FOSSIL ENERGY

BODCAU *IN-SITU* COMBUSTION PROJECT
Final Report, June 1976-June 1982

Work Performed for the Department of Energy
Under Contract No. DE-AC03-76ET12057

Date Published—December 1982

Cities Service Company—Southeastern E&P Region
Jackson, Mississippi

U. S. DEPARTMENT OF ENERGY

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SUMMARY

The Bodcau In Situ Combustion Project was a cooperative venture between Cities Service Company and the United States Department of Energy (D.O.E.). The project was governed by D.O.E. Contract DE-AC03-76ET12057, covering the period from June 1, 1976, through June 30, 1982. The primary objective of the contract was to demonstrate the operations and economics of a commercial scale in situ combustion project utilizing simultaneous air and water injection.

The fifth and final report is mainly a composite of the previous reports and papers presented over the life of the project. The report includes pre-contract work, field facilities, injection and production performance, remedial work, monitoring, research support, a performance evaluation, and economics covering the contract life.

The project was conducted on five patterns of Cities Service Company's Bodcau Fee "B" Lease. The five patterns were part of an eight-pattern expansion of Cities' combustion operations in the field. Thirty-eight producers, five injectors, and five observation wells were included in the patterns.

Injection for the combustion phase (August 1976 through April 1981) was 10.1 BCF of air and 2.64 MM BBL of water. Cumulative water injection over project life was 5.15MM barrels. The combustion phase resulted in recovery of 626 M barrels of 19° API crude. Cumulative oil production amounted to 685 M barrels or 35% of the oil in place.

Total expenditures for the project through June 30, 1982, were \$10,450,790. Development costs for wells and equipment were \$1,710,779.36; production and research services have amounted to \$1,075,311; and lease operations and maintenance were \$4,382,228. Decontrol tax amounted to \$1,300,784. Total cost per barrel of oil produced was \$17.37 based on net production assuming one-eighth royalty. Net income based on net production was 26.7% of the revenue.

Based on the data taken during the six year contract life, the Bodcau In Situ Combustion Project has proven to be both an economical and technical success.

INTRODUCTION

The Bellevue Field is located approximately eighteen (18) miles northeast of Shreveport, Louisiana (Figure 1). It was discovered in 1921 and is a dome type structure covering approximately nine hundred (900) productive acres. Production is from the Upper Cretaceous Nacatoch Sand occurring from 300 to 400 feet. Primary production was by fluid expansion and gravity drainage and recovered less than estimated fifteen percent (15%) of the original oil in place.

In 1966, Getty Oil Company tested dry combustion and proved this method successful for the field. Cities Service's first field test of in situ combustion was initiated in 1971 on the Bodcau Fee "B" Lease. This test utilized dry combustion followed by waterflooding. In 1974, Cities evaluated dry combustion and simultaneous water/air injection on adjacent patterns. It was shown that simultaneous injection improved the efficiency of the process by approximately twenty-five percent (25%). A decision was made in 1975 to further develop Cities' acreage in the field. Wells had been drilled and construction of facilities was in progress when the contract with the Department of Energy was signed. Under the contract, there have been four annual reports and five topical reports published and made available through the National Technical Information Service, U. S. Department of Commerce. All previous reports and papers concerning the project are listed in the Bibliography. Numerous presentations concerning

the Bellevue project have been made and visitors from throughout the world have visited the project site as a result of the D.O.E. contract.

The studies and reports completed under the contract contributed greatly to the understanding of the combustion process in the Bellevue Field. Certain studies would not have been possible without the contributions of the Department of Energy. Cities Service is currently applying the knowledge obtained from this project on other Company properties.

ENGINEERING & OPERATIONS

Pre-Contract Work: The Nacatoch sand in the Bellevue Field has been fireflooded by Cities Service since 1971 and was selected for this D.O.E. (formerly E.R.D.A.) demonstration project. The success of two previous tests prompted Cities Service to evaluate its property as a possible site for demonstration of a commercial scale fireflood operation as proposed by the Energy Research and Development Administration.

The demonstration site was located in the SW 1/4, Section 11, T19N, R11W, Bossier Parish, Louisiana. It was selected by the drilling of five evaluation wells (L-1, L-2, L-4, 15-3 and 16-3). These wells were logged with conventional induction-electrical surveys and compensated formation density logs. The interpretation parameters for the log analysis are shown in Table 1. Reservoir characteristics by log analysis are presented in Table 2. Typical open hole and cased hole logs are shown in Figures 2 to 4. One well, 16-3, was rubber sleeve cored to gather additional reservoir data. Core Analysis is shown in Table 3. Pressure tests indicated a reservoir pressure between 25 and 40 psig. Fluid analysis showed an oil gravity of 19° API with a viscosity of 676 cp at reservoir temperature. A plot showing viscosity versus temperature is shown in Figure 5.

The pattern size and configuration were based on data from the evaluation well program and past experience in engineering and operations. Five, elongated, inverted nine-spot patterns were

Pre-Contract Work, Continued . .

developed encompassing nineteen (19) acres. The dip of the Nacatoch in this area was found to be 4.5° to the northeast. Structure and net pay maps are shown in Figures 6 and 7, respectively. The injection wells were located down-structure to compensate for the movement of air up-structure, increasing sweep efficiency. Project area data are presented in Table 4.

The reservoir properties of the five-pattern area met ERDA's contract specifications. The wells were drilled and construction of facilities was in progress when the contract was signed.

Field Facilities: The equipment required for operation of the project was separated into four systems: air injection, water injection, production gathering, and oil treating.

The gathering system was used to transport produced fluids to the battery facilities for separation. Conventional beam pumping units were installed and 2-7/8 inch tubing was run in 7" casing. Hollow rods of 1.315 inch outside diameter and a 1-25/32 inch insert pump were run inside the tubing. Production was through the hollow rods while the annulus between the rods and tubing was used for pumping fresh water downhole to cool the pump (Figure 8). This method was used until the waterflood phase began in 1981. Conventional two inch pumps were then run, with production flowing up the tubing into the transfer lines.

Individual lines from each well carried tubing production to a header. Originally, the lines were 3-1/2 inch O.D. corrosion-resistant steel pipe buried below ground level. Due to repetitive line leaks caused by sand production and the harsh environment, flowlines were converted to two inch fiberglass. Flowline leaks were not eliminated, but the frequency was substantially reduced.

Casing production was transported from individual wells to concrete-lined pits by use of 3-1/2 inch O.D. steel pipe. These exhaust lines experienced the same corrosion problems as the production lines and were also replaced with fiberglass. At the pits, the liquids were extracted from the gases and collected. Pit production was pumped through 4-1/2 inch O.D. steel pipe to the header at the battery.

Field Facilities, Continued . . .

The battery was designed to handle 13,000 barrels of fluid per day. Production entered the header, where demulsifiers were added. The fluid then entered the free water knockout where approximately 90% of the free water was removed. The oil entered the treater while produced water flowed to two steel storage tanks. The treater separated the oil and remaining water. The oil was then sold to pipeline through a LACT unit or diverted to tankage if it was not salable, ($>2\%$ BS&W). Four welded steel oil tanks served the system: one tank for good oil sales, three tanks for additional settling time for bad oil. A 500 M BTU steam generator was used to circulate steam through coils in the bad oil tanks to aid in separation. Temperatures of 190-200°F were maintained on the oil to decrease separation time. A battery schematic is shown in Figure 9.

The water injection system consisted of two 400 BBL steel tanks, a 2000 BBL plastic-lined overflow tank, and a centrifugal pump for injection and disposal. The pump delivered injection and disposal water through a trunk line and laterals to individual wells. Fiberglass pipe was used for this system. Volumes were metered at each well, utilizing turbine meters. The cooling water system consisted of a fresh water supply well and a system of two-inch PVC line which delivered water to each producing well. Water from this system was also mixed with produced water to supplement injection. The steel water storage tanks had to be replaced with fiberglass due to severe corrosion problems.

Field Facilities, Continued . .

Air required for fireflooding was supplied by three compressors having a combined deliverability of 20 MMCFD. Compressor number one was gas engine driven, but later was converted to electricity due to the high cost of natural gas. Compressors two and three were electrical. The 20 MMCFD was delivered into a trunk line composed of 8-5/8 inch O.D. and 6-5/8 inch O.D. line pipes. Individual injection was supplied by 3-1/2 inch O.D. steel laterals from the trunk system. The rates were metered and regulated at each well. All lines were 1000 psi working pressure corrosion-resistant pipe buried below ground. The distribution system is shown in Figure 10.

Injection wells were completed in the base of the zone with air injected down the casing during the dry burn phase. For simultaneous injection, perforations were added in the top of the zone with a tension packer set between the two sets of perforations. Water was injected down the casing, above the packer, into the upper perforations, while air was injected down the tubing, below the packer, into the lower perforations. For the third phase of the process, the upper perforations were squeeze cemented and water was injected through 2-7/8" tubing into the lower perforations, below the packer. Injection well schematics are shown in Figure 11. Production wells were completed over the entire pay zone. Well completion data are presented in Table 5. All wells were drilled to total depth using natural mud. Cottonseed hulls, gel and lime were added to combat lost circulation. The producers were

Field Facilities, Continued . .

completed with 7"-20#, J-55, 8-rd casing. The standard cementing technique was to use 100 sacks of 50-50 Pozmix - Class H cement with 40 percent silica flour at the top of the hole and 40 sacks of a high temperature Lumnite cement with 40 percent silica flour at the bottom of the hole across the pay zone. The casing was centralized through the pay section.

