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FIELD TEST OF TWO HIGH-PRESSURE, DIRECT-CONTACT
DOWNHOLE STEAM GENERATORS. VOLUME I.
AIR/DIESEL SYSTEM

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ABSTRACT

As a part of Project DEEP STEAM, a project supported by the U. S. Department of Energy to develop technology to more efficiently utilize steam for the recovery of heavy oil from deep reservoirs, a field test of a downhole steam generator (DSG) was performed. The DSG burned No. 2 diesel fuel in air and was a direct-contact, high pressure device which mixed the steam with the combustion products and injected the resulting mixture directly into the oil reservoir. The DSG was used to thermally stimulate a well in the Tar Zone of the Wilmington Oil Field in a cooperative program with the City of Long Beach and the Long Beach Oil Development Company. The objectives of the test program included demonstration of long-term operation of a DSG, development of operational methods, assessment of the effects of the steam/combustion gases on the reservoir and comparison of this air/diesel DSG with an adjacent oxygen/diesel direct contact generator. Downhole operation of the air/diesel DSG was started in June 1981 and was terminated in late February 1982. During this period two units were placed downhole with the first operating for about 20 days. It was removed, the support systems were slightly modified, and the second one was operated for 106 days. During this latter interval the generator operated for 78% of the time with surface air compressor problems the primary source of the down time. Steam at approximately 50% quality, 440°F, and 1300 psi was injected along with exhaust gases which consisted primarily of nitrogen and carbon dioxide with small amounts of carbon monoxide and oxygen. Approximately 8500 MMBtu of energy, 31000 cold-water-equivalent barrels of steam, 2500 tons of nitrogen and 665 tons of carbon dioxide were injected into the reservoir. Gas communication was detected in all wells in the 5-acre, inverted 5-spot pattern; gases from this DSG were also detected in the nearby pattern for the oxygen/diesel system. Thermal contact, as evidenced by a temperature increase in the production well casing gases, and an oil production increase were measured in one of the four wells in the air/diesel pattern. Reservoir scrubbing of carbon monoxide was observed, but no conclusive data on scrubbing of SO_x and NO_x were obtained. Corrosion of the DSG combustor walls and some other parts of the downhole package were noted. Metallurgical studies have been completed and recommendations made for other materials that are expected to better withstand the downhole combustion environment.

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INTRODUCTION

The U. S. Department of Energy (DOE) has supported a program for the development of technology to more efficiently utilize steam as a thermal enhanced oil recovery technique for heavy oil from deep reservoirs. Sandia National Laboratories has been responsible for the technical direction of a major part of this program. The Sandia activities, collectively called Project DEEP STEAM, were centered in two main areas: 1) development and evaluation of hardware for more thermally efficient systems to deliver surface generated steam downhole to the reservoir, and 2) development and testing of downhole steam generators. The emphasis in the first of these two areas was on the evaluation of insulated tubing and on the development and testing of advanced thermal packers. Efforts in these two activities have been reported in quarterly reports (1-16) and a final report on the field evaluation of several commercially available insulating tubing designs has also been prepared (17). The subject of the present report is the second of the two areas of Project DEEP STEAM--namely, development and testing of downhole steam generators.

Early in the downhole steam generator effort, a general survey was made into different combustion techniques with a view toward identifying those that could be developed into hardware suitable for placement in an oil well for downhole steam generation. Two hydrocarbon combustion concepts were considered to be most adaptable to downhole operation and were selected for further study. The first involves combustion at low pressure. A downhole device of this type would exhaust combustion products back up the oil well casing and would require a downhole heat exchanger to provide high pressure steam. A generator of this type is classified as an "indirect contact" device. The second concept involves combustion at high pressure; in this case the steam and combustion products are mixed and injected directly into the oil reservoir. This concept is called a "direct contact" generator. Design and hardware fabrication contracts were placed for a low-pressure combustion concept (18) and for a high-pressure combustion concept having a ceramic for the combustor wall (19). In

parallel with these activities, Sandia undertook the development within the Laboratory of a high-pressure combustion design that used a metallic for the combustor wall.

A phased field test to prove the operation of one of these designs was undertaken. Because the Sandia concept had been operated successfully in the laboratory and hardware was available on a time scale compatible with the required schedule, it was selected for the field test. The first phase of the field test involved the operation of a surface mounted unit using propane as the fuel in the Kern River Field near Bakersfield, California (20). This test was performed in conjunction with Chevron USA from February to May 1980. The objectives, which involved a few months of steaming operation and measurement of the movement of the noncondensable exhaust gases within the reservoir, were successfully met. The second part of the field test program was a test, conducted in the Denton Field in southeast New Mexico in conjunction with ARCO Oil and Gas, to demonstrate techniques to run multiple strings into a well (21). Two jointed tubulars, two continuous tubulars and a multiple conductor electrical cable were successfully run to 2200 ft depth with an inert generator and retrieved.

Following the successful surface tests at Bakersfield, plans were finalized to extend the DSG design to incorporate two new features: first, to burn No. 2 diesel fuel rather than propane in air; and second, to develop a burner that would use oxygen rather than air as the oxidizer, again with diesel as the fuel. It was also determined that the air/diesel system would be placed downhole but, because of its less developed nature, the oxygen/diesel system would be placed on the surface and the steam/combustion products would be delivered to the reservoir through insulated tubing.

The final phase of the test program was to place a downhole generator in operation for a several month period in an oil field application. To implement this, Sandia solicited responses from oil field operators regarding their interest in participating in a cooperative field test program. General guidelines for the application included a 2000-3000 ft deep reservoir, 1000-1500 psi

injection pressure, 2 to 5 acre injection patterns, access to fuel, water and electric power, active thermal recovery operations in adjacent patterns and adequate space nearby to locate the necessary equipment. A Sandia/DOE committee evaluated the responses and selected a site in Long Beach, CA, as most nearly meeting all of the specifications. Sandia entered into an agreement with the City of Long Beach to test two generators, a downhole air/diesel system and a surface mounted oxygen/diesel system. The units were placed on wells operated in the Wilmington Field by Long Beach Oil Development Company (LBOD). Initial operation of the air/diesel system occurred in June 1981 and steam injection was terminated at the end of February 1982. This report will discuss only the air/diesel portion of these tests; results of the oxygen/diesel test program are presented in a companion report (22). Results of post test metallurgical analyses performed on hardware from both of the test programs are contained in a third report (23).

SYSTEM DESCRIPTION

The broad goals of this field project were to place into an oil field environment a complete downhole steam generator (DSG) system and to operate that system for an extended period of time. Figure 1 provides an outline of the goals which guided the project. These goals included not only developing and operating the 5 MMBtu/hr direct contact generator but also developing operational methods, demonstrating continuous operation, establishing maintenance records, and comparing these with similar characteristics of the oxygen/diesel system. Sandia was responsible for the entire system, including the controls and data system, and LBOD completed and maintained the injection well.

The system concept used in this field test was similar to that used in the earlier test program at Bakersfield, CA (20). Control of the entire system was accomplished with a digital computer which not only monitored and provided active control of selected key parameters but also recorded data for post test analyses. In the early part of the test program, this computer was augmented by a larger computer system that was dedicated to data recording at more frequent intervals for use in diagnostic and developmental activities. Figure 2

1. SYSTEM DEVELOPMENT

- **DIRECT CONTACT DOWNHOLE OPERATED GENERATOR**

- **FIT IN A 7" CASING**

- **5 MMBtu/hr GENERATOR**

- **PRESSURES TO 1500 psi**

- **STEAM INJECTION TEMPERATURES TO 500 °F**

- **SAND FACE STEAM QUALITY >70%**

- **SUPPORT SYSTEMS FOR AIR, FUEL, WATER, AND WATER TREATMENT**

2. FIELD TEST DEMONSTRATION

- **DATA ACQUISITION**

- **FEASIBILITY OF CONTINUOUS OPERATION**

- **OPERATIONAL METHODS**

- **ESTABLISH EQUIPMENT MAINTENANCE & LIFETIMES**

3. SYSTEM COMPARISON WITH THE OXYGEN/DIESEL SYSTEM

- **RESERVOIR RESPONSE**

- **OPERATION COST**

Figure 1. Air/Diesel Steam Generator Goals

Figure 2. Downhole Steam Generator System Schematic

is a schematic of the final system, indicating not only the primary mechanical and data elements but also the active control links within the system.

