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LYNCH CANYON COMBINATION THERMAL DRIVE PROJECT

Final Report

Work Performed for the Department of Energy
Under Contract No. DE-AC03-78ET12086

Date Published—November 1980

Mobil-GC Corporation
Newport Beach, California

U. S. DEPARTMENT OF ENERGY

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LYNCH CANYON COMBINATION THERMAL DRIVE PROJECT

Final Report

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ABSTRACT

The following report provides a summary of the Lynch Canyon Thermal Drive Project. This demonstration project, jointly funded by the United States Department of Energy and Mobil - GC Corporation was begun in 1978 and terminated in 1980. The project originally was divided into four phases; Geologic Evaluation, Injectivity Test, Field Development Combined with Air-Water Injection, and a Project Review.

Following the First Phase operations, which included drilling of four wells for geologic evaluation, a joint decision to cancel the project was made. The conditions which were thought to exist at the initiation of the project, would have provided an excellent opportunity to conduct a Pilot Combination Thermal Drive. However, potential problems which were discovered in the Phase One Operations significantly altered the economics of the project and removed the favorable conditions under which the project was begun.

MOBIL-GC CORPORATION

OIL RECOVERY BY COMBINATION THERMAL DRIVE

LYNCH CANYON FIELD

MONTEREY COUNTY

CALIFORNIA

Introduction

In September, 1978 Mobil-GC Corporation (formerly General Crude Oil Company) and the United States Department of Energy entered into a DOE cost-sharing contract to jointly fund the Lynch Canyon Combination Thermal Drive Project. The objective of this research project was to demonstrate and evaluate the recovery of a very viscous crude oil using the Combination Thermal Drive process aided by cyclic steam injection in a large-scale field operation. A further objective was to demonstrate an automatic data accumulation system for optimum project operation and control. The project site was in the Lynch Canyon Oil Field in Section 24, T22S-R10E MDB&M, Monterey County, California.

The project area encompassed approximately 60 acres with full development to eventually include twelve

(12) staggered line drive patterns. Work under the contract was to be conducted in four phases over about a five-year period.

This final report reviews the proposed full scale project, including a geologic description of the reservoir, a history of production, a discussion of the Combination Thermal Drive application to the Lanigan sand, a review of Phase One operations and the factors which led to termination of the project.

Project Summary

The Lynch Canyon Oil Field is located in Sections 23 and 24 of T22S, R10E, MDB&M, Monterey County, California. It is three miles northeast of the San Ardo Field, Figure 1. The productive horizon, the Lanigan sand is at a depth of approximately 1800' and has an estimated oil bearing area of 500 acres, and a net oil sand volume of 8130 acre-feet. The original oil-in-place is currently estimated at 14.6 million barrels.

The field was discovered in 1962 when Moriqui Exploration Company completed Lanigan 172 producing a 9° API oil with a reported viscosity of approximately 9,000 centipoise at the reservoir temperature of 104°F. Three additional wells were completed in 1962, but the extremely high viscosity of the oil prevented effective pumping due to rod-fall problems.

After acquiring the property in 1963, Texaco drilled ten additional wells and attempted to improve the field's productivity first by installing electric bottom hole heaters and later with cyclic steam stimulation. These efforts increased well rates to 25 - 40 BOPD, but due to casing failures, difficulties in shutting

off water in overlying sands, pumping problems, and a low oil price, Texaco abandoned all wells and quit-claimed the property in 1968 after producing 111,000 Bbls. of oil.

General Crude acquired the property in 1972 with the intent of developing and producing the field utilizing a combination of thermal recovery methods. In 1977 a technical proposal was submitted to ERDA for the use of the Combination Thermal Drive process, the simultaneous injection of air and water. One year later, the Department of Energy and General Crude Oil Company entered into a contract to demonstrate applicability of the Combination Thermal Drive in permeable heavy oil sands.

Geologically, the Lynch Canyon field produces from the Lanigan sand, an offshore sand bar which pinches out against the basement. The productive limits of the field are delineated by a water table at 1070' subsea as shown on the structure map, Figure 2. Isopach maps and cross sections are presented in Figures 3, 4, 5 & 6. The Lanigan sand is characterized by a 5' - 10' interval of high water saturation and relatively low permeability (500 MD) immediately above the oil sand, Figure 7. The oil sand can be divided into 2 members, a top section with 70% oil saturation and

3000 - 6000 MD permeability, and a bottom section from 0' - 20' of 60% oil saturation and 1000 - 3000 MD permeability. Reservoir characteristics are shown in Table 1.

General Crude's proposal for conducting a demonstration project was divided into four phases with the DOE providing approximately 40% of the total costs (\$4.5MM) to develop 12 - five acre patterns. At the conclusion of each phase, a review of the project was planned and a formal decision to continue was to be made.

Phase I was begun late in 1978 and was designed to evaluate the geology and reservoir characteristics by drilling four wells and coring three. The time provided for this work was three months, but due to delays in permitting and an interruption in drilling the actual time required was nearly ten months.

Phase II was to be twelve months in duration and would have encompassed completion of an inverted five-spot well pattern, air injection test, laboratory work and ignition of the first well.

Phase IIIA and IIIB were to be sixty months in duration and would have involved facility installation, well drilling and operation of the project. Phase IIIA

would have been a period of dry combustion without water injection. Phase IIIB was to provide for the injection of both air and water.

Phase IV was to be twelve months in duration and would have been a continuation of heat scavenging in the first row of producers. In addition, the final evaluation and reporting on the demonstration project to the DOE would have been completed.

During Phase I operations four (4) wells were drilled and cored to evaluate the geology of the Lynch Canyon Field. In addition laboratory testing of both the reservoir fluids and core samples were performed. After analyzing these results several factors became evident which were unknown at the initiation of the project. These points of concern involved lower oil sand volume than previously estimated, increased drilling costs due to the overlying high pressure water sands, increased investments due to environmental considerations, and substantially higher than anticipated oil viscosity. Due to these adverse conditions and their effect upon the economics of the project, Mobil decided that the termination of the project at Decision Point One was the most prudent option available.

PROJECT DESCRIPTION

Geology

The Lynch Canyon oil field is near the center of Monterey County, California and approximately 30 miles north of Paso Robles. The southern boundary of the field is adjacent to the northern boundary of the San Ardo Field. A location map is presented as Figure 1.

The field derives its name from a narrow valley that passes through the field. The rolling grass-covered hills flanking the valley rise from an elevation of 700 feet at the valley floor to 1,200 feet along the west and east sides. Climate conditions are characteristic of the Salinas Valley with temperatures ranging from below freezing to more than 100°F.

An excellent description of the geology of the Lynch Canyon Field is presented by Elbert R. Wilkinson, "Lynch Canyon Oil Field", Summary of Operations, California Oil Fields, Vol. 50, No. 2, pp 79 (1964). The Lynch Canyon Field is in an elongated synclinal depression flanked by the Gabilan Range along the east side and the Santa Lucia Range on the west. Extensive move-

ment along the King City fault resulted in the east side of the trough being uplifted several thousand feet to form the Gabilan shelf. It is on this shelf that the sedimentary rocks of the Lynch Canyon Field, as well as the San Ardo Field, were deposited. The productive Lanigan sand (which is a member of the Miocene Monterey formation) was accumulated on the flanks of this structure as an off-shore sand bar, and a stratigraphic trap is formed where the sand pinches out against the Jurassic basement along the ancient shoreline. These highly permeable sands are fine to coarse grained, but grade into a pebble conglomerate on bottom. Because of the depositional environment of the sand, it becomes increasingly shaley down-structure and is not productive in the San Ardo Field, three miles southeast. The oil saturated portion of the sand is delineated on three sides by an underlying water table, which lies at -1,072 feet subsea. The average reservoir depth is 1,800 feet.

The Miocene Monterey formation is overlain by the Miocene (lower Delmontian) Santa Margarita formation, which is a water-saturated, fine-grained sand used as a waste water disposal sink in the area. Fresh waters

are contained in the surface sands and gravels comprising the Pleistocene Poncho Rico formation; these shallow sands are extensively used as a source of feed water for steam generation.

Figure 2 is a structure map with contours on the top of the Lanigan sand. Figures 3 & 4 are isopach maps of net oil sand thickness. Figure 5 is a cross section on the area. The structure maps also reveal the location of the water-oil contact where the sand meets the basement rock.

Texaco's earlier drilling gave good geological control over about 175 acres in the center of the reservoir, but did not include the southern portion of the field, the area in which the Combination Thermal Drive Project was to be located. Phase One operations provided for drilling and logging four wells to thoroughly evaluate the reservoir characteristics in this area. A typical log is shown in Figure 7. Three of the wells were cored throughout the producing interval and the fourth had sidewall samples taken.

The material obtained from the cores was analyzed for porosities, saturations, permeabilities and combustion characteristics.

The table below summarizes the comparison of reservoir and fluid properties from the beginning of the project to the completion of Phase One.

SUMMARY OF RESERVOIR ROCK AND FLUID PROPERTIES

	<u>Prior to Phase I</u>	<u>After Phase I</u>
Average Net Pay Thickness, feet	38	38
Porosity, percent	36	34
Absolute Permeability, md	6,000	6,000
Saturation, percent Pore Volume		
Oil	74	69
Water	26	31
Gas	0	0
Oil Gravity, °API	9-11	10
Reservoir Temperature, °F	104	104
Viscosity at T_R , cp	9,000	70,000

Production History

The Moriqui Exploration Company's "Lanigan" 172, drilled in September, 1962, was the discovery well in the Lynch Canyon Field. Thirty-five feet of well saturated, black oil sand was recovered from cores taken between 1,685 feet and 1,745 feet. The initial production rate was reported to be 41 BOPD of 9.7° API oil cutting 6.2% water. The successful completion of well Lanigan 172 encouraged the company to drill two more wells; Lanigan 50 had an initial potential of 14 BOPD of 10.7° API oil cutting 2.7% water. Lanigan 20 failed to find commercial production. Production problems on primary, due to the viscous nature of the crude oil, resulted in transfer of the property to Texaco in 1963.

Lynch Canyon was developed by Texaco in 1963. During 1963 - 1965 Texaco produced the field by cyclic steam operations. Figure 8 is a location map showing the General Crude Oil Company's leases in the area. Primary oil production rates from the wells fell rapidly to 2 to 4 BOPD/well prior to stimulation with the steam soak process.

