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LITTLE TOM THERMAL RECOVERY DEMONSTRATION
PROJECT, ZAVALA COUNTY, TEXAS

MASTER

By

Hanover Petroleum Corporation

9 502 394

Date Published — April 1976

Bartlesville Energy Research Center
Energy Research and Development Administration
Bartlesville, Oklahoma

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LITTLE TOM THERMAL RECOVERY DEMONSTRATION
PROJECT, ZAVALA COUNTY, TEXAS

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Contract E(34-1)-0002

Date Published — April 1976

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LITTLE TOM
THERMAL RECOVERY
DEMONSTRATION PROJECT
ZAVALA COUNTY, TEXAS

FIRST ANNUAL REPORT
FEBRUARY, 1975 - JANUARY, 1976
CONTRACT E(34-1)-0002

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FOREWORD

The ERDA program for enhanced recovery of oil and gas is aimed at demonstrating new recovery technology and transferring it to the private sector. The program is designed to maximize the participation of private industry by awarding cost-sharing contracts to companies which have capability in enhanced oil and gas recovery.

Data generated from these ERDA-industry field demonstration programs will be used to evaluate the technical and economic feasibility of an advanced recovery technique and should hasten the use of such techniques as one of the immediate measures that can be taken to ease the Nation's energy problem. Although much research has been done in both industrial and Government laboratories, additional testing is needed to provide information to reduce the risks associated with these high-cost processes. The ERDA demonstration projects, with full and timely public description of the results, will aid all oil and gas producers.

The Little Tom Thermal Recovery Project is one of several ERDA-industry demonstration projects now in progress. Data generated during the first year under this contract are described in this report.

F. Sam Johnson
ERDA Technical Project Officer

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TABLE OF CONTENTS

	<u>Page No.</u>
<u>INTRODUCTION</u>	1
<u>SUMMARY</u>	2
<u>BACKGROUND INFORMATION</u>	5
<u>SUMMARY OF WORK PERFORMED</u>	7
Thermal Stimulation	7
Thermal Stimulation Well Work	9
Other Project Well Work	11
Project Facilities Improvements	12
Operating Problems	14
 <u>FUTURE PLANS</u>	
Phase I - Injectivity and Production Testing	16
Phase II - Project Start-Up	16
Phase III - Project Operation	18
Phase IV - Project Expansion	18
 <u>TABLES</u>	 <u>Table No.</u>
Reservoir Characteristics	1
Summary of Ignition Attempts	2
Sampled Gas Analyses	3
Estimated Thermal Properties and Displacement Characteristics	4
 <u>FIGURES</u>	 <u>Figure No.</u>
Location Map, Little Tom Field	1
Structure Map, Top San Miguel "A" Sand	2
Isopach Map, Net Oil Sand, Combined San Miguel Sands	3
Stratigraphic Cross Section, Project Pilot Area	4
South Texas Fields with Crude Oil of °API 25.0 and Below	5
Temperature Surveys, Ned Matthews No. 9	6
Total Oil Production, Ned Matthews Lease	7
Producing Well Tests, Ned Matthews Lease	8
Liquid Sample Analyses	9
Operating Schedule, Little Tom Thermal Recovery Project	10

FIRST ANNUAL REPORT
LITTLE TOM THERMAL RECOVERY
DEMONSTRATION PROJECT
ZAVALA COUNTY, TEXAS

INTRODUCTION

This report is submitted in compliance with Sec. 2.6, Article II of Contract No. E(34-1)-0002 (originally H0252002) dated January 24, 1975 between Hanover Petroleum Corporation and the Energy Research and Development Administration of the United States. Presented herein is a summary of work undertaken and accomplished during the first year, and plans for the remainder of the Little Tom Thermal Recovery Project.

The objective of this joint venture project is to demonstrate the efficiency and economics of recovering low gravity, viscous crude oil from a relatively thin, low permeability reservoir utilizing a combination thermal drive process in conjunction with thermal stimulation of the producing wells. The combination thermal drive process combines forward in situ combustion with sequential water injection to provide maximum heat transfer efficiency along the burning front. Thermal stimulation (short term in situ combustion at the producing well) allows productivity increases to be realized long before the burning front approaches the producing well.

