ANNUAL REPORT
OPERATING GRI'S MOBILE TESTING & CONTROL FACILITY

prepared for

Gas Research Institute
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Reservoir Evaluation

prepared by

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DISCLAIMER

RESEARCH SUMMARY

Title	Operating GRI's Mobile Testing and Control Facility
Contractor	S. A. Holditch & Associates, Inc. College Station, Texas GRI Contract No. 5083-211-0877
Principal Investigators	S. A. Holditch B. M. Robinson W. S. Whitehead
Objectives	The initial objectives are as follows: (1) To correlate core analyses, log analyses and well test analyses in an effort to increase the amount and quality of data from these sources, and to use these data directly in the design of hydraulic fracture treatments. (2) To apply and improve the use of real-time fracture treatment diagnostic tests and post-fracture well tests in the evaluation of the shape and extent of a hydraulic fracture. The ultimate objective will be to develop a system that can be used to accurately predict and, possibly, control the shape and extent of a hydraulic fracture.
Technical Perspective	The Gas Research Institute (GRI) has been conducting research directed at improving the recovery efficiency and reducing the cost of producing gas from tight reservoirs. The key to improving recovery efficiency is a better understanding of the hydraulic fracturing process. The operation of GRI's Mobile Testing and Control Facility will allow GRI to collect and analyze extremely comprehensive and accurate data. The complete characterization of a formation coupled with a detailed and accurate fracture treatment analysis should lead to a better understanding and thus, the optimization of fracture treatments in tight reservoirs. Optimum fracture treatment techniques would, in turn, substantially improve the supply of natural gas from tight gas reservoirs.

Technical Approach

To better understand the fracturing process, it is first necessary to improve our understanding of the reservoirs that are being fracture treated. GRI has contracted with several of the industry's most prominent organizations and individuals to perform geological, coring, logging, well testing, fracture treatment monitoring and fracture diagnostic studies on selected cooperative research wells in two targeted formations, the Travis Peak/Hosston formation in the East Texas Embayment/North Louisiana Salt Basin and the Corcoran and Cozzette sandstones of the Piceance Basin.

The success of this program hinges on the cooperation of operating companies. By working with GRI to allow GRI contractors to fully evaluate the reservoir prior to, during and after a fracture treatment, we feel that substantial progress will be realized within the first 2-3 years of this program and this progress can greatly improve the ability to develop tight gas.

The uniqueness of our technical approach is that we plan to put the scientists and engineers "in the field" with the necessary electronic equipment and computers so that they may analyze the fracture treatment data in real time. Once this system is perfected, we should also be capable of predicting fracture shape and extent. If we can successfully predict fracture shape, we will then attempt to control fracture growth by controlling the fracture fluid viscosity or the injection rate.

Results

The GRI Mobile Testing and Control (T&C) Facility was built by Dresser Petroleum Engineering Services in 1983 and was accepted by GRI in early 1984. The equipment that was accepted by GRI consisted of a Data Acquisition Trailer (DAT), a Main Computer Trailer (MCT) and a Production Test Unit (PTU). S. A. Holditch & Associates, Inc. was contracted to operate the Mobile T&C in October, 1983. From October through January of 1984, we were primarily involved with the final stages of equipment fabrication. Modifications were made to the well test separator and the software that was being written for the Mobile T&C unit.

The Main Computer Trailer was moved to Massachusetts in January, 1984, where Resources Engineering Systems (RES) starting adding additional hardware and began software development for the VAX 11-750 computer.

In February, 1984, the Production Test Unit and Data Acquisition Trailer were moved to the Knesek No. 1 well in Burleson County, Texas, to undergo its first field test. The test was performed satisfactorily and the Production Test Unit and most of the Data Acquisition Trailer systems performed as expected. Some problems were discovered with both the software and the wireline unit, and these problems were subsequently corrected.

After several modifications to the Data Acquisition Trailer and Production Test Unit, the equipment was moved to East Texas where work began on Travis Peak cooperative wells. For the remainder of the year, the Mobile T&C equipment was used on six wells in the East Texas/North Louisiana area. These wells were the following:

* Clayton W. Williams, Jr. Sam Hughes No. 1, Panola County, Texas
* ARCO Oil & Gas Hollingsworth No. 3, DeSoto Parish, Louisiana
* ARCO Oil & Gas G. Oliver No. 1, Smith County, Texas
* ARCO Oil & Gas B. F. Phillips No. 1, Smith County, Texas
* American Petrofina Bright No. 1, Smith County, Texas
* Ashland Exploration S.F.O.T. No. 1, Nacogdoches County, Texas

Of the above wells, the ARCO Phillips No. 1 is the only well which had a complete cooperative research effort (logs, cores, injection tests, and post-fracture well tests) completed during 1984. The results from this well are extremely encouraging. When the analyses from all of GRI's various research contractors were combined to provide a complete reservoir and fracture characterization, the production and pressure performance forecast by our three dimensional, finite difference reservoir simulator matched the actual well performance extremely well. We believe that the actual reservoir and fracture properties have been correctly modeled and that the efforts expended to obtain these data will continue to provide us with accurate formation and fracture evaluations on future cooperative wells.

The first year of the GRI Mobile Testing and Control Facility operations has been successful. The Mobile T&C was placed in the field and used to gather a substantial amount of data from pre-fracture flow tests, in-situ stress tests, mini-frac tests, fracture treatments, post-fracture flow tests and pressure buildup tests. In addition, cores have been cut on three of these wells and complete logging suites have been run on four of the wells. Even though the analysis of these data has just begun, we have already witnessed improvements in our evaluation of the Travis Peak formation. Further analysis of these data will continue to provide valuable information for correlations and reservoir descriptions. The field project has met with widespread acceptance by the various operators in the East Texas/North Louisiana area. Based upon the success during 1984 and our conversations with operators who plan to continue developing the Travis Peak/Hosston tight gas area during 1985, we expect the upcoming year to be highly successful for the team of contractors involved in the Mobile Testing and Control Facilities Project.

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1.0 INTRODUCTION

For several years, the Gas Research Institute (GRI) has sponsored research directed at improving the efficiency and reducing the cost of producing gas from tight reservoirs. GRI recognizes that an enormous volume of gas is contained in low permeability reservoirs, and neither current technology nor economic incentives are adequate to allow development of much of these gas reserves.

If the petroleum industry can substantially improve its ability to control fracture growth, chances of achieving the designed propped fracture length are increased, thereby improving the economic incentive for developing tight gas reservoirs. However, to better understand the hydraulic fracturing process, it is first necessary to improve our understanding of both the reservoirs that are being fracture treated and the rock layers surrounding the main productive interval. To reach this goal, GRI is sponsoring a comprehensive effort to perform geological, coring, logging, well testing, fracture treatment monitoring and fracture diagnostic studies on selected cooperative research wells.

In order to provide continuity to the research effort, the GRI program will focus on the Travis Peak/Hosston formation in East Texas and North Louisiana and the Corcoran and Cozzette formations in the Piceance Basin. However, due to the decrease in drilling activity in the Piceance Basin, the current emphasis has been in the Travis Peak/Hosston formation. Hopefully, with an increase in drilling activity, several Corcoran and Cozzette wells can be studied during 1985 and 1986.

The success of the research effort hinges on the cooperation of operating companies. To perform the coring, logging, well testing and fracture monitoring operations, GRI must form a cooperative partnership with an operating company. Since several contractors are involved in the program, GRI has specified S. A. Holditch & Associates, Inc. as the lead contact between the operating company and GRI. S. A. Holditch & Associates, Inc. has the authority to enter into the agreements with an operating company and to coordinate the activities of all GRI contractors during field operations.

S. A. Holditch & Associates, Inc. has also been contracted by GRI to manage the Mobile T&C Facility. Dresser Petroleum Engineering Services has been subcontracted to provide field personnel to operate and maintain the equipment. The Mobile T&C Facility has been built specifically to analyze data from production tests, bottomhole pressure buildup tests, <u>in-situ</u> stress tests and hydraulic fracture treatments.

Data gathered and analyzed with the Mobile T&C Facility, along with detailed geologic studies and extensive coring and logging analyses, will provide the GRI team of contractors with comprehensive and accurate formation evaluations. With accurate input data for three-dimensional fracture design models, it should be possible to learn what is actually occurring during a hydraulic fracture treatment. If we can use this knowledge to successfully calculate and predict the fracture shape and extent, then the economic incentive for developing tight gas reservoirs can be substantially improved.

During 1984, cooperative research was performed on five different wells in East Texas and Northwest Louisiana. These wells were all completed in the Travis Peak/Hosston. A sixth well, which was completed in the Cotton Valley, was used to help evaluate the communications between the Data Acquisition Trailer and the Main Computer Trailer, and to evaluate fracture analysis software and graphics developed by Resources Engineering Systems (RES). However, this well was not a true cooperative well. Data from available logs, cores, well tests and fracture treatments were also studied on numerous other wells which offset the cooperative wells. In addition, specific components of the Mobile T&C Facility were tested during actual field operations on three separate occasions.

In summary, 1984 was an extremely productive and busy year. It was a year of equipment modification and mobilization to the field, as well as data collection. In 1985 and 1986, we plan to start assimilating and analyzing these data, along with additional data which are gathered, in an effort to achieve our research goals.

This report presents a summary of the work performed during 1984 and the results and conclusions obtained thus far from analyses of data collected using the Mobile T&C Facility. In addition, future plans for cooperative research on wells in both the Travis Peak/Hosston and the Corcoran and Cozzette formations are discussed. Brief discussions of geological, coring and logging studies are also presented since they are vital to the success of the project. However, because these studies are entire projects by themselves, we have not attempted to present their data or results. Instead, we refer the reader to specific reports distributed by GRI, which cover these individual subjects.

2.0 DESCRIPTION OF EQUIPMENT AND CAPABILITIES

Electronic and computerized data acquisition and analysis systems are being used in the field to gather, monitor and analyze data from production tests, stress tests and hydraulic fracture treatments. These systems are incorporated into GRI's Mobile T&C Facility. The T&C Facility consists of three main components: Production Test Unit, Data Acquisition Trailer and Main Computer Trailer.

2.1 Production Test Unit

The Production Test Unit consists of a three-phase horizontal separator, gas line heater, and gas, oil and water turbine flow meters, all of which are rated to a working pressure of 1440 psi. All flow rate, pressure and temperature signals are monitored through electronic transducers. In the event of a power or gas turbine meter failure, a standard orifice meter with recorder has been installed for back-up gas flow measurements. In addition, battery powered totalizers are available to back up the liquid flow meters.

An automatic adjustable choke with safety shut-down has been installed on the Production Test Unit. Flow can be set and controlled at a constant rate through the use of a Bailey controller connected to the automatic choke. Similarly, flow can be set against a constant wellhead pressure with the Bailey controller or against a constant surface back-pressure controlled by the separator. Flow rates as small as 5 Mscf/d or as large as 4000 Mscf/d can be measured accurately.

2.2 Data Acquisition Trailer

The Data Acquisition Trailer (DAT) collects and stores all data monitored in the field. During a well test, these data will include bottomhole pressure and temperature, pressure and temperature at the lubricator and the separator, and the gas, oil and water flow rates through the separator. During a fracture stimulation treatment or an injection test, the total injection rate, downhole pressure, surface injection pressure, fluid density, fluid viscosity, pH, and temperature can all be measured and recorded. As the field operations project matures, the DAT system will be expanded to measure additional parameters as needed. Schematic drawings illustrating the current measurement capabilities during a well test and fracture treatment are shown in Figures 1 and 2, respectively.

Two Hewlett-Packard 9836 computers are housed in the DAT. One of the computers is used to record and store data measured from both the downhole and the surface monitoring devices. The second computer is used to analyze pressure drawdown and buildup tests, in-situ stress tests, and fracture treatments.

The Data Acquisition Trailer has an electric wireline unit on which a Hewlett-Packard quartz pressure gauge, temperature probe and casing collar locator can be run. A mast truck and pressure control equipment are available to perform all logging or bottomhole pressure surveys. Surface data from a fracture treatment are being measured using two fracture monitoring skids--one on the suction side of the blender and the other on the discharge side between the blender and the high pressure pumps. Instruments on these skids include an in-line Brookfield viscometer, pH and temperature probes, liquid turbine meters and a radioactive densiometer. Several liquid additives (such as crosslinker or diesel) can also be measured in addition to the surface tubing and casing pressures.

All of the data measured during a well test or fracture treatment are presented visually in the DAT either on a computer screen or on an overhead L.E.D. display, and the data are printed out periodically during the operation. Processed or raw data is also transferred to the Main Computer Trailer during a fracture treatment for the real time fracture geometry analysis.

2.3 Main Computer Trailer

The Main Computer Trailer (MCT) houses a VAX 11-750 computer and other associated hardware necessary to perform on-site, real time analysis of a hydraulic fracture treatment. The fracture diagnostic and control software is currently being developed by Resources Engineering Systems. The Main Computer Trailer software system consists of three major parts: (1) central diagnostics and control; (2) a deterministic real-time simulation model; and (3) a statistical experiential diagnostic/response model. The ultimate goal of the system will be to calculate the three-dimensional shape of a hydraulic fracture from data gathered during a fracture treatment. Changes in the treatment schedule can be made to (1) minimize the chances of a screenout, (2) minimize fracture height growth, or (3) optimize net present value from a treatment.

The Main Computer Trailer will be an interactive real-time system which will receive data during the fracture treatment, analyze the fracture geometry and make recommendations to the operator. The main interface with the operator will be through an interactive color graphics system. This graphics system will illustrate the current and predicted fracture geometry, as well as display all treatment variables.

3.0 SUMMARY OF 1984 WORK AND 1985 PLANS

There is no doubt that 1984 has been an active and eventful year for the GRI field operations research effort. The Mobile T&C Facility was placed in the field and, after several sequences of modification, it is fully capable of measuring, recording and analyzing data from well tests, stress tests and fracture treatments. In addition, the amount of data gathered on cooperative wells with the Mobile T&C equipment, combined with geological, coring and logging studies, has met and, perhaps, exceeded the expectations and goals that were set at the beginning of the project. Virtually all operating companies contacted during 1984 were openly receptive and genuinely interested in the GRI research program. Many of these companies generously supplied us with data. We consider the cooperative attitude of the operating companies as a tremendous asset to the field research program.

In this section, we will summarize the work which has been performed during 1984 using the Mobile T&C Facility. We also have summarized the combined research efforts of all contractors involved in the project, with respect to data obtained on cooperative wells and other wells near the cooperative wells. Finally, we will present our goals for 1985.

3.1 1984 Field Operations

During the latter part of 1983 and first quarter of 1984, S. A. Holditch & Associates, Inc. was involved primarily in the final construction and testing of the Mobile T&C Facility. These tasks included providing recommendations or modifications to the electronic equipment, mechanical equipment and computer software necessary for complete data collection and analysis in the field.

To insure the Mobile T&C Facilities were operating properly prior to acceptance by GRI in January of 1984, we organized and supervised final testing of all the equipment under controlled conditions at the Dresser Industries complex in Houston. After acceptance by GRI, a field test of the Mobile T&C Facility (without the Main Computer Trailer) was performed during February, 1984, on a gas well in Burleson County, Texas. The Mobile T&C Facility was used to measure the gas flow rate, and the lubricator wireline unit and pressure/temperature tools were used for the first time. The field test was a success. Training received by the DPES personnel was invaluable, and several problems were discovered with the electric wireline. These problems were corrected prior to moving the equipment to our first cooperative well in East Texas.