Injection & Production: Injection was initiated in July 1976. The five injection wells (12-1, 13-1, 14-1, 15-1 and 16-1), were ignited between August 7 and September 24, 1976. Ignition was accomplished using a 30-kilowatt, 440-volt, 3-phase electric heater. Power to the heater was supplied through a 0.80" O.D. armored cable. The heater was lowered into the wells through a lubricator by means of a tractor with a drum for spooling the armored cable (Figure 12).

Control of the heater was maintained from a trailer containing all of the ignition monitoring equipment. Panel-mounted charts continually recorded air injection rate and pressure. Downhole temperatures were recorded by means of a thermocouple wire run inside a 1" O.D. thermowell in the 7" casing. A thermostat wired to the thermocouple was used to control the desired heater temperature. Ignition was confirmed by gas analysis at offset producing wells using Orsat and Fyrite apparatus and by temperature profiles taken with the thermocouple wire. Report six of the bibliography discussed the ignition process in greater detail. Initial injection rates of 200 MSCFD per well into the base of the Nacatoch were gradually increased to 1.5 MMSCFPD by March 1977. In April 1977, each injector was then recompleted to allow the simultaneous injection of air and water into the formation for the remainder of the combustion phase. Air was injected through 2-7/8 inch tubing into the base of the Nacatoch pay interval while produced water was reinjected above a packer through the casing into the top of the pay. A four to eight foot thick fossiliferous lime

Injection & Production, Continued . .

deposit provided a partial permeability separation between the two injected fluids. Initial injection ratios were in the range of 100 to 150 barrels per MMCF of air. This ratio was increased during the combustion phase of the project to 710 BW/MMCF in September 1980, when the waterflood phase began. By April 1981, all injectors were converted to water injection only. Target water injection rates were 1200 BWPD per pattern.

Injector 12-1 experienced a casing failure and a replacement, 12-1A, was drilled in October 1977. The only other remedial work performed on the injectors since that time, other than some small acid treatments to remove scale buildup, were the squeeze cement jobs following air termination. These injectors were then reperforated in the base of the Nacatoch for water injection during the heat scavanging phase of the project.

Production rates increased rapidly from 75 BOPD in July, 1976, when the wells were started up, to 601 BOPD by March, 1978. Production then declined at an average rate of 12 BOPD per month through April, 1981. When air was terminated, production declined sharply from 165 BOPD and stabilized between 100 and 118 BPD through the remaining contract life. Production for June, 1982, averaged 104 BOPD.

Cumulative injection for the combustion phase was 10.1 BCF of air and 2.64 MMBW. Cumulative production through April, 1981,

Injection & Production, Continued . .

when air was terminated, was 626 M BO. Injection histories for each pattern are presented in Figures 13 to 17. Cumulative production and injection per pattern are listed in Table 6. Injection and production for the total project are shown in Figure 18. Cumulative water injection through June, 1982, was 5.15 MMBW.

Original reserve estimates for the six year contract period was 700,000 barrels, or 35%, of the oil in place. Cumulative production through June, 1982, totaled 684,942 barrels, or 98%, of the reserve estimates. Table 7 summarizes cumulative production by year, percentage produced by year, and significant changes in operation during the life of the project.

Well Remedial Work: With the advance of the combustion front towards producing wells, the area surrounding the well became thermally stimulated, producing rates greatly increased and, unfortunately, combustion gases broke through or channelled to the producer before the entire reservoir interval could be stimulated. These hot gases, carrying sand, eroded away the cement sheath surrounding the production casing and caused severe wear on downhole pumps and tubulars.

To limit the flow of combustion gases, the section of the Nacatoch where these gas breakthroughs occurred was squeeze cemented and another lower portion was opened for fluid production. This method also improved sweep efficiency by forcing air into intervals which may have not previously been stimulated. Volumes used in squeeze cementing varied from 20 to 200 sacks of Class A cement with 22% silica flour. Figure 19 indicates the frequency and cumulative number of squeeze cement jobs by month for the project.

During 1977, the first full year of the project, 12 wells were squeezed for an average of one per month. Ten of these jobs were performed on wells along the north line of the project area. The frequency of remedial work increased rapidly in 1978 when 44 wells experienced combustion breakthrough. This average of 3.7 wells per month included 26 combustion breakthroughs in north line wells. To solve this problem, in February 1979, it was decided to shut in wells 13-4, 14-2, 14-3, 15-2, 15-3 and 16-3 in

Well Remedial Work, Continued . .

order to optimize air use and force migration of heat to the south. These six wells along the north line had incurred 30 of the total 60 squeeze jobs for the project to that point. The success of this effort was apparent when in 1979 an average of only 2.4 wells were squeezed each month and south line producers became stimulated. Thirty percent of the remedial work that year was performed on south line producers. This trend of stimulation to the south continued through the first half of 1980, and, in July, the six shut-in producers along the north line were returned to production. During 1980, 37 wells were squeezed, including injection wells 15-1 and 16-1. Many of these were up dip as the southern producers became stimulated. With the termination of air injection in April 1981, there was a reduction in remedial work. There has been no remedial work performed since February, 1981, when the perforations in the upper section of the Nacatoch at injection wells were squeeze cemented. This insured that water injection during the heat scavenging phase would be into the lower part of the Nacatoch which had not been fully burned.

In May, 1981, thirteen of the thirty-nine producers were reperforated to open zones that had previously been squeezed. This had no effect on production; therefore, the remaining producers were not reperforated.

Monitoring: Temperature, pressure, and flow rate data were gathered and maintained throughout the contract life of the project. All producing wells were tested at least once each month to measure oil, water, and gas rates. Wells with mechanical problems were tested as needed. Periodic pressure tests were conducted to determine permeabilities and well bore damage and are further examined in the Research Support Section.

Produced gas rates were measured monthly. The percentages of oxygen, carbon dioxide, and carbon monoxide were measured monthly using Orsat Analysis. Typical concentrations of O₂, CO₂, and CO were .6%, 15.0%, and .4%, respectively. These data aided in the decision for any operational changes and were used to determine combustion efficiency. Special testing of gases was done periodically to obtain a more detailed analysis for environmental control. These tests and analyses are presented in the Research Support Section.

Each individual flowline was equipped with a thermometer. Temperatures were checked on a daily basis for an indication of severe downhole conditions and to control the cooling water rates.

Five temperature observation wells were drilled in December, 1976. The locations of the wells were selected based on the structure of the pay zone (Figure 20). The purpose of these wells was to monitor the advancement of the combustion front, indicate process efficiencies, aid in burn volume calculations, and provide data for determining when to initiate and terminate simultaneous

Monitoring, Continued . .

injection. Temperature profiles were recorded on a monthly basis. Figures 21 to 25 are plots of the temperature profiles taken periodically over the life of the project. It was observed that the wells to experience stimulation first retained the hotter temperatures longer. In August, 1980, it was discovered that water in two of the temperature observation wells (15-7 and 16-7) influenced the thermocouple readings. Only one well, 13-7, ever experienced temperatures seen in the combustion tube tests. Therefore, the temperature profiles could only be used as a qualitative tool and could not be used to map the burn front.

In the latter part of '77 and early '78, nine additional producers were drilled along the southern lease line to prevent drainage to an offset operator. These wells resulted in an estimated 36,000 barrels of additional reserves. Off lease drainage, using data from the performance evaluation, was estimated as high as 162M BO. Drilling these wells brought the total number of producing wells to 38.

On February 17, 1980, an explosion occurred in the air injection system, destroying the distribution lines and badly damaging our number three compressor. The explosion was attributed to a lubricating film build-up inside the distribution lines. Details were presented in "The Fourth Annual Report". To prevent any further explosions, automatic temperature shut-downs were installed on the discharge lines of the compressors and set at

Monitoring, Continued . .

300°F. The distribution lines were flushed annually with a caustic solution to prevent lubricating film build-up, and a synthetic lubricant with a higher auto-ignition temperature was used in the compressors.

Performance Evaluation: After terminating air injection, four wells were drilled within Pattern 15, obtaining open hole logs and cores of the producing formation. Results from this post-burn drilling program were used to construct an approximate burned zone map for the pattern, allowing for better understanding of the combustion process and the efficiency of fireflood in the D.O.E. area (Figure 26).

Pattern 15 was typical of the five patterns developed in 1976 for the demonstration project. The original pattern consisted of an air injector and eight surrounding producers, encompassing 3.5 acres. The pattern was elongated to compensate for the preferential migration of injected air towards the structurally higher producers along the south line (Figure 27). The pattern contained 193 ac-ft of pay sand with 368,505 barrels of oil in place.

Well 15-1 was ignited in September, 1976, and was converted to simultaneous air and water injection in April, 1977. Water was injected into Sand S2 (Figure 28) with air injected into the 10 feet of sand immediately above the water-oil contact. Water injected in this manner would remain above the limestone layer between sands S2 and S3, and should improve the vertical sweep efficiency of the combustion process by forcing air to flow beneath this layer for greater distances away from the injector, as shown by an earlier field test.

During the five years of operation, 1905 MMSCF of air and 904,900 barrels of water have been injected, resulting in produc-

Performance Evaluation, Continued . .

tion of 111,567 barrels of oil, approximately 30% of the oil in place (Figure 29). Additional oil was produced by wells located just 40 feet south of the pattern on an adjacent operator's lease, thus the actual recovery was higher than shown on the Figure. In order to minimize this off-lease drainage, two additional producers were drilled between the south row wells in 1978.

Combustion gases were sampled each month at the producing wells, obtaining estimates of flow rate and concentrations of oxygen, carbon dioxide and carbon monoxide. Typical flow rates were from 300 to 500 MCFD per well with 15.2% CO₂, 0.6% O₂ and 0.4% CO, indicating a highly efficient combustion process.