SUMMARY

Progress toward completion of Phase I of the project has been impeded by a number of problems. Three concerted ignition series have been made in an effort to initiate the thermal stimulation experiment on Well No. 9. Of the three efforts, only the first one successfully achieved ignition of the downhole burner for the desired length of time. Formation ignition during this attempt was indicated by the low oxygen content of gases subsequently produced from Well No. 9; however, air compressor breakdowns and subsequent wellhead failure prematurely aborted air injection. Prior to the second ignition series, the downhole burner was lowered 45 feet to just above the top of the main San Miguel pay. It appears that improper air-gas mixtures were experienced at this depth and ignition did not occur. The third ignition series was similarly unsuccessful.

According to the original schedule, the project was to have been in the initial stage of Phase III after one year. Current plans forecast the completion of Phase I in April, 1976, and Phase II in November, 1976. The current operating schedule is outlined in Figure 10.

On the positive side, the following project improvements were accomplished this first year:

- (1) Removal of screen liners and installation of larger rod strings resulted in a remarkable increase in primary productivity of two pilot area wells.
- (2) A pilot area tank battery was installed, solving most

of the production problems caused by pumping heavy crude through long flow lines.

- (3) A dependable long term supply of high pressure natural gas for fuel was obtained by recompleting a depleted gas well on an offsetting lease.

In spite of the difficulties experienced, we are optimistic that Phase I can be completed according to the revised schedule, and that the feasibility of beginning Phase II can be ascertained at the Benchmark Meeting No. 1-A to be convened at that time. Plans for completion of Phase I are basically unchanged, with the exception that the thermal stimulation experiment will be performed on Well No. 8. Attempts to ignite Well No. 9 have been abandoned because of the excessive injection pressure required. Plans for Phases II, III, and IV remain as originally proposed, except, of course, the timing has been delayed.

Contract No. E(34-1)-0002 authorizes a total project cost of \$3,048,059 (\$2,096,334 to be funded by Hanover, \$951,725 by ERDA). Total monies spent during the first year of the project through December 31, 1975, were \$173,934 (\$50,270 by Hanover, \$123,664 by ERDA). Total investment in the project as of the same date amounted to \$1,497,490 (\$1,373,826 by Hanover, \$123,664 by ERDA). Future authorized monies, assuming completion of all four project phases, total \$1,550,569 (\$722,508 by Hanover, \$828,061 by ERDA).

Hanover and its subcontractors would like to express appreciation for the patience and understanding shown by the

ERDA staff during the past year. It has been a pleasure to work with Mr. F. Sam Johnson, Technical Project Officer, and the other ERDA people associated with this project.

BACKGROUND INFORMATION

This project is being conducted by Hanover Petroleum Corporation on their 3,521-acre Ned Matthews lease, Little Tom Field, Zavala County, Texas. Figure 1 shows the general locale of the field within the county and state. The Little Tom Field encompasses some 5,500 acres estimated to hold about 77 million barrels of oil in place in the San Miguel "A," "A-1," "B," and "C" sands at a depth of about 2,800 feet. The faulted elongated domal structure of the San Miguel can be seen in Figure 2.

Although the field was discovered in 1950, less than 15,000 barrels of oil have been produced because of the reservoir's poor primary recovery efficiency. The viscous, heavy crude ranges in API gravity from 12 to 22^o.

Total oil saturated sand thickness ranges from 30 to 40 feet in the project area. An isopach map, Figure 3, shows the distribution of total reservoir net pay throughout the field. Figure 4 presents an electric log cross section through the pilot area.

The pertinent reservoir characteristics are summarized in Table 1. Produced oil samples collected and analyzed during the past year from wells in the project area indicate that the prevailing oil gravity may be much lower than the original estimate of 18^o API listed in Table 1. The arithmetic average of oil samples taken from five wells in or near the pilot area is 14.3^o API.

Hanover has partially developed the Ned Matthews lease by

drilling 14 wells. Efforts to produce these wells profitably by primary depletion have failed, primarily due to the unexpectedly high viscosity and low gravity of the oil. Mormac Oil & Gas Company, operator of offsetting leases, has had some success in producing three wells from the reservoir; however, they have reported higher produced oil gravities in the range of 20 to 22° API.