In addition to assisting with the final construction and testing of the Mobile T&C Facility, we also solicited ideas and recommendations from the major fracturing service companies for equipment necessary to monitor hydraulic fracture treatments. We reviewed recommendations from several service companies and selected a Nowsco Services design which incorporated all the monitoring devices on two portable, skid mounted units. One unit was for the suction side of a blender and one for the discharge side of the blender. The monitoring devices included an in-line Brookfield viscometer, pH and temperature probes, 8 and 4 inch turbine meters, and a radioactive densiometer. In addition, several pressure transducers were included to monitor tubing and casing pressures during the treatment. These skid units were completed and testing during the second quarter of 1984.

During April and May, work was performed on the first Travis Peak cooperative well, the Clayton W. Williams, Jr., Sam Hughes No. 1 in Panola County, Texas. After negotiating a contract with the operator, the team of contractors worked with Clayton W. Williams, Jr. to core the Travis Peak, run a full suite of open hole logs and conduct a series of pre-fracture well tests. Because the well encountered a high permeability sandstone reservoir, the completion interval in the Travis Peak formation was not fracture stimulated. Thus, we did not have the opportunity to monitor a fracture treatment or perform post-fracture well testing on the Sam Hughes No. 1 well. However, the pre-fracture well tests did give us a chance to use the Mobile T&C Facility for the first time on a Travis Peak well.

After work was completed on the Sam Hughes No. 1, the Mobile T&C Facility was moved to the ARCO Oil & Gas Hollingsworth No. 3 in DeSoto Parish, Louisiana. The Hollingsworth No. 3 well had been drilled and completed in the Hosston formation prior to GRI's involvement with ARCO; therefore, no cores or special logs were available for analysis. However, we were able to conduct several pre-fracture and post-fracture well tests with the Mobile T&C. Because the GRI skids had not been completed at the time the Hollingsworth well was fracture treated, a Dowell Treatment Monitoring Vehicle was used to record the fracture treatment data. The well did not produce gas at sustained, measurable flow rates prior to the fracture treatment. Also, after the fracture treatment, the well only produced water; consequently, no useful reservoir data were obtained from the Hollingsworth well. Even though the Hosston formation in the Hollingworth No. 3 was not productive, it did provide GRI with data to allow us to better understand and recognize non-productive intervals using core and log data.

Following the DeSoto Parish well, the Data Acquisition Trailer was moved to Mounds, Oklahoma and used to monitor a series of <u>in-situ</u> stress tests on a joint GRI/Amoco/Dowell research well. The Hewlett-Packard quartz pressure gauges and downhole shut-off tools were used during this operation.

During August and September, work was performed on our first full cooperative well, the ARCO Oil & Gas B. F. Phillips No. 1, in the Chapel Hill Field of Smith County, Texas. The various GRI contractors worked with ARCO to core the Upper Travis Peak, run a complete suite of open hole logs and conduct a series of pre-fracture stress and injection tests. The fracture treatment was monitored using the Mobile T&C Facility and, after the fracture treatment, a production and pressure buildup test were also monitored.

In addition to the Phillips No. 1, data from two other ARCO wells in Chapel Hill Field, the Oliver No. 1 and the Brown No. 1, were incorporated into our research effort. Additional open hole logs were run by GRI in the Oliver No. 1, and the fracture treatment of the Oliver No. 1 was monitored with the Mobile T&C Facility. Data from this treatment and the treatment of the Brown No. 1 (which was performed prior to GRI involvement) were analyzed in an effort to better understand the reservoir behavior in the Chapel Hill Field. Based upon our analyses of the previous treatments, we designed a fracture treatment for the Phillips No. 1 well. ARCO followed our recommendations and the B. F. Phillips No. 1 turned out to be one of the better wells in the Chapel Hill Field.

During October, 1984, the Main Computer Trailer (MCT) was moved from Massachusetts to Tyler, Texas and linked up with the Data Acquisition Trailer (DAT). The communications were successfully developed and tested between the two computer tailers. Once this was accomplished, a well was chosen to test the entire system. In cooperation with American Petrofina, a massive hydraulic fracture treatment in a Cotton Valley well was monitored with the complete Mobile T&C Facility during November. The data acquisition equipment worked properly and the fracture geometry was estimated in the Main Computer Trailer as the treatment was being pumped. Even though the system is still in the development stages, the first test of the complete Mobile T&C Facility was successful.

In December, 1984, the Mobile T&C Facility was moved to the Ashland Exploration S.F.O.T. No. 1 in Nacogdoches County, Texas. This well had been drilled, cored, and logged, and <u>in-situ</u> stress tests were run in order to improve our pre-fracture formation evaluation. We will also be monitoring and analyzing the fracture treatment and performing a post-fracture treatment evaluation. The Ashland well will be the first well in which 100% of the planned research program will be performed on a single well.

3.2 1984 Database Additions

From May through December, 1984, the Mobile Testing and Control Facility was used on six wells in the East Texas/North Louisiana area. Five wells were considered "cooperative" wells and were completed in the Travis Peak/Hosston formation. A sixth well, which was the American Petrofina Bright No. 1 well, was completed in the Cotton Valley Taylor sand. A large volume of data were measured, recorded and analyzed during the last seven months of 1984.

The additions made to our database during 1984 are summarized in Tables 1 - 6. These tables do not include any specific values or analyses of the data; they simply list the well and the type of data that were measured and recorded in our cooperative field project.

Table 1 presents the information concerning the core that was cut on three cooperative wells. These wells were the:

(1) Clayton W. Williams, Jr. Sam Hughes Well No. 1

(2) ARCO Oil & Gas B. F. Phillips Well No. 1

(3) Ashland Exploration S.F.O.T. Well No. 1

A total of thirteen cores were cut in the GRI field project, and a total of 370.7 feet of core were recovered.

There were three intervals cored in the Clayton Williams well. In these three cores the total recovery was 84.1 feet. Core No. 1 included a high permeability Travis Peak "A" sandstone, while Core No. 3 included a clean sand interval that was determined to be low permeability and gas bearing.

The second cored interval contained mostly siltstone and silty sands. The ARCO Oil & Gas Phillips well had four cored intervals. Unfortunately, the first core was completely lost due to a pinched core bit that allowed all of the core to fall out of the barrel during the trip to recover the core. However, 106 feet of core was recovered from Cores No. 2, 3 and 4. Included in the core that was recovered were some clean, productive sandstones and a portion of a thick shale.

The third well that was cored was the Ashland Exploration S.F.O.T. No. 1. Six trips were made with the core barrel on the S.F.O.T. well and 180.6 feet of core were recovered. The first two cores recovered mostly siltstone and mudstone. The third core included several clean, productive sands and the fourth core had virtually no recovery, as the core barrel jammed during the first three to four feet into the coring operations. The last two cores recovered Travis Peak zones that resemble laminated sandstone and mudstone intervals.

Table 2 presents the number of core analyses that have been run on the core recovered from the Travis Peak/Hosston formation. In the Clayton Williams well, routine core analyses were run on 44 plugs and special core analyses were run on twelve plugs. In the ARCO Phillips No. 1 well, 104 core plugs were used in the routine test analysis while special core analyses were run on eighteen cores. The core analysis for the Ashland S.F.O.T. No. 1 well has just begun and the results of these analyses will be reported in 1985.

Four Travis Peak/Hosston wells were included in the GRI cooperative well logging program during 1984. The four wells were the Clayton Williams, Jr. Sam Hughes No. 1, the ARCO Oil & Gas Oliver No. 1 and Phillips No. 1 wells, and the Ashland S.F.O.T No. 1. Table 3 presents a list of the logs that were run on each of those four wells. In addition to the four cooperative wells, the GRI logging contractors also received information on several wells which offset these four cooperative wells. The data from these offset wells were also added to the GRI Travis Peak data base.

One of the most important functions of the Mobile T&C Facility is to determine the in-situ stress distribution of the various layers which comprise the Travis Peak/Hosston formation. Although the stress distribution can be determined using log data and core data, these methods provide only information concerning the elastic components of the in-situ stresses. To determine the true <u>in-situ</u> stress in a particular rock layer, one must inject fluid into that layer and measure the stresses directly. Table 4 presents a summary of the pre-fracture injection tests that were run on the cooperative wells during 1984. As illustrated in Table 4, stress tests were performed on sandstone intervals in the ARCO Hollingsworth No. 3 well and the ARCO B. F. Phillips No. 1 well. Due to various problems, stress tests were not run in the higher stress regions.

In the Ashland S.F.O.T. No. 1 well over 1000 feet of Travis Peak formation was drilled and the completion interval is in the upper portion of the formation. Therefore, it was possible to test a siltstone member at 10,160 feet and a shale member at 9,905 feet. Both of these zones were well below the completion interval and were isolated with a bridge plug after the stress tests were performed.

Table 5 presents the well test data that were added to the 1984 GRI Travis Peak data base. As illustrated in Table 5, pre-fracture tests were run on the ARCO Oil & Gas Hollingsworth No. 3 well, the Clayton Williams Sam Hughes No. 1 well, and the Ashland Exploration S.F.O.T. No. 1 well. Post-fracture tests were run on the Hollingsworth No. 3, the ARCO Oil & Gas Oliver No. 1 well and the ARCO B. F. Phillips No. 1. In all of these tests, the GRI Data Acquisition Trailer, Production Test Unit and associated wireline equipment were used to measure, record and analyze the data.

Table 6 presents the fracture treatment data that were measured during 1984. The fracture treatment data on the ARCO Oil & Gas Hollingsworth No. 3 were recorded using a Dowell Treatment Monitoring Vehicle. This fracture treatment was performed prior to receiving the skids containing the fracture monitoring hardware. The ARCO Oliver No. 1 and B. F. Phillips No. 1 were monitored with the fracture monitoring skids and the DAT. As illustrated in Table 6, there were some problems in recording all of the data on the ARCO wells due to various electrical and mechanical problems with the data acquisition systems. However, by the time the American Petrofina Bright No. 1 well was stimulated, most of the problems had been identified and solved and virtually all of the important data were monitored, recorded and analyzed during the treatment.

Tables 1 - 6 present the data that were measured during 1984 and were included in the GRI Travis Peak data base. Detailed information concerning the coring and logging operations have been published in GRI reports by CER[1,2,3] Corporation. Detailed information concerning the core analyses are included in reports by PSI[4,5] and BEG.[6,7,8] The detailed log evaluations are covered in reports by ResTech.[9,10] S. A. Holditch & Associates, Inc. has issued and will continue to issue cooperative well reports[11,12,13] on each well that is being analyzed in this project. In the cooperative well reports, we include summaries of the core analysis and log analysis results, as well as information concerning the pre-fracture injection tests, the well test data and the fracture treatment data that have been measured and analyzed on each of these wells.

3.3 Plans for 1985

After the successful start of the Field Operations and Analysis Program in 1984, we feel that substantial progress can be made in 1985. Several key areas will be targeted for future development. These areas are: (1) additional cooperative wells; (2) improvements in the Mobile T&C Facility; and (3) improvements in data analysis and correlations. This section will outline our plans in these areas for 1985.

3.3.1 Cooperative Wells

In the first few months of 1985, we will continue our work on the Ashland Exploration S.F.O.T. Well No. 1 in Nacogdoches County, Texas. In December, 1984, we performed three stress tests, a pre-fracture production test, and a pressure buildup test. As soon as a pipeline is laid to the well, we will pump a mini-frac, fracture treat the well, and perform the post-fracture well tests. The S.F.O.T. No. 1 will be the first well in the Tight Gas Sands program which will be fracture treated down an open ended tubing string. Thus, by monitoring the surface annular pressures, we can calculate bottomhole pressures without the inaccuracies involved in accounting for friction pressures due to injection. This data should help us determine the fracture geometry with more confidence.

After completion of our work on the S.F.O.T. No. 1 (which we hope will be in early April), we plan to move the Mobile T&C Facility to another East Texas Travis Peak cooperative well. This well could be spudded in early February, cored and logged during March, and completed and tested during April, May, and June.

Original plans for the Tight Gas Sands Research Program were to study the Travis Peak formation in East Texas and the Corcoran and Cozzette formations in the Piceance Basin in Colorado. Due to the activity levels of each area, we have concentrated our efforts in East Texas. However, we hope to begin gathering data from the Corcoran and Cozzette formations in the summer of 1985. We will begin contacting operators who are active in the Piceance Basin to discuss our field operations program. If a cooperative well can be scheduled which will spud in May, it should be ready for completion and testing in late June. We will move the Mobile T&C to Colorado after testing the 1985 Travis Peak well and perform a complete testing program on the Corcoran/Cozzette well. If possible, we will try to schedule a second Corcoran/Cozzette well to test after completing the testing of the first well.

After testing two wells in the Piceance Basin, which would probably continue until late September or early October, we would then move back to East Texas. A second 1985 Travis Peak well, if spudded in late August or early September, could be ready for testing in October. Testing would then continue through November and December and would complete the 1985 Field Operations and Analysis Program.

3.3.2 Improvements in the Mobile T&C Facility

We have steadily improved our data collection capabilities of the Mobile T&C Facility in 1984 and plan to continue improving our system in 1985. Data gathering, data processing, and data analysis are areas in which we should be able to increase our capabilities. Direct measurements of such items as fracturing fluid volumes and proppant weights will also be studied and possibly added to the Mobile T&C's abilities. Other improvements planned for 1985 include real time display and real time analysis of data which are measured, recorded, or calculated in the Data Acquisition Trailer. A portable testing unit is also planned so that we can circulate fluids through the fracture monitoring units. This will allow us to calibrate or test our equipment at any time. Thus, we can be assured of recording accurate data.

3.3.3 Improvements in the Data Analysis And Data Correlations

One of the most important goals for 1985 is to begin understanding how core data and log data correlate. We plan to work closely with the other Tight Gas contractors, such as ResTech, Bureau of Economic Geology, and Petrophysical Services, to develop correlations from the abundance of data which we have collected. If more accurate correlations can be developed for parameters such as cementation factor, saturation exponent, and shale volume, we can help the industry to better evaluate and develop tight gas reservoirs such as the Travis Peak formation or the Corcoran and Cozzette formations. Also of importance will be correlations between the fracture treatment analysis and the post-fracture well performance. These should help us determine the fracture geometry and could prove invaluable to our goal of calculating fracture shape in real time.

4.0 FORMATION EVALUATIONS

To calculate the shape and extent of a hydraulic fracture, the formation being stimulated must be extensively evaluated. All formations consist of various layers of rock. The Travis Peak formation consists of layers of shale, mudstones, siltstones, silty sandstones and sandstones. The thicknesses and areal extent of these rock layers can vary considerably both within the vertical section and laterally, making the Travis Peak formation extremely complex. Perhaps the discussion presented in Section 3.1, which summarizes earlier reports by the Bureau of Economic Geology (BEG), best illustrates this complexity. The section describes their work regarding the diagenesis and depositional systems of the Travis Peak.

If we are ever to learn how to compute and predict fracture shape and extent, we will also have to improve our ability to quantify the mechanical properties and stress distribution in the various layers of formation rock we encounter. Accurate input data for fracture design models will maximize the chances of successfully calculating fracture dimensions. Therefore, much of the GRI Tight Gas Sands program is targeted towards quantifying these mechanical and stress properties.

The input data for the formation evaluations has come from geologic studies, cores, logs, injection tests and pressure transient tests. The Bureau of Economic Geology (BEG) is providing GRI with both regional and site-specific geologic interpretations concerning the diagenesis and depositional histories of the subject formations. CER Corporation is supervising the coring operations in the field and assuring that high quality open hole logs are acquired. We plan to obtain between 100 and 250 feet of core on every cooperative well. The core will be slabbed and photographed, and the slab will be sent to BEG for detailed analyses. The main portion of the core is shipped to Petrophysical Services, Inc. (PSI) for both the routine and the special core analyses.

ResTech, Inc. has contracted with GRI to supervise the logging operations and to perform detailed analyses of the well logs. ResTech uses sophisticated techniques to analyze the logging data and is very knowledgable concerning (1) the operation of the logging tools, (2) possible calibration problems and (3) the methods required to edit out inferior data.