Air injection was terminated in September, 1980, at which time the cumulative water/air injection ratio was 238 BBLS/MMCF and the produced air/oil ratio was 17.1 MCF/BBL. The injector was recompleted in October, 1980, with water now being injected into sands S3 and S4.

Sand production and the handling of hot combustion gases were the major operating problems during the combustion phase. Of the eight original producing wells, only wells 14-5 and 15-5, which were the furthest from the injector, did not require remedial work to shut off perforations through which the hot gases and sand were being produced. Cement was used to plug the intervals at which the combustion front arrived in the producing wellbores. The three north line wells first required remedial work beginning

Performance Evaluation, Continued . .

in February, 1977, while the east and west side wells did not require work until April 1978, and well 15-6 was not worked on until May, 1979. In all, a total of 37 remedial cementing jobs were performed on these wells. Because of the frequency of the burn through at the north line wells, these three wells were shut in from March, 1979, to June, 1980.

The four evaluation wells were drilled using fresh water gelled mud, and experienced no hole problems. Locations are shown in Figure 30. All four wells were logged in open hole with Induction (DIL-SFL), Gamma Ray-Density-Neutron (GR-FDC-CNL) and Electromagnetic (EPT) tools. The EPT tool could not be interpreted due to extreme borehole effects of the Nacatoch sand. Maximum bottom hole temperatures recorded during logging were less than 110°F in the mud-filled holes.

Well #15-10 was drilled 100 feet northwest of the injector. Top of the Nacatoch was encountered at 158 subsea, two feet lower than at the injector. A conventional core barrel was used with little success, recovering only 21 of 52 feet cored.

Well #15-11 was located 150 feet northeast of the injector and encountered the top of the Nacatoch at 159 feet subsea. A rubber sleeved core barrel was used and recovered all 52 feet cored. Sidewall core samples were also taken for comparison with full core data. The sidewalls samples agreed well with the full core data.

Performance Evaluation, Continued . .

Well #15-12 was drilled 50 feet southwest of the injector, encountering the Nacatoch at 149' subsea, 7 feet higher than at the injector. Rubber sleeved coring recovered all 60 feet cut.

Well #15-13 was drilled 200 feet southwest of the injector and found the top of the Nacatoch at 140 feet subsea. Sidewall cores were taken and 7-inch casing was run and cemented to surface. This well was perforated in the lower fifteen feet of pay and tested 2 BOPD plus 87 BWPD on initial completion. The other three wells were plugged and abandoned after logging.

Basic core and log analyses of the four wells are shown in Figures 31 to 34. A 65% water saturation value was used as a cutoff value for selecting pay for the log analysis. Residual oil saturation obtained from core data are shown in the figures for comparison to the logs.

At well #15-10 (Figure 31), the combustion front apparently passed through sand interval S3. This sand contained no oil. Sand S2 was affected by the combustion process, but not all of the oil was removed. Sand S1 appeared unaffected, while sand S4 appeared partially depleted. The separation between the FDC and CNL curves indicated that air or combustion gases were present in sands S3 and S4. The air saturation in sand S4 was below the original oil-water contact.

Logs from well #15-11 (Figure 32) were very similar to those

Performance Evaluation, Continued . .

of well #15-10. Sand S1 appeared unaffected, while sand S2 was significantly depleted. Sand S3 was not fully depleted at this location, though the extremely high gas saturations indicated by the FDC-CNL shift showed that this sand interval was being processed by the combustion front. Sand S4 was again only partially depleted, with an apparent air saturation below the oil water contact.

Well #15-12, only 50 feet from the injector, had all sands except for the uppermost one processed by the combustion front (Figure 33). There remained only one six-foot pay interval at the base of sand S4. Sands S3 and S4 showed high gas saturations.

At well #15-13, sands S1, S2 and S3 had such high gas saturations that analysis of these intervals was not possible (Figure 34). Sidewall cores were necessary to evaluate these intervals, and showed no residual oil except for the bottom 6' of Sand S4 which was only partially depleted.

Based upon the core and log results, a burned thickness isopach map was made (Figure 26). The burned thickness contours were extended beyond the pattern towards offsetting producers at distances of 165 feet north of the pattern and past producers 40 feet south, towards additional producers 165 feet south of the pattern. Though no well logs or cores were available in these areas north and south of the pattern, severe well problems were experienced at the wells 40 feet south of the pattern and hot combustion gases were vented from the wells 165 feet north and

Performance Evaluation, Continued . .

south. Along the east and west sides of the pattern, combustion fronts from the adjacent patterns may have merged or at least created no flow boundaries along the pattern lines, limiting further east-west growth.

The reservoir volume contained within the total burned area was calculated to be 4,733 MCF. This indicated an air requirement of 402 SCF/Ft³, somewhat higher than expected for the combination of dry and wet combustion which occurred within the pattern. The error potential is high, since no data was available on the areas north and south of the pattern.

Within the pattern outline, the volume burned was approximately 4,123 MCF, or 49%, of the total pay sand. Since the calculated air requirement was close to the laboratory results for dry combustion, a fuel deposit of 2.0 Lb/Ft³ was assumed. Oil displaced from this burned volume would have been 157,162 barrels.

Log and core analyses indicated that in the unburned intervals of the pattern, the oil saturation was reduced to approximately 32%. This would mean that an additional 105,282 barrels was displaced, for a total of 262,444 barrels, or 71.2% of the original oil in place. Actual production of 111,567 barrels indicated a capture efficiency of only 42.5%.

The burned volume outside the pattern indicated that air injection should have been terminated after approximately 1,576 MMSCF of injection, and that the optimum air injection for similar

Performance Evaluation, Continued . .

patterns was approximately 450 MMSCF/Acre.

The fact that injected water overtook the burn front causing quenching downdip of the injector but advanced very little updip did little to improve vertical sweep efficiency. For similar areas with dip of this nature, true wet combustion injecting both air and water into the same interval may be the best method of improving the process efficiency. The conclusions from the evaluation and routine monitoring were as follows:

1. Dense limestone layers can be used to control injected air and water, though their movement is highly influenced by local reservoir structure.
2. The combustion process in the Bellevue Field is highly efficient, utilizing 97% of available oxygen and leaving no residual hydrocarbons in the intervals swept by the burn front.
3. The volume burned within pattern 15 was approximately 49% of the total pay sand.
4. Approximately 329 MMSCF of excess air was injected in pattern 15 causing extensive burning outside of the pattern area.
5. The simultaneous air and water injection process applied in this pattern did not improve sweep efficiency or reduce the air requirement.

Performance Evaluation, Continued . .

6. Total oil displaced by the process from both the burned and unburned intervals may be as high as 262,444 barrels, or 71.2% of the oil in place.
7. Capture efficiency was low, approximately 42.5%. This was caused by excessive down time and equipment problems associated with sand and hot combustion gas production, plus off-pattern drainage to additional producing wells to the north and south.

RESEARCH SUPPORT

The technical feasibility of applying in situ combustion to recover oil from the Nacatoch sand in the Bellevue Field was demonstrated by Cities Service in their 1971 pilot and 1974 expansion. The research goals in this contract work were to determine and report engineering parameters for the area of the field being fireflooded. Included in the research studies were combustion tube tests, pressure transient testing of the project area and reservoir fluid analyses performed during the progress of the project. Results from each of these investigations are presented in detailed topical reports 7, 8, and 9 published by DOE. A summary of the research support is presented in this section.

Combustion Tube Tests: A series of combustion tube tests were performed at the Cities Service Research Laboratory using Bellevue core samples and produced oil. The objectives of the study were to obtain information concerning the basic in-situ combustion process that would aid in understanding the performance of the Bellevue fireflood. Also investigated was the interaction of water with the burning process in order to determine the water/air injection ratio that should be used in field operations. Finally, the formation ignition temperature of the rock-oil system was approximated by means of laboratory oxidation tests.

Combustion Tube Tests, Continued . .

The following conclusions were determined from the laboratory combustion tests:

1. Fuel deposit and air requirement of dry combustion were calculated by means of combustion tube tests to be 2 lb/ft³ and 17 MMSCF/Ac-ft.
2. Injecting water increases the efficiency of the burning process by decreasing fuel deposit and air requirement.
3. Water rates as high as 500 BBL/MMSCF do not extinguish the combustion reaction in the laboratory system.
4. The ignition temperature of the Nacatoch formation is approximately 500°F.

A schematic of the combustion tube used in the study is shown in Figure 35. A mixture of sand, oil and water were packed into the 2.5" diameter stainless steel tube. A 0.25" diameter thermowell traversed the center of the sand pack enabling temperature measurements along the 73" length of the tube. Four 1250 watt strip heaters were strapped to the outside of the stainless steel tube and were controlled by an automatic power unit. The entire tube assembly was placed within an insulated 6" diameter steel jacket. All tests were performed with the system in the vertical position. Air and water were injected at the top and production was taken off the bottom. The products passed through a water-cooled separator which condensed water vapor and hydrocarbons and maintained the gas at a constant temperature. Liquids were drained from the separator while gases passed through a wet test meter, sampling valve and then vented to the atmosphere.

Combustion Tube Tests, Continued . .

A run was performed by first packing the tube with either the unconsolidated, native Bellevue core or a mixture of burned Bellevue sand and produced oil and water. A portion of the mixture was sampled for oil and water determinations. The weight of mixture packed into the tube and the results from the fluid saturation measurements allowed calculation of the porosity and volumetric saturations of each fluid phase. Nitrogen was flowed at 0.2 SCF/Min through the tube to establish a gas permeability and displace mobile fluids. The strip heaters were then activated raising the temperature of the system to the desired temperature. To initiate combustion, a heater at the inlet face increased the sand pack to over 500°F. Nitrogen injection was replaced with air and ignition was usually observed immediately. The three thermocouples in the thermowell and the thermocouple attached to the ignition heater recorded significant increases in temperature upon ignition. Confirmation was also obtained with effluent gas compositions.