Little detail is known concerning the stimulation

program. In general, steam was injected at rates of about 1,000 to 1,500 BPD/well. Initial treatments were approximately 5,000 barrels per well, and the injection pressure was 1,000 to 1,500 psig. Later steam cycles injected 15,000 to 30,000 barrels per well at 400 - 700 psig pressure. Water cuts for the field were fairly high due to steam injection, or water entry from sands behind the casing. In general, primary wells made little water prior to steaming.

Production history for the Lynch Canyon Field is presented in Figure 9. Rates reached 6,000 BOPM in 1964, when 10 wells were on production, and the cumulative oil produced up to abandonment in 1968 was 111,300 barrels. Steam treatments during 1964 resulted in a steam-oil ratio of 1.4. In 1965 when larger treatments were used, the ratio increased to 3.0. No steam was injected in 1966, and the overall steam-oil ratio for the project was 2.1.

A tabulation of production for each well over it's producing life shows the effect of heat on well productivity, Figure 10. Down-hole and lead line heaters were applied to well 172 and 170-X and increased their

production two-fold. Response from huff-and-puff treatments starting in June, 1964, show a three to four-fold increase in productivity for periods on the order of four months.

In May 1979, Lanigan 205 was placed on production to obtain a primary producing rate and verify the competency of the water shutoff due to the evidence of a wet sand immediately above the producing interval. The well produced for less than one day and was idled because of rod-fall problems. A steam stimulation was performed in June and the well returned to production.

Following the steam treatment of 2800 Bbls. of 80% quality steam, the well was placed on production at 30 BOPD with no indications of water problems. The well produced at this rate for 2 weeks. Oil produced during this test was analyzed for its viscosity-temperature relationship and is presented in Figure 11.

Technical Discussion

The Lanigan sand of the Lynch Canyon Field was felt to be similar to a large number of reservoirs in the United States that contain very viscous oil and essentially no natural drive. A typical sand of this type will have a porosity of 34 percent, a maximum sand thickness of about 40 feet, specific or absolute permeabilities of 6,000 millidarcies, and an oil viscosity of approximately 10,000 centipoise.

Primary production from these reservoirs is not economic due to the low initial potential and rapid decline in production rate. The high resistance to flow (viscosity) combines with the high fluid saturation to essentially eliminate any displacement process, operating alone, from being successful. The effective permeability to the injected fluid is so low, due to the high liquid saturation, that adequate injection rates cannot be achieved unless injection pressures are increased to a level that would result in fracturing the reservoir.

A combination of processes is needed to produce the oil from this type of reservoir. A process must result in early stimulation of the producing wells in

order to accelerate production in the early stages of the operations. Also, a displacement process that results in an effective drive mechanism and accomplishes a good sweep efficiency, along with a high specific displacement efficiency is required for a resulting high oil recovery factor. In other words, the production must be matched to the displacement in the early phases of the operation.

In a reservoir producing crude oil as viscous as that found in the Lynch Canyon Field, heat is the only solution to early acceleration of production rates. The first part of the problem can then be solved by the application of heat to the producing well. Cyclic steam injection resulted in an overall steam-oil ratio of 2.1:1 in early field application to the Lanigan sand. When this project was conducted, in 1963, well completion techniques for high temperature wells had not been developed to any great extent. By utilizing the advancements in cementing techniques available today many casing failures experienced by Texaco could be eliminated permitting a successful cyclic steaming program.

In selecting the drive mechanism to be used in Lynch Canyon all the available processes were considered.

The viscous nature of the crude oil narrowed the selection down to a thermal process. Three general classes of thermal processes were available; hot water displacement, steam displacement, and in-situ combustion. Any of these processes were technically feasible in the Lynch Canyon Field. Preliminary evaluation of the three methods indicated that the in-situ combustion process would result in the highest oil recovery and the best economic possibilities in this particular field. A modification of the basic in-situ combustion process that scavenges heat from behind the burning front and increases displacement ahead of the front was planned. This modified process was known as the Combination Thermal Drive Process and utilized the simultaneous injection of air and water to move heat through the reservoir. This burning phase was to be followed by a period of water injection to scavenge more heat and produce additional oil. In summary, we proposed to use the Combination Thermal Drive Process to displace oil and cyclic steam injection in the producing wells to balance the production with the displacement.

A staggered line-drive well array was to be util-

ized in the project, starting in a down-dip portion of the reservoir, Figure 12. Wells were to be drilled on a two and one-half acre density. A line-drive configuration with shifts of producers to injectors had many advantages over pattern operation in this type of reservoir. The anisotropic conditions that exist in this reservoir would control burning front movement. While efforts might be made to control the movement by external methods, control was to be experienced through diligent engineering and data management.

In a reservoir with little structural relief it is very difficult to predict the movement of the front in advance of actual operations. By utilizing a line-drive type of operation, this problem can be minimized. The line-drive allows the burning fronts from two adjacent patterns to proceed rapidly along the major axis of the anisotropy and converge on the first row production well common to the two injectors. This forms a single line-drive perpendicular to the anisotropy and allows time to force both sides of the elongated fronts in the direction of the minor axis. As the burning front enters a well and no more production can be obtained, the well

is converted to injection and the line-drive is continued.

With this approach the fire front is allowed to proceed in the direction it prefers. Oil production is not lost in an almost futile attempt to correct uneven directional movements by back-pressuring the well or shutting it in while waiting for the slower moving portion of the front to catch up. If it is determined, from continued operation, that a particular well cannot be reached from one injector, modification in the injection pattern allows it to be reached later from another injector that takes advantage of the then known directional permeability.

Design of Project

The project was designed to involve some sixty acres of the reservoir. The well density and injection rates were what we considered to be the optimum size for developing the entire reservoir; no scaling of data was to be necessary for future expansion. For the demonstration project we proposed to break the operation down into four phases, with evaluation points at the end of each phase. The four phases were:

Phase I -- Geologic and Reservoir Evaluation
Phase II -- Pilot Testing and Project Development
Phase IIIA -- Project Operation, Dry Combustion
Phase IIIB -- Project Operation, C.T.D.
Phase IV -- Heat Scavenging and Final Evaluation
 of Performance

Displacement Drive

The project area was to be drilled on a 2½ acre well density, with seven downstructure producers, six injectors and three rows of 20 upstructure producers. The project area was sixty acres. A reservoir volume of 1,180 acre-feet, containing 2,440 MBbls. of oil, was involved between the downstructure producers and the first row upstructure producers. An additional 1,200 acre-feet of reservoir volume containing 2,480 MBbls. of oil, was contained in the remaining thirty acres developed. The total original oil-in-place in the 60 acre project area was thus 4,920 MBbls.

The Lynch Canyon Field has very little structural relief, dip less than 3 degrees, so the injection wells were planned to be positioned mid-way between production

wells in rows 1 and 2. While we expected the major axis of the anisotropy to be in an up-dip direction, due to the preferential up-dip migration of the injected air, the central location of the injector between the first two rows of producers was desirable as we expected these downstructure wells to have a life approximately twice as long as the first row upstructure. With continued operation this anisotropy would become more pronounced as higher gas saturations would develop in the upstructure portion of the reservoir.

In Phase II of the demonstration, a rather extensive air injection test was to be conducted to confirm the actual directional permeability that we expected to experience in the project. Depending on the results of this test, certain reorientation of the proposed well locations would probably be necessary to take full advantage of the directional permeability. These wells, if relocation was necessary, would be in the up-dip direction where we had good geologic control.

Utilizing the line-drive well configuration would greatly reduce the operating problems and increase the sweep efficiency of the project. By allowing the

burning front to progress, unretarded in the preferential direction, it would have been possible to produce oil from the affected wells at higher rates. As these early-breakthrough production wells became nonproductive, they would be converted to injectors and the line-drive allowed to progress through the field.

Four wells were drilled in Phase I to delineate the reservoir in the area of the project. Three of the four wells drilled were cored using a rubber sleeve core barrel. Routine core analysis of porosity, permeability, oil saturation and water saturation were obtained on these cores. In addition, laboratory combustion tube studies were conducted on the core material to determine the combustion characteristics of the formation. A detailed discussion of these studies appears in the Appendix.

In Phase II One five-spot pattern was to be completed with four producers surrounding a central injection well. These wells were to produce for a short period of time to determine the productivity of the wells under primary operating conditions. All five wells were planned for cyclic steam stimulation treatment to observe the

production response and to determine the operating problems and characteristics under thermal stimulation.

Air injection was then to be initiated into the central well and an air injection test was to be conducted. Air was to be injected for approximately one month to determine the injectivity, operating pressure required and establish the directional flow of the injected air. All production wells were to be monitored during this period for first gas arrival, nitrogen front arrival, gas flow rates and complete combustion gas analysis would be run daily. Down-hole temperatures were to be monitored in the injection well during air injection. At the first sign of spontaneous ignition in the formation, as detected from gas analysis or injection well temperature increase, water would be injected to protect the injection well from damaging, high temperature back-burn conditions that accompany spontaneous ignition. Ignition of the formation would then be accomplished using steam and air.

Information obtained during this extended air injection test and formation ignition would be used for the final design of equipment and exact location

of the wells for Phase III operation. This information would include injection pressure for the air compression plant, ignition characteristics, gas movement and gas recovery during injection.

A line of six injectors was to be completed and the production wells would be located as shown in Figure 12. Ignition of the line of injectors would be accomplished and the burning operation continued through Phase IIIA. Air injection was to be controlled to attempt to balance displacement by the burning front with production from the cyclic steam stimulated production wells. Air was to be injected until the proper heat-pad volume had been established around the injection well. After attaining stable burning conditions and a sizable heat-pad simultaneous injection of air and water was to be initiated. A water-air ratio of approximately 220 barrels per million standard cubic feet of air would have been used.

Simultaneous injection of air and water was to continue throughout Phase IIIB. The line-drive would be established and, depending on the extent of areal distortion of the pattern, approximately four years of stable

operation was to follow. At the end of this period we expected several of the up-dip producing wells to have been reached by the burning front and they would be converted to air injection. The line, thus formed, would then be propagated on toward the second row of producing wells. Figure 13 shows the proposed air injection schedule which was to have been utilized in Phase III and IV.