It is the responsibility of S. A. Holditch & Associates, Inc. to help integrate the ideas, data and knowledge of BEG, PSI and ResTech with the data measured during stress tests and pressure transient tests into a concise, accurate formation evaluation. It would be impossible to present the results from all of these studies in a single document. Thus, we refer the reader to individual topical or well reports for more specific details. However, in the following section we present a summary of the formation evaluations for each well studied in 1984 based on our current assessment of the data analysis.

4.1 Geological Descriptions

The cores and logs gathered in the Travis Peak/Hosston formation of East Texas and North Louisiana have been used to study the geologic environments present in the Travis Peak. This work was performed by the Bureau of Economic Geology and has been reported previously.[6,7,8,14,15] We have incorporated much of their work into our analyses of the cooperative wells. This section is intended to give a brief summary of the geologic environments near the cooperative wells.

4.1.1 Reservoir Diagenesis

The Travis Peak cores from the Sam Hughes No. 1 and the B. F. Phillips No. 1 have been described and analyzed for mineralogic composition.[6,7] The cores consist of intervals of fine to very fine grained sandstone, siltstone, and mudstone. Some limestone was found in the Phillips cores. Figure 3 is a descriptive log of the cored intervals in the Hughes well. The sandstone units primarily have fining-upward sequences; however, a sandstone at 8196 feet in the Phillips No. 1 has an upwards-coarsening sequence at the base. Calcareous nodules, wood fragments, and pyrite are found in the mudstones and siltstones from both wells. The calcareous nodules are calcite and ankerite.

Dead oil, or reservoir bitumen, was noted in several of the sandstone and siltstone intervals. In some cases these intervals had fluorescence; however, other intervals that lacked dead oil also had bright fluorescence. This bright fluorescence may be caused by carbonate cement and not the dead oil. A dull fluorescence that diminished over time was observed in the upper core from the Hughes No. 1. This is the zone that was completed, so it is likely that the weak fluorescence was caused by hydrocarbons that gradually volatilized out of the core.

Authigenic cements constitute a significant amount of the sandstone volume in cores from both wells. Quartz overgrowths, ankerite, and chlorite or illite are the most abundant authigenic minerals, with up to 34% of the sandstone volume consisting of quartz cement. The chlorite and illite cements (which average by volume about 5%) occur as rims of tangentially oriented crystals around detrital grains and as pore-lining cement. Ankerite cement (which averages approximately 1-2% by volume) fills pore space and may replace framework grains. Other authigenic minerals are feldspar, pyrite, barite, and anhydrite. Each mineral averages less than 1% by volume.

Primary porosity has been decreased by the presence of the dead oil, which is a solid organic matter. Secondary pores do not contain the dead oil. This solid organic matter probably migrated as liquid oil and matured to form bitumen. Average porosities range from 0 to 22% as measured by thin section. Pre-cement porosity averages 35% in the clean sandstones, which suggests that 10% porosity may have been lost by early burial compaction before cementation began.[14]

4.1.2 Depositional Systems

Based on the studies of the cores and logs which were available on a regional basis, a major delta complex in the Travis Peak was defined.[14] Six lithofacies have been recognized, including a sand-rich fluvial-deltaic facies, silt-rich delta-front facies, clay-rich shelf facies, carbonate-rich shelf facies, carbonate reef facies, and clay-rich open marine facies. The best developed of these facies are the fluvial-deltaic and delta-front facies. The fluvial-deltaic facies is best developed over the Sabine and Monroe Uplifts, whereas the delta-front facies is best developed at the downdip margins of the large lower Travis Peak delta system. Most of the fine sand accumulated in shallow water and was reworked into extensive, but thin, offshore bars and lenticular sheet sands. These areas are the most favorable for hydrocarbon accumulation.

Preliminary interpretations of depositional history in the Pinehill, S.E. Field have been made based on the features seen in the cores from the Clayton Williams, Jr. Sam Hughes Well No. 1.[6] The lower core is interpreted as having been deposited in a lower alluvial valley in a coastal plain setting. It contains red mudstones with caliche nodules, which apparently formed in flood plain soils in a semiarid environment. Pyrite and woody organic matter are abundant in burrowed gray mudstones, which can be interpreted to be poorly drained swamp deposits. Thicker sandstones are interpreted as fluvial channel deposits, whereas thinner sandstone beds may represent natural-levee and crevasse-splay deposits.

The upper core, which occurs only a few feet below the Sligo carbonate, contains calcareous nodules, pyrite, and, below 6845 feet, organics within mudstones. This core probably represents the transition to a marine environment. Ripple trough cross beds are dominant in the uppermost sandstones and siltstones. Long, vertical burrows in mudstones at 6838 feet suggest a marine setting, perhaps associated with a tidal flat or estuarine environment. Rippled sandstones and siltstones at the top of the core may have been deposited on an intertidal sand flat.

Preliminary interpretations have also been made of the depositional environment of the Travis Peak near the ARCO Oil & Gas B. F. Phillips Well No. 1.[7] These interpretations were based on the cores obtained in this well and log correlations of nearby wells. The core interval is interpreted to represent marginal marine deposits, except for the interval below 8390 feet. Below this depth, red mudstones occur which probably indicate nonmarine deposition or a lower delta plain environment. The sandstones appear to represent very shallow, marine deposition, possibly including estuarine environments, tidal flats, and distributary channels. Marine incursion over the central Chapel Hill Field is indicated by the widespread occurrence of limestone in the lower sections of the Travis Peak. Such occurrence is expected in a delta fringe-tidal flat-shallow bay environment which has been postulated for the uppermost Travis Peak.

4.2 Individual Well Summaries

After gathering and recording results from pre-fracture core, log and well test analyses for a specific well, we evaluate the results to arrive at a reservoir description which is felt to best represent the actual well conditions. In general, the reservoir description includes properties such as initial reservoir pressure, net gas pay, total porosity, water saturation, in-situ permeability to gas, and in-situ stresses and mechanical properties of the various layers or rock. It is from this reservoir description that a stimulation treatment is designed and analyzed and a post-fracture performance analysis is performed.

The following sections summarize the reservoir properties which have been estimated for each well studied during 1984. Also presented is a discussion of the fracture treatment diagnostic results and post-fracture performance analysis, where applicable. It should be mentioned that some of the analyses have not been completed; however, when appropriate, the best estimate of a particular formation property is provided.

4.2.1 Clayton W. Williams Jr. Sam Hughes No. 1

The Sam Hughes No. 1 was cored, logged and tested in the upper portion of the Travis Peak formation. Three separate sands were cored and the well was completed in the uppermost cored interval, the Travis Peak "A" reservoir. A full suite of logs was run across the Travis Peak, and ResTech generated both a FRACLOG and a CORELOG for the well. The following information best describe the three cored sandstones.

Zone	Sand 1	Sand 2	Sand 3
Interval, ft	6838-6842	7045-7070	7089-7108
Net Pay, ft	5.5	4.0	9.5
Average Porosity, %	10.5	7.5	9.7

Average Water Saturation, %	35.4	60.0	41.7
In-Situ Permeability, md	4.15*	0.003**	0.016**
In-Situ Stress Gradient, psi/ft	0.70	0.65	0.69
Initial Reservoir Pressure, psi	3415	3525	3550

*From pressure buildup test.

**Logarithmic average from stressed cores.

The Sam Hughes No. 1 well was completed in the Travis Peak "A" sand from 6838-6842 ft. Based upon the above results, the only stimulation this well will require is a small acid treatment to remove slight damage (skin factor = +6.0) around the borehole. After the skin is removed, the zone could initially produce gas at flow rates of up to 2000 Mscf/day. However, there appears to be a boundary in the Travis Peak "A" reservoir about 200 feet from the Sam Hughes No. 1 well. Assuming this boundary is a sand pinchout, it is difficult to determine an effective drainage area for the well. If the sandstone remains thin (i.e., 4 feet or less) away from the wellbore, the projected rate of 2000 Mscf/day will decline rapidly. However, if the interval increases in thickness, the rate could be sustained longer.

Because it was not necessary to fracture stimulate the Travis Peak "A" sand, no fracture treatment analysis or postfracture performance evaluation is possible.

4.2.2 ARCO Oil & Gas Hollingsworth No. 3

4.2.2.1 Pre-Fracture Analysis

Even though GRI did not become involved with the ARCO Hollingsworth Well No. 3 until after it had been drilled and cased, we did manage to perform a reasonable formation evaluation prior to the fracture treatment. Using data from the logs, the <u>in-situ</u> stress tests and the pressure buildup tests, the following properties were estimated.

Perforated Interval, ft	8713-24, 8750-58
Net Pay, ft	22
Average Porosity, %	7
Average Water Saturation, %	35-40
<u>In-Situ</u> Formation Permeability, md	< 0.001
<u>In-Situ</u> Stress Gradient, psi/ft	0.7 - 0.73
Initial Reservoir Pressure, psia	4300
Fluid Loss Coefficient (2% KCl Water), ft/$\sqrt{\text{min}}$	0.0005

These data, coupled with the fact that the Lower Hosston interval would not produce gas at sustained, measurable flow rates, led to the conclusion that the interval was not productive and would probably not be productive even after a fracture treatment, unless better quality reservoir could be connected to the wellbore by the fracture.

4.2.2.2 Fracture Treatment Diagnostics

Even though the Hollingsworth did not produce gas at measurable rates, a fracture treatment of the Hosston formation was performed. However, since we were just beginning our project in the Hosston and the Hollingsworth No. 3 was not a full cooperative well, S. A. Holditch & Associates, Inc. did not become involved in designing the fracture treatment. The treatment was designed to use 168,000 gallons of Dowell's SF 650 gel carrying 324,400 lbs of 20/40 mesh sand. This fluid is a 50 lb/1000 gallon HPG system with which the crosslinking mechanism can be delayed as much as desired.

The Hollingsworth No. 3 was fracture treated on May 31, 1984. The treatment was successfully pumped as designed down 2-7/8", N-80 tubing with a packer set at 8150 feet. The designed pumping schedule is shown in Table 7 and a summary of the fracture treatment data is presented in Table 8. Because the GRI Mobile T&C Facility was not yet capable of monitoring and recording data from a fracture treatment, a Dowell Treatment Monitoring Vehicle (TMV) was used to measure and record the fracture treatment data. These data were subsequently sent to Resources Engineering Systems (RES) for their data base.

Using surface pressures, flow rates and fluid densities measured and recorded during the fracture treatment, downhole pressures were calculated.[16] Such calculations are not straightforward when one is dealing with pseudo-plastic fluids that are extremely shear sensitive. However, when one is using a delayed crosslink fluid, the frictional properties are more easily estimated provided the crosslinking is delayed until the fluid enters the formation.

Figure 4 is a Nolte graph[17] (logarithmic plot of downhole pressure minus closure pressure vs injection time) for the Hollingsworth fracture treatment. Our estimated value of closure pressure was 5650 psi. We have attempted to normalize the data for small fluctuations in rate during the treatment by plotting the change in pressure divided by the injection rate ($\Delta p/q$).

As illustrated in Figure 4, the pressure above closure pressure, or friction pressure down the fracture, remains essentially constant throughout the job. Based on this character of the Nolte plot, it appears fracture height growth may have been somewhat restricted throughout the treatment; however, perfect containment was not achieved. RES has not yet performed an analysis of the fracture treatment data for fracture geometry. RES has only recently finished its hydraulic fracture analysis models, such that actual data can be analyzed. However, as previously mentioned, the data is available in RES's data base for future analysis.

4.2.2.3 Post-Fracture Performance Analysis

After fracture treating the Hollingsworth No. 3, the well produced 2039 barrels of water in eleven days. This total includes both the load water and formation water. Only traces of gas were produced and the gas flow rate was too small to measure. The well initially produced about 400 barrels of water per day (BW/day) and declined to 15 BW/day at the end of the test. After eleven days of flow, the well was shut in for a bottomhole pressure buildup test with the HP pressure gauge. Because the well was non-productive and ARCO Oil & Gas had decided to abandon the interval, the buildup test was discontinued after 53 hours.

Because of the very short buildup time and lack of consistent production data, an analysis of these data is qualitative at best. The formation appears to be stimulated; however, any quantitative estimates of fracture properties would be very suspect.

4.2.3 ARCO Oil & Gas G. Oliver No. 1

The G. Oliver No. 1 was a partial cooperative well in that additional open hole logs were run by GRI and the fracture treatment was monitored with the Data Acquisition Trailer. These data were gathered and analyzed in preparation for the work to be performed on the B. F. Phillips No. 1. We did not become involved with the pre-fracture formation evaluation or the actual fracture treatment design; however, we felt it was important to monitor the fracture treatment and analyze the data in an effort to learn more of what to expect for the Phillips fracture treatment.

The original fracture treatment on the Oliver well was designed to use 240,000 gallons of HPG gel and 482,000 pounds of 20/40 mesh sand. Unfortunately, the designed fracture treatment on the Oliver well was not pumped successfully. A screenout occurred at the start of the 4 lb/gal stage after 220,000 gallons of fluid and 265,000 pounds of sand had been pumped. The treatment was performed down 2 7/8-inch tubing at an average rate of 17 bbls/min and an average pressure of 5000 psi before the screenout occurred.

Prior to our involvement in the Oliver well, a similar screenout had occurred on another well in the area, the Brown No. 1, at about the same point in the fracture treatment. Thus, we were able to review and evaluate these data in addition to data from the Oliver well. Nolte graphs for both these treatments are shown in Figures 5 and 6.

In general, both these plots indicate a decline in the pressure above closure throughout most of the job. Such a decline is indicative of excessive vertical fracture growth during pumping operations. This excessive vertical fracture growth, coupled with a high Young's modulus (7.5×10^6 psi - calculated from subsequent logs on the Oliver and logs and cores on the Phillips well), and the presence of natural fractures indicated in the cores, led us to conclude that the screenouts were a result of narrow fracture widths. In addition, the presence of the natural fractures may have depleted the pad volume, which was approximately 25 per cent of the total design volume.

The only way to prevent similar problems from occurring would be to minimize the vertical fracture growth while trying to maintain adequate fluid viscosity, in addition to increasing the pad volume. Unfortunately, higher fluid viscosity is detrimental to vertical fracture containment. However, we felt that if the pad volume were increased and a fluid could be pumped with viscosity sufficient to maintain a wide fracture, then we could successfully place a treatment in the Travis Peak.

Using the knowledge gained from the logs, cores and diagnostic analyses of the previous fracture treatments, we recommended the following changes for the fracture treatment of the Phillips well.

(1) Increase pad volume from 25% to 35% of the total thick fluid.

(2) Use more perforations and perforate the Travis Peak with a casing gun.

(3) Use a delayed crosslink gel system and be sure the gel does not crosslink in the tubing. It should crosslink immediately downstream of the perforations.

(4) Increase the gel concentration to 50 lb/1000 gals.

4.2.4 ARCO Oil & Gas B. F. Phillips No. 1

4.2.4.1 Pre-Fracture Analysis

The Phillips No. 1 was cored, logged, and tested in the upper portion of the Travis Peak formation. A full suite of logs was run across the Travis Peak formation and ResTech provided FRACLOG and CORELOG. An *in-situ* stress test was performed in a sandstone interval at 8316 - 8318 ft and a mini-frac was performed on the entire perforated interval. No pre-fracture pressure buildup test was run on this well. A summary of the reservoir properties from this pre-fracture formation evaluation is presented below.

Perforated Interval, ft	8190-8383
Net Pay, ft	41.5
Average Porosity, %	8.51

Average Water Saturation, %	47.20
<u>In-Situ</u> Permeability*, md	5.7
<u>In-Situ</u> Stress Gradient, psi/ft	0.67
Initial Reservoir Pressure, psia	4100
Fluid Loss Coefficient, ft/ min	0.003

*Average of stressed core measurements. Value is high due to two high permeability intervals (>20 md). Most of perforated interval is less than 0.01 md.

