GULF COAST GEOPRESSURED - GEOTHERMAL PROGRAM SUMMARY REPORT COMPILATION

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VOLUME II - A

RESOURCE DESCRIPTION, PROGRAM HISTORY, WELLS TESTED, UNIVERSITY AND COMPANY BASED RESEARCH, SITE RESTORATION

WORK PERFORMED UNDER U.S. DEPARTMENT OF ENERGY
CONTRACT NO. DE-FG07-95ID13366

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JUNE, 1998

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THE GEOPRESSURED - GEOTHERMAL RESOURCE

RESOURCE DESCRIPTION

Geopressured - geothermal reservoirs are essentially subsurface reservoirs containing hot pressurized brine saturated with dissolved methane at the temperature, pressure and salinity of the formation. Such reservoirs are found in many large basins which contain sedimentary rocks under higher than normal confining pressure (0.465 lb/in^2/ft) in the Gulf Coast). These rock formations are termed "geopressured" and the energy contained in them is termed as "geopressured - geothermal energy (Wallace, 1982). The most intensely studied basin containing geopressured - geothermal energy is the northern Gulf of Mexico basin, mainly because of the occurrence of large quantities of hydrocarbons.

The brine occurs under high pressure at depths ranging from 12,000 ft. To more than 20,000° ft. Temperatures range from 250°F to 500°F and bottomhole pressures range from 7,500 to over 18,000 pounds per square with (psi). Such geopressured geothermal reservoirs are known to occur in the United States along the Gulf of Mexico, onshore as well as offshore, the Pacific West Coast, in parts in Alaska, and in the Rocky mountain regions of the U.S. and Canada, (Figure 1).

Geopressured - geothermal aquifers contain three forms of energy: (1) chemical energy: methane dissolved in brine under pressure; (2) thermal energy: hot brines with temperatures ranging from 250°F to 350°F or more, which could be utilized for direct heating or secondary hydrocarbon recovery; and (3) mechanical energy: the high water pressure and high brine slow rates could be used for driving turbines to generate electricity (Division of Geothermal Energy, 1980). The ideal geopressured - geothermal resource system would be a total energy system in

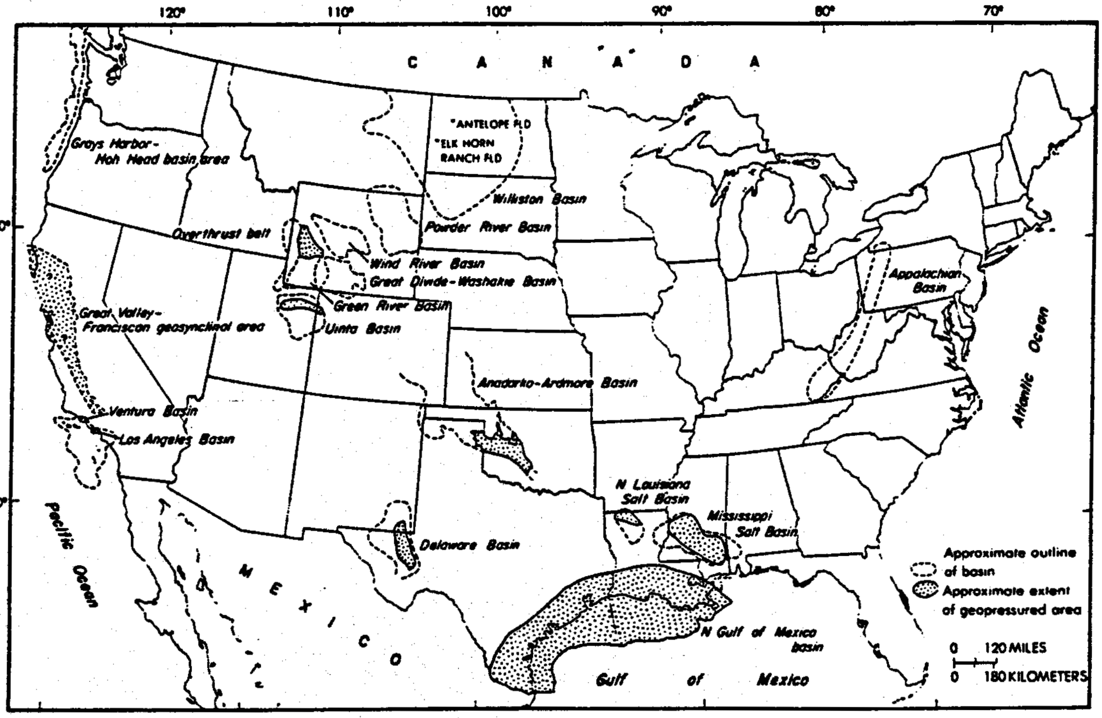


Figure 1. - - Geopressured basins of the United States. (from Wallace, 1982)

which all three associated forms of energy - chemical, thermal and mechanical could be utilized. Though such a system seems to be a long way from realization at the present time, with the current test paced development and utilization of this resource may become viable in the twenty-first century.

RESOURCE ORIGIN AND SEDIMENT TYPE

The Gulf of Mexico basin has a sediment thickness of over 50,000' feet (Figure 2) brought in and deposited by large river systems since early Tertiary time. Over geological time, these sediment depocenters have shifted laterally and vertically depending on climate, tectonics and sediment supply (Figure 3). Rapid sedimentation was accompanied by subsidence and growth faulting. As the river deltas were built outward into the Gulf, the younger deltaic sediment moved over the older sediments and formed deposits that gradually thickened gulfward. The weight of the sand resulted in its sinking into the less dense shale sediments forming growth faults and sealing in the water in the sand. With increasing depth of burial and sediment load, temperature and fluid pressure increased accompanied by chemical changes (diagenesis) causing development of geopressure.

The Tertiary and Quaternary sediments of the Gulf Coast basin consist of three types or facies: (1) massive sandstone facies, in which 50% or more of the volume is sand; (2) alternating sandstone and shale facies which contains only 15-35% sand; and (3) massive shale facies, in which sand comprises less than 15% of the total section. (Norwood & Holland, 1974, Tharsen, 1964).

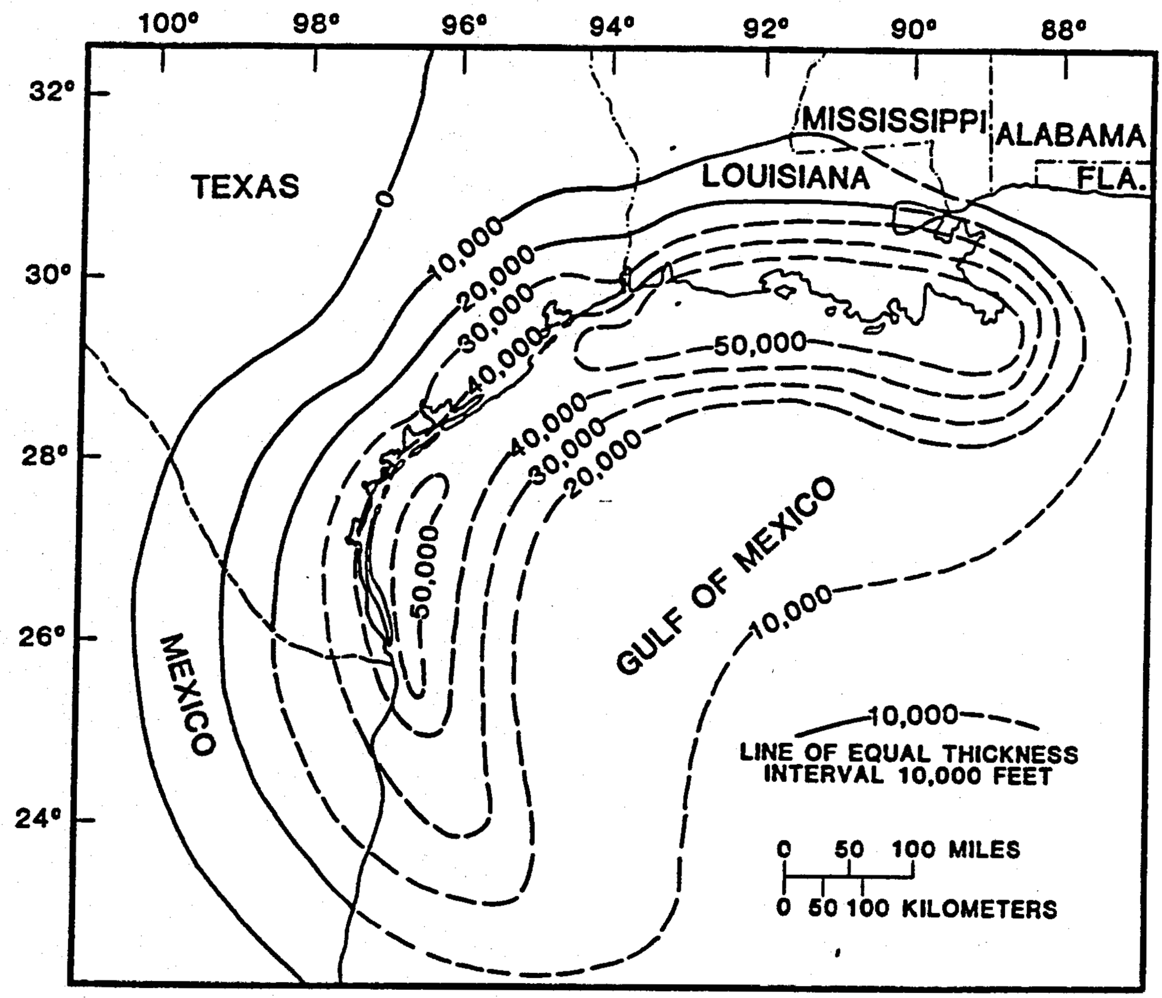


Figure 2. - - Thickness of Cenozoic sedimentary rocks in the northern Gulf of Mexico basin (Hardin, 1962).

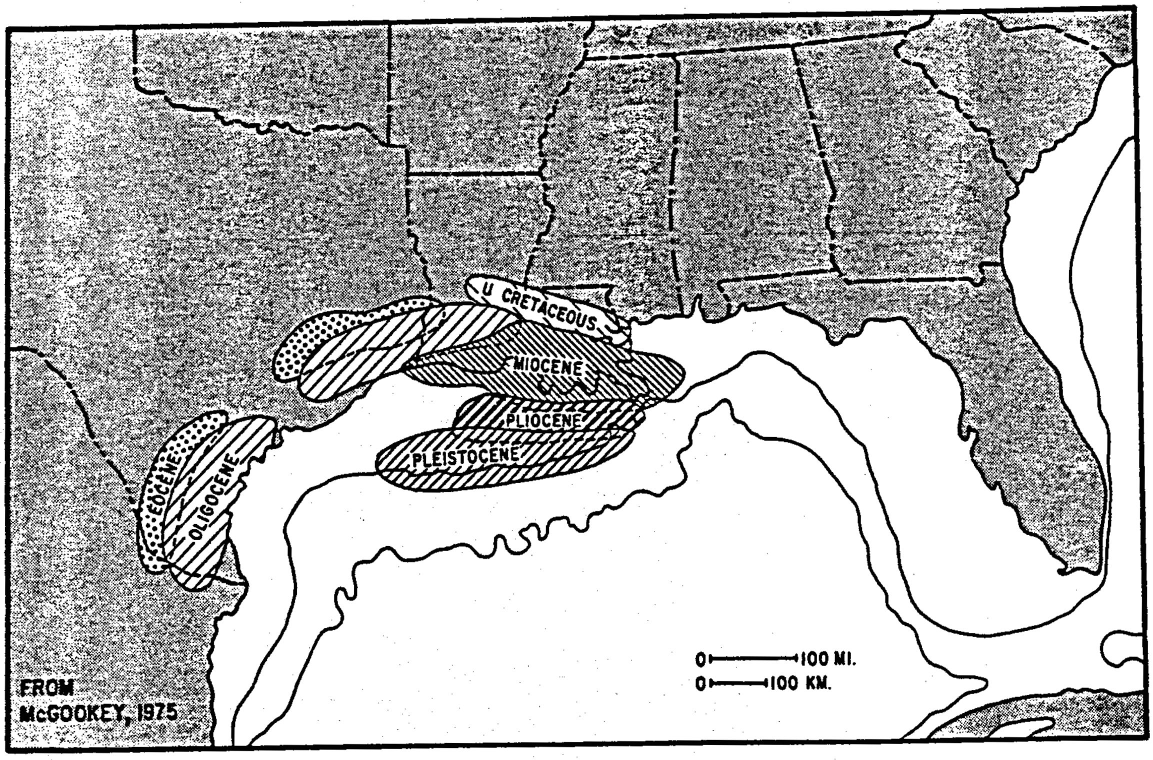


Figure 3. - - Major sediment depocenters, during the Upper Cretaceous, Tertiary and Quaternary, along the northern Gulf of Mexico.

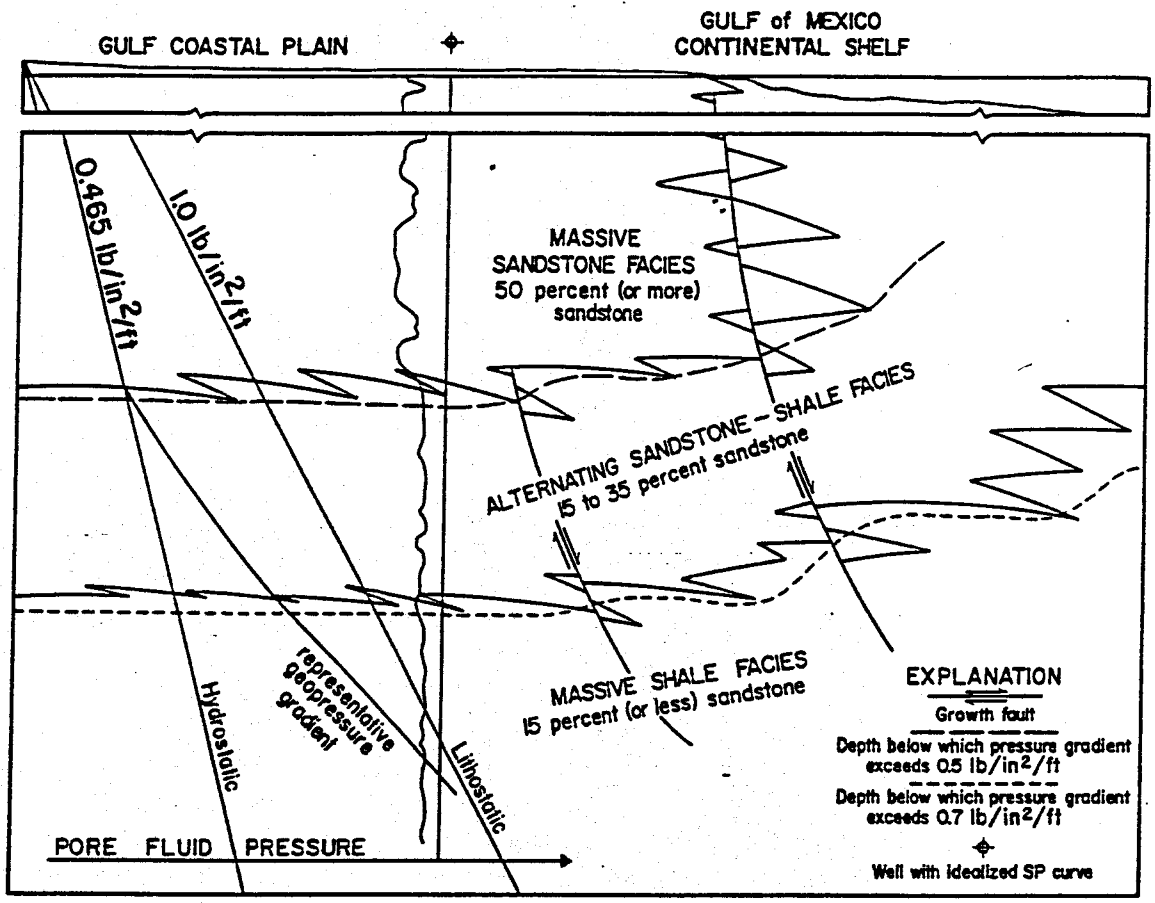


Figure 4. - - Generalized sedimentary model of the northern Gulf of Mexico basin, based on percentage sandstone and showing, diagramatically, the relation of gross lithology to fluid-pressure gradient and growth faulting (modified from Norwood and Holland, 1974).

GULF COAST RESOURCE EXTENT

The area covered by the geopressured zone in the northern Gulf of Mexico basin is shown in Figure 5. The oldest growth faulted and geopressured sediments were deposited seaward of the Lower Cretaceous shelf margin. This area shown also contains the largest potential for geopressure - geothermal energy resources.

RESOURCE ESTIMATES

Investigations conducted to determine the quantity of energy recoverable from the geopressured - geothermal reservoirs of the Gulf Coast are highly variable as is evidence by the resource estimates shown in Table 1. Generally these studies are in agreement that there is a large area in the Gulf Coast underlain by potentially producible geopressured - geothermal reservoirs but the different estimates reflects the different assumptions, and approaches used in the various studies, including the number and quality of the geopressured reservoirs and the volume of methane present in the brine under varying physical and chemical conditions.

As seen in Table 1 the estimates range from 50 to 5,000 Tcf which is equivalent to many times more than the currently known methane resources of the United States. (Division of Geothermal Energy, 1980). Figure 6 is an estimate for the methane and thermal energy by location and reservoir lithology published by the U.S. Geological Survey (Circular 790, 1979). The U.S. Department of Energy research program was focused on determining the viability of exploitation of this potentially large energy resource.

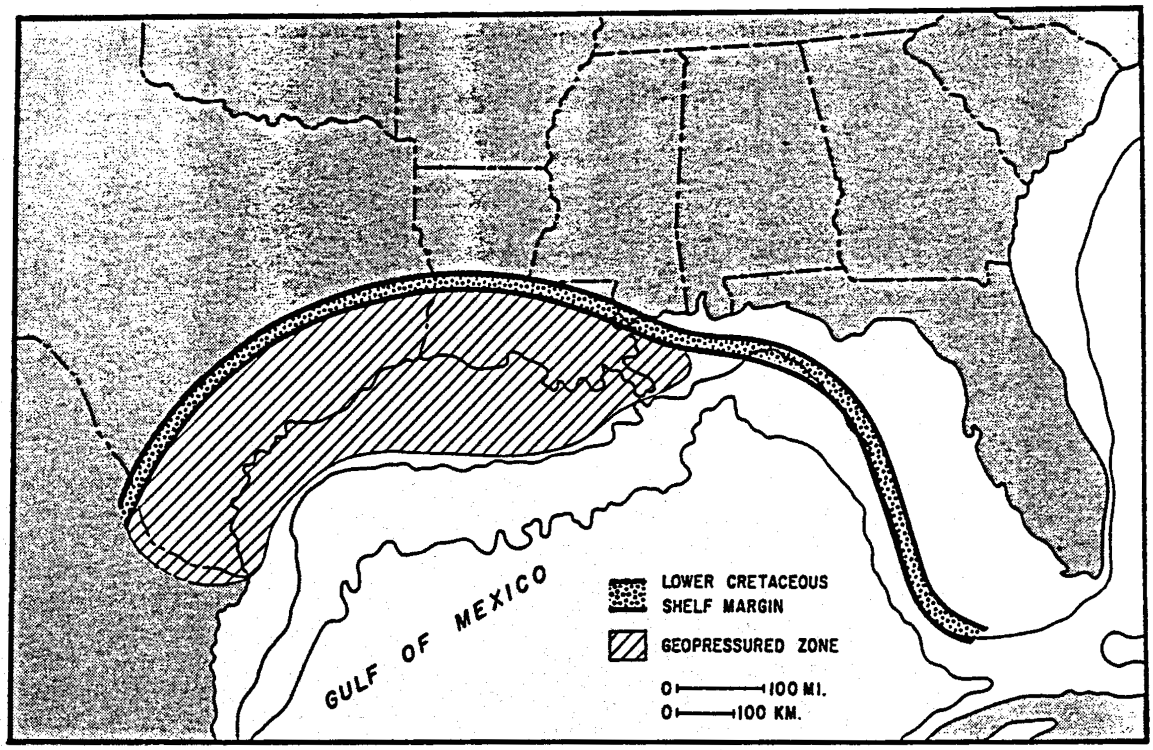


Figure 5. - - Geopressured zone along the Texas and Louisiana Gulf Coast (from Bebout 1982).

