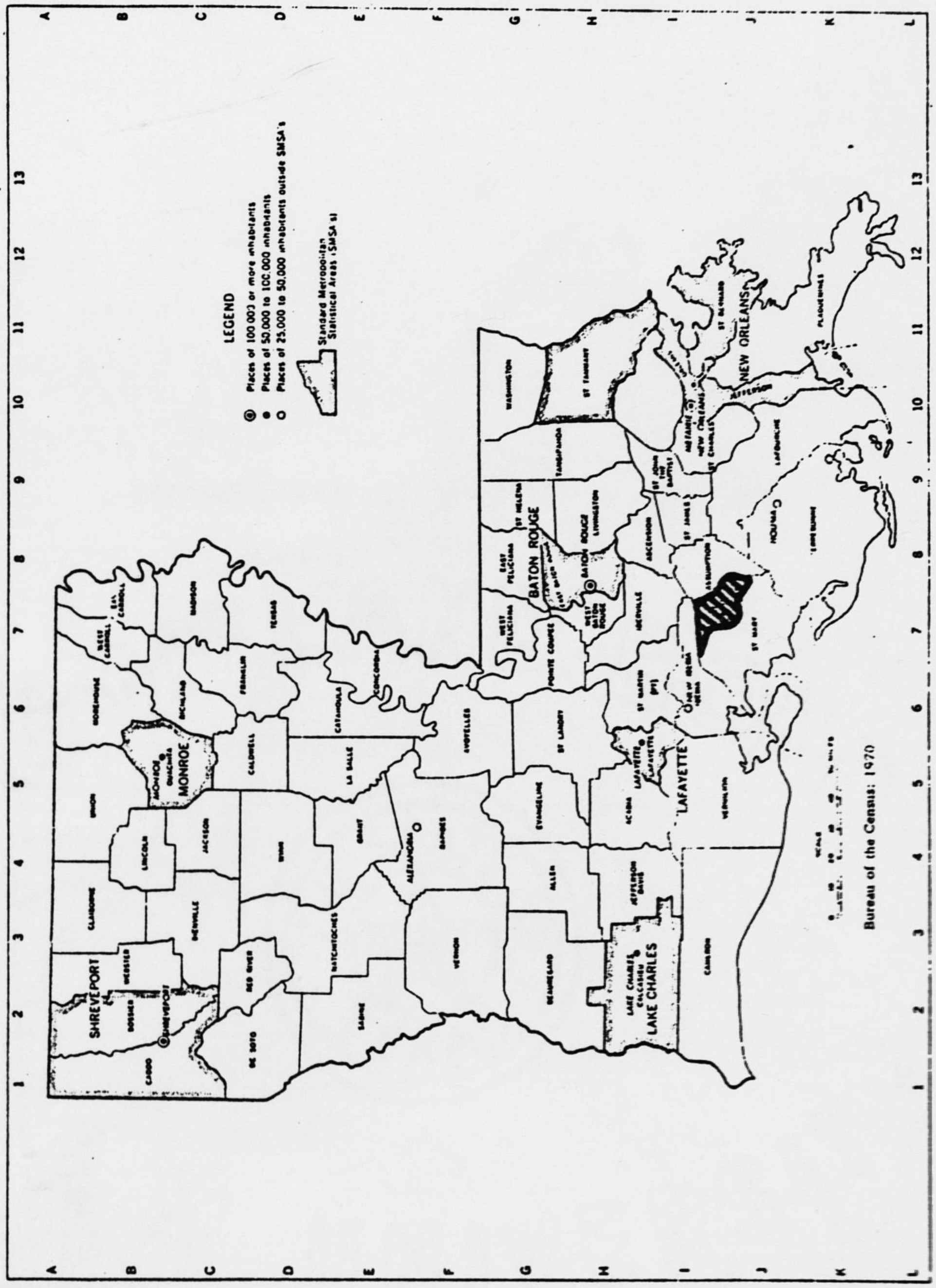
DEPTH

PROPOSED 18,000' ACTUAL

SIZE	Wt.	GRADE
7-5/8	45.3#	P-110

Fig. B-1--Well program.

LOUISIANA | State and Parish Map



[270]

Fig. B-2--Map of Louisiana.

Fig. B-3--Map of Lower St. Martin Parish.


IBERIA PARISH
ASSUMPTION PARISH
ATTAKAPAS ISLAND WILDLIFE MANAGEMENT AREA
ST MARY PARISH
LAKE PALOURDE
FLAT LAKE
WARD I
BASIN
TIGER ISLAND

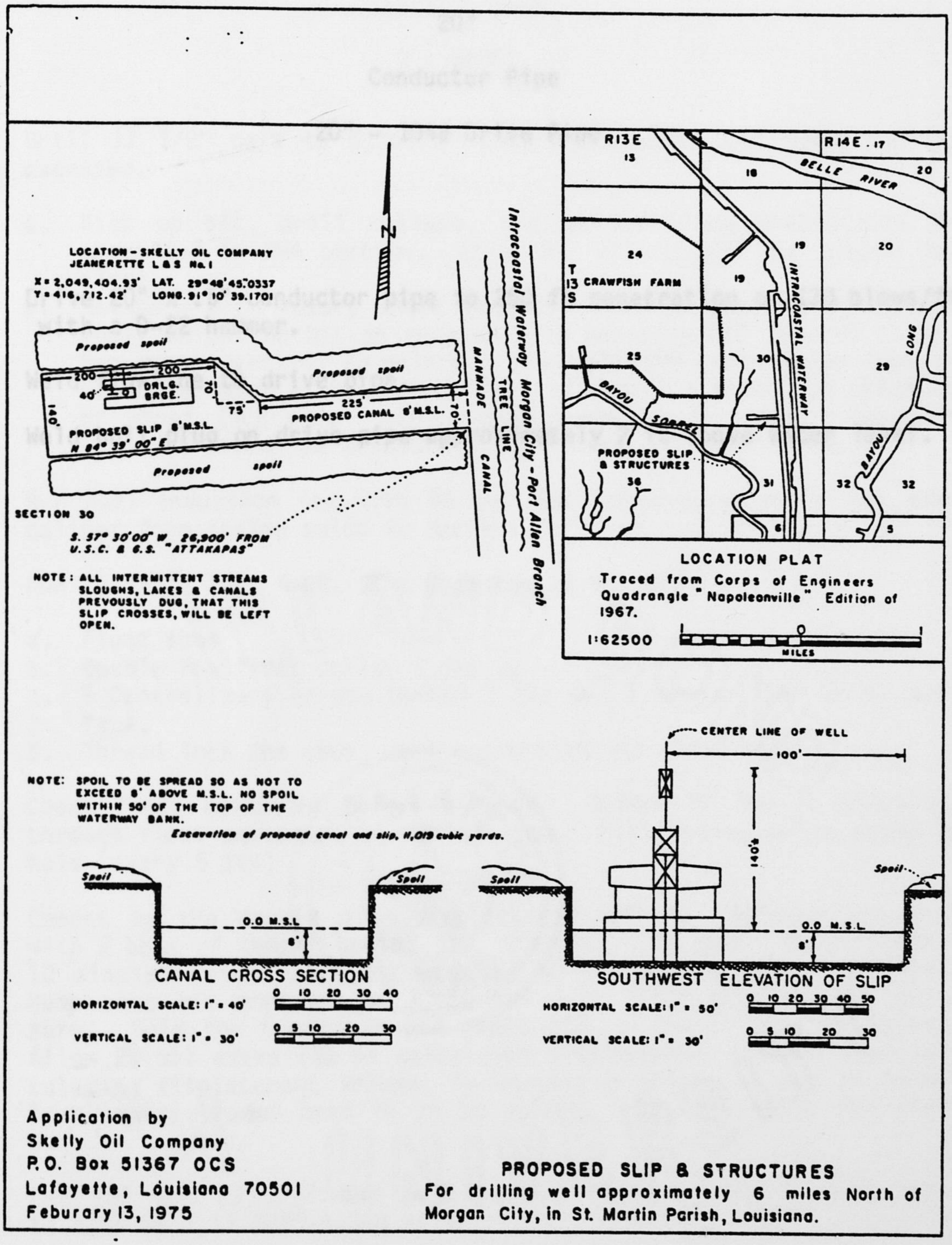


Fig. B-4--Location plat.

JEANERETTE LUMBER & SHINGLE #1

DRILLING PROGRAM

20"

Conductor Pipe

20" - 104# Drive Pipe

1. Drive 20" x .5" conductor pipe to 250 ft penetration or 130 blows/ft with a D-22 hammer.
2. Weld flowline to drive pipe.
3. Weld bull plug on drive pipe approximately 2 ft above water level.

JEANERETTE LUMBER & SHINGLE CO. #1

17 1/2"

Surface Hole

0 - 6000'

1. Drill 17 1/2" hole to 6,000'. Lost circulation and gumbo may be expected.

   a. Pick up bit, drill collars, and welded blade stabilizers as specified in BHA section. (See "BIT HYDRAULICS" for proper jet size).
   b. Maintain high rotary speed (140-180 RPM) to control deviation. Apply weight on bit as necessary to maintain ROP 100-200 ft/hr. Run pumps parallel to maintain 900-1,100 GPM circulation rate in the upper part of the hole. This will give a standpipe pressure of about 2800 psi. Adjust pump speed to maintain a constant 2800 psi standpipe pressure at all times while drilling.

2. Run dual induction log with GR and BHC acoustic velocity log with caliper from casing point to surface.

3. Run 13 3/8", 72#, N-80, ST & C casing as follows:

   a. Float shoe
   b. Double box float collar 2 jts up
   c. 5 Centralizers across bottom 2 jts and 1 every other jt to surface.
   d. Thread lock the shoe, next connection and float collar.

   Check float equipment before running. Before PU 3rd jt circulate through float equipment to see if open. Fill casing while going in hole (every 5 jts)

4. Cement by the double plug displacement method. Release top plug with 2 bbls of cement behind it. Displace with mud. Approximately 10 minutes before plug is expected to bump, slow pump rate down. Bump plug and pressure to 1,000 psi over final displacement pressure. Hold for 5 minutes and bleed off to check float equipment. Allow 25 bbl extra (5% of calculated displacement volume) when calculating displacement volume. Be certain a collar is not at ground level where braden head is to be welded. Top out w/100 sks Class H.

5. Cut 20" and 13 3/8" and weld 13 3/8" braden head (Flange size: 13 5/8" SW x 13 3/8"-5,000 psi).

6. NU 13 5/8"-BOPs (RSRRA) and manifold. Test rams and manifold to 300 psi low-4,000 psi high. Test hydril to 300 psi low - 3,000 psi high. Test BOPs every 7 days.

7. TIH with 12 1/4" bit and slick BHA. (8-8" DC, 9 Jts-6 3/4" HW, 12-5" HW). Tag cement, circulate bottoms up, test casing to 2,500 psi.

8. Drill out + 20' new formation. Use low weight and med. rotary while drilling out. Run leak off test, do not exceed 15.0#/gal EMW.

9. Drill ahead and bury DCs for pendulum BHA.

10. Run CBL. Run casing caliper every 14 days.

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1-5-82

JEANERETTE LUMBER & SHINGLE CO. #1

12 1/4" Hole

6,000'-14,000'

1. Drill 12 1/4" hole to 14,000'. Look for transition zone around 10,000±. Prepare for high pressure salt water at 13,550' (12.3 ppg.)

   a. Size jets as specified in "BIT HYDRAULICS." Pick up collars & stabilizers as specified in BHA section.
   b. Maintain high rotary (120-150) to control deviation while drilling sand shale sequence in this part of the hole. Adjust pump speed to maintain a constant 2800 psi standpipe pressure. Apply weight on bit to maintain ROP 40-100 ft/hr above 10,000 ft From 10,000-14,000' refer to "ROP vs DEPTH" graph in drilling section.
   c. There is no need to "fan" the hole unless deviation exceeds 2°.

2. Run GR-Dual Induction/BHC Sonic with integrated caliper. Additional logs to be run at discretion of wellsite geologist 1" and 5" scales.

3. Run 9 5/8" 53.5#, S-95, 8RL casing as follows:

   (1) Float shoe
   (2) Double box float collar 2 jts up.
   (3) 5 Centralizers across bottom 2 jts and 1 every other jt to surface.
   (4) Thread lock the shoe, float collar, and all connections inbetween.

4. Cement by the double plug displacement method. Release top plug with 2 bbls of cement behind it. Displace with mud. Approximately 10 minutes before the plug is expected to bump, slow pump rate down. Bump plug and pressure to 1,000 psi over final displacement pressure. Hold for 15 minutes and bleed off to check float equipment. Allow 50 bbls extra (5% of calculated displacement volume) when calculating displacement volumes. Be certain casing collar is not in the braden head.

5. Hang off casing on slips with 80% of the hanging weight. Cut casing.

6. NU 9 5/8" casing head spool + BOPs. (Flange size (3 5/8" - 5,000 psi x 11" - 10,000 psi.)

7. TIH w/8 1/2" bit and slick BHA. Tag cement, circulate bottoms up, test casing to 6,000 psi.

8. Drill out + 10' new formation. Use low weight and med. rotary while drilling out. Run leak off test. Do not exceed 18.0 ppg EMW.

9. Drill ahead and bury drill collars. POH.

10. Run CBl and casing caliper.

RMS/lr
10-26-81

JEANERETTE LUMBER & SHINGLE CO. #1

8 1/2" Hole

14,000'-18,000'

1. PU 8 1/2" bit & pendulum BHA w/6 1/2" DC's.

2. Watch for 1st Planulina sand @ 15,700±', 2nd Planulina sand @ 16,350±', and 3rd Planulina @ 17,000±'.

3. Run GR-Dual Induction/BHC Sonic + FDC-CNL w/dipmeter log w/integrated caliper from csg point to bottom of previous csg.

4. Make wiper trip to condition hole. Tie 150' of .092 wire on DP rabbit & drop rabbit before POH.

5. Run 7 5/8" hydraulic set liner as follows:
   a. Float shoe. (Inspect all float equipment before running.)
   b. Ball catcher.
   c. Landing collar 3 jts up.
   d. 5 Centralizers across btm 2 jts and 1 every other jt up to hanger and 2 across last jt. (Note: Use Gemoco centralizer anchored by set screws due to special clearance.)
   e. Hanger assembly on top of liner w/tieback sleeve as per Service Co. specifications.
   f. Run minimum of 300' overlap in previous csg string.
   g. Thread lock all connections on btm 3 jts.
   h. Check to see liner wiper plug is loaded.

6. Break circulation after running float equipment.

7. Run liner to btm of DP filling up DP every 1,000'. Do not surge when filling DP as this may prematurely set hanger.

8. CBU. PU liner 1' off btm. Pump down setting ball & set slips w/1,200-1,500 psi. After hanging liner, shear out ball receptacle 2/2,500 psi.

9. Rotate to right to get off liner. PU above liner to check. Then set back in seals & displace bottoms up.

10. Pump cmt. Order sufficient cement to give 500' fill on top of liner w/50% excess in open hole. Cmt density should be 1#/gal greater than mud weight for liners. Increase retarder to give 1-2 hr extra pumping time. Specify low water loss cement.

11. Drop DP wiper plug w/1 bbl cmt behind it. Check displacement when plug latches liner wiper plug. Overdisplace 5% of calculated displacement if plug does not bump as expected.