The DSG, which used No. 2 diesel as the fuel and air as the oxidizer, was operated in LBOD well SZ1-44 in the Tar Zone of the Wilmington Field in Long Beach, CA. Characteristics of this reservoir are shown in Table 1. Figure 3 indicates the field test location in the Long Beach area and Figure 4 is a photograph of the surface test site. Figure 5 shows the well spacing at reservoir depth for the 5-acre, inverted 5-spot pattern. In these latter two figures, note the proximity of the companion oxygen/diesel system.

As shown in Figure 6 and discussed throughout this report, two separate air/diesel DSG units were placed in the well during the course of this test program. The first (Test #1) was placed downhole in June 1981 and removed in August 1981 because of operational uncertainties. The second unit (Test #2), modified only slightly from the first one, was placed downhole in November 1981 and remained there throughout the remainder of the test. The following sections describe the various subsystems; reference to Unit #1 and Unit #2 are consistent with this Test #1 and Test #2 distinction.

1. Mechanical Subsystem

As shown in the schematic in Figure 2, five fluids - treated water, fuel, compressed air, caustic (NaOH) and annulus treatment - were pumped downhole. Pumps and controllers, flow rate, pressure and temperature instrumentation, pressure safety devices, and a manual control station were located on two skids positioned near the injection wellhead (see Figure 4).

Combustion air was provided to the generator at pressures up to 1450 psi by a 3-stage compressor system, shown in Figure 7. The first stage was a diesel powered, twin-screw rotary machine that compressed the air to about 250 psi. For Test #2 the air was then dried to a dew point of 35°F to remove moisture that could condense and cause scale buildup in the high pressure downhole air line; for Test #1 the air was not dried. The air then passed sequentially into an intermediate and a final stage of the compressor system; both stages were electrically driven, piston type machines. Air flow to the

TABLE 1
Reservoir Characteristics
Wilmington Field, Tar Zone

POROSITY	30-33%
PERMEABILITY	500 md
OIL GRAVITY	12-16° API
VISCOSITY	700 Cp
CURRENT OIL SAT.	55%
CURRENT BHP	900-950 psi
INITIAL TEMPERATURE	115°F
DEPTH (VSS)	2000-2500 ft.
THICKNESS	80-120 ft.

Figure 3. Downhole Steam Generator Test Location

Figure 4. Downhole Steam Generator Field Test Site at Long Beach

Figure 5. Field Test Well Patterns

MARCH 1981	EQUIPMENT ON SITE-WELL COMPLETED
APRIL	INJECTIVITY TESTS, SURFACE BURN
MAY	REWORKED WELL-INJECTIVITY TESTS
JUNE	INSTALLED DOWNHOLE PACKAGE
JULY	TEST #1
AUG	SECOND CONFIGURATION FABRICATED
SEPT	
OCT	
NOV	TEST #2
DEC	
JAN 1982	
FEB	
MARCH	REMOVED AND SURFACE TESTED DOWNHOLE GENERATOR SYSTEM
APRIL	

Figure 6. History of Air/Diesel Field Test

Figure 7. Air Compressor System for Downhole Steam Generator Tests

generator was controlled by manually adjusting a hand valve to dump unneeded air to the atmosphere. The downhole portion of the air was passed through a separator to minimize the oil mist in the air and then through the instrumentation section on the skids to record its pressure, temperature and flow rate. Data from these instruments were monitored and recorded by the control system.

Both cooling water and diesel fuel were pumped from LBOD storage tanks. The pre-softened water was further "polished" to less than 1 ppm calcium carbonate and dissolved oxygen was scavenged to less than 50 ppb by metering cobalt-catalyzed ammonium bisulfite solution into the water. This treated water was then passed through filters designed to remove particulate greater than 3 microns and on to a variable speed, positive displacement, high pressure pump located on one of the skids. Pressure, temperature and flow rate were measured in the instrumentation section on the skid. The diesel fuel was likewise filtered, its flow rate measured, and pumped downhole by a variable speed, positive displacement pump on one of the skids. Pressure and temperature transducers and an emergency shutoff valve completed the fuel flow circuit. Annulus treatment fluid (hydrazine and a corrosion inhibitor) and a 50% sodium hydroxide - 50% water mixture for treatment of the generator exhaust were pumped by constant speed, variable stroke pumps that had been adjusted to provide the necessary flow rates as determined by pretest calibrations.

2. Control/Data Subsystem

The underlying philosophy in the control of this system was that the air flow rate could be manually preset, the desired air-fuel and air-water ratios entered into the control system by an operator, and the flow rates of the fuel and water would then be computer controlled to the required values. This control was accomplished by the computer generating and sending the proper current level to the appropriate controller located on the skids; pump speeds were adjusted if necessary by the controller. It was also required that the control system monitor the air-fuel and water-fuel ratios - along with other key parameters such as steam temperature and water flow rate - and execute corrective actions (including automatic shutdown) in certain situations. Automatic

shutdown was accomplished by closing the emergency shutoff valve in the fuel line.

The digital control/data system was built around a Hewlett-Packard 9845B desk top calculator with scanners, multiprogrammers, video display, data plotting capabilities, and a keyboard for operator interaction. Interconnections of the control/data system with the different fluid supply systems are shown as dashed lines on Figure 2; pressure and temperature transducers, although not shown in this figure, were also connected to the control/data system. A dedicated data system, used in the early stages of the field test for diagnostic purposes, was built around a larger computer that provided for more extensive, frequent data sampling and analysis. Generally where parameters were measured redundantly, one of the measurements was provided to the control system and the other to the data computer. Operational parameters (i.e., flow rates, temperatures, pressures, etc.) were displayed at about 30 second update intervals on the control system video display for operator monitoring; data plotting on both systems could be accomplished within a few minutes after an event of interest. Figure 8 is a photo of the control system operator station; Figure 9 is a reproduction of typical data continuously displayed for the operator on the video screen; Figure 10 presents a typical plot from the control system computer; and Figure 11 presents a typical plot from the data computer.

3. Combustor/Steam Generator

The unique portion of this steam generation technique is the direct contact, high pressure combustor/steam generator that produces a mixture of steam and combustion products. A combustor such as this has several potential advantages over a more conventional steam generator system for thermal EOR applications. Examples include elimination of wellbore heat loss when the unit is placed downhole and the possibility that the combined effects of CO₂ and steam act to reduce the viscosity of the oil in the reservoir. In addition, the DSG is potentially a very high combustion efficiency device; this translates directly into overall system efficiency since essentially all of

Figure 8. Control Station for Air/Diesel Downhole Steam Generator

Date 01:05:01

Time 17:21:44

Record # 699
(AIR SYSTEM)

Air temp = 141.52 deg F
Water temp = 58.55 deg F
Fuel temp = 65.09 deg F
Down-hole Steam temp(TC#1) = 445.43 deg F
Down-hole Steam temp(TC#2) = 315.96 deg F

Air press(surf) = 1326.10 psia
Water press = 1203.42 psia
Fuel press = 1271.38 psia

Air mass flow #1(surf-Brooks) = 0.00 lbs./min.
Air mass flow #2(surf-Turbine) = 0.00 lbs./min.
Air mass flow #3(surf-Venturi,b.u.) = 2.96 lbs./min.
Air mass flow #4(surf-Venturi,prim) = 48.88 lbs./min.
Air mass flow(down-hole) = 51.18 lbs./min.

Water mass flow #1 = 82.59 lbs./min.
Water mass flow #2 = .24 lbs./min.

Fuel mass flow #2 = -.53 lbs./min.
Fuel mass flow #3 = 3.41 lbs./min.

Mass flow air to fuel ratio = 14.99
Mass flow water to fuel ratio = 24.17
Steam quality(energy) = .41
Total energy = 4064590.00 btu/hr

Figure 9. Data Sample From Control Computer

** EOF was reached at RECORD # 1699 Only 1690 records will be plotted.
* t calculation may not be correct. 3 Time discontinuities (|) exist in data.