Data recorded during the run include air and water injection rates, injection pressure, produced oil, produced water and combustion gas volume. The gases produced were sampled and analyzed for oxygen, carbon dioxide and carbon monoxide using both an Orsat apparatus and a gas chromatograph. Oxygen was also monitored continuously with an oxygen analyzer. Thermocouples within the thermowell tracked the shape and movement of the combustion zone. Air flow rate was controlled using a rotometer

Combustion Tube Tests, Continued . .

and exit gases were monitored with a wet test meter. During simultaneous water/air injection the water rate was measured with a constant rate pump.

The air flow rate used in all runs was 0.2 SCF/Min or 435 SCF/ft²-HR. The high air flux helped to reduce heat losses and decreased run time. The exit of the tube was vented to the atmosphere and no backpressure was held on the system. Therefore, the effective pressure at the combustion zone was controlled by the pressure drop through the sand pack which was quite low. The low pressure resulted in a low steam temperature and often the failure of a stabilized steam zone to form ahead of the front. These conditions were not significantly different than those existing in the reservoir which has an average pressure of only 40 psig.

The results of the combustion tube runs are summarized in Table 8. The parameters of primary interest, fuel deposit and air requirement, were determined to be 2 lb/ft³ and 17 MMSCF/Ac-ft³ for dry combustion. Increasing water/air ratios had a desirable effect on the process by decreasing both of the parameters. Fuel deposits of 1.5 lb/ft³ and air requirements of 12 MMSCF were observed as the water rate was increased to 500 B/MMSCF. Water rates in excess of 500 B/MMSCF resulted in quenching of the combustion zone and difficulties in controlling laboratory test conditions.

Combustion Tube Tests, Continued . .

A series of small scale tests were performed to determine the ignition temperature of the formation. A small tube was packed with native Bellevue sand and placed in an oven. As air was flowed through the sample at different temperatures, the oxygen concentration of the effluent varied. By correlating the concentration of oxygen with temperature, the ignition temperature of the crude could be predicted.

The small scale test to determine ignition temperature showed that oxidation became appreciable at 300°F. As the temperature of the sand pack was increased, the concentration of oxygen in the produced gas became lower. Finally, at 500°F all of the oxygen in the injected air was reacted indicating that the ignition temperature of the Bellevue field is less than 500°F. Table 9 presents a summary of the produced oxygen concentration versus the sand pack temperature for the experimental runs.

Pressure Transient Tests: During 1976 and 1977, extensive pressure transient testing was conducted in the five patterns of the DOE Project Area. Falloff tests were run prior to ignition and prior to conversion of the injectors to simultaneous air and water injection. Pulse tests were conducted along with the second falloff tests prior to conversion to simultaneous injection.

The purposes of the falloff tests were to determine the injection wellbore conditions prior to working on the wells and to investigate the average pattern permeabilities and flow capacities prior to ignition and after six months of continued combustion. Falloff tests involved shutting in each injection well for a period of two to five hours and recording wellhead pressures with a test gauge. A typical falloff curve is shown in Figure 36.

Before ignition, the average permeability to air in the five patterns ranged from a low of 5.9 md in Pattern 14 to 32 md in Pattern 16. A second preignition test on Pattern 16 one month after the first test indicated an increase to 82 md, probably due to a high mobile water saturation in the pattern. No damage was indicated and the wells were then ignited. After six months of combustion, a second set of falloff tests were run prior to converting the injectors to simultaneous air and water injection. Permeabilities from these tests ranged from 112 md to 544 md. This 15-fold increase was expected with the increased gas

Pressure Transient Tests, Continued . .

saturations in the patterns because of continued air injection and combustion. Tables 10 and 11 summarize the two sets of falloff tests.

Pulse tests were used to determine directional permeability as an aid to predicting combustion front movement within the patterns. A pulse was created by shutting in an injector for five hours and then reinjecting at the previous rate. The response to this pulse was monitored at surrounding producing wells. Water manometers were used to monitor the change in exhaust gas flow rates at producing wells in the pattern tested. A typical response curve is shown in Figure 37. The time from the start of reinjection to the time of increasing gas rate is taken as the time lag (t_L). The directional permeability between injector and producer was calculated using this time lag value. Table 12 summarizes the results of pulse tests on each of the five patterns. The directional permeabilities towards wells in the southern half of each pattern were generally highest. However, closer examination revealed that the permeabilities were directly proportional to the square of the distance between injector and producer, as shown in Figure 38.

The characteristic time lag (Δt_1), which is a function of shut in time and measured time lag, was calculated to determine the degree of connectedness between injector and producer. These values are listed in Table 12. Unlike directional permeability, characteristic time lag showed no correlation with distance.

Pressure Transient Tests, Continued . .

The calculated characteristic time lags indicate greater tendency for migration of air, and thus the combustion front, along a north-south axis with greatest movement towards the south. Characteristic time lags for Pattern 15 are shown in Figure 39.

Reservoir Fluid Analyses. A detailed analysis of combustion

gases, produced oil, produced water and injected water were performed periodically during the project. Produced gas compositions should reflect the efficiency of the burning process and the formation of undesirable combustion by-products. Produced oil and water analyses should indicate changes occurring from reservoir differences, burning characteristics or varying water/air ratios. Injection water analyses insured high water quality to prevent formation damage and loss of injectivity. A series of seven analyses were performed from 1976 to 1979. A summary of the produced oil, gas and water analyses are presented in Tables 13, 14 and 15. The following conclusions were determined from the results of the study:

1. The oil produced during the fireflood was lighter compared to native oil. The viscosity decreased from native oil viscosity and the API gravity increased slightly. The boiling point curves show that the percent low temperature boiling components increased in 1978-1979. In 1980, the boiling point curves became slightly heavier and were similar to 1978 oils.
2. The sulfur content of the crude oil decreased during the early part of the fireflood and then increased. Native oil had 0.9 percent sulfur compared to 0.62 percent sulfur in May 1979 oil. The increase in the hydrogen sulfide in the produced gas shows that crude oil sulfur is being converted to hydrogen sulfide by the fireflood.

Reservoir Fluid Analyses, Continued . .

No sulfur dioxide (SO_2) or carbonyl sulfide (COS) was found in produced gas. However, increased sulfate in produced waters was found in 1980, indicating that part of the sulfur in oils has been converted to sulfate in water.

3. The crude oil acid number decreased from 5.1 in native oil to 2.9 in May 1979. The acid number decrease shows that there is no oxidation of the crude oil by air. Apparently, the heat passes ahead of the firefront to lower the crude oil viscosity without oxidation. The lowering of the acid number is due to removal of sulfur and other components from the crude oil. The acid number in March 1980 oils increased to 4.3, indicating that native oils that are relatively unchanged by the fireflood are produced late in the project. This acid number increase made the water-in-oil emulsion more difficult to break.
4. Comparison of oil viscosities with emulsified water to the viscosities after the water is removed shows that the emulsions have higher viscosities. The emulsions also have viscosity variations with shear rate (non-Newtonian behavior) compared to Newtonian viscosities of the oil without emulsified water.
5. The produced combustion gas was a mixture of nitrogen, carbon dioxide, carbon monoxide, oxygen, hydrogen sulfide and hydrocarbons. No ammonia or nitrogen oxides were

found. The average carbon monoxide concentration varied from 0.34 to 0.61 percent. The low carbon monoxide concentration indicates that any excess carbon monoxide initially formed further reacts to form carbon dioxide or methane.

6. The methane concentration increased during the wet combustion phase of the fireflood. There was no corresponding increase in the other hydrocarbon gases. The lack of evidence of oil cracking indicates that the increased methane concentration was produced by reduction of carbon monoxide. The reaction of steam to produce hydrogen followed by reduction of carbon monoxide to methane is the mechanism of coal gasification to produce methane.
7. The water salinity decreased throughout the project. Injection of low salinity waters started six months after air injection began and the produced water was a mixture of injection water, condensed steam and formation water. When the fire reached a producing well, low salinity water was injected down the annulus for cooling and this further reduced water salinity.
8. The water specific gravity (1.00 to 1.01) is only slightly higher than the oil specific gravity (0.93 to 0.94) and the oil and water separate slowly. The slow separation rate and the tendency of heavy oils to emulsify water make water separation from oil difficult.

ECONOMICS

The Cities Service-D.O.E. cost sharing agreement provided for an estimated \$8,229,898 expenditure over the six year life of the demonstration project. Cumulative expenditures through June, 1982, were \$10,450,789 (Figure 40). The D.O.E. portion of these expenses was \$3,102,120 with Cities Service providing the remaining funds.

Project Investments. The contract provided for the funding of investments for wells and facilities on the basis of tangible and intangible costs. All tangible equipment was paid for by Cities Service Company while a portion of the intangible charges was funded by D.O.E.

Cumulative investment expenditures through June 1982 were \$1,710,779. Of this total, the Department of Energy contributed \$661,641 or 39%. Project investments are summarized in Table 16.

Operating Expenses. The remaining \$8,740,010 which has been spent to date is summarized in Table 17. These are expenses incurred in routine operation of the project, such as maintenance of wells and facilities, research and production services, taxes and overhead expenses. These expenditures are compared on a cost per barrel basis, in Table 18. To provide a better understanding of the drastic impact of the crude oil decontrol tax on project economics, a comparison has been included of operating cost before this tax became effective (through March 1980) and

Operating Expenses, Continued . .

since that time (April 1980 - June 1982) in Tables 19 and 20. Operating costs increased from \$11.52/barrel before decontrol tax to \$37.35/barrel afterwards.