The combination thermal drive process, if successful, is expected to result in a potential recovery of from 32 to 42 percent of the oil in place. Successful application in the entire Little Tom Field would result in the additional recovery of about 25 to 32 million barrels of oil. Numerous other oil fields in Zavala and neighboring counties have similar heavy oil reservoirs. Some of these fields are shown in Figure 5.

SUMMARY OF WORK PERFORMED

All work performed to date has been aimed toward accomplishing the Phase I portion of the project. The objectives of Phase I are:

- (1) Establish the productivity of thermally stimulated producing wells.
- (2) Evaluate the injectivity of air into the San Miguel formation.

Neither of the two objectives has been fully accomplished. The work required to complete Phase I has exceeded all expectations due to a number of delays and operational problems.

Thermal Stimulation

Completion of Phase I and the feasibility of continuing this project currently hinges upon successful air injection and ignition of Well No. 8. At Benchmark Meeting No. 1, held February 2, 1976, a decision was made to abandon the attempt to ignite the formation in Well No. 9 and to shift the thermal stimulation experiment to Well No. 8, one of the proposed pilot pattern wells.

A total of three efforts have been made to ignite and sustain the thermal stimulation program designed for Well No. 9 for a 10 to 20 day period. A brief chronology of these ignition attempts is presented in Table 2.

Formation burning may have resulted from the first ignition attempt initiated on July 25, 1975. This was the only time that the planned ignition procedures were completed. The air injection was not continuous during the stimulation treatment, however,

because a compressor hose ruptured a few hours after ignition and the well lost pressure and back-flowed liquids into the hole. Several factors (i.e., parts delivery, mechanic availability, weather) delayed continuous air injection for 1 month until August 25, 1975. Air was then injected until September 4, 1975.

A temperature survey run on August 6 measured temperatures up to 30° F. higher than normal. This survey and the base temperature survey are compared in Figure 6. The fact that temperature increases were measured as low as 2,800 feet indicates that the fluid level dropped during injection and that the San Miguel "C" sand was taking air. A calculated total of 12.58 million Btu were delivered to the formation during this burn period. Permeability of the formation to air was calculated to be 1.2 millidarcys during pre-ignition injection.

Gas samples collected from Well No. 9 on August 1, 1975, shortly after ignition indicated a burning efficiency of 54 percent. Table 3 lists this analysis and those of other gas samples from Well No. 9 and the producing wells in the pilot area. After additional air injection, analysis of gas from Well No. 9 indicated 71 percent oxygen utilization.

Ignition temperatures at the downhole burner were calculated to be about 900° F., based on an air-gas ratio of about 62. With the heat shield set at the top of the perforations at 2,668 feet, hot gases had to move 151 feet to reach the bottom perforation. At low injection rates, the gases may have cooled to temperatures below that required for formation ignition. The heat shield was

lowered 47 feet to the top of the San Miguel "A" perforations following the August, 1975, ignition attempts; however, declining injectivity and other problems foiled later attempts.

Examination of the air injection rates and pressures in Table 2 reveals a general deterioration of injectivity with each successive series of air injection. In January, 1976, the well was circulated with hot diesel oil to clean heavy viscous oil from the tubing and sand face; this improved injectivity for only a short while.

The decision to cease ignition attempts in Well No. 9 was based on the probability that adequate injection rates to achieve and maintain formation ignition could not be attained at less than the formation fracturing pressure.

Thermal Stimulation Well Work

Extensive well work was required to prepare and repair Well No. 9 for the various ignition attempts. Initially the well was test pumped and found to have a production capacity of 1.00 barrel oil and 5.85 barrels water per day. Following the pumping test, a static bottom-hole pressure was recorded. The 12.5 hour shut-in pressure was 378 psig at 2,800 feet. The short shut-in time was insufficient for build up to the true reservoir pressure, estimated to be about 750 psig.

The screen liner was pulled and the well cleaned out. Diesel fuel was circulated to clean out the tubing and casing and the San Miguel perforations were acidized with 500 gallons of 15 percent hydrochloric acid.