12. Bump plug w/100 psi over final displacement pressure. Release pressure & check for back flow.

13. POH w/DP immediately. Do not reverse off TOL. After pulling 1000-1500', pump slug & finish POH.

14. PU 8 1/2" bit, slick BHA & GIH to dress off TOL, clean out hole to TOL after sufficient WOC time.

15. Test TOL to 2000 psi.

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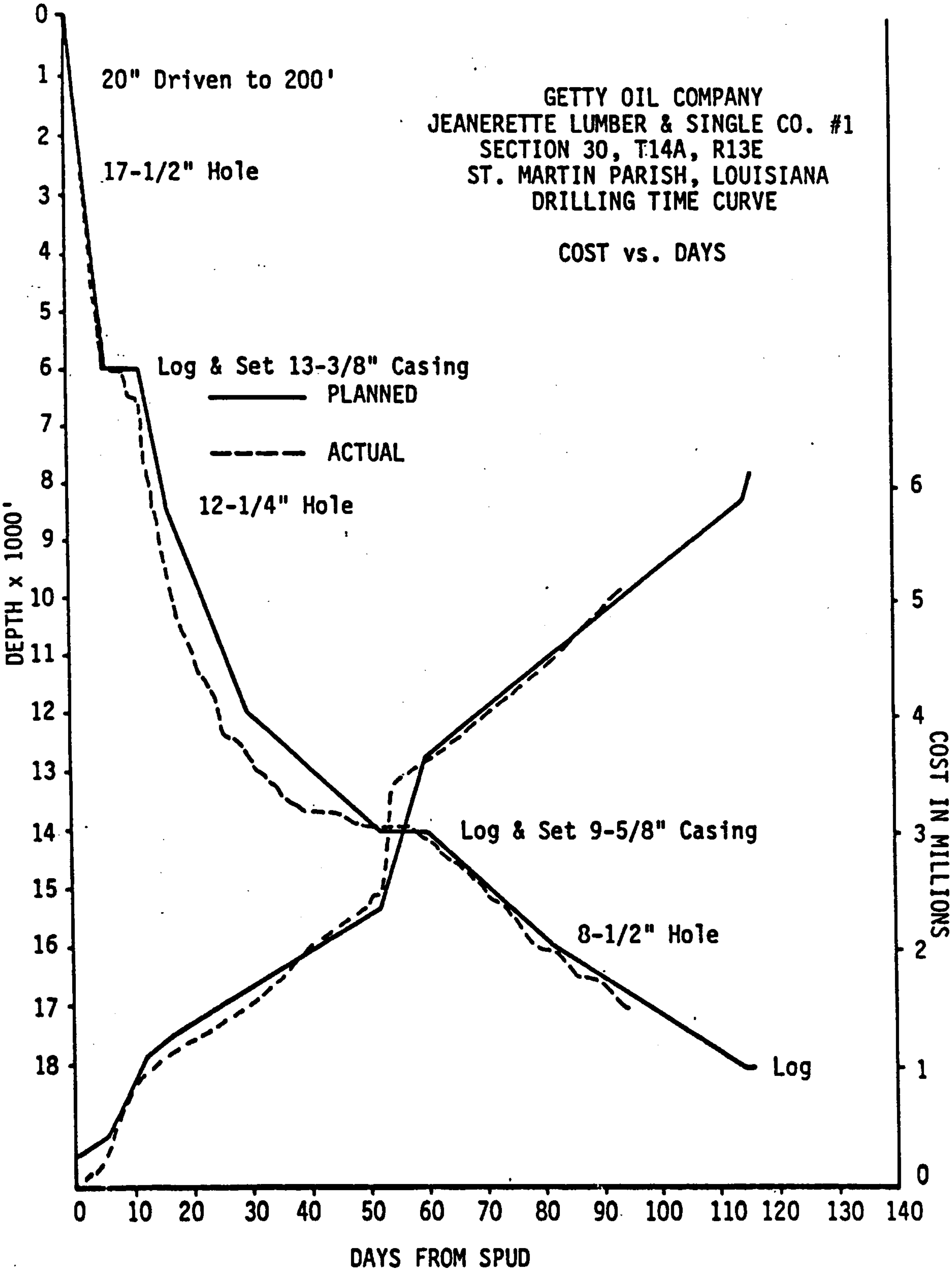


Fig. B-5--Drilling time curve.

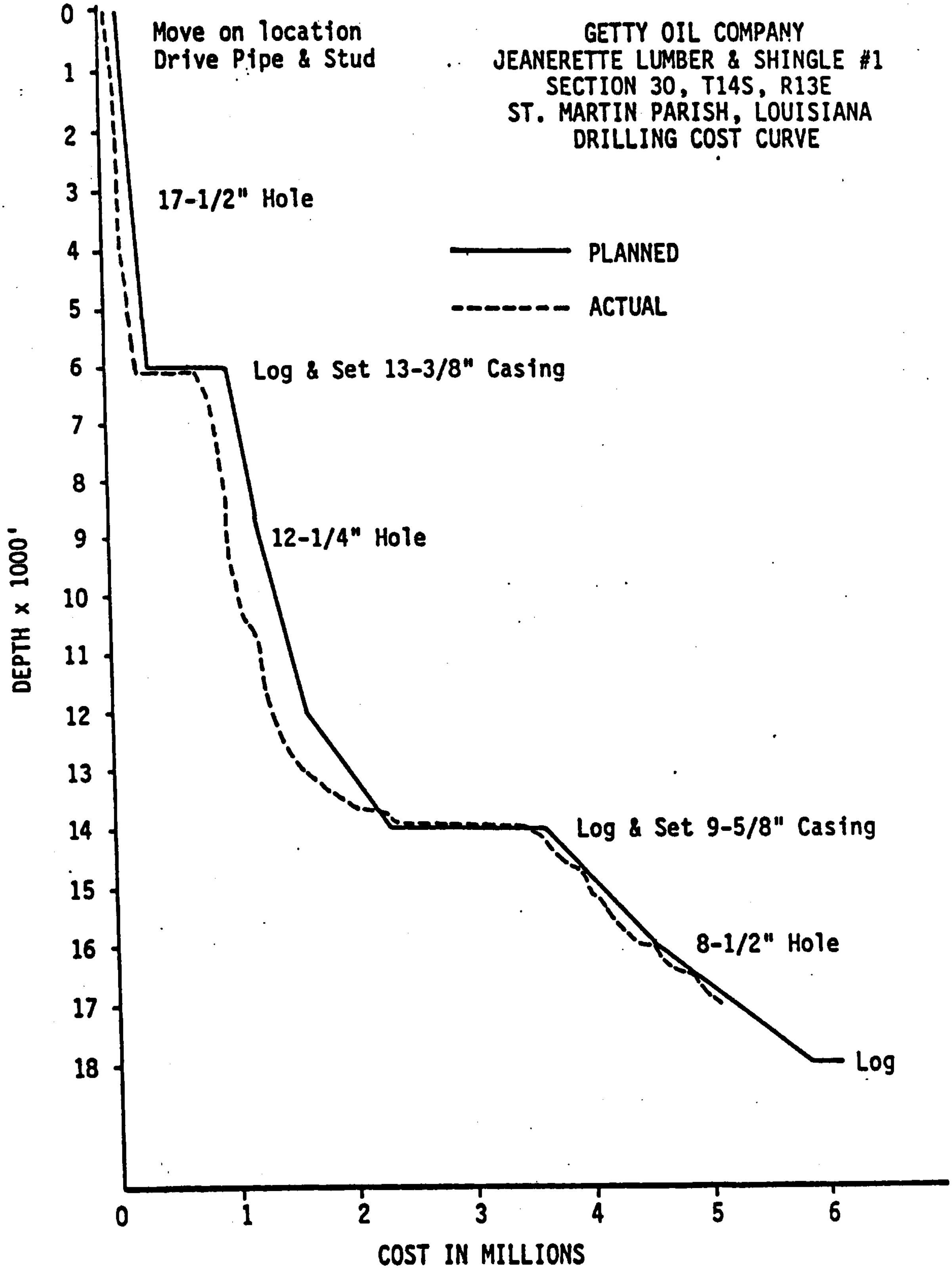


Fig. B-6--Drilling cost curve.

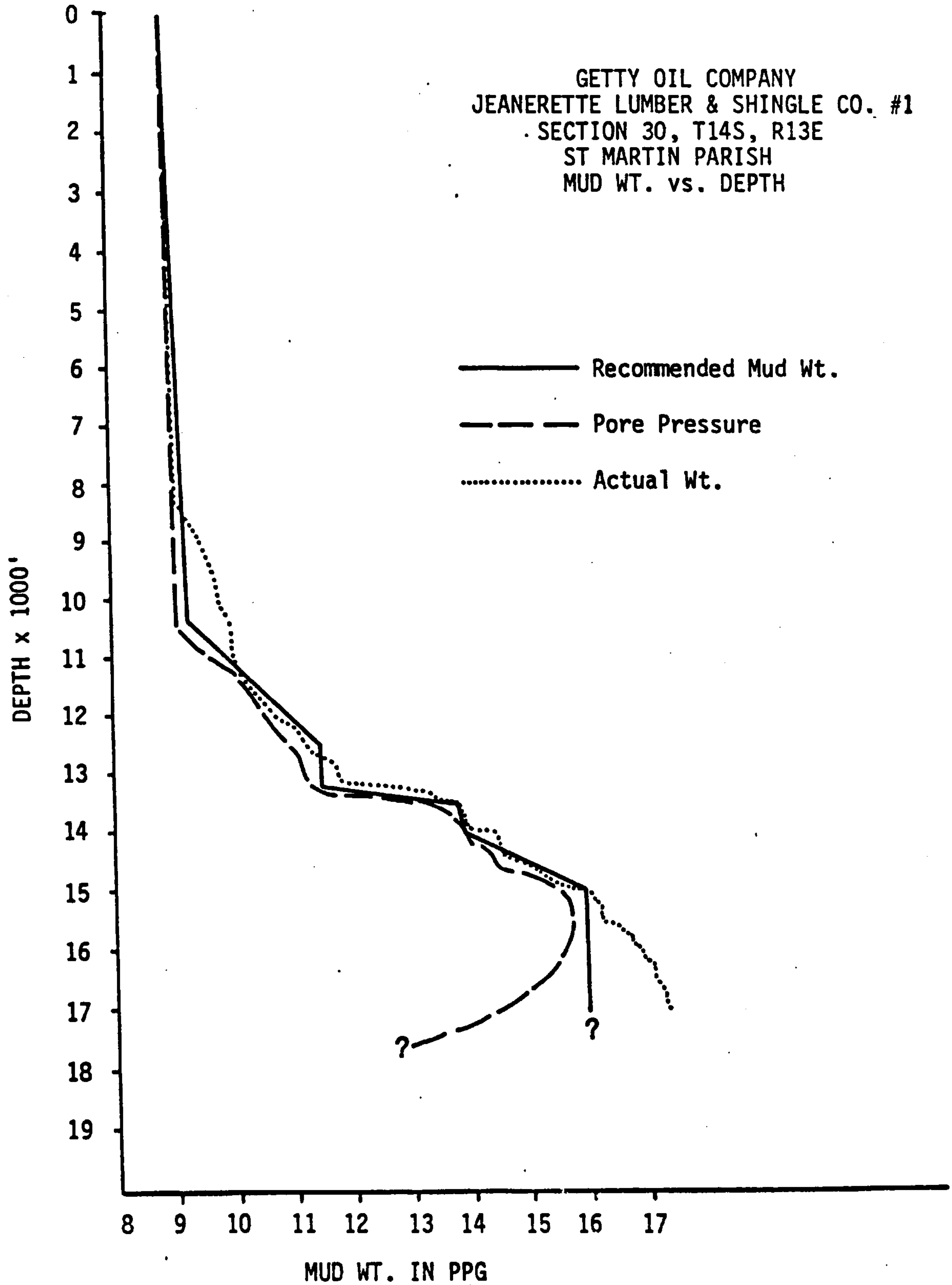


Fig. B-7--Mud weight and pore pressure curve.

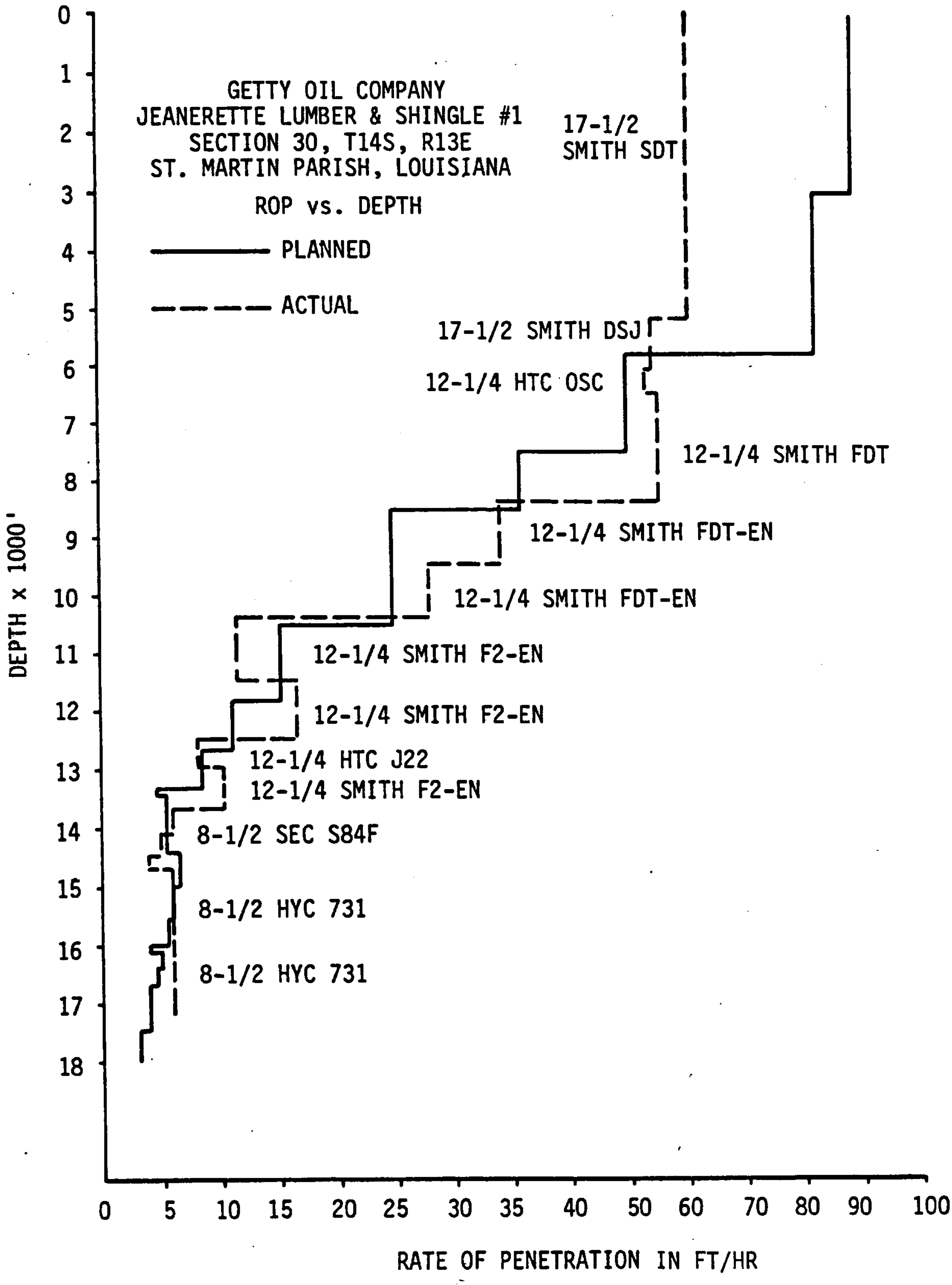
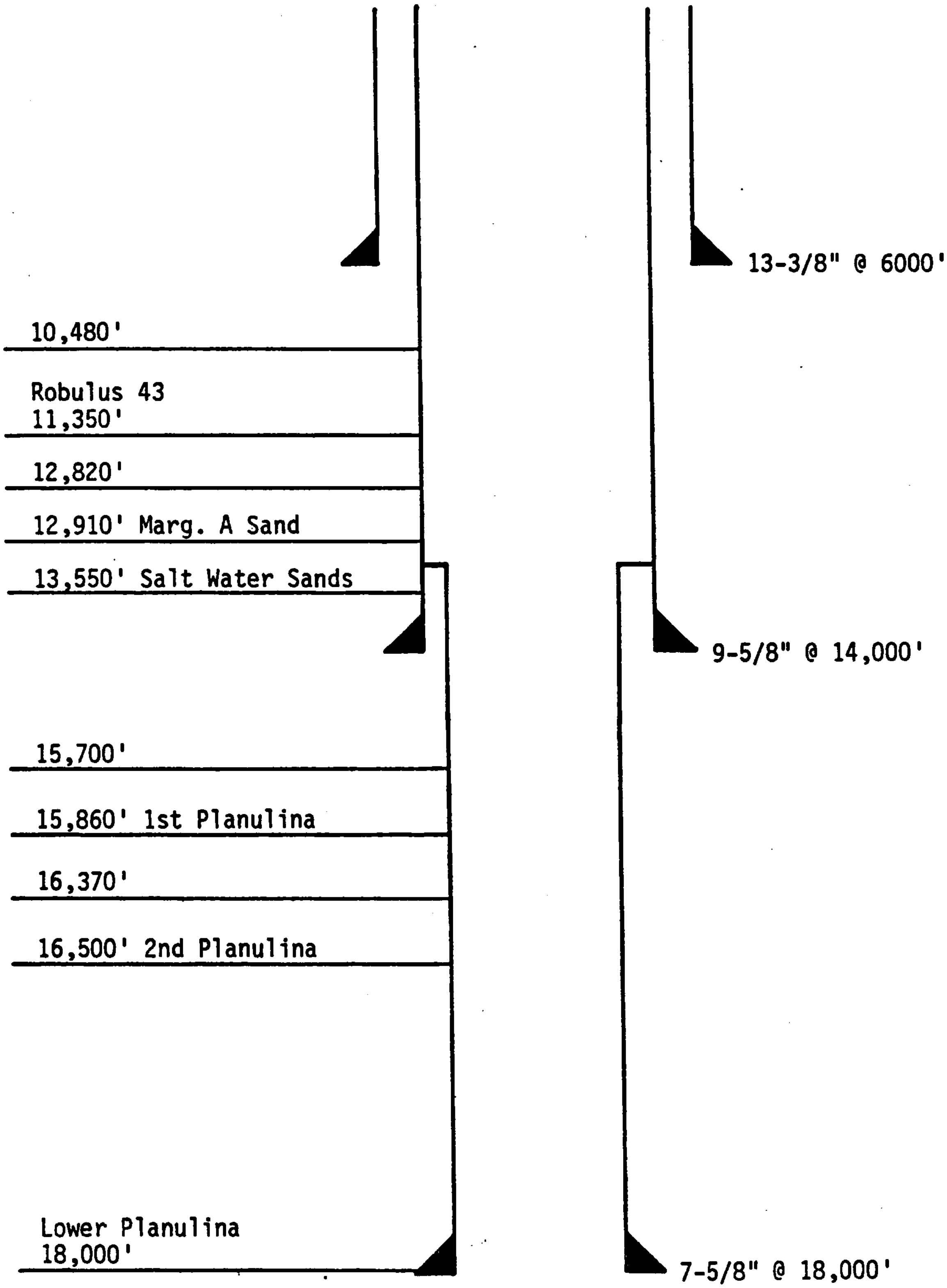


Fig. B-8--Rate of Penetration Curve

Fig. B-9--Geological program.