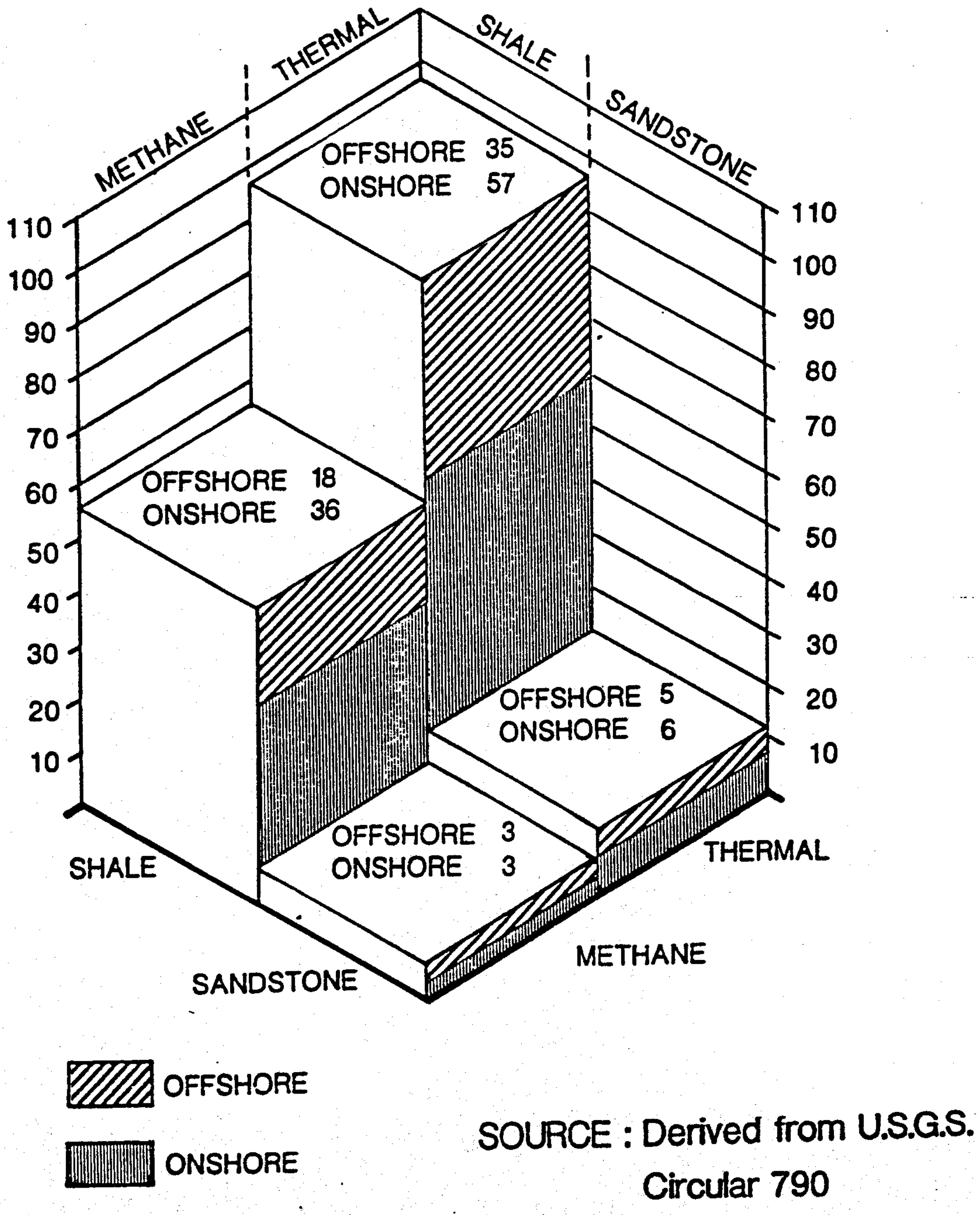


Figure 6. - - Methane and thermal resource base in geopressured aquifers (thousands of quads) (Division of Geothermal Energy, 1980).

Table 1

ESTIMATES OF NATURAL GAS IN GEOPRESSURED AQUIFIERS
(Trillions of Cubic Feet)

		(Resource Base) Total Methane In-Place			Recoverable Methane***			Recovery
Date	**Source**	**Texas**	**La.**	**Total**	**Texas**	**La.**	**Total**	**(%)**
1977	Jones	—	—	50,000	—	—	5,000	10
1977	Dorfman (UT)	—	—	5,700	82	175	257	5
1977	Hise (LSU)	—	—	3,000	—	—	150	5
1978	Lewin & Assoc.*	300	800	1,000	10	40	50	5
1978	Bernard	—	—	—	40	14	54	—
1979	USGS, #790 **							
	Onshore	1,800	1,300	3,100	72	25	97	3
	Offshore	—	—	2,600	—	—	53	2
1980	National Petr. Council****	—	—	—	—	—	81	MMcf/day

* The Lewin estimate for Texas includes only the Frio formation.

** USGS estimate is for sandstone only. The estimate of recoverable resource assumes sufficiently high wellhead pressure to limit subsidence to one meter, based on 1975 information.

*** Assumes no reinjection into the produced aquifer. Reinjection could theoretically increase the recoverable resource by five to six times, but may not be either technically or economically feasible.

**** The production rate in the year 2000 under the most optimistic case for onshore Gulf Coast sandstones.

PROJECT HISTORY

The early history of investigations leading up to the passage of the House bill establishing the DOE Geopressure - Geothermal Research Program is given below and is taken from the 1985 annual report on the Sweetlake Geopressured - Geothermal project by Durham, O'Brien and Rodgers:

Gulf Geothermal Corporation (GGC) was incorporated in 1973 to investigate the geopressured-geothermal potential resources of the Texas and Louisiana coastal plain. Previously, in the final report of the Geothermal Resources Research Conference of 1972, chaired by Walter J. Nickel, special attention had been given to geopressured water as an energy resource among other types of geothermal energy. The report emphasized the need for resource assessment including exploration, reservoir development, and production methods. Electrical power generation was considered as the most important use, with space heating, mineral production, and water desalination as additional important uses. Problems considered included production technology, the legal regulation of geothermal fluid production, mineral rights, and environmental issues including subsidence, seismic activity, groundwater and disposal problems.

Gulf Geothermal Corporation began its evaluation of the geopressured/geothermal resources of Texas and Louisiana in 1973, beginning with initial studies in South Texas. Areas having the highest subsurface temperature and pressure and greatest thickness of reservoir sands were identified using every available deep well log. A geothermal curve with mud weight and sand occurrences was plotted for each area using a profile designed by the Company. These studies sought to identify drillable prospects where the opportunity to drill and produce was most assured. The only areas of interest were those where previously drilled wells depicted desirable temperatures, pressure and sand conditions. Once identified, these areas had also to qualify as environmentally suitable and available for acquisition. A further restriction was the need for shallow sands suitable for water disposal.

Although GGC was not organized until May 1973, two of its principals, Dr. C. O. Durham, Jr. and Mr. W. A. Roman s, both geologists, had attempted to raise funds for a proprietary investigation of Gulf Coast geothermal resources beginning in 1970. Their interest was sparked by Dr. Paul H. Jones, whose U. S. Geological Survey deep basin hydrology study was located in its early years at Louisiana State University, where Dr. Durham was Director of the School of Geoscience, and also served as major professor for Dr. Jones PhD. dissertation program on the subject.

By the time funding to organize GGC became available in 1973, Durham and Romans had already accumulated considerable geologic and technologic information through their own efforts supportive of the potential of Gulf Coast geopressured-geothermal energy, and had individually participated in various local and national conferences including a House Republican hearing on the subject in 1972, and a seminar sponsored by the United Nations in 1973.

By the fall of 1973, GGC expertise on the subject attracted the attention of the Library of Congress, which was assembling information to be used by the House McCormick subcommittee on energy to prepare a bill to foster investigation on geopressured and hot, dry rock geothermal resources. The bill ultimately passed as the Geothermal Research and Development Act in 1974. Cost estimates for wells obtained by GGC for its in-house studies from Goldrus Drilling Company of Texas and Ben Holt Company of California were relayed to Congress with permission of these companies.

Subsequently, in February 1974, Durham and Romans were invited to testify on the needs for geopressured-geothermal research, and they proposed a six year $27.4 million program. Fortunately, GGC work was well advanced because the other two testimonials were in direct contradiction. Representatives of Shell Oil Company testified that appropriate geothermal resources did not exist in Texas and Louisiana, whereas representatives of Dow Chemical Company testified to the tremendous potential of the resource.

As a result of that impasse GGC testimony that the company had already identified appropriate reservoirs (contrary to Shell), but that these were definitely not universally distributed (contrary to Dow) was important to demonstrate the need for the type of government-sponsored research program that GGC recommended and that ERDA ultimately implemented.

Gulf Geothermal Corporation had largely completed its investigations by the middle of 1974, as ordinally planned, but was unable to lease any properties until a joint venture with Magma Power Company was implemented. At that time, a lease form was developed incorporating earlier legal findings of GGC, the newly issued federal geothermal lease form, and geothermal legal expertise of Magma Power Company supplied by Mr. Joseph Aidlin.

AUTHORIZING LEGISLATION

The Geothermal Energy Research, Development, and Demonstration Act of 1974 (P.L. 93-410) authorized the research, development, and demonstration of the geopressured - geothermal resources. The complete details and language contained in this Act along with its legislative history is provided in Appendix 1. An abstract of this act provided by DOE Headquarters is given below:

Abstract (P.L. 93 - 410)

The Geothermal Energy Research, Development and Demonstration Act of 1974 establishes the Geothermal Energy Coordination and Management Project which has overall responsibility for the coordination and management of a national geothermal energy research, development, and demonstration program. This program includes the (1) determination and evaluation of the resource base; (2) research and development with respect to exploration, extraction, and utilization technologies; (3) the demonstration of appropriate technologies; and (4) a loan guaranty program.

The project is composed of six members — one appointed by the President, an Assistant Director of the national Science Foundation, an Assistant Secretary of the Department of Interior, an Associate Administrator of the NASA, the General Manager of the Atomic Energy Commission, the Assistant Administrator of the Federal Energy Administration. The Chairman, to be designated by the President, acting through the appropriate Federal agencies and in cooperation with non-Federal entities, to initiate a research and development program for the purpose of resolving all major technical problems inhibiting the commercial utilization of geothermal resources in the U.S.

The law also authorizes the Chairman of the Project to designate an appropriate Federal agency to guarantee loans to encourage and assist in the commercial development of geothermal resources. The amount of the guaranty for any loan for a project shall not exceed $25 million, with no single qualified borrower securing guarantees above $50 million. In order to carry out the loan guaranty program, the law establishes in the Treasury a Geothermal Resources Development Fund.

PROGRAM OBJECTIVES

The main purpose of the DOE geopressured - geothermal research program was to narrow down the uncertainties involved with the commercial extraction of the energy associated with this resource to demonstrate its economic viability, and if demonstrated, to ensure the timely development of this large domestic energy resource. The Department of Energy established the following seven objectives [Division of Geothermal Energy, 1980]:

(1) Define the extent of geopressured reservoirs within the recoverable resource.

(2) Determine the technical feasibility of reservoir development, including downhole, surface and disposal technology.

(3) Establish the economics of production from a statistically significant number of reservoirs.

(4) Conduct supporting research on reservoir and fluid characteristics;

(5) Identify and mitigate adverse environmental impacts.

(6) Identify and resolve legal and institutional barriers; and

(7) Promote commercialization.

The results from this research program also provided a greater understanding and experience for reservoir characterization, and assisted in improving technology for producing and disposing large volumes of water, and drainhole and surface technology to handle hot geopressured saline brines.

PERCEIVED CONSTRAINTS

Preliminary estimations of the geopressured - geothermal resource base potential and recoverability were based on theoretical or hydrogeologic and production models and not on any actual production data. The need to address the numerous historical perceptions that resulted in very limited industry interest, combined with the country's need to develop alternate energy resources in view of the increasing dependence on imported fossil fuel energy provided ample justification for a Federal role in the beginning of a research program to investigate all aspects of the geopressured - geothermal resource (Wallace, 1982).

Resource exploitation models in the northern Gulf of Mexico are primarily developed from data gathered from oil and gas well drilling and production in this area and are constantly evolving. One of the earlier concepts was that oil and gas deposits were usually found in fault controlled reservoirs or traps of small areal extent and therefore the industry perception was that geopressured reservoirs would also be small and would deplete rapidly. In addition, production of gas from geopressured - geothermal reservoirs involved the extraction of large volumes of brine having low gas concentrations which was uneconomic in comparison with conventional natural gas. Environmental uncertainties related to the safe disposal of such large volumes of brine, combined with the potential for land surface subsidence, fresh water aquifer contamination, and growth fault activation were further perceived constraints limiting industry interest in the development of this resource. Uncertainties about mineral rights legal and socio-economic issues further caused this resource to be considered as a high risk venture by industry.

The Federal research program was initiated to address these perceived constraints by gathering and providing the required data and information by well drilling and testing in addition to environmental studies at the different sites.

PROGRAM ACTIVITIES AND STRUCTURE

Federal research involvement in geopressured - geothermal energy began in 1966 at the U.S. Department of Interior's Geological Survey (USGS). However, major involvement began in 1974 with the passage of act P.L. 93-410 when the research program was conducted by the U.S. Department of Energy's (DOE) Division of Geothermal Energy. Well drilling and testing, and supporting research and technology development in the DOE program was carried out by contracts with industrial, academic, private companies and laboratories, and other government organization (Wallace, 1982).

Regional resource assessments were initially made by the U.S. Geological Survey and the first estimates were published in Circular 726 in 1975. This study was further expanded and updated in 1979 and results were published in Circular 790. The resource definition work consisting of the identification and characterization of the Texas and Louisiana geopressured - geothermal fairways was carried out at the University of Texas at Austin, TX (UT) and the Louisiana State University (LSU) at Baton Rouge, LA.

WELL TESTING

The DOE Geopressured - geothermal research program in the Gulf Coast developed two well testing programs to field test the geopressured - geothermal resources. These testing programs were (1) Wells of opportunity and (2) Design wells.

The Wells of Opportunity program tested industry wells that were abandoned due to the absence of oil and gas or due to their being depleted or uneconomic for hydrocarbon production provided they penetrated geopressured - geothermal aquifers. The wells under this program were subjected to short term testing (less than a month) only mostly to determine fluid characteristics and reservoir parameters.

Wells of Opportunity selected by DOE were based on the following criteria:

(1) Bottom hole temperature greater than 275°F (flexible)

(2) Pressure gradient of 0.8 psi/ft (flexible)

(3) Salinity less than 75,000 ppm tds

(4) Minimum of 100 essentially continuous net feet of 100% water saturated porous sand of good permeability, as determined by available logs, and core data.

(5) Readily accessible land site near optimum reservoir areas

(6) Reasonably continuous drainage area

(7) Adequate casing and completion to mechanically permit the desired test

(8) Same geographical dispersion of the test sites

(9) Adequate well logs and other geologic data

(10) Suitable financial arrangements

(11) Indication of adequate gas in solution

[Division of Geothermal Energy, 1980]

The Design Wells program was developed to gather information on all reservoir, fluid, production, and environmental parameters in favorable prospects identified from geologic studies. Wells under this program were subjected to long term testing in order to acquire the required information. The general guidelines for selection of wells in this category are given below:

(1) Reservoir volume - at least one cubic mile, with good thickness.

(2) Fluid temperature - greater than 275°F

(3) Minimum permeability - 20 millidarcys

(4) Water salinity - less than 50,000 mg/l

(5) Initial bottom hole pressure - greater than 0.7 psi foot

(6) Production rate - capable of 40,000 barrels of water per day

[Division of Geothermal Energy, 1980]

Figure 7 is a flow chart showing the major components of the implementation strategy for the DOE geopressured - geothermal research program in the Gulf Coast area.

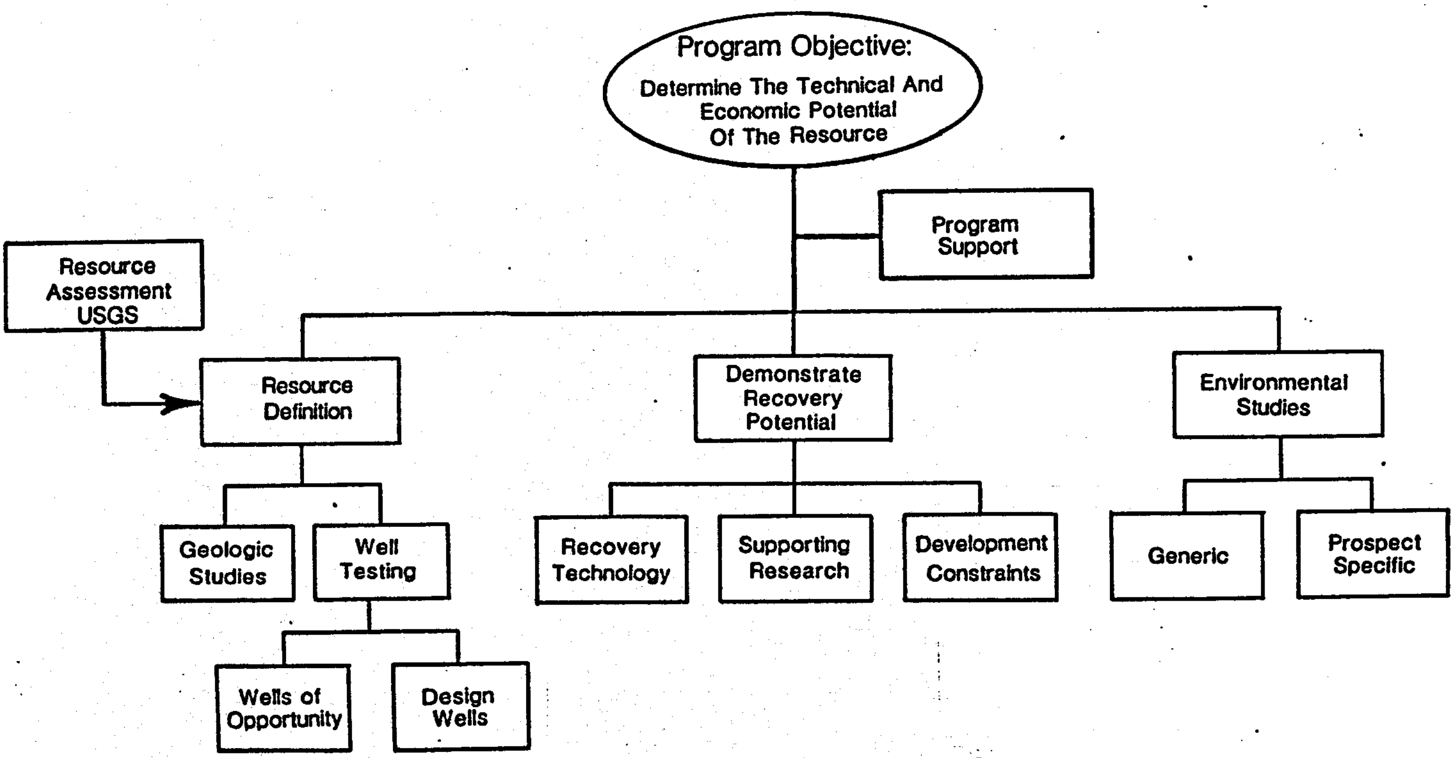


Figure 7. - - Major components of implementation strategy (Division of Geothermal Energy, 1980).