In addition to the data collected on the Phillips, we analyzed data from two offset wells, the ARCO Oliver No. 1 and the ARCO Brown No. 1, as part of the GRI project. The logs, fracture treatment data, and production data from these two wells were used to evaluate the area near the Phillips and to design the fracture treatment. Based on an evaluation of data from the three wells in the Chapel Hill Field, we felt the Phillips well could be successfully stimulated. Although fracture treatments on the Oliver and Brown wells screened out, analysis of the available data led to the conclusion that insufficient fracture width was the problem.

Using an analysis of the Brown and Oliver wells, and the core and log data gathered on the Phillips well, we assisted ARCO in designing a fracture treatment for the Phillips. Our original design was for 270,000 gallons of 50 lb delayed crosslink gel with 481,000 pounds of 20/40 mesh sand. However, ARCO wanted to modify the design somewhat and the revised pumping schedule is shown as Table 9. As the table indicates, this design called for using 211,700 gallons of 50 lb and 40 lb gel with 428,400 pounds of 20/40 mesh sand. The pad volume used was 40 per cent of the total volume.

After reviewing the calculated stress gradients and mechanical properties from the Phillips logs and our evaluation of the previous treatments, we concluded that the vertical fracture height could be on the order of 250 feet and possibly as much as 500 feet. Using the designed fracture treatment volumes and assuming a created fracture height of 260 feet, the estimated propped fracture half-length was expected to be about 750 feet. The average created fracture width was estimated to be 0.5 inches and a dimensionless conductivity greater than 10 was predicted.

4.2.4.2 Fracture Treatment Diagnostics

The Phillips No. 1 was fracture treated during September, 1984. The treatment was successfully pumped down 2 7/8-inch tubing at an average rate of 26 BPM at an average injection pressure of 6300 psi. The instantaneous shut-in pressure (ISIP) was about 2300 psi for a fracture gradient of 0.72 psi/ft. All of the fracture treatment data were monitored and recorded with the Data Acquisition Trailer and a summary of the actual fracture treatment data is shown in Table 10.

Figure 7 shows our Nolte plot for the fracture treatment on the Phillips well. Based on current theory, the shape of this curve indicates that fairly good vertical fracture containment, or at least restriction of vertical fracture growth, was maintained for about the first 2 1/2 hours of the treatment. However, at the start of the 3 ppg stage, the slope of the curve begins to decrease indicating the fracture began growing in the vertical direction. As with the Brown and Oliver wells, this could have been a point at which a screenout might have occurred. However, we feel that because we were pumping a much more viscous fluid at a higher injection rate, sufficient fracture width was maintained to pump the higher concentrations of proppant into the formation. Similarly, good lateral extension of the fracture prior to the start of vertical growth probably allowed us to place more proppant further out into the formation.

Nolte plots, such as the ones presented thus far, can provide a qualitative indication of the fracture growth patterns during a fracture treatment. However, a more rigorous analysis using a finite difference reservoir simulator is necessary to quantify the fracture properties.

Using the fracture treatment data collected on the Phillips well, a quantitative analysis of fracture geometry was performed by RES using its fully implicit, real-time hydraulic fracturing model. Although this version is not quite capable of handling complex three dimensional fracture geometries and reservoir characteristics, it can calculate created fracture length, width, height and proppant distribution assuming a somewhat simplified reservoir medium. RES expects to complete its full three dimensional fracturing model by the end of 1985.

Based on the RES analysis, the hydraulic fracture created in the B. F. Phillips No. 1 is estimated to have the following dimensions:

Created Length, ft	1900
Propped Length, ft	800
Created Width (wellbore), in	0.3
Created Height, ft	390

To arrive at these results, in-situ stress values and formation mechanical properties from log analysis and from special core analysis were input into the fracturing model. Given these physical formation properties, the above fracture dimensions were determined based on a history match of the bottomhole pressures calculated from the treatment data.

4.2.4.3 Post-Fracture Performance Analysis

Approximately twenty-four hours after the fracture treatment, the Phillips No. 1 was opened and flowed to a frac tank.

Within 24 hours of being opened, the well was making over 700 Mscf/day, and within 48 hours, the well was making approximately 1,800 Mscf/day. After 9 days, fluid production had declined to the point where flow could be directed through the GRI separator. The well produced 1700 - 1800 Mscf/day for approximately seventeen days; it was then shut in for a thirteen day pressure buildup test.

Figures 8 and 9 present Horner and type-curve plots, respectively, of the buildup data in terms of pseudo-pressure[18] and pseudo-time[19,20]. The flowing bottomhole pressure was measured with the Hewlett-Packard quartz pressure gauge for 10 1/2 hours before the well was shut in. During the entire shut-in period, pressures were monitored with the downhole gauges. Periodic, on-site analyses were made of the pressure buildup data.

The pressure buildup data measured on the ARCO Phillips No. 1 were analyzed using numerous techniques. Onsite analyses included the more conventional Horner and type-curve techniques. Often, such conventional techniques can provide reliable results if the reservoir and fracture properties are relatively homogeneous. However, given the general shape of the curve and the vertical and lateral heterogeneity of the Travis Peak indicated in geologic descriptions and log and core analyses, homogeneous reservoir models cannot be used to correctly analyze the production and buildup data. Thus, it was necessary to use our three dimensional, fully implicit reservoir simulator to history match these data and determine the most probable reservoir and fracture properties.

Using the results of geologic studies performed by BEG, individual sand layers were identified and grouped according to their specific reservoir quality and lateral continuity. These groups roughly correspond to the three types of sands identified in a recent report by BEG[21]. The physical properties and expected sizes of these individual layers were then input into our reservoir simulator.

Initial estimates of porosity, water saturation, and net pay thickness for each layer were those values reported from log and core analysis studies. The lateral extent of each layer (drainage area) was based on the expected continuity of permeability, given the depositional history of each layer. We felt that the three dimensional reservoir model which was constructed would describe the vertical and lateral characteristics of the Travis Peak formation surrounding the Phillips well.

We then placed in the reservoir simulator a hydraulic fracture which had the same physical properties as was calculated by Resources Engineering Systems. Only the propped lengths and widths were used, however, since these properties constitute the "effective" part of the fracture.

Schematic diagrams of this reservoir model are provided in Figure 10. Figure 10 is a series of sketches which describe the technique used in modeling the reservoir. Rather than model the entire reservoir, we modeled only a symmetrical portion of the reservoir, which in this case was 1/4 of the area. Figure 10a indicates a thick, low permeability interval which covers a large area and which contains a significant amount of the gas in place. BEG also identified an areally limited, thin, high permeability streak, which is represented in Figure 10b by a smaller "block" placed on top of the larger block. Another distinct layer identified by BEG studies is represented in Figure 10c by a third block situated on top of the small block. This top layer covers the same area as the thick, low permeability layer, but it is thin and has much higher permeability. Finally, the hydraulic fracture, shown in Figure 10d, was placed along one edge of the model.

A reservoir simulation history match of the actual post-fracture production and pressure buildup data was then performed using these estimated reservoir and fracture characteristics. The method uses a trial and error technique to determine the combination of reservoir and fracture properties which leads to the most accurate match of the actual production and pressure history of the well.

Figure 11 illustrates our final match of the actual pressure buildup survey conducted after the fracture treatment.

An excellent match of these data was obtained using reservoir properties similar to those which were determined in geologic studies, log and core analyses, and hydraulic fracture simulation. The following table summarizes the properties used to generate the simulated production and pressure buildup data.

	Layer 1	Layer 2	Layer 3
Permeability, md	1.0	10.0	0.007
Net Pay, ft	1.0	4.0	35.0
Gas Porosity, %	8.0	11.0	4.7
Initial Pressure, psia	4100	4100	4100
Drainage Area, acres	160	13.8	160
Drainage Area Dimensions, ftxft	2640x2640 (square)	1200x500 (rect.)	2640x2640 (square)
Propped Fracture Length, feet	575	575	575
Initial Fracture Conductivity, md-ft			
At the Wellbore	300	300	300
At the Fracture Tip	200	200	200

Actual Gas Production = 27,600 Mscf

Simulated Gas Production = 27,550 Mscf

The Phillips well has been on production for several months since the buildup test. Therefore, to further test the accuracy of the fracture and reservoir description, we used the same model to analyze this longer term production history from the well. These results are illustrated in Figure 12, which shows the actual gas flow rate and flowing tubing pressure since the fracture treatment and the simulated production rate and bottomhole pressure history from our model. The figure shows that, by simulating the flow rates from the Phillips well, the simulated bottomhole pressures closely parallel the trend of the actual flowing tubing pressures. Because the hydrostatic head of the gas and fluid column in the tubing was not known or measured, an exact comparison to actual bottomhole pressures during this period could not be made. However, during the production period before the buildup, actual bottomhole pressures were measured with the Mobile T&C Facilities and there was excellent agreement between the actual and simulated pressures. A projection of production for 10 years using our reservoir simulator resulted in an estimated ultimate recovery of 750 MMscf of wet gas. This estimate of ultimate recovery assumes the bottomhole pressure can be reduced to 300 psia and that there will be no liquid loading in the wellbore.

The excellent results of our post-fracture performance analysis leads us to believe we have correctly modeled the actual reservoir and fracture properties associated with the Phillips well. The encouraging aspect of our analysis is that we were able to use essentially the same results derived from independent geologic, petrophysical, core and hydraulic fracture simulation studies. It was necessary in our analysis to slightly alter some of these variables before an accurate match of the actual production and pressure buildup data could be achieved. However, our final results are still consistent with these independent studies. Therefore, we feel that the efforts expended to define the physical characteristics of the Travis Peak through GRI's extensive field operations program will continue to provide accurate reservoir and fracture analyses.

4.2.5 Ashland Exploration S.F.O.T. No. 1

Although the Ashland S.F.O.T. No. 1 analysis is still in progress, some preliminary results are available. Coring, logging, and pre-fracture testing were completed in the Travis Peak formation in 1984. ResTech has generated a FRACLOG for this well. Based on the analysis to date, a summary of the reservoir properties is given below.

Perforated Interval, ft	9580-90, 9748-58
Net Pay, ft	14
Average Porosity, %	8.8
Average Water Saturation, %	30.7
In-Situ Permeability, md	0.03
In-Situ Stress Gradients,	
Siltstone, psi/ft	0.80
Shale, psi/ft	1.00
Sandstone, psi/ft	0.60
Initial Reservoir Pressure, psia	5000

This well flowed 170 Mscf/day for two days. A fracture treatment should be able to increase production significantly. However, based on the FRACLOG, there are no obvious barriers to fracture height growth. Fracture height may be as large as 450-500 feet. Final recommendations for the fracture design have not been made, but these will be completed in early 1985. A mini-frac will be pumped before the fracture treatment and post-fracture well testing will be performed to help determine the success of the treatment.

5.0 DISCUSSION OF CONCLUSIONS AND OBSERVATIONS

From our studies of individual well data collected over the course of this year, several general observations regarding the Travis Peak and the overall direction of the project can be made. These are as follows.

(1) Natural fractures associated with the Travis Peak formation will likely have a significant effect on the performance of a typical well. Further studies using pressure transient tests, cores and open hole logs will help to quantify the relationships between the occurrence of natural fractures and well performance.

(2) High permeability lenses are scattered in the upper Travis Peak interval. By correlating the depositional environment to the log characteristics of these high permeability lenses, we hope to develop criteria to identify these intervals more reliably. If successful, we can decrease the risk of exploring for gas in the Travis Peak formation.

(3) It may not be feasible to produce extremely low permeability sands (less than 0.001 md) without the presence of natural fractures to enhance well performance. Through our research, we hope to develop the correlations and criteria necessary to identify commercial intervals, thus

reducing unnecessary completion, testing and stimulation expense.

(4) Clay type, clay volume and matrix cementation all have significant effects on the absolute value of permeability and, possibly, the distribution of permeabilities within the Travis Peak interval. Further studies of the depositional environments which control these mechanisms should also help to differentiate between potential pay zones and unproductive sands.

(5) A solid form of hydrocarbon (bitumen) was found to be occluding some of the pore space in every well that we cored during 1984. The presence of the bitumen could be reducing the effective formation permeability of a sandstone interval which might otherwise appear from the log analysis to be a permeable zone. Additional coring and logging research will be performed in an attempt to recognize the presence of bitumen from log analysis and to determine its effect on reservoir performance.

(6) Containment of vertical fracture height during a hydraulic fracture treatment is definitely a problem in the Travis Peak formation. The lack of significant stress contrast and similarity of rock properties between the pay zones and the surrounding rock layers is conducive to excessive vertical fracture growth. As a result, fracture geometry

studies funded by GRI will be very important to the success of the Mobile T&C research effort. If we can ultimately learn to control the shape of the fracture by minimizing growth through weak or thin stress barriers, the results will have a significant and positive impact on the development of the Travis Peak formation.

(7) Natural fractures may also have a significant effect on fluid leakoff during a fracture treatment. High leakoff rates can cause narrow fracture widths which will prevent pumping high concentrations (up to 5 ppg) of proppant into the formation. Extremely hard formations, such as the Travis Peak, will also result in narrow fractures during pumping. To minimize the leakoff problem, the normal solution is to increase both the fracture fluid viscosity and the injection rate. Unfortunately, these changes increase the tendency of a fracture to grow in the vertical direction. In our research, we will need to experiment with methods of reducing leakoff down natural fractures while minimizing fracture height growth.

(8) In its extensive field operations program, GRI is collecting and analyzing data which appear to accurately describe the vertical and lateral characteristics of the Travis Peak and the hydraulic fractures created within the formation. This conclusion is based on excellent results from post-fracture performance analysis using the descrip-

tions from geologic, petrophysical, core and reservoir simulation studies.

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3) "Coring and Logging Operations Summary: Ashland Exploration S.F.O.T. No. 1, Nacogdoches County, Texas," CER Corporation, November, 1984.

4) "Tight Gas Sand Core Analysis: Sam Hughes No. 1, Revision Level 2," Petrophysical Services, Inc., June, 1984, GRI Contract No. 5083-211-0813.

5) "Tight Gas Sands Core Analysis: B. F. Phillips No. 1, Revision Level 7," Petrophysical Services, Inc., October, 1984, GRI Contract No. 5083-211-0813.

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7) Dutton, Shirley P., and Finley, Robert J.: "Preliminary Geologic Description: ARCO No. 1 B. F. Phillips," Bureau of Economic Geology, September, 1984, GRI Contract No. 5082-211-0708.

8) Dutton, Shirley P., and Finley, Robert J.: "Preliminary Geologic Description: Ashland S.F.O.T. No. 1," Bureau of Economic Geology, December, 1984, GRI Contract No. 5-82-211-0708.

9) "Petrophysical Analysis for Clayton W. Williams, Jr., Sam Hughes No. 1, S. E. Pinehill Field, Panola County, Texas," ResTech, Inc., July, 1984.

10) "Petrophysical Analysis for ARCO Oil & Gas B. F. Phillips No. 1, Chapel Hill Field, Smith County, Texas," ResTech, Inc., October, 1984.

11) "Cooperative Well Report: ARCO Oil & Gas Hollingsworth No. 3, Logansport Field, DeSoto Parish, Louisiana," S. A. Holditch & Associates, Inc., October, 1984, GRI Contract No. 5083-211-0877.

12) "Cooperative Well Report: Clayton W. Williams, Jr. Sam Hughes No. 1, Pinehill S. E. Field, Panola County, Texas," S. A. Holditch & Associates, Inc., December, 1984, GRI Contract No. 5083-211-0877.

