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**DEVELOPMENT AND FIELD TESTING OF A PROCESS FOR RECOVERING
HEAVY CRUDE OIL IN THE CARLYLE POOL – ALLEN COUNTY,
KANSAS USING THE VAPOR THERM® GENERATOR – FINAL REPORT**

Work Performed for the Department of Energy
Under Contract No. EY-76-C-02-2880

MASTER

Date Published—September 1980

Carmel Energy, Inc.
Houston, Texas

U. S. DEPARTMENT OF ENERGY

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HEAVY CRUDE OIL IN THE CARLYLE POOL — ALLEN COUNTY,
KANSAS USING THE VAPOR THERM® GENERATOR

FINAL REPORT

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FINAL REPORT

DEVELOPMENT AND FIELD TESTING OF A PROCESS FOR RECOVERING HEAVY CRUDE OIL IN THE CARLYLE POOL-ALLEN COUNTY, KANSAS USING THE VAPOR THERM® GENERATOR

DOE Contract No. EY-76-C-02 2880.*000

SUMMARY

Carmel Energy, Inc. completed an 18 month cost sharing contract with the U.S. Department of Energy in December, 1977. The purpose of the field test was to demonstrate the commercial applicability of recovering heavy oil using a Vapor Therm generator on the Clinkenbeard lease in Allen County near the town of Iola, Kansas.

A Vapor Therm generator capable of producing steam and inert gases was designed and constructed to ASME codes. The unit was built specifically for conditions encountered in the Carlyle pool, and is capable of delivering heated gases at 900 psi and 700°F. New wells were drilled in a five spot pattern with an inter-well distance of 208.7 ft. Logs and cores from these new wells were obtained and the subsurface reservoir was evaluated. Oil content of 1197 BSTO/Ac-Ft was encountered. This oil was 19.5° API with a viscosity of 1026 cps at 70°F. The net pay thickness beneath the pattern exceeded thirty-five feet. Bartlesville sand porosity was 23.6% and absolute permeability was 695 md. Initial reservoir pressure was 235 psi. The oil reservoir is underlain by an extensive aquifer whose thickness exceeds one hundred feet.

Prior to drilling the new wells, primary production from the lease during its 50-60 year productivity history is estimated to have been 6.5% of the original oil in place. Each of the new wells was completed and placed on production and the production of well fluids was metered.

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On January 31, 1977, the first of four stimulation cycles in the Bartle-ville sand was begun. The final cycle was concluded on March 5, 1978. During these months of cyclic stimulation-production, the wells produced at a sustained average rate of 7.82 BSTO/day and a water/oil ratio of 1.3. Over three barrels of oil per barrel of steam injected was recovered on the 4th cycle. Maximum production rate is 151 BSTO/well/week. Total oil production during the four cycles was 9034 barrels of stock tank oil, indicating an enhanced recovery of 6.04% of original oil in place or 71.2 BSTO/Ac-Ft.

The principal mechanisms responsible for the enhanced recovery include oil viscosity reduction due to heat and CO₂ solubility, oil expansion, gravity drainage, gas repressurization, and water encroachment. An analytical model of the process has been developed. This model takes into account each of the recovery mechanisms and can be used to predict the production rate of heavy oil in the Carlyle pool.

The most significant problems encountered during these tests were sand production, water/oil emulsions, surface handling of produced fluids, injectivity of Vapor Therm gases, and gas leakage during production. Corrosion of steel tubulars and the presence of bottom water in the reservoir were not found to be detrimental to the application of the process in this reservoir. Each of the above mentioned problems was successfully resolved so as to minimize their impact on subsequent operations.

Economic analysis of the Vapor Therm process in the Carlyle pool indicate that a typical optimized development program would consist of 60 wells alternately stimulated by one Vapor Therm unit. Capital cost for such a program is \$4,788,000 and annualized operating expense is estimated to be \$1,396,750/year.

INTRODUCTION

Carmel Energy, Inc. completed an 18 month cost-sharing contract with the U. S. Department of Energy in December, 1977. The purpose of the field test was to demonstrate the commercial applicability of the Vapor Therm process in the Clinkenbeard lease in Allen County near the town of Iola, Kansas. Figure 1 shows the location of the Clinkenbeard lease.

Carmel Energy's Vapor Therm process was designed to produce a mixture of inert gases and steam to stimulate the production of low gravity viscous crude oil reservoirs. Production stimulation is achieved by the action of the following mechanisms:

1. Oil viscosity reduction by the application of heat.
2. Driving potential achieved by the presence of inert gas acting at the radius of drainage.
3. CO₂ absorption into the crude oil.

Using an injection-production cycle nitrogen, CO₂ and water vapors are injected directly into the oil bearing formation for a period of 2-7 days and subsequent oil production is begun.

PROCESS DESCRIPTION

Carmel Energy's Vapor Therm generator is designed to produce a mixture of inert gases and steam to stimulate the production of low gravity crude. The Vapor Therm generator is composed of (1) a high pressure air compressor system, (2) a high pressure combustion chamber and (3) a steam drum where steam is formed, harmful combustion products are removed and solids are removed. In addition there are water and chemical injection pumps, fuel feed pumps, fuel storage, attendant instrumentation and control systems. Water should normally be softened; however, in this field test, water was pumped from a creek and was not treated or filtered in any manner. The Vapor Therm process is based on (1) the high pressure combustion of a liquid fuel or natural gas, (2) temperature adjustment and control by direct contact of combustion gases with water and (3) injection of steam and inert gas into the oil bearing formation.

Figure 2 is a schematic diagram showing the equipment and process flows. Air is compressed in a conventional compressor to the desired operating pressure (900 psig maximum), then flows directly into the combustion chamber.

In the burner section of the thermal generator, high pressure air is mixed with either liquid or gaseous fuel and burned. The fuel is injected through nozzles into the burner section. The design of the air inlet baffles and burner barrel is such that very high turbulence is obtained which results in essentially complete combustion of the fuel. In this field test No.2, diesel fuel was burned and near stoichiometric combustion was obtained routinely.

The hot combustion gases flow from the burner section at a temperature of over 3500°F into the water injection and steam generation drum. This drum is designed to provide direct contact of the hot combustion gases with water. The net effect of this contact is the conversion of a high percentage of the sensible heat contained in the combustion gases to the vaporization of water. The steam

generated combines with the combustion products and flows to the well head at 350-650°F. Temperature control is maintained through manipulation of a combination of factors which include operating pressure, water flow rates and efficiency of contact between combustion gases and water. For a given operating pressure the outlet temperature can be easily controlled through instrumentation which adjusts the various variables.

In addition to its function as a steam generator, the drum also acts to scrub the combustion gases. This step is vital since the combustion products contain acidic and other potentially corrosive components which will seriously damage the equipment unless removed. The scrubbing action of the water absorbs these acids which, in turn, are neutralized by addition of chemicals to the drum.

The hot gases are then carried to the wellhead through insulated pipes and injected down the tubing string. The gases can be injected down one well or several wells at the same time. Thus, the operator has good control on the mixture and amount of nitrogen, carbon dioxide, steam, temperature and heat output at the surface. Total output of the Vapor Therm unit is 200 million Btu per day containing 1,746,000 SCFD of inert gas(carbon dioxide and nitrogen) and 500 Bbl/day of steam as condensate in the reservoir.

SUBSURFACE INFORMATION

Lease Location and Field History

The Carmel Energy, Inc. heavy oil recovery project is situated in the Carlyle pool located in Allen County, Kansas. The field was discovered in 1918 and is a part of the older Iola gas field which was discovered in about 1873. Oil production is from the Bartlesville sand of the Pennsylvanian age. Oil has been produced from this zone continuously since about 1920.

The Clinkenbeard lease, upon which the test is located, is an 80 acre tract located at the northern most productive limit of the Carlyle pool. The lease is bounded on the south by a county road, and on the east by U.S. Highway 169.