PROGRAM MANAGEMENT

The main overall responsibility for management of the doe Geopressured - Geothermal research program at the inception of the program was with the Geopressure Resources Section of the Division of Geothermal Energy. Figure 8 shows the management organization of the Division of Geothermal Energy at that time. Management of the drilling, completing and testing of reservoirs was initially administered by the Nevada Operations Office and its Houston Geopressure Projects Office . This work was later moved to the DOE Idaho National Engineering Office, located at Idaho Falls, Idaho. Eaton Operating Company, Inc., was the contractor for the wells of opportunity program while Jenix and Scisson, Magma Gulf Technadril, and Dow Chemical Company were the contractors for the earlier planned design wells. They were followed by Eaton Operating Co., Inc., who took over the work on the design wells when Technadril - Fenix and Scisson, a joint venture, ceased to exist.

A generalized chart showing the management structure of the geopressured - geothermal research program supplied by Mr. Ray Fortuna of DOE's Washington headquarters office of geothermal energy is shown in Figure 9.

PROGRAM COST SUMMARY

The following information on the geopressured - geothermal program funding history was provided by the headquarters office:

FUNDING HISTORY

($ in millions)

YEAR	FUNDING
FY 1976	$ .3
Transition Qtr.	$ .8
FY 1977	$ 6.6
FY 1978	$ 16.5
FY 1979	$ 27.7
FY 1980	$ 36.0
FY 1981	$ 31.9
FY 1982	$ 16.7
FY 1983	$ 8.4
FY 1984	$ 5.0
FY 1985	$ 5.4
FY 1986	$ 4.4
FY 1987	$ 4.0
FY 1988	$ 4.9
FY 1989	$ 10.3*
FY 1990	$ 5.9
FY 1991	$ 5.9
FY 1992	$ 4.9
FY 1993	$ 0
Total	$ 195.6

* Includes $4.5 million from sale of Baca equipment.

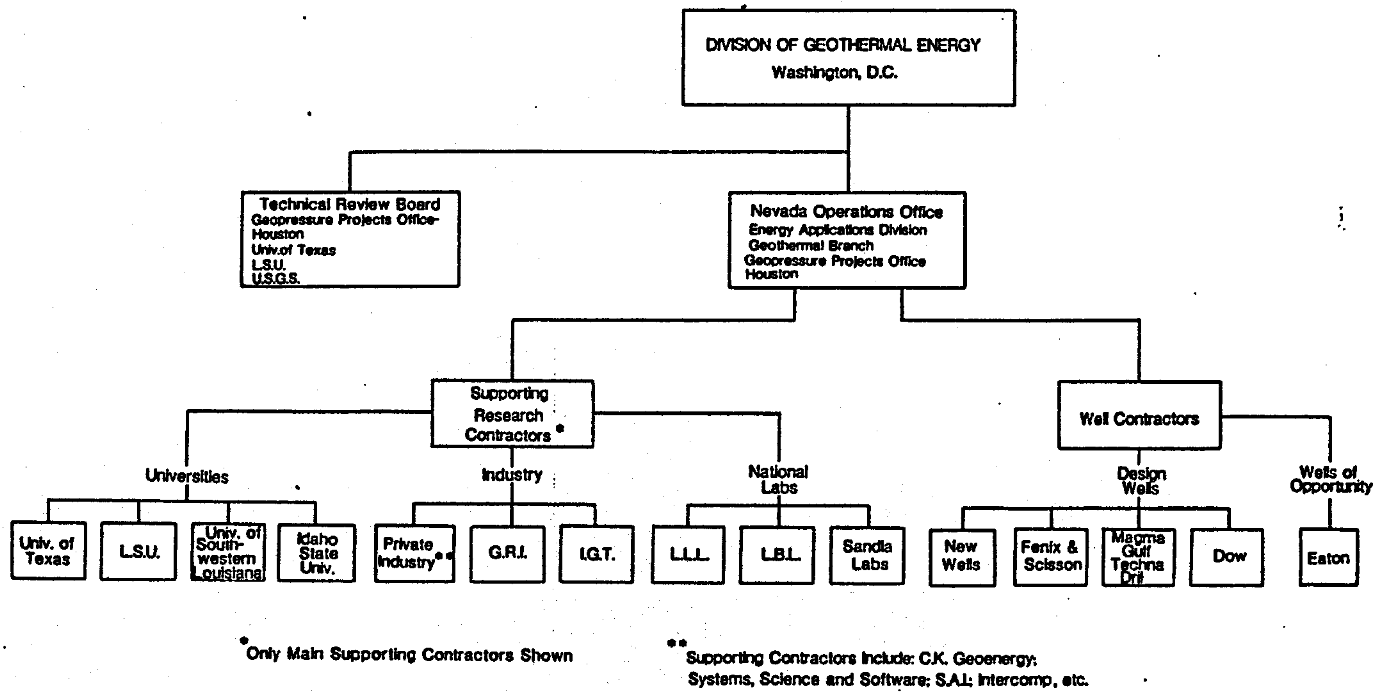


Figure 8. - - Management Organization of The Division of Geothermal Energy (from,Division of Geothermal Energy, 1980).

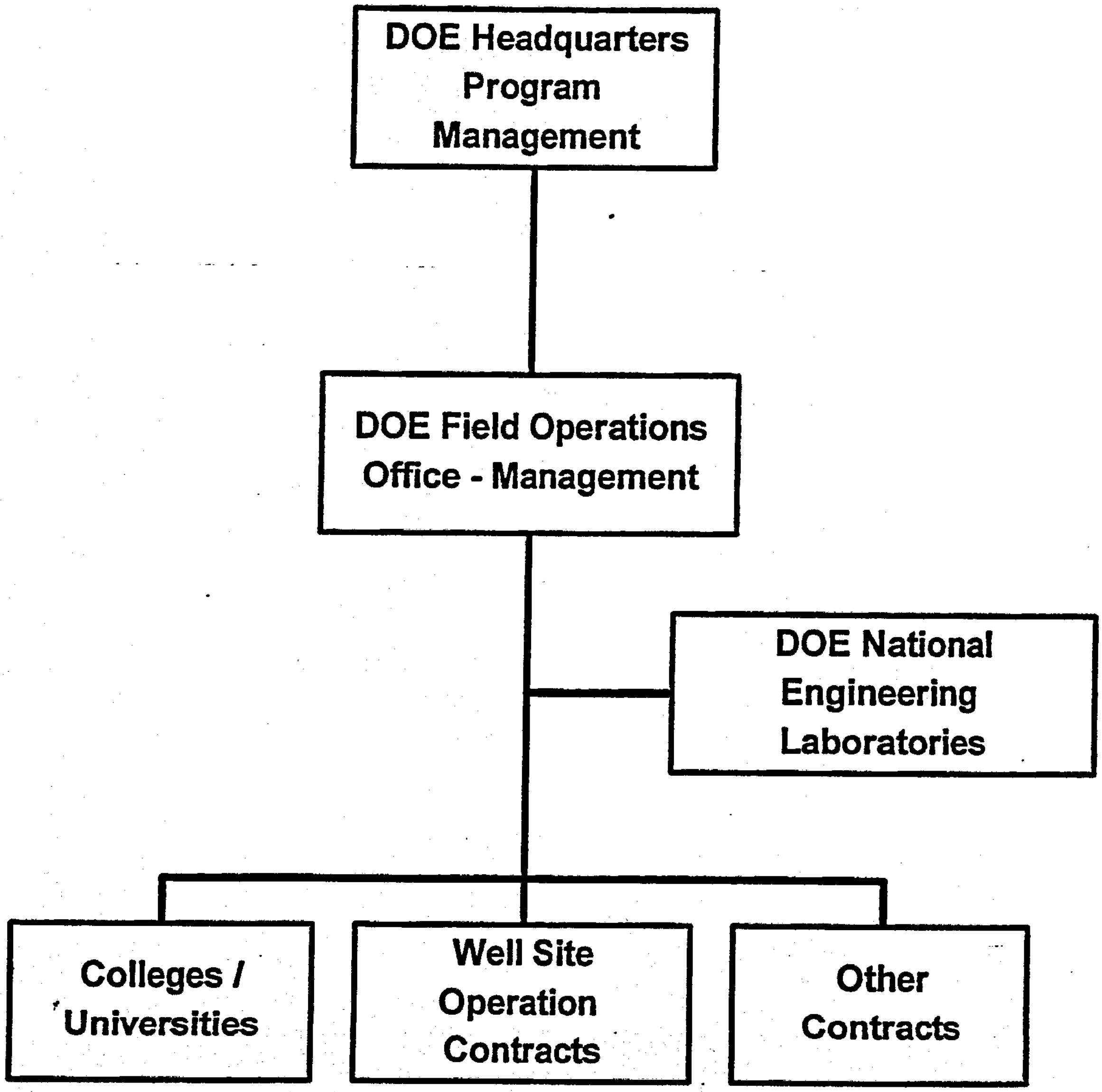


Figure 9. - - Geopressured - Geothermal program management structure.

Figure 10 is a bar graph illustrating the funding history of the geopressured - geothermal research program from its beginning in 1976 to its conclusion in 1993.

RESOURCE CHARACTERIZATION

Resource characterization work consisted of regional geological and geophysical studies of all known onshore geopressured - geothermal resources in Texas (Frio, Vicksburg and Tuscaloosa ages) and Louisiana (Miocene, Frio, Wilcox and Tuscaloosa ages). These studies were carried out to delineate the optimum prospect areas for drilling and testing geopressured - geothermal fairways in the Texas Gulf Coast was performed by the Bureau of Economic Geology, University of Texas at Austin, Resource definition in Louisiana was done by the Louisiana State University and the Louisiana State Geological Survey. The geopressured - geothermal fairways were defined taking into consideration regional geology, well log data, well production information and seismic surveys where available. Other data integrated into defining the geopressured - geothermal fairways included potential reservoir volume, temperature, pressure, porosity, permeability and salinity.

Figure 11 shows the geopressured - geothermal fairways of South Louisiana and Figure 12 shows the fairways for the Texas Gulf Coast as defined by these studies. These broadly defined geopressured - geothermal fairways contain localized prospects which are characterized by the presence of thick permeable sandstones containing fluids at temperatures greater than 250°F. Figure 13 shows the depth to the "operational" top of geopressure (Bebout, 1982), which was picked at the point where a distinct break to lower resistivity (density) in the shale occurred as seen on the electrical log which was also the point where drilling mud weight exceeding 13 ppg

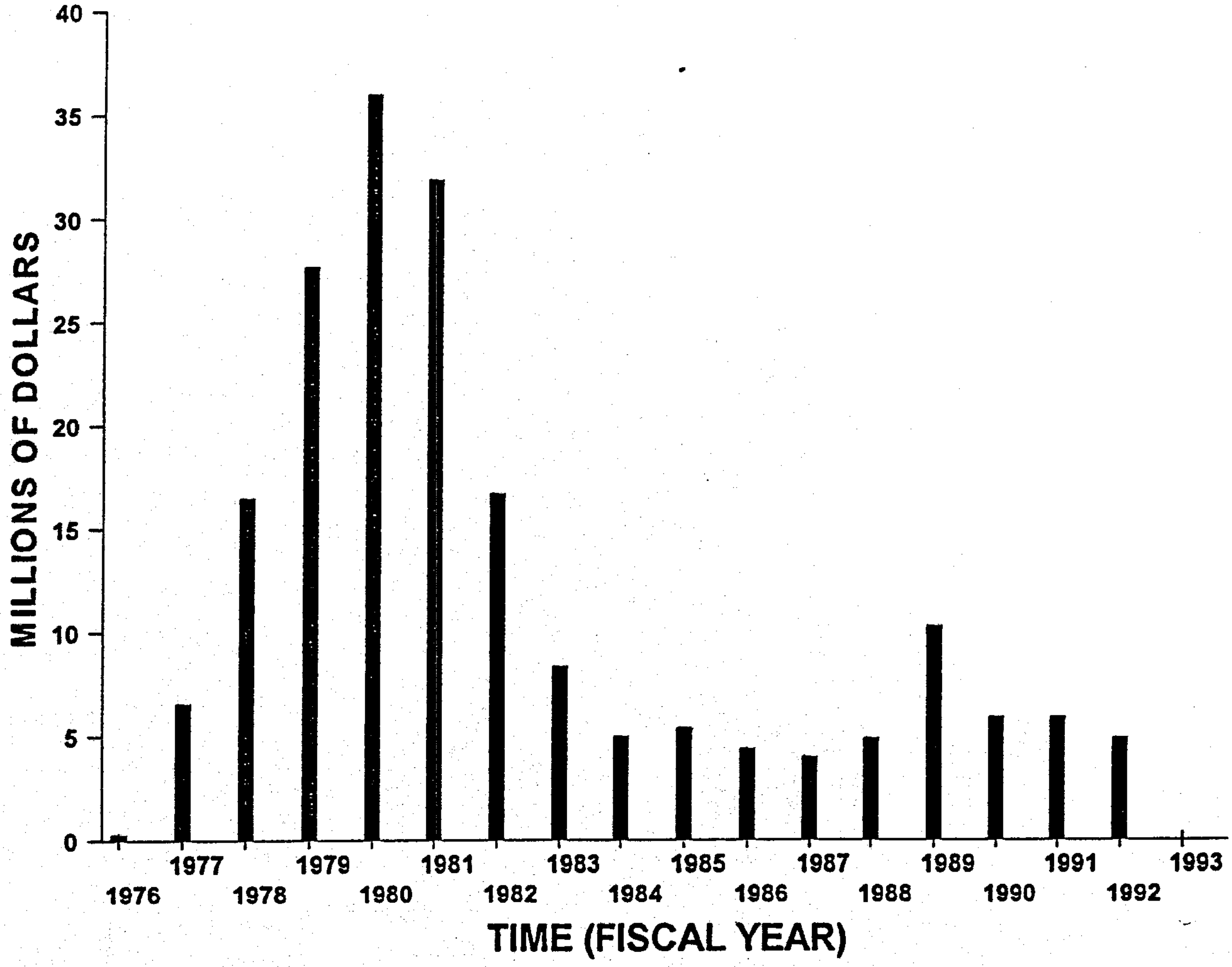


Figure 10. - - Funding history of the geopressured - geothermal research program.

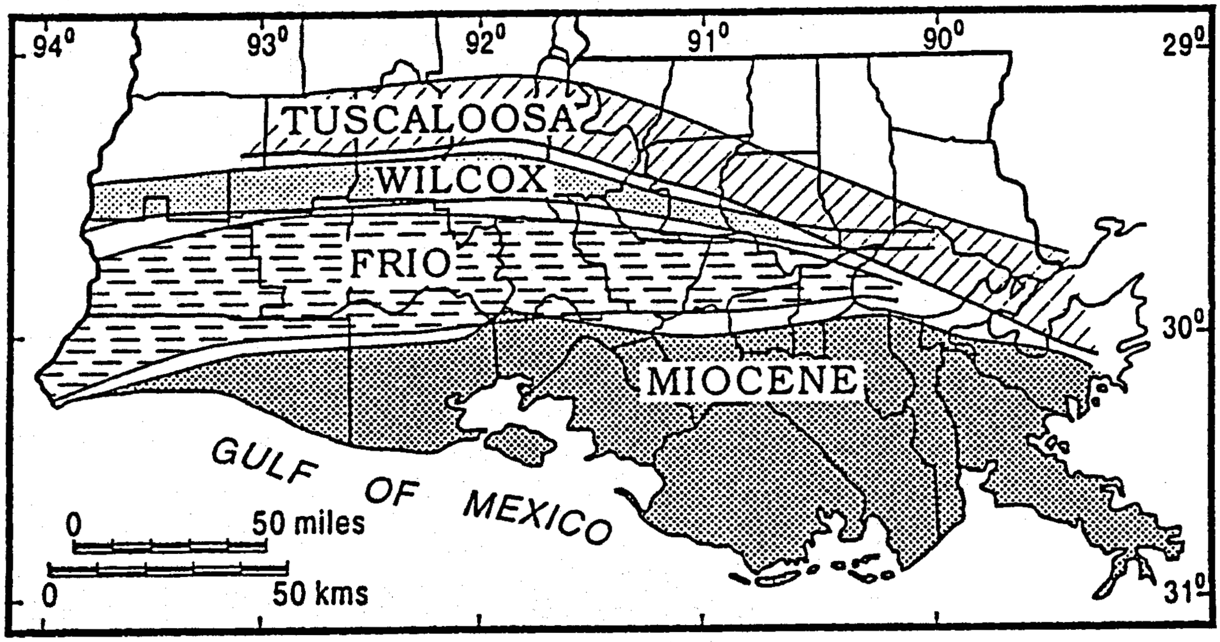


Figure 11. - - Location map of Geopressured - Geothermal corridors of South Louisiana (modified from Bebout, 1982).