JEANERETTE LUMBER & SHINGLE CO. #1
GEOLOGICAL PROGRAM



JEANERETTE LUMBER & SHINGLE #1

PROBLEM INTERVALS

0-3,000'

Gravel beds and gumbo will be encountered. Addition of caustic and dispersant to mud may be required.

3,000'-13,500'

This should be a fairly trouble free section to drill. Look for a gradual transition zone beginning at about 10,500'. Mud logger should be rigged up at 9,000'.

13,500'-16,000'

This will be one of the most difficult sections of hole to drill. Using the Skelly Well as a reference, a 12.3 ppg saltwater flow will be encountered at 13,550'± followed by sand-shale sequences which do not clear up until about 13,950'. Mud weight must be held to very close tolerances (see Mud Wt vs Depth). The transition zone is very severe in this interval, increasing by as much as 2 ppg over a 300' interval from 13,500'-13,800'. HTHP water loss should be held to 10 CC to prevent excessive wall cake build-up over this zone. Short trips to the 9 5/8" casing should be made daily checking for drag.

16,000'-18,000'

This section of hole should show a pore pressure regression from 16 ppg to 12 ppg ± to control high pressure sections around 16,000'. HTHP water loss must be kept to 10-12 CC to prevent wall cake build-up while drilling over balanced. It is possible that there is a second transition zone in the lower most section of the hole (17,500'-18,000'). After regressing, the pore pressure could build back up to 16-17 ppg. It is imperative that the mud logger accurately monitor pore pressure for the entire interval 13,500'-18,000'.

JEANERETTE LUMBER & SHINGLE CO. #1

LOGGING PROGRAM

<u>0-6,000'</u>

A dual induction guard log with GR and BHC acoustic velocity log with integrated caliper will be run prior to setting casing.

<u>6,000-14,000'</u>

Same as above. Additional logs to be run at discretion of wellsite geologist.

<u>14,000-16,000'</u>

Dual induction guard log with GR and BHC acoustic velocity log with integrated caliper. CNL-CDL with dipmeter.

<u>16,000-18,000'</u>

Same as 13,500'-16,000'.

<u>DISTRIBUTION:</u>

New Orleans District Office
Mr. Ray Greenwell - 2 Field Prints and 4 Final Copies

Lafayette Onshore Area Office
Mr. Don A. Nichols - 2 Field Prints and 2 Final Copies

<u>MUDLOGGING</u>

The Analyst will perform the mudlogging services and should be rigged up and logging at 9,000'.

JEANERETTE LUMBER & SHINGLE #1

REFERENCE WELLS

Offset wells primarily used for planning the E. American Island Prospect include:

1) Skelly - Jeanerette Lumber & Shingle #1
   Section 30, T14S, R13E. Drilled to
   15,257'. P & A.

2) Atlantic - Richfield - Atchafalaya Basin
   Levee District #1. Section 29, T14S, R13E.
   Drilled to 19,000+ ft.

3) Quintana - So. Natural - D.J. McHugh #1
   Section 6, T15S, R13E. Drilled to
   15,029'. P & A.

HUGHES TOOL COMPANY

ENGINEERED BIT PROGRAM

HTC 1099-A

COUNTY	FIELD	STATE	LEGAL	COMPANY	DATE
ST. MARTIN	WILDCAT	LOUISIANA	30-14S-13E	GETTY OIL COMPANY	10/27/81
CONTRACTOR		LEASE	WELL NO.	TOOL PUSHER	SALESMAN
		E. AMERICAN ISLAND	1		
PUMP	PUMP POWER	MAKE RIG	RIG POWER	DRILL PIPE	DRILL COLLARS

RUN NO.	SIZE	TYPE	JET SIZE	DEPTH FROM	DEPTH TO	FEET	HRS.	ACCUM. HOURS	WEIGHT 1000 POUNDS	RPM	PUMP PRESS.	SPM	~~FT.~~ FT./HR.	MUD	REMARKS
A	17½	OSC3AJ		0	3000	3000	30	30	0-30	160-180			100		
1	12¼	X3A		3000	5800	2800	30	60	10-25	140-160			93		
2	12¼	X3A		5800	7500	1700	28	88	15-30	120-140			61		LOWER WEIGHT w/ HIGHER RPMs.
3	12¼	J1		7500	8500	1000	24	112	20-35	120-140			42		
4	12¼	J11		8500	10500	2000	80	192	20-35	100-120			25		RECOMMEND SHOC-SUB w/ ALL
5	12¼	J22		10500	11800	1300	85	277	30-40	70-90			15^{3}		T-C INSERT BITS.
6	12¼	J22		11800	12700	900	80	357	30-45	60-80			11^{3}		
7	12¼	J22		12700	13450	750	80	437	35-45	60-80			9^{4}		
8	12¼	J22		13450	14000	550	85	522	35-45	60-70			6^{5}		
	SET 9⅝" CASING														
9	8½	J2/J3		14000	14100	100	24	546	10-25	70-100			4^{2}		
10	8½	J22		14100	14600	500	90	636	25-30	60-80			5^{6}		
11	8½	J22		14600	15200	600	90	726	25-30	60-80			6^{7}		
12	8½	J22		15200	15700	500	90	816	25-30	60-70			5^{6}		
13	8½	J22		15700	16200	500	90	906	25-30	60-70			5^{6}		
14	8½	J22		16200	16650	450	90	996	25-30	60-70			5		
15	8½	J22		16650	17050	400	85	1081	25-30	60-70			4^{7}		
16	8½	J22		17050	17400	350	85	1166	25-35	60			4^{1}		
17	8½	J22		17400	17700	300	85	1251	25-35	60			3^{5}		
18	8½	J22		17700	18000	300	90	1341	25-35	60			3^{3}		

MUD: P-RATES SHOWN BASED ON BALANCED MUD WEIGHTS.

TOTAL BIT COST — $88,566^{00}$

DAYS FROM SPUD — T.D. @ 18000' — 95½

HUGHES BIT RECORD

PRINTED IN U.S.A. SHEET 1 OF

COUNTY	FIELD	STATE	X IF OFFSHORE	SECTION	TOWNSHIP	RANGE	OPERATOR	X (1)	FILE NUMBER
St. Martin	Lake Verret	LA.		29	14S	13E	Atlantic Richfield	X	

CONTRACTOR	X(2)	RIG NO.	LOCATION	WELL NO.	SPUD	US	INTER	TOTAL DEPTH DATE	TOOL PUSHER
Atlantic & Pacific Marine Corp		2	Atch Basin Levee Dist	#1	1-11-74	1-15-74			

TOOL JOINTS: GIVE SIZE & TYPE	O.D.	DRILL COL. NO.	O.D.	I.D.	PUMPS	LINER	DRAWWORKS & POWER	FUEL	WATER
1.		21	7¼	2 13/16	1. DW 1700 P	6½		Diesel	Barge
2. 4½ H	6⅛				2. DW 1000 P	6½			

SALESMAN	AREA	STOCKPOINT NO.	DO NOT USE	STATE	ZONE	COUNTY	CONTRACTOR	OPERATOR	DATE	PURCHASE
[illegible] Willis III	South LA. Region	14242								

DO NOT USE: R.	TYPE	WC	NO.	SIZE	MAKE	TYPE	JET 32ND IN	SERIAL	DEPTH OUT	FEET	HOURS	FT HR	ACCUM. DRLG. HRS.	WT. 1000 LBS.	RPM	VERT DEV.	PUMP PRESS	SPM 1	SPM 2	MUD WT.	MUD VIS.	MUD W.L.	DULL COND. T	B	G	OTHER	FORMATION CALL DATA REMARKS
			1	18½	HTCO	OSC3AJ	2-24 1-0	Rerun	3650	3650	33½			15/25	180		1300	52	52	9.0	38						
			2	12¼	✓	X3A	13	ZF530	6474	2824	29½			25/35	120		2500	45	46	9.0	36		2	6		BT	1-16-74
			3	✓	✓	✓	14	XZ774	8241	1767	33½			25/30	150		✓	40	40	9.8	44		4	8		BT	
			4	✓	✓	✓	✓	VK966	8800	559	22½			27/25	✓		✓	60	60	10.0	41		6	7		BT	1-20-74
			5	✓	✓	✓	✓	AS895	9605	805	15			30/30	140		2850	40	40	9.8	44		6	7		BT	
			6	✓	✓	✓	✓	AS896	10258	653	15½			40/46	135		✓										1-23-74
			7	✓	✓	✓	✓	AS154	10869	611	17½			50/60	✓		✓	42	42	9.8	43						
			8	✓	✓	✓	✓	AM622	11210	341	17			40/50	✓		✓	44	44	10.1	✓						1-24-74
			9	✓	✓	J-33	2-12 1-11	AS354	11388	178	23½			40/60	40/50		✓	54	54	10.0	38						
			10	✓	✓	X3A	2-13 1-12	ZB763	11562	174	15			✓	100		2500	58	58	✓	✓						1-26-74
			11	✓	✓	✓	1-12 2-13	AS893	11796	234	18½			✓	✓		2800	59	59	10.2	40						
			12	✓	✓	✓	✓	VK515	12098	302	14½			✓	✓		✓	58	58	10.1	41						1-29-74
			13	✓	✓	✓	13	RC703	12454	356	16			✓	120		3000	61	61	10.5	40		8	8			
			14	✓	✓	✓	2-13 1-12	VK521	12629	175	14			✓	100		✓	✓	✓	✓			5	5			
			15	✓	✓	J-33	13	Rerun #9	12892	263	39½			45/50	45/60		✓	✓	✓	10.9	38						2-3-74
			16	✓	✓	✓	✓	AB363	13732	840	120½			40/50	45/50		2800	59	59	11.6	40		2	6			
			17	✓	✓	✓	✓	Rerun #9	14070	338	62½			✓			3000	56	56	12.5	45		3	8			
			18	✓	✓	J-33	✓	(RR)				Circle & Cont. Hole															2-13-74
			19	8½	✓	X3A	✓	X2525	14079	Cement 5504	41½			Drlg. Cement & Float Collar													
			20	✓	✓	✓	12	VZ261	14178	99	13	1'		30	60		3000			14.5							2-20-74
			21	✓	✓	X1G	13	WR490	14286	108	13			30	60/100		✓	40		15.5	43						
			22	✓	ACC	Trigg #23 (Partial)	FO	10231	14945	659	86			14/25	100/120		✓	40									2-25-7

FORM 308 H

BIT CONDITION CODE: RP – REPAIRED RR – RERUN

HUGHES BIT RECORD

SHEET 2 OF 2

FILE NUMBER: ✓	X (1): X				
(COUN)TY: St. Martin	FIELD: Lake Verret	STATE: LA.	X IF OFFSHORE:	SECTION: 29	TOWNSHIP: 14S
RANGE: 13E	OPERATOR: Atlantic Richfield				
(CONT)RACTOR: Atlantic & Pacific Marine	X(2) RIG NO.: 2	LOCATION: Atch Levee Dist#	WELL NO.: 1	SPUD: 1-11-74	US: 1-15-74
INTER:	TOTAL DEPTH DATE: 5-13-74	TOOL PUSHER:			
(T)OOL (JO)INTS GIVE SIZE & TYPE: 1. / 2. 4½ XH	O.D.: / 6⅛	DRILL COL. NO.:	O.D.:	I.D.:	PUMPS: 1. OW 1700 P / 2. OW 1000 P
LINER: 6½ / 6½	DRAWWORKS & POWER:	FUEL: Diesel	WATER: Barge		
(SALE)SMAN: (W)illis III	AREA: South LA. Region	STOCKPOINT NO.: 14242	DO NOT USE	STATE:	ZONE:
COUNTY:	CONTRACTOR:	OPERATOR:	DATE:	PURCHASE:	

DO NOT USE TR.	TYPE	WC	NO.	SIZE	MAKE	TYPE	JET 32ND IN	SERIAL	DEPTH OUT	FEET	HOURS	FT HR	ACCUM. DRLG. HRS.	WT. 1000 LBS.	R P M	VERT DEV.	PUMP PRESS	SPM 1	SPM 2	MUD WT.	MUD VIS.	MUD W.L.	DULL. COND. T	B	G	OTHER	FORMATION CALL DATE REMARKS
			23	8½	Trigg	Trig #23		9716	16131	1186	181½	6.5	843	15/25	120		2000	37		16²	46						3-1-74
			24	✓	Hyclog	717 ALRC.		13796	16644	513	104½	4.9	947½	20	110		✓	35		✓	47						3-15-74
			25	✓	Acc	Trigg		RR	17066	422	78	5.4	1025½	30	✓		2200	27		✓	46						3-19-74
			26	✓	✓	✓		10340	17666	600	113½	5.2	1139	15/20	120		2000	36		✓	47						3-24-74
			27	✓	HTco	X3A	out	ZD180	17666	0	0		✓		Circ & Condition Hole												
			28	6½	✓	OWV	16	ARZ41	✓	✓	✓				Circ & Condition Hole												3-30-74
			29	✓	✓	✓	✓	AW713	17679	5	½		1143	18	80		2500	32		16²	48						3-31-74
			30	✓	✓	OSC1G-J	✓	BW386		WAShing and Reeming																	4-7-74
			31	✓	✓	✓	✓	BW396																			4-22-74
			32	✓	✓	✓	✓	BR163	17450																		
			33	✓	✓	✓	out	CF375		Running Dyna drill																	4-23-74
			34	✓	Acc	AB-23		10044		Drilling with Dyna drill from 17335 to 17356																	
			35	✓	Williams	102N04		DA102	18181	817	151	5.4	1294	15	120		3000	40		16²	50						5-4-74
			36	✓	Trigg	#23																					
			37	✓	HTco	OSC1G-J	out	CF377	18207	26	6	4.3	1320	10	70		2000	57		16²	65						5-9-74
			38	✓	Acc	Trigg 23																					5-13-74

(FOR)M 305 H

BIT CONDITION CODE: RP – REPAIRED RR – RERUN

IMCO Services
A Division of HALLIBURTON Company

COMPANY GETTY OIL COMPANY
WELL East American Island Prospect
FIELD
LOCATION Section 30, 14S-13E
COUNTY St. Martin STATE Louisiana
PROPOSED DEPTH 18,000' TVD

SUGGESTED MUD PROGRAM

SUGGESTED CASING PROGRAM

20 " @ 150'
13-3/8" @ 6,000' TVD
9-5/8" @ 14,000' TVD
7-5/8" @ 18,000' TVD

DEPTH ft	WEIGHT ppg	VISCOSITY sec/qt	FLUID LOSS API	FLUID LOSS HTHP	SOLIDS % Vol	MBT #/bbl BENTONITE EQUIVALENT
0- 6,000 TVD	8.8-9.0	42-48	N/C	N/C	0-4	N/C

IMCO Gel, Caustic Soda, Shurlift, IMCO MD

In preparing the spud mud for the initial drilling of the well, we recommend 1 sack of Shurlift for every 4 sacks of IMCO Gel. By using this ratio, the mud should have a funnel viscosity of approximately 45-48 sec/qt. This range will greatly increase the carrying capacity and hole cleaning ability of the mud. In this section we recommend 4-6 sacks of Gel per 100' of new hole drilled. This combination should insure a good compressible filter cake across shallow sands and weaker formations. In addition, IMCO MD is suggested to reduce tension in the drilling fluid and aid in dropping out sand and other undesirable particles from the surface system. It would be desirable through this period to run the desander and desilter to help minimize solids and improve drilling rates. We also recommend an API fluid loss of 20 cc or less before 6,000' to avoid excessive wall cake buildup along the face of the very porous sands in this interval.