Figure 10. Control Computer Plotted Data Sample -
Downhole Steam Temperature

Figure 11. Data-Computer Plotted Data Sample - Downhole Steam Temperature

the heat lost to the cooling water is reclaimed as the water is mixed directly into the combustion zone. Preliminary tests were performed in which relative amounts of combustion gas species were measured as a function of air fuel ratio; calculations were then made to determine the combustion efficiency. Figure 12 presents a plot of these data. For air fuel ratios between 14 and 15, the efficiency ranged from 92 to 98%; an air-fuel ratio near 15 was chosen as the control parameter.

As shown in Figure 1, the constraints upon the generator for this particular test program were that it fit into a 7-in casing, have a range of thermal output from 2 to 5 million Btu/hour, operate at pressures up to 1500 psi, and produce steam at temperatures up to 500°F and qualities up to 70%. Based on earlier developmental activities, including the propane fired tests at Bakersfield, the burner design shown schematically in Figure 13 was utilized. An inner sleeve (the combustor wall), a middle sleeve (the wall of the steam generation zone), and the outer body of the unit, all made of 310 stainless steel (SS), form concentric annular passages through which cooling water passes. Both the inner and middle sleeves are spiral wrapped with small diameter wire to insure full, turbulent water flow over the entire surface of each sleeve. The final passage of the water carries it downward behind the combustor wall where it enters into the steam generation region at the lower end of the combustion zone. Figure 14 is a photo of the elements before they have been welded together to form the combustor/steam generator assembly.

Diesel enters the top head through a 0.25-in diameter passage along the combustor head centerline. Near the top surface of the combustor, the fuel divides into four 0.024-in diameter ports spaced at 90° intervals around the generator longitudinal axis. At that point fuel from each port enters orthogonally into a corresponding 0.20-in diameter passage through which air is flowing (see combustor head detail in Figure 13). The high velocity air flow breaks up the fuel into droplets suitably small for combustion as the air/fuel

Figure 12. Combustion Gas Species for Air/Diesel Downhole Steam Generator

Figure 13. Schematic of High Pressure Air/Diesel Combustor

Figure 14. Air/Diesel Downhole Steam Generator Elements

mixture flows through four passages and enters the combustion zone at a 45° angle to the generator longitudinal axis. A commercial glow plug with its tip protruding through the top head into the recirculation zone of the combustor is the primary ignition technique; the pyrophoric liquid triethylborane (TEB), injected as a slug into the fuel line on the surface, is the secondary ignition technique.

4. Downhole Instrumentation and Filters

A cylindrical package welded to the top of the combustor/steam generator unit contained filters, pressure and temperature sensors, electrical connections for the glow plug ignitors, instrumentation connections, and check valves in the fuel and water lines. Figure 15 presents a schematic of the first unit placed downhole and Figure 16 is a schematic of the second unit. Major differences between the two units are related to the type of filters in the fluid lines and the temperature sensors. In the first unit, pleated SS mesh filters were utilized. In the second unit the design was changed to provide debris settling chambers and different filter types with both greatly increased areas and larger mesh size. In this redesign the air line was equipped with a 30-ft length of 1 1/4-in diameter cylindrical "sandpoint" (helical wire element) filter with individual openings of 0.06-in x 0.135-in; the water line had a 25-ft length of 3/4-in diameter "sandpoint" filter with 0.015-in x 0.15-in openings, and the fuel line contained a 5-ft length of 1/2-in diameter "sandpoint" filter with 0.004-in x 0.085-in openings followed by a pleated mesh filter.

An electronics package and temperature sensors within the instrumentation/filter package were eliminated in the second unit, permitting a reduction in the instrumentation package length from about 15 to about 6 feet. In the first unit, downhole pressures and temperatures were measured entirely with resistance devices; three resistance temperature devices (RTD's) were located in a closed annulus volume on the tailpipe just below the steam generator to measure the temperature of the generator effluent. In the second unit two

DOWNHOLE FILTER CAN SCHEMATIC (1ST UNIT)

Figure 15. Schematic of Downhole Filter/Instrumentation Package - Unit #1

DOWNHOLE FILTER CAN SCHEMATIC (2ND UNIT)

Figure 16. Schematic of Downhole Filter/Instrumentation Package - Unit #2

RTD's and two type-K (chromel-alumel) thermocouples with continuous sheaths to the surface were placed in this chamber. Figure 17 shows the downhole configuration of the first unit and identifies the six lines that connected the unit to the surface. Figure 18 is a similar schematic for the second unit showing the additional features which resulted in nine lines to the surface.

5. Supply Lines and Well Deployment

At a minimum, three fluids (fuel, oxidizer, and water) required for DSG operation must be supplied to the unit in the well. Further, since the prototypes used in this test program were developmental in nature, additional fluid lines as well as data and instrumentation lines were required. As a result six lines -- a jointed 2 3/8-in air line, a jointed 1 1/4-in water line, two continuous 3/8-in SS tubes, and two electrical cables -- were deployed with the first unit placed into the well in June 1981. Because of modifications to the second unit placed in the well in November 1981, two 1/8-in thermocouple leads and two 3/8-in SS lines were added to the string and one of the electrical cables was deleted. This resulted in a total of nine lines for the second unit. Loads incurred during placement of the units in the well and any loads or stress produced during operation of the unit were carried by the air line. Pulleys were attached to the rig derrick to play the continuous lines off of large spools and into the well.

In the first unit cast aluminum-magnesium alloy clamps were used to attach the four continuous lines to the 1 1/4-in water line at about 30- to 40-ft intervals; the two jointed lines were then banded together at regular intervals with carbon steel bands. Because of serious corrosion which the clamps suffered during the approximate two month interval in the well, the clamps were omitted and banding techniques were used entirely for the second unit. The seven (7) smaller lines and the 1 1/4-in water line were carefully assembled and banded to the air line with SS bands at about 30- to 40-ft intervals. As post-test examinations showed, this latter technique proved entirely satisfactory. All lines were operable after the unit was placed at its downhole location and, as discussed in a later section, the bands were in excellent

Figure 17. Air/Diesel System Downhole Configuration - Unit #1

Figure 18. Air/Diesel System Downhole Configuration - Unit #2

condition when the unit was removed.

6. Well Completion

A sketch of the completed well is shown in Figure 19. The well was completed with a 120-ft long, 2 7/8-in slotted liner in a gravel pack inside the casing that was perforated for a 60-ft interval in the reservoir. Interconnections to the generator are shown in this figure for the first unit placed downhole; for the second unit the changes noted on the figure were made to accommodate the increased number of lines to the unit. Figure 20 shows details of the modified Shafco wellhead for the first unit; for the second unit the wellhead was further modified to include two additional 3/8-in diameter tubing outlets, to delete one of the 1/2-in cable packoffs, and to add feed-throughs for the two 1/8-in diameter thermocouples. For both test periods, the completion was such that the well could be operated with either an open or a closed-in (pressurized) casing.

Figure 21 presents dimensions and details of the first unit as it was installed. The second unit was similar except that the instrumentation and filter package length was decreased from 15.4 feet to about 6 feet. The steam generator, tailpipe, centralizer, and connection to the packer seal assembly were as shown in this schematic for both units.

For the first generator a Baker Oil Tools, Model DA-T "Thermaperm" packer with a fluorocarbon packing element was placed at 2260-ft measured depth. Because this packer was damaged and had to be removed from the well after the initial operational period, LBOD requested that a retrievable packer be used for the second phase of the test program. The packer used was Baker's Packer No. 47B6, model C-2, "Thermoseal" with a high temperature (graphite asbestos composite) packing element. It was placed in the well at 2232-ft measured depth. For both units the locator seal assembly was a Baker Model NT-22 "Thermoseal" with the seals made of a fluorocarbon material.

OPERATIONAL RESULTS

The operational strategy for the test program was guided by the goals of developing operational methods, demonstrating the feasibility of continuous

- NOTES: 1) ALL DEPTHS MEASURED FROM KB: 11' ABOVE GROUND
 2) AVERAGE DRIFT AT BHL = 38°
 3) BHL = 1042' N 74°35'36" W OF SHL

Figure 19. Injection Well Completion

Figure 20. Schematic of SZL-44 Wellhead

Figure 21. Dimensions of Downhole Steam Generator

operation, establishing equipment maintenance/lifetimes, and injecting as much steam and exhaust gases as possible so that reservoir response for this pattern might possibly be compared with that for the oxygen/diesel pattern. This strategy was implemented by a plan whereby the generator was operated initially at lower than maximum thermal output and steam quality, and the output was then increased in steps to the maximum.