Thermal Stimulation

Cyclic steam stimulations of the producing wells has been proven to be an effective means of producing oil from the Lanigan sands of the Lynch Canyon Field. This early work in the field accomplished an average steam-oil ratio of 2.1 barrels of steam to one barrel of oil. This favorable ratio was accomplished while mechanical failures and operational problems plagued the operation. We felt that with the advanced well completion technology available today, and with the improvements that have been made in steaming technology over the last 13 years, that a ratio at least this favorable should be accomplished in this demonstration

project.

Initial steam treatments were to be in the range of 4,000 to 5,000 barrels of steam. Optimization of the size of these treatments would be made when actual field data became available. For the preliminary design we estimated that a 4,000 barrel steam treatment would require a downtime on the producing well of about 7 to 9 days and accelerated oil production should last about 90 days. With an average oil production rate of 21 BOPD/well over a 90 days period, each cycle should produce approximately 1,900 barrels of oil, or a steam-oil ratio of 2.1 barrels/barrel.

An attempt would be made to balance the displacement at the burning front with the production during the early phases of the project. The frequency of cyclic stimulation would decrease and eventually cease as upgraded oil and heat approach the first row of producing wells.

Phase One Operations

Beginning in June of 1978 various permit applications were initiated for the drilling of wells and

construction of the facilities required for all phases of the project. Approvals were sought from the Monterey Bay Unified Air Pollution Control District, United States Environmental Protection Agency and Monterey County Planning Commission. After several months of discussions, a revised application was approved for Phase One and Two operations. No permit was issued for Phase Three because of the SO₂, NOX and hydrocarbon emissions associated with the full project air compression and steam generation operations. Diesel engines had been proposed for use in air compression due to lower cost and fuel availability. A decision to continue with Phase One was adopted while a study was undertaken to review the possibility of economically changing fuel types or utilizing scrubbing devices.

Locations for the first three wells were begun in March 1979 and the drilling of Lanigan #102 commenced on March 27. After setting 315' of 13-3/8" casing and drilling to 1715' the hole was conditioned for coring operations. However, prior to coring, the well began to flow from an overpressured salt water sand penetrated from 1300' - 1400'. Control of the well was regained

with a combination of weight material and lost circulation additives. A second string of 9-5/8" casing was set at 1557' and drilling operations were resumed with 90' of rubber-sleeved cores taken to basement rock.

Results from coring and logging of Lanigan #102 revealed 23' of well-saturated oil sand. This total was less than anticipated but not completely unexpected since Lanigan #102 was the farthest downstructure well drilled in the field. In addition to the lack of oil sand, a second problem was discovered which could interfere with well completions. A thin water sand was found immediately above the Lanigan oil sands and although the production casing could be set through this sand, communication around the casing shoe might occur especially following thermal operations.

A decision was made to plug the well back to the 9-5/8" casing and suspend operations until drilling of the remaining wells was completed. If the remaining wells indicated it would be beneficial to move the entire project upstructure, then Lanigan #102 might be utilized as a water source or disposal well.

Lanigan #205, a structurally higher well, was

drilled next. Added precautions were taken to prevent the hole problems which occurred in Lanigan #102, by carefully controlling the mud qualities and by using lost circulation material in the Lanigan sands.

Full cores were not taken in Lanigan #205 although a full suite of electric logs and sidewall samples were obtained. After analyzing both logs and samples it was determined that the 38' of oil sand was producible and that the field did extend further to the south than Texaco's original development.

Lanigan #205 was completed for production utilizing 7", N-80 casing with buttress joints. This casing design was required due to the anticipation of high steam injection pressures and temperatures and the thermal stresses they would apply to the tubulars. The cementing program utilized a light weight cement for lost circulation with silica flour for thermal integrity.

The completion utilized a 5½", .060" slotted liner, gravel packed with 6 X 9 mesh gravel. Sand sieve analysis was used in determining the proper gravel size and slot width. Figure 14 shows the typical well completion and Figure 15 is a sand sieve plot of the Lanigan

formation.

Lanigan #205 like #102 had a thin water sand immediately above the producing interval. Before proceeding with further drilling operations it was decided to production test Lanigan #205 and determine if a water problem would be experienced on either primary or cyclic steamed production.

A pumping unit was installed, but the well was incapable of producing due to the extremely viscous oil and the resulting rod-fall problems. A 12 MMBTU per hour steam generator was moved on location and the well steamed for 11 days at a rate of 250 BSPD at 75% quality and 950 PSIG. The well was soaked for 8 days prior to being placed on production, at which time it produced an average of 30 BOPD and 220 BWPD. Lanigan #205 produced at this rate for two weeks without any indications of problems from the water sands above the casing shoe, however, the subsurface rod pump failed and the well was allowed to remain idle because of insufficient surface facilities to handle the produced fluids.

Drilling operations were resumed in August, 1979 with wells Lanigan #204 and #305. Both of these wells

were drilled and completed in the same manner as Lanigan #205. Each of these wells were cored throughout the producing interval. Lanigan #305 was drilled first and penetrated 36' of oil sand. An analysis of the electric log indicated the zone was structurally higher at #305 than originally anticipated. Lanigan #204 was drilled last and penetrated nearly the same thickness of net sand.

All three wells were completed alike with 7", N-80 casing and 5½" slotted liners, gravel packed with 6 X 9 gravel. After completion of drilling operations all three wells were left shut-in awaiting laboratory results of core samples and a decision to proceed with Phase Two.

Total expenditures for completion of Phase One amounted to \$700,000, or 66% over the estimated \$420,000, Figure 16. Two primary reasons were responsible for the additional expenditures. First was the increased drilling time, drilling fluids, tubulars and cementing costs associated with the abnormally overpressured Santa Margarita formation. Secondly, the steam stimulation and subsequent production of Lanigan #205 was moved forward from Phase Two, in order to provide pertinent information prior to

proceeding with the project.

Conclusions

Core analysis from all four wells are presented in the Appendix. These analyses indicated the oil saturation of the Lanigan sands to be slightly less than originally projected, 74% compared to 69%. More specifically, the lower portion of the sands appeared to have substantially higher water-oil ratios and as a consequence reduced the productive limits of the field in the down-structure areas.

The discovery of only marginal oil sand thickness at Lanigan #102 along with the geologic data obtained from the other three wells was used in the re-evaluation of oil-in-place volumes. Originally General Crude had projected oil volumes of 26 million barrels in 12,500 acre-feet. With the completion of Phase One drilling, the volumes were recalculated at 14.6 million barrels in 8130 acre-feet.

The oil viscosity of the Lanigan reservoir had previously been reported about 9000 centipoise. The well fluids produced from Lanigan #205 revealed the vis-

cosity to be nearly eight times greater or 70,000 centipoise. This change in a critical reservoir parameter was seen as having a significantly detrimental affect on the thermal processes proposed in this project.

The Phase One drilling operations were conducted without problems, after modifications were made for the conditions encountered by the first well. Each subsequent well required an additional casing string and better drilling fluid control than originally planned. In addition, the water sands immediately above the producing interval provided a potential problem in the future even though the steam treatment of Lanigan #205 presented no difficulties.

In reviewing the economics of the project, the potential oil recovery had to be reduced because of both smaller reserves and less attractive combustion properties associated with higher viscosities. The operating costs and capital expenditures of the project were also modified. Phase One drilling operations revealed a need to increase the estimated drilling costs for each of the wells in the project. The plans for remedial workovers of producing wells also were increased due to potential

casing problems arising from both the high pressure salt water sands and the water sands at the casing shoe.

Significantly higher capital expenditures and operating costs were also expected as a result of the discussions with the Monterey Bay Unified Air Pollution Control District and the United States Environmental Protection Agency. In order to obtain the required permits it was necessary to change from diesel to electric driven compressors and to collect all casing annulus vapors. These unforeseen requirements further escalated the costs of the project.

As required in the Cost Sharing Contract, an evaluation of all available reservoir data was made jointly by the DOE and Mobil-GC following completion of Phase One operations. This evaluation reviewed the economic viability of the total project with respect to the significant discoveries made in drilling four Phase One wells. The joint decision reached by the DOE and Mobil-GC was to terminate the project at Decision Point One. The conditions which were thought to exist at the initiation of the project provided an excellent opportunity to conduct a pilot combination thermal drive. However, the

potential problems which are now known to exist, combined with the current unfavorable economics no longer present an acceptable climate to test the Combination Thermal Drive Process.

EXHIBIT I

ESTIMATED RESERVOIR CHARACTERISTICS AS OF SEPTEMBER 1979Lanigan Sand, Lynch Canyon Field
Monterey County, California

Depth, ft.	1,800
Size, Acres	400
Avg. Thickness, ft. in area of interest	38
Reservoir Volume, A-F	8,133
Porosity, percent	34.0
Permeability, md (estimated)	6,000
Saturation, percent	
Gas	0
Oil	69
Water	31
Estimated Formation Volume Factor	1.03
Original Oil-in-place, STB	14,639,000
Oil Produced, Bbls.	111,300
Water Produced, Bbls.	292,460
Estimated Oil Content, STB/A-F	1,800
Pressure, psig	650
Reservoir Temperature, °F	104
Estimated Solution GOR, SCF/B	10
Oil Gravity, °API	10.0
Estimated Oil Viscosity at 115°F Dead Oil	70,000

FIGURE 1

R. 10 E.

T.
22
S.

MOBIL	
TOP LANIGAN STRUCTURE	
LYNCH CANYON FIELD	
MONTEREY CO., CALIFORNIA	
SCALE:	
Contour Interval: 10'	Drawn By: ZE
Date: 4-9-80	FIGURE 2

R. 10 E.

C.H.I.