Geology

The Bartlesville sand dips to the north, with the highest portion of the sand body at approximately 115 ft. above sea level. Sand depths have been acquired through study of older drillers' logs, limited gamma ray logs in older wells, and more complete evaluation through log and core analysis obtained by Carmel with the drilling of five new wells, No. 14, 15, 16, 17 and 18, in a 5-spot configuration. A contour map on top of the Bartlesville sand is shown in Figure 3. Two wells have penetrated the oil water contact at approximately 62 ft. above sea level. These wells are CH-7, an older evaluation test drilled in 1964 and Well No. 16, drilled in 1976 by Carmel. The Bartlesville sand is approximately 160 feet thick under the entire Bartlesville sand section.

The sand body is characteristic of recent non-marine fluvial bar build-up as indicated by the absence of marine fossils.

The oil column varies in thickness from 0 feet north of Well 5A to 43 feet in the southern portion of the lease. An isopachous map of net Bartlesville oil saturation is shown in Figure 4.

The Bartlesville section is broken by a 4-8 foot hard shaley-lime stringer located approximately 10 feet into the sand within the oil zone. A similar shaley-lime section is located within the aquifer. The uppermost lime stringer effectively separates the reservoir into two sections, as the vertical permeability of this limey zone is zero. A cross-section of the lease, A-A' is shown in Figure 5, together with available log data.

Rock Properties

The sand consists of fine to very fine, well-rounded and well-sorted quartz sand grains. Bedding plains are clearly marked by flakes of platy material. Sand consolidation varies from good to completely unconsolidated. Wells No. 17 and No. 18 were cored through the top 30 feet of sand. Core recovery was approximately 90%.

Sand porosity is 23.6% and permeability to air is 695 md.

Fluid Saturations

Fluid saturations were determined by log analysis and laboratory analysis of cores from Wells No. 17 and No. 18. On Well No. 18, a complete suite of logs was run, including IES, sonic, density, and gamma ray-neutron. Average fluid saturations computed from these logs are:

Gas saturation	9.7%
Oil saturation	65.4%
Water saturation	24.9%
	<u>100.0%</u>

The gas saturation is dispersed throughout the two productive intervals in the sand and is due, in part, to the injection of large quantities of air into an adjoining lease. Some evidence of an original gas cap is apparent, as computed gas saturation in the top ten feet of sand exceed 15%.

Fluid Properties

The oil produced from the Clinkenbeard lease is a heavy, viscous asphaltic based crude. The gravity of the gas-free crude is 19.5° API @ 60°F, with a pour point of +10°F. The bubble point is 771 psi. Viscosity as measured from a fluid sample from Well No. 14 in September, 1976 is as follows:

<u>Temp. °F</u>	<u>Oil Viscosity, cps.</u>
70	1026
100	304
150	65
225	15.1
300	5.76

The brine produced from the Bartlesville sand has an average salinity of about 20,000 ppm. The pH is 7.7 and electrical resistivity is 22.0 Ohm-meters @ 77°F.

Reservoir Conditions

The Bartlesville oil reservoir is located at a depth of 870 ft., or approximately 110 ft. above sea level at the location of the Carmel Energy project. Reservoir temperature, as measured by wireline logs, is 74°F. Reservoir pressure as measured by static fluid level, is about 235 psi. The pressure is being partially maintained by the presence of an active aquifer below the oil. Producing energy has been provided by gas cap expansion, solution gas drive, liquid expansion and water drive.

Reservoir

Oil in place within the Bartlesville reservoir is approximately 1197 barrels of stock tank oil per acre-foot of reservoir volume. Total Clinkenbeard reservoir volume is $17.414 \times 10^6 \text{ ft}^3$. Total Clinkenbeard oil reserve is $2.020 \times 10^6 \text{ BSTO}$. Oil reserve within the 5 acre pattern area of Carmel's thermal recovery project is 256,925 BSTO.

Previous Work

One year prior to the DOE contract, a single well field test was conducted on the Clinkenbeard lease using Carmel Energy, Inc. Vapor Therm technology. A prototype Vapor Therm unit and its ancillary equipment were installed on the lease. A new well, No. 14 was drilled, completed and stimulated. An injection technique was developed which allowed injection rates of 1300 MSCF/day of gas and steam containing 100 million BTU/day. Beginning April 24, 1975, the well was stimulated for eight days, then the well was turned around for production. Production rates ranged from 20-25 BOPD initially, then over a 60 day period declined to 5 BOPD. It maintained a 4-5 BOPD rate until January, 1977 and at no time declined to 1/2 BOPD rate typical of other wells on this reservoir.

In April 1976, Carmel Energy entered into a cost sharing contract with DOW to demonstrate the commercial applicability of the Vapor Therm Process.

Well Completion

Four new wells were drilled to complete a 5-spot injection/production pattern including Well No. 14. Drilling and completion of all wells was similar. A 7-7/8" hole was drilled to 865 ft., near the top of the Bartlesville sand, using rotary drilling tools. The well was then cored to 910-912 ft. using a 3-7/8" rotary core barrel. After logging, the well was reamed to total depth using a 6-1/4" bit. A Halliburton formation packer shoe was set at 870 ft. on the bottom of 4-1/2" J-55, buttress threaded casing and cemented to surface with 40% silica flour-class H cement mixture. After setting for 72 hours

the cement was drilled out with a 3-7/8" bit run to TD. The drilling mud was then displaced with lease-produced salt water. An under-reamer was run into the hole to a point 2 feet below the packer. The hole was enlarged from 6-1/4" to 7" using salt water as the drilling fluid to remove the mud filter cake from the walls. After under-reaming to TD, the cuttings were flushed from the hole and the wells were left standing full of lease-produced salt water.

Well No. 16 was drilled to a TD of 1040 ft. After logging, the well was plugged back to 912 ft. with class A common cement and completed the same as the other wells. After a pump was set, this well produced up to 80 barrels of fluid per day (BFPD) primarily salt water, with only a trace of oil. Evidently the cement plug was not holding. An attempt to plug back with Hydromite using a dump bailer was unsuccessful. In late November, another attempt to plug back with Hydromite by pumping down the tubing was attempted and was successful. Over a one-week period, following this plug back, Well No. 16 produced at a rate of 15-20 BFPD with 3-5 barrels oil. These 5 wells were produced to mid-December to develop the primary production decline curve. (See Figure 6).

Vapor Therm Unit

While the new wells were being drilled, construction of the new commercially sized Vapor Therm unit which was described earlier was begun in Houston. The unit was designed and built to conform with ASME Section 1- Power Boilers of the ASME Boiler and Fired Pressure Vessel Code. Construction was routine.

Air Compressors

Two 550 Hg air compressors were leased for this contract. The primary air compressor is a 2 stage Ingersoll-Rand HHE compressor driven by a L5108 Waukesha natural gas engine. It compresses 2,000 MSCFD of air from atmospheric pressure to 102 psig. The secondary air compressor is a 2-stage Clark driven by a VLROU Waukesha gas engine. It takes suction from the first compressor and boosts it to 900 psig. The compressors can be run on either natural gas or propane.

Primary Production

Primary production began on the various wells as they were completed and pumps were set. For a 45 day period from mid-October to early December 1976, primary production data was measured and recorded from all five wells. Initial production was about 25 BOPD declining to about 18 BOPD 45 days later. As shown on the primary decline curve on Figure 1, total production by primary would have declined to 13 BOPD on January 31, when the first injection run was begun and is projected to decline to less than 6 BOPD within 12 months. This primary production is consistent with the field wide average. The adjacent oil operator is averaging 1/2 to 1 BOPD per well on primary production.

FIELD TESTING

Test Run

A test of the equipment was begun on January 13, 1977. All systems on the Vapor Therm unit operated properly except for difficulty controlling the temperature of the gas/steam mixture leaving the steam drum. After operating for 29 hours, the unit was shut down for inspection. The difficult temperature control problem was determined to be caused by a welding failure at an elbow in the steam drum. After this elbow was replaced, the unit operated properly.

First Stimulation

During the ten day injection run which began January 31 and ended February 10, the Vapor Therm Unit operated as designed. There were two 3 hour automatic shutdowns during the run both of which were caused by minor operating mistakes. The system operated at 850 psig in a temperature range from 460°F - 500°F. All of the automatic controllers operated as designed and only routine adjustments were necessary throughout the entire run.