As discussed earlier the system was designed to be fully computer controlled with regard to maintaining the pre-selected operating conditions as well as executing automatic shutdowns in the event of situations such as high exhaust steam temperature or loss of flow of any of the fluids. Restart of the unit, of course, did require operator interaction to set up the start conditions, to sequence the computer control system, and (after the glow plugs became inoperable) to valve the TEB into the fuel line at the proper point in the computer start sequence. The site was staffed at all hours, during the day by Sandia engineers and/or technicians and at night by locally hired non-technical personnel who hourly recorded operational data and performed general observations. Sandia personnel were notified of any abnormality and directed the necessary response. Shutdowns were always responded to immediately and restarts usually carried out as soon as possible, regardless of the hour.

The following sections describe the operational history, the removal sequence, and the post-test examination for each of the air/diesel units operated downhole.

1. Operational History - Unit #1

The different parts of the system arrived and were assembled at the Long Beach test site during March and April 1981. Initial surface firing of a system checkout generator prototype was accomplished on April 14, 1981.

Intermittent operation with this unit continued until the actual downhole test unit arrived; that generator was interconnected into the system and surface operated on a checkout basis beginning on May 20. Injection of surface generated steam/combustion gases into the reservoir through an uninsulated work string occurred on an intermittent basis throughout the latter part of May.

Intermixed with these steaming operations, the air compressors were operated additionally to check system operation and to assess the injectivity of the well as originally completed by LBOD. As a result of initially restricted air flow and high injection pressures, the well was recompleted by extending the length of perforations in the casing and adding a gravel packed, slotted liner to obtain the final configuration shown in Figure 19.

The downhole unit was picked up (see Figure 22), placed atop the packer locator seal assembly, and placed over the well in preparation for run-in late on June 16, 1981. Run-in of the unit was started on June 17 (see Figure 23). The continuous tubing was fed from large spools and each joint in the air and water lines was hydrostatically tested after makeup. The locator-seal was positioned in the packer on June 18 and final wellhead connections were made on June 19. Air flow was started immediately and continued into the well through June 20 and 21. After final system checkout, combustion in the generator was started under computer control late on June 22, 1981. Typical parameters for this initial operational period are shown in Table 2.

Immediately after start of operation it was evident that two of the three downhole temperature resistance devices (RTD) were faulty, a condition which had been suspected during the earlier air flow tests. Further, the final RTD and the resistance pressure devices (RPD) all became unreliable, as evidenced by erratic high and low readings early in the initial period of sustained operation. This condition not only made confirmation of combustion difficult but, because of erratic false readings, it also presented potential difficulties with high and low temperature automatic shutdown controls in the computer logic.

A second parameter that became a source of concern was the surface water pressure, which gradually increased from near the initial 1250 psi operating pressure shown in Table 2 to about 2500 psi operating pressure during the first week of operation. Similarly, gradual but less severe buildup of the surface air pressure became apparent. Since there was no corresponding pressure increase in the surface fuel pressure, it was evident that the downhole air

Figure 22. Start of Air/Diesel Downhole Steam Generator Installation

Figure 23. Air/Diesel Downhole Steam Generator Starting into Well

TABLE 2

Typical Air/Diesel Operating Conditions

Test #1

FUEL	1.75 lb/min
AIR	26 lb/min
WATER	55 lb/min
AIR/FUEL RATIO	14.7
FIRING RATE	2.1 MM Btu/hr
QUALITY	38%
PRESSURE	1250 psi
TEMPERATURE	330°F (Est.)

and water filters were gradually plugging. Both the air and the water filters were treated during down periods -- the water filter with hydrofluoric acid and the air filter by opening the air line at the surface to backflow through the filter and blow out the debris.

Figure 24 presents a summary of the key events from the initial run-in of this generator until it was pulled from the well in early August. Figure 25 shows the operational history and steam injection rates. The first shutdown, due to overheating of the air compressor first stage, occurred on July 2 following 10 days of continuous operation. Compressor repair required 12 days and the unit was successfully restarted on July 14. Two days later cooling water to the generator was lost when a fuse on the low pressure water supply pump motor electrical circuit opened. Fuel flow and combustion continued however, as the automatic low-water-flow shutdown safeguard had been removed from the computer control logic during some earlier, low-flow checkout tests. The absence of the safety shutdown logic and the continuing, unreliable behavior of the RTD's allowed the unit to continue operation. After a period estimated to be about 10 minutes, the high pressure water pump was found to be cavitating and a manual shutdown was executed.

Following reestablishment of the water supply, a computer restart was carried out and an increase in the downhole steam temperature as indicated by RTD output was observed. During the next two weeks a number of shutdowns were incurred as a result of surface electrical problems, control computer power interruptions, compressor shutdown, and downhole air filter cleaning operations. However a more serious problem during this entire period was the increasing uncertainty as to whether combustion was occurring in the unit, an uncertainty brought about by the continuing degradation of the downhole instrumentation.

On July 27 arrangements were made to sample the generator effluent through the caustic injection line (see Figure 17 for its location in the generator tailpipe). Absence of any significant level of either CO_2 or CO in the sample confirmed the unit was not burning. Repeated glow plug starts followed by

Figure 24. Highlights of Downhole Steam Generator Test - Unit #1

Figure 25. . Injection History for Downhole Steam Generator - Unit #1

several attempts to start the unit using TEB, the secondary ignition system, failed to provide any distinct evidence of combustion. The unit was therefore removed from the well on August 6-7 and the generator/instrumentation package was returned to Albuquerque for examination in view of preparing a second unit to be returned to the test site.

In summary the first unit operated at nominal condition for at least 12 days and may have operated for up to 22 days total. Figure 25 summarizes this initial period of operation related to injection rates and operational problems. No shutdowns resulted from the generator itself; all were due to failure of surface support equipment. The loss of cooling water, the event that most likely caused generator damage, should have resulted in shutdown without damage. This did not occur due to the earlier removal of and subsequent failure to re-instate, the control low-water-flow shutdown logic and to the degraded state of the RTD's which did not show a high temperature condition.

2. Removal - Unit #1

For most of the downhole length, removal of the generator from the well proceeded uneventfully. The aluminum-magnesium (al-mag) clamps and steel bands were all in place with minimum evidence of corrosion or degradation. The water line contained some scale on its inner wall while the air line was relatively clean; the continuous SS tubes and power cables were all intact. However at about 500 to 700 feet above the bottom of the string, loss of some carbon steel bands was noted and corrosion of the al-mag clamps became noticeable. For the last 100 to 150 feet of the string, neither the bands nor the clamps were found in place. Figure 26 shows both the pre- and post-test condition of the clamps; clearly these materials are not satisfactory for this use. As the unit neared the surface, the tubing and electrical cables were found to be tangled and damaged, probably as a result of slack created due to failure of the bands and clamps near the top of the generator.

Other observations included scale and corrosion on the outer surface of both the air and water lines and evidence of thermal damage to the tailpipe

Figure 26. Pre- and Post-Test Condition of Downhole Tubing Clamps - Unit #1

stinger and to the elements of the packer locator seal assembly. The locator had "necked" down in the area of the seal assembly and considerable mass loss from the fluorocarbon seals was evident; both observations suggested overheating and thermal damage. Tests by LBOD confirmed that the packer in the well would no longer hold pressure. It is possible that the few minutes of operation without cooling water may have been responsible for the apparent loss of packer integrity; in any event removal and replacement of the packer was necessary.

3. Post Test Examination - Unit #1

The post test analysis sequence included a series of observations on the general state of the unit, pressure and electrical checkout, and finally disassembly and internal inspection. Externally the generator and instrumentation package, made of 310 SS, showed no evidence of corrosion or any other type of damage (i.e., overheating). A number of leaks were found in the SS tubes and fittings which encased the data transmission cables along side the generator. Leaks of this kind would allow fluid from the annulus to leak into the system. Specifically, the annular volume in which the RTD's were located (see Figure 17) was found to be filled with liquid that had in all probability entered through leaks in the tubing in which the RTD's leads were contained along the outside of the generator. The RTD leads were corroded/rusted in their housings. Evidence in the form of heavily corroded ordinary steel and aluminum parts, which suggested that the entire instrumentation package had been substantially filled sometime during the operation, was also found.