T.
22
S.

MOBIL	
UPPER LANIGAN	
NET OIL SAND ISOPACH	
LYNCH CANYON FIELD	
MONTEREY CO., CALIFORNIA	
SCALE:	
Contour Interval: 5'	Drawn By: ZE
Date: 4-9-80	FIGURE 3

R. 10 E.

T
22
S

MOBIL	
TOTAL NET OIL SAND ISOPACH (UPPER PLUS LOWER LANIGAN SAND) LYNCH CANYON FIELD MONTEREY CO., CALIFORNIA	
SCALE:	
Contour Interval: 10'	Drawn By: ZE
Date: 4-9-80	FIGURE 4

CROSS SECTION A-A'

CROSS SECTION B-B'

CROSS SECTIONS
LYNCH CANYON FIELD
Figure 5

R. 10 E.

T.
22
S.

MOBIL	
TOP LANIGAN STRUCTURE	
LYNCH CANYON FIELD MONTEREY CO., CALIFORNIA	
SCALE:	
Contour Interval: 10'	Drawn By: ZE
Date: 4-9-80	FIGURE 6

TYPICAL E-LOGS
 LYNCH CANYON FIELD
 Figure 7

MOBIL

LYNCH CANYON FIELD
MONTEREY COUNTY, CALIFORNIA

PRODUCTION GRAPH

Scale:	Geology By:
Contour Interval:	Drawn By: E. L. R.
Date: October 5, 1976	FIGURE 9

MONTHLY OIL PRODUCTION
LYNCH CANYON

Figure 10

<u>1962</u>	<u>50</u>	<u>140X</u>	<u>170X</u>	<u>172</u>	<u>108</u>	<u>110</u>	<u>138</u>	<u>142</u>	<u>174</u>	<u>106</u>	<u>136</u>
	334	267	448	411							
<u>1963</u>											
Dec.	174	406	429	333							
Feb.	319	403	276	445							
Mar.	305	368	792*	805*							
Apr.	304	377	767*	821*							
May	306	327	631*	662*							
Jun.	131	232	802*	971*							
Jul.	161	248	885*	1080*							
Aug.	237	690	452*	968*							
Sep.	299	881	444*	1376*							
Oct.	324	536	914*	697*	273	316	119	203	128		
Nov.	138	651	712*	993*	545	398	276	617	66		
Dec.	56	310	358	809*	114	207	221	554	228		
<u>1964</u>											
Jan.	65	330	333	326	473	262	317	795	440		
Feb.	65	279	686	445	135	180	162	280	77		
Mar.		387	852	532	425	67	194	335			
Apr.		302	665	430	111	180	140	262			
May		231	527	285	272	142	124	214			
Jun.		139	383	48		601	523	874		546	129
Jul.		770	986	555	1063	189	1360	401		877	222
Aug.	119	252	787	444	958	88	1364	289		700	267
Sep.	167	462	1538	366	894	439	1269	176		171	291
Oct.	128	1170	1300	309	757	363	1073	149		616	229
Nov.	66	542	602	143	350	168	496	69		285	114
Dec.	90	744	825	197	480	231	637	95		392	126
<u>1965</u>											
Jan.	132	1166	1206	287	692	320	995	138		537	215
Feb.	110	967		242	515	268	828	116		928	171
Mar.	88	775		194	412	187	620	92		743	123
Apr.	99	870		217	463		744	104		834	
May	66	583		145	310		497	70		558	
Jun.	77	677		169	360		578	81		649	
Jul.	73	643	35	161	342		531	77		617	
Aug.	64	554	31	138	294		473	66		532	
Sep.	71	609	33		33		521	73		584	
Oct.	58	497	27	96	264					477	
Nov.	42	537	29	9	286					34	
Dec.	1	6	1	2	3					5	
<u>1966</u>											
Jan.	20	171	9	22						126	
Feb.	145	1247	258	136						302	
Mar.	159	577	145	94						1250	
Apr.	296	92	30	30						1017	
May	206	387	97	63						837	
Jun.	170	53	53	160						583	
Jul.	101	189	47	31						409	
Aug.	159	59	59	150						547	
.	91	171	42	28						367	
.	65	20								225	
Nov.		132	33							286	
Dec.		23								253	

*Bottom hole heater in operation -45-

MOBIL	
VISCOSITY TEMPERATURE CHART	
205	
LYNCH CANYON FIELD	
MONTEREY CO., CALIFORNIA	
Date: 4-14-80	Drawn By: ZE
FIGURE 11	

14 13
23 24

13 18
24 19

LEGEND

- ⊙ Phase I Wells
- △ Phase II Wells
- △ Observation Wells
- Phase III Wells

Texas
Lanigan
C.H.I.

23 24
26 25

24 19
25 30

MOBIL

Lynch Canyon-McCool Ranch Area

SCALE: 1" =	GEOLOGY BY:
CONTOUR INTERVAL:	DRAWN BY: E.L.R.
DATE:	FIGURE 12

MOBIL	
INJECTION SCHEDULE	
LYNCH CANYON FIELD	
MONTEREY COUNTY, CALIFORNIA	
Scale:	Geology By:
Contour Interval:	Drawn By: Z.E.
Date: JUNE 8, 1978	FIGURE 13

TYPICAL PRODUCTION WELL

TYPICAL INJECTION WELL

MOBIL	
LYNCH CANYON FIELD MONTEREY COUNTY, CALIFORNIA	
TYPICAL WELL COMPLETIONS	
Scale:	Geology By:
Contour Interval:	Drawn By: E.L.R.
Date: October 5, 1976	FIGURE 14

Name General Crude Oil Company
 Lanagan #205 Well
 Lynch Canyon Field
 Core Laboratories, Inc.
 Job #BP-1-8182

Date April 9, 1979

MOBIL	
SCREEN ANALYSIS	
LANAGAN 205	
LYNCH CANYON FIELD	
MONTEREY CO., CALIFORNIA	
DATE: 4-14-80	FIGURE 15

Figure 16

LYNCH CANYON PROJECT

EXPENSE SUMMARY

PHASE I OPERATIONS

Well Costs

Tangible	\$180,000
Intangible	425,000
Direct Labor	25,000
Overhead	9,000
Operating Costs	61,000
Administrative	7,000
Total	\$707,000

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

PAGE 1

GENERAL CRUDE OIL CO.
"LANIGAN" #204
LYNCH CANYON
MOUNTEREY, CLIFORNIA

DATE : 27-AUG-79
FORMATION :
DRLO. FLUID: WB
LOCATION : SEC. 24-T22S/R10E

FILE NO : BP-1-8436
LABORATORY: BAKERSFIELD
ANALYSTS : DK BB
ELEVATION : 735'KB

DEAN-STARK CORE ANALYSIS

SMP NO	DEPTH	HORIZ PERM	HELI POR %	OIL % P.V.	WTR % P.V.	TOTAL FLUID	O/W RATIO	DESCRIPTION
DEAN-STARK CORE ANALYSIS/SAMPLES MOUNTED IN SLEEVES/A TRI-AXIAL PRESSURE EQUAL TO THE DEPTH MINUS 100 psig., TO A MAXIMUM OF 700 psig.								
1*	1723.0-24.0	1.03	31.8	2.6	83.0	85.6	0.03	SS; TAN, VF-FGR, SLTY, MSTN
2*	1724.0-25.0	1.72	31.2	4.0	82.5	86.5	0.05	SAME
3*	1725.0-26.0	1.56	33.6	7.5	76.1	83.6	0.10	SAME
4*	1726.0-27.0	2.83	31.5	5.8	82.4	88.2	0.07	SAME
5*	1727.0-28.0	3.74	31.8	1.2	75.0	76.2	0.02	SAME
6*	1728.0-29.0	0.67	37.3	7.0	79.5	86.4	0.09	SS; GY, VFGR, VSLTY, MSTN
7	1729.0-30.0	362.	34.5	3.0	76.9	79.9	0.04	SD; GY, F-MGR, LT STN
8	1730.0-31.0	877.	34.2	1.0	67.9	68.9	0.01	SAME
9	1731.0-32.0	681.	34.2	3.4	78.4	81.8	0.04	SD; GY-BRN, F-MGR, DK SP STN
10	1732.0-33.0	1036.	34.7	6.3	78.8	85.1	0.08	SAME
11	1742.0-43.0	437.	38.8	2.0	79.6	81.6	0.02	SAME
12	1743.0-44.0	310.	36.9	2.4	80.2	82.6	0.03	SAME
13	1744.0-45.0	519.	34.5	2.6	74.6	77.2	0.03	SAME
14	1745.0-46.0	757.	30.6	3.6	72.9	76.5	0.05	SAME/CGR
15	1746.0-47.0	596.	33.2	7.6	73.7	81.3	0.10	SAME/CGR
16	1747.0-48.0	567.	30.9	8.8	74.6	83.4	0.12	SAME
17	1748.0-49.0	2790.	37.1	39.1	39.9	79.0	0.98	SD; DK BRN, F-MGR/CGR, DK STN
18	1749.0-50.0	2954.	37.4	67.3	24.1	91.4	2.79	SAME
19	1750.0-51.0	2756.	33.8	62.4	37.3	99.7	1.68	SAME
20	1751.0-52.0	3348.	35.2	67.9	28.8	96.8	2.36	SAME
21	1752.0-53.0	6893.	37.5	78.5	17.0	95.5	4.60	SAME
22	1753.0-54.0	2287.	32.5	66.5	21.8	88.3	3.05	SAME/VCGR
23	1754.0-55.0	4986.	37.4	62.0	35.1	97.1	1.76	SAME
24	1755.0-56.0	4645.	38.3	76.6	22.9	99.5	3.34	SAME
25	1756.0-57.0	4793.	35.4	71.3	22.9	94.2	3.12	SAME
26	1757.0-58.0	7039.	35.9	72.5	21.8	94.3	3.32	SAME