The first two wells used for injection were Wells No. 16 and No. 17. After two days of injection, an old unplugged well (No. 4) which is 60 ft. from Well No. 16 began to flow salt water. Injection was discontinued into Well No. 16 and begun on Well No. 15. On February 6, injection was discontinued into Wells No. 15 and No. 17 and begun on Wells No. 14 and No. 18. Injection continued in these two wells until February 10th at which time the unit was shut down. During the injection into Wells No. 15 and 17, the pump which had been installed on Well No. 18, stopped producing fluid and began producing only gas, indicating premature breakthrough of gas. The pump was pulled and Well No. 18 was shut-in until injection into this well commenced on February 6th. During this stimulation, a total of 1473 barrels of steam and 12,857 MSCF inert gas which contained 516 million Btu of heat were injected into those wells.

First Production Run

Oil production was begun from Wells No. 14 and No. 18 on February 12th using gas lift by injecting air down the annulus and forcing the fluids up the tubing through the flow line and into the gas oil separators. Production from these two wells by gas lifting varied from 28 to 61 BOPD over a four-day period. From February 16th to February 19th, downhole pumps were installed in Wells No. 14 and No. 18. Subsequent individual well tests indicated production from 20-40 BOPD per well. However, a severe emulsion problem was experienced on these two wells during this entire period. The viscosity of the oil/water emulsion was four times that of free oil. This severely restricted flow rate from the well heads to the gas/oil separator and to the heater-treater located some 2,000 ft. from the wells. Once the oil was received in the heater-treater, the emulsion was very easy to break by maintaining the heater-treater at 180°F and using a proprietary emulsion breaker at a rate of one gallon per 100 barrels of fluid. Stock tank oil consistently analyzed less than 1% BS&W.

Severe emulsion viscosity problems were encountered on Wells No. 15 and No. 17. A sample of the emulsion taken from Well No. 17 indicated a viscosity 13 times that of free oil at the same temperature. It is believed that this very high viscosity emulsion severely affected the amount of oil able to flow into the well bore. Maximum production from either of these wells was 7 BFPD containing 68% BS&W.

Production from these four wells continued until the total daily production declined to the primary production decline curve.

Second Stimulation

On April 2, 1977, the second injection run began. This time 4 wells, No. 13, No. 15, No. 17 and No. 18 were stimulated simultaneously. A proprietary chemical to reduce emulsion forming tendencies was added to the inert gas and steam mixture downstream of the steam drum at approximately 500 ppm. Laboratory tests had indicated that this chemical would reduce the viscosity of an oil/water emulsion to half that of free oil. During this stimulation, approximately 7000 MSCF of inert gas and 1500 barrels of steam containing 450 million Btu were injected. Following this 4 day injection run, the wells were put on production.

The initial production rate peaked 103 BOPD from 4 wells. No high viscosity oil/water emulsion problems were experienced. Over a 56 day period, a total of 2084 barrels of oil were produced from these 4 wells, giving a daily average of 36 BOPD. The oil to steam ratio was 1.3 bbls of oil per bbl of steam, 2.34 MSCF gas per bbl oil, and 3.72 bbl oil per million Btu.

Third Stimulation

On June 9, 1977, the third stimulation cycle began and lasted for four days. Injection rates were the same as the previous runs but the required injection pressure had declined from 850 psig to 650 psig indicating an improvement in effective permeability to injected fluids. About 580 million Btu were injected over a 92 hour period. During a 96 day production period, 3121 barrels of oil were produced, giving a daily average of 32.5 BOPD.

Fourth Stimulation

On September 24, 1977, the fourth stimulation cycle was begun. During this run, an experiment was tried in two wells, No. 14 and No. 17. This experiment consisted of simply unseating the downhole pump but leaving the pump and the 1 inch hollow-rod pumping string in the 2-3/8 inch injection tubing string. Early during this stimulation, the 2-3/8 inch tubing string failed and injection into these two wells was discontinued. Failure was caused by erosion of the 2-3/8 inch tubing string internally caused by high velocity of the injection gases across the collars of the 1 inch hollow-rod pumping string. At each location of a 1 inch collar (1.66 inch O.D.) a hole was created in the wall of the 2-3/8 inch tubing string. (1.995 inch I.D.).

The stimulation of wells No. 15 and No. 18 continued with no problems and about 285 million Btu were injected into these two wells.

Production from these two wells, No. 15 and No. 18 was 2717 BO over a 161 day period. The other two wells, No. 14 and No. 17 contributed 612 BO over this same period to give a total production of 3329 BO from this fourth stimulation. Data taking for the DOE test was discontinued on March 5, 1978.

RESULTS OF FOUR INJECTION/PRODUCTION CYCLES

Fluid Injection and Production

A comparison of quantities of fluid injected, producing days and oil and water production for each of the four cycles is shown in Table 1. While four wells were stimulated during the first three cycles, only two were included in the fourth cycle for comparison purposes. This is because of downhole experimentation in two wells during the fourth cycle and resultant intermittent oil production. Cycle length for these four cycles was dictated by the terms of the DOE contract which stipulated that four complete cycles would be attempted within the 13 months duration of the field test. An average of 129×10^6 Btu was injected into each well during each of the four cycles at a rate of approximately 32.25 MM Btu/day. Oil production varied from a low of 1112 BSTO on cycle one to 3121 BSTO on cycle three. A total of 9646 BSTO was recovered during the duration of the contract. Approximately 1154 BSTO would have been recovered by primary production during this period, resulting in 8492 BSTO being produced by enhanced recovery.

The average oil production rate per well per day for each cycle varied from a low of 4.96 to a high of 9.30. The average over 1154 well-days was 7.82.

For comparison purposes, convenient oil production ratios are also shown in Table 1. The oil/steam ratio varied from 0.75 on Cycle 1 to 3.33 on Cycle 4. The MCF gas/Bbl oil ratio varied from a high of 4.05 on Cycle 1 to a low of 0.916 on Cycle 4. The barrels of oil produced per MM Btu injected exceeded 9.5 on the fourth Cycle.

Oil and water production by week for Cycles 1-4 is shown in Tables 2-5. The oil production is graphed as a function of time in Figure 7 for each cycle, together with the observed water/oil ratio.

With reference to Figure 7, each of the four cycles is characterized by a period of highly accelerated oil production, peaking at an initial rate of over 130 bbls/well/week. Oil production then stabilizes at a rate of about 50 bbls/well/week for the remainder of the production phase of the cycle. These observed phenomena are remarkably similar for each of the four cycles.

Water production commences upon the production of oil at a ratio of about 1.0. The water/oil ratio slowly and gradually increases to a maximum near the end of the cycle. Cumulative water/oil ratio was 0.66, 1.28, and 1.33 for Cycles 2-4 respectively.

The cumulative oil production for each of the four cycles is shown graphically in Figure 8. These curves confirm the linear response noted for each cycle beyond the initial acceleration period.

Recovery

The injection/production wells were drilled in a 5 spot configuration with an inter-well spacing of 208.7 feet. Using 104.3 feet as the radius of drainage, the area drained by the four test wells was 3.138 acres. With 1197 Bbls stock tank oil in place per Ac-Ft., and an average net thickness of 38 ft., the reserve under the test pilot area was 142,735 BSTO. Total production during the contract test period was 9,646 BSTO as shown in Table 1. The net oil production attributable to enhanced recovery was 8492. Therefore, the recovery of enhanced oil during the test was 6% of OOIP or 71-2 BSTO/Ac-Ft. Total energy consumed in generating recovery energy (neglecting electrical and compression energy) was equivalent to 362.9 BSTO assuming a combustion heat of 6.133 MM Btu/Bbl for the crude-diesel fuel mixture. This calculation also assumes four producing wells on the fourth cycle. Including compression energy, 709.8 BSTO of equivalent energy were consumed. This total energy consumption including compression, is equivalent to 8.35% of the oil produced.