Net operating income was 26.7% of crude selling price over project life. Operation and maintenance, compression, and severance tax amounted to 44.1% of selling price. Summary of revenue distribution is presented in Table 21.

Based on economic data, Bellevue has proven to be an economical success.

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CA, March 24-26, 1982.

FIGURE 1

FIGURE 2

COMPENSATED FORMATION DENSITY LOG FOR WELL 13-3

CALIPER HOLE DIAM. IN INCHES	DEPTHS	<div style="display: flex; justify-content: space-between; border-bottom: 1px solid black; margin-bottom: 5px;"> 25 0 25 </div> CORRECTION GRAMS/CC
<div style="display: flex; justify-content: space-between; border-bottom: 1px solid black; margin-bottom: 5px;"> 6 16 </div>		BULK DENSITY GRAMS CC
GAMMA RAY API UNITS		
<div style="display: flex; justify-content: space-between; border-bottom: 1px solid black; margin-bottom: 5px;"> 0 100 </div>		<div style="display: flex; justify-content: space-between; border-bottom: 1px solid black; margin-bottom: 5px;"> 2.0 2.5 3.0 </div> <div style="display: flex; justify-content: space-between; border-bottom: 1px solid black; margin-bottom: 5px;"> 1.0 1.5 2.0 </div>

FIGURE 3

INDUCTION - ELECTRICAL LOG

FOR

WELL 13-3

FIGURE 4
GAMMA RAY - NEUTRON LOG
FOR
WELL 13-3

FIGURE 5

**VISCOSITY-TEMPERATURE RELATIONSHIP
(19° API, BELLEVUE CRUDE)**

PROJECT AREA STRUCTURE MAP

FIGURE 7

PROJECT AREA NET PAY MAP

FIGURE 8

PRODUCTION WELL SCHEMATICS

FIGURE 9

BATTERY FACILITIES

FIGURE 10

FIGURE 11

INJECTION WELL SCHEMATICS

FIGURE 12

IGNITION SCHEMATIC

FIGURE 13

FIGURE 14

BELLEVUE INSITU INJECTION HISTORY
WELL 14-1
AUGUST 1976-JUNE 1982

FIGURE 15

BELLEVUE INSITU INJECTION HISTORY
WELL 15-1
AUGUST 1976-JUNE 1982

55

FIGURE 16

BELLEVUE INSITU INJECTION HISTORY
WELL 16-1
AUGUST 1976-JUNE 1982

FIGURE 17

FIGURE 18

D.O.E.-CITIES SERVICE IN SITU COMBUSTION PROJECT
BELLEVUE FIELD, LOUISIANA
PRODUCTION AND INJECTION PERFORMANCE

**BODCAU IN SITU COMBUSTION PROJECT
JANUARY 1977-FEBRUARY 1981**

FIGURE 19

FIGURE 20

PROJECT PATTERN MAP

○ TEMPERATURE
OBSERVATION
WELL

FIGURE 21

**BODCAU IN SITU COMBUSTION PROJECT
TEMPERATURE PROFILE WELL #12-7**

FIGURE 22

**BODCAU IN SITU COMBUSTION PROJECT
TEMPERATURE PROFILE WELL #13-7**

FIGURE 23

**BODCAU IN SITU COMBUSTION PROJECT
TEMPERATURE PROFILE WELL #14-7**

FIGURE 24

**BODCAU IN SITU COMBUSTION PROJECT
TEMPERATURE PROFILE WELL #15-7**

FIGURE 25

BODCAU IN SITU COMBUSTION PROJECT
TEMPERATURE PROFILE WELL #16-7

FIGURE 26
PATTERN 15
Burned Sand Isopach

FIGURE 27

STRUCTURE MAP

PATTERN 15

WELL 15-1 LOGS

GAMMA RAY

BULK DENSITY

INDUCTION

FIGURE 28

FIGURE 29

PATTERN 15

INJECTION & PRODUCTION HISTORY (JULY 1976-DECEMBER 1981)

FIGURE 30

EVALUATION WELL LOCATIONS

CITIES SERVICE COMPANY

BODCAU B-15-10

CITIES SERVICE COMPANY

BODCAU B-15-11

FIGURE 32

CITIES SERVICE COMPANY

BODCAU B-15-12

FIGURE 33

CITIES SERVICE COMPANY

BODCAU B-15-13

FIGURE 35

LABORATORY COMBUSTION TUBE SCHEMATIC

**TYPICAL FALLOUT TEST #1
WELL 14-1
AUGUST 16, 1976**

FIGURE 36

FIGURE 37

TYPICAL INTERFERENCE RESPONSE PATTERN 14 WELL 14-5

DIRECTIONAL PERMEABILITY VS. r^2

FIGURE 38

FIGURE 39

CHARACTERISTIC TIME LAG, Δt_1 PATTERN 15

FIGURE 40

BODCAU IN SITU COMBUSTION D.O.E. PROJECT

CUMULATIVE EXPENDITURE VS TIME

TABLE 1

WELL NO. 15-3INTERPRETATION PARAMETERS

Maximum Gamma-Ray Deflection = 6.0 div. a Cutoff = 0.4
 RW = 0.33 ohm-meters @ formation temp. A = 0.62
 Grain Density = 2.65 gms/cc M = 2.15
 Fluid Density = 1.0 gms/cc n = 2.0
 Porosity Cutoff = 25% Water Saturation Cutoff 50%

LOG EVALUATION DATA

<u>Depth, Feet</u>	<u>Number of Feet</u>	<u>Gamma-Ray Deflection, Div.</u>	<u>Bulk Density, gms/cc</u>	<u>Induction Resistivity, RT</u>
376	2	5.0	2.10	20.00
378	2	4.8	2.23	40.00
380	1	4.6	2.32	38.00
381	2	6.0	2.44	38.00
383	2	6.0	2.39	38.00
386	3	6.0	2.36	28.00
389	4	4.8	2.15	18.00
393	3	4.2	2.01	14.00
395	2	3.9	2.05	10.40
397	2	4.0	2.12	12.00
399	1	5.2	2.20	16.00
400	2	6.0	2.28	34.00
402	2	6.0	2.20	34.00
406	6	5.1	2.02	20.00
410	1	5.2	2.10	20.00
411	2	5.3	2.15	22.00
413	1	5.1	2.23	24.00
414	2	5.3	2.11	22.00
416	2	5.1	2.14	17.00
418	2	5.2	2.14	14.80
420	2	5.1	2.15	13.60
422	2	4.8	2.15	9.80
424	1	4.6	2.20	7.60
426	3	4.6	2.11	3.40
428	2	4.9	2.08	3.20

TABLE 2
RESERVOIR CHARACTERISTICS BY LOG ANALYSIS

Well No.	Elevation	Top	Subsea	Base or WOC	Subsea	Net Pay	Porosity	Water Saturation
2-3	222	355	-133	424	-204	61		
2-4	221	344	-123	415	-194	63		
2-5	213	330	-117	400	-187	67		
2-8	216	324	-108	392	-176	56	34.4	28.9
12-1	218	348	-130	427	-209	62		
12-2	219	362	-143	435	-216	58		
12-3	217	362	-145	437	-220	55		
12-4	215	343	-128	423	-208	62		
12-5	213	324	-111	404	-191	56		
12-6	215	328	-113	405	-190	65		
13-1	215	351	-136	428	-213	61		
13-2	216	358	-142	429	-213	55		
13-3	213	360	-147	426	-213	58	33.6	30.9
13-4	213	346	-133	426	-213	62		
13-5	211	328	-117	409	-198	67	34.4	25.4
13-6	212	324	-112	404	-192	66		
14-1	212	356	-144	425	-213	54		
14-2	214	368	-154	427	-213	47		
14-3	215	378	-163	428	-213	39		
14-4	213	357	-144	426	-213	55		
14-5	211	338	-127	419	-208	68		
14-6	211	336	-125	417	-206	64		
15-1	210	366	-156	423	-213	44		
15-2	211	378	-167	424	-213	33		
15-3	212	376	-165	425	-213	38	32.4	27.0
15-4	211	362	-151	424	-213	47		
15-5	211	352	-141	424	-213	61		
15-6	211	342	-131	424	-213	60	34.3	22.6
16-1	210	371	-161	423	-213	42		
16-2	211	375	-164	424	-213	39		
16-3	213	384	-171	426	-213	19	33.5	36.6
16-4	215	374	-159	428	-213	46		
16-5	216	367	-151	429	-213	49		
16-6	212	355	-143	425	-213	56		
L-1	224	408	-184	434	-210	19	32.0	35.0
L-2	215	384	-169	427	-212	33	32.4	35.0
L-4	217	404	-187	426	-209	11	33.6	35.0

Producing wells were perforated 2 shots/foot and injection wells were perforated 4 shots/

TABLE 3
CORE ANALYSIS OF WELL 16-3
Core Laboratories, Inc., Petroleum Reservoir Engineering, Dallas, Texas

CITIES SERVICE OIL COMPANY
NO. 16-3 BODCAU FEE
BELLEVUE FIELD
BOSSIER PARISH, LOUISIANA

DATE: 2-3-76
FORMATION: NACATOKH
DRLG. FLUID: WATER BASE MUD
LOCATION:

FILE NO: 2203-3
ANALYSIS: HK RB
ELEVATION:
LABORATORY: SHREVE

CONVENTIONAL CORE ANALYSIS

SMP. NO.	DEPTH	PERMEABILITY MD. MAXIMUM VERT.	% POR.	GAS VOL.	PORE OIL	SATS WTR.	PROB PROD	DESCRIPTION
	385.0-405.0	Core No. 1 Cut 20 Ft. Rec. 20 Ft.						
	385.0-89.0	Shale Blank No Analysis						
1	389.0-90.0	<0.1	14.6	4.5	61.5	27.5		LM FOS CHKY G ODR DUL GLD
2	390.0-91.0	87	26.5	3.3	67.0	25.4		LM FOS CHKY G ODR DUL GLD
3	391.0-92.0	140	33.9	2.7	75.8	17.6		LM FOS CHKY G ODR DUL GLD
4	392.0-93.0	65	24.4	1.6	65.1	30.6		LM FOS CHKY G ODR DUL GLD
5	393.0-94.0	16	19.2	1.9	68.8	28.3		LM FOS CHKY G ODR DUL GLD
6	394.0-95.0	<0.1	5.3	1.6	35.2	54.4		LM FOS G ODR SPT GLD FLU
7	395.0-96.0	<0.1	2.3	3.2	34.5	43.9		LM FOS G ODR SPT GLD FLU
8	396.0-97.0	41	16.5	3.5	47.3	40.1		LM FOS G ODR SPT GLD FLU
9	397.0-98.0	37	11.6	4.2	59.0	28.9		LM FOS G ODR SPT GLD FLU
10	398.0-99.0	4.2	16.1	3.2	64.5	26.0		LM FOS G ODR SPT GLD FLU
11	399.0-00.0	0.6	8.2	2.8	59.4	29.7		LM FOS G ODR SPT GLD FLU
12	400.0-01.0	15	18.5	1.5	51.7	37.9		LM FOS V CHKY G ODR SPT GL
13	401.0-02.0	169	29.0	2.3	50.9	42.4		SD VFG LM FOS G ODR DUL GL
14	402.0-03.0	190	31.2	3.1	56.7	34.2		SD VFG LM FOS G ODR DUL GL
15	403.0-04.0	81	22.7	2.8	51.7	40.5		SD VFG LM FOS G ODR DUL GL
16	404.0-05.0	25	22.5	4.8	55.6	31.6		SD VFG FOS SLI SH G ODR DU

TABLE 3, Continued
CORE ANALYSIS OF WELL 16-3
Core Laboratories, Inc., Petroleum Reservoir Engineering, Dallas, Texas

CITIES SERVICE OIL COMPANY	DATE:	2-3-76	FILE NO:	2203-3
NO. 16-3 BODCAU FEE	FORMATION:	NACATOH	ANALYSIS:	HK RB
BELLEVUE FIELD	DRLG. FLUID:	WATER BASE MUD	ELEVATION:	
BOSSIER PARISH, LOUISIANA	LOCATION:		LABORATORY:	SHREVE

CONVENTIONAL CORE ANALYSIS

SMP. NO.	DEPTH	PERMEABILITY MD. MAXIMUM VERT.	% POR.	GAS VOL.	PORE OIL	SATS WTR.	PROB PROD	DESCRIPTION
	405.0-24.0	CORE NO. 2 CUT 20 FT.		REC. 19 FT				
17	405.0-06.0	700	39.2	2.9	53.1	39.7		SD VFG SLT SH G ODR DUL GL
18	406.0-07.0	640	40.7	2.4	56.7	37.3		SD VFG SLT SH G ODR DUL GL
19	407.0-08.0	730	40.7	2.4	49.2	45.1		SD VFG SH LAM G ODR DUL GL
20	408.0-09.0	589	32.2	1.9	49.6	45.8		SD VFG SH LAM G ODR DUL GL
21	409.0-10.0	372	30.5	2.1	51.3	43.3		SD VFG SH G ODR DUL GLD FL
22	410.0-11.0	439	35.9	2.2	51.2	43.1		SD VFG SLI SH G ODR DUL GL
23	411.0-12.0	489	33.3	1.7	46.7	48.0		SD VFG SLI SH G ODR DUL GL
24	412.0-13.0	730	29.5	2.4	47.9	45.6		SD VFG SH G ODR DUL GLD FL
25	413.0-14.0	<0.1	5.5	1.2	67.1	22.4		SD VFG LM HRD G ODR DUL GL
26	414.0-15.0	<0.1	7.1	3.7	33.2	50.3		SD VFG FOS HRD G ODR DUL GL
27	415.0-16.0	<0.1	3.0	2.8	34.8	52.7		SD VFG FOS HRD G ODR DUL GL
28	416.0-17.0	11	39.4	2.2	39.1	55.8		SD VFG SLT G ODR DUL GLD F
29	417.0-18.0	926	37.8	3.7	47.6	43.6		SD VFG SLI SH G ODR DUL GL
30	418.0-19.0	328	26.1	3.5	47.9	43.9		SD VFG SLI SH G ODR DUL GL
31	419.0-20.0	358	36.0	2.6	23.3	70.2		SD VF-FG G ODR DUL GLD FLU
32	420.0-21.0	914	39.3	3.1	15.6	75.9		SD VF-FG G ODR V DUL GLD F
33	421.0-22.0	439	37.2	2.8	15.6	76.8		SD VF-FG G ODR V DUL GLD F
34	422.0-23.0	482	38.4	3.3	14.4	77.0		SD FG SLT G ODR V DUL GLD
35	423.0-24.0	804	35.4	2.7	17.5	75.0		SD FG SLT G ODR V DUL GLD

(*) NO INTERPRETATION MADE

NOTE: POROSITY FROM HELIUM PORISIMETER; GAS VOLUME AND PORE SATURATIONS FROM SUMMATION OF FLUIDS

TABLE 4
PROJECT AREA DATA

Pattern Area	19 acres
Average Thickness	54 feet net
Net Pay Volume	1,039 acre-feet
Oil Saturation	1,909 bbls/acre-foot
Oil in Place	1,984,000 barrels
Estimated Recovery	700,000 barrels
Porosity	33.9%
Permeability	700 md
Water Saturation	27.4%
Reservoir Temperature	75°F
Crude Gravity	19° API
Crude Viscosity	676 CP

TABLE 5
WELL COMPLETION DATA

Well No.	Location Sec.11-19N-11W		Completion Date	Top of Pay, Ft.	Net Pay, Ft.	Total Depth, Ft.	Production Casing			Completion Interval Ft
							Casing Size, In.	Depth, Ft.	Cement, No. of Sacks	
2-3	495'	FSL & 825' FWL	2/20/71	355	61	456	5-1/2	449	75	385-419
2-4	330'	FSL & 825' FWL	2/20/71	344	63	452	5-1/2	452	75	372-412
2-5	165'	FSL & 825' FWL	2/19/71	330	67	452	5-1/2	449	75	358-405
2-8	825'	FWL & 20' FSL	5/27/75	326	56	465	7	464	90	336-388
12-1	330'	FSL & 990' FWL	8/13/76	348	62	452	7	452	80	410-425
12-2	495'	FSL & 990' FWL	6/11/76	362	58	461	7	461	80	367-418
12-3	1155'	FWL & 495' FSL	5/21/76	362	55	458	7	458	110	368-420
12-4	600'	FNL & 1133' FWL	6/11/76	343	62	462	7	462	110	351-423
12-5	1155'	FWL & 20' FSL	5/17/76	324	56	454	7	454	110	324-404
12-6	1485'	FWL & 20' FSL	5/25/76	328	65	458	7	458	110	328-405
13-1	330'	FSL & 1320' FWL	8/15/76	351	61	453	7	453	100	410-426
13-2	1320'	FWL & 495' FSL	5/24/76	358	55	465	7	465	110	358-412
13-3	1485'	FWL & 495' FSL	7/23/75	360	58	467	7	466	140	361-398
13-4	1485'	FWL & 245' FSL	5/18/76	346	62	456	7	456	110	346-412
13-5	1485'	FWL & 20' FSL	5/22/76	328	67	451	7	451	110	328-402
13-6	1320'	FWL & 20' FSL	5/18/76	324	66	458	7	458	110	324-404
14-1	1650'	FWL & 330' FSL	8/19/76	356	54	453	7	451	140	412-425
14-2	1650'	FWL & 495' FSL	9/01/76	368	47	460	7	457	140	369-424
14-3	1815'	FWL & 495' FSL	9/06/76	378	39	450	7	450	140	379-416
14-4	1815'	FWL & 250' FSL	9/01/76	357	55	457	7	456	140	357-417
14-5	1815'	FWL & 20' FSL	9/01/76	338	68	452	7	450	140	339-419
14-6	1650'	FWL & 20' FSL	9/07/76	336	64	454	7	452	140	336-417
15-1	2000'	FWL & 330' FSL	9/13/76	366	44	456	7	454	140	410-423
15-2	2000'	FWL & 495' FSL	9/01/76	378	33	445	7	443	140	380-416
15-3	2145'	FWL & 495' FSL	9/07/76	376	38	458	7	458	140	376-414
15-4	2185'	FWL & 250' FSL	9/07/76	362	47	459	7	457	140	364-416
15-5	2185'	FWL & 20' FSL	9/07/76	352	61	454	7	452	140	354-415
15-6	2000'	FWL & 20' FSL	9/08/76	342	65	450	7	450	140	344-416
16-1	2400'	FWL & 295' FSL	9/23/76	371	42	461	7	460	140	411-421
16-2	2400'	FWL & 440' FSL	9/07/76	375	39	460	7	456	140	375-414
16-3	2615'	FWL & 440' FSL	9/07/76	384	19	449	7	447	140	386-411