APPENDIX A
CORE ANALYSIS DATA

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

PAGE 1

GENERAL CRUDE
"LANAGAN" #102
LYNCH CANYON
MONTEREY, CALIFORNIA

DATE : 4-APR-79
FORMATION : LANIGAN SAND
DRLG. FLUID: WB
LOCATION : SEC 24-T22S/R10E

FILE NO : BP-1-8179
LABORATORY: BAKERSFIELD
ANALYSTS : DK
ELEVATION : 685'KB

DEAN-STARK CORE ANALYSIS

SMP NO	DEPTH	HORIZ PERM	HELI POR %	OIL % P.V.	WTR % P.V.	O/W RATIO	DESCRIPTION
DEAN-STARK CORE ANALYSIS/SAMPLES MOUNTED IN SLEEVES/A TRI-AXIAL PRESSURE EQUAL TO THE DEPTH MINUS 100 PSIS., TO A MAXIMUM OF 700 PSIS.							
-53-	1 1717.0-18.0	533.	37.8	0.2	81.7	0.00	SD:GY-TAN,VF-FGR,VLT STN
	2 1718.0-19.0	850.	39.8	2.2	76.0	0.03	SAME
	3 1719.0-20.0	580.	38.1	1.6	85.3	0.02	SAME
	4 1720.0-21.0	527.	36.9	0.2	79.2	0.00	SAME
	5 1721.0-22.0	166.	37.9	1.7	83.1	0.02	SAME
	6 1722.0-23.0	240.	37.5	2.0	87.2	0.02	SAME
	7 1723.0-24.0	541.	38.4	1.0	81.8	0.01	SAME
	8 1724.0-25.0	293.	37.7	0.3	85.2	0.00	SAME
	9 1725.0-26.0	255.	39.7	1.6	83.1	0.02	SAME
	10 1726.0-27.0	976.	37.8	6.6	75.6	0.09	SD:GY-BRN,F-MGR,MICA,DK SP STN
	11 1727.0-28.0	626.	36.9	14.4	71.9	0.20	SAME
	12 1728.0-29.0	591.	38.4	20.9	62.2	0.34	SAME
	13 1729.0-30.0	999.	38.1	28.2	54.2	0.52	SAME
	14 1730.0-31.0	1469.	36.9	56.3	39.0	1.44	SD:BRN,F-CGR,MICA,DK STN
	15 1732.0-33.0	1550.	37.8	57.1	31.7	1.80	SAME
	16 1736.0-37.0	1473.	35.0	59.6	29.7	2.00	SAME
	17 1737.0-38.0	3001.	34.2	64.4	25.5	2.52	SAME
	18 1738.0-39.0	677.	34.2	45.1	51.2	0.88	SAME/CLY INCLS
	19 1739.0-40.0	580.	35.9	46.8	38.1	1.23	SAME/CLY INCLS
	20 1740.0-41.0	1751.	32.7	68.1	24.3	2.80	SAME
	21 1741.0-42.0	3229.	36.8	55.7	35.2	1.59	SAME
	22 1742.0-43.0	4260.	35.6	49.2	37.3	1.32	SAME
	23 1743.0-44.0	3146.	36.3	23.7	54.0	0.44	SAME
	24 1745.0-46.0	3443.	36.9	54.8	35.3	1.55	SAME
	25 1746.0-47.0	3812.	36.7	55.0	37.6	1.46	SAME
	26 1747.0-48.0	2267.	39.4	44.6	44.6	1.00	SAME

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
 DALLAS, TEXAS

PAGE 2

GENERAL CRUDE
 "LANAGAN" #102

DATE : 4-APR-79
 FORMATION : LANIGAN SAND

FILE NO : BP-1-8179
 LABORATORY: BAKERSFIELD

DEAN-STARK CORE ANALYSIS

SMP NO	DEPTH	HORIZ PERM	HELI POR %	OIL % P.V.	WTR % P.V.	O/W RATIO	DESCRIPTION
27	1748.0-49.0	4541.	38.5	42.5	47.4	0.90	SAME
28	1749.0-50.0	3695.	36.1	58.3	36.9	1.58	SAME
29	1750.0-51.0	8340.	37.3	57.5	35.2	1.63	SAME
30	1751.0-52.0	2786.	34.2	53.8	42.3	1.27	SAME
31	1752.0-53.0	3120.	37.4	42.4	46.1	0.92	SAME
32	1753.0-54.0	1859.	38.4	32.7	53.8	0.61	SD; BRN, VF-FGR, MICA, DK STN
33	1754.0-55.0	1080.	38.4	27.4	62.5	0.44	SAME
34	1755.0-56.0	1392.	39.2	14.2	70.9	0.20	SAME
35	1762.0-63.0	3265.	36.8	10.6	70.0	0.15	SAME
36	1763.0-64.0	1506.	37.6	5.9	75.8	0.08	SD; GY-BRN, F-MGR, MICA, DK STN
37	1764.0-65.0	850.	37.4	1.5	77.3	0.02	SAME
38	1765.0-66.0	1022.	36.6	5.6	74.9	0.07	SAME
39	1766.0-67.0	2279.	31.8	5.3	74.9	0.07	SAME/UCGR
40	1767.0-68.0	1846.	31.0	1.3	78.8	0.02	SAME/UCGR
41	1768.0-69.0	3562.	37.6	19.6	65.9	0.30	SD; BRN, F-CGR, MICA, DK STN
42	1769.0-70.0	6389.	37.4	48.2	40.1	1.20	SAME
43	1770.0-71.0	5621.	39.0	66.0	38.0	1.74	SAME
44	1771.0-72.0	7946.	38.0	59.7	31.6	1.89	SAME
45	1772.0-73.0	9536.	39.2	52.6	33.9	1.55	SAME
46	1773.0-74.0	4187.	36.6	32.3	57.4	0.56	SAME
47	1774.0-75.0	7865.	37.3	4.8	79.0	0.06	SD; GY-TAN, F-CGR, MICA, LT SP STN
48	1775.0-76.0	4822.	36.0	1.5	84.0	0.02	SAME
49	1776.0-77.0	1822.	31.0	4.9	79.8	0.06	SAME
50	1777.0-78.0	1485.	30.3	0.4	84.6	0.00	SAME
51	1778.0-79.0	5181.	38.0	62.0	29.6	2.09	SD; BRN, F-MGR, MICA, DK STN
52	1779.0-80.0	6763.	37.9	6.6	62.3	0.11	SD; GY-BRN, F-CGR, MICA, DK SP STN
53	1780.0-81.0	4849.	37.6	5.8	68.3	0.08	SAME

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CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

PAGE 2

GENERAL CRUDE OIL CO.
"LANIGAN" #204

DATE : 27-AUG-79
FORMATION :

FILE NO : BP-1-8436
LABORATORY: BAKERSFIELD

DEAN-STARK CORE ANALYSIS

SMP NO	DEPTH	HORIZ PERM	HELI POR %	OIL % P.V.	WTR % P.V.	TOTAL FLUID	G/W RATIO	DESCRIPTION
27	1758.0-59.0	4712.	38.3	60.0	25.9	85.9	2.31	SAME

* INSUFFICIENT SAMPLE TO MOUNT IN SLEEVE.

POROSITY AND FLUIDS WERE DETERMINED BY SUMMATION OF FLUIDS METHOD.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

PAGE 1

GENERAL CRUDE OIL COMPANY
"LANAGAN" #205
LYNCH CANYON
MONTEREY, CALIFORNIA

DATE : 8-APR-79
FORMATION :
DRLG. FLUID: WB
LOCATION : SEC. 24-T225/R10E

FILE NO : BF-1-8182
LABORATORY: BAKERSFIELD
ANALYSTS : DK
ELEVATION : 834'

SIDEWALL CORE ANALYSIS

REC IN	DEPTH	PERM MD	POR %	OIL% PORE	WTR% PORE	O/W RATIO	SAMPLE WEIGHT	DESCRIPTION
1.8	1834.0	232.	30.3	0.0	90.9	0.00	11.23	SD:GY,VF-FGR,CLY,NO STN,NO FLU.
1.8	1836.0	289.	32.5	0.0	94.6	0.00	13.62	SAME
2.0	1838.0	321.	32.5	0.0	85.0	0.00	14.92	SAME
2.0	1840.0	398.	30.4	11.2	76.4	0.15	16.14	SD:GY-BRN,VF-FGR/CGR,DSP. STN,DGLD FLU
1.7	1842.0	384.	30.8	18.0	69.8	0.26	14.76	SD:GY-BRN,F-CGR,CLY,DSTN,SPDGLD FLU
1.8	1842.5	562.	30.9	25.1	60.1	0.42	16.13	SD:BRN,F-CGR,CLY,DSTN,DGLD FLU
1.6	1844.0	1820.	36.3	47.0	28.1	1.67	12.91	SD:BRN,F-CGR,CLY,DSTN,DGLD FLU
1.6	1846.0	2341.	37.7	49.1	23.9	2.05	11.49	SAME
1.3	1848.0	2478.	36.2	46.4	28.6	1.63	11.53	SAME
1.6	1848.5	2542.	37.8	46.2	25.4	1.82	9.60	SD:BRN,F-MGR,DSTN,DGLD FLU
1.5	1850.0	2506.	35.1	48.2	30.7	1.57	12.51	SAME
1.4	1852.0	2281.	34.5	44.3	24.8	1.79	12.52	SAME/CGR
1.6	1852.0	1976.	33.9	41.6	27.9	1.49	10.71	SD:BRN,F-CGR,CLY,DSTN,DGLD FLU
1.0	1854.0	2471.	30.3	26.7	43.0	0.62	8.73	SD:BRN,F-MGR,DSTN,DGLD FLU
1.3	1856.0	2874.	35.0	46.4	28.1	1.65	12.05	SAME
1.6	1858.0	3096.	35.9	43.9	24.9	1.76	11.41	SAME
1.7	1860.0	2789.	35.1	42.4	36.9	1.15	14.85	SAME
1.2	1862.0	2673.	36.2	43.4	39.3	1.10	14.64	SAME
1.8	1866.0	1538.	36.9	38.0	49.6	0.77	13.69	SD:BRN,VF-MGR,CLY,DSTN,DGLD FLU
1.6	1866.5	2321.	34.2	35.3	47.4	0.75	13.29	SAME
1.8	1870.0	1382.	32.9	31.5	46.2	0.68	15.72	SD:BRN,F-VCGR,DSTN,DGLD FLU
1.8	1874.0	1892.	33.4	36.0	46.9	0.77	14.18	SD:BRN,F-CGR,DSTN,DGLD FLU
1.7	1878.0	584.	32.5	76.4	77.0	0.08	11.52	SD:GY-BRN,F-MGR/CGR,DSP STN,SP DGLD FLU
1.5	1882.0	786.	32.0	36.5	46.4	0.79	14.48	SD:BRN,F-CGR,CLY INCLS,DSTN,DGLD FLU

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CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

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GENERAL CRUDE OIL COMPANY
"LANIGAN" 30S
LYNCH CANYON FIELD
MONTEREY COUNTY, CALIFORNIA