MATHEMATICAL MODEL OF VAPOR THERM PROCESS

Early explanations of cyclic steam injection for improved oil production related viscosity reductions and changes in the external drainage radius boundary condition for the cold and hot condition of the reservoir, before and after steaming² are as follows:

$$\frac{Q_{hot}}{Q_{cold}} = \frac{\mu_{cold} / \mu_{hot} \log (r_e / r_w)}{\log (r_h / r_w) + \mu_{cold} / \mu_{hot} \log (r_e / r_w)} \quad (1)$$

where:

Q_{cold} = oil production rate before steam injection, B/d.

Q_{hot} = oil production rate after steam injection, B/d.

μ_{cold} = oil viscosity before steam injection, cp.

μ_{hot} = oil viscosity after steam injection, cp.

r_e = external drainage radius of well, ft.

r_h = heated zone radius, ft.

r_w = radius of wellbore, ft.

Equation (1) is developed from Darcy's radial flow equation derived from the imposed boundary conditions and the expression provides a reasonably accurate analytical approach to calculating individual well stimulation rates for cyclic steam generation. Equation 1 neglects changes in potential which is a reasonable assumption for cyclic steam injection as will be illustrated later in this presentation. Predicted versus actual stimulated production rates compare favorably when Equation 1 is used and this expression can provide a first approach to approximate stimulated production rates but for cyclic steam only.

However, Equation 1 failed to predict with any degree of accuracy stimulated production rates from the Vapor Therm process because several important terms in Darcy's radial flow equation were assumed constant in developing this ratio - namely no changes in potential, constant permeability and viscosity reductions due to temperature affects only. Assuming such conditions for the Vapor Therm process completely invalidates the expression.

In the Vapor Therm unit N_2 , CO_2 , and superheated steam enter the formation where steam instantaneously² condenses giving up its latent heat and reducing the viscosity of the oil around the wellbore. CO_2 dissolves in the oil and water phases further reducing the viscosity of the liquid phases. Oil that has been heated to a reduced viscosity will tend to bank in front of a hot water zone. N_2 will pass through these zones, migrating due to gravity effects to the top² of the reservoir where it will increase the pressure of the reservoir. After several days of Vapor Therm injection, the producing zone would be simply described by Figure 9, assuming a homogeneous, isotropic formation.

By limiting discussion to formation heat losses, it can be readily seen that convective heat transmitted into the formation by Vapor Therm always stays within the formation and is used productively in reducing the viscosity of the oil which, in turn, increases oil production rates. Conductive heat is lost to the overburden and underburden and this heat can be considered to be lost since it will not be used to reduce the viscosity of the oil. However, conductive heat lost within the formation is productive since this heat stays in the oil bearing sandstone and serves to reduce the viscosity of the oil.

Referring to Figure 9, it can be seen that as Vapor Therm gases are injected into the formation a zone of saturated steam vapor, carbon dioxide and nitrogen gas at the saturation temperature of steam will develop and grow as a function of injection time at a steady rate. This heated zone is described as a cylinder with a heated zone radius, r_h . Therefore, the ratio of overburden/underburden conductive heat loss to conductive heat retained within the sandstone reduces to the following expression (assuming a sandstone reservoir bounded by shale):

$$\frac{\text{Heat Loss}}{\text{Heat Retained}} \approx \frac{2\pi r_h^2 \times K_{\text{shale}}}{2\pi r_h h \times K_{\text{sandstone}}} \approx \frac{r_h}{h} \quad (2)$$

where:

r_h = heated zone radius, ft.

h = formation thickness, ft.

$K_{\text{shale}} \approx K_{\text{sandstone}}$ = thermal conductivity

Development of mathematical models to define the Vapor Therm process logically breaks into two cases at this point. Case 1 is when r_h is small relative to formation thickness, h , and Case 2 is when r_h is large compared to formation thickness, h .

Consider first the case of negligible conductive heat losses to the overburden/underburden - i.e. small r_h relative to h . With the assumption of no conductive heat losses, r_h can be readily calculated from a simple heat balance on the formation. After r_h is known or calculated it can be compared to r_h calculated by material balance from known cumulative fluid production during a production cycle versus a residual oil saturation. This has been done and from small r_h , say $r_h \leq 20$ ft., the two r_h values compare very closely.

For reservoirs with high oil saturation, i.e. 1197 STB/Ac ft; net sand thickness of 38 ft; porosity of 23.6% and 65.4% oil saturation - as actually exists in the Carlyle Field test in Kansas which will be discussed later, the assumption of no conductive heat losses or small r_h relative to h is not a bad assumption since at the heat injection rates used in this test, the heated zone radius, r_h , is only 50 ft. after $2\frac{1}{2}$ years.

Now for large r_h relative to h which would be the case after many injection and production cycles, we must consider heat losses to the overburden and underburden as a function of time. The only way an analytical solution to the differential equation of continuity which describes the system can be obtained is by assuming a step function for the temperature profile and by neglecting conductive heat losses in the radial direction. Otherwise, laborious numerical solutions must be obtained on a computer using finite difference techniques.

Referring to Figure 9, assume that Vapor Therm gases (steam, CO_2 and N_2) enter the reservoir and bank hot water and oil in the region shown. N_2 and CO_2 pass through the heated zone and CO_2 is dissolved in the oil and water phases. Nitrogen saturates the oil bearing formation to the critical gas saturation, S_{gc} , and gradually begins to form a gas cap in the upper part of the formation out to a radius of r_{N_2} . Temperature of the heated zone after steaming is the saturation temperature for steam, T_s at the indicated pressure. Temperature is further assumed to remain constant throughout the steamed out zone for the duration of the injection cycle and after injection ceases, the temperature will be reduced as heat is given up to the overburden and underburden formation and fluid is produced. The temperature out in front of the

hot water and oil bank remains at the initial reservoir temperature, T_r . Then the temperature of the reservoir during the injection cycle and immediately at the beginning of the production cycle is the following step function:

$$T(r) = T_s \quad | \quad r \leq r_h$$

$$T(r) = T_r \quad | \quad r > r_h$$

where r_h = radius of heated zone from wellbore, ft.

For the case of infinite thermal conductivity in the vertical directions, into the overburden and underburden i.e. $\frac{\partial T}{\partial r} = 0$; the heated zone radius, r_h can be obtained from a heat balance on the reservoir and is a function of injection time, t_i , and injected mass, M_s , and thermal properties of the rocks. The heated zone radius, r_h is calculated by the equation of Marx and Langenheim assuming no heat conduction in the radial direction as follows:

$$r_h^2 = r_{h(ti)}^2$$

$$= h \left[\frac{M_s (H_{S_{T_s}} - H_{W_{T_r}}) + M_{CO_2} (H_{CO_{2T_s}} - H_{CO_{2T_r}}) + M_{N_2} (H_{N_{2T_s}} - H_{N_{2T_r}})}{4 K \pi (T_s - T_r) t_i} \right] \xi_s \quad (3)$$

at constant daily injection rates,

where: h = thickness, ft.

M_s, M_{CO_2}, M_{N_2} = total mass of steam, CO_2, N_2 injected in the current cycle, lb.

$\xi_s = e^{\tau} \operatorname{erfc}(\sqrt{\tau}) + \frac{2\sqrt{\tau}}{\sqrt{\pi}} - 1$, temp. profile

$\tau = 4Kt_i/h^2(\rho c)_1$, dimensionless

K = formation thermal conductivity, $\frac{BTU}{ft/day/^\circ F}$

t_i = time of injection (current cycle)

$H_{S_{T_s}}, H_{CO_{2T_s}}, H_{N_{2T_s}}$ = enthalpy of steam, CO_2, N_2 at T_s BTU/lb.

$H_{S_{T_r}}, H_{CO_{2T_r}}, H_{N_{2T_r}}$ = enthalpy of steam, CO_2, N_2 at T_r BTU/lb.