The estimated fracture gradient at 6,000' is 15.2 ppg. Drill out 13-3/8" casing, test formation to an equivalent mud weight of 14.5 ppg and drill ahead.

IMCO Services
A Division of HALLIBURTON Company

COMPANY GETTY OIL COMPANY
WELL East American Island Prospect
FIELD
LOCATION Section 30, 14S-13E
COUNTY St. Martin STATE Louisiana
PROPOSED DEPTH 18,000' TVD

DEPTH ft	WEIGHT ppg	VISCOSITY sec/qt	FLUID LOSS API	FLUID LOSS HTHP	SOLIDS % Vol	MBT #/bbl BENTONITE EQUIVALENT
6,000-10,000 TVD	9.0-9.5	34-36	15-20	N/C	4-6	N/C

IMCO Gel, Caustic Soda, IMCO MD, RD-111 (lightly dispersed)

In this interval, a low solids IMCO Gel-Caustic system will be the most desirable and economical system to maintain. While drilling, continue to add 3-5 sacks of IMCO Gel per 100' of new hole drilled. Continue the constant usage of the desander and desilter to help control solids build-up in the mud system. IMCO MD should still be applied to aid in minimizing bit balling, reducing surface tension and the dropping out of sand particles and other undesirable drill solids. Controlling pH in a 9.0-9.5 range, with light additions of Caustic Soda, should be sufficient. In addition, we recommend light additions of RD-111 to help control rheological properties and control your fluid loss to a desired range. Controlling of these properties will greatly reduce any problems that may be encountered.

DEPTH ft	WEIGHT ppg	VISCOSITY sec/qt	FLUID LOSS API	FLUID LOSS HTHP	SOLIDS % Vol	MBT #/bbl BENTONITE EQUIVALENT
10,000-12,000 TVD	9.5-11.0	34-38	6 or less	18 or less	6-14	N/C

IMCO Gel, Caustic Soda, RD-111

At this point, we recommend the breakover to an inhibitive RD-111 lignosulfonate system. This system will provide for better flow properties and develop a good compressible filter cake for better hole stability and lower fluid losses.

These improvements at this depth will greatly reduce any problems that may be encountered due to the amount of open hole that you will have before you set the 9-5/8" intermediate casing. Additions of IMCO Gel (2-4 sacks per 100' of

IMCO Services
A Division of HALLIBURTON Company

COMPANY GETTY OIL COMPANY
WELL East American Island Prospect
FIELD
LOCATION Section 30, 14S-13E
COUNTY St. Martin STATE Louisiana
PROPOSED DEPTH 18,000' TVD

new hole drilled) should be continued. Run desander through this interval. Once the mud weight exceeds 10.0 ppg we suggest discontinuing the usage of the desilter. Above this point, it will tend to throw away barite.

DEPTH ft	WEIGHT ppg	VISCOSITY sec/qt	FLUID LOSS API	HTHP	SOLIDS % Vol	MBT #/bbl BENTONITE EQUIVALENT
12,000-14,000 TVD	11.0-14.0	38-48	3 or less	10 or less	12-25	27.5-32.5

IMCO Gel, Caustic Soda, RD-111, IMCO Lig, Poly Rx

It will be important to control your HTHP fluid loss below 10 cc to minimize excess wall cake buildup and prevent sticking problems. To aid in lowering the HTHP fluid loss, we recommend an initial treatment of RD-111 consisting of 2#/bbl with ¼ ppb daily treatments. Poly Rx will increase the temperature stability of the mud and in turn, lower the HTHP. All drilling parameters should be closely monitored.

It will be important to have a highly dispersed system to maintain minimum flow properties to control equivalent circulating densities (ECD's), swab pressures and surge pressures.

Since the 9-5/8" casing will be set in a steep transition zone, we stress again that all drilling parameters be closely monitored.

Set your 9-5/8" intermediate casing at 14,000' TVD. Drill out approximately 10', test formation to a 17.5 ppg equivalent mud weight, weight system up to 15.0 ppg and drill ahead.

Recommend a centrifuge be brought onto location at this time.

IMCO Services
A Division of HALLIBURTON Company

COMPANY	GETTY OIL COMPANY
WELL	East American Island Prospect
FIELD	
LOCATION	Section 30, 14S-13E
COUNTY	St. Martin STATE Louisiana
PROPOSED DEPTH	18,000' TVD

DEPTH ft	WEIGHT ppg	VISCOSITY sec/qt	FLUID LOSS API	FLUID LOSS HTHP	SOLIDS % Vol	MBT #/bbl BENTONITE EQUIVALENT
14,000-15,000 TVD	15.0-16.0	43-48	3 or less	10 or less	27-32	32.5-37.5

IMCO Gel, Caustic Soda, RD-111, IMCO Lig, Poly Rx, Soltex

If sloughing shale should become a problem below 14,000', we recommend additions of Soltex. Initial treatment should consist of 5#/bbl with ½#/bbl increments while drilling. Solids should be kept at a minimum utilizing fine shaker screens, some type of mud cleaner (Sweco, Brandt, etc.), and a centrifuge. All drilling parameters should be closely monitored.

If torque or drag should become a problem, we recommend additions of Lube 106 in 1 ppb increments.

DEPTH ft	WEIGHT ppg	VISCOSITY sec/qt	FLUID LOSS API	FLUID LOSS HTHP	SOLIDS % Vol	MBT #/bbl BENTONITE EQUIVALENT
15,000-16,200 TVD	16.0	45-50	3 or less	10 or less	30-32	32.5-37.5

IMCO Gel, Caustic Soda, RD-111, IMCO Lig, Poly Rx, Soltex

Since the mud weights are extremely high, we suggest running all mud properties (solids, gel strengths, viscosities, PV and YP) at minimum values so as to keep both surge and swab pressures at a minimum. We recommend maintaining at least 3 ppb of Poly Rx in the system. Poly Rx will help stabilize rheology and viscosities as temperatures increase with depth.

DEPTH ft	WEIGHT ppg	VISCOSITY sec/qt	FLUID LOSS API	FLUID LOSS HTHP	SOLIDS % Vol	MBT #/bbl BENTONITE EQUIVALENT
16,200-17,000 TVD	16.0	45-50	3 or less	10 or less	30-32	32.5-37.5

IMCO Gel, Caustic Soda, RD-111, IMCO Lig, Soltex, Poly Rx, Sodium Chromate

IMCO Services
A Division of HALLIBURTON Company

COMPANY GETTY OIL COMPANY
WELL East American Island Prospect
FIELD
LOCATION Section 30, 14S-13E
COUNTY St. Martin STATE Louisiana
PROPOSED DEPTH 18,000' TVD

Below 16,200', we recommend additions of Sodium Chromate for mud stability. Sodium Chromate is designed to economically extend the temperature limitations of water base muds. We recommend treatments of ½ ppb while drilling. Estimated bottom hole temperature at total depth should be about 300°. Maintain solids at a minimum with fine shaker screens. Continue to control HTHP values in their recommended ranges. The system should continue to be highly dispersed to control ECD's. Continue additions of Poly Rx as in the above intervals. Also, continue similar additions of other products as in the above intervals.

DEPTH ft	WEIGHT ppg	VISCOSITY sec/qt	FLUID LOSS API	FLUID LOSS HTHP	SOLIDS % Vol	MBT #/bbl BENTONITE EQUIVALENT
17,000-18,000 TVD	16.0	45-50	3 or less	10 or less	30-32	32.5-37.5

IMCO Gel, Caustic Soda, RD-111, IMCO Lig, Poly Rx, Soltex, Sodium Chromate

Maintain similar properties as in the above interval. It will be important to maintain a highly dispersed system to control ECD's, and swab and surge pressures. Maintain solids at a minimum with fine screen shakers, a mud cleaner, and a centrifuge.

Hole conditions will be the main factor in determining optimum mud weights in this interval. An increase in background gas, increased chlorides or a change in the size or shape of drill cuttings will indicate rising pore pressure.

IMCO Services recommends lost circulation material and Spot be on location at all times as a precautionary measure.

IMCO Services
A Division of HALLIBURTON Company
2400 West Loop South, P.O. Box 22605
Houston, Texas 77027 A/C 713 871-4800

COMPANY GETTY OIL COMPANY
WELL East American Island Prospect
FIELD
LOCATION Section 30, 14S-13E
COUNTY St. Martin STATE Louisiana
PROPOSED DEPTH 18,000' TVD

We estimate an approximate mud cost of $450,000-$500,000 to drill to 18,000' based on 100-110 days.

Prepared by: Gary Schlegel
Division Technical Advisor
New Orleans Division

GS:br

JEANERETTE LUMBER & SHINGLE CO. #1

PROPOSED BOTTOM HOLE ASSEMBLY

0/6,000'	6,000'/10,000'	10,000'/13,000'	13,000'/14,000'	14,000'/18,000'
12 Jts 5" HW	12 Jts 5" HW	12 Jts 5" HW	12 Jts 5" HW	11 Jts 5" HW
WB Stab.	6 Jts 6 3/4" HW	Jars	Jars	Jars
5 - 7 1/4" DC		2 Jts 5" HW	2 Jts 5" HW	30 Jts 5" HW
WB Stab. (Undergauge)	WB Stab. (Undergauge)	WB Stab. (Undergauge)	WB Stab. (Undergauge)	
4 - 8" DC	3 Jts 6 3/4" HW	6 Jts 6 3/4" HW	6 Jts 6 3/4" HW	
WB Stab. (Gauge)	WB Stab. (Undergauge)	WB Stab. (Undergauge)	WB Stab. (Undergauge)	WB Stab. (Gauge)
1 - 8" DC	4 - 8" DC	3 Jts 6 3/4" HW	3 Jts 6 3/4" HW	1 - 6 1/2 DC
WB Stab. (Gauge)	WB Stab. (Gauge)	WB Stab. (Undergauge)	WB Stab. (Gauge)	WB Stab. (Gauge)'
3 - 8" DC	1 - 8" DC	4 - 8" DC	1 - 8" DC	2 - 6 1/2 DC
17 1/2" Bit	WB Stab. (Gauge)	WB Stab. (Gauge)	WB Stab. (Gauge)	8 1/2" Bit
ABW = 40,000	3 - 8" DC	1 - 8" DC	2 - 8" DC	ABW = 35,000
	12 1/4" Bit	WB Stab.	12 1/4" Bit	
		3 - 8" DC		
	ABW = 50,000	12 1/4" Bit	ABW = 30,000	
		ABW = 50,000		

JEANERETTE LUMBER & SHINGLE #1

BOTTOM HOLE ASSEMBLY INSPECTION PROCEDURE

All BHA inspection will be done by B & M Ultrasonic Specialists (Liggins/Clark) 318-269-9408, Scott, La. Pins and boxes on all drill collars will be both black light and ultrasonic inspected. The inspection schedule will be as follows:

I. INITIAL INSPECTION - the entire BHA will be inspected before spudding and should not have to be reinspected until 13 3/8" casing is set.

II. The BHA should be inspected after surface casing is cemented and about every 90-110 rotating hours until 14,000 feet.

III. The BHA should be inspected after 9 5/8" casing is set and every 140-160 hours afterwards until TD.

RMS/lr
11-24-81

DOWELL DIVISION OF DOW CHEMICAL U.S.A.

P. O. Box 51785, OCS
Lafayette, Louisiana 70506
January 8, 1981

CEMENTING RECOMMENDATION

FOR

GETTY OIL COMPANY

WILDCAT
JEANERETTE LUMBER & SHINGLE #1
ST. MARTIN PARISH, LOUISIANA

PREPARED FOR: MR. ROBERT SHIVERS

SERVICE FROM: HOUMA, LOUISIANA
504/868-0195

PREPARED BY: FRED W. PETERS
REGIONAL ACCOUNTS MANAGER
LAFAYETTE, LOUISIANA
318/232-3216

Mr. Robert Shivers
GETTY OIL COMPANY
January 8, 1982

13 3/8" SURFACE CASING

Well Data:

Open Hole	- 17 1/2" BIT
T.D.	- 6000'
Mud	- 9 ppg waterbase
BHST	- 146°F (1.2°F/100')
BHCT	- 114°F
Frac Gradient	- 15 ppg @ 6000'

Casing String:

13 3/8" Casing to 6000'
Float @ 5960'±

Volume Calculations:

Shoe Joint	- 40' x .8406 cf./ft. =	33.6 cf
O.H. Annulus	- 6000' x .6946 cf./ft. =	4167.6 cf
100% Excess		467.6 cf
	Total volume required =	8368.8 cf

Tail Slurry required for 1000' of fill with excess:
(1000 x .6946 x 2) + 33.6 = 1422.8 cf

Lead Slurry volume = 8368.8 - 1422.8 = 6946 cf

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Systems:

Lead Slurry: 2700 sks. Class 'H' + 1.5% D79 Extender + 0.2% D46 Antifoamer.

Density	- 12 ppg
Yield	- 2.58 cf/sk.
Mix Water	- 15.6 gal./sk.
Thickening Time	- 6 hours
Volume Lead Slurry	- 6966 cf
Mix water required	- 1003 bbl.

FANN RHEOLOGIES:

RPM	600	300	200	100	6	3	PV	n	ty
80°F	44	32	29	26	21	17	12	.0081	.20
114°F	39	29	28	26	20	12	10	.0067	.19

Critical rate for turbulence: 66 BPM
Critical rate for plug flow: 17 BPM

Tail Slurry: 1320 sks. Class 'H' + 0.2% D46 Antifoamer + 0.15% D13 Retarder.

Density	- 16.2 ppg.
Yield	- 1.08 cf/sk.
Mix Water	- 4.52 gal./sk.
Thickening Time	- 4 hr. 43 min.
Volume Tail Slurry	- 1425.6 cf
Mix water required	- 142 bbl.
Compressive Strength	- 12 hr. - 1050 psi
	24 hr. - 2350 psi

FANN RHEOLOGIES:

RPM	600	300	200	100	6	3	PV	n	ty
80°F	106	70	61	49	19	5	36	.0242	.34
114°F	111	86	74	60	20	13	25	.0168	.61

Critical rate for turbulence: 100 BPM
Critical rate for plug flow: 26 BPM
(20" hole)

Top Outside Slurry: 100 sks. Class 'H' + 0.2% D46 Antifoamer + 2% Calcium Chloride Accelerator.