Within the instrumentation package, both the air and the water filters were filled with debris and collapsed; presence of debris was expected based on the previously discussed pressure increases observed in both fluid lines during operation. A flexible SS coupling in the air line below the filter was ruptured. The fuel filter was found to be clean, again a condition consistent with the lack of fuel pressure increase during operation.

The final step in the post test analysis was to separate the combustor/steam generator from the instrumentation package and cut it apart for internal

examination. The resulting observations were consistent with what one would expect from loss of cooling in a region filled with high temperature combustion gases. As stated earlier water flows through annular passages to cool the unit and then enters directly into the combustion products at a point just below the combustion zone to form the steam. The entire inner sleeve - the wall of the combustor - was melted away. Further, the top 12 to 18 inches of the middle sleeve had also melted away. Some molten debris was found on the burner head and in the glow plug cavities, but most of the debris was found at the bottom of the burner in the tailpipe. The air passages into the burner were open but two of the four fuel injection ports were plugged with debris. Although no attempts were made to fire the unit on the surface after its removal, its general condition strongly suggested that stable operation was not possible. Figure 27 summarizes the findings on Unit #1 after removal from the well.

4. Operational History - Unit #2

A second test unit, with the combustor/steam generator portion identical to the first unit but with modified filter and electronics elements, was connected on the surface and test fired in October 1981. Operational data, including temperatures, pressures, and exhaust gas composition, were obtained for comparison with downhole data. The unit, now with two jointed and seven continuous lines, was uneventfully placed into well SZ1-44 in mid-November. As before, the continuous tubing was rolled from large spools and each joint in the air and water lines was hydro tested after makeup. After final supply and data line connections and checkout were completed, combustion and steam injection were initiated on November 15, 1981. Plans called for the unit to be operated at less than maximum output for an initial period (Phase I) to be followed by extended operation at full power (Phase II). Table 3 presents typical operational parameters for each of these periods. Maximum thermal output of the generator, about 4.0 MM Btu/hr, was determined not by the combustor/generator itself, but rather by the maximum output (~49 lb/min) of the air compressor system. Throughout the test period the generator was operated

- **TUBING CLAMPS BADLY CORRODED:
SS TUBING TANGLED DURING UNIT REMOVAL**
- **EXTERNAL CORROSION OF AIR AND WATER LINES**
- **LEAKS IN SS TUBING NEAR UNIT**
- **SIGNIFICANT DEBRIS IN AIR AND WATER LINES
AND FILTERS: FILTERS RUPTURED**
- **CORROSION WITHIN FILTER CAN**
- **SIGNIFICANT MELTING OF COMBUSTION LINER**

Figure 27. Summary of Removal and Examination -
Unit #1

TABLE 3

Typical Air/Diesel Operating Conditions

TEST #2 PHASE I

FUEL	1.7-2.6 lb/min
AIR	26-44 lb/min
WATER	52-73 lb/min
AIR/FUEL RATIO	14.9
FIRING RATE	3.2 MM Btu/hr.
QUALITY	35%
PRESSURE	1300 psi
TEMPERATURE	440°F

TEST #2 PHASE II

FUEL	3.3 lb/min
AIR	49 lb/min
WATER	84 lb/min
AIR/FUEL RATIO	14.8
FIRING RATE	4.0 MM Btu/hr.
QUALITY	40-50%
PRESSURE	1380 psi
TEMPERATURE	440°F

to produce steam at about 40 to 50% quality; plans called for eventual operation at up to 70% quality but the test program was terminated before this was accomplished.

Figure 28 presents the operation and injection history; injection was terminated in late February. Table 4 presents explanations for each shutdown incident shown on Figures 25 and 28, Table 5 provides a tabulated summary of the shutdowns as well as the total run time, and Table 6 provides hours down and fraction of the total hours down for each of the different system elements. The air compressors accounted for about 1/3 of the shutdown incidents and for about 2/3 of the non-operational hours. Instrumentation malfunctions (mainly momentary, very high temperature readings that proved to be erroneous) and computer initiated shutdowns that occurred during switch-over from automatic-to-manual control were the other major causes of shutdown incidents.

Initially both exhaust gas composition and condensed steam samples were withdrawn from the generator exhaust through the sample line. Table 7 presents typical gas composition data for this initial downhole operation period along with similar data taken on the surface before the unit was placed down hole and again after it was removed. The data, specifically the presence of 12 to 13% CO₂, provide independent confirmation of generator operation. The condensed steam samples were used to assess the effect of the caustic (NaOH) added to the generator exhaust. The pH reading of the effluent without treatment was about 2 or 3 and it was the intent to add sufficient caustic to maintain the pH level near 7. After about one month of operation, problems were experienced with both sample extraction and caustic addition. The sample line became plugged during one of the shutdowns and a period of very high pressures in the caustic injection system suggested that line may also have plugged and perhaps ruptured in the casing annulus. Thus, for much of the operation, gas samples were not possible and while the caustic pump was kept in operation except for short repair periods, it is not known for certain that the fluid went into the generator effluent.

With the exception of the downhole resistance pressure and temperature

TABLE 4

Air/Diesel System Down Times

1. - COMPRESSOR SHUTDOWN	
2. - BLOWN FUSE IN POWER CIRCUIT TO WATER PUMP	
3. - DELIBERATE SHUTDOWN TO BACK FLUSH FILTER	
4. - BLOWN FUZE IN FUEL CONTROL CIRCUIT	UNIT # 1
5. - COMPUTER HUNG UP	
6. - COMPUTER HUNG UP	UNIT # 2
7. - WATER SUPPLY PUMP LOST POWER	
8. - SERVICE COMPRESSORS	
9. - FUEL GAGE OUT ON COMPRESSOR	
10. - SERVICE COMPRESSOR	
11. - COMPRESSOR SHUTDOWN	
12. - COMPRESSOR SHUTDOWN	
13. - COMPUTER SHUTDOWN	
14. - COMPRESSOR SHUTDOWN	
15. - COMPRESSOR SHUTDOWN	
16. - COMPUTER HUNG UP	
17. - COMPRESSOR SHUTDOWN	
18. - HIGH TEMPERATURE SHUTDOWN	
19. - COMPUTER HUNG UP	
20. - HIGH TEMPERATURE SHUTDOWN	
21. - LOW TEMPERATURE SHUTDOWN	
22. - LOW TEMPERATURE SHUTDOWN (2)	

TABLE 5
Air/Diesel Test Statistics

	TEST #1 6/22/81 - 7/26/81	TEST #2 11/15/81 - 2/26/82
TOTAL HOURS	814	2484
TOTAL RUN TIME, hrs.	469	1934
PERCENT RUN TIME	58%	78%
NUMBER OF STARTS OR ATTEMPTED STARTS		
GLOW PLUGS	9	23
T.E.B.	4	20
NUMBER OF TIMES DOWN		
AIR SYSTEM	2	8
WATER SYSTEM	2	
FUEL SYSTEM	1	
CONTROL COMPUTER	1	4
INSTRUMENTATION		5
ELECTRICAL		2
PLANNED		2
GENERATOR		<u>3</u>
TOTAL	<u>6</u>	24
TOTAL BARRELS OF WATER INJECTED	4,320	27,000

TABLE 6
Air/Diesel Down Time Statistics

<u>SYSTEM ELEMENT</u>	<u>INCIDENTS</u>	<u>HOURS DOWN</u>	<u>FRACTION OF TOTAL HOURS DOWN</u>
AIR SYSTEM	8	355	.65
CONTROL COMPUTER	4	33.5	.06
INSTRUMENTATION	5	52.5	.10
ELECTRICAL	2	11.5	.02
GENERATOR	3	29	.05
PLANNED	2	8.5	.01
GLO PLUG FAILURE		<u>57</u>	<u>.11</u>
TOTAL		547	1.0