(ρc) = Volumetric heat capacity of reservoir rock including interstitial fluids, $BTU/ft^3 - ^\circ F$

$$= \{ (1 - \phi) \rho_r c_r + S_w \phi \rho_w c_w + S_o p_o \phi c_o \} \frac{BTU}{ft^3 - ^\circ F}$$

Equation 3 assumes that the value of average density, ρ , times heat capacity, c , (i.e. ρc) for the barren strata is the same as that for the oil sands
 $\{ (\rho c)_{\text{shale}} = (\rho c)_1 \}$

Now determine, T_{avg} , average reservoir temperature of the heated region after termination of steam, CO_2 and N_2 injection from an approximate energy balance around the region $r_w < r < r_h$:

$$T_{\text{avg}} = T_r + (T_s - T_r) \{ \bar{v}_r \bar{v}_z (1 - \delta) - \delta \}, \text{ } ^\circ\text{F}$$

where: $\bar{v}_r$, $\bar{v}_z$ are unit solutions at component conduction problems in the radial r and z vertical directions and are a function of dimensionless time as follows:

In general $\{ \bar{v}_r \bar{v}_z (1 - \delta) - \delta \}$ is a decay function; ≤ 1.0 which changes with t . δ is a correction term which accounts for the energy removed from the oil sand by produced oil, gas and water. It is the fraction of heat removed to heat remaining in the oil sand zone. If little energy is removed by produced fluids, i.e. low rate well, δ can be set equal to zero. In any case, δ will be a small number determined as follows:

$$\delta = \frac{\text{heat removed by produced fluids that day}}{\text{heat in oil sands at beginning of day.}} \quad (5)$$

$$= \frac{5.61 [q_o (H_{o_{T_{\text{avg}}}} - H_{o_{T_r}}) + q_w (H_{w_{T_{\text{avg}}}} - H_{w_{T_r}})]}{h \pi r_h^2 \times (\rho c)_1 (T_{\text{avg}} - T_r)}$$

where q_o , q_w , Bbls oil and water produced, assuming no gas production.

It is often assumed that due to pressure drop unheated fluids move back into the heated area and pick up heat from the overburden and underburden and that heat gain is approximately equal to heat lost from the oil zone by produced fluids. Then, in this case $\delta=0$.

An empirical method⁵ for calculating T_{wb}^{avg} makes use of a mathematical expression for calculating wellbore temperature, T_{wb} as follows:

$$(T_{wb})_n = T_r + \frac{\Delta T_i}{1 + D_i t} \quad (6)$$

$(T_{wb})_n$ = temperature difference at time (t), days, n = no. days

ΔT_i = initial temperature difference

T_r = $T_s - T_r$; = initial reservoir temperature]

D_i = initial % declines rate in the temperature difference as a fraction of the temperature difference.

t = time in days after date of measurement of initial T_i

Equation 6 will provide a calculation of wellbore temperature for each day after termination of injection according to the following general function:

For "Huff-N-Puff" operations in California it was found that $D_i = .14$ provided a general fit to measured wellbore temperatures.

In the Vapor Therm process, T_{wb} can be continuously measured by use of permanently installed thermocouples in the wellbore at the sandface. This data will permit calculation of the best D_i for Equation 6. It is believed that T_{wb} will be approximately equal to T_{avg} at any time during the production cycle and at optimum injection lengths^{avg} the rate of temperature decline will be duplicated during each production cycle. Therefore, once D_i is accurately determined, it may be used with reliability to calculate T_{avg} for future production cycles.

When T_{avg} is known for each day of production, viscosity of the oil can be calculated from the following general expression:

$$\mu_o = \text{fcn } (T_{avg}) = A e^{\left(\frac{B}{T_{avg} + C} \right)} \quad (7)$$

where: $A \approx .01 - .04$
 $B \approx 2200 - 2800$
 $C \approx 100 - 115$

Generally we will know one value of oil viscosity at T_r and from this information we can calculate the viscosity at elevated temperatures for each day of production. A semi-log plot of viscosity against temperature generally approximates a straight line function for crude oils over the temperature range of 60 to 500°F and the slope of this curve is approximately constant for crudes over this temperature range.

Fluid production after injection of Vapor Therm is best described by modifying Equation 1 for steady state radial flow with gravity drainage superposed on a pressure head. The following expression results:

$$Q_o = \frac{6.667 \times 10^{-4} k_o \rho (2hh_e - h^2 - h_w^2)}{B_o \mu_o \log_{10} \left(\frac{r_e}{r_w} \right)} \quad (8)$$

where: Q_o = oil production rate, $\frac{\text{Bbls STO}}{\text{Day}}$

k_o = effective permeability for oil, md

h = sand thickness, ft.

h_e = fluid head at external boundary, ft. (note $h_e > h$)

h_w = fluid level in wellbore, above bottom of pay maintained by pumping equipment, ft.

μ_o = viscosity of oil, cps.

B_o = formation volume factor, $\frac{\text{Bbls Reservoir Oil}}{\text{Bbls STO}}$

r_e = radius of external boundary, ft.

r_w = wellbore radius, ft.

Notice that for the case where $h = h_e$, Equation 8 reduces to the gravity drainage expression. In general, h_e declines as a function of time due to cooling of the heated zone and fluid production. As the heated zone cools oil viscosity increases resulting in a reduced production rate. The heated zone radius remains constant for each production cycle and is a function of the last injection cycle only. The pressure at the heated radius, P_{r_h} , is a sum of the component partial pressures as follows:

$$P_{r_h} = P_o + P_{N_2} + P_{CO_2} + P_{H_2O} \text{ (St)} \quad (9)$$

Where: P_o = hydrocarbon vapor pressure, psi @ T_{avg} .

P_{N_2} = partial pressure of N_2 , psi, @ T_{avg} .

P_{CO_2} = partial pressure of CO_2 , psi, @ T_{avg} .

$P_{H_2O} \text{ (St)}$ = partial pressure steam, psi, @ T_{avg} .

P_o is a function of temperature for a given gravity crude oil. Either a general correlation of vapor pressure for a known API gravity crude oil can be used or experimental data on the actual crude oil system can be obtained and used. In any event, heavy oil does not contain appreciable $C_1 - C_{10}$ components and consequently its vapor pressure even for temperatures of 500°F is generally less than 50 psi.

P_{N_2} can be calculated from the gas equation as follows:

$$\begin{aligned} PV &= znRT \\ P_{N_2} &= \frac{znRT_{avg}}{\phi h \pi (r_h)^2} \end{aligned} \quad (10)$$

Assume $z = 1.0$

then $n = \frac{M_{N_2}}{28.2}$ where: M_{N_2} = total lbs. N_2 inj. last inj. cycle

R = gas constant for lb/lb-moles, °R, psi, ft³ = 10.73

To determine the partial pressure of nitrogen, P_{N_2} for use in Equation 9, one must first calculate P_{N_2} FROM Equation 10 and compare this pressure with the initial reservoir pressure, P_r . If $P_{N_2} \geq P_r$ as will frequently be the case

for heavy oil reservoirs, nitrogen will "escape" from the volume defined by r_h until the partial pressure of nitrogen within the heated region equals the virgin reservoir pressure. Any steam that "escapes" will be quickly condensed within the cool area outside r_h and CO_2 will go into solution with oil and water in increasing amounts as CO_2 enters the cool region outside r_h so the only gas that should "escape" is nitrogen. This, of course, assumes a homogeneous reservoir without "thief" zones such as fractures, faults, etc.

The fact that nitrogen escapes from the heated region until nitrogen pressure inside the heated region equals the initial reservoir pressure has been confirmed in field tests. Pressure transients were measured after cessation of injection and for small r_h nitrogen had "escaped" to reservoir pressure within 20 hours after stopping injection. Thereafter, nitrogen pressure was observed to decline due to heated region cooling.

For heated r_h it may become important to quantify nitrogen pressure within the heated zone up until the time nitrogen pressure reaches initial reservoir pressure. One can calculate partial pressure of nitrogen within the heated region as a function of time and T_{avg} assuming no "escape" - i.e. 100% confinement. In general the pressure profile will follow the temperature profile within the heated zone. The following expression can be used to calculate transient nitrogen pressure:

$$P_{N_2} = \text{fcn (time)}$$

$$P_{N_2} = \frac{P_r + P_{N_{2i}} - P_r}{e^{ct}} \quad (11)$$

where: P_{N_2} = adjusted partial pressure of N_2 in heated zone, psi

P_r = initial reservoir pressure, psi

$P_{N_{2i}}$ = initial partial pressure of N_2 after completion of injection cycle assuming no "escape" of N_2 , psi

t = time since injection cycle stopped, days

$1/c$ = half life of decay function time, days, measured when partial pressure of N_2 has decreased 63% total.

