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BODCAU IN SITU COMBUSTION PROJECT

Third Annual Report — July 1, 1978—August 31, 1979

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

Date Published—August 1980

Cities Service Company
Jackson, Mississippi

U. S. DEPARTMENT OF ENERGY

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BODCAU IN SITU COMBUSTION PROJECT

Third Annual Report
for the Period
July 1, 1978—August 31, 1979

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SUMMARY

The Bodcau In Situ Combustion Project is a cooperative venture between Cities Service Company and the U.S. Department of Energy. The project is governed by DOE Contract EY-76-C-03-1189, covering the period from June 1, 1976 through June 30, 1982. The main objective is to demonstrate the operation and economics of a successful commercial scale In Situ Combustion Project in a heavy oil reservoir. During the six year contract life, total estimated cost for the project is \$8,229,898. The Department of Energy will fund a maximum of \$3,102,112 of the cost of the project with Cities being responsible for the remaining cost.

The Third Annual Report deals primarily with performance, development and economics of the project in the third year of operation. However, pertinent information from the First and Second Annual Report will be included for background information.

The five elongated patterns were developed for this demonstration on Cities Service Company's Bodcau Fee "B" lease in the Bellevue Field, Bossier Parish, Louisiana, approximately 18 miles northeast of the city of Shreveport. Figure 1 shows the location of the field in northwest Louisiana.

The field was discovered in 1921 and is a dome type structure covering approximately 900 productive acres. Production is from the Upper Cretaceous Nacatoch Sand occurring from 300

to 400 feet deep. Primary production by fluid expansion and later gravity drainage amounted to only about five percent of the original oil-in-place.

Reservoir properties and project area data are presented in Tables 1 and 2. Project area net pay and structure maps are included in Figures 2 and 3.

Thirty-eight producers, five injectors and five temperature observation wells are included in the 19-acre project. Estimated recoverable reserves from the project is 700,000 barrels. During the first three years of the contract, cumulative air and water injection has been 7,046,589 MCF and 1,319,270 barrels. Oil production has been 449,816 barrels. This recovery represents 64% of the total estimated recoverable reserves.

Current expense at the field level for operations, development, maintenance, well service and Louisiana Severance Total Tax is \$10.60 per gross barrel produced.

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COMPRESSION FACILITY

The facility for the compression and injection of air for use during the combustion phase is probably the single most important component of physical plant for the project. Efficient operations, proper maintenance and care are vital to project performance and economics.

Three compressors supply the air required for combustion on Cities Service Company's acreage in Bellevue Field. A portion of the total deliverability is used for the DOE Demonstration Project. Descriptions of the three units and histories of their operation during the first three years of the contract follow.

Compressor No. 1

This unit was initially installed under a rental/purchase agreement with Southwest Industries in 1970. The compressor is an Ingersoll Rand 4RDS-3. Originally this unit was equipped with a Waukesha L-7042 GSI Engine. The unit was rated for 3.18 MMSCFD at 315 psia and 742 BHP at a speed of 800 RPM.

Because of the shortage of natural gas supplies in past winters and the likelihood of future cuts in supply to the field, the Waukesha Engine was reclaimed in late 1977 and replaced by a 1000-HP, 900 RPM General Electric Motor. The total cost of this change in equipment was \$74,029. The unit was out of service from August 3, 1977 through April 20, 1978.

Following completion of work on this unit, it was put into service once again and has encountered no operating problems.

Compressor No. 2

A second compressor was installed in 1973 on a rental/purchase agreement. This unit was also an Ingersoll-Rand 4RDS-3 with a 1250-HP General Electric Motor, capable of delivering 5.74 MMSCFD at 300 psig and 1170 HP at 885 RPM.