Total mix water required: 1156 bbl. + excess
App. Job time @ 12 BPM: 4 hours
Maximum equivalent density @ shoe (12 BPM) ~ 13 ppg

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Estimated Cost - 13 3/8" Surface Casing

4120 sks. Class 'H' @ 6.35	$ 26,162.00
3800# D79 Extender @ 1.05	3,990.00
775# D46 Antifoamer @ 2.75	2,131.25
200# $CaCl_2$ @ .27	54.00
185# D13 Retarder @ 1.15	212.75
4177 cf service charge @ 1.26	5,263.02
1569 Tmi (392,240#) @ .82	1,286.58
Equipment charge to 6000'	1,725.00
6 hr. barge travel time @ 140.00	840.00
24 hr. barge on location	1,150.00
Add 24 hours	1,200.00
30 hr. craft equipment time @ 125.00	3,750.00
13 3/8" Top & Bottom cementing plugs	430.00
Total estimated cost:	$ 48,194.60

9 5/8" INTERMEDIATE CASING

Well Data:

Previous Casing	- 13 3/8" set @ 6000'
Open Hole	- 12 1/4" Bit
T.D.	- 14000'
Mud	- 14 ppg. waterbase
BHST	- 242°F (1.2°F/100')
BHCT	- 201°F
Frac Gradient	- 18 ppg

Casing String:

9 5/8" casing to 14000'
Float @ 13920'±

Volume Calculations:

Shoe Joint	- 80' x .4257 cf/ft =	34.1 cf
O.H. Annulus	- 8000' x .3131 cf/ft =	2504.8 cf
Casing Annulus	- 6000' x .3489 cf/ft	2093.4 cf
50% Excess	- 2504.8 x .5 =	1252.4 cf
	Total volume required =	5884.7 cf

Tail Slurry volume required for 1500' fill with excess:
(1500 x .3131 x 1.5) + 34.1 = 738.6 cf

Lead Slurry volume = 5884.7 - 738.6 = 5146.1 cf

Volumes should be recalculated as caliper volume + 20%

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Systems:

Lead Slurry: 4560 sks. Dowell Lightweight + 1% D65 Turbulence Inducer + 0.2% D28 Retarder + 0.2% D46 Antifoamer.

Density	- 14 ppg
Yield	- 1.13 cf/sk.
Mix Water	- 5.23 gal./sk.
Thickening Time	- 6 hr. 30 min.
Volume Lead Slurry	- 5153 cf
Mix water required	- 568 bbl.

FANN RHEOLOGIES:

RPM	600	300	200	100	6	3	PV	n	ty
80°F	48	21	14	8	1	.5	27	.0181	.005
200°F	20	10	6	3	1	.5	10	.0067	.005

Critical rate for turbulence = 3.8 BPM
Critical rate for plug flow = 1.3 BPM
(13.5" OH)

Tail Slurry: 535 sks. Class 'H' + 35% D30 Silica + 0.2% D46 Antifoamer + 0.2% D28 Retarder.

Density	- 16.5 ppg.
Yield	- 1.38 cf/sk.
Mix Water	- 5.25 gal./sk.
Thickening Time	- 4 hr. 45 min.
Volume Tail Slurry	- 738.3 cf
Mix water required	- 67 bbl

FANN RHEOLOGIES:

RPM	600	300	200	100	6	3	PV	n	ty
80°F	98	54	50	42	16	12	44	.0296	.10
200°F	111	89	79	64	17	11	22	.0148	.67

Critical rate for turbulence = 41 BPM
Critical rate for plug flow = 10.9 BPM
(13.5" OH)

Total mix water required - 635 bbl. + excess
App. job time @ 8 BPM ≃ 4.5 hours
Maximum equivalent density @ shoe (8 BPM) ≃ 14.5 ppg

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Estimated Cost - 9 5/8" Intermediate Casing

535 sks. Class 'H' @ 6.35	$ 3,397.25
4560 sks. Dowell Lightweight @ 6.50	29,640.00
785# D46 Antifomaer @ 2.75	2,158.75
3420# D65 Turbulence Inducer @ 3.90	13,338.00
735# D28 Retarder @ 3.50	2,572.50
17600# D30 Silica @ .16	2,816.00
5271 cf service charge @ 1.26	6,641.46
1660 Tmi (414,830# 8 mi) @ .82	1,361.20
Equipment charge to 14000'	6,590.00
6 hr. barge travel @ 140.00	840.00
24 hr. barge on location	1,150.00
Add 48 hrs.	2,400.00
60 hr. craft equipment time @ 125.00	7,500.00
9 5/8" Top & Bottom cementing plugs	195.00
Total estimated cost:	$ 80,600.16

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7 5/8" PRODUCTION LINER

Well Data:

Previous Casing	- 9 5/8" set @ 14000'
Open Hole	- 8 1/2" Bit
T.D.	- 18,000'
Mud	- 16.5 ppg waterbase
BHST (BOL)	- 290°F (1.2°F/100')
BHCT (BOL)	- 257°F
BHST (TOL)	- 236°F
BHCT (TOL)	- 196°F
Frac Gradient	- 18.7 ppg @ 18,000'

Liner:

7 5/8" Casing TOL @ 13,500'
BOL @ 18,000'
Float @ 17920'±

Volume Calculations:

Shoe Joint	- 80' x .2394 cf/ft.	=	19.2 cf
OH Annulus	- 4000' x .0769 cf/ft.	=	307.6 cf
Overlap	- 500' x .1009 cf/ft.	=	50.5 cf
50% Excess	- 307.6 x .5	=	153.8 cf
	Total volume required	=	531.1 cf

Volume should be recalculated as caliper volume + 20%.

Systems:

SPACER: 60 bbl. SPACER 3001 @ 17.0 ppg

FANN RHEOLOGIES:

	RPM	600	300	200	100	6	3	PV	n	ty
80°F		261	152	110	61	6	3	109	.0732	.43
257°F		43	13	7	4	1	.5	30	.0202	.005

Critical rate for turbulence = 5.3 BPM
(10" OH)

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Slurry: 435 sks. Class 'H' + 35% D30 Silica + 0.42 gals. D108 FLAC + 1% D65 Turbulence Inducer + 0.2% D46 Antifoamer + 0.6% D28 Retarder

Density	- 17.5 ppg.
Yield	- 1.23 cf/sk.
Mix Water	- 3.70 gal./sk.
Total Liquid	- 4.12 gal./sk.
Thickening Time	- 5 hr. 45 min.
Slurry Volume	- 535 cf
Mix water required	- 39 bbl.

FANN RHEOLOGIES:

	RMP	600	300	200	100	6	3	PV	n	ty
80°F		162	78	45	22	2	1	84	.0564	.005
257°F		43	13	7	4	1	.5	30	.0202	.005

Critical rate for turbulence ≃ 2.6 BPM
Critical rate for plug flow ≃ 0.7 BPM
(10" OH)

App. job time @ 5 BPM ≃ 2 hr
Maximum equivalent density @ shoe ≃ 17.0 ppg @ 5 BPM

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__Estimated Cost - 7 5/8" Liner__

435 sks. Class "h" @ 6.35	$ 2,762.25
14300# D30 Silica @ .16	2,288.00
80# D46 Antifoamer @ 2.75	220.00
410# D65 Turbulence Inducer @ 3.90	1,599.00
183 gal. D108 FLAC @ 18.50	3,385.50
250# D28 Retarder @ 3.50	875.00
22350# D31 Barite for Spacer @ 15.50/cwt	3,472.00
4600# D18 Ilmenite for Spacer @ 19.50/cwt	8 .00
60 bbl. SPACER 3001 @ 49.25	2,955.00
775 cf service charge @ 1.26	976.50
332 Tmi (82880# 8 mi) @ .82	272.24
Equipment charge to 18000'	10,150.00
6 hr. barge travel @ 140.00	840.00
24 hr. barge on location	1,150.00
Add 24 hrs.	1,200.00
30 hr. craft equipment time @ 1.25.00	3,750.00
Total estimated cost:	$ 36,792.49

The prices in this recommendation are estimates. Actual charges may vary with equipment, materials and time required to perform the service.

Service for this job will be provided from our Houma, Louisiana District, 504/868-0195.

Dowell has established an on location safety policy to which all Dowell personnel must adhere. A prejob tailgate safety meeting will be held with company representatives and other on location personnel to familiarize everyone with existing hazards and safety procedures. We would appreciate close cooperation between customer representatives and the Dowell representative to insure a smooth and safe operation.

If there are any questions or I can be of further assistance, please contact me.

Sincerely,

Fred Peters
F.W. Peters
Regional Accounts Manager
Lafayette, Louisiana
318/232-3216

Primary Squeeze Procedure:

1. Mix and pump cement slurries with Dowell pumps at maximum available rate (8-12 BPM).

2. Drop plug and displace with rig pump at maximum rate of 17 BPM.

3. When plug is 50 bbls short of float, drop pump rate to 2 BPM. (Hydrostatic differential ≃ 925 psi)

4. When plug is 20 bbls short of float, drop pump rate to 1 BPM. (Hydrostatic differential ≃ 960 psi)

5. When plug is 10 bbls. short of folat, stop pump for 1-2 minutes, then resume pumping at 1 BPM until plug bumps, or pump pressure increases 200 psi. (Hydrostatic differential ≃ 1000 psi)

6. Check float. Leave wellhead without pressure if possible.

*NOTE: If pump pressure increases beyond changing hydrostatic differential, do not hesitate in Step #5. The pressures listed above are inaccurate; use pump pressure at beginning of Step #3 to determine when squeeze pressure occurs.

APPENDIX C

C. RICHARD WELL #2
RECOMPLETION EVALUATION

I. WELL HISTORY

The C. Richard #2 well originally produced after blowing out through squeeze perfs at 13,196'-13,198' (2SPF) on 12-30-79. The well blew out while washing with coil tubing and flowed gas and several hundred barrels of condensate before it was brought under control approximately 12 hours later. The well was subsequently tested for two days and flowed approximately 2,900 MCFPD with 300-600 BCPD. The well was shut in with the coil tubing string still in it on 1-3-80 to hook up production equipment and was not reopened until 7-4-80. The well was reopened and flowed for 68 hours. FTP decreased steadily from 2,750 psi down to 1,000 psi and flowrate decreased from 2,000 MCFPD to 0 MCFPD. A snubbing unit was moved in on 7-22-80. After retrieving the coil tubing, the perforations at 13,196'-13,198' were squeezed off and the well was perforated twice at 13,217'-13,220' and 13,236'-13,239' (4SPF) with no success. After being perforated a third time, the well began to flow. FTP 1,100-1,400 psi, FARO 1,000-2,500 MCFPD, 18-131 BCPD.

After four days, the well began making mud and died on 9-20-80. A workover rig was moved on, the tubing was fished out, and a TDT-CCL and CBL were run from 13,384'-11,384' on 12-9-80. Existing perfs (13,217'-20', 13,236'-39') were squeezed, packer and tubing were run, and the well was perforated three times with 1 11/16" through tubing guns at 13,236'-13,244' (4SPF). The well would not flow in spite of being jetted as deep as 12,000' and the formation could not be pumped into with pressures as high as 9,800 psi. After many unsuccessful attempts to pump into the formation and jet and/or swab it in, the well was plugged back and completed in the Champagne sand at 12,676'-12,684'. The Champagne sand was produced from April 1981 until December 1981, when it watered out. Initial reserves were estimated at 1,264 MMCF and cumulative production was 349 MMCF.

II. DISCUSSION

The Area does not feel that there are any significant recoverable reserves left in the Champagne sand and recommends that it be abandoned. Logs do not show any sands that would be good candidates for a recompletion above the Champagne sand. Log analysis of the 13,200' sand indicates the following:

Net Pay	4'
Porosity	24%
Water Saturation	44%
Recoverable Reserves for AF	1,100 MCF/AF

Condensate yield is estimated at 100 bbls/MMSCF based on past production from the sand. Reservoir size is estimated at 320 AF.

Failure to produce the 13,200' sand after it was squeezed the second time was probably due to inadequate penetration of the 1 11/16" through tubing guns that were used. This theory is strongly supported by the fact that there was no feed in when the well was jetted and that the formation could not be pumped into with pressures of up to 9,800 psi at surface. By re-entering the well, the sand would be shot with a 4" casing gun, a Vann gun, or a 2 1/8" enerjet. Penetration of these guns is estimated as follows:

DEPTH OF PENETRATION

	Cement	Berea
1 11/16" uni jet	6.36	6.23
2 1/8" enerjet	18.41	10.25
4" casing gun	23.07	14.13
4" Vann gun	23.2	14.73

Estimated cost to recomplete to the 13,200 ft. sand is $350,000.

III. CONCLUSIONS

The fact that this reservoir has been logged and produced leaves little doubt that the reserves are there. The questions are: 1) what is the extent of the reservoir, and 2) can it be produced? The first question can be handled only by risking the size of the reserves in the PECON program. Reservoir size was risked as follows:

Minimum: 80 AF
Expected: 320 AF
Maximum: 640 AF

Whether the reservoir can be produced will only be known after the well is perforated and put on test. Two things stand as favorable evidence that the sand can be produced: 1) The fact that it has been produced previously and 2) that failure to reestablish production can be explained with some confidence by inadequate communication between the sand and the wellbore. Dry hole probability was risked as follows:

Minimum: .1
Expected: .3
Maximum: .45

Another favorable aspect of this reservoir is its relatively high (100 bbls/MMCF) condensate yield. Approximately 45% of the total revenue derived from the sale of hydrocarbons is contributed by condensate sales.

The attached WP9-CIP shows that with risk analysis included, the proposed recompletion has a PW-AFIT of $308,000 and a PW/I of 0.9. For these reasons the Area is submitting this proposal to the District for review.

TABLE C-1--RECOMPLETION DATA

WELL PROPOSAL — DATE 05/20/82
LEASE-C. RICHARD - RECOMPLETIONFIELD-N. ERATH — DEPTH - 13,236
COUNTY,STATE-VERMILION LA — OPERATOR- GETTY — COMPLETION-SINGLE

RESERVES		GROSS	GETTY NET
Liquids M-bbls.	Most likely case	35.	31.
	Risk and uncertainty	28.	25.
Gas mmcf	Most likely case	352.	308.
	Risk and uncertainty	280.	245.

PRODUCTION DURING PAYOUT (RISK CASE)	GROSS	GETTY NET
Liquid barrels per day	93.	82.
Gas mcf per day	933.	817.

$-M INVESTMENT (MOST LIKELY)	CONSTANT GROSS	CONSTANT GETTY NET	CURRENT GETTY NET
Dry Hole Cost	350.	350.	350.
Completed Well Cost	350.	350.	350.
Facilities	0.	0.	0.
Artificial Lift	0.	0.	0.
Other	0.	0.	0.
Total Cost	350.	350.	350.

ECONOMIC DATA (03/09/82) ESCALATION FACTORS) GETTY OIL NET AFIT	MOST LIKELY	RISK UNCERTAINTY
DCF ROR Percent	99.9	99.9
Current $ P.W. $-M (Disc 16.0 PCT)	443.	308.
Current $ PW/I (Disc 16.0 PCT)	1.3	0.9
Constant $ Total Investment Payout (MOS)	2.	3.
Constant $ Total Cash Surplus ($-M)	476.	348.
Probability of Exceeding Corporate DCF for Percent		72.
Dryhole Probability Percent		28.

REMARKS

$367M GOC net is requested to recomplete to the 13,200' sand in the C. Richard #2 Well, N. Erath Field, Vermilion Parish, Louisiana.

The 13,200' sand is situated in the abnormally pressured transition zone on the northwest section of the Erath domal structure. Deposition appears to be very erratic with major structural differences between wells that penetrated the zone. This miocene sand was probably deposited in a deltaic of flood plain environment which would limit the potential reservoir area.

No offset wells have penetrated the 13,200' sand. Well control below 13,000' is very poor.

Economics are based on a gas price of $2.638/MCF in July 1982 when production is scheduled to begin, and escalates according to the 3-9-82 PPCEF guidelines.

Fig. C-1--Present wellbore schematic.