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TABLE 1

1984 DATA BASE ADDITIONS - CORE FROM COOPERATIVE WELLS*

Well Name	Core	Cored Interval (ft)	Recovery (ft)	Remarks
Clayton Williams, Jr.	1	6834-6853	17.7	Included Travis Peak "A" sand
Sam Hughes No. 1	2	7044-7083	39.0	Mostly siltstone and silty sands
	3	7083-7110.4	27.4	Included clean sand interval
ARCO Oil & Gas	1	8134-8188	0	Core bit was pinched by formation
B. F. Phillips No. 1	2	8188-8236	45	Included clean, productive sands
	3	8237-8278	33	Included clean, productive sands
	4	8367-8397	28	Included portion of a thick shale
Ashland Exploration	1	9665-9702.3	33.4	Mostly siltstone and mudstone
S.F.O.T. No. 1	2	9702.3-9729.2	25.8	Mostly siltstone and mudstone
	3	9729.2-9783.8	53.9	Included clean, productive sand
	4	10080.3-10083.9	0.4	Core barrel jammed
	5	10083.9-10118.4	30.3	Laminated sandstone and mudstone
	6	10118.4-10172.0	36.8	Laminated sandstone and mudstone
TOTAL	13		370.7	

*Note: Bureau of Economic Geology has received and is analyzing core from operating companies on eight additional wells. These are:

Stallworth Oil & Gas	Renfro #2	Smith County, Texas
Stallworth Oil & Gas	Everett "B" #2	Smith County, Texas
Delta US	Williams #1-A	Smith County, Texas
ARCO	S. F. Hammon #2	Smith County, Texas
Amoco	Kangerga "C" #1	Rusk County, Texas
Amoco	Caldwell #2	Harrison County, Texas
SUN	Janie Davis #2	Harrison County, Texas
SUN	D. Candle #2	Panola County, Texas

TABLE 2

1984 DATA BASE ADDITIONS - NUMBER OF CORE ANALYSES

Well Name	Routine Tests	k vs Confining Pressure	k vs Water Saturation	Resistivity Index	Formation Factor	Capillary Pressure	Porosity vs Confining Pressure	Acoustic Velocity
Clayton Williams, Jr. Sam Hughes No. 1	44	12	12	11	12	9	8	8
ARCO Oil & Gas B. F. Phillips No. 1	104	18	9	10	13	12	16	17
Ashland Exploration* S.F.O.T. No. 1								

*Tests are being completed at this time.

TABLE 3

1984 DATA BASE ADDITIONS - LOGS ON COOPERATIVE WELLS*

Type of Log	C. Williams, Jr. Hughes	ARCO Oliver	ARCO Phillips	Ashland S.F.O.T.
Dual-Laterolog			X	
Dual-Induction	X	X	X	X
Spherically Focused	X	X	X	X
Litho-Density Log	X	X	X	
Comp. Density Log				X
Comp. Neutron Log	X	X	X	X
Acoustic - Normal	X			X
Acoustic - Long Spacing	X	X	X	X
Gamma Ray	X	X	X	X
Spontaneous Potential	X	X	X	X
Micro-Laterolog	X			X
Microlog	X	X	X	X
Electromagnetic Propagation	X	X	X	X
Natural GR Spectroscopy	X		X	X
Induced GR Spectroscopy			X	X
Microspherically Focused		X	X	
Dipmeter	X		X	X
Cement Bond - Variable Density	X		X	X
Cement Evaluation Log			X	X
Digital Sonic				X
Carbon Oxygen				X

*NOTE: ResTech has received and analyzed logs from operating companies on seven additional wells. These are:

Delta US	E. Williams "A" #1	Smith County, Texas
ARCO	Hollingsworth #3	DeSoto Parish, Louisiana
SUN	J. Davis #2	Harrison County, Texas
TXO	Finley #1	Nacogdoches County, Texas
Ashland	Tatum #1	Nacogdoches County, Texas
Ashland	Christian #1	Nacogdoches County, Texas
Amoco	Kangerga "C" #1	Rusk County, Texas

TABLE 4

1984 DATA BASE ADDITIONS - PRE-FRACTURE INJECTION TESTS

Well Name	Type of Test	Perforated Interval (ft)	Lithology	Remarks
ARCO Oil & Gas Hollingsworth #3	Stress	8714-24, 8750-58	Sandstone	Surface pressures
ARCO Oil & Gas B. F. Phillips #1	Stress	8316-18	Sandstone	Downhole pressures & downhole shut-off tool
	Mini-frac	8190-8383	Sandstone	Surface pressures
Ashland Exploration S.F.O.T. #1	Stress	10,160	Siltstone	Surface pressures
	Stress	9,905	Shale	Downhole pressures & downhole shut-off tool
	Stress	9,754	Sandstone	Downhole pressures & downhole shut-off tool

TABLE 5

1984 DATA BASE ADDITIONS - WELL TEST DATA

Well Name	Type of Test	Perforated Interval (ft)	Test Duration (hrs)	Remarks
ARCO Oil & Gas Hollingsworth #3	Pre-Frac Production and Buildup	8714-24, 8750-58	196	76 hr flow, 120 hr shut-in; well had to be swabbed and flowed less than 3 Mscf/day
	Post-Frac Production and Buildup	8714-24, 8750-58	307	254 hr flow, 53 hr shut-in; flowed only water; zone was abandoned
Clayton Williams, Jr. Sam Hughes #1	Pre-Frac Production and Buildup	6838-6842	116	75 hr flow, 41 hr shut-in; flowed 580 Mscf/day; performed buildup with HP downhole pressure gauge
	Pre-Frac Production	6838-6842	16	Texas Railroad Commission Potential Test; AOF = 980 Mscf/day
ARCO Oil & Gas G. Oliver #1	Post-Frac Production	8224-8383	450	Monitored production with GRI test separator
ARCO Oil & Gas B. F. Phillips #1	Post-Frac Production and Buildup	8190-8383	708	384 hr flow, 324 hr shut-in; flowed 1,800 Mscf/day; performed buildup with HP downhole pressure gauge
Ashland Exploration S.F.O.T. No. 1	Pre-Frac Production and Buildup	9580-90, 9748-58	270	50 hr flow, 220 hr shut-in; flowed 170 Mscf/day; perforated buildup with HP downhole pressure gauge

TABLE 6

1984 DATA BASE ADDITIONS - FRACTURE TREATMENT DATA

					Data Measured and Recorded						
Well Name	Date Of Treatment	Perforated Interval (ft)	Fluid Volumes (gals)	Proppant (lbs)	Flow Rate	Pressure	Density	Temp	pH	Viscosity	X-Link
ARCO Oil & Gas Hollingsworth #3*	5/31/84	8714-24, 8750-58	168,000	324,400	X	X	X				X
ARCO Oil & Gas G. Oliver #1	8/2/84	8224-8383	220,000	265,000	X	X	X	X			X
ARCO Oil & Gas B. F. Phillips #1	9/3/84	8190-8383	211,700	428,400	X	X					
American Petrofina Bright #1	11/9/84	11490-11750	365,000	1,022,000	X	X	X	X		X	X

*Data recorded by Dowell's TMV and made available to GRI by ARCO.

TABLE 7

ARCO OIL & GAS, INC.
HOLLINGSWORTH NO. 3

FRACTURE TREATMENT PUMPING SCHEDULE

Fluid	Volume (gals)	Proppant Concentration (ppg)	Proppant Weight (lbs)
Slick Water	10,000	Pre-Pad	-
SF 650	50,400	Pad	-
SF 650	25,200	1	25,200
SF 650	25,200	2	50,400
SF 650	32,550	3	97,650
SF 650	22,050	4	88,200
SF 650	12,600	5	63,000

Total SF 650 Gel Fluid - 168,000 gals
Total 20/40 Sand - 324,400 lbs

5/31/84
Date

TABLE 8

S. A. HOLDITCH & ASSOCIATES, INC.

ACID AND FRACTURE TREATMENT SUMMARY SHEET

Company Arco Oil & Gas
Well Name Hollingsworth No. 3

Tubing Size & Weight 2-7/8", 6.5#, N-80
Tubing Volume 47.2 bbls
Packer Depth 8150
Casing Volume To Perfs 13.1 bbls
Casing Size & Weight Below Packer 5 1/2", 17#, N-80
Total Flush Volume 60.3 bbls
Casing Size & Weight (If frac down casing)
Perforations 8713-8724, 8750-8758 (78 holes)
SITP 830
SICP 0
Tested Frac Lines to 10,000 psig
Pressured Tubing-Casing Annulus to

ISIP 2491   5 min 2348   10 min 2288   15 min 2230   30 min 2097

Time	Fluid Type	Stage Volume (bbls) *	Cum. Volume (bbls) *	Inj. Rate (BPM)	Tubing Pres. (psi)	Casing Pres. (psi)	Remarks
0725	Slick Water		0	15.2	6294	1084	Start Slick Water Pre-pad
0726		9	9	6.0	3463	739	Shut down for ISIP
							ISIP = 2331 (F.G. = .707)
0730				9.0	4670	681	Resume pumping
0732		30	30	15.3	6869	841	Pumps full speed
0735		76	76	15.2	6231	1231	Slick Water on perfs
0737		111	111	15.2	6588	1083	Shut down for ISIP
							ISIP = 2693 (F.G. = .748)
0739				15.5	6522	1208	Resume pumping
0741		144	144	15.5	5684	1136	
0747		238	238	15.2	5275	1093	Finish Pre-pad; Start
							SF 650 gel pad
0748	SF 650	14	252	15.2	5300	1100	
0753		85	323	15.2	5128	1199	Pad on perfs
0758		171	409	15.1	5388	1215	
0816		440	678	15.2	5389	1090	
0834		716	954	15.4	5386	1097	
0852		993	1231	15.4	5327	1078	
0905		1197	1435	15.3	5272	1167	Finish Pad; Start 1#
0907		20	1455	15.3	5217	1154	
0910		76	1511	15.3	5150	1134	1# on perfs
0927		325	1760	15.2	4902	1180	
0945		599	2034	15.4	5089	1220	

Well Name Hollingsworth No. 3

Time	Fluid Type	Stage* Volume (bbls)	Cum.* Volume (bbls)	Inj. Rate (BPM)	Tubing Pres. (psi)	Casing Pres. (psi)	Remarks
0947	SF 650	630	2065	15.4	5093	1225	Finish 1#; Start 2#
0949		31	2096	15.4	5029	1230	
0951		61	2126	15.4	5010	1233	2# on perfs
1002		234	2299	15.3	5030	1239	
1016		443	2508	15.3	4907	1196	X-linker problems;
							new x-linker tank
1024		566	2631	15.4	4434	1148	X-linker problems
1031		574	2739	15.3	4782	1155	X-linker problems solved
1035		740	2805	15.2	5048	1167	Finish 2#; Start 3#
1038		40	2845	15.2	5108	1174	
1040		80	2885	15.3	5211	1183	3# on perfs
1056		309	3114	15.3	5282	988	Bled off csg press ~ 200 ps
1114		584	3389	15.2	5254	967	
1129		823	3628	15.3	4800	871	Finish 3#; Start 4#
1131		31	3659	15.3	4791	840	Possible X-linker problems
1135		82	3710	15.3	4791	824	4# on perfs
1149		301	3929	15.3	4859	822	
1207		576	4204	15.4	4901	838	
1210		627	4255	15.3	4851	826	Finish 4#; Start 5#
1212		26	4281	15.3	5024	842	
1215		72	4327	15.4	4731	838	5# on perfs
1224		214	4469	15.3	4578	820	
1230		301	4556	15.3	4594	798	Finish 5#; Start Flush
1232		31	4587	15.2	4808	801	
1234		62	4618	15.3	4514	759	Flush complete; ISIP = 2491
							(F.G. = 725)
1239				0	2348		5 min SIP
1244				0	2288		10 min SIP
1249				0	2230		15 min SIP
1254				0	2185		20 min SIP
1259				0	2140		25 min SIP
1304				0	2097		30 min SIP
1309				0	2055		35 min SIP
1311				0	2049		37 min SIP

*All reported volumes are slurry volumes.

TABLE 9

ARCO OIL & GAS, INC.
PHILLIPS NO. 1

FRACTURE TREATMENT PUMPING SCHEDULE

Fluid	Volume (gals)	Proppant Concentration (ppg)	Proppant Weight (lbs)
Slick Water	36,000	Pre-Pad	
SF 650	84,000	Pad	
SF 650	21,000	1	21,000
SF 650	47,250	3	141,700
SF 650	31,500	4	126,000
SF 640	27,950	5	139,700

Total 50 and 40 lb Gel - 211,700 gals

Total 20/40 Mesh Sand - 428,400 lbs

TABLE 10

9/3/84
Date

S. A. HOLDITCH & ASSOCIATES, INC.

ACID AND FRACTURE TREATMENT SUMMARY SHEET

Company ARCO Oil & Gas
Well Name Phillips No. 1

Tubing Size & Weight 2 7/8", 6.5#
Packer Depth 8074
Casing Size & Weight Below Packer 5½", 17.0#
Casing Size & Weight (If frac down casing)
SITP

Tubing Volume 1960 gals.
Casing Volume To Perfs 110 gals.
Total Flush Volume 2070 gals. (49 bbls)
Perforations 8190-8383' 22 holes
SICP

Tested Frac Lines to 10,000
Pressured Tubing-Casing Annulus to 1700

ISIP 2290 5 min 2200 10 min 2190 15 min 2180 30 min 2160

Time	Fluid Type	Stage Volume (bbls)	Cum. Volume (bbls)	Inj. Rate (BPM)	Tubing Pres. (psi)	Casing Pres. (psi)	Remarks
1:25	Slick Water	0	0	inc	inc	1650	Start pumping
1:33+	Slick Water	135	135	24.6	6440	1450	
1:35	Slick Water	175	175	26.3	6940	1500	inc. casing press.
1:45	Slick Water	285	285	26.3	6600	1990	
1:52	Slick Water	620	620	23.0	6900	2110	Lost rate
1:53	Slick Water	640	640	26.0	7630	2100	Rate back up
1:56	Slick Water	720	720	26.0	7640	2100	
2:02	Slick Water	850	850	26.4	7640	1950	All slick water. Start gel pa
2:03	50 lb gal	30	880	26.3	6640	2000	Press. dec.
2:20	50 lb gal	480	1330	26.2	6350	2010	1.9 BPM diesel, 3.0gpm X linke
2:37	50 lb gel	910	1760	26.4	6490	1980	2.0 BPM diesel, 3.0 gpm X link
2:45	50 lb gel	1125	1975	26.4	6520	1960	
2:54	50 lb gel	1375	2225	26.4	6550	2070	
3:11	50 lb gel	1810	2660	26.3	6550	2050	2.0 BPM diesel 3.0 gpm X linke
3:20	50 lb gel	2010	2860	26.2	6580	2020	All pad start 1 ppg
3:22	50 lb gel	40	2900	26.1	6540	2020	Good 1 ppg
3:22	50 lb gel	49	2909	26.2	6540	2020	Sand on perfs
3:24+	50 lb gel	80	2980	26.1	6530	2020	6 tanks gel gone
3:31	50 lb gel	230	3130	26.0	6590	2030	
3:36	50 lb gel	360	3260	26.1	6680	2040	Press. inc. slightly
3:41	50 lb gel	490	3390	26.0	6710	2040	All ppg. start 3ppg
3:43	50 lb gel	50	3440	26.3	6600	2050	2.6 ppg. conc. sd on perfs.
3:44+	50 lb gel	80	3470	26.2	6650	2060	good 3 ppg