This unit had always been somewhat more troublesome than the first compressor, with numerous periods off line for repairs. On October 18, 1976, during an electrical storm, this unit failed to shut down after an electrical line surge and was virtually destroyed. The cause of the failure in the shutdown systems was not known. However, considerable corrosion was observed at numerous electrical contacts. The unit was disassembled and shipped to Houston for repairs. It was returned to service on December 6, 1977. Total cost of the repairs was \$90,866. During May, 1979, the compressor was shut down for installation of a Resistance Temperature Detector (RTD). This additional automatic shutdown system was installed to provide added protection for the unit. Cost for this installation was \$10,310.

Compressor No. 3

This unit was purchased in 1975 and installation was completed in May of 1976. The compressor is an Ingersoll-Rand

4HHE-3-VG powered by a 3000-HP, 327 RPM General Electric motor. Rated capacity of this unit is 12.00 MMCFD at 265 psig.

After ordinary initial startup difficulties between May and October, 1976, the unit has run very smoothly. In August, 1977, three 660-volt capacitors failed and had to be replaced because of delivery problems. In February, 1979, the oil lubrication system failed in the third stage discharge cylinder. This failure caused the rod and piston to overheat and expand causing extensive damage to both along with damage to the cylinder wall. A new rod and piston was purchased and the cylinder was repaired. Cost for these repairs was \$16,453. The unit was then returned to service and only routine maintenance has been performed

TEMPERATURE OBSERVATION WELL MONITORING

During December, 1976, five (5) wells were drilled for use as temperature observation wells to monitor the progress of the combustion front. The location of these wells shown on Figure 4 were determined by the results of pulse tests which were conducted to determine directional permeability within each pattern. Each well has 5-1/2 inch casing cemented to surface and a thermocouple is run inside the casing.

Observation Well #12-7 is located 212 feet northeast of Injection Well #12-1A. This observation well was located where the directional permeability was only 26 millidarcies. The injector in Pattern 12 was ignited in August 1976, but no indication of heat was noted until March, 1978 as indicated by Figure 5. The maximum temperature, to date, has been 200°F.

Located 228 feet south of Well #13-1, Observation Well #13-7 is positioned within the pattern which has a directional permeability of 413 millidarcies, highest in the project area. This relatively high measurement of directional permeability has been verified since this has been the only observation well in the project to be reached by a combustion front. Stimulation was noticed by January, 1977 as the upper 35 feet of pay had increased from reservoir temperature of 75°F to 190°F, indicated in Figure 6. By August, 1977 combustion front arrival was observed at the

observation well as 825°F was recorded at a depth of 340 feet. The heating was still concentrated in the upper 35 feet of zone. Since that time the temperatures above and below 340 feet have risen somewhat more rapidly as the thickness of burned interval increases. The maximum recorded temperature in the wellbore was 1060°F in March, 1978. A decrease in temperature was recorded in the interval from 330 to 350 feet during April, 1978, which may be due to the cooling effect of water injection into the pattern. In June, 1978 the well developed a casing leak, which was probably due to the rapid cooling effect of the steam or water phase arrival. In August, 1978, to continue monitoring the advancing phase of the project, 3-1/2 inch casing was cemented inside the 5-1/2 inch casing. Temperatures by October, 1978 had decreased to a maximum of 750°F at 350 feet. Only minor fluctuations were noticed in the temperature from October, 1978 until July, 1979 when an increase of 200°F was recorded from 310 to 320 feet.

Well #14-7 is located 225 feet southwest of Injection #14-1, on line with Producer #13-5. Pulse testing indicated directional permeability in the vicinity of #14-7 to be 176 millidarcies. As expected, stimulation was seen at Well #14-7 shown in Figure /, but not to the extent that has been seen at Well #13-7. Slight temperature increases were seen beginning in February, 1977, but the heating has been very slow. By February, 1978 temperatures had approached a maximum of 300°F at 350 feet and

remain practically constant until July, 1979. As in the case with well #13-7, the heat has appeared to increase in the upper portion of the formation and decrease in the lower section.