TABLE 5, Continued
WELL COMPLETION DATA

Well No.	Location Sec.11-19N-11W	Completion Date	Top of Pay, Ft.	Net Pay, Ft.	Total Depth, Ft.	Production Casing			Completion Interval Ft
						Casing Size, In.	Depth, Ft.	Cement, No. of Sacks	
16-4	2615' FWL & 230' FSL	9/08/76	374	46	454	7	452	140	376-420
16-5	2615' FWL & 20' FSL	9/07/76	367	49	459	7	457	140	368-421
16-6	2400' FWL & 20' FSL	9/06/76	355	56	457	7	456	140	355-416
L-1	1320' FSL & 165' FWL	8/14/75	408	19	469	7	469	140	-
L-2	1485' FWL & 825' FSL	8/13/75	384	33	464	7	462	140	-
L-4	3000' FWL & 290' FSL	8/26/75	404	11	460	7	454	140	-

TABLE 6

CUMULATIVE PATTERN PRODUCTION AND INJECTION SUMMARY

<u>Pattern</u>	<u>Oil Production (BBL)</u>	<u>Air Injected (MCF)</u>	<u>Water Injected (BBL)</u>	<u>Formation (Ac-Ft)</u>
12	215,815	2,081,453	1,209,057	237
13	129,847	2,180,163	856,809	225
14	100,986	2,042,579	856,173	212
15	116,011	1,904,564	1,137,136	193
16	122,283	1,861,261	1,122,519	172
TOTAL	684,942	10,070,020	5,181,694	1039

TABLE 7

SUMMARY OF PRODUCTION AND OPERATIONS

DATE	Cumulative Oil (BBL)	Percentage of Cumulative (per year)	Significant Changes in Operation
June 1977	92,702	14	Began converting to simultaneous injection (April 1977).
June 1978	270,802	26	
June 1979	423,610	22	Drilled 4 additional producers(September 1978). Shut in 6 wells on North Line (February 1979).
June 1980	558,574	20	Drilled 5 additional producers (July 1979).
June 1981	641,660	12	Returned 6 wells on North Line to production (July 1980). Began converting to water injection only (September 1980). Terminated air injection (April 1981).
June 1982	684,942	6	
		100	

TABLE 8

SUMMARY OF COMBUSTION TUBE RESULTS

	<u>Run #1</u>	<u>Run #2</u>	<u>Run #3</u>	<u>Run #4</u>	<u>Run #7</u>	<u>Run #8</u>	<u>Run #9</u>
<u>Packing Conditions</u>							
Porosity, %	51.	48.	44.	43.	49.0	47.	51.
Oil Saturation, % PV	31.	36.	19.	21.	30.0	25.	22.
Sand Weight, grams	6267.	6624.	7068.	7187.	6493.0	6680.	6227.
Oil Weight, grams	693.	780.	372.	399.	663.0	534.	498.
Water Weight, grams	0.0	2.	0.0	399.	377.0	58.	54.
Native or mixed	N	N	M	M	N	N	N
<u>Operating Conditions</u>							
Combustion Temperature, °F	1053.	1116.	980.	936.	1531.	1022.	965.
Burning Efficiency, %	74.	80.	83.	90.	76.	89.	99.
Water/Air Ratio, B/MMSCF	0.0	0.0	0.0	125.	195.	336.	342.
<u>Results</u>							
Fuel Deposit, 16/ft. ³	2.79	1.94	1.31	1.50	1.76	1.55	1.
Air Requirement, MMCF/A-F	19954.	12788.	9540.	11100.	13400.	12035.	15476.
Mole Weight of Fuel Unit	13.37	12.77	13.59	13.67	13.70	13.64	13.9
Air/Oil Ratio, MCF/B	19.95	13.69	23.61	28.32	17.15	21.10	101.

TABLE 8, Continued

SUMMARY OF COMBUSTION TUBE RESULTS

	<u>Run #10</u>	<u>Run #11</u>	<u>Run #12</u>	<u>Run #13</u>	<u>Run #14</u>	<u>Run #15</u>	<u>Run #17</u>
<u>Packing Conditions</u>							
Porosity, %	50.	50.	52.	51.	49.	45.	41.
Oil Saturation, % PV	23.	28.	25.	18.	33.	25.	57.
Sand Weight, grams	6344.	6403.	6138.	6234.	6416.	6976.	7478.
Oil Weight, grams	506.	618.	574.	412.	738.	511.	1051.
Water Weight, grams	55.	14.	15.	13.	14.	22.	17.
Native or Mixed	N	N	N	N	N	N	M
<u>Operating Conditions</u>							
Combustion Temperature, °F	908.	1023.	919.	931.	823.	1031.	1094.
Burning Efficiency, %	87.	92.	86.	84.	82.	99.	98.
Water/Air Ratio, B/MMSCF	342.	352.	485.	503.	335.	0.0	0.0
<u>Results</u>							
Fuel Deposit, 16/ft. ³	1.77	1.76	1.45	1.49	2.24	1.86	2.5
Air Requirement, MMCF/A-F	13201.	12510.	11060.	11052.	16444.	13907.	17666.
Mole Weight of Fuel Unit	13.58	13.17	13.80	13.65	13.52	13.54	13.11
Air/Oil Ratio, MCF/B	15.6	12.66	86.50	222.	19.43	20.79	13.0

TABLE 8, Continued

SUMMARY OF COMBUSTION TUBE RESULTS

	<u>Run #18</u>	<u>Run #19</u>	<u>Run #20</u>	<u>Run #24</u>	<u>Run #24</u>	<u>Run #25</u>
<u>Packing Conditions</u>						
Porosity, %	47.	46.	52.	47.	48.	46.
Oil Saturation, % PV	34.	23.	21.	19.	18.	25.
Sand Weight, grams	6786.	6799.	6141.	6761.	6568.	6905.
Oil Weight, grams	712.	481.	479.	401.	390.	508.
Water Weight, grams	0.0	8.	8.	15.5	15.1	21.4
Native or Mixed	N	N	N	N	N	N
<u>Operating Conditions</u>						
Combustion Temperature, °F	941.	967.	976.	1048.	1199.	1361.
Burning Efficiency, %	98.	62.	74.	61.	58.	66.
Water/Air Ratio, B/MMSCF	0.0	0.0	225.	226.	188.	182.
<u>Results</u>						
Fuel Deposit, 16/ft. ³	2.78	1.57	1.65	1.33	1.57	2.0
Air Requirement, MMCF/A-F	19430.	10228.	10637.	8706.	10370.	12395.
Mole Weight of Fuel Unit	13.18	12.55	12.71	12.60	12.66	12.21
Air/Oil Ratio, MCF/B	22.59	24.17	15.87	26.18	26.92	43.66

TABLE 9

BELLEVUE CORE SAMPLES
IGNITION TEST RESULTS

OVEN TEMPERATURE VS % OXYGEN PRODUCED

<u>System Temperature, °F</u>	<u>Run 1 Flux=32 SCF/ft²-HR</u>	<u>Run 2 35</u>	<u>Run 3 16</u>	<u>Run 4 16</u>	<u>Run 5 30</u>
200	21.0	--	--	--	--
250	21.0	--	21.0	21.0	21.0
300	19.8	--	19.6	19.1	21.0
350	17.0	16.5	15.0	14.3	17.5
400	10.5	8.9	5.3	6.9	9.4
450	7.2	1.5	0.5	1.0	3.3
500	0.0	0.0	0.0	0.0	0.0

Average pressure drop through tube = 4 psi.

TABLE 10
SUMMARY OF PREIGNITION FALLOFF TESTS
DATE: AUGUST, 1976

<u>Pattern</u>	<u>Kgh, Md-ft</u>	<u>Kg, md</u>	<u>Skin Factor, S</u>
12	897	14	- .3
13	761	12	-3.4
14	320	6	-2.5
15	594	14	-2.4
16	1338	32	-0.2
16(a)	3434	82	+0.9

TABLE 11
SUMMARY OF SECOND FALLOFF TESTS
DATE: FEBRUARY, 1977

<u>Pattern</u>	<u>Kgh, Md-ft</u>	<u>Kg, md</u>	<u>Skin Factor, S</u>
12	8418	136	-5.3
13	12828	210	2.3
14	6038	112	-1.9
15	8459	192	-4.1
16	22862	544	-3.3

(a) Second test performed on September 21, 1976

TABLE 12
RESULTS OF PULSE TEST ANALYSIS
DATE: JANUARY 31, 1977 - FEBRUARY 10, 1977

<u>Pattern</u>	<u>Well</u>	<u>q (MMSCFD)</u>	<u>r (Ft.)</u>	<u>t_L (Min.) Feb. 1977</u>	<u>Δt₁, (Min.) Feb. 1977</u>	<u>K_g (md) Feb. 1977</u>
12	12-2	0.456	165	200	1222	37
	12-3	0.379	233	730	3451	26
	12-4	0.258	175	120	842	61
	12-5	0.273	351	180	1130	182
	12-6	0.190	310	160	1036	155
	2-8	0.218	351	100	739	278
	2-5	0.208	233	100	739	122
	2-4	0.092	170	220	1312	37
	2-3	0.061	233	220	1312	69
13	12-3	0.379	233	148	979	92
	12-4	0.258	178	92	697	76
	12-5	0.273	355	148	979	215
	13-6	0.170	310	40	388	413
	13-5	0.110	355	80	632	332
	13-4	0.110	178	185	1153	46
	13-3	0.277	233	420	2173	42
	13-2	0.097	165	30	317	143
14	13-4	0.110	170	180	1129	43
	13-5	0.110	345	180	1129	176
	14-6	0.098	310	120	842	190
	14-5	0.154	360	420	2173	99
	14-4	0.183	195	480	2423	26
	14-3	0.240	230	220	1312	67
	14-2	0.120	165	180	1129	40
	13-3	0.277	215	520	2590	30