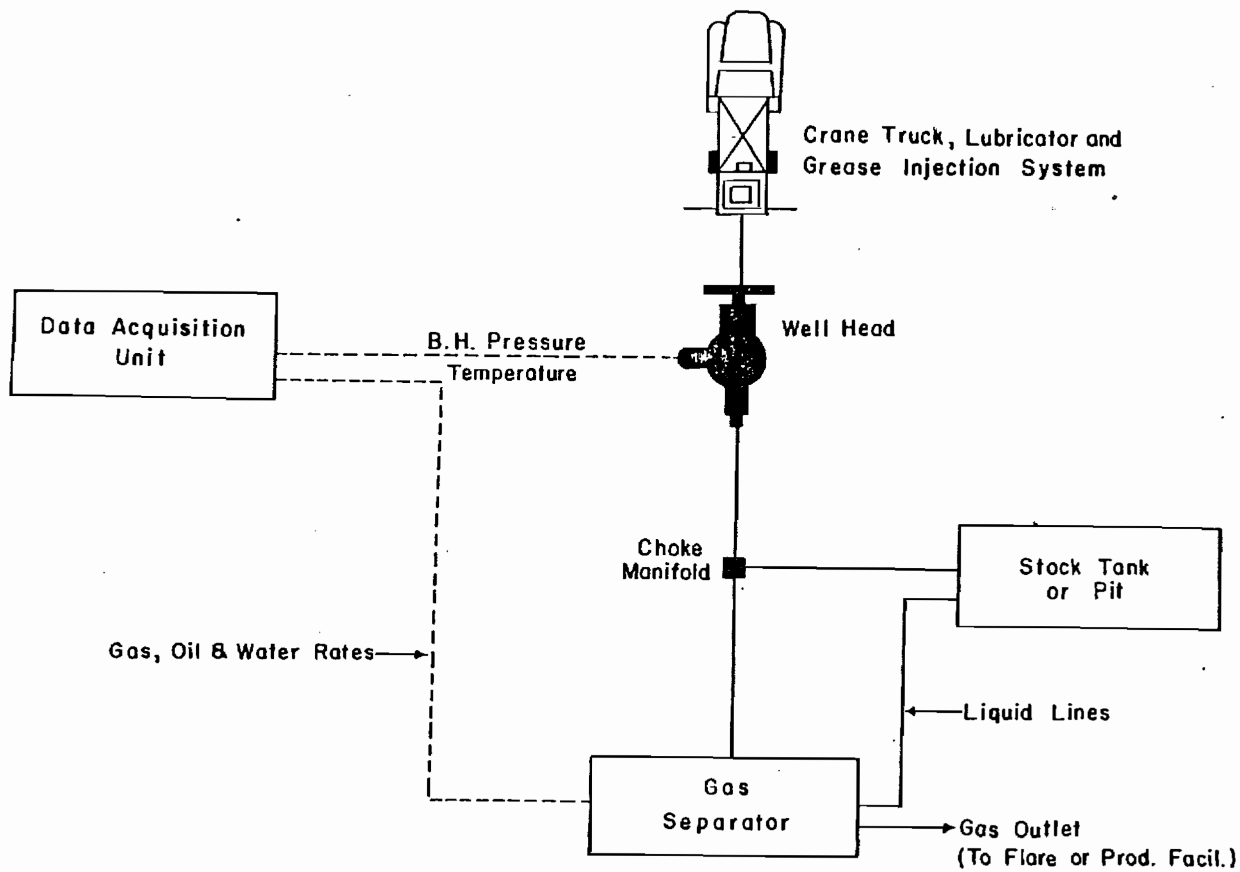
Well Name Phillips No. 1

Time	Fluid Type	Stage Volume (bbls)	Cum. Volume (bbls)	Inj. Rate (BPM)	Tubing Pres. (psi)	Casing Pres. (psi)	Remarks
3:46	50 lb gel	130	3520	26.4	6730	2080	Good 3 ppg on perfs.
3:50	50 lb gel	230	3620	26.2	6680	2080	
3:57+	50 lb gel	390	3780	26.3	6430	2080	Press. dec., Cut diesel rate
4:00	50 lb gel	500	3890	26.2	6530	2070	1.3 BPM diesel, 3.0 gpm X link
4:05	50 lb gel	640	4030	26.3	6490	2060	Cut diesel off
4:11	50 lb gel	780	4170	26.0	6440	2040	3.3 ppg
4:18	50 lb gel	940	4330	26.3	6480	2040	
4:20	50 lb gel	1130	4520	26.3	6400	2020	3.0 ppg
4:30	50 lb gel	1270	4660	26.2	6430	2020	All 3.0 ppg, Start 4 ppg
4:31+	50 lb gel	30	4690	26.2	6310	2020	Good 4 ppg.
4:33+	50 lb gel	50	4710	26.3	6250	2010	4 ppg on formation
4:36	50 lb gel	130	4790	26.3	6200	2020	4.2 ppg
4:52	50 lb gel	560	5220	26.2	5980	2180	
5:00	50 lb gel	790	5450	26.1	6000	2170	
5:06	50 lb gel	900	5560	26.0	5960	2140	All 4 ppg Start 5
5:06+	40 lb gel	20	5580	26.2	5900	2130	5.4 ppg
5:07+	40 lb gel	50	5610	26.3	5840	2130	5 ppg on form.
5:08+	40 lb gel	80	5640	26.2	5910	2140	
5:14	40 lb gel	240	5800	26.2	5850	2140	
5:20	40 lb gel	390	5950	26.4	5570	2140	inc. to 5.5 ppg
5:25+	40 lb gel	130	6080	26.4	5410	2130	5.7 ppg
5:27	40 lb gel	170	6120	26.2	5470	2130	Press. inc. slightly
5:28	40 lb gel	200	6150	26.2	5500	2120	Press. stable
5:31	40 lb gel	270	6220	26.2	5510	2120	
5:35	40 lb gel	370	6320	26.3	5480	2120	
5:39	Slick Water	474	6424	26.4	5500	2120	Cut sand, start flush
5:41+	Slick Water	50	6474	dec.	dec.	2120	All flush. SD.
5:41+					2290		ISIP F.G = 0.72 psi/ft
5:46					2200		5 min.
5:51					2190		10 min.
5:56					2180		15 min.
6:01					2170+		20 min.
6:06					2170		25 min.
6:11					2160		30 min.

FIGURE I

FIELD OPERATIONS – WELL TESTING

DATA ACQUISITION TRAILER



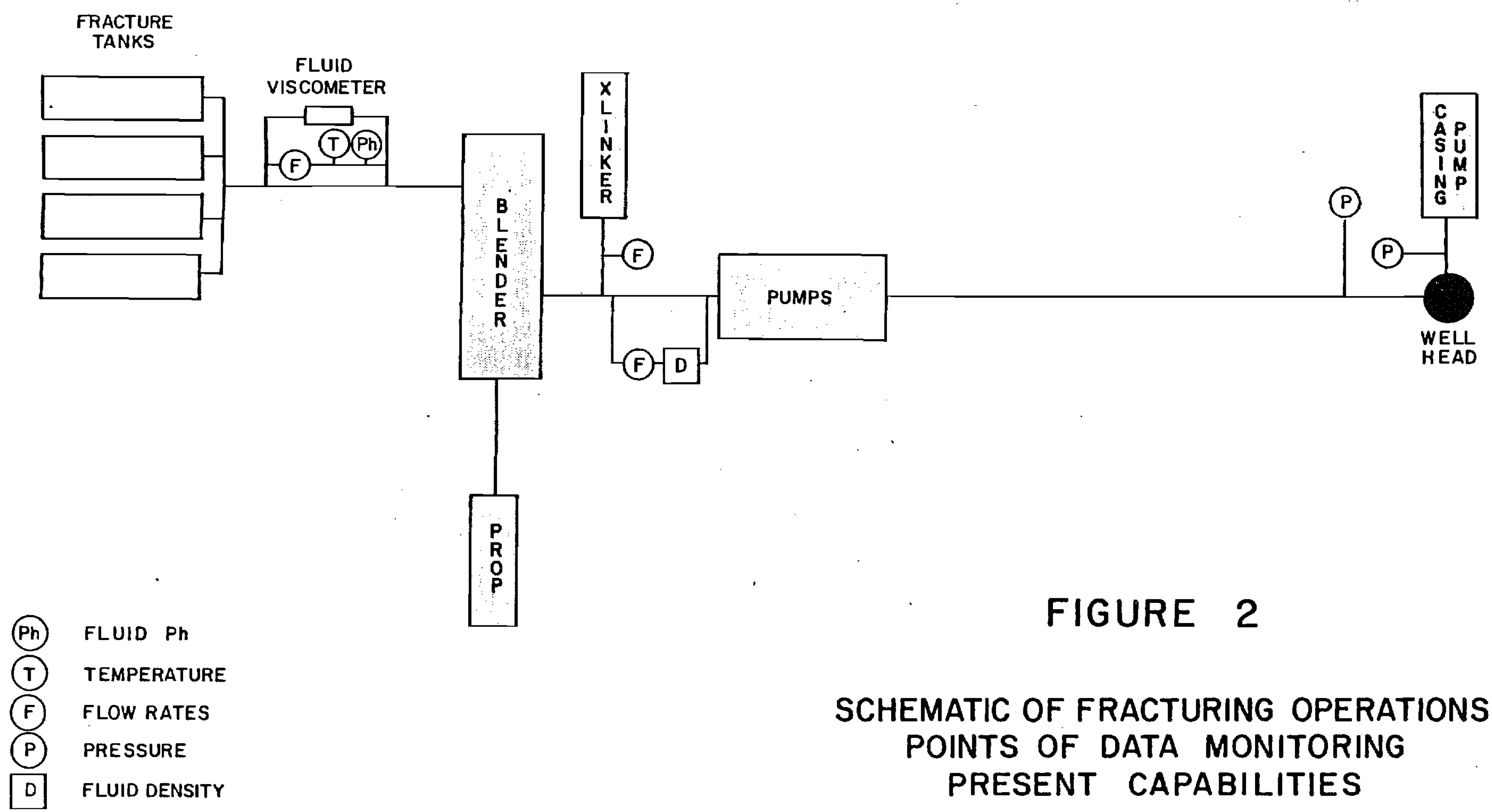


FIGURE 2

SCHEMATIC OF FRACTURING OPERATIONS
POINTS OF DATA MONITORING
PRESENT CAPABILITIES

(BY GRI DATA ACQUISITION TRAILER)