Observation Well #15-7, Figure 8, is located 258 feet southeast of Well #15-1. Directional permeability in the vicinity of Well #15-7 is 145 millidarcies which compares to the permeability of Observation Well #14-7. Much of the same type of heating has occurred in this well as in Well #14-7. Initial response was seen in August, 1977. Peak temperatures were recorded May 2, 1979.

Well #16-7, is located 224 feet northwest of Injector #16-1. Pulse tests indicated that the directional permeability was greater in Pattern 15 than Pattern 16, which suggests that heating would primarily be due to the stimulation from Pattern 15. Stimulation was not seen until March 1978, Figure 9. The maximum temperature, 420^oF was recorded in December, 1978. Since that time temperatures have decreased throughout the zone with the peak temperature now being 350^oF.

RESEARCH SUPPORT

Tasks performed by Cities Service Research Laboratory in Tulsa, Oklahoma, have included combustion tube studies on Bellevue core samples, pressure transient tests in the five project patterns and analyses of produced oil, water and gas. The combustion tube studies, Table 3, and the pressure transient tests, Table 4 and Figures 10-14, were completed prior to the third project year and details of the results are presented in DOE topical reports. Reservoir fluid analysis is a continuing program in which samples are analyzed on a semi-annual schedule to determine changes in fluid composition during the life of the project.

Reservoir Fluid Analysis

Analyses of produced oil, water and combustion gas are conducted at six-month intervals. Oil and water were sampled from 29 producing wells in June 1978 and May 1979. These are the fourth and fifth such analyses since the start of the project. Determination of crude oil acid number, percent sulfur, specific gravity, viscosity and chromatographic analyses were made. The chloride and pH of produced waters were measured. Produced combustion gases were analyzed on-site in October 1978 and May 1979 for carbon dioxide, carbon monoxide, oxygen and hydrocarbon content by chromatography. The hydrogen sulfide concentrations of produced gases were measured

by the Tutweiler Method. Table 5 shows the composition of produced gases in October 1978 and May 1979. Hydrocarbons are shown individually in Table 6. Crude oil gravity, acid number and percent sulfur are shown in Table 7 and the average viscosity is shown in Figure 15. The salinity of the produced water is shown in Figure 16 and the effect of emulsified water on oil viscosity is shown in Table 8.

Some general conclusions can be drawn from results of tests to date:

1. Crude oil acid numbers are being reduced during the combustion phase. Native crude acid numbers of 5 have been reduced to 3.6 in June 1978 and 2.9 in May 1979.
2. The crude oil sulfur content was 0.45 percent in June 1978, showing that one-half of the native crude oil sulfur has been converted to hydrogen sulfide gas.
3. The methane concentration in produced gases has increased from 1.11 percent in January 1978 to 2.03 percent in October 1978 and 5.05 percent in May 1979.
4. The average hydrogen sulfide concentration in produced gases peaked at 2177 ppm in January 1978 and decreased to 1572 ppm in October 1978 and 1486 ppm in May 1979.

REMEDIAL WORK

As the area around the wellbore becomes thermally stimulated, due to the advance of the combustion front, the producing rates greatly increase. However, the combustion front breaks through to the producer before the entire reservoir can be thermally stimulated. This reduces the efficiency of the project because of the unreacted oxygen that escapes the reservoir. This loss of oxygen requires that additional air be injected to compensate for the amount that escaped.

When the combustion front reaches a producer, hot gases and sand erode away the primary cement sheath, causing extreme wear and tear on downhole pumps and tubing. To combat this problem, a quench water system was designed and installed, shown in Figure 17. This bottomhole cooling system allows the equipment to be operated as long as possible.

As the approach of the front comes closer to the wellbore and the control of the well becomes impossible, a portion of the producing zone must be squeeze cemented. During the three years of the project, a total of 77 squeezes, Table 9, have been performed on 26 wells. The majority of the squeezes were encountered during the last year. This was anticipated as the combustion front began to develop in intensity and areal coverage within the patterns.