TABLE 7
COMPOSITION OF NONCONDENSIBLE GAS IN
AIR/DIESEL STEAM GENERATOR EXHAUST

<u>Date Sample Taken</u>	<u>Nitrogen</u>	<u>Carbon Dioxide</u>	<u>Carbon Monoxide</u>	<u>Oxygen</u>	<u>Hydrogen</u>	<u>Hydrogen Sulfide</u>	<u>Ethane</u>	<u>Methane</u>
10-21-81 ⁽¹⁾	67-75	12-21	ND-2	1.0	ND-1	ND	ND	ND
11-15	83.2	13.4	0.5	1.0	0.3	ND	ND	ND
11-20	79.2	13.3	0.5	1.0	0.4	ND	ND	ND
11-26	81.1	13.0	ND	1.0	0.8	ND	ND	ND
12-1	76.2	12.6	0.6	1.0	0.4	ND	ND	ND
12-5	72.0	12.1	0.4	1.0	ND	ND	ND	ND
12-12	80.7	12.3	1.5	0.9	0.8	ND	ND	ND
4-7-82 ⁽²⁾	74.2	10.6	0.3	2.1	--	--	--	--

All values given in percentage by volume

ND - below detection limit

(1) Surface burn; ranges represent multiple samples taken for a variety of air/fuel ratios.

(2) Post test surface burn; unburned carbon was also found in the steam condensate.

measuring devices (RPD's and RTD's), instrumentation on the system performed as designed. Similar to the tests with Unit #1, both the RPD's and RTD's worked initially but became erratic and unreliable within a few days. Figure 11 illustrates the good agreement between RTD and thermocouple data for the downhole steam temperature early in the program before the RTD failed. Three shutdown/restart incidents, each of which illustrates the clearly desirable changes that occur in the exhaust temperature, are included. Post test examination indicated that the RTD sensing elements were flooded, probably due to small leaks at downhole splices in the tubing which encased the electrical leads. The downhole thermocouples functioned reliably until near the end of the program. Post test examination revealed that steam from a cracked weld in the exhaust pipe jetted directly onto the thermocouple leads and eventually penetrated the SS sheaths, permitting the leads to become wet. Clearly, neither technique can maintain its calibration under those conditions. No significant increases in any fluid pressures were seen; the filter design modifications and/or the improved water/air treatments incorporated into Unit #2 eliminated debris build-up in the filters.

Initially the well was operated with an open casing. However, after 15 days and a few shutdowns and restarts, excessive fluid leakage rates at the wellhead required that the annulus be closed. Therefore, for the majority of the test period, operation was in the shut-in mode with casing pressures from 500 to 900 psi at the surface.

Figure 29 presents the air mass flow, generator output and surface air pressure parameters over the entire period of testing. As expected, air (and thus injection) pressure correlates with mass flow rates. Of more interest is the absence of any long term, gradual increase in injection pressure that would indicate either plugging of the reservoir or blockage of the filters.

Ignition was initially carried out using the glow plugs; however, after only 10 restarts and one month of operation, repeated attempts to restart the generator were unsuccessful. A number of attempts which included increased current and voltage levels, series and/or parallel connections of the two

Figure 29. Pressure, Air Flow and Energy Conditions - Unit #2

plugs, and extended on-time durations were tried without success. At that point the first downhole ignition using the backup system was carried out. Approximately 4 liters of triethylborane (TEB) were valved into the fuel line as a "slug" preceded and followed by diesel. Flow rate calculations provided an estimate of the time required for the TEB to reach the burner and temperature increase was noted within 1 minute of the estimate. Thereafter TEB was routinely used to start the burner and the only unsuccessful attempts resulted when insufficient quantities of TEB were injected. No operational problems (e.g., fires) were experienced throughout the program; the method proved very reliable.

Operation of the system continued until the end of February 1982 at which time a sudden change in the burner behavior was noted. This new behavior was characterized by a sudden exponential-like decay in the steam temperature from the nominal operation condition ($\sim 440^{\circ}\text{F}$) to a value near the reservoir condition ($\sim 100^{\circ}\text{F}$). Figure 30 illustrates this behavior and can be compared with corresponding data from Figure 11. The short run time shown on Figure 30 was repeated on a number of occasions in this final stage of downhole operation. Since it was no longer possible to sample the exhaust gases as a means of confirming combustion, the thermocouple output was the only indication of burner operation. Although there was also some concern regarding the reliability of the thermocouples, it was concluded (after a careful study of the temperature data obtained from a number of restart-temperature decay incidents) that the unit should be removed from the well.

5. Removal and Surface Testing - Unit #2

Removal of the unit required about 16 hours. All continuous tubing, including the 1/8-in diameter thermocouple leads, was rewound onto spools. Figure 31 summarizes the significant findings of the removal and external inspection of the unit. All of the SS bands used to tie the tubings together remained in place; no breaks, tangles or loosened sections were found. As suspected during operation, the sample line had become plugged. In addition a crack was found in a fitting that joined the caustic line to the generator

Figure 30. Downhole Steam Temperature Response for Ignition and Sudden Loss of Combustion

- **Removal w/o incident, tube banding satisfactory**
- **Only external damage was crack in SS tailpipe weld**
- **Sample line plugged**
- **Possible leak in caustic line**
- **Thermocouples damaged by steam leak thru weld crack**
- **Evidence of corrosion on tailpipe below packer**
- **Minimum debris in filters**
- **Surface operation confirmed burner instability**
 - **Soot in burner effluent**
 - **High CO and O2 levels in effluent gas**
 - **Cracks in burner walls- water leak**
 - **Sudden combustion termination and temperature decay**

Figure 31. Summary of Removal and Examination - Unit #2

housing, providing further evidence that some unknown fraction of the caustic may have been injected into the annulus rather than into the generator exhaust pipe. Other visible damage to the exterior included: (1) a circumferential crack extending about half way around the weld joining two sections of the SS exhaust pipe below the burner but above the packer, (2) damage to the thermocouple lead sheathing at a point where steam jetting from this crack would strike the sheathing, (3) and significant corrosion to a piece of carbon steel pipe at the very bottom of the exhaust pipe below the packer. The filters were very clean except for a piece of rubber (likely dropped into the line during hydrostatic testing of the joined pipe) and a small amount of "rust" debris located atop the water filter.

Pressure checks were made on the generator at the Long Beach site and no unusual results were detected. A boroscope was used to examine the internal walls of the combustion chamber; the examination showed water leaking into the combustion zone, suggesting perhaps a crack in the combustor walls. With this information, the unit was connected to the supply lines for post test operation. A nominal TEB start was carried out; combustion was initiated with nominal pressure and flow conditions but operation continued for only about 4 minutes. The exponential-like decay in steam temperature that was observed in the final period of downhole operation was repeated in these surface tests, confirming that the downhole response was a combustion stability phenomena rather than a thermocouple reliability problem. Two subsequent restarts produced combustion for only 5 and 3 minutes with similar, sudden shutdowns. Steam condensate and combustion gas samples were taken during these short burn periods. The condensate samples contained significant soot (unburned carbon) and, as indicated in Table 7, the combustion gas products contained relatively low levels of CO_2 and high levels of CO and O_2 . All of these findings were different from corresponding data obtained during surface tests before the unit went downhole and during the first month of downhole operation. This response confirmed that stable, complete combustion was no longer possible in the unit, and based on these findings, the burner was shipped to Albuquerque

for complete analysis.

6. Post-Test Examination - Unit #2

Since pressure checks were performed at the Long Beach site and no additional unit-type tests were appropriate, the generator was cut apart so that the various components, and particularly the combustor, could be examined. Figure 32 is a photograph of the disassembled unit; Figures 33-36 are close up views of key elements. The most significant information in these figures, related to the inability to maintain combustion in the downhole generator, is contained in Figure 33, a photograph of the combustor head, and in Figures 34 and 35, photographs of the combustion chamber. Corrosion and degradation of the 310 stainless steel walls are evident. Mass loss and surface cracks, some extending well into the material, are observed on the inside walls of the combustor. Apparently this was the cause of the unstable combustion behavior that was observed at the end of the 3 1/2-month test period. Two ways in which mass loss and/or surface cracks could cause unstable combustion are: (1) fuel enters into the combustion chamber through cracks in such a way that proper fuel/air mixing and complete combustion are not attained, and (2) water enters into the combustion zone through cracks in the combustor wall and cools the reaction before the combustion process is complete. A photograph of the stinger, the very bottom section of the exhaust pipe, is shown in Figure 36. Significant corrosion of this carbon steel pipe is also evident. Samples from these components and from other portions of the downhole assembly were selected for metallurgical analyses. Results of these analyses, along with the results of metallurgical studies from selected parts of the oxygen/diesel system, are reported in a companion report (23). The corrosion processes were studied and recommendations, including alternate materials for the combustor, are presented in that report.