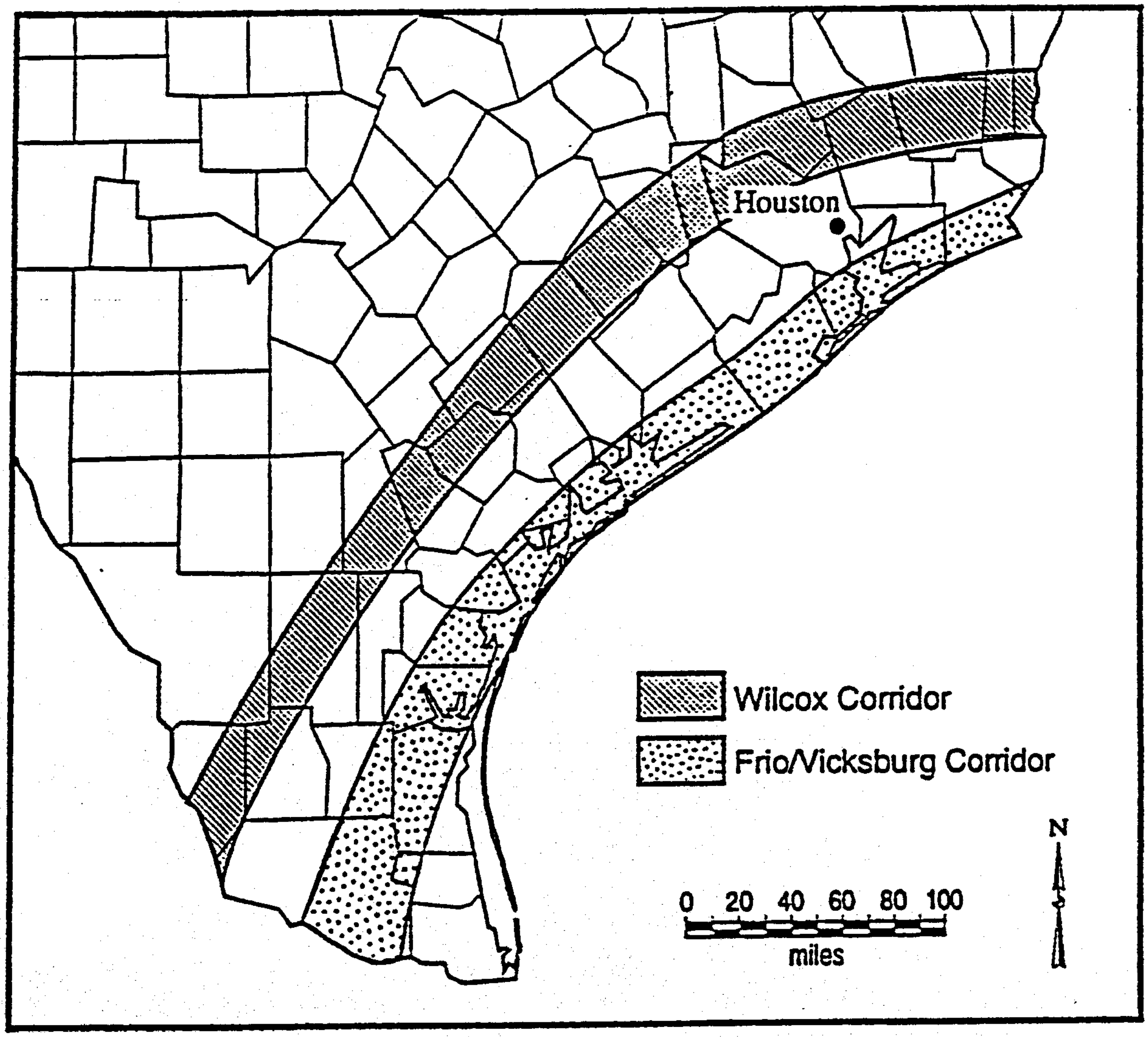


Figure 12. - - Location map of Geopressured - Geothermal corridors, Texas Gulf Coast (modified from Seni and Walter, 1993).

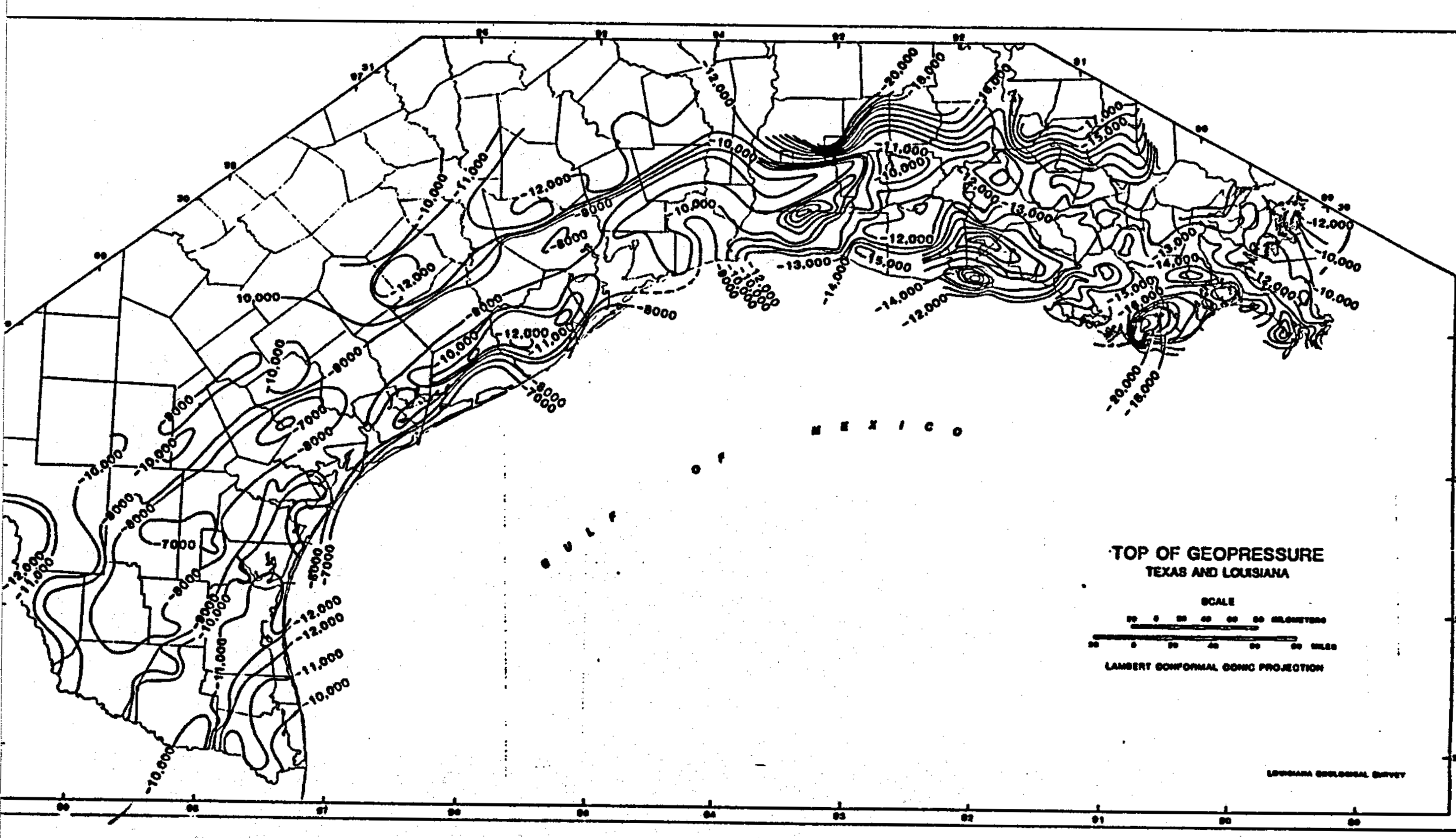


Figure 13. - - Operational top of geopressure along the Texas and Louisiana Gulf Coast, as determined by the occurrence of "low-density" shale.

(equivalent to 0.675 psi/ft) was used for drilling the well. Some other general findings from the geopressured - geothermal resource characterization studies reported by Bebout (1982) are given below:

(1) In general, the depth to the operational top of geopressure is shallower along the Texas Gulf Coast (7,000 - 12,000 ft.) and deeper to the northeast in Louisiana (9,000 to > 18,000 ft.).

(2) Porosity generally decreases uniformly with depth; however, locally depending on the differences in the original sand composition, burial history and formation fluid chemistry, wide variations to the general observation may be present.

(3) Plots of bottom hole temperatures recorded in well logs helps to estimate subsurface temperature with depth in the geopressured - geothermal fairways. Such plots show that the 100°C isotherm occur at about 8,000 ft. Locally isotherm may not respond to lithological changes in a similar way as does the top of geopressure.

(4) Generally salinity is highest in the zone above the geopressured zone and increases with depth. Salinities in hydrocarbon producing zones are highly variable (100,000 ppm to < 20,000 ppm). Factors influencing salinity include porosity, permeability, faults, aquifer size, presence of salt, fluid movement, and burial history. The effects of each of these factors on reservoirs salinity is poorly understood.

WELLS OF OPPORTUNITY

The Wells of Opportunity program tested industry wells that were to be abandoned for lack of commercial hydrocarbon sands on initial drilling or depleted hydrocarbon producing wells. The tests conducted on these wells were for short time periods. The locations of the wells tested, including the design wells are shown in Figure 14.

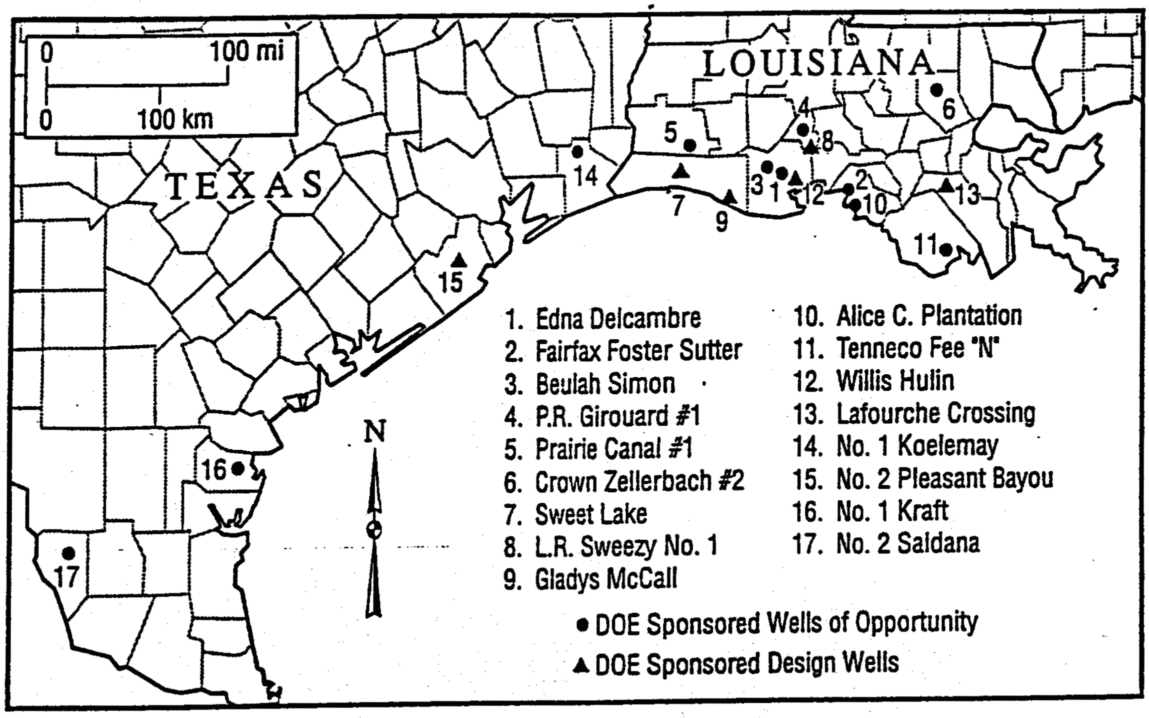


Figure 14. - - Location of wells tested for the DOE geopressured - geothermal research program in the Gulf Coast.

EDNA DELCAMBRE #1

The Edna Delcambre #1 well in Vermilion Parish, Louisiana, was the first well tested under the DOE Wells of Opportunity program. This well is located in the Tigre Lagoon Field and is approximately one mile north of the Intracoastal canal and about ¼ mile west of the Iberia - Vermilion Parish boundary, about 25 miles south of Lafayette in Section 5, Township 14S, Range 5 East. Originally drilled to a total depth of 14.314 ft. by Coastal States Producing Company, gas production was established in three *Planulina* sands (*Planulina* #6, #7, #8 sands) beginning at about 13,700 ft. The total cumulative production for the well was 9.9 BCF before the well was temporarily abandoned. DOE acquired and re-entered the well to test the shallower *Planulina* #1 and #3 sands. Engineering services work dealing with well site operations, transient pressure tests and collection of gas and fluid samples was contracted by DOE to Osborn - Hodges - Roberts - Wieland Engineering Company (OHRW) of Bryan, Texas. Another contract for analyses of water and gases from the well was awarded to McNeese State University, Lake Charles, Louisiana (Terratek , 1980). Detailed information on the Edna Delcambre well can be found in reports by Terratek, 1980, (DOE Contract #EG-77-C-01-4060) Consad Research Corporation, 1978 (DOE Contract #EG-77-C-01-4060) McNeese State University and OHRW Engineering, 1977, (ERDA Contract #E - (40-1) - 4937, ERDA Report No. ORO-4937-R-1) and in the Proceedings volumes of the Third (1977) and Fourth (1978) Geopressured - Geothermal Energy Conference. Figure 15 shows the drilling rig and related equipment used for drilling the Edna Delcambre No. 1 well. Because the well was located in the coastal marsh, all field operations were conducted from barges. In order to protect the environment, the salt water obtained from the Delcambre was reinjected into sands between 1,300 and 2,500 feet in a disposal well that was drilled and

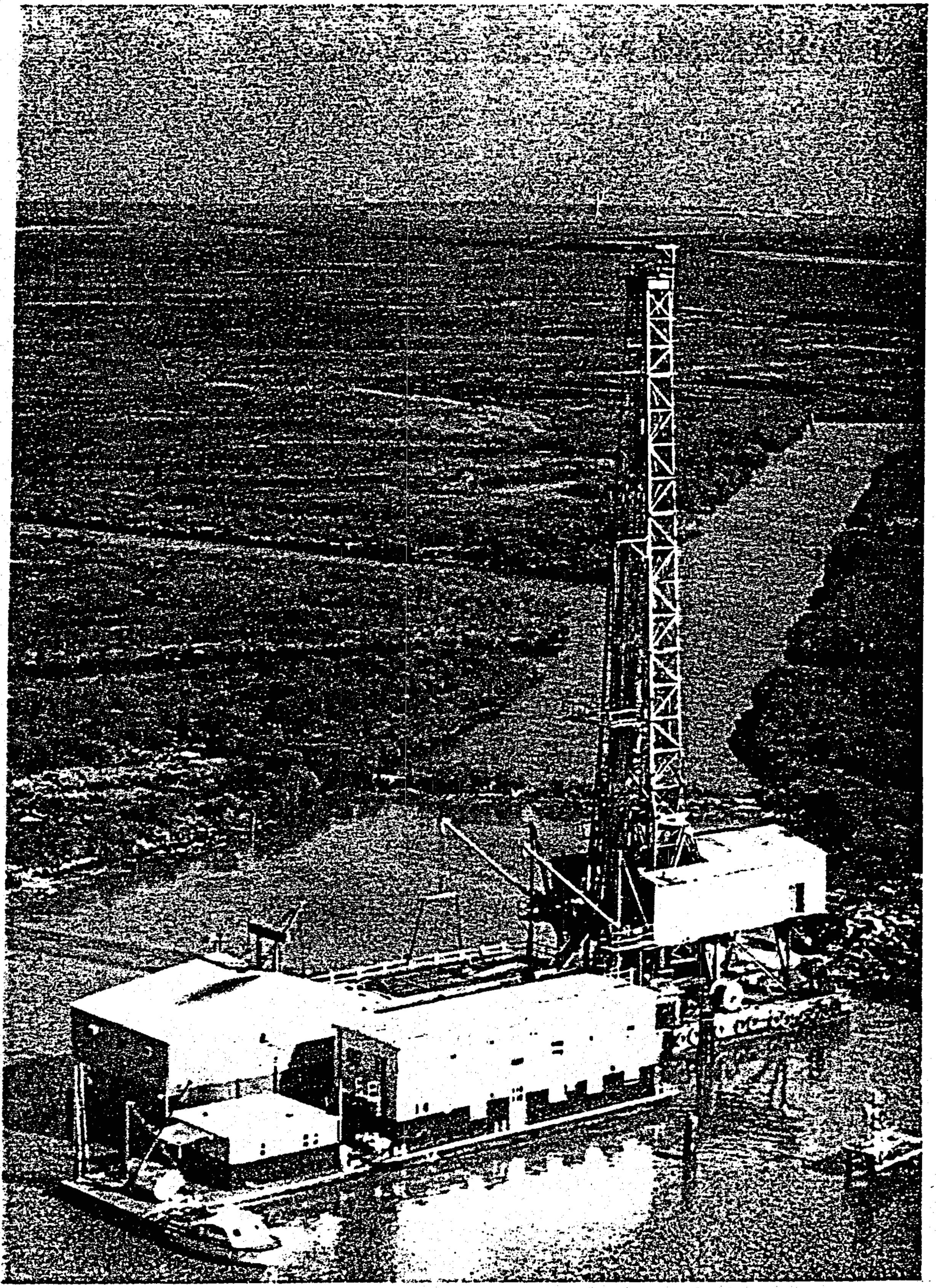


Figure 15. - - Edna Delcambre No. 1 Well, Tigre Lagoon Field, Vermilion Parish, Louisiana (from Terratek, 1980).

completed for this project. These sands had been also successfully used by other operators to inject water produced in association with oil production in the Tigre Lagoon Field.

The well was flow tested during a period of about six weeks and all field operations and testing were completed by late July 1977. (Terratek, 1980).

The following summary of the test results and conclusions is taken from Miller, 1991 found on the Technical Report by the Louisiana Geological Survey done under the DOE Contract No. DE-FC07-85NV10425, with C.G. Groat as the Program Co-ordinator:

The well (Edna Delcambre) was drilled approximately 300 ft. downdip from the crest of an anticlinal structure at the *Planulina* #1 sand horizon (Figure 16). The well as mapped is approximately 120 ft. structurally downdip and 1,100 ft. laterally offset to a free gas/water level. The *Planulina* #3 sand test was penetrated in a similar structural position, but no information on the presence location of free gas accumulations was given. A north-south cross section going through this well is shown in Figure 17.

The *Planulina* #1 and #3 sands were tested in the summer of 1977. The #3 sand is 48 ft. net sand, log porosity 26%, original formation pressure 11,012 psia, and temperature 238°F (Weiland, 1977, Proceedings 3rd Geopressured Conference). The sand was perforated at 12,869 to 12,911 ft. And flow tested for 24 days. The maximum flow rate was 10,333 BWPD and salinity was 133,000 mg/l 7DS. The *Planulina* #1 sand was perforated at 12,573 ft. to 12,605 ft. and tested for 25 days after the *Planulina* #3 sand had been tested and isolated. The *Planulina* #1 sand has 30 ft. net sand, log porosity 29%, original formation pressure 10,858 psia, temperature 234°F. Maximum flow rate was 12,653 BWPD; salinity 113,000 mg/l TDS.