During the first two years of the project the majority of the squeezes were in the northern wells in Patterns 14, 15 and 16. This problem increased in intensity during the third year. In order to force the migration of heat to the south and obtain a more uniform sweep and ultimate recovery, six wells, 13-4, 14-2, 14-3, 15-2, 15-3, and 16-2 were temporarily shut in during February, 1979. These six wells had been squeezed cemented a total of 35 times; therefore most of the producing interval had been shut off. Also these wells were producing high levels of oxygen which was causing the efficiency of the combustion process to decrease. These wells will be evaluated again during the heat scavaging phase to determine their contribution to the project.

DRILLING PROGRAM

During the past year a drilling program was enacted to prevent migration of oil, water and combustion gases across our south lease line. The migration of the fluids and gases towards the south line was excessive due to the drilling of production wells by an offset operator along this line. The drilling of these wells made it necessary that we start a drilling program along this line to improve our capture efficiency.

Four wells (13-8, 13-9, 14-8 and 15-8) were drilled and equipped by Cities in the fall of 1978 at a cost of \$98,300 along our south lease line in Patterns 13, 14 and 15 in an effort to determine the actual effect of increased well density versus normal density. As of June, 1979, approximately 17,000 barrels of oil have been recovered from these four wells.

Based on the performance of the four wells drilled in 1978 and the fact that fluid is being lost from patterns which are still on normal well spacing, five additional wells (12-8, 12-9, 15-9, 16-8 and 16-9) were drilled along the south lease line during July, 1979 at a cost of \$125,800 to increase well density within remaining patterns. Location of the additional line wells are shown in Figure 18.

INJECTION AND PRODUCTION PERFORMANCE

Between August 7 and September 24, 1976, the five injection wells (12-1, 13-1, 14-1, 15-1, & 16-1) were ignited. By March 1977, the injection rate had been stabilized at 1.5 MMCFD per well. Each injector was then recompleted to allow the simultaneous injection of air and water into the formation for the remainder of the combustion phase. Initial injection ratios were in the range of 100 to 150 barrels per MMCF of air. The water/air ratio was then increased to 250 BBLS/MMCF in each well. Problems arose at once at wells 12-1, 13-1, & 14-1, making the injection of water and air difficult.

During ignition of Well #12-1 excessive temperatures caused by the ignition of oil remaining inside the wellbore caused the failure of the casing. The burning oil inside the well generated 1300°F which over stressed the casing. Water injection was abandoned in this pattern until a replacement injector could be drilled. Well #12-1A was drilled in October 1977 and injection rates remained constant throughout 1978. However, during early 1979 water injection pressure began to increase again. This well was killed and additional perforations were added. No problems have developed with water injection since that time.

At Well No. 13-1, initial scaling was so severe that the packer could not be retrieved. The packer was pushed to bottom and a bit along with an acid treatment were used to clean up the casing and perforations. During July 1979 injection pressures had again reached a high level and another acid job was used to decrease injection pressure.

Initially, Well No. 14-1 had packer trouble. The tension packer had not properly been set and pressures on casing and tubing were equalized. When the packer was pulled, scale was noticed on the tubing and packer. A bit was run to bottom and the well was acidized with 250 gallons of HCL. No further injection problems arose with injection until mid-1979. Injection was hampered to the point that the well had to be acidized again with 500 gallons of HCL.

Patterns 15 and 16 had no initial injection problems when injection was started. However, during July 1979 attempts at increasing the water injection rates in Well 15-1 were unsuccessful. To accomplish the desired rates, the well was acidized with 500 gallons HCL acid. The well responded to the treatment and desired rates could then be achieved.

Individual injection histories for each of the patterns are shown in Figures 19 through 23.