Prior to the first ignition attempt, a heat shield was run on the bottom of the tubing. An attempt to run a gamma ray neutron log while injecting air failed when the logging sonde would not pass through the heat shield. Because of the higher than expected air injection pressures, the San Miguel was reperforated prior to running tubing with a larger diameter heat shield.

Following blowout of the wellhead pack-off rubber in September, 1975, air injection was terminated and the well was tested for production as soon as a pulling unit became available. Produced fluids were mostly water with heavy oil accumulated at the bottom of the tubing. Preparations for a second stimulation were made. The tubing was pulled for inspection of the heat shield and the tubing was rerun and the heat shield hung about 47 feet lower than its previous position. This placed the heat shield at 2,715 feet, below the top perforations in a stray sand not believed to be of primary interest. By reducing the length of the hole to be heated by the gas burner, chances for achieving ignition in the formation at the low air injection rate associated with this well were improved. The stripper type tubing head on Well No. 9 was replaced with a flange type tubing head rated at 2,000 psi working pressure (4,000 psi test) to allow injection at higher pressures.

Surface and downhole work was not completed until the latter part of November, 1975. Air and gas injection rates were again stabilized and the burner assembly was run December 11, 1975. A rapid pressure increase of about 100 psi was noted and

the burner assembly was lost in the hole. The tubing was pulled to recover the wireline ignition tools. Plugging of the lower five joints of tubing with rust, coke and heavy oil was observed. The well was circulated clean with heated diesel fuel and a radioactive tracer log run while injecting diesel fuel, indicating a leak in a casing collar between perforations in the San Miguel Stray and "A" zones. A packer was run on tubing and set below the indicated leak. Neither the leak nor the Stray zone perforations above would take fluid at 1,800 psi. The remaining perforations took fluid at 4 barrels per minute at 2,400 psi. The packer was pulled and the heat shield rerun and hung at 2,699 feet.

The third effort to stimulate Well No. 9 was terminated January 29, 1976. Pressures reached 2,400 psi in an effort to maintain desired injection rates. Partial plugging of the heat shield restricted passage of the full size ignition tools. Burner ignition was achieved using special procedures; however, it is believed that the downhole air-gas ratio was not as desired, and present indications are that higher than normal temperatures were experienced for a short time. Further work on Well No. 9 was terminated because of the high injection pressures.

Other Project Well Work

One of the pilot area wells, No. 13, was selected for a single zone completion in the San Miguel "C" sand, believed to be the initial target for thermal operations. All other wells had been completed in the complete section of San Miguel sands. Following the hydraulic fracturing treatment, the well was tested in

February, 1975. On the last day of a 4-day test, the well pumped 43 barrels water and a trace of oil. Intermittent testing during the year indicated decreasing water production with a slight increase in oil. On the most recent test in August, 1975, Well No. 13 pumped 0.5 barrels oil and 11 barrels water per day. Although these test results are disappointing, thermal stimulation, if successful in other wells, should greatly benefit Well No. 13.

A considerable amount of other well reconditioning has been accomplished in the pilot area. Screen liners were pulled from Well No. 8 and 12. After cleaning out, the tubing was lowered to about 30 feet from the bottom. Larger rod strings (3/4 inch) were installed in the two wells to improve pump operation and prevent stress failures. The heavier rods fall faster through the viscous crude on the pump downstroke, helping to maintain a smoother, more efficient pump action.

Well tests indicate productivity was significantly improved by these procedures. Total lease production and the periodic well tests of all project wells are presented in Figures 7 and 8.

Valves were installed on the casingheads of Well Nos. 5, 6, 8, 12, and 13 to allow monitoring of casing pressures and collecting of gas samples.

Project Facilities Improvements

Several additional tasks were successfully accomplished which had not been expected to be required until after Phase I. A dependable natural gas supply was obtained by recompletion of the Electrothermic Company Matthews Navario Gas Unit No. 1 in a

sand at 1,553 to 1,560 feet. This well, with an absolute open flow potential of 6,300 Mcf per day, should be capable of supplying ignition, crude treating and compressor fuel gas requirements for the life of the project. Although the well belongs to Electrothermic, Hanover has first call on the gas produced from this well. A previous attempt to recomplete Hanover Matthews No. 2 in two gas sands was unsuccessful.