RESERVOIR RESPONSE AND EFFECTS

As shown in Figure 5, the air/diesel DSG was operated near the center of a 5-acre, inverted 5-spot pattern. The production wells were monitored by LBOD for oil production and water/oil ratio and by Sandia for casing gas pressure,

Figure 32. DSG Unit #2 Prepared for Post Test Examination

Figure 33. Post Test View Into Combustor Head - Unit #2

Figure 34. Post Test Combustion Chamber Exterior - Unit #2

Figure 35. Post Test Combustion Chamber Interior - Unit #2

Figure 36. Post Test View of Exhaust Pipe Stinger - Unit #2

temperature and composition. The sampling program was started prior to the earliest steam injection in Test #1 and continued for a period of about two months after injection was terminated in Test #2. Casing gas pressure data, and in some cases the gas temperature data, were on occasion affected by other field operations that LBOD performed. However a large fraction of the temperature data and all of the gas composition data can be used in an effort to understand the interaction and effects of the downhole steam generator on the reservoir. Gas composition was characterized as to the percentages by volume of carbon dioxide, carbon monoxide, hydrogen, hydrogen sulfide, nitrogen, nitric oxide, nitrous oxide, oxygen, sulfur dioxide and hydrocarbons including methane, ethane, propane, butanes, and pentanes.

1. Description of Gas Sampling Equipment

Gas composition data were obtained with two systems; a gas chromatographic system and a mobile instrumented van. By far the largest fraction of the data was obtained using the gas chromatograph whereas the instrumented van was developed primarily as a means to gather NO_x and SO_x data.

The gas chromatograph was equipped with a thermal conductivity detector (TCD), a flame ionization detector (FID), and a hydrogen transfer system. High-pressure, stainless-steel bottles were used to collect samples from the generator and the wells with a specific bottle dedicated to each well and generator. Daily calibrations were performed by flowing certified calibration standard gases through the instruments and adjusting to the prescribed values. Estimates of precision of the data, taking into account the steps in the entire process, are better than 5% for TCD measurements and 1% for FID measurements except at high (80%) concentrations of CO_2 , methane or nitrogen.

The mobile van consisted of a gas sample conditioning system, gas analyzers, and an automatic sample and data handling system. The system was designed to handle either hot, wet generator effluent or relatively dry, warm gases such as those from the wells. Sample conditioning consisted of drying, separation, filtering, and pressure adjustment. A chemiluminescent gas analyzer was used for the NO and NO_2 measurements and a photometric analyzer was used for the

SO₂ measurements. Volume percentages of hydrogen, oxygen, carbon monoxide, and carbon dioxide could also be determined from instruments in this van. The system used a sample gas stream for analysis and the sampling/data system controlled the process on a continuous, automatic basis.

2. Communication of Exhaust Gases with Production Wells

Production well pressure data were obtained but were difficult to interpret because of field adjustments periodically made by the operator. Sudden pressure increases, ranging from 50 to 100% of the previous values, were seen in three of the four production wells within one or two days after initiation of combustion. However similar changes that were seen at other times were difficult to correlate with DSG operation. By far the most reliable data on well communication was the casing gas composition data. Table 8 presents the composition of the casing gas for each of the production wells for both "before steaming" and "after steaming." Before steaming the casing gas from all wells is predominantly methane with small amounts of nitrogen, CO₂, oxygen, and ethane. Sharp increases in the volume percentages of nitrogen and oxygen together with the appearance of trace amounts of CO can be used to confirm the presence of gases from the DSG exhaust in the production wells.

Figure 37 shows the 5-spot injection pattern for the air/diesel system along with the corresponding pattern for the oxygen/diesel system. Shown on the figure are volume percentages of nitrogen, oxygen and carbon monoxide together with the dates on which the gases were first detected. Well Z-235, the nearest well up-dip of the air/diesel DSG injector well and in a direction of decreasing pressure, was the most responsive of the four in the air pattern; wells Z-99 and Z-225 were only slightly less responsive. All experienced a sharp increase in nitrogen within two days of the start of steam/exhaust gas injection. Well Z-233, the most distant well down-dip of the injector and in a direction of increasing pressure, was the last well in the air/diesel pattern to see pressure and gas composition changes; these occurred in about 9 days. Nitrogen was detected in Z1-37, the well in the oxygen/diesel pattern that is nearest to and up-dip of the air/diesel pattern, in 7 days and in J-75,

TABLE 8
Gas Compositions

		AIR-PATTERN WELLS				AIR DIESEL DSG
		GAS	Z-99	Z-233	Z-225	Z-235
BEFORE STEAMING	CH ₄	80-90	88-95	70-80	70-85	ND
	N ₂	2-5	0.2-0.5	4-8	5-8	72-85
	CO ₂	2-3	2-3	4-6	1-2	12-13
	CO	ND	ND	ND	ND	0.5-1.5
	O ₂	0.03-0.05	ND	0.06-0.2	0.1-0.2	0.9-1.0
	H ₂	ND	ND	ND	ND	0.6-0.8
	SO _x	NT	NT	NT	NT	0-1 ppm
	NO _x					
AFTER STEAMING	CH ₄	15-25	20-40	10-20	6-15	
	N ₂	60-75	45-60	68-80	65-80	
	CO ₂	3-5	3-5	4-6	6-10	
	CO	ND,T to 0.05	ND,T	ND,T to 0.1	ND,T to 0.2	
	O ₂	0.6-1.0	0.2-0.7	0.6-1.0	0.6-1.0	
	H ₂	ND	ND	ND	ND	
	SO _x	0-0.4 ppm	ND	0-0.6 ppm	0-2 ppm	
	NO _x					

NO_x MEASUREMENTS MADE BUT DATA INTERPRETATION NOT COMPLETE

DATA IN % BY VOLUME

ND - NOT DETECTED

NT - NOT TAKEN

T - TRACE, DEFINED AS <0.01%

Figure 37. Gas Breakthrough Times and Analyses

the most distant well, on the 97th day. Thus the injected gases spread to all of the sampled wells but moved most rapidly up-dip and in a direction of decreasing pressure; gases from the air/diesel system were dominant in the oxygen/diesel as well as the air/diesel pattern.

3. Reservoir Absorption Effects

In addition to the timing and direction of the DSG exhaust gas migration, reservoir absorption effects can also be examined. Of particular interest from an environmental standpoint is the movement of CO, SO_x and NO_x. As shown in Table 8 the exhaust gases injected into the reservoir contained from 0.5 to 1.5% CO by volume and from 72 to 85% nitrogen, a ratio of CO to nitrogen ranging from 6×10^{-3} to 2×10^{-2} . For the operational period November 15, 1981, through February 26, 1982, casing gas samples were taken on a near daily basis through early April from the four production wells in the 5-spot air/diesel DSG pattern. For about 85% of those samples no CO was detected, for about 8% a trace (<0.01%) of CO was found, and in only about 7% of the samples was a measurable quantity (>0.01%) of CO found. The measured CO was never greater than 0.2%, whereas nitrogen was measured in quantities up to 80%; therefore the CO to nitrogen ratio in the production gases was thus never greater than 2.5×10^{-3} . By comparing this ratio to the corresponding ratio for the combustor exhaust gas one concludes that even in those relatively few occasions when some CO was detected in the casing gas, it had been reduced, compared to the nitrogen, by a factor of 3 to 10. Thus, the reservoir appears to be very effective in removing CO, at least in this time frame.