Since initiation of the project, cumulative air and water injection has been 7,046,589 MCF and 1,319,270 barrels, Cumulative water/air ratio for the project is 187 BBL/MMCF. Table 10 lists the cumulative water/air ratio and cumulative injections on a per pattern basis. The cumulative air/oil ratio is shown in Figure 24.

During the six year contract period an estimated 700,000 barrels or 35% of the total oil in place will be produced. Oil production through August has totaled 449,816 barrels. Estimated burn volumes in the project area is shown on Table 11.

In March 1978 oil production reached a peak of 601 BOPD, however, this rate was not maintained. During the third year of operation daily production has averaged 419 barrels of oil. Project production is shown in Figure 25. The production is presently in the range of 425 BPD and is expected to remain at this level until the termination of air injection.

PROJECT ECONOMICS

DOE Cost-Sharing is \$3,102,112 for the six-year demonstration and the total estimated project cost is \$8,229,898. Cumulative expenditures through August, 1979 have been \$5,606,149, Figure 26, of which Cities Service Company's share has been \$3,552,445.

Project Investments

The contract provides for the funding of investments for wells and facilities on the basis of tangible or intangible charges. All tangible equipment is paid for by Cities Service Company while a portion of the intangible charges are funded by the DOE.

Precontract estimates for development costs were \$1,205,600. Of this total, tangible and intangible portions were \$704,324 and \$301,276, respectively. Several changes in the project have increased the actual development costs beyond the original estimates; however, these changes should not affect the overall project funding.

Cumulative expenditures for wells and facilities through August 31, 1979 have been \$1,553,842. Of this total, Cities Service Company's share has been \$892,861 or 57.5%, while the Department of Energy has contributed \$660,981. A breakdown of project investments are summarized in Table 12.

Additional expenditure during the previous year included the cost of drilling nine additional line wells to increase well density along the south lease line. The cost for these wells were \$224,053. Also, a Resistance Temperature Detector (RTD) was installed in the No. 2 compressor at a cost of \$10,310.

Based on ultimate production of 700,000 barrels, recovery of the \$1,553,842 investment to date will occur at the rate of \$2.53 per net barrel of oil produced less a one-eighth royalty interest. Cumulative production to date of 449,816 barrels has thus recovered \$998,142 or 64% of investments.

Operating Expenses

A summary of project net expenses is listed in Table 13. These are expenses that occurred in routine operation of the project, maintenance of wells and facilities, research and production services, taxes and overhead expenses. These expenditures, Table 14, based on a per net barrel basis are \$10.60 per barrel of oil produced.

Research and production services through August 31, 1979 have cost \$217,188 and \$462,688 respectively or a total of \$1.72 per net barrel. These are charges to the project for laboratory and field work conducted by Company personnel. In addition to

these charges, the Company's overhead rate amounts to \$618,191 or \$1.57 per net barrel. Louisiana severance taxes have amounted to \$805,514 or \$2.05 per net barrel.

The remaining charges can be grouped under the general category of direct lease operations and maintenance. Expenditures to date of \$1,948,725 amount to \$4.95 per net barrel of oil produced. This includes charges for replacement materials, labor, chemicals, utilities and well servicing. These expenditures have been summarized in Table 15.

APPENDIX A

TABLE 1
BELLEVUE FIELD AVERAGE RESERVOIR PROPERTIES

Porosity	33.9%
Permeability	700 md
Water Saturation	27.4%
Reservoir Temperature	75°F
Reservoir Pressure	40 psig
Crude Gravity	19° API
Crude Viscosity	676 CP

TABLE 2

PROJECT AREA DATA

Pattern Area	19 acres
Average Thickness	54 feet net
Net Pay Volume	1039 acre-feet
Oil Saturation	1909 bbls/acre-foot
Oil in Place	1,984,000 barrels
Estimated Recovery	700,000 barrels

TABLE 3
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.	664.0	554.	423.
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.	85.	90.	76.	89.	99.
Water/Air Ratio, B/MMSCF	0.0	0.0	0.0	125.	195.	336.	342.
<u>Results</u>							
Fuel Deposit, lb/ft. ³	2.79	1.94	1.31	1.50	1.76	1.55	1.90
Air Requirement, MMCF/A	10941.	12788.	9540.	11100.	13400.	12055.	15476.
Mole Weight of Fuel Unit	13.37	12.77	13.59	13.67	13.70	13.64	13.90
Air/Oil Ratio, MCF/B	19.95	13.69	23.61	28.32	17.15	21.10	101.