A 500-barrel storage tank and treater were moved to the pilot area from the central tank battery located about 1 mile away. This move was made to shorten the flow lines, lowering the pressures required to pump the viscous produced oil to the tanks. High pumping wellhead pressures had caused frequent stuffing box blowouts at the pilot area producing wells. Flow lines occasionally became plugged as the heavy crude cooled on the way to the tanks.

Gas supply lines were installed to serve the tank battery during emulsion treating operations. Extensive heating and chemical treatment is required to meet purchaser specifications because of the heavy composition of the oil. Emulsions are difficult to break, particularly in such a viscous low gravity oil. As the API gravity approaches 10° , separation of water from the oil becomes more difficult. Several of the wells are known to produce 12 to 13° API gravity oil. Figure 9 illustrates the viscosity-temperature relationship for oil produced from project wells.

Operating Problems

Many of the delays incurred in completing Phase I of this project are attributable to the remoteness of the project site. The nearest location which offers a full line of oil field services, supplies, and equipment is at Alice, Texas, some 125 miles to the southeast.

Delays of up to several weeks have been experienced in waiting on well servicing units. The general increase in oil industry activity following the Arab oil embargo and oil price increases of 1973 has continued to outstrip trained labor and equipment availability.

The lease roads become slick and impassable for several days following rain. Upgrading to all weather roads cannot be economically justified during Phase I. Violent electrical storms have on several occasions damaged the electrical distribution systems, requiring a total shut down of operations until repairs were made.

A lack of adequate natural gas supply hampered ignition attempts in Matthews Well No. 9 until a successful recompletion of the Electrothermic gas well. Prior to the recompletion the well had to be swabbed intermittently at great expense in order to maintain flow.

Sustained operation of the project producing wells in the pilot area proved impossible until a tank battery was moved to the pilot area. The high pressures required to move the viscous crude through the long flow lines caused numerous stuffing box

failures at the producing wells.

Air injection pressures in Well No. 9 were much higher than anticipated. To keep within the pressure rating of the main compressor, air rates have been limited; however, at pressures as high as 2,400 psi, frequent repairs and expert maintenance are necessary. This problem should be alleviated by the lower injection pressures to be encountered in Well No. 8. An attempt is being made to secure a higher pressure compressor or booster for use if required.

FUTURE PLANS

Plans for completion of this project are basically unchanged from those originally proposed. Figure 10 presents the current operating schedule, which divides the experiment into three test phases prior to expansion.

Phase I - Project Injectivity and Production Testing

Phase I is scheduled to end in April, 1976, upon completion of the thermal stimulation test in Well No. 8.

The thermal stimulation test will be accomplished by igniting the formation and injecting air into Well No. 8 for a period of 10 to 14 days. Prior to cessation of air injection, a temperature and neutron log will be run. These logs will be compared to pre-ignition logs to evaluate the vertical extent of the formation taking air during the burn. The well then will be test pumped for a period of about two weeks to evaluate the effectiveness of the stimulation treatment. If (1) adequate air injection can be maintained at reasonable pressures, (2) vertical sweep of injected air is fair, and (3) post-stimulation oil production rates of 8 to 15 BOPD can be attained, then Phase II will be initiated.

Phase II - Project Start-Up

An injection well will be drilled in the location shown in Figure 2 to complete the inverted, four-spot pilot pattern.

While drilling the injection well, a full core will be obtained through the various San Miguel sand sections. A laboratory analysis of each section will be made to determine thermal characteristics. Particular attention will be given to fuel and

air requirements for the CTD (Combination Thermal Drive) process for the "A," "B," and "C" sand sections. In addition, three-phase flow data will be obtained on the "C" sand section, assuming that this zone is still the target for the initial project in the Little Tom Field. Data obtained from these thermal studies will be used to update the estimated thermal properties and displacement characteristics listed in Table 4 and the new data will furnish the basis for the design and evaluation of the project during Phase III.