DATE : 20-AUG-79
FORMATION : LANIGAN SAND
DRLG. FLUID: WB
LOCATION : SEC.24-T23S/R10E

FILE NO : BP-1-8417
LABORATORY: BAKERSFIELD
ANALYSTS : DLK DS BB
ELEVATION :

DEAN-STARK CORE ANALYSIS

SMP NO	DEPTH	HORIZ PERM	HELI POR %	OIL % P.V.	WTR % P.V.	O/W RATIO	DESCRIPTION
DEAN-STARK CORE ANALYSIS/SAMPLES MOUNTED IN SLEEVES/A TRI-AXIAL PRESSURE EQUAL TO THE DEPTH MINUS 100 psia., TO A MAXIMUM OF 700 psia.							
1	1905.0-06.0	54.	42.4	12.6	71.1	0.18	SD;BRN,F-MGR,CLY,DSTN
2	1906.0-07.0	316.	38.5	0.1	83.6	0.00	CLY;GY,SDY,NO STN
3	1907.0-08.0	5100.	37.8	47.6	37.0	1.29	SD;BRN,F-MGR,DSTN
4	1908.0-09.0	3501.	38.5	33.9	48.5	0.70	SAME
5	1909.0-10.0	3567.	38.1	37.6	42.0	0.90	SAME
6	1910.0-11.0	7184.	38.1	48.4	35.0	1.38	SAME
7	1911.0-12.0	6714.	37.7	27.5	57.7	0.48	SAME
8	1912.0-13.0	2399.	27.8	32.6	62.1	0.53	SAME
9	1913.0-14.0	5676.	38.8	35.3	51.8	0.68	SAME
10	1914.0-15.0	3201.	41.6	34.1	47.8	0.71	SAME
11	1915.0-16.0	5129.	41.9	52.3	30.1	1.74	SAME
12	1923.0-24.0	2157.	39.5	59.5	31.5	1.89	SAME
13	1924.0-25.0	2300.	36.5	72.0	21.1	3.42	SAME
14	1925.0-26.0	1609.	37.2	69.4	21.0	3.30	SAME
15	1926.0-27.0	501.	31.0	63.3	20.2	3.14	SAME
16	1927.0-28.0	646.	36.6	65.8	18.9	3.48	SAME
17	1928.0-29.0	201.	31.5	55.7	36.7	1.52	SAME
18	1929.0-30.0	990.	33.9	50.3	33.7	1.50	SAME
19	1930.0-31.0	831.	31.7	54.2	32.9	1.65	SAME
20	1931.0-32.0	3349.	41.2	44.7	48.3	0.92	SAME
21	1932.0-33.0	6313.	38.3	38.5	38.4	1.00	SAME/CLY
22	1933.0-34.0	5334.	38.9	58.2	27.2	2.14	SAME
23	1934.0-35.0	3188.	39.4	24.4	55.3	0.44	SAME
24	1935.0-36.0	3088.	36.5	19.4	66.1	0.29	SAME
25	1936.0-37.0	3837.	35.7	14.3	67.5	0.21	SAME
26	1937.0-38.0	1800.	27.8	16.0	65.9	0.24	SD;GY-BRN,F-MGR,LSTN

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PAGE 2

GENERAL CRUDE OIL COMPANY
'LANIGAN' 305

DATE : 20-AUG-79
FORMATION : LANIGAN SAND

FILE NO : BP-1-8417
LABORATORY: BAKERSFIELD

DEAN-STARK CORE ANALYSIS

SMP NO	DEPTH	HORIZ PERM	HELI POR %	OIL % P.V.	WTR % P.V.	O/W RATIO	DESCRIPTION
27	1938.0-39.0	6877.	37.5	23.4	53.1	0.44	SAME
28*	1939.0-40.0	464.	21.4	41.5	47.4	0.87	SD;GY-BRN,VF-VC,SLTY,CALC,DSTN
29	1940.0-41.0	5701.	33.6	36.2	42.0	0.86	SD;BRN,F-MGR,DSTN
30	1941.0-42.0	5512.	33.0	7.0	69.7	0.10	SD;GY-BRN,F-MGR,LSTN
31	1942.0-43.0	4913.	38.7	5.0	63.9	0.08	SAME
32*	1943.0-44.0	0.01	5.0	5.2	62.1	0.08	SD;GY,VF-CGR,V CALC,NO VIS STN
33*	1944.0-45.0	0.01	13.1	5.2	88.6	0.06	SAME
34	1945.0-46.0	1408.	32.0	34.9	43.1	0.81	SD;BRN,F-CGR,DSTN
35	1946.0-47.0	1323.	37.6	17.2	65.1	0.26	SD;BRN,VF-FGR,LSTN
36	1947.0-48.0	1294.	37.3	17.2	68.2	0.25	SAME
37	1948.0-49.0	2603.	27.2	19.0	64.5	0.29	SAME
38	1950.0-51.0	2108.	32.6	17.6	65.0	0.27	SD;BRN,F-CGR,DSTN
39	1951.0-52.0	3426.	31.9	41.3	39.9	1.03	SD;BRN,F-CGR,DSTN
40*	1952.0-53.0	1.82	18.1	6.4	73.3	0.09	SD;GY-BRN,VSHLY,CALC,LSTN
41	1954.0-55.0	1158.	32.2	43.1	27.1	1.59	SD;BRN,F-CGR,FOS FRAGS,DSTN
42	1955.0-56.0	1327.	30.3	28.2	51.0	0.55	SD;BRN,VF-MGR,MSTN
43	1956.0-57.0	1319.	30.3	16.1	51.7	0.31	SD;BRN,VF-FGR,LSTN
44	1957.0-58.0	2248.	36.4	11.2	51.7	0.22	SAME

* INSUFFICIENT SAMPLE TO MOUNT IN SLEEVE.
POROSITY AND FLUIDS WERE DETERMINED BY SUMMATION OF FLUIDS METHOD.

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PAGE 1

GENERAL CRUDE OIL CO.
 "LANIGAN" #305
 LYNCH CANYON FIELD
 MONTEREY COUNTY, CALIFORNIA

DATE : 16-AUG-79
 FORMATION :
 DRLG. FLUID: WB
 LOCATION : SEC. 24-T22S/R10E

FILE NO : BP-1-8417
 LABORATORY: BAKERSFIELD
 ANALYSTS : DK BB
 ELEVATION : 915'KB

SIDEWALL CORE ANALYSIS

REC IN	DEPTH	PERM MD	POR %	OILX PORE	WTRX PORE	O/W RATIO	SAMPLE WEIGHT	DESCRIPTION
1.5	1881.0	390.	30.6	22.2	66.5	0.33	10.39	SD:GY-BRN,VF-FGR,DSTN,DGLD FLU
1.5	1883.0	243.	34.3	12.7	82.3	0.15	9.12	SAME
1.6	1895.0	329.	30.5	18.5	70.9	0.26	10.16	SD:GY-BRN,VF-FGR,CLY INCLS,DSTN,DGLD FLU
1.3	1897.0	1121.	35.5	38.0	42.8	0.89	10.19	SD:BRN,VF-FGR,DSTN,DGLD FLU
1.4	1901.0	2463.	34.4	50.4	32.6	1.55	7.54	SAME
1.2	1903.0	2359.	36.1	51.3	32.5	1.58	8.17	SAME
1.1	1905.0	1086.	31.5	53.1	30.3	1.75	9.15	SD:BRN,VF-FGR/CGR,DSTN,DGLD FLU
1.3	1911.0	2329.	34.6	49.4	35.1	1.41	8.64	SD:BRN,VF-FGR,DSTN,DGLD FLU
1.6	1915.0	937.	34.7	37.2	44.9	0.83	8.64	SAME
1.5	1919.0	1112.	36.8	39.8	48.3	0.82	9.23	SAME
1.5	1923.0	1296.	34.8	45.5	39.4	1.15	9.31	SAME
1.0	1929.0	528.	29.9	20.2	62.2	0.32	8.08	SD:BRN,VF-FGR/CGR,DSTN,DGLD FLU
1.2	1931.0	1118.	34.6	35.3	46.0	0.77	7.74	SAME
1.5	1941.0	845.	33.3	35.4	47.5	0.75	9.40	SD:GY-BRN,VF-FGR,DSTN,DGLD FLU

PERMEABILITY VS POROSITY

COMPANY: GENERAL CRUDE OIL COMPANY
FIELD : LYNCH CANYON FIELD

WELL : "LANIGAN" 305
COUNTY, STATE: MONTEREY COUNTY, CALIFORNIA

AIR PERMEABILITY : MD - HORIZONTAL (UNCORRECTED FOR SLIPPAGE)
POROSITY : PERCENT (HELIUM)

DEPTH INTERVAL	RANGE & SYMBOL	PERMEABILITY		POROSITY		POROSITY AVERAGE	PERMEABILITY AVERAGES		
		MINIMUM	MAXIMUM	MIN.	MAX.		ARITHMETIC	HARMONIC	GEOMETRIC
1903.0 - 1958.0	1 (X)	0.005	7200.0	4.5	43.0	33.8	2742.	0.25	998.

EQUATION OF REDUCED LINE RELATING PERMEABILITY(K) TO POROSITY :
 $\text{LOG}(K) = (\text{SLOPE})(\text{POROSITY}) + \text{LOG OF INTERCEPT}$
 $K = \text{ANTILOG}((\text{SLOPE})(\text{POROSITY}) + \text{LOG OF INTERCEPT})$

RANGE	EQUATION OF THE LINE
1	$\text{PERM} = \text{ANTILOG}((0.1294)(\text{POROSITY}) + -1.3675)$

APPENDIX B

LABORATORY EVALUATION OF THE
COMBUSTION CHARACTERISTICS

LYNCH CANYON FIELD
MOBIL GC CORPORATION

January 10, 1980

TOR Developments, Inc.
2809-B Allen Street
Dallas, Texas 75204

Report by:

Jon T. Moss, Jr.