Steam partial pressure or vapor pressure can be determined from steam table data or use of the following expression which is very accurate from 75 to 500°F:

$$T_s = 115.1 P_{H_2O}^{0.225}(\text{St}) \quad (12)$$

T_s = saturation temp, °F

$P_{H_2O}(\text{St})$ = partial pressure of water, psi

Obtain P_{H_2O} (St) from Equation 12 for T_{avg} .

Determination of P_{CO_2} is a very difficult task since CO_2 is very soluble in water at low temperatures and therefore must be considered a condensing gas. To calculate saturation pressure of CO_2 one must know the volume of oil and water coming into contact with a known volume of CO_2 and know or assume the degree to which equilibrium saturation is reached. From this information P_{CO_2} saturation pressure of CO_2 above the oil and water, can be determined. Undoubtedly as CO_2 saturates a volume of oil and water, its pressure drives CO_2 further into the cool region. Then a temperature profile other than that assumed is needed. CO_2 reduces the viscosity of the oil, swells the oil, drives the oil to the wellbore as in solution gas drive when it comes out of solution due to a pressure drop and acts to reduce interfacial tension in multiphase flow of oil and water. However, in the Vapor Therm process, CO_2 concentrations are thought to never exceed 13% by volume even after full steam condensation, therefore effects of CO_2 , while undoubtedly important are neglected because one cannot readily quantify them. Neglecting the partial pressure component for CO_2 Equation 9 reduces to:

$$P_{r_h} = P_o + P_{N_2} + P_{H_2O} \text{ (St)} \quad (13)$$

Due to nitrogen escape at r_h into the cool region, one knows that at r_h , the pressure will at all times be equal to, or greater than, the initial reservoir pressure. Therefore, any component of flow to the wellbore past r_h can be neglected. Then $r_e = r_h$ - i.e., the external drainage radius equals the heated radius which is constant for any production cycle, increasing only with each injection cycle. Furthermore h_e can be calculated from P_{r_h} obtained from Equation 8 as follows:

$$h_e = \frac{2.3077}{\rho} P_{r_h}, \text{ ft.} \quad (14)$$

where: ρ = heated zone pressure as a function of time, psi

Darcy's radial flow (Equation 8) expresses oil flow rates as a function of, among other variables, effective permeabilities for oil flow.

As a simplification it is often assumed that water produced during a production cycle is exactly equal to water injected as steam during the last injection cycle. With this assumption $S_{w_{avg}}$ can be estimated as a function of t_n , production time.

Then assuming only two phase fluid flow - i.e. nitrogen gas is trapped and retained in the production zone - $\{S_o = 1 - S_{w_{avg}}(t_n)\}$. Core analysis usually provides reasonably accurate values for air permeability and residual oil saturation. Due to steam distillation effects, field tests and laboratory experimentation have documented that residual oil saturation is reduced by at least 50% when one pore volume of steam is injected into the reservoir. Typical residual oil saturation after injection of one pore volume of Vapor Therm are thought to be 10% or less. Some laboratory data indicated 2% residual oil after two pore volume of steam injection. Residual oil after steam injection should be determined routinely as part of the core analysis when using Vapor Therm technology. From this information relative permeability data for oil flow can be obtained. Generally, one assumes constant average oil saturation for each production cycle and a constant $k_{o(\text{residual})}$ results.

One can now calculate Q_o from Equation 8 for each day of production after each injection cycle. Optimum injection and production lengths can be calculated from cost of injection information, net revenue from oil sales and field operating cost information. Optimum well spacing can be similarly determined.

A comparison of steam "Huff-N-Puff" with Vapor Therm flow potential has been calculated from Equation 13 and tabulated in Table 6. Clearly any pressure potential of a cyclic steam process has dissipated within 10 to 20 days as can be seen upon examination of Equation 12 and a free surface of oil will form in the reservoir with only gravity drainage to account for flow of fluids to the wellbore. The exceptionally long production life at Carlyle can only be explained by nitrogen pressure within the heated zone maintaining 135 psi after 200 days of production and clearly this pressure term is independent and additive with steam, CO_2 , and hydrocarbon vapor pressure. The last two pressure terms were considered negligible for purposes of the above comparison.

Production rates for the Carlyle Field test were calculated using Equation 8 for each day of production after the fourth injection cycle and are presented in Table 7 and illustrated in Figure 10. Reasonable fits of actual production versus predicted production rates were obtained for production rates 60 days after end of the injection cycle. No fit was obtained for the first 60 days. It is thought that the mechanical problems encountered at Carlyle prevented the process from realizing its maximum production potential. However, clearly the superimposed pressure head expressed as the h_e term has a favorable effect in the production rate and largely explains the favorable difference between the Vapor Therm process and the cyclic steam injection- "Huff-N-Puff" process.

PROBLEMS ENCOUNTERED AND SOLUTIONS

During testing of the Vapor Therm process in the Carlyle pool, six significant problems were encountered. These problems were:

- a. sand production
- b. water/oil emulsions
- c. surface handling of produced fluids
- d. injectivity of Vapor Therm gases
- e. gas leakage during production
- f. pumping problems

While the Bartlesville sand is a well consolidated sedimentary body, certain intervals are more friable as evidenced by poor core recovery in zones of higher permeability. All wells were completed open hole with $4\frac{1}{2}$ " casing set to the top of the sand. This configuration was chosen to enhance injectivity. It was found by experimentation that by burning with an excess of 5% air over stoichiometric requirements, a degree of sand consolidation was achieved, presumably by a coking process. Periodic washing of the wellbore with saltwater was also used to overcome the sand problem. Other solutions under consideration include slotted liners, gravel packing and perforated completions.

During the production phase of the first cycle, a very viscous oil/water emulsion was recovered. The viscosity of this emulsion was thirteen times as high as the clean oil viscosity. On subsequent cycles, a proprietary chemical was injected along with the Vapor Therm gases to inhibit the formation of in-situ emulsions. The lack of a serious emulsion problem on cycles 2-4 would indicate that the special treatment has been effective. In addition, hollow rods were used as pumping equipment, and it is believed that this reduced turbulence and emulsion forming tendencies.

Surface handling of viscous crude oils at low temperature presents a special problem. These fluids are difficult to move through pipes, even at relatively high differential pressure. As a result, heated lines have been used, and during periods of extreme cold, vacuum trucks have been utilized to move the oil. These remedial measures have made it possible to continue field operations under the severest of conditions.

In most thin (20-40 ft. thick) heavy oil reservoirs, injecting gas is difficult and injecting liquids is nearly impossible. However, by preheating the wellbore with high rate reverse circulation, and by insuring that Vapor Therm gases enter the formation at a temperature above the dew point, the injectivity problem has been resolved.

As previously discussed, an extremely high flow potential exists within the formation at the drainage radius upon termination of gas injection. To take advantage of this high potential in combination with the heated oil would require extremely large initial flow rates. By completing the test wells open-hole, with casing set at the top of the formation, severe gas by-passing has been experienced during the initial production period. While gas leakage has been a problem in terms of quickly dissipated energy, oil recovery rates have been satisfactory. More ideal completion methods would involve setting casing deeper into the oil zone, causing the formation of a trapped gas accumulation. Unfortunately, this technique can be used only when the formation contains no impermeable barriers, and vertical permeability is high.

During the early stages of oil production on a new cycle, high gas/liquid ratios are experienced. This problem has been partially alleviated by use of special "Pampa" type pumps, but is an area of concern which is in need of additional consideration.

Corrosion of the Vapor Therm unit and associated pipes, wellhead fittings and wellbore tubulars was initially thought to be a potential problem, particularly if liquid condensation was experienced. However, after many days of operation and subsequent close inspection, no evidence of corrosion due to injection of Vapor Therm gases has been observed.