As soon as it appears certain that the project will be expanded, an air compressor, rated at about 2,000 Mcf/D, will be placed on order. It probably will be at least the end of June, 1976 before a proper basis for sizing of this machine can be ascertained. Current estimates are 2,000 psig and 880 hp. Shortly after Phase II starts, however, a second rental unit will be moved to the lease to treat additional production wells with high temperature stimulation, assuming that this gives better production results than conventional fracture treatments.

About 2 or 3 months after the injection well has been ignited, a temperature and neutron log will be run across the sand section to determine the vertical entry profile. This should assist in early confirmation of the estimated sweep efficiency for the thermal operation.

The oil, water, and gas rates from individual wells will be frequently monitored with emphasis on the wells in the thermal pattern. In addition, it may be necessary to install gas-oil separators, both on the flow lines and on the gas lines from the

individual wells. Much of Phase II will be used as a training period to bring operating personnel up to the experience level required for this complicated displacement process. Routine gas samples will be obtained from all wells producing gases. These will be analyzed for oxygen, nitrogen, carbon oxides, methane, and other miscellaneous gases. The results of these analyses are the key to successful thermal operations in that combustion (displacement) efficiency can be detected and rate adjustments can be made as necessary.

Phase III - Project Operation

Assuming the progress of Phase II is satisfactory, a water well will be drilled to insure adequate water supply for the CTD process during Phase III. After about 7 months of operation of Phase II, the permanent air compressor should be delivered and installed. We anticipate this being about the end of 1976. During Phase III, water injection will be started and additional production wells will be stimulated until at least all wells have been treated once. Water-air injection is estimated to continue for about 2 years after the start of Phase III.

Phase IV - Project Expansion

If results are favorable and the project meets the required economic profitability criteria, expansion of the project might be considered after about 1½ years of operation. It is anticipated that following Phase III another 6 months to a year will be required to fully evaluate the results of the initial test pattern. If the project is completely successful by the end of

Phase III, it is anticipated that Hanover will have increased the compressor capacity by 100 percent (4,000 Mcf/D) and installed at least three additional injection patterns.

Preliminary production estimates have forecast a project producing rate of 380 to 560 BOPD at 4,000 Mcf/D injection with profitable thermal operations to have a life of several years. The volumetric extent of the Little Tom Field is sufficient to warrant considerably larger expansions if process economics and investment opportunity analysis so dictate. Further fieldwide expansion will require additional manpower and equipment to handle the larger scale project operations, and is beyond the scope of the demonstration project.

TABLE 1

RESERVOIR CHARACTERISTICS
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

<u>Little Tom Field</u>	<u>San Miguel Sand Member</u>				<u>Field</u>
	<u>A</u>	<u>A-1</u>	<u>B</u>	<u>C</u>	
Average Depth, ft					2,800
Productive Area, ac					5,500
Average Porosity, percent	22.3	23.1	23.4	21.3	22.3
Average Permeability, md	99	115	62	31	64
Average Water Saturation, percent					40
Reservoir Pressure(a), psi					750
Oil Gravity, °API					18
Solution Gas-Oil Ratio(a), cu ft/bbl					77
Reservoir Temperature, °F.					125
Oil Viscosity (dead), cp					230
Oil Viscosity (reservoir), cp					90
Formation Volume Factor, vol/vol					1.05
Pore Volume, bbl/acre-ft					1,730
Initial Oil In Place, bbl/acre-ft					988
Primary Recovery Factor, percent					3
Reservoir Volume, acre-ft					77,675
Initial Oil In Place, Mbbl					76,768
Potential Thermal Oil Recovery					
Recovery Factor (low range), percent					32
Recovery Factor (high range), percent					42
Oil Recovery (low range), Mbbl					24,565
Oil Recovery (high range), Mbbl					32,242
 <u>Hanover Petroleum Corporation Leases</u>					
Productive Area, ac					3,521
Initial Oil In Place, Mbbl					40,280
Potential Thermal Oil Recovery(b), Mbbl					12,900

(a) Estimated

(b) Low range (32 percent recovery factor)