TABLE 3--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	N
<u>Operating Conditions</u>							
Combustion Temperature, °F	908.	1023.	919.	931.	823.	1051.	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, lb/ft. ³	1.77	1.76	1.45	1.49	2.24	1.86	2.55
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 3 - -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, lb/ft. ³	2.78	1.57	1.65	1.33	1.57	2.04
Air Requirement, MMCF/A-F	19450.	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 4

SUMMARY OF FALLOFF TEST RESULTS

PRE-IGNITION TESTS

<u>PATTERN</u>	<u>CUMULATIVE INJ. -MCF</u>	<u>CAPACITY MD-FT</u>	<u>PERMEABILITY MD</u>	<u>INJECTION PRESSURE-PSIA</u>
12	3,010	897	14.5	145
13	4,068	761	12.5	135
14	3,525	320	5.9	181
15	3,798	594	13.5	162
16	4,532	1,338	32.0	141
16	11,536	3,434	82.0	90

SECOND TESTS

<u>PATTERN</u>	<u>CUMULATIVE INJ. -MCF</u>	<u>CAPACITY MD-FT</u>	<u>PERMEABILITY MD</u>	<u>INJECTION PRESSURE-PSIA</u>
12	158,618	8,418	136	115
13	170,010	12,828	210	138
14	150,461	6,038	112	171
15	152,684	8,459	192	138
16	123,841	22,862	544	84

TABLE 5
ANALYSES OF PRODUCED GASES
AVERAGE MOLE PERCENT

<u>Component</u>	<u>October 1978</u>	<u>May 1979</u>
Nitrogen	78.0	76.3
Oxygen	2.7	5.7
Carbon dioxide	15.6	13.1
Carbon monoxide	0.6	0.6
Hydrogen sulfide	0.16	0.15
Hydrocarbons	3.79	5.82

TABLE 6
ANALYSES OF HYDROCARBONS IN PRODUCED GASES
AVERAGE MOLE PERCENT

<u>Component</u>	<u>October 1978</u>	<u>May 1979</u>
Methane	2.03	5.05
Ethane	0.59	0.49
Propane	0.45	0.16
Butane	0.48	0.10
Pentane	0.24	0.02
BTU/SCF	67.5	67.7

TABLE 7
ANALYSES OF PRODUCED CRUDE OILS

<u>Sample</u>	<u>API Gravity</u>	<u>Acid Number</u>	<u>Percent Sulfur</u>
Native	19.0	5.1	0.90
June 1978	19.7	3.6	0.45
May 1979	19.6	2.9	0.62

TABLE 8
AVERAGE VISCOSITY OF PRODUCED CRUDE OIL

<u>Sample</u>	<u>Viscosity, cps</u>			<u>Average Percent Water Removed</u>
	<u>100°F</u>	<u>120°F</u>	<u>140°F</u>	
<u>May 1979</u>				
Before Removing Water	196	107	76	--
After Removing Water*	160	87	53	5.6

*Emulsified water was removed by distillation. Small amounts of low temperature boiling components of the crude oils were collected and replaced in the undistilled crude oil.