TABLE 12, Continued
RESULTS OF PULSE TEST ANALYSIS
DATE: JANUARY 31, 1977 - FEBRUARY 10, 1977

<u>Pattern</u>	<u>Well</u>	<u>q (MMSCFD)</u>	<u>r (Ft.)</u>	<u>t_L (Min.)</u> <u>Feb. 1977</u>	<u>Δt₁ (Min.)</u> <u>Feb. 1977</u>	<u>K_g (md)</u> <u>Feb. 1977</u>
15	14-3	0.183	240	600	2919	33
	14-4	0.129	200	320	1749	38
	14-5	0.170	355	300	1663	126
	15-6	0.183	310	140	940	170
	15-5	0.110	370	280	1577	145
	15-4	0.289	200	240	1401	48
	15-3	0.395	215	120	842	92
	15-2	0.839	160	100	739	58
16	16-2	0.273	145	220	1312	27
	16-3	0.146	260	Not Analyzable		
	16-4	0.146	225	160	1036	81
	16-5	0.051	345	Not Analyzable		
	16-6	0.269	270	60	516	234
	15-5	0.098	340	520	2672	46
	15-4	0.281	220	420	2173	49
	15-3	0.395	320	820	3818	45

TABLE 13

BODCAU IN-SITU COMBUSTION PROJECT

CRUDE OIL ANALYSES - SUMMARY

<u>Sampling Date</u>	<u>Average API Gravity at 60°F</u>	<u>Average Acid Number mg KOH/g Oil</u>	<u>Average Percent Sulfur</u>	<u>Average Viscosity, cps</u>			<u>Average Percent Emulsified Water</u>
				<u>37.8°C</u>	<u>48.9°C</u>	<u>60°C</u>	
Native Oil	19.1	5.1	0.9	225	112	69	—
November 1976	18.8	—	—	179	83	51	4.7
May 1977	19.8	4.0	0.36	163	88	52	3.6
January 1978	18.0	3.7	0.47	161	91	57	10.4
June 1978*	19.7	3.6	0.45	209	126	86	10.5
May 1979*	19.6	2.9	0.62	160	87	53	5.6
March 1980*	19.0	4.3	0.59	166	88	51	18.5
September 1980*	19.0	3.5	0.61	183	95	62	9.8

*Emulsified water removed.

TABLE 14

BODCAU IN-SITU COMBUSTION PROJECT

PRODUCED GAS ANALYSES

	<u>H₂S</u> <u>ppm</u>	<u>CO₂</u> <u>%</u>	<u>CO</u> <u>%</u>	<u>O₂</u> <u>%</u>	<u>N₂</u> <u>%</u>	<u>C₁</u> <u>%</u>	<u>C₂</u> <u>%</u>	<u>C₃</u> <u>%</u>	<u>iC₄</u> <u>%</u>	<u>nC₄</u> <u>%</u>	<u>C₅</u> <u>%</u>	<u>Heat</u> <u>BTU/SCF</u>
Jan 1977 Average - 20 Wells	1302	14.0	—	1.5	—	1.5	—	0.07	0.01	0.02	0.13	23.1
Aug 1977 Average - 28 Wells	1278	12.2	0.34	2.52	84.1	0.43	0.05	0.05	0.02	0.06	0.12	13.0
Jan 1978 Average - 23 Wells	2177	12.1	0.58	2.71	80.1	1.11	0.10	0.06	0.03	0.02	0.01	16.5
Oct 1978 Average - 28 Wells	1572	15.6	0.61	2.66	78.0	2.03	0.59	0.45	0.12	0.36	0.24	67.5
May 1979 Average - 21 Wells	14.6	13.1	0.59	5.7	76.3	5.05	0.49	0.16	0.02	0.08	0.02	67.7
Mar 1980 Average - 29 Wells	697	11.9	0.53	5.6	80.1	0.5	0.50	0.20	0.05	—	Trace	18.9
Sep 1980 Average - 29 Wells	197	8.2	0.4	11.0	79.8	0.2	0.1	Trace	Trace	0	0	3.4

TABLE 15
BODCAU IN-SITU COMBUSTION PROJECT
PRODUCED WATER ANALYSES - SUMMARY

	<u>Chloride, mg/l</u>	<u>pH</u>	<u>Sulfate, mg/l</u>
Native Water	11143	6.9	--
November 1976	7060	--	--
May 1977	5926	--	--
January 1978	4570	7.2-8.0	--
June 1978	3619	4.5-8.1	--
May 1979	4223	4.8-8.0	--
March 1980	3893	5.9-8.1	417
September 1980	3619	6.5-7.6	624

TABLE 16
SUMMARY OF PROJECT INVESTMENTS
JUNE 1982

<u>DESCRIPTION</u>	<u>CUMULATIVE COSTS</u>	<u>ORIGINAL ESTIMATE</u>
<u>Drill and Equip Wells</u>		
Evaluation Wells	\$ 180,968.01*	\$ 34,544.00
Development Wells	717,813.18	624,237.00
Observation Wells	43,304.47	35,700.00
Saltwater Disposal	15,535.98	13,232.00
Redrill Well #12-1A	16,246.20	
Drill 9 Line Wells	<u>236,781.78</u>	
Sub-Total	\$1,210,649.62	\$ 707,713.00
<u>Install Facilities</u>		
Production and Injection Facilities	\$ 491,490.57	\$ 497,888.00
Electrify Compressor #1	<u>8,639.17</u>	
Sub-Total	\$ 500,129.74	\$ 497,888.00
 TOTAL INVESTMENTS	 <u>\$1,710,779.36</u>	 <u>\$1,205,601.00</u>

* Includes Pattern 15 performance evaluation wells originally not provided for.

TABLE 17

SUMMARY OF PROJECT EXPENSES

JUNE 1982

<u>DESCRIPTION</u>	<u>CUMULATIVE COST</u>	<u>ORIGINAL ESTIMATE</u>
<u>Exploration and Production Services</u>		
Region Expense	\$ 490,774.99	\$ 747,642.00
Production Foreman Expense	<u>279,475.28</u>	<u>256,179.00</u>
Sub-Total	\$ 770,250.27	\$ 1,003,821.00
<u>Research Services</u>		
Research and Development	\$ 305,060.50	\$ 360,835.00
Environmental Assessment	<u>50,000.00</u>	<u>50,000.00</u>
Sub-Total	\$ 305,060.50	\$ 410,835.00
<u>Lease Operations and Maintenance</u>		
Direct Lease Expenses	\$ 4,382,228.22	\$ 3,877,000.00
Producing Well Overhead	1,508,077.74	1,257,080.00
Louisiana Severance Taxes	1,774,393.10	475,561.00
Decontrol Tax	<u>1,300,783.84</u>	<u>1,300,783.84</u>
Sub-Total	\$10,676,262.26	\$ 5,609,641.00
 TOTAL EXPENSES	 \$11,751,573.03	 \$ 7,024,297.00

TABLE 18
PROJECT EXPENDITURES
JUNE 1982

<u>CATEGORY</u>	<u>COST TO DATE</u>	<u>COST PER BARREL*</u>
Lease Operation	\$ 1,138,331.96	1.90
Lease Maintenance	2,053,126.26	3.43
Compression Facility	1,190,770.00	1.99
Louisiana Severance Tax	1,774,393.10	2.96
CSC Overhead	1,508,077.74	2.51
Depletion & Depreciation	1,444,243.00	2.41
Decontrol Tax	1,300,783.84	2.17
	<hr/>	<hr/>
TOTALS	\$10,409,725.90	17.37

* Costs were determined on a net barrel basis assuming a normal 1/8 royalty.

TABLE 19
PROJECT EXPENDITURES
THROUGH MARCH 1980

<u>CATEGORY</u>	<u>COST THRU 3/80</u>	<u>COST PER BARREL*</u>
Lease Operation	\$ 522,299.76	\$ 1.12
Lease Maintenance	979,271.74	2.10
Compression Facility	937,839.96	2.01
Louisiana Severance Tax	1,175,085.40	2.51
CSC Overhead	767,010.18	1.64
Depletion & Depreciation	1,001,255.00	2.14
	<hr/>	<hr/>
TOTAL	\$ 5,382,762.04	\$ 11.52

* NOTE: Costs were determined on a net barrel basis assuming a normal 1/8 royalty.

TABLE 20
PROJECT EXPENDITURES
APRIL 1980 - JUNE 1982

<u>CATEGORY</u>	<u>COST 4/80 - 6/82</u>	<u>COST PER BARREL*</u>
Lease Operation	\$ 522,299.76	\$ 3.95
Lease Maintenance	1,073,854.52	8.13
Compression Facility	252,930.04	1.92
Louisiana Severance Tax	599,307.70	4.54
CSC Overhead	741,067.56	5.61
Depletion & Depreciation	442,988.00	3.35
Decontrol Tax	1,300,783.84	9.85
	<hr/>	<hr/>
TOTAL	\$4,933,231.42	\$37.35

* NOTE: Costs were determined on a net barrel basis assuming a normal 1/8 royalty.

TABLE 21
REVENUE DISTRIBUTION
PROJECT CUMULATIVE

<u>CATEGORY</u>	<u>PERCENTAGE OF CRUDE SELLING PRICE</u>
Lease Operation	6.8
Lease Maintenance	13.2
Compression Facility	10.0
Severance Tax	14.1
Operating Overhead	9.4
Depletion and Depreciation	10.6
Decontrol Tax	9.2
Net Operating Income	26.7

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