The oil reservoir in the Carlyle pool is underlain by a water-bearing section whose thickness exceeds one hundred feet. Prior to the initial injection of gases, consideration was given to the possibility of Vapor Therm passing preferentially into the water zone and establishing permeability between the wellbore and water source rock. With such an occurrence, extremely high water production rates could be anticipated.

While some gas undoubtedly did find its way to the water zone, the injection temperature was sufficient to maintain a dry gas composition, and even connate water appeared to be boiled away. As has been discussed previously, water/oil ratios did not exceed 2.0, and it would appear that a water production problem of the anticipated magnitude did not occur.

ECONOMIC ANALYSIS

To develop the economics of using the Vapor Therm generator, certain assumptions as to project scale and ultimate oil recovery must be made. From results of four injection cycles in the Carlyle pool, for example, it has been found that 60 wells can be alternately injected with Vapor Therm gases from one processing unit and one set of four-stage air compression equipment.⁷ Using one Vapor Therm unit and 60 wells as a basis, a development package totaling \$4,788,000 in capital overlay has been detailed. This package includes all expenditures required to evaluate a suitable site and install a complete 60 well program. Details are shown in Table 8.

Further, based on observed operating costs of one pilot program, the costs incurred in operating 60 wells is estimated to be \$1,396,750/year as shown in Table 9.

Unfortunately, repetitive cyclic behavior and ultimate recovery of oil cannot be estimated with confidence from the limited information obtained from the pilot test. Only when these figures become available and are evaluated in the later life of an actual project will they be quantifiable.

CONCLUSIONS

Based upon the experience of a four well injection-production test in the Carlyle pool, the following has been concluded:

1. Vapor Therm apparatus can be successfully constructed and operated under conditions encountered in the Carlyle pool.
2. The Vapor Therm process is an efficient method of stimulating wells in the Carlyle pool.
3. Mechanical conditions limit oil recovery during the early portion of the production cycle.
4. An analytical model has been developed for the process, and this model describes the observed results of the field test beyond the initial 60 days of production.
5. The more serious problems encountered in applying the Vapor Therm process to the Carlyle pool have been resolved.

PROJECT COST

The cost of this contract (EY-76-C-02-2880.*000) was \$933,244.45, which exceeded the budget by \$27,760.45 or 3%. Of this total cost, DOE funded \$740,971 or 79% and Carmel Energy, Inc. funded \$192,273.45 or 21%. Detailed costs are shown on Table 10.

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TABLE 1

CARMEL ENERGY, INC.

CLINKENBEARD LEASE

COMPARISON OF STIMULATION CYCLES

<u>Stimulation Cycle</u>	<u>Date</u>	<u>Heat MM Btu</u>	<u>Steam Bbls.</u>	<u>Inert Gas MSCF</u>
1st	Jan. 31-Apr. 5, 1977	516	1473	4500
2nd	Apr. 9-June 3, 1977	560	1600	4890
3rd	June 14-Sept. 17, 1977	580	1660	5060
4th	Sept. 29, 1977- March 5, 1978	285	815	2490

PRODUCTION DATA

<u>Production Cycle</u>	<u>Producing Days</u>	<u>Producing Wells</u>	<u>Bbl. Oil Produced During Cycle</u>	<u>Average Pro- duction Rate Bbls/Day/Well</u>	<u>RATIOS</u>		
					<u>BO BS</u>	<u>MSCF Bbl</u>	<u>Gas BO Oil MM Btu</u>
1st	56	4	1112	4.96	0.75	4.05	2.16
2nd	56	4	2084	9.30	1.30	2.34	3.72
3rd	96	4	3121	8.12	1.88	1.62	5.26
4th	161*	2	2717**	8.43	3.33	0.916	9.53

* Data for DOE Test Discontinued March 5, 1978

** Total Oil Produced from all Wells during fourth Cycle= 3,329 BBI Oil

TABLE 2
CARMEL ENERGY, INC.
CLINKENBEARD LEASE
OIL AND WATER PRODUCTION

FIRST CYCLE

Feb. 10, 1977 - April 5, 1977

<u>Week</u>	<u>No. Wells Producing</u>	<u>Net Bbls Stock Tank Oil</u>	<u>Cumulative Bbls STO</u>	<u>Bbls Water</u>	<u>WOR</u>	<u>Bbls Oil per Well per Week</u>
1	1.3	197.1	197.1			151.6
2	2	175.7	372.8			87.9
3	3.8	202.5	575.3	Wells on Gas lift: Insufficient date available to deter- mine overall WOR		53.3
4	3.0	157.4	732.7			52.5
5	2.7	147.8	880.5			54.7
6	2.6	116.7	997.2			44.9
7	1	51.7	1048.9			51.7
8	1	63.5	1112.4			63.5

TABLE 3
CARMEL ENERGY, INC.
CLINKENBEARD LEASE

SECOND CYCLE

April 9, 1977 - June 3, 1977

<u>Week</u>	<u>No. Wells Producing</u>	<u>Net Bbls Stock Tank Oil</u>	<u>Cumulative Bbls STO</u>	<u>Bbls Water</u>	<u>WOR</u>	<u>Bbls Oil per Well per Week</u>
1	4	495.1	495.1	277.3	0.56	123.4
2	3.7	293.6	788.1	105.7	0.36	79.4
3	3	208.0	996.7	147.7	0.71	69.3
4	3.4	276.6	1273.3	206.6	0.76	80.0
5	3.3	286.4	1559.7	217.7	0.76	86.8
6	4	185.3	1745.0	142.7	0.77	46.3
7	3.6	212.1	1957.1	169.7	0.80	58.9
8	3.0	127.4	2084.5	<u>109.6</u>	<u>0.86</u>	42.5
				1377.0	0.66	

TABLE 4
CARMEL ENERGY, INC.
CLINKENBEARD LEASE
OIL AND WATER PRODUCTION

THIRD CYCLE

June 14, 1977 - Sept. 17, 1977

<u>Week</u>	<u>No. Wells Producing</u>	<u>Net Bbls Stock Tank Oil</u>	<u>Cumulative Bbls STO</u>	<u>Bbls Water</u>	<u>WOR</u>	<u>Bbls Oil per Well per Week</u>
1	4	363.8	363.8	315	0.86	90.9
2	4	297.2	661.0	319	1.07	74.3
3	4	148.0	809.0	202	1.36	37.0
4	4	235.0	1044.0	255	1.08	58.8
5	4	246.8	1290.8	271	1.10	61.7
6	4	200.4	1491.2	276	1.38	50.1
7	4	213.5	1704.7	262	1.23	53.4
8	4	198.0	1902.7	243	1.23	49.5
9	4	208.4	2111.1	275	1.32	52.1
10	4	241.1	2352.2	291	1.20	60.3
11	4	214.9	2567.1	317	1.47	53.7
12	4	216.7	2783.8	359	1.65	54.2
13	4	202.2	2986.0	386	1.91	50.5
14 *	4	<u>134.8</u>	3120.8	<u>221</u>	<u>1.63</u>	58.9
		3120.8		3992	1.28	