TABLE 9

SUMMARY OF WELL REMEDIAL WORK

WELL	NO. JOBS	
2-3	0	
2-4	1	October 23, 1978
2-5	1	June 6, 1979
2-8	0	
12-2	4	April 19, 1977; April 6, 1978, May 25, 1978; July 10, 1978
12-3	3	April 10, 1978; July 10, 1978; May 23, 1979
12-4	3	March 30, 1978; May 25, 1978; May 23, 1979
12-5	0	
12-6	0	
13-2	4	July 5, 1977; October 27, 1977; January 5, 1978; June 26, 1978
13-3	1	September 13, 1978
13-4	8	March 28, 1978; April 20, 1978; July 24, 1978; September 26, 1978; January 9, 1979; April 2, 1979 May 15, 1979; June 19, 1979
13-5	1	April 16, 1979
13-6	4	August 16, 1977; February 8, 1978; April 16, 1978 August 15, 1979
13-8	1	August 14, 1979
13-9	1	May 11, 1979
14-2	6	September 21, 1977; September 27, 1977, December 19, 1977; January 3, 1978; February 23, 1978, August 28, 1978;
14-3	4	December 28, 1977; March 2, 1978; September 11, 1978; November 21, 1978 June 14, 1979; July 9, 1979
14-4	2	
14-5	0	
14-6	2	June 29, 1978; November 7, 1978
14-8	2	May 8, 1979; July 15, 1979
15-2	6	February 18, 1977; April 15, 1977; April 19, 1977 August 2, 1977; April 19, 1978; July 19, 1978
15-3	6	February 16, 1978; June 19, 1978; June 28, 1978; July 31, 1978; August 18, 1978; November 16, 1978 April 18, 1978; June 21, 1978; May 29, 1979
15-4	3	
15-5	0	
15-6	1	May 16, 1979
15-8	1	May 30, 1979
16-2	5	February 8, 1978; March 17, 1978; August 2, 1978; October 4, 1978; November 10, 1978
16-5	1	October 13, 1978
16-4	3	December 11, 1978; December 20, 1978; May 18, 1979
16-5	0	
16-6	3	May 15, 1978; July 5, 1978; July 10, 1979
---	---	
TOTAL	77	Cement Squeeze Repairs

TABLE 10

CUMULATIVE INJECTION SUMMARY

<u>PATTERN</u>	<u>INJECTION</u>		<u>RATIO</u>
	<u>MCF</u>	<u>BBLS</u>	<u>BBLS/MMCF</u>
12	1,251,820	350,433	280
13	1,499,731	208,926	139
14	1,457,882	229,047	157
15	1,422,829	262,747	185
16	1,414,327	268,117	190

TABLE 11

PATTERN ESTIMATED BURNED VOLUMES

<u>PATTERN</u>	<u>NET AF</u>	<u>BURNED AF*</u>	<u>PERCENT</u>
12	237	104.2	.439
13	225	124.9	.555
14	212	121.4	.573
15	178	118.4	.665
16	187	117.8	.629

*Note: Assumes Wet Combustion Air Requirement of
12 MMSCF/Acre-Foot

TABLE 12
SUMMARY OF PROJECT INVESTMENTS

<u>DESCRIPTION</u>	<u>CUMULATIVE COSTS</u>	<u>ORIGINAL ESTIMATE</u>
<u>Drill and Equip Wells</u>		
Evaluation Wells	\$ 36,759.26	\$ 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>224,053.60</u>	
Sub-Total	\$ 1,053,712.69	\$ 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>\$ 1,553,842.43</u>	 <u>\$ 1,205,601.00</u>

* Amount of \$70,633.08 was shown erroneously on the Second Annual Report. This amount represents total gross cost of 100% Cities A.F.E. at the time of the report. Actual final A.F.E. cost was \$74,029.00, which was cleared to D.O.E. project on a percentile basis of 11.67, or \$8,639.17.