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LABORATORY EVALUATION OF THE COMBUSTION CHARACTERISTICS

LYNCH CANYON

MOBIL GC CORPORATION

I. INTRODUCTION

In July 1979, Mobil GC Corporation authorized TOR Developments, Inc. to conduct a laboratory combustion tube study with core material from Lynch Canyon. Mobil GC provided core material and produced oil from the reservoir. The produced water was made using distilled water and sodium chloride. This laboratory study was conducted to determine specific thermal characteristics of the Lynch Canyon reservoir. The study establishes necessary design and evaluation parameters for a thermal oil recovery program.

Lynch Canyon Run # 1

II. SUMMARY

Oxygen utilization during combustion was high and indicates that all of the injected air will be utilized in the combustion reaction during field operations. The results of the study are summarized in the following table:

COMBUSTION CHARACTERISTICS

LYNCH CANYON RUN#1

Mobil GC Corporation

1. Equivalent Oil Burned as Fuel, STB/A-F	322
2. Fuel deposition, #/ft.3	2.51
3. Molecular weight of Fuel Unit, CHx	12.932
4. Air Required to Burn:	
SCF/ft.3 Reservoir Burned	409
MSCF/A-F	17,816
5. Water of Combustion, STB/A-F	204
6. Average Combustion Temperature, Deg. F.	1038

Displacement parameters listed above must be translated to field flow patterns and sweeps.

Lynch Canyon Run # 1

III. RESERVOIR AND LABORATORY CONDITIONS

A. RESERVOIR CONDITIONS

The reservoir data used in this study are tabulated below:

RESERVOIR DATA

Porosity, %	36.0
Saturation, % :	
Oil	74
Water	26
Temperature, Deg. F.	104
Gravity, °API @ 60°F.	10.7
Viscosity, dead oil at Tf	9000

B. COMBUSTION TUBE CONDITIONS

Mobil GC Corporation furnishd core material from Lynch Canyon Well #102. The core material used was taken from the 1740-1748 foot interval. The core material was packed in the combustion tube as received.

The laboratory combustion tube is 2.5 inches inside diameter and the packed length for this study was 50.125 inches. The following pack conditions existed at the start of the combustion tube study:

Porosity, percent	51.0	Weight, grams
Saturation	%	
Oil	40.0	817.5
Water	14.0	287.2
Core Material Sand (dry basis)		<u>5204.2</u>
Total charge in tube		6308.9

To measure temperatures at various positions during the combustion tube study, a thermocouple is positioned inside a 3/16 inch O.D. thermowell at the center of the pack. Air and/or water are injected at the top end of the tube. Liquids are measured as they are produced from the lower end of the tube. Gases are continuously metered and analyzed at 1/2 hour intervals during the tube study. The production system for liquids can be either heated or cooled, as necessary. A water-cooled condenser is placed in the exit gas

Lynch Canyon Run # 1

stream. The pack is ignited at the top with an electric heater maintaining a temperature of 800 degrees F. The igniter was turned off after 2 hours of operation.

IV. THERMAL DRIVE RESULTS

A. Air Injection

Figure 1 shows the air injection rate, the injection and discharge pressures, the burning front location and the cumulative air injected during the combustion tube study. The air injection rate was controlled at an air flux (SCFH/ft.2) of approximately 200 during the stable portion of the tube run between 10 and 12.5 hours. The injection pressure was maintained at about 600 psig over the run. The discharge pressure was maintained between 200 and 400 psig between 10 and 12.5 hours. The discharge pressure prior to this time was near 0 psig because of a fluid block through the combustion tube. A total of 39.3 SCF of air was used in moving the burning front through 34 inches of pack.

B. Combustion

Gases produced from the tube discharge are analyzed for carbon dioxide (CO₂), carbon monoxide (CO), oxygen (O₂), nitrogen (N₂), methane (CH₄), argon (Ar), hydrogen (H₂), and other hydrocarbons. Figure 2 presents these analyses and they are tabulated below:

Lynch Canyon Run # 1

LYNCH CANYON RUN # 1

GAS ANALYSIS

TIME	CO2	O2	N2	CH4	CO	Other	Ar	H/C Ratio	O2 Eff.
0.25	10.95	2.22	79.11	2.79	3.43	0.50	0.98	1.78	89.57
0.75	16.06	0.00	78.66	1.09	3.11	0.10	0.98	0.74	100.00
1.25	14.97	0.17	78.67	1.04	3.94	0.25	0.98	0.86	99.20
1.75	14.38	0.00	79.11	1.05	4.47	0.00	0.98	0.99	100.00
2.25	13.80	0.00	80.95	0.63	3.57	0.05	1.00	1.43	100.00
2.75	13.94	0.13	80.97	0.53	3.56	0.05	1.00	1.36	99.40
3.25	14.16	0.00	81.29	0.47	3.02	0.05	1.01	1.44	100.00
4.25	15.50	0.00	80.52	0.44	2.49	0.05	1.00	1.09	100.00
4.75	10.08	0.00	86.56	0.42	1.82	0.05	1.08	4.13	100.00
5.25	9.55	0.00	86.97	0.42	1.91	0.05	1.08	4.50	100.00
5.75	7.88	0.00	88.62	0.43	1.92	0.05	1.10	6.12	100.00
6.75	8.62	0.00	87.94	0.37	1.98	0.00	1.09	5.30	100.00
7.75	7.77	0.91	87.72	0.42	2.09	0.00	1.09	5.63	96.14
9.75	11.35	0.00	82.36	0.37	4.90	0.00	1.03	2.06	100.00
10.25	16.13	0.00	78.56	0.57	3.78	0.00	0.96	0.63	100.00
10.75	13.12	0.00	81.72	0.92	3.22	0.00	1.02	1.78	100.00
11.25	17.48	0.00	79.48	1.08	1.38	0.00	0.99	0.68	100.00
11.75	16.48	0.00	78.61	1.15	2.77	0.00	0.98	0.68	100.00
12.25	15.55	0.00	79.34	1.67	2.45	0.00	0.99	1.01	100.00

Lynch Canyon Run # 1

The combustion reaction between 10 and 12.5 hours time can be described by the following equation:

This reaction equation is used to determine the amount of air required to react with hydrocarbon material, coke, deposited by the burning front on the sand, and consumed as fuel during the burning test. The apparent atomic hydrogen-carbon (H/C) ratio of the fuel is 0.932. This ratio is plotted against time in Figure 2. Fuel for the process would then have a molecular formula of $\text{CH}_{0.932}$ and the fuel unit molecular weight is 12.932. The average fuel consumption for the dry combustion portion of the run was 1.92 #/ft.3, between 10.5 and 12.5 hours. Combustion efficiency during this period was 100%.

During this period, the air required to burn one pound of fuel was 163.1 SCF/#-fuel. 165.1 SCF/#-fuel. The average fuel consumption for the stabilized portion of the run corrected to field conditions was 2.51 #/ft.3 of reservoir rock clean burned.

The following combustion characteristics during dry combustion are obtained for the Lynch Canyon Field Well # 102:

Air Requirement, SCF/# fuel	163.1
Air Requirement, SCF/ft.3 Rock	409
Air Requirement, MSCF/A-F	17,816
Fuel Consumption, #/ft.3	2.51
Fuel Consumption, Bbls/A-F	322
Water of Combustion, Bbls/A-F	204

Lynch Canyon Run # 1

C. Liquid Production

Oil and water production from the combustion tube study are shown on Figure 3. During a 24-hour gravity drainage and pre-heat period, prior to the injection of air, no oil or water was produced. The pre-heat involved heating the tube to a uniform temperature of 115 degrees F.

After the tube run was completed, the produced liquids were treated with chemical and heat for separation. Oil emulsions were not difficult to break. The viscosity and gravity of the various samples was determined, when possible. The results are plotted on Figure 5.

506 gm. of oil were produced during the run. Total water produced was 427cc. Figure 5 shows that there was some reduction in viscosity during the run.

The produced water was tested for pH and chloride content. The results are tabulated below:

<u>Sample</u>	<u>pH</u>	<u>cl-, ppm</u>
#1	7	3,420
#2	7	3,450
#3	6	890
#4	6	330
#5	6	161

Changes in oil and water physical properties should be less evident in field operations due to the complex flow system and pattern arrangement.

Lynch Canyon Run # 1

D. Temperature History

Temperatures are continuously monitored at various positions in the sand pack by small thermocouple probes located in the center axis. The advance of the burning front is determined from these observations. In this run, the leading edge of the combustion front was defined as the 800 degree F. isotherm. The burning front location (BFL) is shown in Figure 1. Temperature surveys through the combustion tube are plotted on Figure 4A and 4B.

In the figures, the flow direction is from 0-50 inches. Temperature profiles taken at various times show (1) the high residual temperature behind the front, (2) high temperature at the burning front, (3) the rapid decrease in temperature ahead of the front, (4) steam or condensation zone formation, and (5) hot water zone ahead of the condensing steam. The average combustion temperature was 1038 degrees F. The peak temperature observed was 1170 degrees F. at 11.10 hours.

Lynch Canyon Run # 1

E. Oil Recovery

1. Combustion Drive Oil Displacement

Oil displaced by the burning front depends on the saturation conditions at the time of combustion drive and on the amount of oil used as fuel for the process. The oil content of the laboratory pack was 1583 STB/A-F . The fuel consumption is equivalent to 322 barrels per acre foot. The oil displaced from the burned zone is 1,261 barrels per acre foot burned.

TEJAS PETROLEUM ENGINEERS

Figure 1

Lynch Canyon Run #1

MOBIL G-C CORPORATION

Injection Rates and Pressures

TEJAS PETROLEUM ENGINEERS

Figure 2

Lynch Canyon Run #1

MOBIL G-C CORPORATION

Gas Analysis and Related Information

TEJAS PETROLEUM ENGINEERS

FIGURE 3

RUN # 1

LIQUID PRODUCTION

TEJAS PETROLEUM ENGINEERS

FIGURE 4A

RUN # 1

TEMPERATURE PROFILES

TEJAS PETROLEUM ENGINEERS

FIGURE 4B

RUN # 1

TEMPERATURE PROFILES

TOR DEVELOPMENTS, INC.