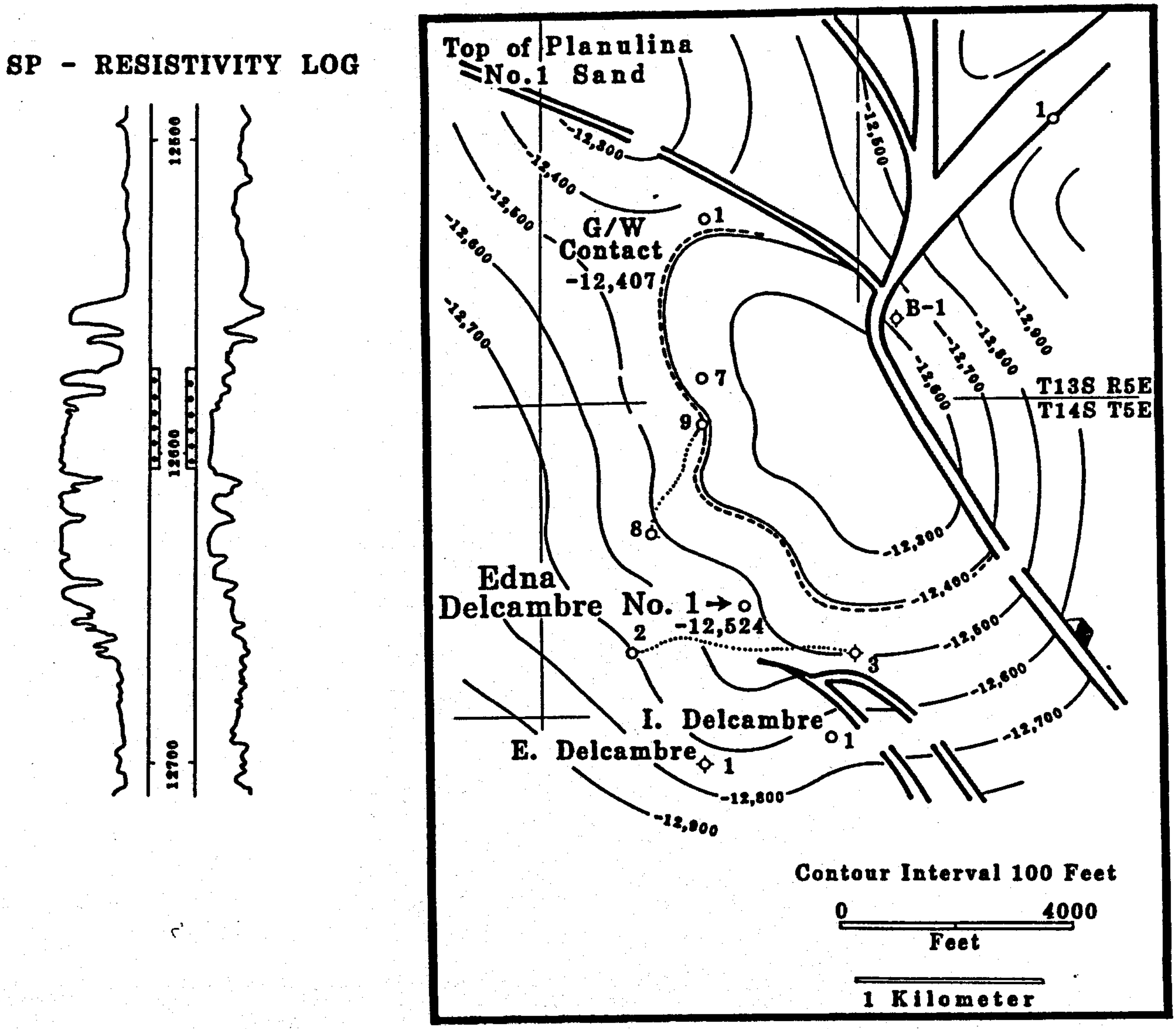
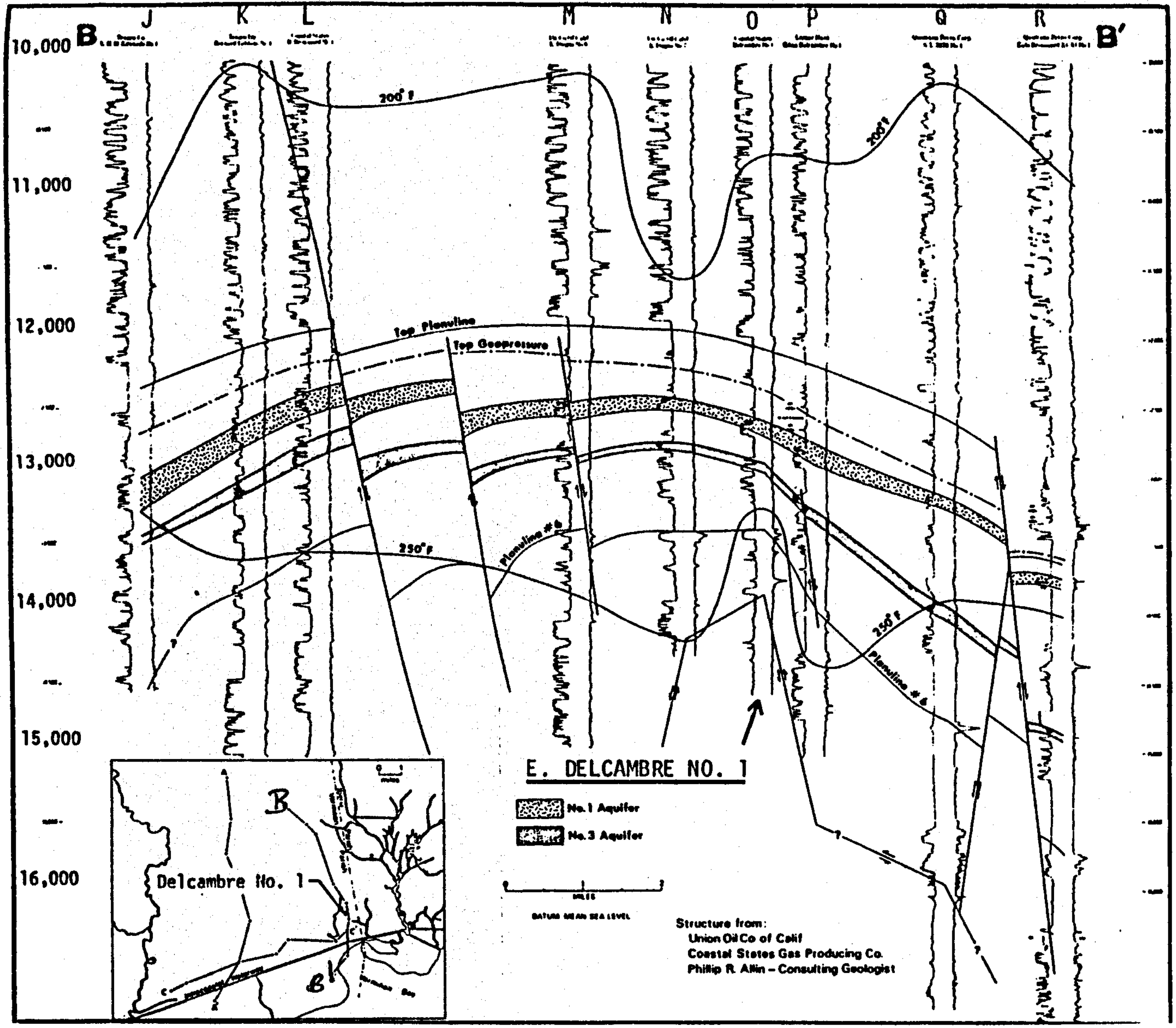


Figure 16. - - Structure map and log of the OHRW-DOE No. 1 Edna Delcambre test well (WOO).



J. Texaco Co.,
L.M.M. Edwards No. 1

K. Texaco Inc.,
Bernard Leblanc No. 1

L. Coastal States,
R. Broussard No. 1

M. Union Oil of Calif.,
E. Dugas No. 6

N. Union Oil of Calif.,
E. Dugas No. 7

O. Coastal States,
E. Delcambre No. 1

P. Lamar Hunt,
E. Delcambre No. 1

Q. Quintana Pet. Corp.,
. S/L 3236, No. 1

R. Quintana Pet. Corp.,
Eula Broussard No. 1

Figure 17. - - Geologic Cross Section B-B' with 200° and 250°F Isothermal Surfaces (from Jones, 1978, in Terra Tek Rept., 1980).

Pressure transient data indicated a barrier at 460 ft. from the well. The geologic structure map (Figure 3) indicates a fault may extend close to the well bore.

The #1 Delcambre well produced anomalously high amounts of solution gas. The *Planulina* #1 sand, in particular, initially produced approximately 20 SCF /bbl and suddenly increased to over 50 SCF /bb; after eight days of flow testing. Both sands, after rates stabilized, produced 50-60 SCF /bbl solution gas. However, recombination studies yielded brine saturation volume of 22.8 to 25.4 SCF /bbl ; indicating that the well was yielding more gas than possible by gas solubility alone (Karkalits and Hankins, 1979, Proceedings fourth Geopressured - Geothermal Conference). Post separator gas composition was similar for both sands, averaging 941 mol % methane, 1.6 mol % CO_2 and 4.3 mol % other gases. Since this was the first geopressured - geothermal well tested, the excess gas recovery and the possibility of additional, unrecognized mechanism for the liberation of geopressured gas created intense excitement.

A variety of mechanism for producing excess gas were postulated (Rogers and Randolph, 1979, Proceedings Fourth Geopressured - Geothermal Conference). These included free gas from coning down of a nearby gas cap; free gas present as a dispersed phase in the rock matrix, free gas exsolution and migration resulting from a decrease in pressure; free gas from other zones, flowing via channels between casing and wellbore due to poor cement bond; and excess gas from the nearby #4 Delcambre well, which experienced an underground blowout, the #4A Delcambre, drilled as a blowout relief well. The first two mechanisms, gas coming from a nearby free gas cap verses a dispersed free gas phase, were evaluated with computer simulation models by Rogers and Randolph , 1979, and reported in the Proceedings of the Fourth Geopressured - Geothermal Conference. The dispersed gas model did not give a reasonable match to the production plots.

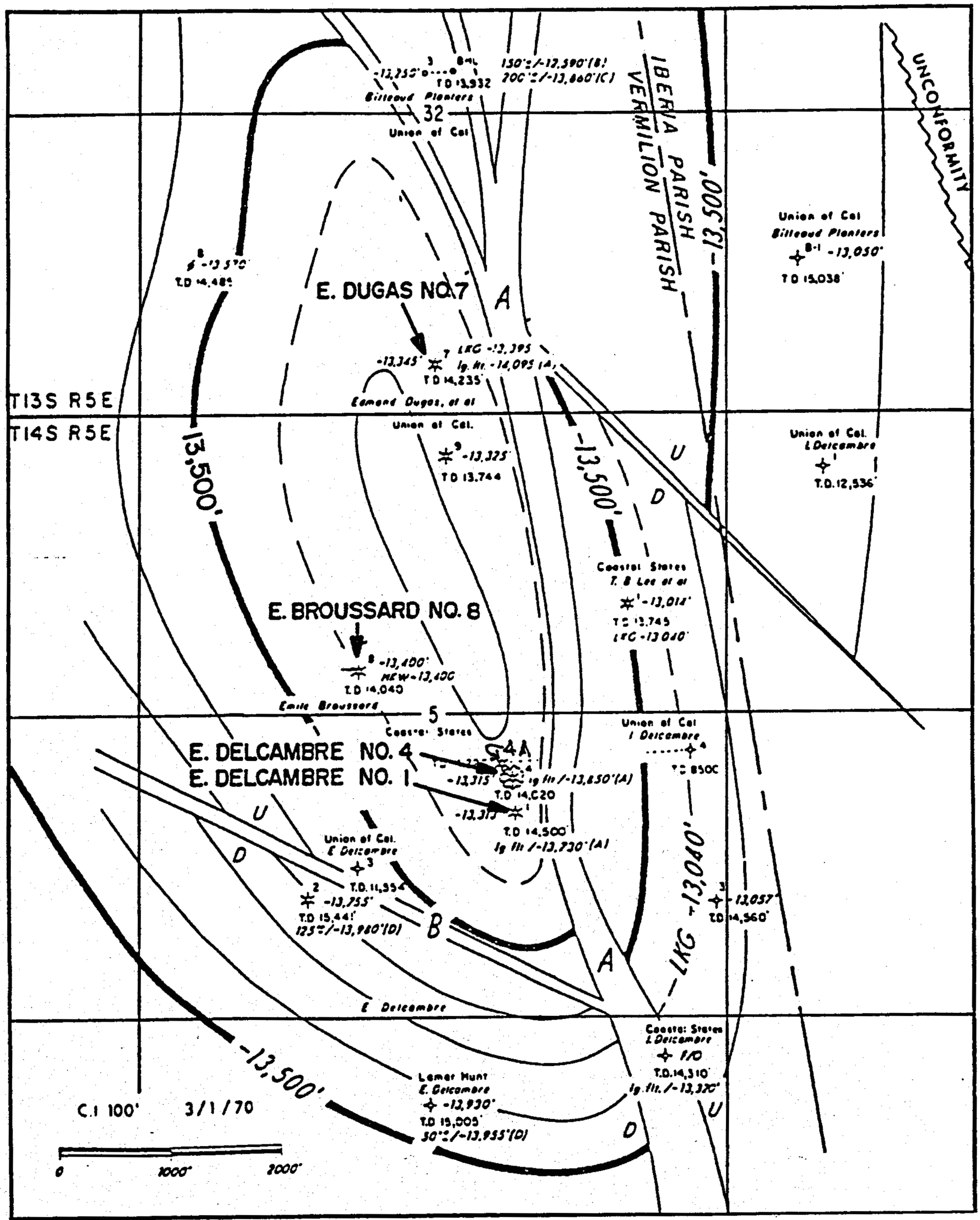


Figure 18. - - Geological Structure Map of the Planulina No. 6 Sand (from Wolgemuth et.al., 1980, Clark, 1979).

The free gas cap hypothesis gave an approximate fit to the production data if the edge of the gas cap is only about 400 ft. away. The geologic structure map indicated a free gas cap approximately 1,100 ft. away, but the #4 and #4A wells are located 400 ft. away and could be the source of the free gas (Figure 18).

The Coastal States Delcambre #4 well was drilled 400 ft. away from the #1 Delcambre and completed in the *Planulina* #8 sand. Cumulative production from this sand was 5.2 BCF. The #4 well suffered an underground blowout during workover operations. The #4A well was drilled directionally as a relief well to kill the blowout. The #4A well was completed in an upper *Planulina* sand, possibly the *Planulina* #1 sand, and produced 3.7 BCF after successfully killing the #4 blowout. The #4A well was finally junked and abandoned after killing a second blowout in the #4 well. The #4 well was subsequently abandoned.

The production problems associated with the #4 and #4A wells, and the documented hydrocarbon flow between reservoirs make those wells a likely source for possible free gas in the tested geopressured zones. In addition, all the *Planulina* sands have proven hydrocarbon productive in the Tigre Lagoon field. Therefore, a free gas phase near the #1 Delcambre well is possible. A summary of the test results from the Edna Delcambre No. 1 well is given in Table 2.

EDNA DELCAMBRE #1 WELL RECOMPLETION

The information following is taken from the Terra Tek, Inc. final report by Wolgemuth et al., 1977 (Contract EG-77-C-01-4060):

The Delcambre #1 well was left by Coastal States Producing Company with the production string intact. The last gas production was reported in May, 1975, and came from

Table 2
SUMMARY OF TEST RESULTS
Edna Delcambre No. 1

TOTAL DEPTH:	14,500 feet	
FORMATION:	Planulina basin; lower Miocene	
	Sand No. 1	Sand No. 3
PERFORATED INTERVAL	12,573' - 12,605' (32 feet)	12,869' - 12,911' (42 feet)
BOTTOMHOLE STATIC PRESSURE:	10,858 psia (at 12,589 feet)	11,012 psia (at 12,893 feet)
BOTTOMHOLE STATIC TEMP:	234°F	238°F
POROSITY:	29%	26%
NET PAY:	30 feet	48 feet
MAXIMUM WATER PRODUCTION:	12,700 BWPD	10,300 BWPD
MAXIMUM SURFACE FLOWING TEMP:	222°F	219°F
TESTING: DATES:	June 23-July 13, 1977	May 22-June 7, 1977
TESTS:	8 Pressure Drawdown 4 Pressure Buildup	5 Pressure Drawdown 3 Pressure Buildup
EFFECTIVE PERMEABILITY:	104	33 md
GAS SOLUBILITY:	22.8 SCF/bbl	24.6 SCF/bbl
PRODUCED GAS/WATER RATIO:	17-64	25-222
SAND PRODUCTION:	Minimal	Some
ANALYSIS OF WATER:		
Total Dissolved Solids:	133,000 mg/l	113,000 mg/l
Sodium Chloride:	117,000	109,000
Density:	1.0852 @ 20°C	1.0712 @ 20°C
ANALYSIS OF GAS:		
Methane:	95.4 mole %	92.8 mole %
Ethane	1.7	3.5
Propane	2.0	1.1
CO_2:	2.0	1.1
Energy Content:	920,000 Btu/mcf	1,065,000 Btu/mcf

(From Wolgemuth et.al., Terra Tek, Inc. Rept., 1980)

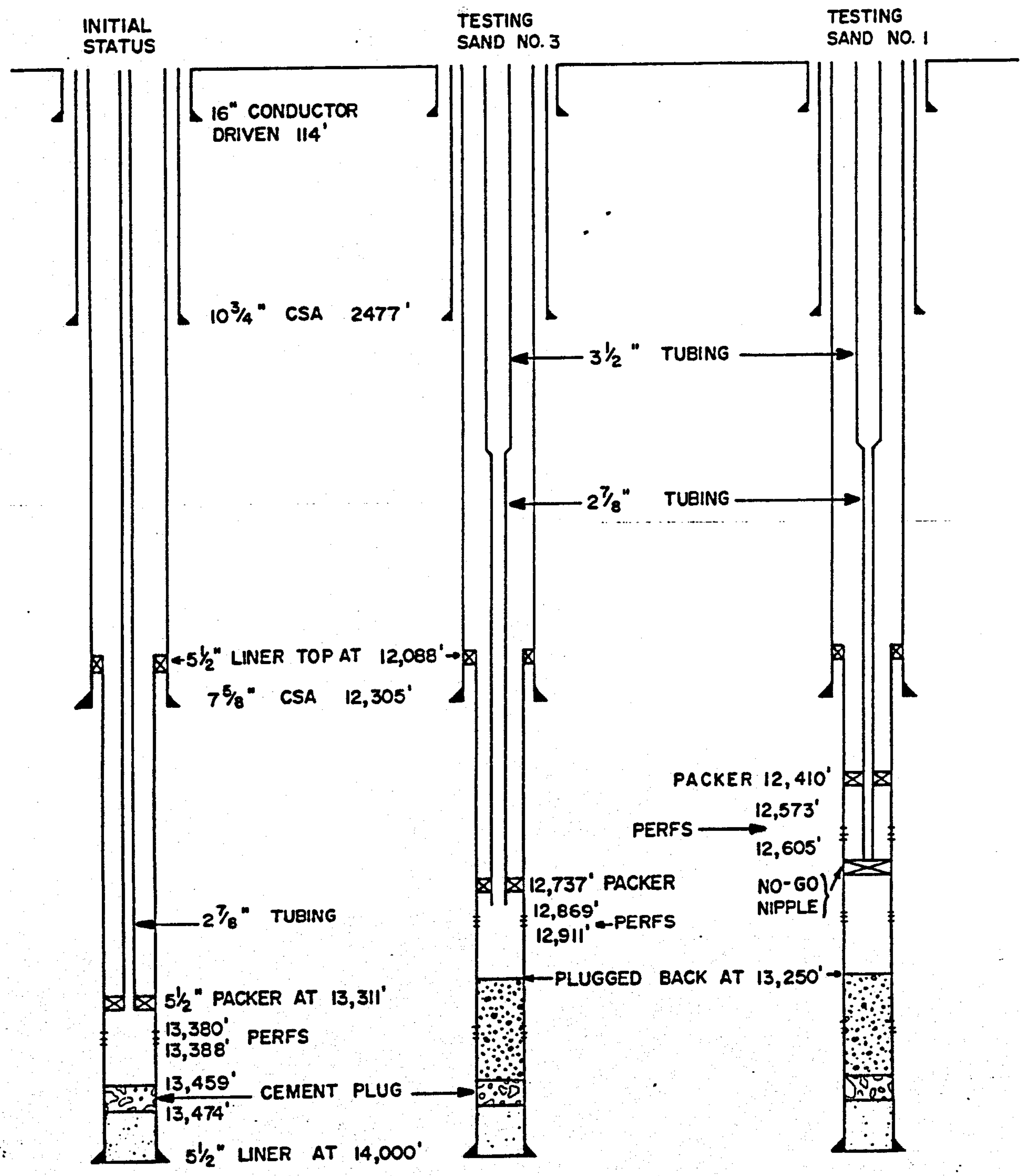


Figure 19. - - Schematic of Downhole Hardware for the Edna Delcambre #1 Well (from Wolgemuth et.al., 1980 in Terra Tek Rept. 1980).

perforations between 13,380 ft. and 13,388 ft. (Sand No. 6). Figure 19 shows the condition of the well at the start of the Well of Opportunity program. Sixteen inch conductor pipe was in-place and extended down to 114 ft. Surface casing was 10¾ inch in diameter and set to 2,477 ft. The production string consisted of 2⅞ inch tubing and was set at 13,306 ft. on top of a Baker Tool Model 43-F-30 packer at 13,311 ft. A cement plug extending from 13,459 ft. to 13,474 ft. was in place. The 5½ inch liner extended from slightly over 12,000 ft. to over 14,000 ft.