Similar statements can be made for hydrogen, which was present in measurable quantities in the generator exhaust but was not detected in the casing gas. On the other hand, oxygen was found in the production gases in approximately the same proportion, relative to nitrogen, as measured in the injected gases. Very limited SO_x data were obtained due to continual problems with the mobile van sampling equipment and no conclusive remarks can be made about reservoir scrubbing of that gas species. Results for NO_x are also inconclusive because of data interpretation uncertainties. These uncertainties involve

possible interactions between different gas species in the casing gas that might have occurred as the samples were being analyzed. If this proves to be the case, recalibration of the instruments will be necessary before any conclusions can be made; this question is presently under study.

Since one of the possible advantages of a direct contact, downhole steam generator is the combined effect of CO_2 and steam, CO_2 movement is also of primary interest. Because absolute mass flow rates at the production wells were not measured for any gas species, one must infer information from relative comparisons of the volume percentage of the species of interest. Figure 38 shows the variation with time of the CO_2 /methane (C_1) and CO_2 /nitrogen ratios for two wells in the air system pattern. For simplicity the ratios have been normalized by their maximum values for each well; results for the other two wells were similar. For both wells the CO_2 /nitrogen ratio is seen to increase with time as steaming continued. The curves suggest that the reservoir fluids initially preferentially absorbed the CO_2 but that the mechanism eventually saturated. In fact the maximum value of the CO_2 /nitrogen ratio was reached after steam and air injection had ceased. This suggests that the drop-off response of nitrogen was more rapid than that of CO_2 , an observation consistent with the previously discussed rapid movement of nitrogen to the production wells after the start of injection.

The CO_2/C_1 ratio also increases with time in both wells, further suggesting that the CO_2 is initially absorbed by reservoir fluids, but the process leads to saturation of CO_2 . As illustrated during the period of burner shutdown in late January, these curves on Figure 38 correlate particularly well with periods of burner operation. Very quickly after burner combustion ceases, the methane percentage increases and becomes the predominant gas species in a return toward the pretest condition. However during any period of sustained burner operation (e.g., the month of January), after the methane percentage has become essentially constant, there is a distinct increase in the amount of CO_2 relative to the methane.

Figure 38. Normalized CO₂ Levels in Production Well Casing Gas

4. Effect on Production

Data provided by LBOD on the total fluid as well as the oil production from each of the four wells identified only one well where production changes could possibly be correlated with operation of the DSG. That well, Z-235, was also the one that was most responsive in terms of the first appearance of nitrogen and other combustion gases in the casing gases. Figure 39 presents plots of key data from well Z-235 that relate to changes thought to be caused by injection of steam and exhaust gases from the DSG. Oil production increased from about 50 to 60 bbl/day in mid-81 and before, to a peak near 100 bbl/day in early 82; production is seen to drop sharply to the mid-81 values after operation of the DSG was terminated. During the period of increased production, the water/oil ratio decreased from about 30 to about 15, confirming that the increase in oil production did not result from an increase in total produced fluids. In addition, early in January 1982 the casing gas temperature increased from a uniform and constant 126°F to about 133°F and continued there for the duration of steam injection. This increase is a strong indication of contact of the injected thermal energy with the production well. None of the other three wells showed any changes similar to these, and in fact the pattern-averaged production for the four wells was unchanged.

The nitrogen and CO₂ data shown on Figure 38 illustrate characteristics that were discussed previously, namely, the very rapid response of well Z-235 to injection of nitrogen into the pattern. The gradual increase in the amount of CO₂ in the casing gas is also shown.

SUMMARY AND CONCLUSIONS

The goals that guided this field test, presented in Figure 1, are discussed in earlier sections of this report. The broad objective - to develop, install and operate a downhole high pressure, direct contact steam generator in an oil field environment - was satisfied. The 3 1/2-month operation and steam injection period not only demonstrated the technology, but it also identified some specific areas where modifications to both the DSG and the operating system can improve the 78% on-line record of this unit and extend the 3 1/2-month

Figure 39. Summary Data for Well Z-235

operational lifetime. The decision to terminate the field test program, after it became apparent in late February that reliable burner operation could not be verified in the unit downhole, was based on a variety of factors. These included a change in emphasis for the Department of Energy's efforts in enhanced oil recovery and the desire of Long Beach Oil Development Company to build upon these tests and place a commercial downhole steam generator into the particular injector well being used. A Sandia backup combustor/generator could have been deployed almost immediately in this well, but the aforementioned constraints would only have resulted in another injection period of 3 to 4 months. Since this would have been essentially a duplication of the test period described herein and would have presented no new data on operational lifetime, the field test was terminated. The following is a summary of specific findings, conclusions, and recommendations.

1. Installation and removal of a downhole steam generator were demonstrated. The nine lines used in this developmental test program almost certainly are greater than will be required for commercial applications. However even this number was easily handled in this well which had a 38° downhole drift. A trip in or out of the well required two to three 8-hr shifts for this 2200-ft depth; experience along with a reduced number of lines will most certainly reduce this requirement.
2. System control was demonstrated and in fact can be accomplished with a significantly less complex system than that used in these tests. Unattended operation, while not attempted in this program, is clearly feasible. In the 3 1/2-month test operation of Unit #2, all shutdowns were implemented by the control computer without any system damage. Other than the single, undetected loss-of-water incident that caused damage to test Unit #1, all out-of-bound parameters were detected by the control system and operation safely stopped. The cause of that single incident was identified and corrected.
3. Reliable restart of the DSG using triethylborane (TEB) was demonstrated. Glow plugs were found to have a very limited lifetime and their use in

future operation is not recommended. No safety or handling problems were experienced with TEB; techniques to valve the fluid into the fuel line proved very straightforward.

4. These tests emphasized the need for reliable surface support equipment. In particular, the air compressor system used in these tests was the single, most frequent cause for shutdown; it was the cause of about two-thirds of the non-operating time.
5. Satisfactory treatment and filtering of the fluids pumped downhole were demonstrated. Although the filter area and the micron size openings in the filters in Unit #1 proved unsatisfactory, in-line "sandpoint" filters, several feet in length and with openings on the order of a few thousands of an inch, proved entirely satisfactory in the second unit. Standard water softening and oxygen scavenging techniques on the surface proved satisfactory as did surface-located, micron size filters on each fluid line.
6. No adverse effects on the reservoir were seen in the several month time frame of these tests. Injection pressure, while clearly showing a dependence on air flow rate, remained essentially constant throughout the last two months of the injection period when the mass flow rate was maximum and constant.
7. The primary area of concern based on these tests is related to the metallurgy of the entire unit. Corrosion of the metal combustor walls was the cause of unstable combustion in the unit and was therefore responsible for removal of the burner from the well. Extensive analysis of selected parts, reported in a companion report (23), have been performed. Recommendations for metals that should experience greatly reduced corrosion in the combustor have been made. Extension of this technology to the use of less refined fuels must be demonstrated.
8. Significant corrosion of a carbon steel tailpipe occurred. Reliable pH control is required to minimize this undesirable effect.
9. Conclusions regarding which of the two systems (the air/diesel or the

oxygen/diesel (22)) is preferred from either an economic or a technical standpoint cannot be made based on these tests. Both systems still appear feasible and each has distinct, potential advantages. More operational data are necessary.

10. No conclusive remarks can be made regarding the postulated additive effect of injecting CO₂ with steam. Evidence suggesting both initial but diminishing absorption of the CO₂ by the reservoir and thermal contact by the steam with one of the wells was seen. A significant change in production that appeared to be correlatable with the DSG operation was also measured for one of the production wells. However, longer operation will be necessary before conclusions related to this effect can be made.
11. Based on relative amounts of CO in the production gases compared to the generator exhaust gases, the reservoir appears to act as a scrubber for the exhaust gases. Insufficient data related to SO_x and NO_x were gathered to support conclusions related to those potential atmospheric pollutants.

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 2364 T. D. Donham
 2513 J. E. Kennedy
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 3711 J. M. Hart
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 8500 D. L. Hartley
 9000 G. A. Fowler
 9700 E. H. Beckner
 9720 D. G. Schueler
 9730 W. D. Weart
 9740 R. K. Traeger
 9741 J. R. Kelsey
 9750 V. L. Dugan
 9752 H. M. Dodd
 9753 D. A. Northrop
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 3151 W. L. Garner (3)
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