PRESENT COMPLETION 4/20/81
Ceva Richard #2
Erath Field
Vermilion Parish, La. RKB 31.75'

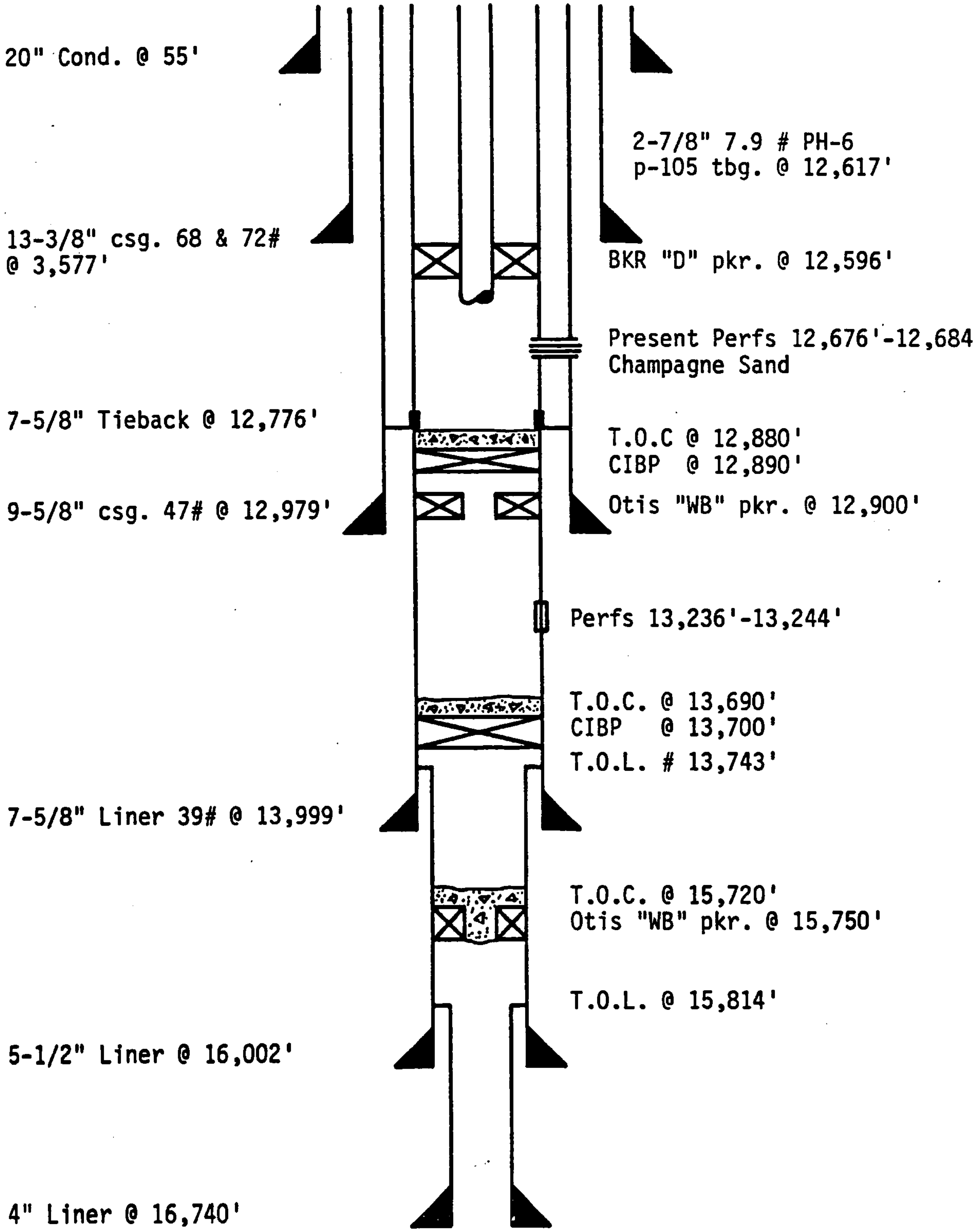
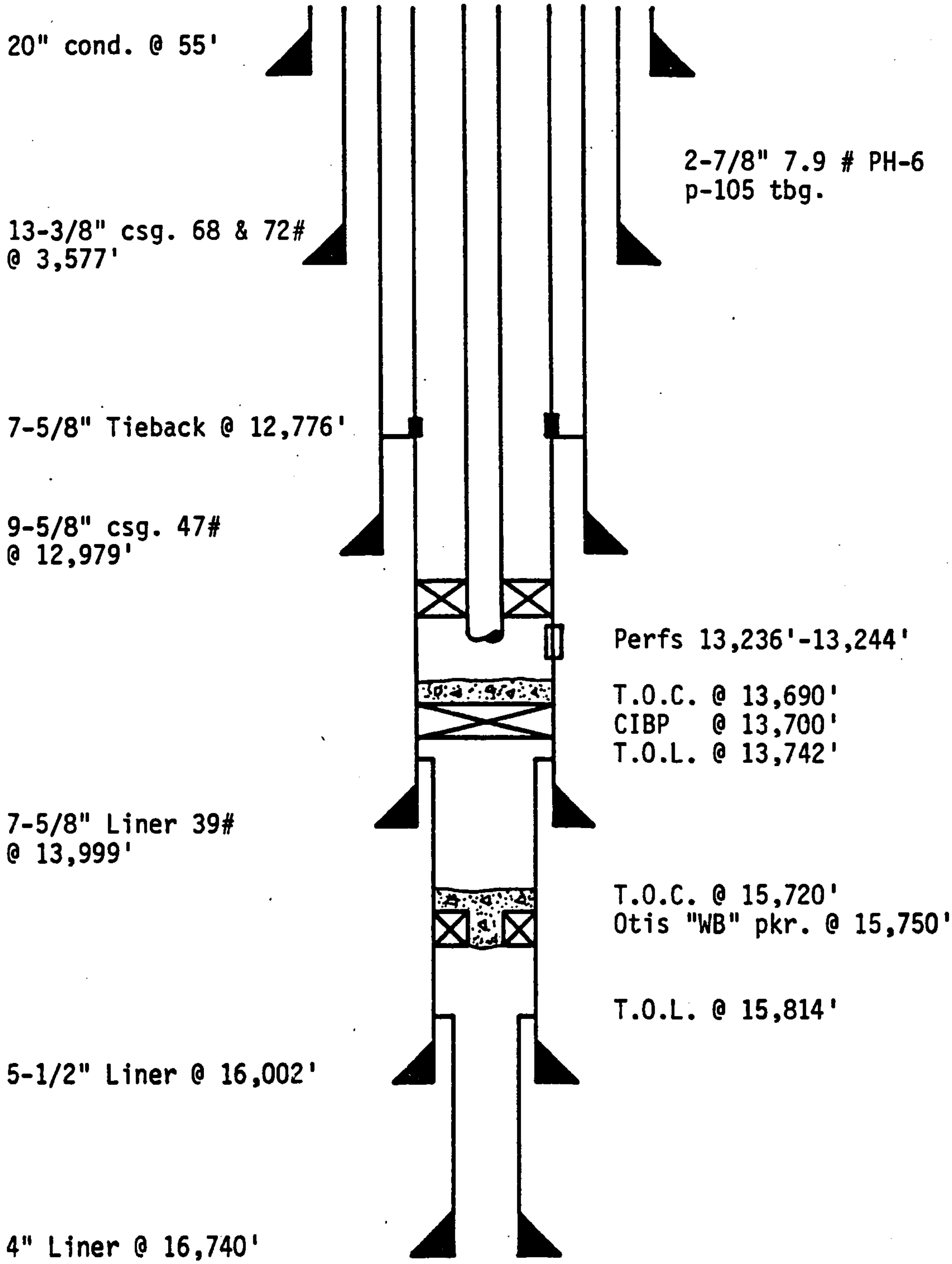


Fig. C-2--Proposed wellbore schematic.

PROPOSED COMPLETION 5/14/82
Ceva Richard #2
Erath Field
Vermilion Parish, La. RKB 31.75'



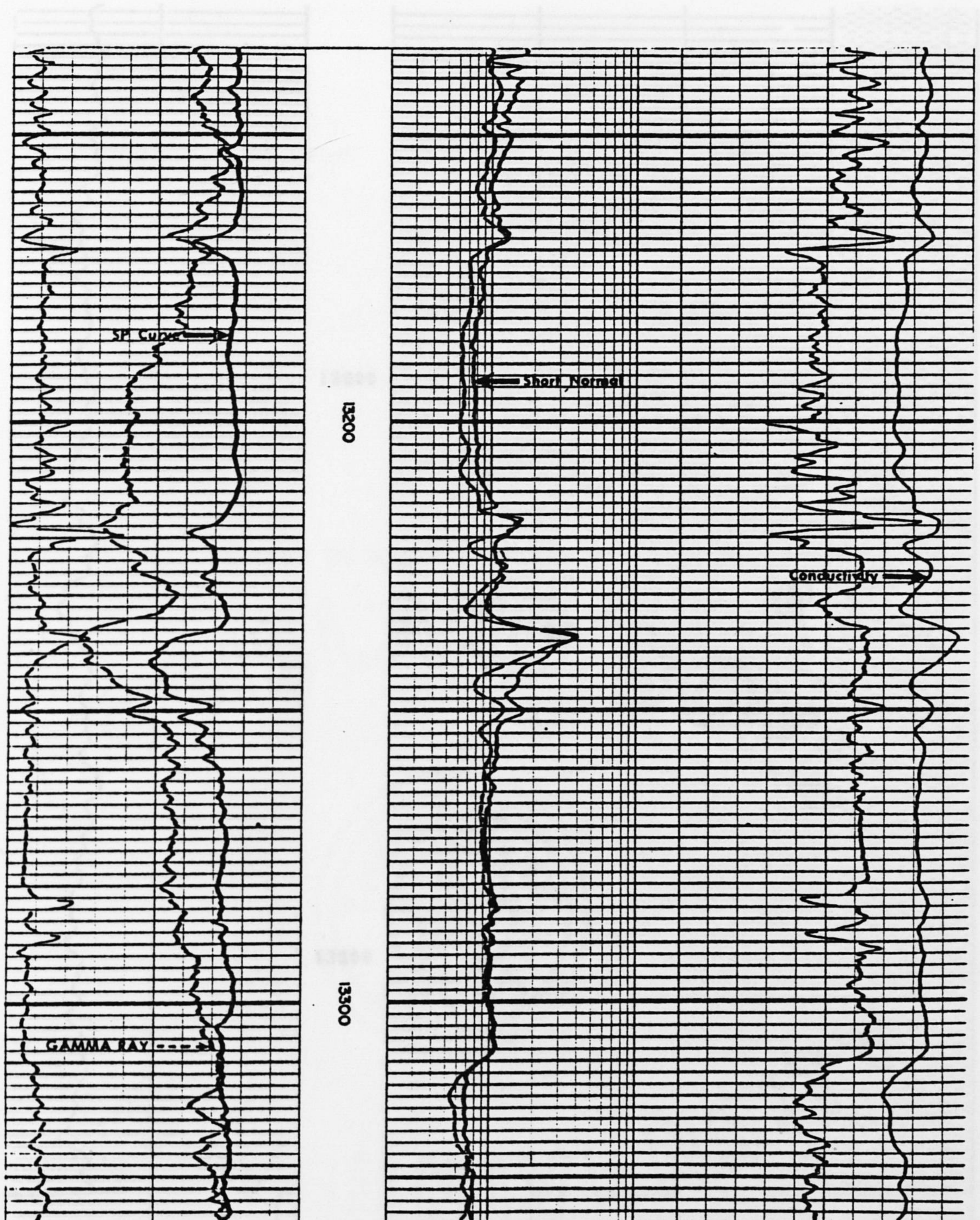


Fig. C-3--Induction log.

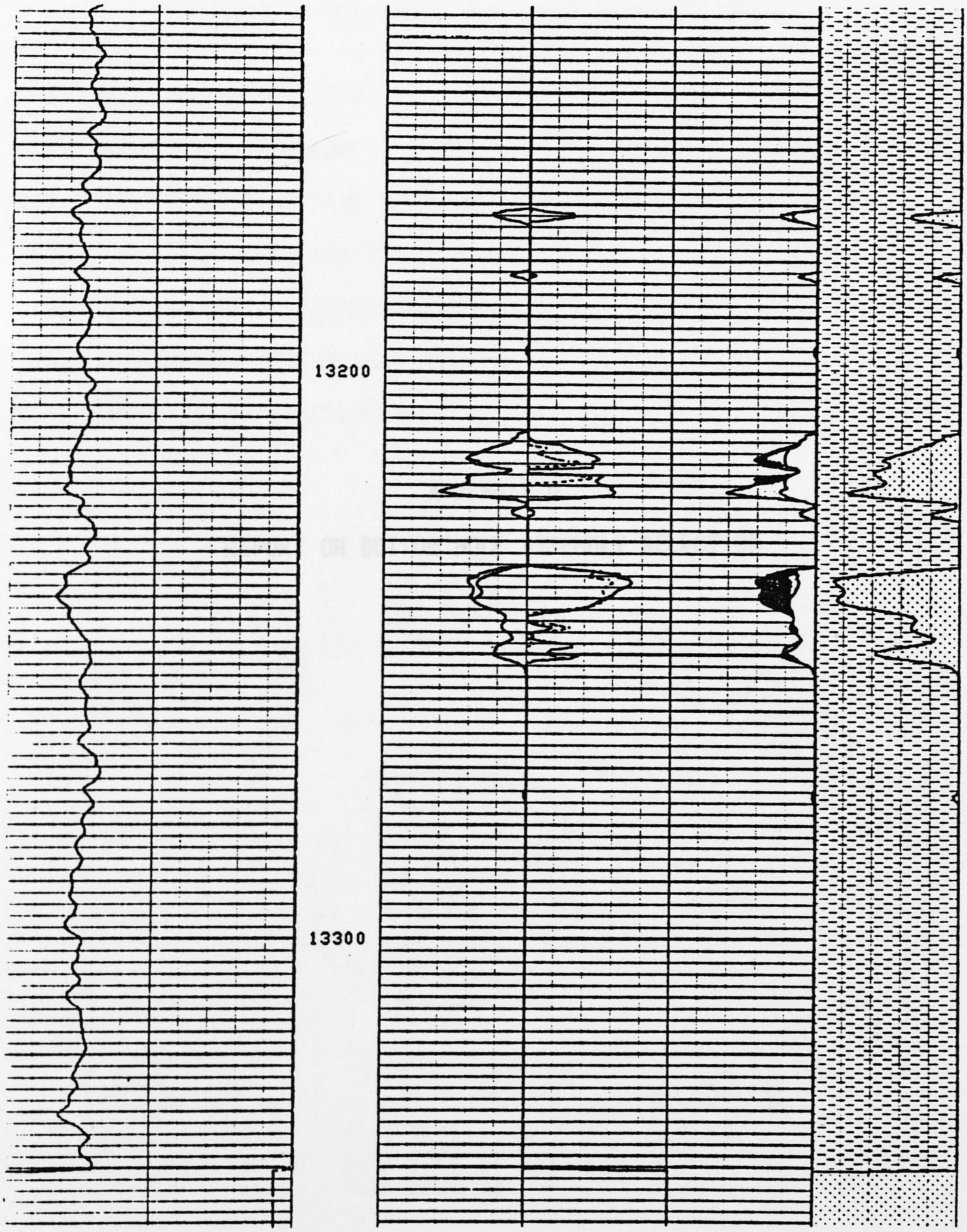


Fig. C-4--TDT log.

APPENDIX D

REPORT ON BOTTOM HOLE ASSEMBLY SELECTION

BOTTOM HOLE ASSEMBLIES

SIZE OF COLLARS & PLACEMENT OF STABILIZERS

I. EQUILIBRIUM DRILLING

II. PACKED VS. PENDULUM

III. STABILIZER PLACEMENT & COLLAR SIZE

IV. PRACTICAL CONSIDERATIONS

V. CONCLUSIONS & RECOMMENDATIONS

VI. RECOMMENDED BOTTOM HOLE ASSEMBLIES

VII. DRILL STRING CALCULATIONS

I. EQUILIBRIUM DRILLING

In a dipping formation neither a pendulum nor a packed hole assembly will drill a perfectly vertical hole. For a given amount of weight on the bit and BHA configuration the bit will drill at some equilibrium angle. This will cause the hole to be slanted, but once it finds the equilibrium point, the bit will not gain or drop angle; the hole will be straight, but deviated from vertical. The equilibrium angle will be influenced by the size of the hole, the size of the drill collars, the formation dip angle, weight on the bit, placement of stabilizers, and the crooked hole tendency of the formation. Charts developed by Woods & Lubinski are available which will quantitatively predict the effect of each one of these parameters. The only parameter which is difficult to pin down is the crooked hole tendency of the formation.

II. PACKED VS. PENDULUM

As mentioned before, neither of these assemblies will drill a perfectly vertical hole in a dipping formation, but they each have advantages that cause one or the other to be applicable for most any drilling situation. The purpose of this section is to outline the criteria to be used in selecting either a pendulum or a packed assembly.