During well recompletion for this project, a casing leak occurred around 11,570 ft. To insure the integrity of the casing above and below the leak, a 5½ inch liner was set from 9,844 ft. to 12,014 ft. and cemented in place. No further problems were encountered with the casing string.

The tubing strings for testing of both sands is shown schematically in Figure 19. For Sand #3, the completion string was:

9,734 ft., 3½ inch OD, 12.95 lb/ft., P-105 IJ355 tubing

1,056 ft., 2⅞ inch OD, 8.9 lb/ft., P105 IJ355 tubing

1,935 ft., 2⅞ inch OD, 7.9 lb/ft., P-105 IJ355 tubing

17.4 ft. Baker seals

33.25 ft., 2⅞ inch OD, N-80 EF perforated tubing

65.53 ft., 2⅞ inch OD, N-80 EF tubing

A Baker Model W-F-30 packer was set at 12,737 ft. Sand #3 was perforated from 12,870' - 12,919' at a density of four shots per foot. Flow tests were done on this sand for 24 days.

For Sand #1, the completion string was:

9,630 ft., 3½ inch OD, 12.95 lb/ft., P-105 IJ355 tubing

1,036 ft., 2⅞ inch OD, 8.9 lb/ft., P-105 IJ355 tubing

1,725 ft., 2⅞ inch OD, 7.9 lb/ft., P-105 IJ355 tubing

16 ft. Baker seals

33.25 ft., 2⅞ inch OD, N-80 EF perforated tubing

65.53 ft., 2⅞ inch OD, N-80 EF tubing

NO-GO nipple on bottom

The Baker seals seated into a Baker 5½ inch by 3 inch Model W-F-30 packer which was set at 12,410 ft. The seal assembly allowed for expansion and contraction of the tubing string through the packer. Sand No. 1 was perforated in the interval 12,573' - 12,605' at the rate of four shots per foot and was flow tested for 25 days.

FAIRFAX FOSTER SUTTER #2

The Fairfax Foster Sutter #2 well is located in Sec. 6, T 15S, R 10E, St. Mary Parish, Louisiana and is approximately four miles east of the town of Franklin. Bayou Teche lies about a mile to the south of the well location.

The site can be reached by State Highway 87 and a short stretch of oyster shell and board roads as it lies in an area of marshes and waterways. Detailed information on all the testing and other investigations carried out on this well are discussed by Willits et.al (1979) in the reports by Gruy Federal Inc. (DOE Contract No. DE-AC08-77ET28460) and No. EG-77-C-08-1528). The Garden City gas field lies approximately 3 miles to the south of this well which is associated with the East Franklin gas condensate field where production is from the Miocene age MA-4 and MA-5 series sands (Willits et.al., 1979). These two fields are separated from each other by faulting. Gruy Federal took over the well in March 1978 after it was abandoned as a dry hole by Neuhoff Oil and Gas Company who had drilled it to a total depth of 16,340 ft.

The prospective geopressured - geothermal section tested was the *Marginulina ascensionensis* (MA) 6 sands of lower Miocene age. These sands were interpreted as being deposited in the shallow marine or inner neritie environment as regressive blanket sands. The MA-6 sand does not produce hydrocarbons in the East Franklin field but is hydrocarbon productive in the Garden City Field. A structure map of the MA-6 sand and the log of the Fairfax Foster Sutter #2 well is shown in Figure 20. The general structure of the Franklin area is essentially a domal uplift which is truncated to the north by a large regional growth fault and to the south by smaller bifurcating faults (Figure 20).

The MA-6 sand in this well has a gross thickness of 270 ft., (190 ft. net sand). The perforated interval was from 15,781 to 15,916 ft. However, as a result of problems involved with setting the production packs, only the upper 58 ft. of perforations were tested. Original formation pressure was 12,220 psia, temperature 270°F, and effective porosity, derived from the electrical log averaged 19.3%. A summary of the test results of the Fairfax Foster Sutter #2 well is shown in Table 3.

Testing of the geopressured - geothermal MA-6 reservoir consisted of two flow tests and two buildup tests over 73 days. The maximum flow rate was 7,747 BWPD. This rate could not be sustained, presumably due to the low permeability. An effective permeability of 14.3 md was obtained by pressure transient analysis. The geologic interpretation which placed the well

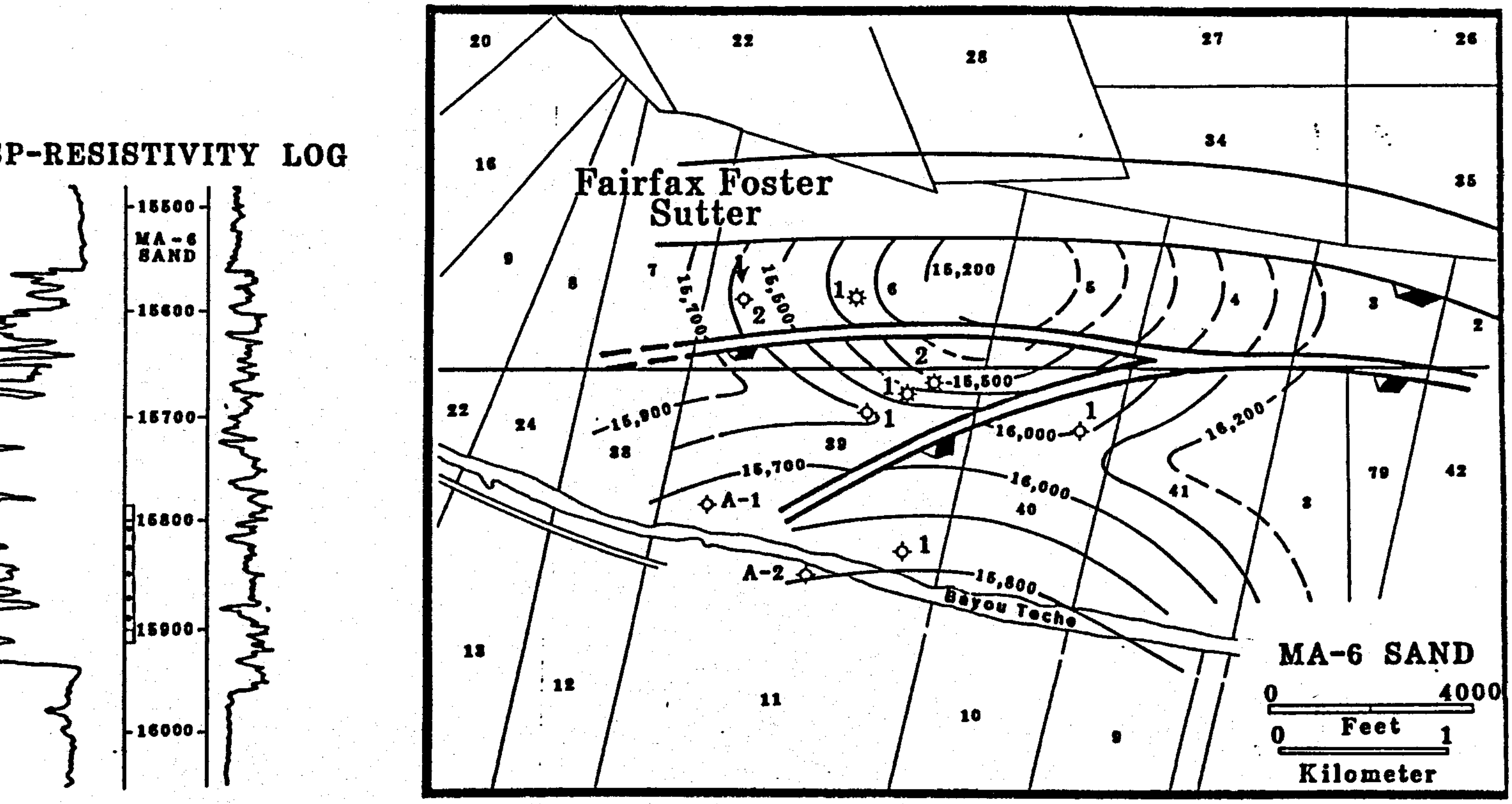


Figure 20. - - Structure map of the MA-6 sand and log of the Gruy Federal-DOE No. 2 Fairfax Foster Sutter test well (modified from Gruy 1979, from Miller, 1991, *in* Groat, 1991).

Table 3

SUMMARY OF TEST RESULTS
Fairfax Foster Sutter No. 2
East Franklin Area
St. Mary Parish, Louisiana

TOTAL DEPTH: 16,340 feet

FORMATION: Marginulina ascensionensis (MA) 6
Lower Miocene

GROSS PERFORATIONS: 15,781-15,916 feet

ORIGINAL RESERVOIR PRESSURE: 12,220 psia

ORIGINAL RESERVOIR TEMPERATURE: 270°F (132°C)

AVERAGE POROSITY: 19% (Formation density and compensated neutron logs)

TESTING:

Duration: 73 days including cleanup.
Tests: 3-day drawdown
6.5-day buildup
11 day drawdown
19.5 day buildup

EFFECTIVE PERMEABILITY: 14.3 md (Pressure transient tests)

GAS SOLUBILITY: 22.8 cubic feet per barrel

SAND PRODUCTION: None

SCALE FORMATION: Severe

ANALYSIS OF WATER:

Total Dissolved Solids - 203,475 mg/l
Chlorides - 91,387 mg/l
pH - 6.18
Density - 1.0932 gm/cc
SuS Viscosity - 31.3

ANALYSIS OF GAS:

Methane 89.57 mol percent
CO_2 7.85 mol percent

AQUIFER GEOMETRY: Two parallel sealing faults

(From Willits et.al., 1979, Gruy Federal Inc. Rept., 1979).

approximately 900 ft. and equidistant from two parallel faults was confirmed as a result of barriers identified by interpretation of the pressure data. The test data did not provide any indication of aquifer limits. Solution gas averaged 22.8 SCF /bbl, which is near the estimated volume of 249 SCF /bbl based on recombination tests. Separator gas composition was 89.6 mol % methane, 7.9 mol % CO_2 and approximately 47 ppm H_2S. A high concentration of magnesium and calcium salts caused severe scaling problems during well testing (Miller, 1991).

Seven gas samples and 20 water samples were taken for chemical analyses during the testing. A summary of the gas analyses is shown in Table 4. Several water samples were collected by the staff of the chemistry department at McNeese State University and analyzed in their laboratory. Analyses were also performed by Southern Petroleum labs on site. Table 5 and Table 6 shown the average of the analyses done by McNeese State University and Southern Petroleum labs. McNeese's results show closer agreement between total dissolved solids and the sum of individual ton concentrations (Gruy Federal, Inc., Rept., 1979).

Produced water was reinjected into shallower sand formations between 3400' and 3830' through a salt water disposal well, located 125 ft. from the test well. The disposal well was designed to provide an injection capacity up to 10,000 B/D at an injection pressure up to 300 psi and temperature up to 280°F (138°C). A schematic figure of the disposal well is shown in Figure 21.

The status of the hole at the time of takeover by Gruy Federal Inc. from NEOHOFF, the anticipated design arrangements, the actual design, and the status of the well after final plugging and abandonment is shown in Figure 22.

TABLE 4

CHEMICAL ANALYSIS OF GAS
(7 samples)

Constituent	Mol Percent	Standard Deviation
Nitrogen (N_2)	0.518	0.017
Carbon dioxide (CO_2)	7.85	0.22
Methane (CH_4)	89.57	0.20
Ethane (C_2H_6)	1.78	0.03
Propane (C_3H_8)	0.20	0.003
Isobutane (C_4H_{10})	0.061	0.004
n-Butane (C_4H_{10})	0.014	0.005
Hydrogen sulfide (H_2S)	4-5 ppm first day 6-7 ppm remainder of test	
Radon (corrected to time of sampling)	238 picocuries per liter	

(From Gruy Federal Inc., Report, 1979)

TABLE 5

CHEMICAL ANALYSIS OF PRODUCED WATER
(20 Samples)

Constituent	Milligrams per liter	Standard Deviation
Total dissolved solids	190,904	10,000
Total solids	203,475	20,000
Calcium (hardness, as $CaCO_3$)	18,305	1,000
Magnesium (as $MgCO_3$)	2,320	187
Bicarbonate (HCO_3)	208	49
Carbonate	0	0
Chloride (Cl)	91,387	3,500
Total iron (Fe)	56	14
Sulfate (SO_4)	< 1	
Dissolved silicate (SiO_2)	60	18
Copper (Cu)	0.33	0.07
Zinc (Zn)	2.11	1.55
Boron (B)	68.5	7.3
Arsenic (As)	-	-
Chromium (Cr)	0.16	0.03
Mercury (Hg)	< 0.0005	-
Lead(Pb)	-	-
Cadmium (Cd)	0.77	0.22
Sodium (Na)	48,281	2,000
Potassium (K)	988	100
Uranium (U)	0.00003	-
Radium (Ra)	1,765 disintegrations per minute per liter	
Density	1.0932 g/ml	
pH	6.18	
Sus viscosity at 95°C	31.3	

(From Gruy Federal Inc. Report, 1979)

TABLE 6

CHEMICAL ANALYSIS OF PRODUCED WATER
(McNeese State University)

Constituent	Milligrams per liter
Total dissolved solids	155,880
Chloride (Cl)	94,705
Dissolved silicate (SiO_2)	86
Sodium (Na)	44,400
Potassium (K)	900
Iron (Fe)	57
Zinc (Zn)	0.89
Calcium (Ca)	7,670
Magnesium (Mg)	623
Cadmium (Cd)	0.2
Strontium (Sr)	597

(From Gruy Federal, Inc. Report, 1979)

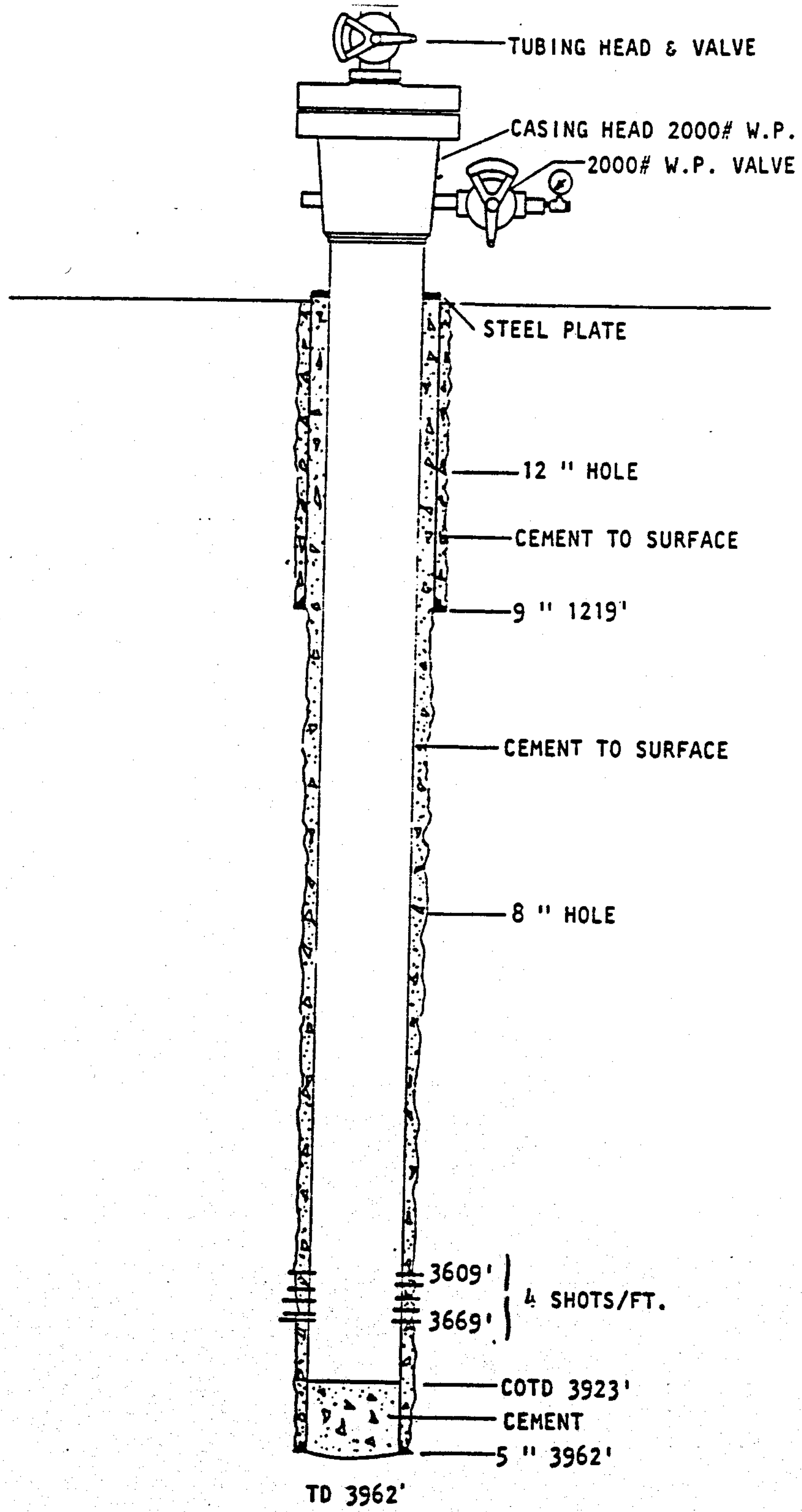


Figure 21. - - Fairfax Foster Sutter No. 2 Schematic for Disposal Well (From: Gruy Federal, Inc., Report, 1979).