FIGURE 3

DESCRIPTIVE LOG OF TRAVIS PEAK CORE

CLAYTON WILLIAMS, JR.
SAM HUGHES WELL NO. I
PANOLA COUNTY, TEXAS

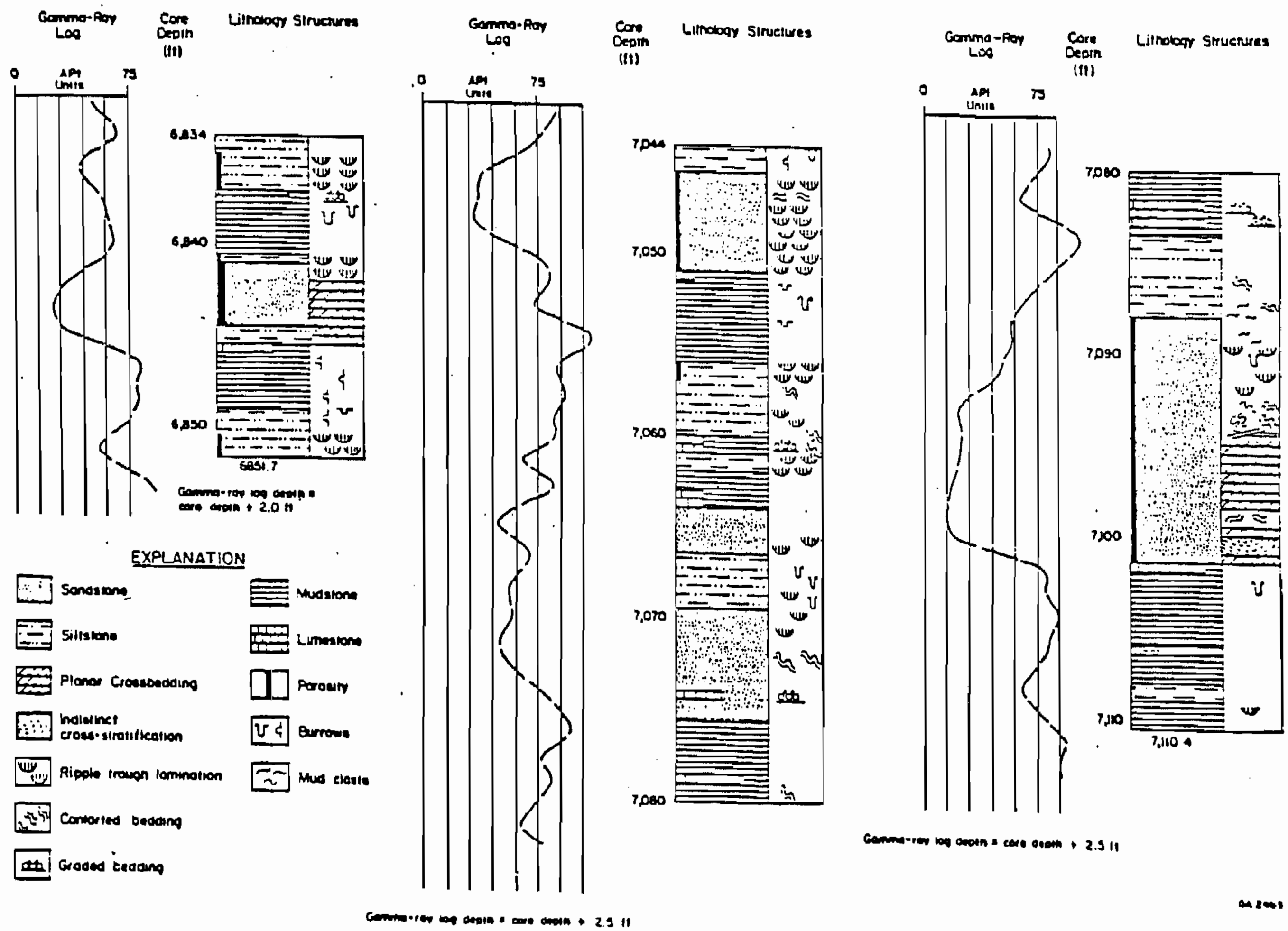


FIGURE 4
FRACTURE TREATMENT
NOLTE GRAPH
ARCO OIL AND GAS
HOLLINGSWORTH NO. 3
DE SOTO PARISH, LOUISIANA

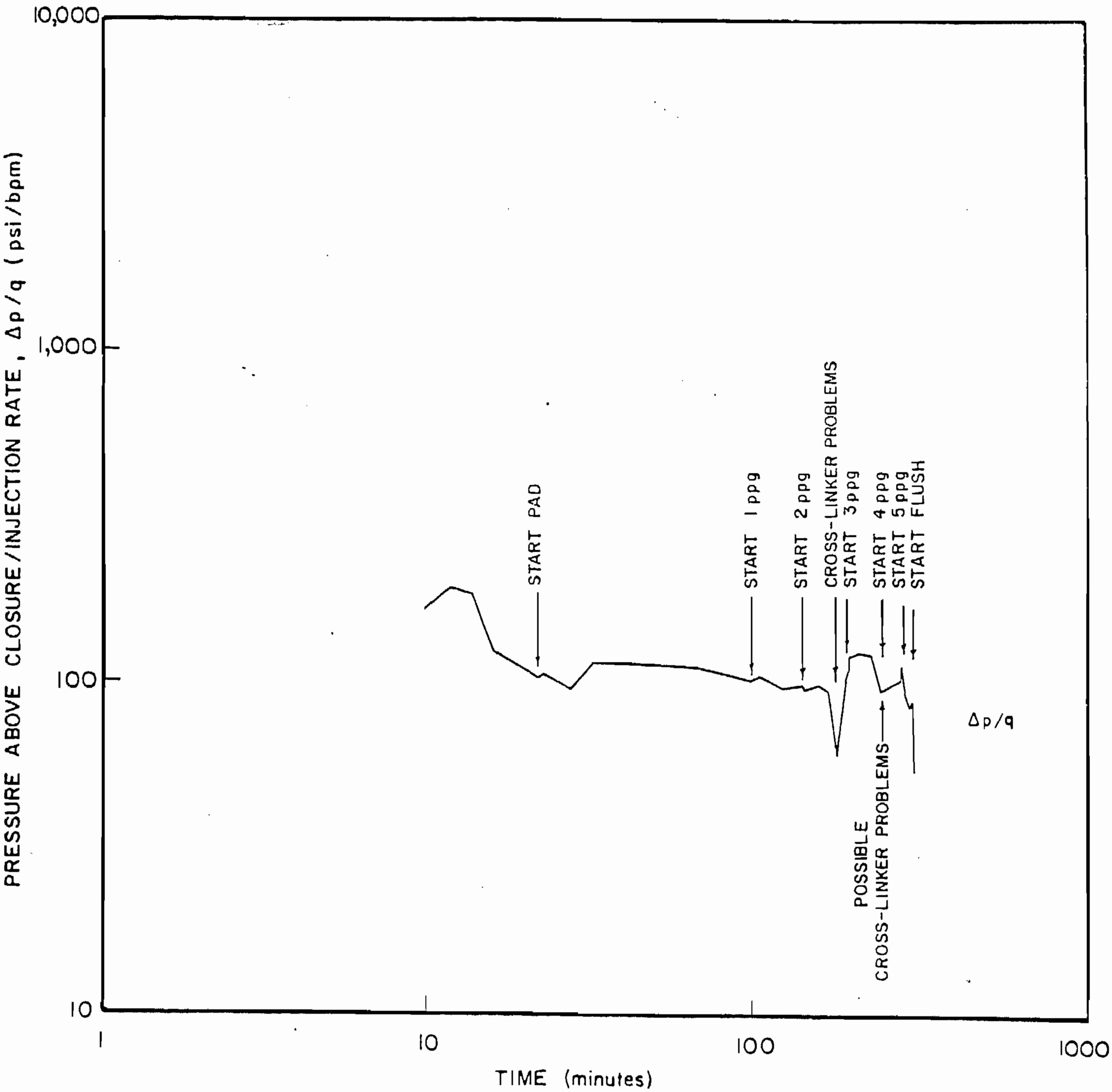


FIGURE 5
NOLTE GRAPH

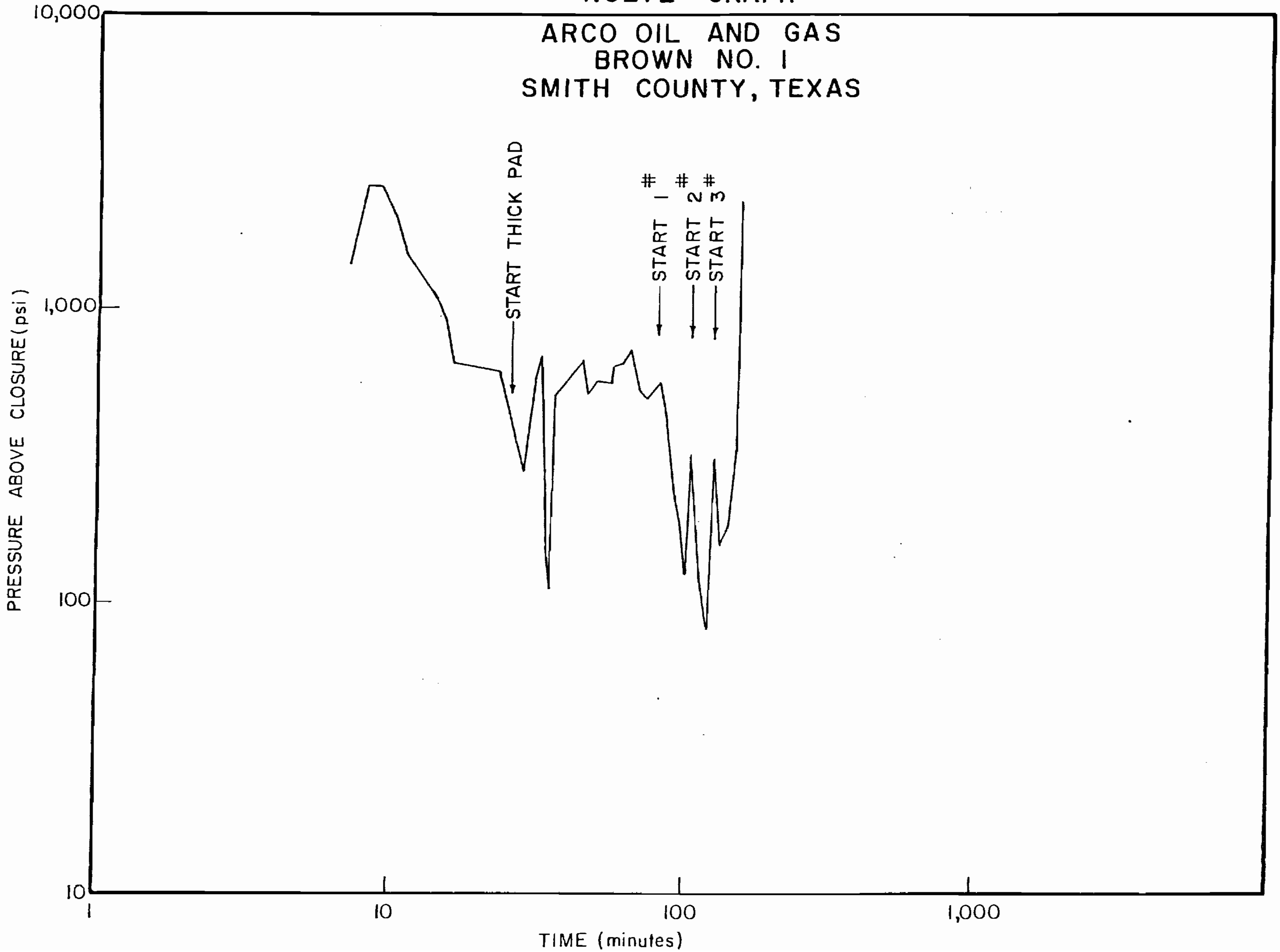


FIGURE 6

NOLTE GRAPH

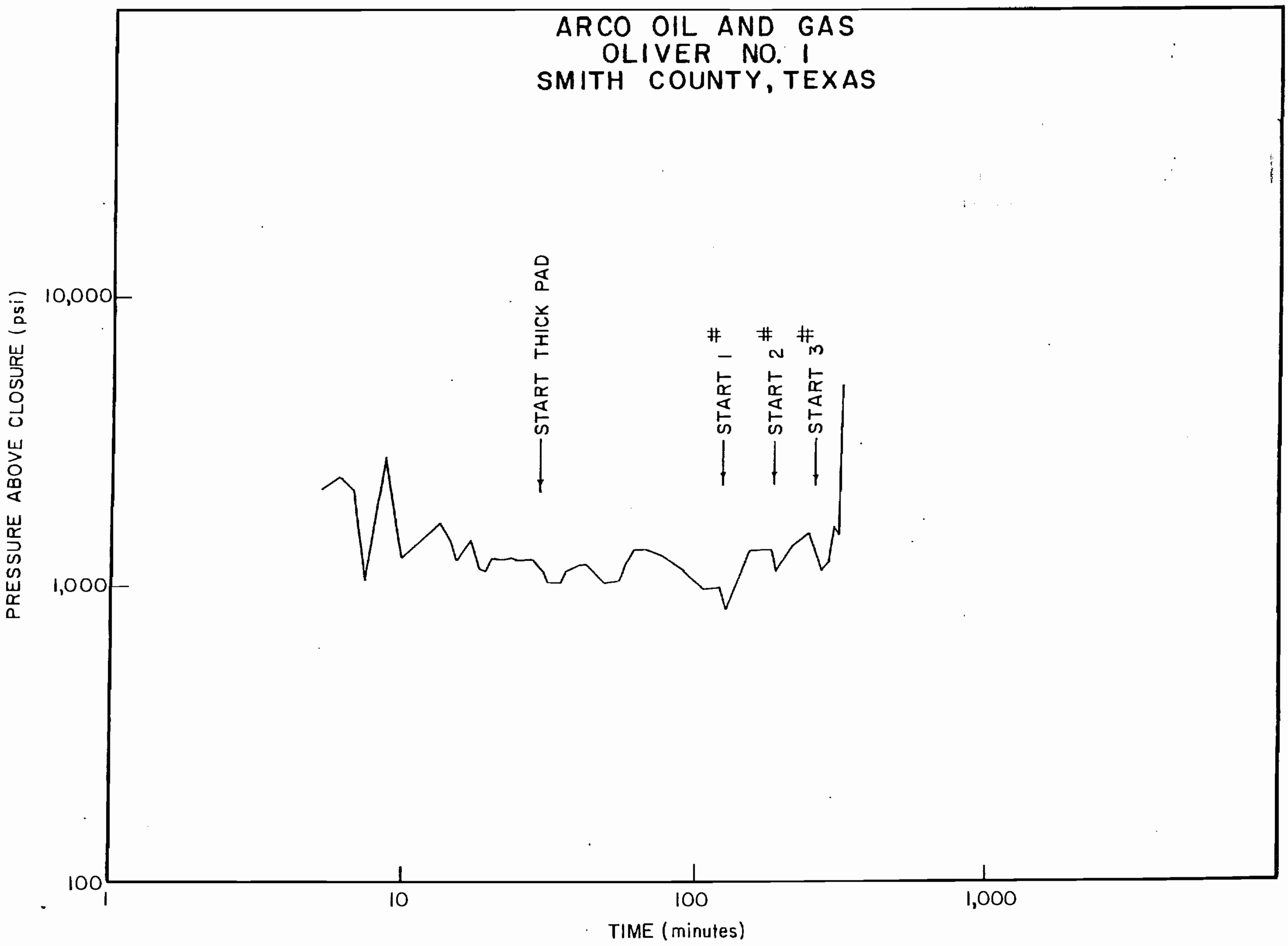
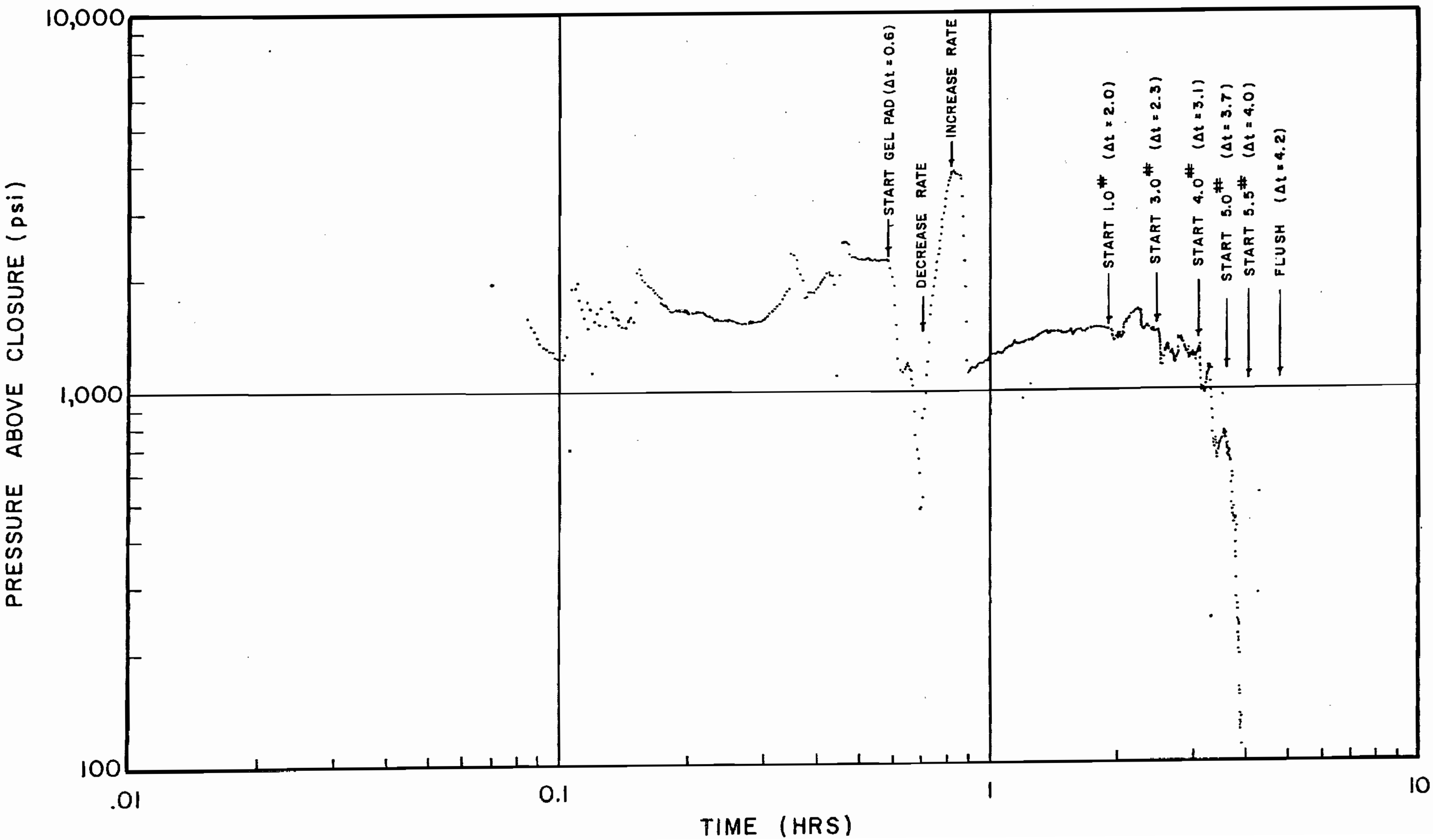