TABLE 13
SUMMARY OF PROJECT EXPENSES

<u>DESCRIPTION</u>	<u>CUMULATIVE COST</u>	<u>ORIGINAL ESTIMATE</u>
<u>Exploration and Production Services</u>		
Region Expense	\$311,083.21	\$747,642.00
Production Foreman Expense	<u>151,605.11</u>	<u>256,179.00</u>
Sub-Total	\$462,688.32	\$1,003,821.00
<u>Research Services</u>		
Research and Development	\$217,187.69	\$ 360,835.00
Environmental Assessment	<u> </u>	<u>50,000.00</u>
Sub-Total	\$217,187.69	\$ 410,835.00
<u>Lease Operation and Maintenance</u>		
Direct Lease Expenses*	\$1,948,725.20	\$3,877,000.00
Producing Well Overhead	618,191.18	1,257,080.00
Louisiana Severance Taxes	<u>805,514.82</u>	<u>475,561.00</u>
Sub-Total	\$3,372,431.20	\$5,609,641.00
TOTAL EXPENSES	<u>\$4,052,307.21</u>	<u>\$7,024,297.00</u>

*See Table 14

TABLE 14
PROJECT EXPENDITURES

<u>CATEGORY</u>	<u>COST TO DATE</u>	<u>COST PER BARREL*</u>
Lease Operation	403,461.66	1.02
Lease Maintenance	766,028.12	1.95
Compression Facility	779,235.42	1.98
LA Severance Tax	805,514.82	2.05
CSC Overhead	618,191.18	1.57
Depletion & Depreciation	<u>799,271.00</u>	<u>2.03</u>
TOTAL	4,171,702.20	10.60

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

CUMULATIVE STRIPPER PRICE - \$15.23

TABLE 15
SUMMARY OF DIRECT LEASE OPERATIONS AND
MAINTENANCE EXPENSES

<u>CATEGORY</u>	<u>TOTAL EXPENDITURES</u>	<u>COST PER BARREL*</u>
Materials	\$ 175,237.97	\$ 0.45
Chemicals	164,822.32	0.42
Labor	323,739.36	0.82
Utilities	744,495.06	1.89
Well Service	<u>540,430.49</u>	<u>1.37</u>
TOTAL	\$1,948,725.20	\$ 4.95

*NOTE: Based on net cumulative oil production, assuming a normal 1/8 royalty, of 393,589 barrels through August 31, 1979.

FIGURE 1

FIGURE 2

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PROJECT AREA NET PAY MAP
BODCAU FEE FIREFLOOD

PROJECT AREA STRUCTURE MAP
BODCAU FEE FIREFLOOD

FIGURE 3

PROJECT PATTERN MAP **BODCAU FEE FIREFLOOD**

○ TEMPERATURE OBSERVATION WELL

FIGURE 5

FIGURE 6

FIGURE 7

FIGURE 8

FIGURE 9

FIGURE 10

BODCAU IN SITU COMBUSTION PROJECT
RESULTS OF PATTERN 12 PULSE TEST

FIGURE 11

BODCAU IN SITU COMBUSTION PROJECT
RESULTS OF PATTERN 13 PULSE TEST

FIGURE 12

BODCAU IN SITU COMBUSTION PROJECT
RESULTS OF PATTERN 14 PULSE TEST

FIGURE 13

BODCAU IN SITU COMBUSTION PROJECT.
RESULTS OF PATTERN 15 PULSE TEST

FIGURE 14

BODCAU IN SITU COMBUSTION PROJECT
RESULTS OF PATTERN 16 PULSE TEST

FIGURE 15

FIGURE 16

Production Well Schematic

Pumping Unit

Production

Thermometer

Quench Water

Combustion Gases

1" Hollow Sucker Rods

2 7/8" Tubing

Perforated Interval

FIGURE 18

FIGURE 19

FIGURE 20

FIGURE 21

FIGURE 22

FIGURE 23

FIGURE 24

BODCAU IN SITU COMBUSTION PROJECT PRODUCTION PERFORMANCE MONTHLY

FIGURE 25

FIGURE 2G
 BODCAU IN SITU COMBUSTION DOE PROJECT
 CUMULATIVE EXPENDITURE VS TIME

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