TABLE 2

SUMMARY OF IGNITION ATTEMPTS
 HANOVER PETROLEUM CORPORATION
 NED MATTHEWS NO. 9
 LITTLE TOM FIELD
 ZAVALA COUNTY, TEXAS

<u>Beginning Date (1)</u>	<u>Air Injection (2) (3)</u>		<u>Gas Injection (3)</u>		<u>Downhole Burner Ignition</u>	<u>Ending Date</u>	<u>Reason for Termination</u>	<u>Work Performed Prior to Next Ignition Attempt</u>
	<u>Rate, Mcf/D</u>	<u>Casing Pressure, psig</u>	<u>Rate, Mcf/D</u>	<u>Tubing Pressure, psig</u>				
June 5	300	1300	None	-	-	June 6	Heat shield too small to pass GR-N tool.	Changed heat shield and reperforated.
June 24	-	-	None	-	-	June 24	Rain storm (4).	
July 8	130	1530	None	-	-	July 10	Rupture of compressor cooler.	
July 14	-	-	None	-	-	July 15	Rain storm.	
July 21	166	1440	3.8	1580	Yes	July 22	Gas supply well died.	Swabbed water from gas well.
July 22	142	1520	3.4	1640	Yes	July 24	Compressor line rup- tured.	
July 25	114	1620	2.2	1770	Yes	July 28	Compressor hose rup- tured.	
August 14	65	1400	None	-	-	August 15	Compressor head gasket failure.	
August 25	75	1600	None	-	-	September 4	Wellhead stripper rubber failed.	Installed 2000 psi WP flanged wellhead; lowered heat shield.
November 13	158	1700	None	-	-	November 15	Compressor instru- mentation problem.	
November 24	60	1770	None	-	-	November 24	Compressor head gasket and clutch failure.	
December 5	35	1800	-	-	-	December 9	Shut down to allow pres- sure to decrease.	
December 11	100	1780	1.68	1930	No	December 12	Downhole explosion during ignition.	Pulled tubing, recovered igni- tion tools, cleaned out well.
January 22	289	2010	-	-	-	January 23	Compressor line rup- tured.	
January 23	240	1990	4.0	2090	Yes	January 25	Compressor line rup- tured.	
January 26	137	2250	2.5	2350	No	January 29	High injection pressure.	

(1) Date began injecting air for pre-ignition stabilization.

(2) Data listed are for final day of injection period, except when downhole burner ignition attempted.

(3) Where downhole burner ignition attempted, data listed are rates immediately prior to ignition attempt.

(4) Dirt lease roads become impassable when wet.

TABLE 3

SAMPLED GAS ANALYSES
 HANOVER PETROLEUM CORPORATION
 NED MATTHEWS LEASE
 LITTLE TOM FIELD
 ZAVALA COUNTY, TEXAS

Well No.	Sampling Date	Constituent, Mol Percent								
		C ₃	C ₄	CH ₄	C ₅	CO ₂	O ₂	N ₂	CO	A _r
5	July 8	18.1	-	66.2	1.2	-	2.7	11.6	-	0.2
6	July 8	16.9	4.1	78.0	0.7	-	-	-	-	-
8	July 24	7.8	2.6	89.1	0.5	-	-	-	-	-
	August 28	15.4	2.4	81.6	0.6	-	-	-	-	-
	September 19	2.2	4.7	92.6	0.5	-	-	-	-	-
	September 19	2.5	3.9	93.0	0.6	-	-	-	-	-
9	August 1	-	-	6.4	-	1.0	10.1	81.5	0	1.0
	September 19	-	-	12.8	1.8	0.9	6.8	76.7	-	1.0
	September 19	-	-	14.8	-	0.9	4.9	78.4	-	1.0
12	July 8	20.1	Tr	78.0	1.0	-	-	-	-	-
	July 24	18.1	3.6	78.0	0.3	-	-	-	-	-
	August 28	17.9	3.5	77.5	1.1	-	-	-	-	-
	September 19	3.3	4.5	91.0	1.2	-	-	-	-	-
13	July 8	15.1	4.1	80.4	0.4	-	-	-	-	-
	July 24	19.9	-	35.1	-	-	9.4	35.1	-	0.5