Under continuous drilling in a uniform formation, both the packed and pendulum assemblies will seek their own equilibrium angle. Once the hole reaches this equilibrium angle, it will remain straight but deviated. However, the packed hole assembly will seek a much higher equilibrium angle than the pendulum assembly. Whereas in a certain formation a pendulum assembly may build angle to 2° and reach equilibrium, the packed assembly may build to 20° or 30° before reaching equilibrium. This is because the use of a near bit stabilizer cancels out most of the pendulum restoring force. Generally, if left unchecked, the packed hole assembly will ultimately build angle to an unacceptable level for vertical hole drilling. The only advantage the packed hole assembly has over the pendulum assembly is that it will build angle at a slower rate. If a pendulum assembly encounters a formation which is very hard or has a very strong dip angle, it could suddenly build up to a much higher equilibrium angle than it had been drilling. This will cause a dog-leg in the hole which could lead to fatigue failures, keyseating, sticking, or inability to run casing. this sudden change in hole angle will not occur with a packed assembly because the placement of the stabilizers uses the stiffness of the drill collars to force the bit to drill a straight hole.

Theoretically, a pendulum assembly could be used to drill these exremely crooked hole formations but you would have to run very little weight on the bit which would result in an unacceptably low rate of penetration. A more practical method is to use the packed assembly, run more weight on the bit, and "fan" the hole with a pendulum assembly if deviation becomes excessive. In summary, many Gulf Coast wells can be drilled to 20,000 ft or more with a pendulum assembly. If strongly dipping or other "crooked hole" formations cause deviation problems which cannot be remedied by running less weight on the bit, or if running less weight on the bit reduces the rate of penetration too much, then a packed hole assembly should be considered. If a packed assembly is run, more weight can be applied to the bit but it will eventually start to build angle. Once angle has built up with a packed assembly in the hole, it is generally a waste of time to try to "fan" the hole to drop angle. A pendulum assembly should be run to bring the hole back to vertical before running the packed assembly again.

III. STABILIZER PLACEMENT AND COLLAR SIZE

A. Stabilizer Placement

For both packed and pendulum assemblies there is an optimum stabilizer position which will maximize the stiffness or pendulum effect, whichever the case may be. Factors that influence the optimum stabilizer position are hole size, drill collar size, weight on the bit, hole deviation, formation dip, the crooked hole tendency of the formation, and stabilizer clearance. For the pendulum assembly, as long as the drill collars do not contact the wall of the hole, the higher the stabilizer is placed, the more pendulum force that is applied to the bit. In a slanted hole, if the stabilizer is placed too high, the drill collars will sag and lay against the wall of the hole reducing the pendulum effect. (Fig. D-1) This represents the upper limit to the stabilizer placement and is what would be desired for most "crooked hole" formations. Unfortunately, as the stabilizer is placed higher to increase the pendulum effect, the weight which can be run on the bit without buckling the pendulum collars decreases. This is why in extremely crooked hole formations it pays to go with a packed assembly in order to be able to run more weight on the bit. In formations which have very little or no crooked hole tendency, the pendulum stabilizer can be run closer to the bit. The decreased pendulum effect will not be a problem if the formation is not "crooked hole," while the advantage gained is that more weight can be run on the bit without buckling the pendulum collars. Optimum stabilizer placement for a pendulum assembly is easily determined from charts once the crooked hole tendency of the formation has been determined. If the crooked hole tendency of the formation has not been determined, a close approximation for stabilizer placement can be made as follows:

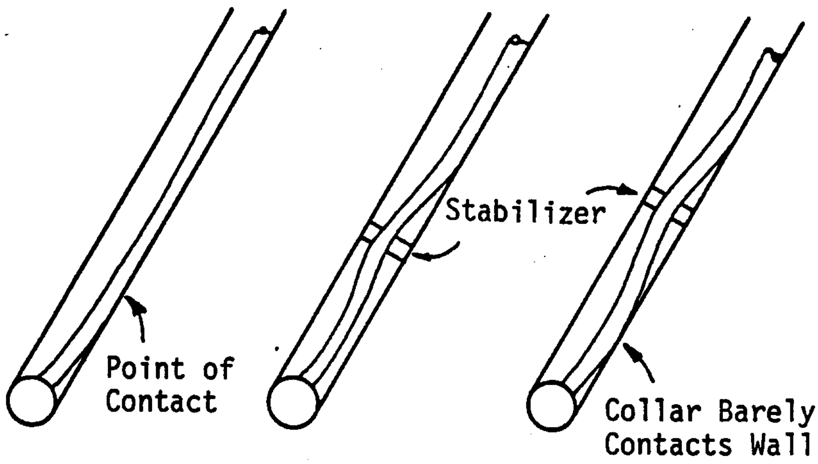


Fig. D-1--Pendulum Schematic.

Hole Size	Fulcrum Point
13 3/8 & Larger	120-140 ft
9 7/8 - 12 1/4	90-100 ft
7 5/8 - 9 7/8	60-70 ft
6 3/4 & Smaller	30-40 ft

The primary factors governing stabilizer placement in a packed hole assembly are stabilizer clearance, hole deviation, rate of change of hole deviation, drill collar size, and weight on the bit. Formulas are available to calculate optimum stabilizer placement for a 2 stabilizer packed assembly but a 3 stabilizer system is more common and provides a stiffer hook-up due to using the extra stabilizer. This system uses a near bit stabilizer, a pony collar whose length in feet is equal to the diameter of the hole in inches (±2 ft), a stabilizer, drill collar and another stabilizer on top of that. Two or three stabilizers may be run piggyback on top of the near bit in severe crooked hole formations. (See Fig. D-2)

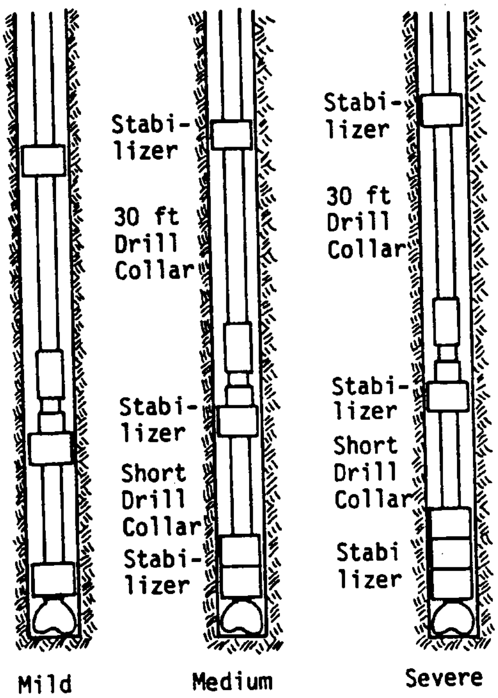


Fig. D-2--Packed hole assemblies.

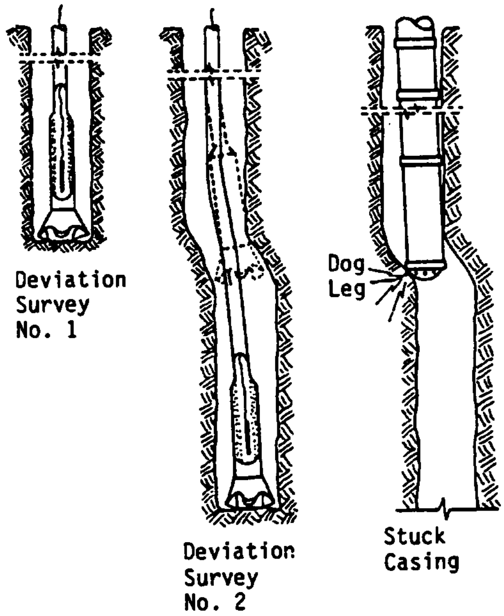


Fig. D-3--Why dog-legs stick casing and why they cannot be detected.

B. Collar Size

From a standpoint of pure deviation considerations, it is desirable to run the largest size collars possible in both packed and pendulum assemblies. However, there are obvious limitations to collar size due to both handling and fishing problems. Large collars improve the performance of pendulum assemblies for two reasons: (1) they weigh more per foot and therefore give more of a pendulum force for a given length pendulum, and (2) larger collars are stiffer (stiffness is proportioned to the 4th power of diameter: $I = \frac{\pi}{64}(D_o^4 - D_i^4)$) The increased stiffness of the collar means that the first stabilizer can be placed higher because the collars will not sag and contact the wall of the hole. Larger collar sizes improve the performance of packed hole assemblies because of their stiffness. The increased pendulum effect is very small in a packed hole assembly due to the presence of a near bit stabilizer.

IV. PRACTICAL CONSIDERATIONS

A. Deviation

The pendulum force of a pendulum BHA is roughly proportional to the amount of deviation. That is, there is no pendulum force on the bit of 0° deviation, and there is twice as much restoring force at 2° as there is at 1°. Unless there are geological or legal restrictions on the wellbore trajectory, there is probably no need to "fan" a hole that has less than 2° deviation. When running a packed BHA, if deviation builds up in excess of 2° and it is necessary to drop angle, run a 60 ft pendulum and decrease the weight on the bit slightly. Maintain the rate of change of angle of 2°/100 ft or less in order to avoid drill pipe fatigue problems.

B. Stabilizer Placement

The ideal position for the first stabilizer is influenced by many factors and it would be impractical to continually recalculate and reposition the stabilizer as drilling conditions change. Most of the pendulum force will be retained by placing the stabilizer between the ideal position and a position 10% closer to the bit. The easiest way to determine the spacing range is to determine the crooked hole tendency of the formation and then refer to the pendulum charts. For example, suppose after drilling out a casing shoe with a slick BHA of 8" drill collars and 12 1/4" bit, the hole showed a deviation of 2° with a constant bit weight of 33,000 lbs. Assuming a dip angle of 4°, the charts show that this is a Class M formation. Also, it can be seen that by placing a stabilizer at 81-90 ft above the bit, 50,000 lbs of weight could be carried on the bit without increasing the deviation over 2°. These charts only tell where to position the first stabilizer, they say nothing about the other stabilizer. By placing the second stabilizer 30 ft above the first one, the buckling resistance of the lower collars will be almost doubled.

C. Collar Size

Larger collars offer advantages for deviation control due to their increased weight and stiffness as explained before, but they also cause problems that could outweigh their benefits because of rig floor handling problems and downhole sticking and fishing problems. As far as deviation control is concerned, most holes in South Louisiana can be drilled with 8" or smaller collars. An exception may be deep 17 1/2" holes which are drilled to the top of the transition zone. As a quantitative example, consider the situation discussed previously: 12 1/4" hole, 2° deviation, 4° formation dip, Class M hole (mild crooked hole tendency). The chart indicates that with 8" collars and an 81-90' pendulum, 50,342 lb of weight could be carried on the bit. If 9" collars were used, a 97-107' pendulum could be run and 70,542 lb could be carried on the bit. Similarly, 10" drill collars would allow 91,064 lb to be run on the bit with no increase in deviation. Obviously, the 9" and 10" drill collars are unnecessary in this case because the bit itself would probably not be run with over 50,000 lb. The larger collars may be useful in more severe crooked hole environments. The table below shows weight that could be carried on the bit for various formations.

TABLE D-1--MAXIMUM WEIGHT TO BE CARRIED ON BIT TO LIMIT DEVIATION TO 2°

Crooked Hole Tendency	Class	Collar Size and Pendulum Length		
		8"	9"	10"
Mild	M	50342, 81-90	70542, 97-107	91064, 85-94
Medium	H	21154,109-119	28069,111-121	34678,109-119
Severe	D	9355,116-126	11983,116-126	13467,115-125

In the more severe crooked hole formations, the increase in weight that results from the larger collars could be useful, but they would cause a very difficult fishing job if they ever got stuck.

In order to avoid fishing problems, a good rule of thumb is not to run any collar larger than 75% of the diameter of the hole. Following this logic, the largest size collars that should be run in various holes are given in Table 2.

TABLE D-2--LARGEST COLLAR SIZE TO RUN IN VARIOUS HOLE SIZES

Hole Size	Collar Size
6 1/2"	4 3/4"
8 1/2"	6 1/4"
9 7/8"	7 1/4"
12 1/4"	9"
14 3/4"	11"

D. Mechanical Transition Zones

In order to minimize the possibility of fatigue damage when running different sizes of drill collars, limit size changes in collars to 2". For example, 6" collars on top of 8" collars are okay, but 6" collars run directly on top of 9 1/4" collars would be too severe of a stiffness change and could lead to fatigue problems. A 7 1/4" - 8" intermediate collar should be run to make a more gradual transition. The same principle applies to heavyweight drill pipe. 4 1/2" heavyweight is allright for collar sizes up to 7 1/4". 5" heavy weight should be run for 7 1/2" - 8" collars.

V. CONCLUSIONS AND RECOMMENDATIONS

Most wells on the Gulf Coast can be drilled with a properly designed pendulum assembly. A pendulum assembly should be run from spud until it has been determined that it is no longer economical. This will happen only when it becomes necessary to reduce weight on the bit to control deviation, and rate of penetration drops to an unacceptable level. At this point, it will pay to pick up a packed BHA in order to apply more weight on the bit and increase the rate of penetration. Bear in mind however, that in the long run a packed BHA will build angle to an unacceptable value and will have to be fanned with a pendulum to bring it back on course.

Refer to Section VI for recommended Bottom Hole Assemblies.

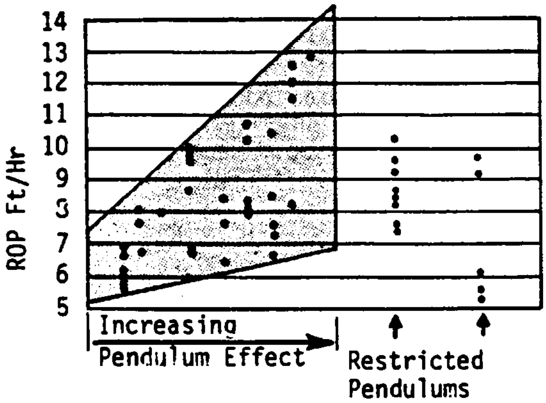


Fig. D-4--Pendulum effect and ROP.

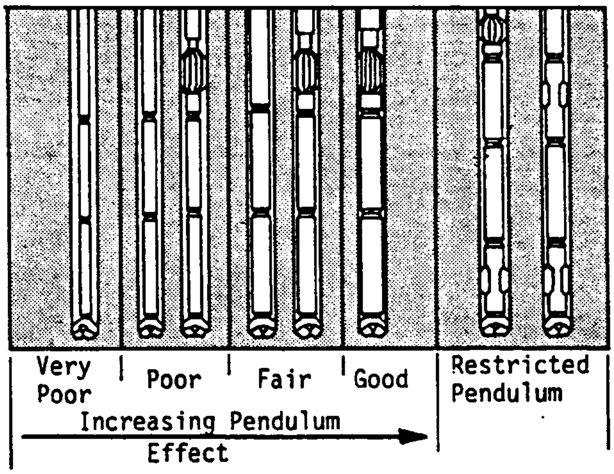


Fig. D-5--Pendulum assemblies.