* 4 days

TABLE 5
CARMEL ENERGY, INC.
CLINKENBEARD LEASE

OIL AND WATER PRODUCTION

FOURTH CYCLE

Sept. 29, 1977 - March 5, 1978

<u>Week</u>	<u>No. Wells Producing</u>	<u>Net Bbls Stock Tank Oil</u>	<u>Cumulative Bbls STO</u>	<u>Bbls Water</u>	<u>WOR</u>	<u>Bbls Oil per Well per Week</u>
1*	4	294.4	294.4	312	1.06	128.8
2	4	265.4	559.8	329	1.24	66.3
3	4	160.7	720.5	260	1.62	40.2
4	4	170.5	891.0	297	1.74	42.6
5	4	175.3	1066.3	309	1.76	43.8
6	3	141.9	1208.2	248	1.75	47.3
7	3	115.2	1323.4	132	1.15	38.4
8	3	130.3	1453.7	108	0.83	43.4
9	3	140.2	1593.9	121	0.86	46.7
10	3	142.8	1736.7	86	0.60	47.6
11	2	108.5	1840.6	110	1.01	36.9
12	2	82.8	1893.4	103	1.24	41.4
13	3	156.6	2050.0	294	1.88	52.2
14	3	162.4	2212.4	242	1.49	54.1
15	3	181.2	2392.6	275	1.52	60.4
16	3	143.7	2537.3	172	1.20	47.9
17	3	139.3**	2676.6	174	1.25	46.4
18	3	146.1	2822.7	183	1.25	48.7
19	2	80.9	2903.6	104	1.29	40.5
20	2	158.6	3062.2	195	1.23	79.3
21	2	65.2	3127.4	86	1.32	32.6
22	2	69.4	3196.8	121	1.74	34.7
23	2.6	<u>132.0</u>	3328.8	<u>158</u>	<u>1.20</u>	50.8
		3328.8		4419	1.33	

* 4 Days

-29-

** Includes 70 Bbls treated in 19th Week

TABLE 6

COMPARISON OF HUFF-N-PUFF POTENTIAL
WITH VAPOR THERM POTENTIAL
CARLYLE FIELD, IOLA, KANSAS

TIME DAYS	CALCULATED $T_{wb}(D_i = .21) ^\circ F$	STEAM HUFF-N-PUFF		VAPOR THERM		
		P_{steam} (psia)	h_e (ft)	P_{steam} (psia)	P_{N_2} (psia)	h_e^* (ft)
0	500	680	1569	680	240	2265
5	282	52	120	52	185	584
10	212	15	35	15	168	451
15	177	6	14	6	159	406
20	157	4	9	4	154	389
25	143	3	7	3	150	377
30	133	2	5	2	148	369
60	106	1	2	1	141	350
90	96	< 1	1	< 1	139	342
96	95	< 1	1	< 1	138	340
120	91	< 1	1	< 1	138	339
150	88	< 1	< 1	< 1	137	337
180	86	< 1	< 1	< 1	136	335
197	85	< 1	< 1	< 1	136	334

* $h_e = \left(\frac{2.3077}{0.937} \right) (P_{steam} + P_{N_2})$

TABLE 7

CALCULATED PRODUCTION RATES FOURTH CYCLE

CARLYLE FIELD, IOLA, KANSAS

(at $r_h = 23.2\text{ft.}$)

TIME DAYS	CALCULATED $T_{wb}, D_i = .21^\circ\text{F}$	MEASURED $T_{wb} \quad ^\circ\text{F}$	μ_o, cp	CALCULATED PRODUCTION: STO/D	ACTUAL PRODUCTION, STO/D
0	500	500	1.6	13,685	18.2
5	282		6.2	865	18.2
10	212		16.2	254	14.3
15	177		31.0	117	12.3
20	157		49.0	70	11.8
25	143		63.0	53	11.2
30	133		90.0	36	10.6
60	106		215.0	14.2	6.4
90	96		325.0	9.2	7.6
96	95	94	330.0	9.0	7.6
120	91		420.0	7.0	6.7 *
150	88		500.0	5.9	4.9 *

* Extrapolated

TABLE 8

CARMEL ENERGY, INC.
CAPITAL SUMMARY
For
60 WELL PROGRAM
(CONSTANT 1980 DOLLARS)

CAPITAL

Vapor Therm Unit (Rented from Carmel Energy, Inc. under license) -0-	
Compressor	\$ 350,000
Wells- 60 @ 40,000/Well	2,400,000
Injection Line 15,000 ft. @ \$15/ft	225,000
Roads	150,000
Electrical	100,000
Tankage and Heater/Treater	90,000
Salt Water Injection Well & Pump	45,000
Building/Shop	50,000
Pulling Unit	50,000
Field Vehicles	30,000
Construction Labor	200,000
Geology & Reservoir Engineering	100,000
Core Holes and Logging	200,000
	<hr/>
	\$3,990,000
Engineering Fee @ 10%	399,000
General and Administrative Overhead @ 10%	<hr/>
	399,000
	<hr/>
TOTAL Capital Cost	\$4,788,000

TABLE 9

CARMEL ENERGY, INC.

DIRECT COSTS
For
60 WELL PROGRAM
(CONSTANT 1980 DOLLARS)

<u>DIRECT COSTS.</u>	<u>\$/Year</u>
Vapor Therm Rent @ \$15,000/month +1/16 ORR	\$180,000
Fuel-Crude Oil-9260 Bbl @ \$25/Bbl	231,000
Fuel-Diesel-138,000 gal. @ \$1.00/gal.	138,000
Fuel- Gasoline-6,000 gal. @ \$1.25/gal.	7,500
Fuel- Natural Gas-70,000 MSCF @ \$3.00/MSCF	210,000
Electricity- 1,104,000 KWH/yr. @ \$0.045/KWH	44,160
Chemicals-Anti-Corrosion-2400 gal. @ \$1.60/gal.	3,840
-Proprietary Chemical-3000 gal. @ \$7.00/gal	21,000
-Emulsion Breaker-3500 gal. @ \$7.50/gal.	26,250
Maintenance Materials- Surface Equipment	100,000
-Downhole Equipment	50,000
Labor-Hourly- 9 people @ \$18,000/yr.	162,000
-Supervision	44,000
Labor Burden @ 25%	<u>51,000</u>
Total Direct Costs	\$1,269,750
General and Administrative Overhead @ 10%	<u>127,000</u>
Total Operating Costs	\$1,396,750/ year

TABLE 10

TOTAL PROJECT COSTS
DOE CONTRACT EY-76-C-02-2880.*000

	<u>Cost</u>
Purchased Materials	\$286,467.23
Subcontracted Items	142,303.56
Other Materials & Utilities	57,308.08
Direct Labor	173,230.99
Labor Overhead	18,540.57
Outside Research & Consultation	36,543.42
Other Direct Costs	30,741.51
Travel	55,158.25
General & Administrative Expenses	<u>132,950.84</u>
Total Cost	<u>933,244.45</u>
Budget Cost	905,484.00
Amount Over Budget	27,760.45
Cost Paid by DOE	740,971.00
Cost Paid by Carmel Energy	192,273.45

Figure 1

CARMEL ENERGY, INC.

VAPOR THERM PROCESS FOR

HEAVY-OIL RECOVERY

CLINKENBEARD LEASE

Figure 2
 VAPOR THERM. TECHNOLOGY
 CARMEL ENERGY INC.

CLINKENBEARD

Legend

- OIL WELL
- / ABANDONED OIL WELL
- ⬡ CYCLIC INJECT. PRODUCER
- ▲ WATER INJECTOR
- ⊙ CORE HOLE

FIGURE 3
STRUCTURE MAP
TOP BARTLESVILLE SAND
CARLYLE FIELD
ALLEN CO. KANSAS

April, 1977 0' 100' 200' C.I.: 10 Ft.

CARMEL ENERGY INC.

CLINKENBEARD

Legend

- OIL WELL
- / ABANDONED OIL WELL
- ⬡ CYCLIC INJECT. PRODUCER
- ⬠ WATER INJECTOR
- CORE HOLE

FIGURE 4

NET OIL SAND MAP
BARTLESVILLE SAND
CARLYLE FIELD

ALLEN CO. KANSAS

April, 1977 0' 100' 200' C.I.: 10 Ft.

CARMEL ENERGY INC.

OIL & WATER PRODUCTION
FOR FOUR CYCLES

Figure 7
CLINKENBEARD LEASE
CARMEL ENERGY INC.

Figure 8
CLINKENBEARD LEASE
COMPARISON OF FOUR CYCLES
CARMEL ENERGY INC.

FIGURE 9 - PRODUCING ZONE MODEL
CARMEL ENERGY INC

Figure 10
Calculated vs Predicted
Production Rates
CARMEL ENERGY INC.

UNITED STATES DEPARTMENT OF ENERGY
BARTLESVILLE ENERGY TECHNOLOGY CENTER
P.O. BOX 1398
BARTLESVILLE, OKLAHOMA 74003

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