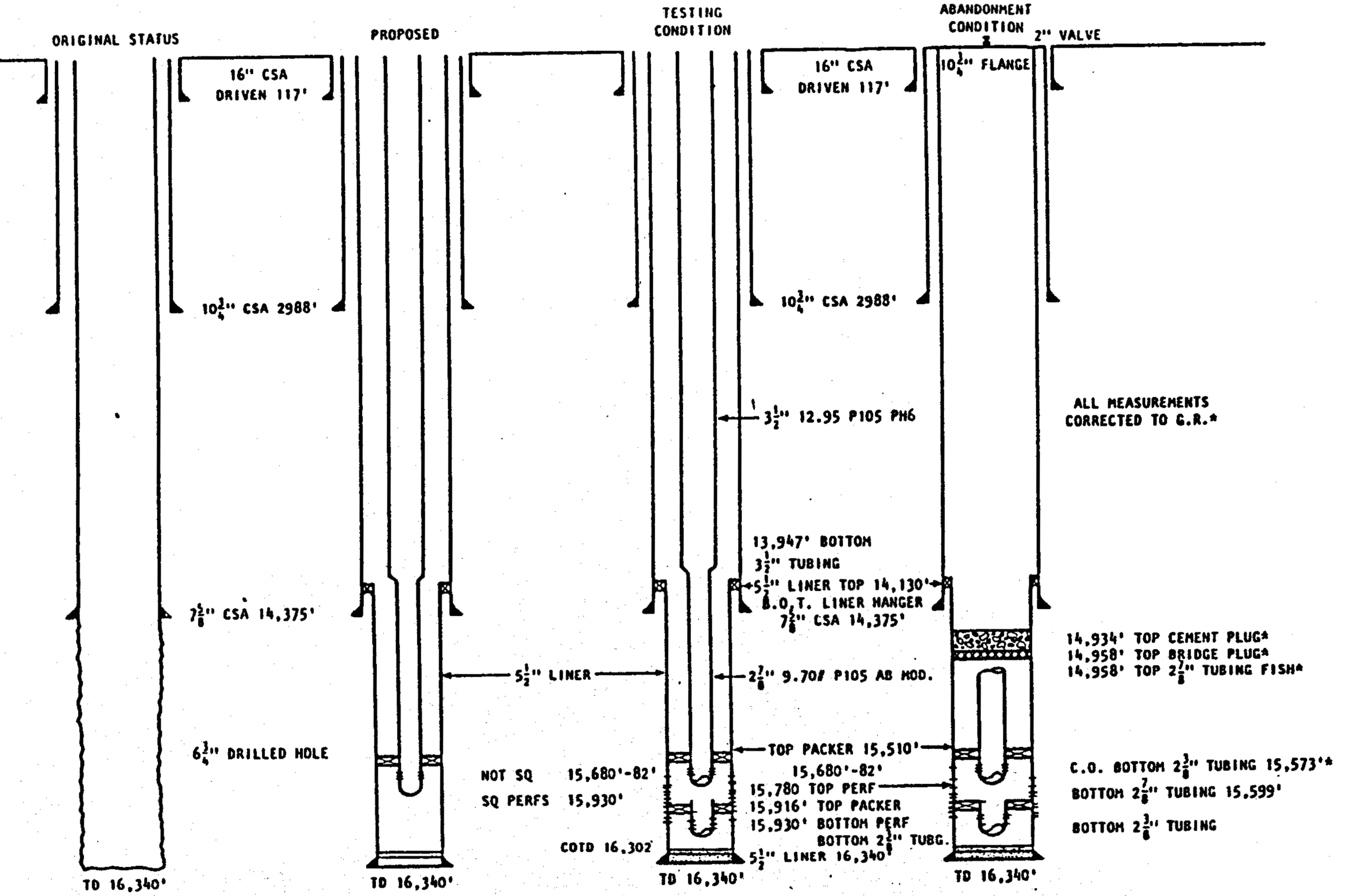


Figure 22. - - Fairfax Foster Sutter No. 2 Schematic of Downhole Condition (From Gruy Federal Inc., Report, 1979).

Production testing was completed and the well was shut in for pressure build up on June 20, 1979. The well was killed on July 10, 1979 and handed over to Neuhoff Oil and Gas on August 20, 1979, in accordance with the agreement.

BEULAH SIMON #2

The Beulah Simon #2 well is located in Section 26, T 11S, R 2E, Vermilion Parish, Louisiana, about five miles northeast of the town of Kaplan and about 30 miles southeast of Lafayette. Details of all the investigations, testing and analyses done at this well are provided in the Gruy Federal Inc. report (DOE Contract No. AC08-77ET28460) written by Dobson et.al. (1980). The well site is about 20 ft. above sea level and was protected by a ring levee. The well site was accessible via parish and oil field roads, which included about 2,200 feet of board and shell road installed by Southpart Exploration. The well location was adjacent to the Abbeville field to the southeast, LeRoy to the east, Leleux to the north, Perry Point to the northwest and Kaplan to the southwest. The Southpart Beulah Simon #1 well, about a mile to the west produced as from a different reservoir and fault block. (Gruy Federal Inc., 1980).

The Beulah Simon #2 well was originally drilled to a depth of 15,265 ft. by a group for which Southpart Exploration, Inc. was the operator. As the well was dry it was taken over by Gruy Federal Inc., under an arrangement with Southpart for geopressured - geothermal testing for the Department of Energy with whom Gruy Federal had a contract. Geopressured - geothermal test operations were conducted by Gruy Federal from September through December 1979.

The well was completed in a geopressured Oligocene age *Camerina* A sand (Upper Frio). Structurally, the well as positioned near the crest of a fault wedge trap in a downdip, synclinal position between hydrocarbon producing fields. Regionally the test site was identified to be in the Cossinade field area.

This *Camerina* section is thought to have been deposited in an inner neritie environment during a regressive stage. Figure 23 shows a structure map at the top of the *Camerina* A sand and an electrical log of the sand tested showing the perforated interval. The test well is bounded on the north, south and west by down to the south growth faults. Interpretation of the transient pressure data indicated the presence of two parallel barriers, probably faults at distances of 556 ft. and 794 ft. from the well (Gruy, 1980).

Beulah Simon #2 penetrated 260 ft. net sand in the *Camerina* A section. The well was perforated from 14,674 ft. to 14,770 ft. Original formation pressure at 14,722 ft. (ie. midpoint of the perforated interval) was 13,015 psia, formation temperature 266°F, measured salinity was 103,925 ppm TDS. Log derived porosity averaged 17.4% being 14.5% at the top of the sand section and ranging to 22.4% at the base of the section. The well was flow tested for 10 days with an average flow rate of 11,000 BWPD being maintained throughout the test. The brine is saturated with gas at 24 SCF /bbl. Contents of the produced gas is 88.9 mol % methane and 7.7 mol % CO_2. Effective water permeability is 11.6 md. A summary of the test results of the Beulah Simon #2 well is shown in Table 7. Chemical analysis of the gas is shown in Table 8, and the chemical analysis of produced water is shown in Table 9.

A schematic illustration of the downhole conditions of the Beulah Simon #2 well at the time of takeover by Gruy Federal, Inc. for geopressured - geothermal well testing, its condition while testing and after being abandoned is shown in Figure 24.

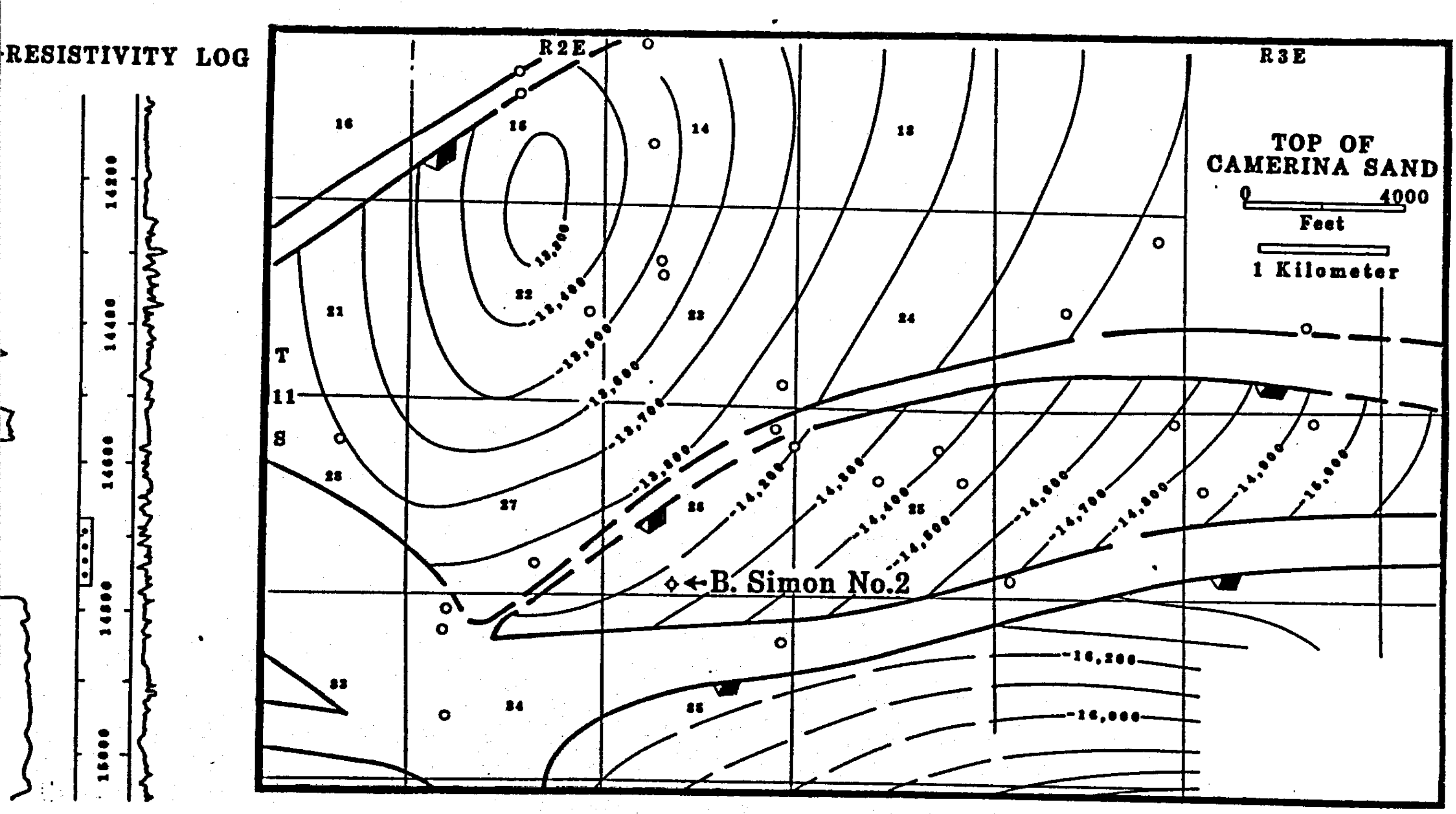


Figure 23. - - Structure map and log of the Beulah Simon #2 test well (From Miller 1991, in Groat, 1991 and modified from Gruy, 1980).

TABLE 7

SUMMARY OF TEST RESULTS

BEULAH SIMON NO. 2 TEST WELL

Total depth:	15,265 ft (surface elevation 24 ft)
Formation:	Camerina (Upper Oligocene)
Perforated interval:	14,674-14,770 ft
Original reservoir pressure:	13,015 psi at 14,722 ft
Original reservoir temperature	266°F (130°C)
Completion and testing:	
Duration:	62 days, Oct. 28 to Dec. 29, 1979
Tests:	10-day drawdown, Nov. 28 to Dec. 8; 20-day buildup, Dec. 8 to Dec. 29
Production Rate:	11,011 BWPD initial 10,833 BWPD final
Gas/water ratio:	19.6-20.8 scf/STB (separator pressure of 500 psi) 24.0 scf/bbl at standard conditions
Sand production:	None
Scale formation:	None
Analysis of water:	
Total dissolved solids	103,925 ppm
Chlorides	50,300 ppm
pH	6.61
Density	1.066 gm/cc
Analysis of gas:	
Methane	88.868 mol percent
Carbon dioxide	7.726 mol percent
Aquifer geometry:	Two parallel faults
porosity	18.7 percent
Permeability	12 md
Disposal interval:	2,464 to 2,524 feet
Injection pressure:	70-90 psi
Injection temperature:	251-255°F

TABLE 8

CHEMICAL ANALYSIS OF GAS (MOLE PERCENT)

	SPL (10 Samples)		IGT (6 Samples)	
	AVE.	STD. DEV.	AVE.	STD. DEV.
Nitrogen (N_2)	0.271	0.015	0.066	0.038
Carbon Dioxide (CO_2)	7.726	0.745	5.062	0.141
Methane (CH_4)	88.868	0.682	91.079	0.107
Ethane (C_2H_6)	2.202	0.052	2.291	0.037
Propane (C_3H_8)	0.601	0.006	0.722	0.025
ISO Butane ($i\text{-}C_4H_{10}$)	0.178	0.004	0.162	0.012
Normal Butane ($n\text{-}C_4H_{10}$)	0.070	0	0.091	0.011
Others (Hydrogen, C_5+, Benzene, Toluene)	0.084	.008	0.527	0.054

BTU Content (Calculated)

Wet 970

Dry 987

(From Gruy Federal, Inc., 1980)

TABLE 9

CHEMICAL ANALYSIS OF PRODUCED WATER
BEULAH SIMON NO. 2

Constituent	Southern Petroleum Labs (10 Samples) Milligrams Per Liter	Southern Petroleum Labs (10 Samples) Standard Deviation	National Gas Institute (6 Samples) Milligrams Per Liter	National Gas Institute (6 Samples) Standard Deviation
Total Dissolved Solids	103,925	8016	91,533	1524
Total Solids	104,947	7815	102,250	25,924
Calcium ($CaCO_3$)	7,869	548	6,955	736
Magnesium ($MgCO_3$)	910	39	887	18
Bicarbonate (HCO_3)	606	93	868	118
Carbonate	1	0	0	--
Chloride (Cl)	50,300	909	54,050	1372
Total Iron (Fe)	33	9.4	N.D.	--
Dissolved Silicate (SiO_2)	92	9.5	69	35.6
Copper (Cu)	0.152	0.019	N.D.	--
Zinc (Zn)	0.136	0.163	N.D.	--
Boron (B)	89.6	2.757	67.8	9.4
Arsenic (As)	0.002	0.000	< 0.01	--
Chromium (Cr)	0.086	0.014	N.D.	--
Mercury (Hg)	0.005	0.000	N.D.	--
Lead (Pb)	7.73	10.646	N.D.	--
Cadmium (Cd)	0.269	0.077	N.D.	--
Sodium (Na)	32,190	1521	28,150	2620
Potassium (K)	454	68	470	15
Ammonia (NH_3)	29.8	2.94	N.D.	--
Barium (Ba)	30.4	1.96	N.D.	--
Sulfate (SO_4)	444	15	381	64
Density (gm/ml)	1.066	0.0023	--	--
pH	6.61	0.088	7.03	0.46
SUS Viscosity	28.55	0.314	--	--

(From Gruy Federal, Inc., 1980)

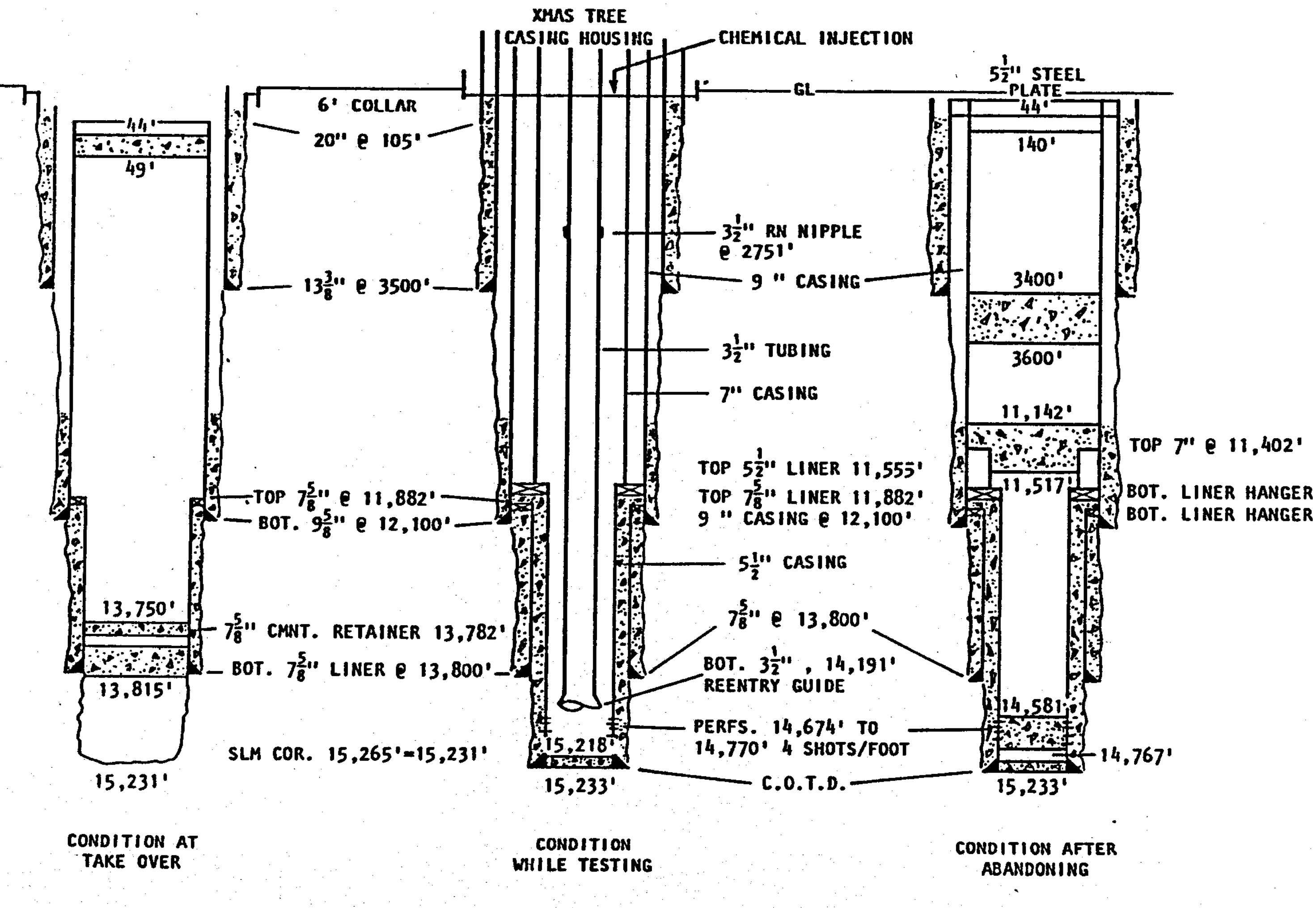


Figure 24. - - Schematic of downhole conditions, Beulah Simon No. 2 (from Gruy Federal, Inc., 1980).

The brine produced from the Beulah Simon #2 testing was injected through a salt water disposal well (Beulah Simon #1) which was drilled about 160 ft. from the test well. It was designed to provide an injection capacity of up to 10,000 B.D. at an injection pressure of up to 300 psi and an injection temperature up to 280°F (138°C). The water was disposed although perforations between 2,464 ft. and 2,524 ft. into a formation made of unsolidated to poorly consolidated sands. A schematic of the salt water disposal well, its electric log and condition after plugging and abandonment is shown in Figure 25.