TABLE 4

ESTIMATED THERMAL PROPERTIES AND
DISPLACEMENT CHARACTERISTICS
SAN MIGUEL "C" ZONE
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

Molecular Weight of Fuel Unit CH_x	13.8
Apparent Atomic Hydrogen Carbon Ratio	1.8
Fuel:	
lbs/cu ft	1.50-1.98
bbl/acre-ft	197-260
Estimated Combustion Efficiency, percent	85
Air Required for Combustion	
Scf/cu ft	300-396
Mcf/acre-ft	13,000-17,250
Oil Displaced by Combustion, bbl/acre-ft	791-728
Air-Oil Ratio, Mcf/bbl	16.4-23.7
Water Formed by Combustion, bbl/acre-ft	225
Combustion Temperature, °F.	950
Heat Capacity of Reservoir, Btu/cu ft - °F.	
Saturated Sand	36.5
Dry Sand	26.0
Thermal Conductivity, Btu/hr - Ft - °F.	
Saturated Sand	0.85
Dry Sand	0.62
Thermal Diffusivity, sq ft/day	
Saturated Sand	0.56
Dry Sand	0.57
Overburden	0.74
CTD Zone Conditions, bbl/acre-ft	
Oil 30 percent	519
Water 50 percent	865
Volume Ratio, CTD Zone/Burned Vol.	0.73
CTD Water-Air Ratio, bbl/MMcf	210
CTD Air-Oil Ratio, Mcf/bbl	11.5-16.1
Residual Saturations after Water Fill-Up, percent	
Oil	18
Water	70
Ultimate Air-Oil Ratio, Mcf/bbl	10.1-14.1
Total Water Injected, bbl/acre-ft	1,341

FIGURE 1
LOCATION MAP
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

HANOVER PETROLEUM CORPORATION

HANOVER
Matthews No. 9

HANOVER
Matthews No. 8

HANOVER
Matthews No. 12

HANOVER
Matthews No. 13

HANOVER
Matthews No. 14

FIGURE 4
STRATIGRAPHIC CROSS SECTION
PROJECT PILOT AREA
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

DATUM: TOP OLMOS SCALE H: NONE
FEBRUARY, 1976 V: 1" = 200'

HANOVER PETROLEUM CORPORATION

FIGURE 6
TEMPERATURE SURVEYS
NED MATTHEWS NO. 9
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

HANOVER PETROLEUM CORPORATION

WELL NO.	PRODUCED WATER CL, PPM	PH	PRODUCED OIL GRAVITY, °API AT 60° F.
5	17,400	7	19.9
6	18,000	7	12.4
8	18,750	7	12.5
9*	18,750	7	12.2
12	17,400	7	14.5

*SAMPLE TAKEN MAY 9, 1975. ALL OTHER SAMPLES TAKEN JULY 26, 1975.

FIGURE 9
LIQUID SAMPLE ANALYSES
NED MATTHEWS LEASE
LITTLE TOM FIELD
ZAVALA COUNTY, TEXAS

HANOVER PETROLEUM CORPORATION

COMPLETED TESTING WELL NO. 13
 RENTED 350 MCF/D COMPRESSOR
 ATTEMPTED TO IGNITE WELL NO. 9
 COMPLETED GAS WELL
 IGNITE WELL NO. 8
 TEMPERATURE AND NEUTRON LOG WELL NO. 8 ...
 EVALUATE WELL NO. 8 RESULTS
 DRILL AND CORE INJECTION WELL
 IGNITE INJECTION WELL
 CORE ANALYSIS AND THERMAL STIMULATION
 RENT NO. 2 COMPRESSOR AND STIMULATE WELLS
 ORDER 2000 MCF/D COMPRESSOR
 TEMPERATURE LOG AND N-LOG INJECTION WELL ..
 INSTALL TEST EQUIPMENT
 DRILL WATER WELL
 INSTALL 2000 MCF/D COMPRESSOR
 START WATER INJECTION
 STIMULATE OTHER WELLS
 CONTINUOUS AIR-WATER INJECTION
 WATER INJECTION
 PROJECT EXPANSION
 TEST EVALUATION