VI. BOTTOM HOLE ASSEMBLIES

17 1/2" HOLE

Surface Hole	"Deep" Hole
Bit	Bit
3 - 8" DC	3 - 9 1/4" DC
17 1/4" WB Stab (Free Flow)	7 1/4" WB Stab (Free Flow)
1 - 8" DC	1 - 9 1/4" DC
17 1/4" WB Stab (Free Flow)	17 1/4" WB Stab (Free Flow)
3 - 8" DC	3 - 9 1/4" DC
17" WB Stab (Free Flow)	17" WB Stab (Free Flow)
8" DC as needed for wt	8" Drill collars as needed for wt
15 Jts HWDP	3 Jts HWDP
	Jars (Optional)
	14 Jts HWDP

14 3/4" HOLE

Surface Hole	"Deep" Hole
Bit	Bit
3 - 8" DC	3 - 8" DC
14 1/2" WB Stab (Free Flow)	14 1/2" WB Stab (Free Flow)
1 - 8" DC	1 - 8" DC
14 1/2" WB Stab (Free Flow)	14 1/2" WB Stab (Free Flow)
8" DCs as needed for wt	3 - 8" DC
15 Jts HWDP	14 1/2" WB Stab (Free Flow)
	8" DCs as needed for wt
	3 jts HWDP
	Jars (Optional)
	14 jts HWDP

12 1/4" HOLE

Surface Hole	Mild	Moderate
Bit	Bit	Bit
2 - 8" DC	3 - 8" DC	12 1/4" Stabilizer
12 1/4" WB Stab (Free Flow)	12 1/4" WB Stab (Free Flow)	8" Pony collar (10-15')
1 - 8" DC	1 - 8" DC	12 1/4" Stabilizer
12 1/4" WB Stab (Free Flow) (Long Neck)	12 1/4" WB Stab (Free Flow) (Long Neck)	1 - 8" DC
6 3/4" HWDP as needed for wt	6 3/4" HWDP as needed for wt	12 1/4" Stabilizer
2 jts HWDP (Free Flow)	2 jts HWDP	2 - 8" DC
Jars (Optional)	Jars (Optional)	12" Stabilizer (Long Neck)
15 Jts HWDP	15 jts HWDP	6 3/4" HWDP as needed for wt
		2 Jts HWDP
		Jars (Optional)
		15 Jts HWDP

9 7/8" HOLE

Crooked Hole Tendency

None/Mild	Moderate
Bit	Bit
2 - 1 1/4" DC	9 7/8" WB Stab
9 7/8" Stab (Free Flow)	7 1/4" Pony Collar (8'-12')
1 - 7 1/4" DC	9 7/8" WB Stab
9 7/8" WB Stab (Long Neck) (Free Flow)	1 - 7 1/4" DC
	9 7/8" WB Stab
5" HWDP as needed for wt	9 7/8" WB Stab
	2 - 7 1/4" DC
Jars (Optional)	9 5/8" WG Stab (Long Neck)
11 Jts HWDP	5" HWDP as needed for wt
	Jars (Optional)
	11 Jts HWDP

8 1/2" HOLE

Crooked Hole Tendency

None/Mild

Bit

2 - 6 1/4" DC

8 1/2" WB Stab
(Free Flow)

1 - 6 1/4" DC

8 1/2" WB Stab
(Free Flow)
(Long Neck)

5" HWDP as
needed for wt

Jars (Optional)

11 Jts. HWDP

Moderate

Bit

8 1/2" WB Stab

1 - 6 1/4" Pony Collar
(6'-10')

8 1/2" WB Stab

1 - 6 1/4" DC

8 1/2" WB Stab

2 - 6 1/4" DC

8 1/4" WB Stab
(Long Neck)

5" HWDP as needed
for wt

Jars (Optional)

11 Jts HWDP

6 1/2" HOLE

Crooked Hole Tendency

None/Mild	Moderate
Bit	Bit
1 - 4 3/4" Pony Collar (10'-20')	6 1/2" WB Stab
1 - 4 3/4" DC	1 - 4 3/4" Pony Collar (4'-8')
6 1/2" WB Stab	6 1/2" WB Stab
1 - 4 3/4" Pony Collar	2 - 4 3/4" DC
6 1/2" WB Stab (Long Neck)	6 1/4" WB Stab (Long Neck)
3 1/2" HWDP as needed for wt	3 1/2" HWDP as needed for wt
Jars (Optional)	Jars (Optional)
9 Jts HWDP	9 Jts HWDP

VII. DRILL STRING CALCULATIONS

This article explains how to determine how much of a particular weight and grade of drill can be used for a given Bottom Hole Assembly and mud weight and still be able to allow 100,000 lbs over string weight pull.

A. Look up tensile yield strength and wt/ft of drill pipe being picked up. Multiply this value by 80% to obtain maximum allowable pull. Also record mud weight and bouyancy factor.

B. Subtract 100,000 from maximum allowable pull.

C. Subtract bouyant weight of BHA plus bouyant weight of any drill pipe already in the hole that is different from the pipe being picked up.

D. Divide quantity obtained in step 3 by the bouyant wt/ft of the drill pipe being picked up. This will indicate how much of this particular type of drill pipe can be run in the hole before a stronger grade will be needed.

EXAMPLE I.

BHA Information	Weight	Length
Collars & Stabilizers	62,000	420'
Heavy Weight Drill Pipe	23,000	465'
TOTAL	85,000	885'

Drill Pipe - 4 1/2", Grade E, 16.6 lb/ft, min tensile yield = 331,000 lbs

Mud Weight - 9.3 ppg, bouyancy factor = .858

1. Figure maximum allowable pull:
   .8 x 331,000 = 265,000 lbs

2. Allow for 100,000 lbs OSW pull:
   265,000 - 100,000 = 165,000 lbs

3. Subtract BHA wt.
   Bouyancy wt. of BHA = .858 (85,000) = 73,000 lbs
   165,000 - 73,000 = 92,000 lbs

4. Figure maximum amount of drill pipe that can be run.
   $$\frac{92{,}000}{.858(16.6)} = 6459 \text{ ft.}$$

Therefore, this hole should not be drilled any deeper than 7,344' (6,459' + 885') without picking up stronger drill pipe.

EXAMPLE II

Assume that after drilling to 7,344' in Example I, the driller started picking up 4 1/2", 20 lb/ft grade G drill pipe. With the same BHA and 17 ppg mud, how deep could the hole be drilled without overloading the drill pipe?

Drill Pipe - 4 1/2", Grade G, 20.0 lb/ft, min tensile yield = 577,000 lbs, bouyancy factor = .74

1. Figure maximum allowable pull
   .8 x 577,000 = 462,000 lbs

2. Allow for 100,000 lbs OSW
   462,000 - 100,000 = 362,000 lbs

3. Subtract BHA and drill pipe in the hole

BHA	.740 (85,000) =	63,000 lbs
16.6# drill pipe	.740 (16.6) 6,459 =	79,000 lbs
		142,000 lbs

   362,000 - 142,000 = 220,000 lbs

4. Figure maximum amount of pipe that can be run

$$\frac{220{,}000}{.74(20)} = 14{,}865 \text{ ft}$$

Thus the well could be drilled to 22,209' (14,865 + 6,459 + 855) with this drill string and still have the capability for 100,000 lbs OSW pull.

APPENDIX E

REPORT ON THE EFFECT OF BOUYANCY AND HYDROSTATIC PRESSURE ON DRILL COLLAR WEIGHT

EFFECT OF BOUYANCY AND HYDROSTATIC PRESSURE ON DRILL COLLAR WEIGHT

I. Buckling and Hydrostatic Pressure

It is natural phenomena that a body immersed in a fluid will not buckle due to the hydrostatic pressure of the fluid unless the buckling stress exceeds the hydrostatic pressure. A formal proof of this is fairly complicated (see Lubinski, "A Study of the Buckling of Rotary Drilling Strings," Drilling & Production Practice, 1950) but the principle can be easily demonstrated.

EXAMPLE I

Consider a 2000 ft long steel cable with a cross sectional area of 1 in.^{2} suspended from a boat in the ocean. The bottom of the cable is subjected to a hydrostatic force of 1 in.^{2} x .444 psi/ft x 2000 ft = 888 lb yet the cable does not buckle. (Fig. E-1) If the cable is lowered into the water by a submarine such that the top of the cable is at 3,000 ft and the bottom is at 5,000 ft, a force of 1,332 lbs acts on the top end and a force of 2,220 acts on the bottom end. The cable will still not buckle.

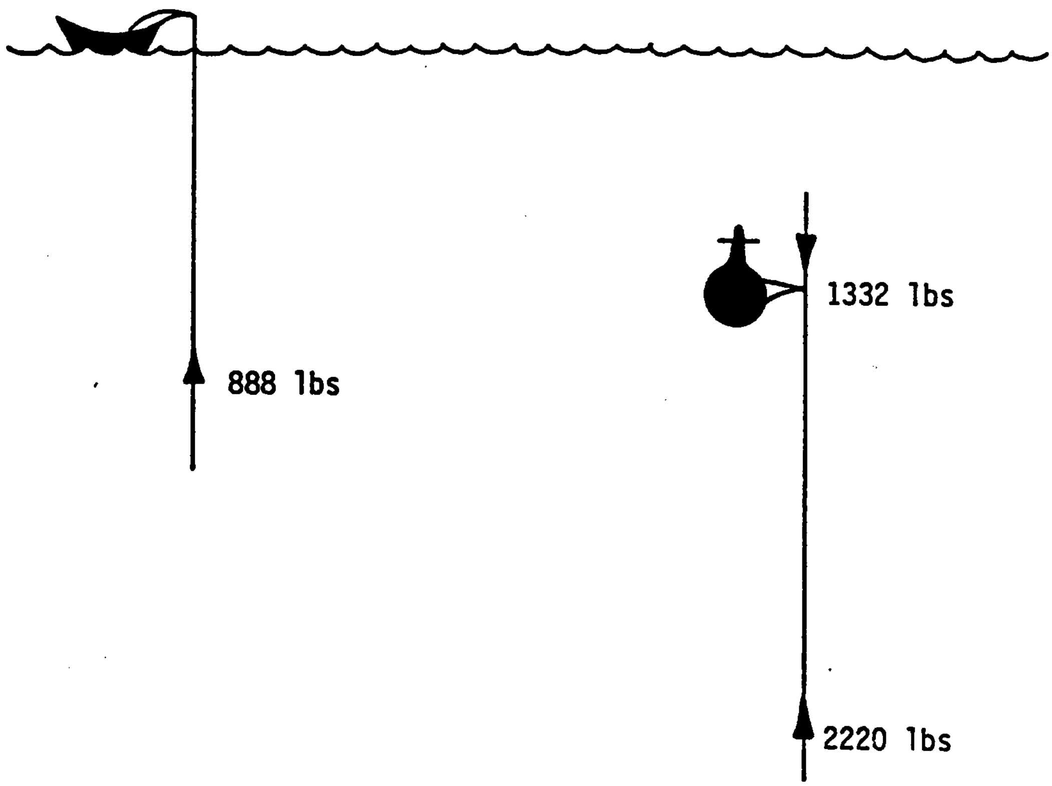


Fig. E-1--Hydrostatic forces on a cable.

In both cases, the reason the cable does not buckle in spite of the large axial hydrostatic compressive forces is because the axial compressive stresses are not greater than the hydrostatic pressure. In this special case they are exactly equal. If additional upward force is applied to the bottom of the cable, the cable, having no rigidity, will buckle. In this case the axial stress has exceeded the hydrostatic pressure, therefore buckling can occur.

This example is directly analogous to drill pipe hanging in a wellbore full of mud. If 10,000 ft of pipe is hung in a hole filled with 17 ppg mud, the lower end of the pipe will be subject to a compressive stress of .052 x 10,000 x 17 = 8,840 psi but the pipe will not buckle. Now, if the pipe is set down on the bottom of hole and weight is slacked off such that the axial stress at the bottom of the pipe exceeds the hydrostatic pressure, then buckling can occur.

II. Hydrostatic Pressure and Bouyancy

Consider a string of drill collars 1,000 ft long with net cross sectional area equal to 100 in.^{2} standing on the bottom of a 10,000 ft hole. Mud wt = 19.25 bbl/gal (1.0 psi/ft). Collars weight 250 lb/ft in air.

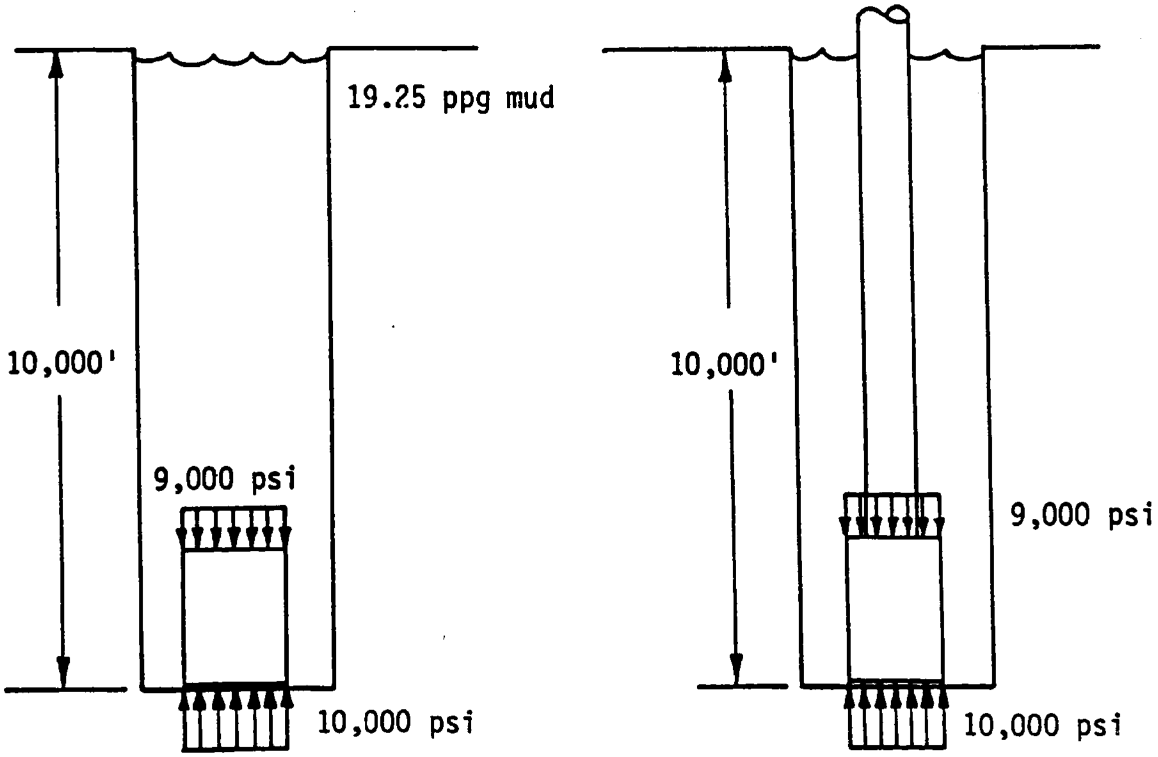


Fig. E-2--Hydrostatic forces on a drill string.

The total weight on the bottom of the hole is:

Air wt of collars	+	Pressure at top	-	Pressure at bottom	=	Bouyant wt
250,000	+	9,000 (100)	-	10,000 (100)	=	150,000

Now, if a string of drill pipe could be run into the hole and fused to the top of the collars, up to 9,000 psi compressive stress could be applied to the bottom of the drill pipe with no danger of buckling. Thus, the load on top of the collars would still be a uniform 9,000 psi and the weight on the bottom of the hole would still be 150,000 lbs. Thus the fact that the drill pipe covered up a portion of the top face of the collars which had previously been exposed to 9,000 psi is immaterial. This 9,000 psi can be restored by slacking off on the drill pipe with no danger of buckling.

If the collars are lowered into a 20,000 ft hole with the same mud weight, the forces will be as shown in Fig. E-3. The hydrostatic pressure at the top of the collars is 19,000 psi, therefore up to 19,000 psi compressive stress can be run on the bottom of the drill pipe without buckling. The total weight on the bit would be:

Air wt of collars	+	Pressure on top	-	Pressure on bottom	=	Bouyant wt of drill collars
250,000	+	19,000 (100)	-	20,000 (100)	=	150,000 lbs

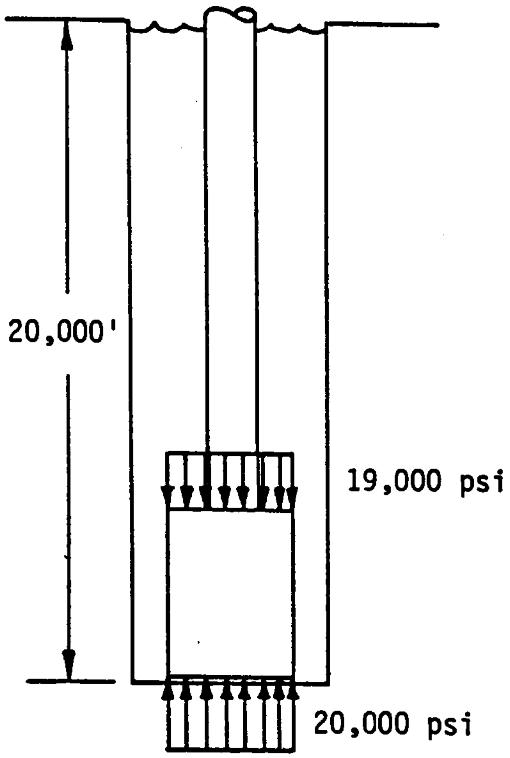


Fig. E-3--Hydrostatic forces on a drill string.

This is the same available weight as there was at 10,000 ft. This is also equal to the bouyant weight of the drill collars. Thus, the area on top of the collars covered by the drill pipe and the depth to which the collars are immersed is totally irrelevant to determining available weight on the bit. Only the bouyant weight of the drill collars needs to be considered. There would be no need to add additional collars to drill deeper unless either mud weight was increased or more weight on the bit is desired.

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