2809-B Allen Street
Dallas 4, Texas

Phone RI 2-8583
Area Code 214

Lynch Canyon Run # 2

V. SUMMARY

Oxygen utilization during combustion was high and indicates that all of the injected air will be utilized in the combustion reaction during field operations. The results of the second run are summarized in the following table:

COMBUSTION CHARACTERISTICS

LYNCH CANYON RUN #2

Mobil GC Corporation

1. Equivalent Oil Burned as Fuel, STB/A-F	303
2. Fuel deposition, #/ft.3	2.37
3. Molecular weight of Fuel Unit, CH _x	12.9145
4. Air Required to Burn:	
SCF/ft.3 Reservoir Burned	364
MSCF/A-F	15,855
5. Residual Oil in Steam Displaced Zone,	
Saturation, % Pore Space	17.1
Oil Content, Bbl./A-F	616
6. Water of Combustion, STB/A-F	185
7. Average Combustion Temperature, Deg. F.	1070

Displacement parameters listed above must be translated to field flow patterns and sweeps.

Lynch Canyon Run # 2

VI. RESERVOIR AND LABORATORY CONDITIONS

A. RESERVOIR CONDITIONS

The reservoir data used in this study are tabulated below:

RESERVOIR DATA

Porosity, %	36.0
Saturation, % :	
Oil	74
Water	26
Temperature, Deg. F.	104
Gravity, °API @ 60°F.	10.7
Viscosity, dead oil at Tf	9000

B. COMBUSTION TUBE CONDITIONS

The clean burned sand from the first combustion tube run was mixed with produced oil and salt water.

The laboratory combustion tube is 2.5 inches inside diameter and the packed length for this study was 55 inches. The following pack conditions existed at the start of the combustion tube study:

Porosity, percent	46.5	Weight, grams
Saturation	%	
Oil	32.4	660.0
Water	29.3	600.1
Core Material Sand (dry basis)		<u>6237.4</u>
Total charge in tube		7497.5

Lynch Canyon Run # 2

VII. THERMAL DRIVE RESULTS

A. Air and Water Injection

Figure 1 shows the air injection rate, the injection and discharge pressures, the burning front location, the water injection rate and the cumulative air injected during the combustion tube study. The air injection rate was controlled at an air flux (SCFH/ft.2) of approximately 200 during the stable portion of the tube run between 0 and 2 hours and between 13.5 and 15.5 hours. The injection pressure was maintained at about 250 psig during the first part of the run. As the fluid block formed the pressure was increased to 600 psig until the fluid block was broken and it was possible to control the air injection rate. A total of 45.7 SCF of air was used in moving the burning front through 42 inches of pack.

Water injection was initiated at 12 hours. During the Combination Thermal Drive the injected water/air ratio was 74.5 cc./SCF or 468 STB/MMSCF. Air injection was terminated at 15.5 hours and water injection was continued until 1800 cc. had been injected.

B. Combustion

Gases produced from the tube discharge are analyzed for carbon dioxide (CO₂), carbon monoxide (CO), oxygen (O₂), nitrogen (N₂), methane (CH₄), argon (Ar), hydrogen (H₂), and other hydrocarbons. Figure 2 presents these analyses and they are tabulated below:

Lynch Canyon Run # 2

LYNCH CANYON RUN # 2

GAS ANALYSIS

TIME	CO2	O2	N2	CH4	CO	Other	Ar	H/C Ratio	O2 Eff.
0.50	14.01	0.40	78.65	0.96	4.84	0.17	0.98	0.92	98.11
0.75	14.21	0.19	78.35	1.07	4.90	0.29	0.97	0.88	99.10
1.25	14.33	0.00	77.58	1.22	4.75	1.16	0.96	0.87	100.00
1.75	14.71	0.21	76.80	1.41	5.19	0.73	0.95	0.63	98.98
2.25	15.69	0.16	76.41	1.43	4.58	0.78	0.95	0.48	99.22
2.75	16.72	0.21	77.08	1.01	3.54	0.96	0.49	0.40	98.99
3.25	16.37	0.12	77.93	0.85	3.63	0.15	0.97	0.53	99.43
3.75	14.50	0.05	78.55	1.27	4.10	0.55	0.97	0.97	99.76
4.25	16.34	0.05	77.81	0.92	3.62	0.30	0.96	0.55	99.76
7.50	14.89	0.08	82.09	0.39	1.44	0.10	1.02	1.57	99.64
7.75	10.31	0.00	86.77	0.39	1.45	0.00	1.08	4.19	100.00
8.00	7.80	0.00	88.08	0.42	2.61	0.00	1.09	5.61	100.00
8.25	7.85	0.00	87.59	0.45	3.02	0.00	1.09	5.23	100.00
8.75	10.61	0.00	83.51	0.45	4.39	0.00	1.04	2.58	100.00
9.25	15.91	0.00	78.73	0.46	3.92	0.00	0.98	0.67	100.00
9.75	17.59	0.00	76.91	0.58	3.96	0.00	0.96	0.21	100.00
10.25	16.97	0.07	77.41	0.84	3.60	0.15	0.96	0.39	99.66
10.75	16.66	0.05	78.17	0.77	3.18	0.20	0.97	0.55	99.76
11.25	16.49	0.05	77.64	1.05	3.36	0.45	0.96	0.54	99.76
11.75	15.64	0.04	78.58	1.02	3.37	0.37	0.97	0.79	99.81
12.25	15.70	0.10	78.18	1.02	3.69	0.35	0.97	0.70	99.52
12.75	14.64	0.10	78.31	0.99	4.54	0.45	0.97	0.85	99.53
13.25	14.19	0.07	78.84	0.89	4.87	0.15	0.98	0.95	99.67
13.75	14.47	0.23	81.22	0.58	2.40	0.10	1.01	1.41	98.95
14.25	14.31	0.08	80.91	0.87	2.53	0.30	1.00	1.45	99.63
14.75	15.28	0.09	77.87	0.98	4.52	0.30	0.97	0.67	99.57
15.25	14.94	0.09	78.00	0.68	5.07	0.25	0.97	0.68	99.57

Lynch Canyon Run # 2

The combustion reaction between 0 and 2 hours time can be described by the following equation:

This reaction equation is used to determine the amount of air required to react with hydrocarbon material, coke, deposited by the burning front on the sand, and consumed as fuel during the burning test. The apparent atomic hydrogen-carbon (H/C) ratio of the fuel is 0.9145. This ratio is plotted against time in Figure 2. Fuel for the process would then have a molecular formula of $\text{CH}_{0.9145}$ and the fuel unit molecular weight is 12.9145. The average fuel consumption for the dry combustion portion of the run was 2.37 #/ft.³, between 0 and 2.0 hours. Combustion efficiency during this period was 99.05%.

During this period, the air required to burn one pound of fuel was 153.3 SCF/#-fuel.

The following combustion characteristics during dry combustion are obtained for the Lynch Canyon Field Well # 102:

Air Requirement, SCF/# fuel	153.3
Air Requirement, SCF/ft. ³ Rock	364
Air Requirement, MSCF/A-F	15,855
Fuel Consumption, #/ft. ³	2.37
Fuel Consumption, Bbls/A-F	303
Water of Combustion, Bbls/A-F	185

During wet combustion between 14 and 15.5 hours the fuel consumption was 2.23 #/ft.³ and the air requirement was 155.3 SCF/#-fuel. The overall fuel consumption was 2.49 #/ft.³.

Lynch Canyon Run # 2

C. Liquid Production

Oil and water production from the combustion tube study are shown on Figure 3. During a 24-hour gravity drainage and pre-heat period, prior to the injection of air, no oil or water was produced. The pre-heat involved heating the tube to a uniform temperature of 130 degrees F.

After the tube run was completed, the produced liquids were treated with chemical and heat for separation. Oil emulsions were not difficult to break. The viscosity and gravity of the various samples was determined, when possible. The results are plotted on Figure 5.

441 gm. of oil were produced during the run. Total water produced was 1,392 cc. Figure 5 shows that there was some reduction in viscosity during the run.

The produced water was tested for pH and chloride content. The results are tabulated below:

<u>Sample</u>	<u>pH</u>	<u>cl-, ppm</u>
#1	6	3,000
#2	6	3,420
#3	6	3,420
#4	6	660
#5	6	228
#6	7	990

Changes in oil and water physical properties should be less evident in field operations due to the complex flow system and pattern arrangement.

Lynch Canyon Run # 2

D. Temperature History

In this run, the leading edge of the combustion front was defined as the 800 degree F. isotherm. The burning front location (BFL) is shown in Figure 1. Temperature surveys through the combustion tube are plotted on Figure 4A and 4B. Observed peak temperatures are plotted on Figure 4A.

In the figures, the flow direction is from 0-55 inches. Temperature profiles taken at various times show (1) the high residual temperature behind the front, (2) high temperature at the burning front, (3) the rapid decrease in temperature ahead of the front, (4) steam or condensation zone formation, and (5) hot water zone ahead of the condensing steam. The average combustion temperature was 1070 degrees F. The peak temperature observed was 1237 degrees F.

Lynch Canyon Run # 2

E. Oil Recovery

1. Combustion Drive Oil Displacement

Oil displaced by the burning front depends on the saturation conditions at the time of combustion drive and on the amount of oil used as fuel for the process. The estimated oil content in the Lynch Canyon Field is 2066 STB/A-F . The fuel consumption is equivalent to 303 barrels per acre foot. The oil displaced from the burned zone is 1763 barrels per acre foot burned.

2. Oil Displaced by Water Injection

Air injection was terminated when the burning front was located at 42 inches. After the run was completed, samples of the unburned core material between 42 inches of pack and 55 inches of pack were removed from the tube and analyzed for oil content. This represents the residual oil in the steam zone ahead of the burning front. The average residual saturation in the steam zone is determined. The oil displaced is the difference between original saturation and residual saturation in the steam zone.

The average weight percent hydrocarbon in the steam zone was found to be 4.49 percent. This is equivalent to 17.1 % of pore volume or 616 barrels per acre foot. The relative size of the burned zone to the steam zone is a variable value depending on time, formation thickness, and other heat loss factors.

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Figure 1

Lynch Canyon Run #2

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Injection Rates and Pressures

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Figure 2

Lynch Canyon Run #2

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Gas Analysis and Related Information

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FIGURE 3

RUN # 2

LIQUID PRODUCTION

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Figure 4-A

Lynch Canyon Run #2

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Temperature Profiles

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Figure 4-B

Lynch Canyon Run #2

MOBIL G-C CORPORATION

Temperature Profiles

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