FIGURE 7
NOLTE GRAPH

ARCO OIL AND GAS
B. F. PHILLIPS NO. 1
SMITH COUNTY, TEXAS



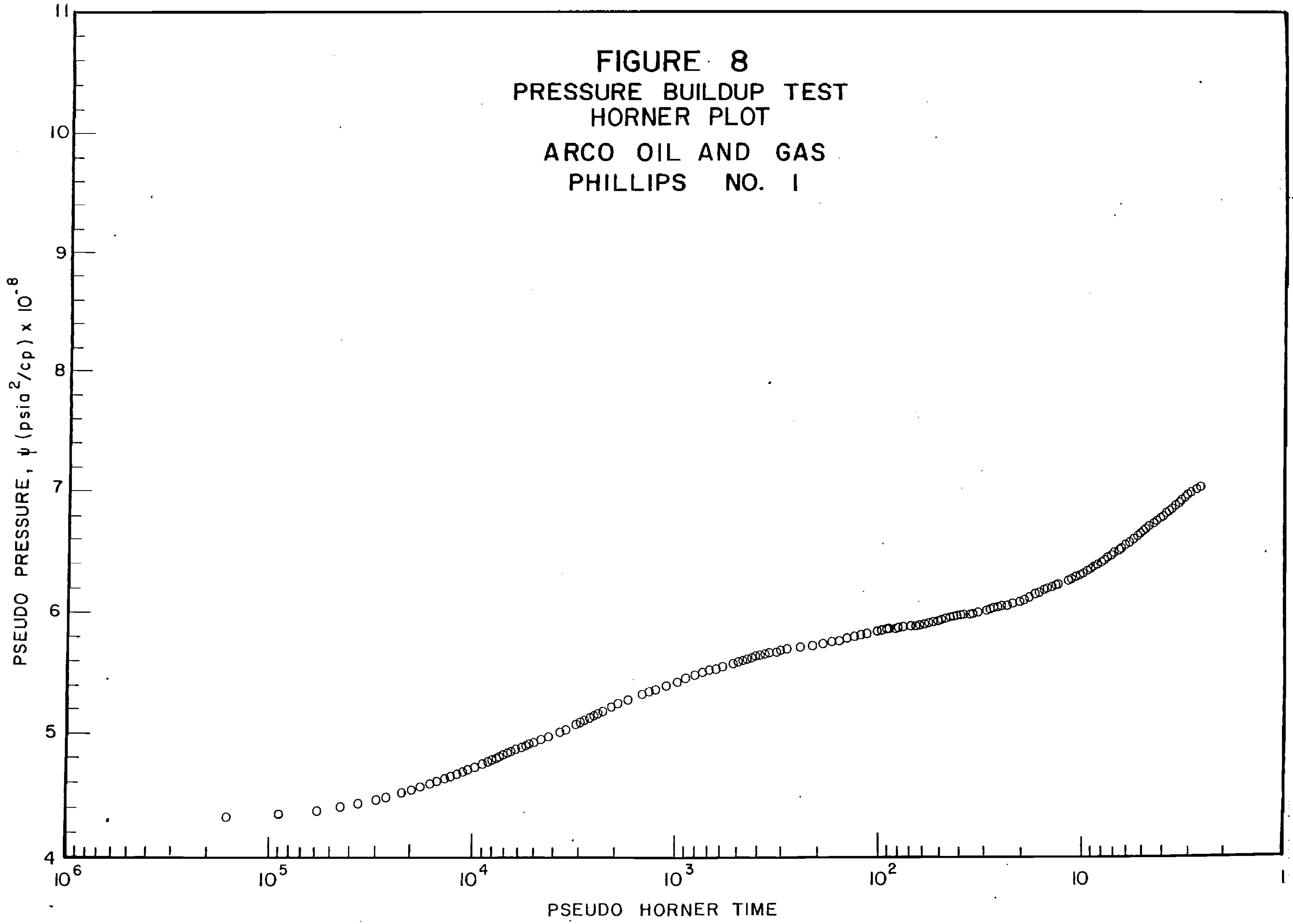


FIGURE 8
PRESSURE BUILDUP TEST
HORNER PLOT
ARCO OIL AND GAS
PHILLIPS NO. 1
PSEUDO PRESSURE, ψ (psia^2/cp) x 10^{-8}
PSEUDO HORNER TIME
11
10
9
8
7
6
5
4
10^6
10^5
10^4
10^3
10^2
10
1

FIGURE 9

PRESSURE BUILDUP TEST
TYPE CURVE PLOT

ARCO OIL AND GAS
PHILLIPS NO. 1

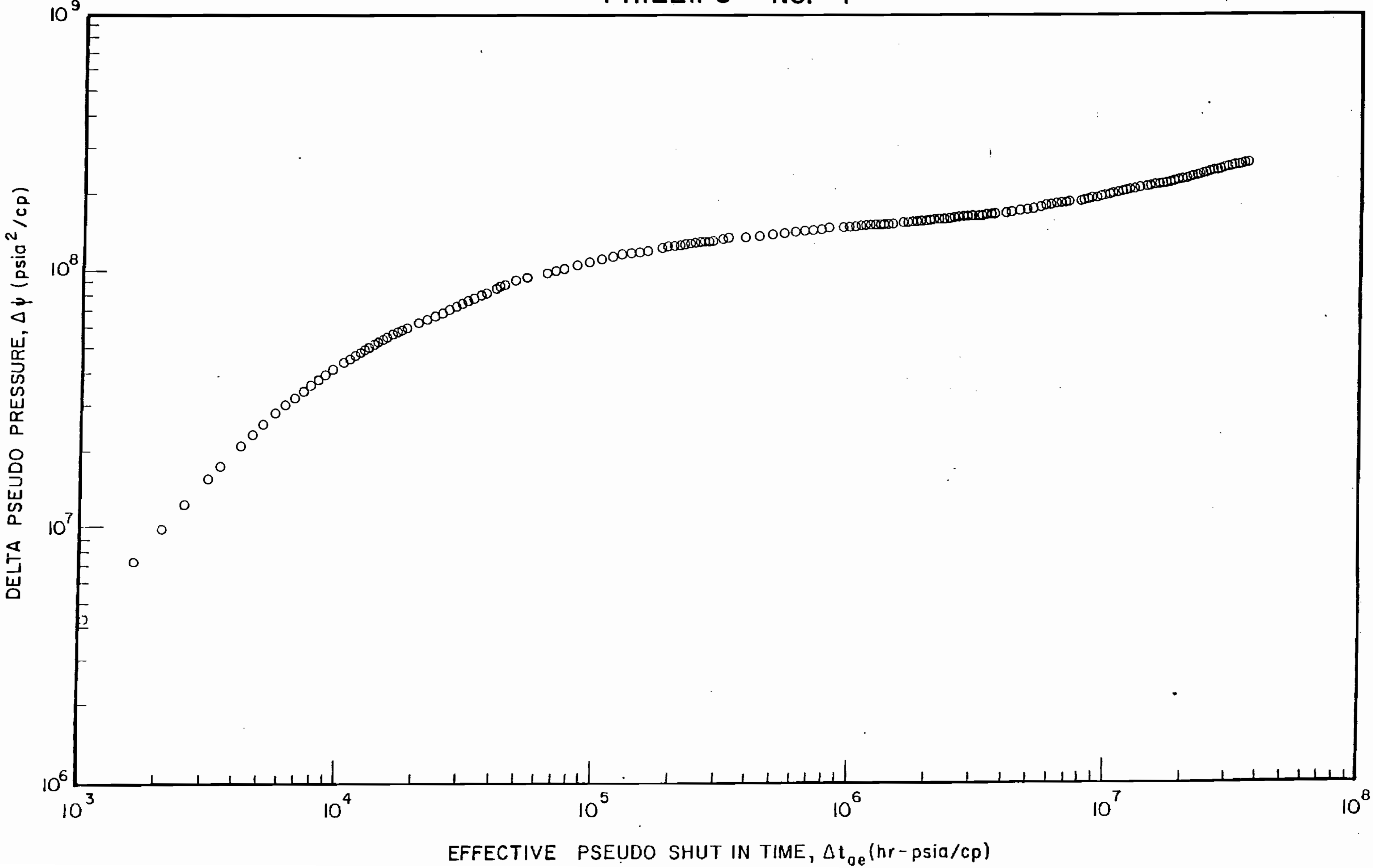
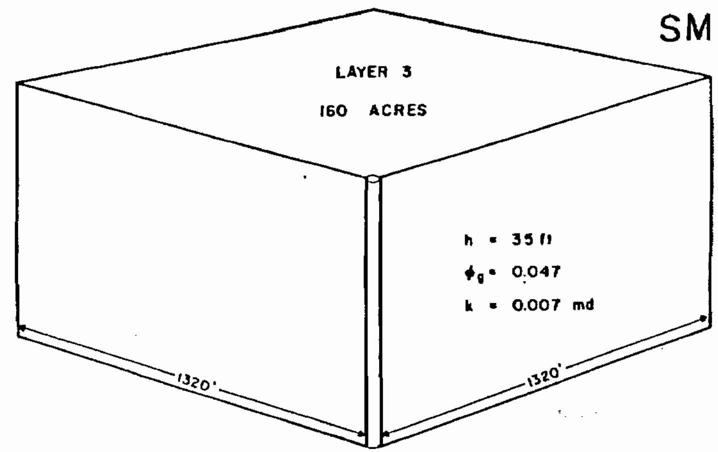
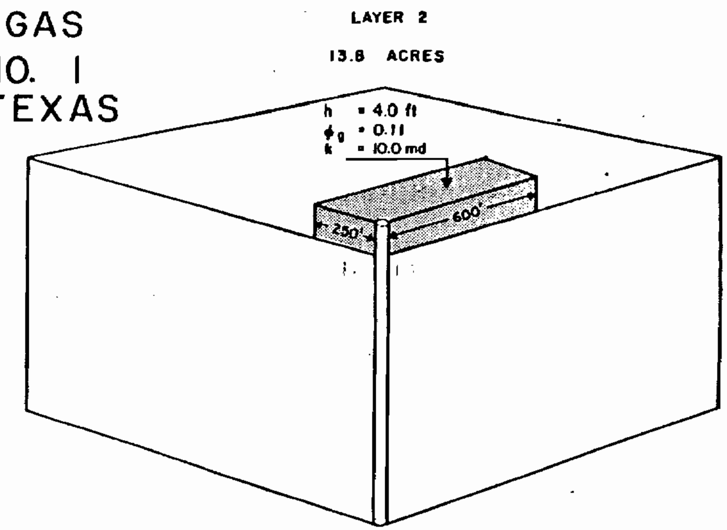


FIGURE 10

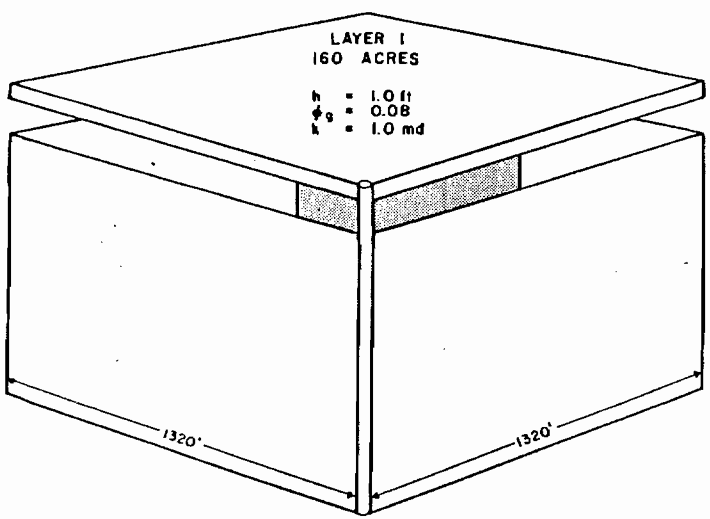
RESERVOIR SIMULATION
MODEL DESCRIPTION
ARCO OIL AND GAS
B. F. PHILLIPS NO. 1
SMITH COUNTY, TEXAS



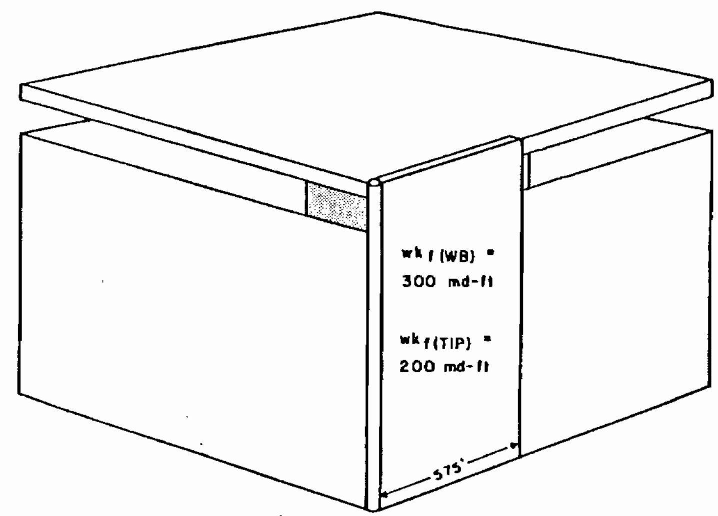
10-A



10-B



10-C



10-D

FIGURE 11

POST-FRACTURE PRESSURE BUILDUP TEST
HISTORY MATCH

ARCO OIL AND GAS
B. F. PHILLIPS NO. 1
SMITH COUNTY, TEXAS

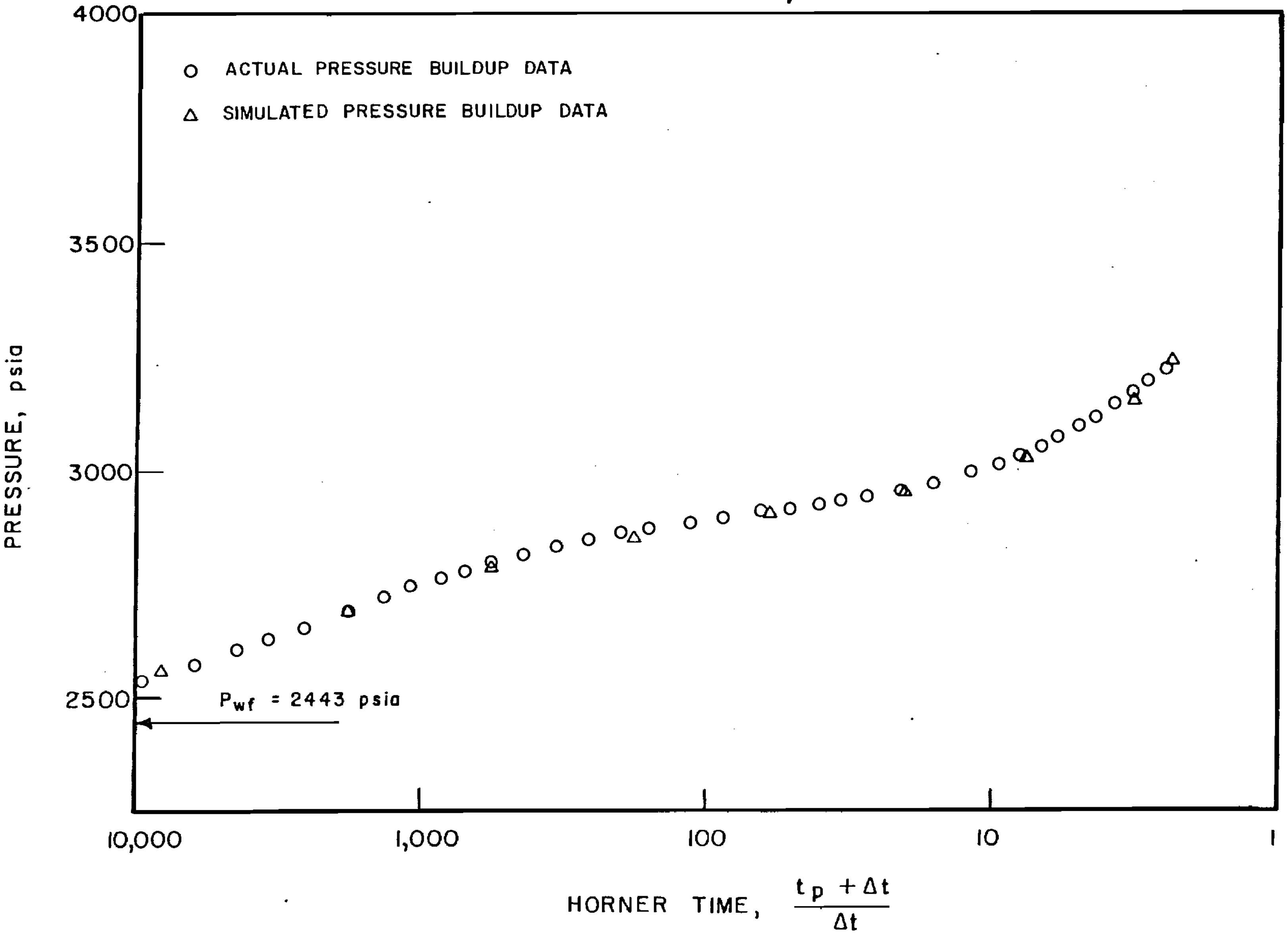


FIGURE 12

POST-FRACTURE PRODUCTION HISTORY

ARCO OIL AND GAS
B. F. PHILLIPS NO. 1
SMITH COUNTY, TEXAS