P. R. GIROUARD #1

The P.R. Girouard #1 well is located about 10 miles southeast of Lafayette, Louisiana, and is approximately 1,500 ft. west of U.S. Highway 90. Specifically it is located in Section 10, Township 11S, Range 5E, and is in the Cade field area in Lafayette Parish, Louisiana. Eaton Operating Company, Houston, Texas, assumed control of this well from Wainoco Oil and Gas Company after it was abandoned as dry hole at a total depth of 15,700 feet. The objectives of testing this well, under the wells of opportunity program, were similar to those of other wells tested under this program. These tests were conducted to obtain accurate, reliable, short term information concerning the following : (Eaton Operating Company, 1981):

(a) The aquifer fluid properties, including in situ temperature, chemical composition hydrocarbon content, and pressure.

(b) The characteristics of geopressured - geothermal reservoirs, including permeability and porosity, extent and distribution of sands and shales, degree of compaction, and rock composition.

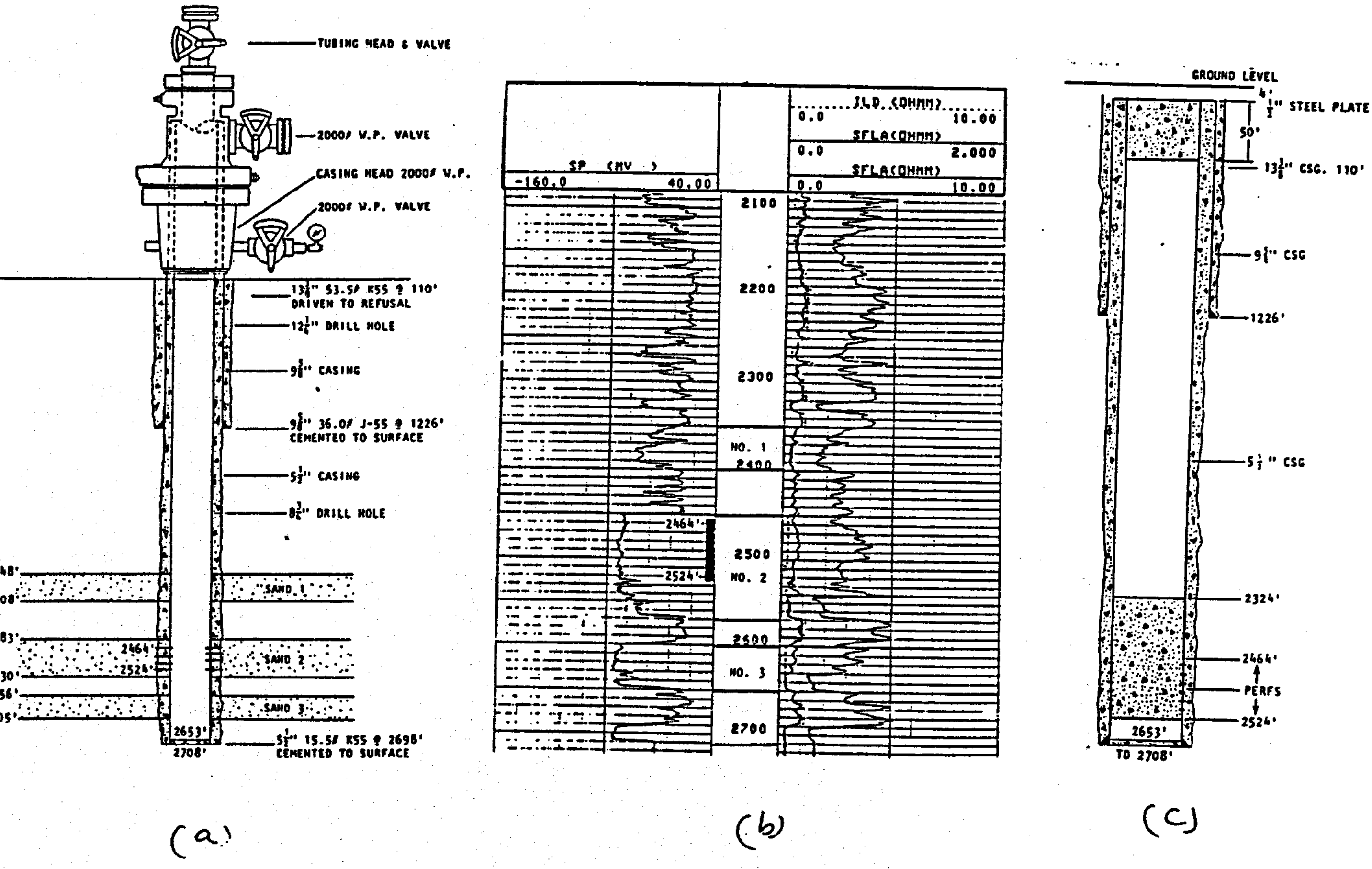


Figure 25. - - (a) Beulah Simon No. 1 salt water disposal well schematic. (b) Electric log © Well status after plugging and abandonment. (From Gruy Federal, Inc., 1980).

(c) The behavior of fluids and reservoirs under conditions of fluid production at moderate and high rates, including pressure time behavior at different flow rates, fluid characteristics under varying production conditions, and other information related to the reservoir drive mechanisms and physical and chemical changes that may occur with various production conditions.

(d) The evaluation of completion techniques and production strategies for geopressured - geothermal wells.

(e) Analysis of the long-term environmental effects of an extensive commercial application of geopressured - geothermal energy, to the extent determinable during testing.

Detailed information on the testing and evaluation of the above mentioned objectives for the P.R. Girourad #1 well is contained in the reports by Eaton Operating Company (1981) under DOE Contract No. DE-AC08-80ET27081. The information compiled here for this well is taken from this source.

The prospective geopressured - geothermal sand section tested in the P.R. Girouard Well is the *Marginulina Texana* No. 1 sand (*Marg. Tex* 1) in the Upper Frio formation of Oligocene age. It is generally interpreted as a lenticular sand body deposited on a broad continental shelf in a barrier bar or strand plain environment. These sands are mostly medium to five grained and contain some illite, mentmarillonite and organic debris according to Jones (1969). Structurally the well penetrates this horizon in a southwest dipping downthrown fault block on the southern flank of the Cade field. The north bounding fault (Figure 26) is approximately 1,200 ft. from the wellbore and fault displacement varies from 100 ft. to 300 ft. across the field. Figure 27 shows an southwest -northeast cross section showing the *Marg. Tex* sand in the P.R. Girouard #1 (Wainoco-Girouard) well. As seen in this cross section this sand pinches out in the northeast

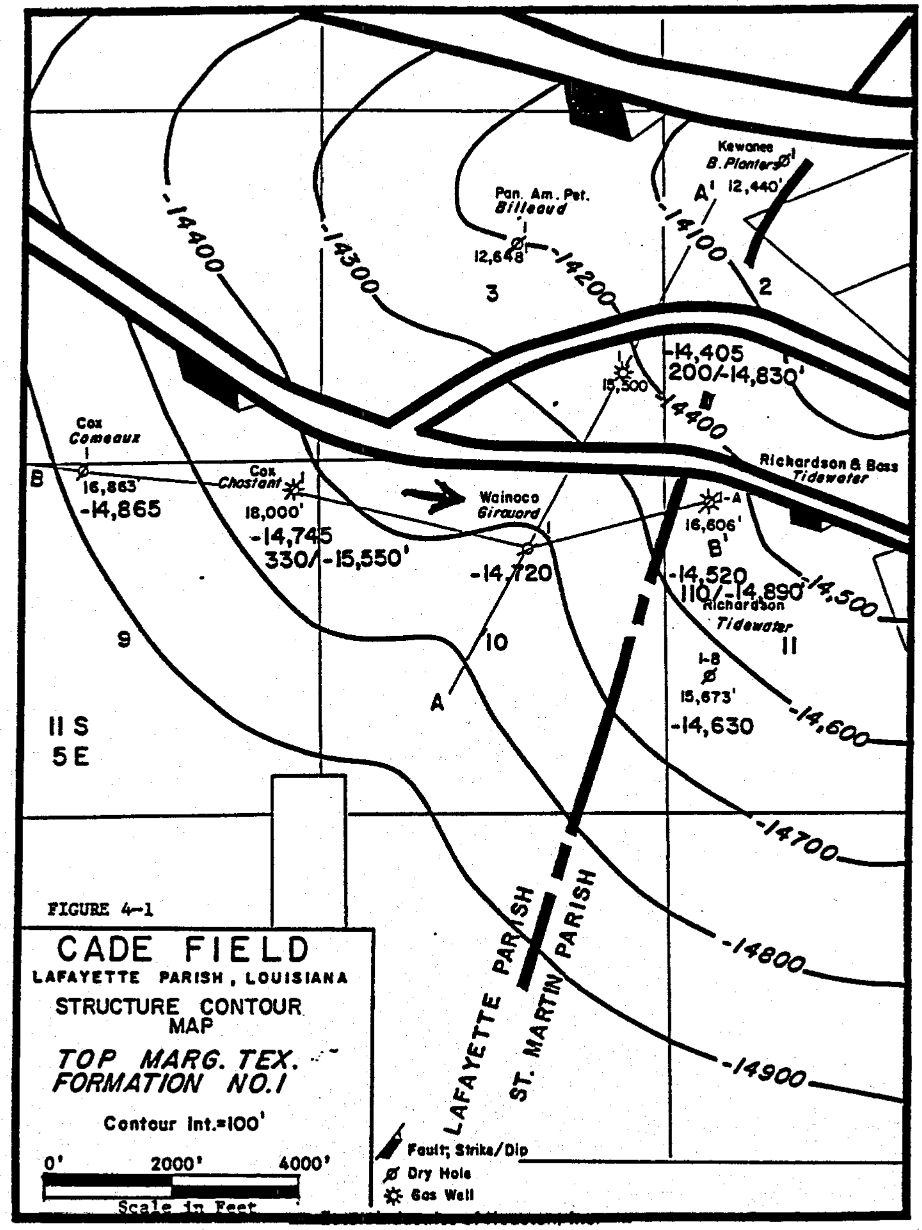


Figure 26. - - Structure map drawn at the top of the *Marg. Tex* sand showing the location of the P.R. Girouard Well #1 (From Eaton, 1981).

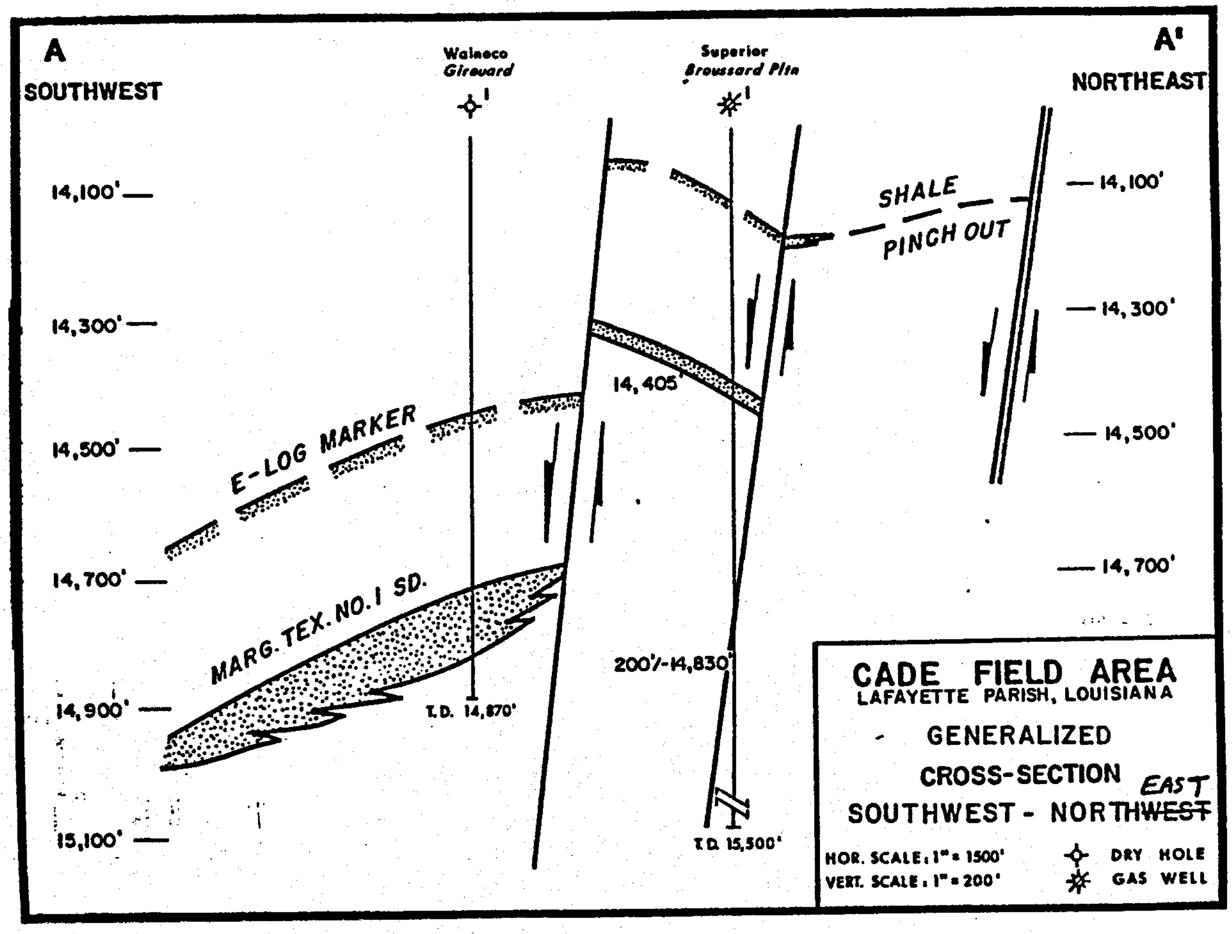


Figure 27. - - A southwest - northeast cross section illustrating the *Marg. Tex.* #1 sand in the P.R. Girouard #1 well. The cross section line is shown in Figure 26 (From Eaton Operating Co. Report, 1981).

direction and its thickness varies from approximately 105 ft. in this well to about 15 ft. in the Superior - Broussard #1 well to the north. An east - west cross section of the Cade field area through the test well shows that the *Marg. Tex* No. 1 sand is best developed and thickest in this well (Figure 28).

The *Marg. Tex* #1 sand in the P.R. Girouard #1 well has a net sand thickness of 91 ft. Sonic derived average porosity is 26%. The sand was perforated from 14,744 ft. to 14,819 ft. (Figure 29). Original formation pressure was 13,203 psia, temperature 274°F, measured salinity 23,500 ppm. A summary of the test results is provided in Table 10. A total of five flow tests were conducted over 15 days. Drawdown permeability ranged from 200 to 240 md. The maximum flow rate achieved was 15,000 BWPD and the cumulative production of brine was 41,930 bbl. Solution gas-to-water ratio was 40 SCF /bbl. Recombination studies yielded a brine saturation volume of 44.5 SCF /bbl, indicating that the brine slightly under saturated. Post-separator gas composition is 91.3 mol % heavy hydrocarbons and 0.2 mol % other. Pressure transient analysis indicated a permeability barrier near the wellbore, restricting the flow angle to less than 50 which was interpreted as indicating a lenticular sand body geometry. In general it was concluded that this well could not sustain flow rates over 10,000 BWPD due to the position of the well relative to the lenticular sand body geometry, and not because of reservoir sand quality (from Miller, 1991 in Groat, 1991).

The test well conditions at the time Eaton Operating Company took over the well from Wainoco and during testing of the well by Eaton Operating Company is shown in Figure 30.

Brine produced during testing of the P.R. Girouard #1 well was disposed by subsurface injection. The brine disposal well was located 110 ft. southeast of the test well. The disposal well

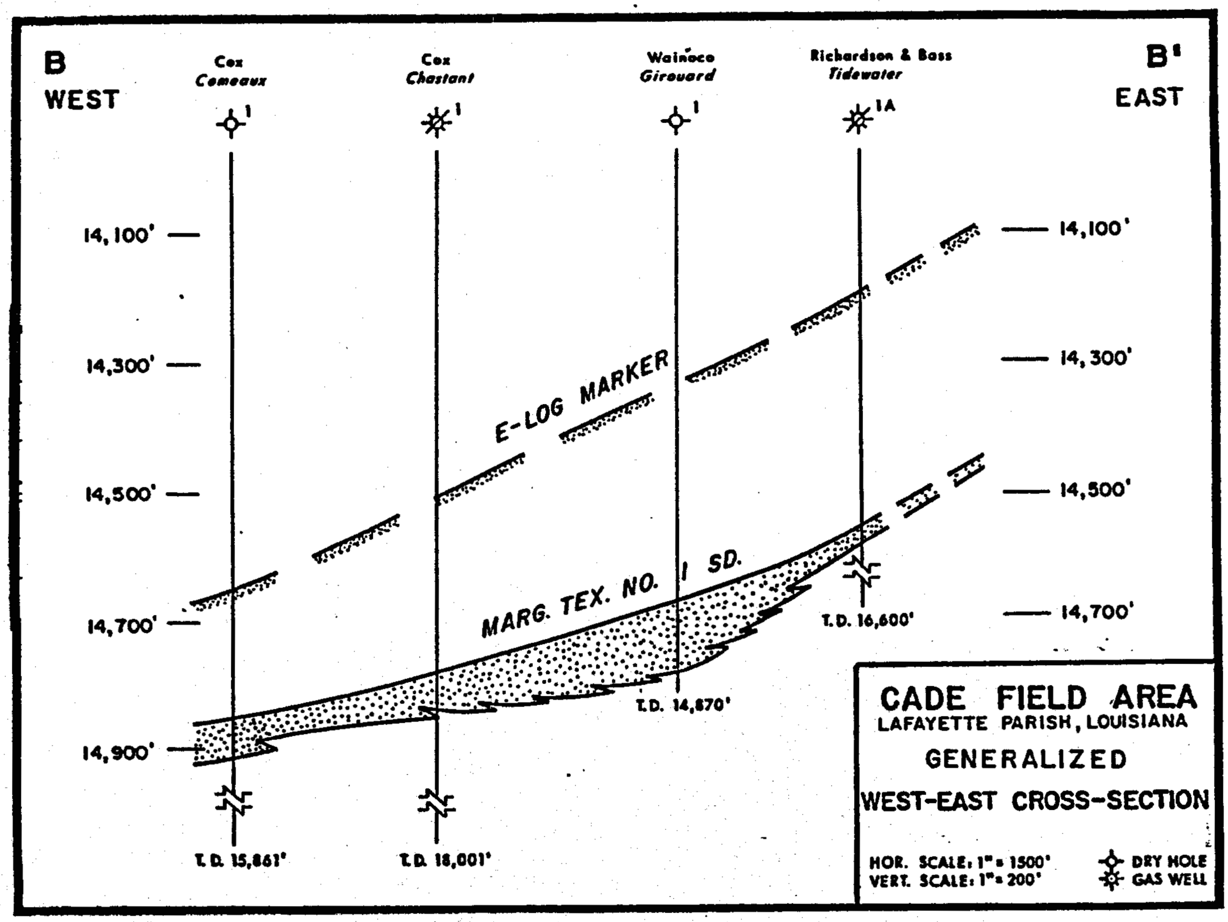


Figure 28. - - An east-west cross section through the Cade field area illustrating that the *Marg. Tex* #1 sand is thickest in the Girouard test well. The cross section line is shown in Figure 26 (From Eaton Operating Co. Report, 1981).

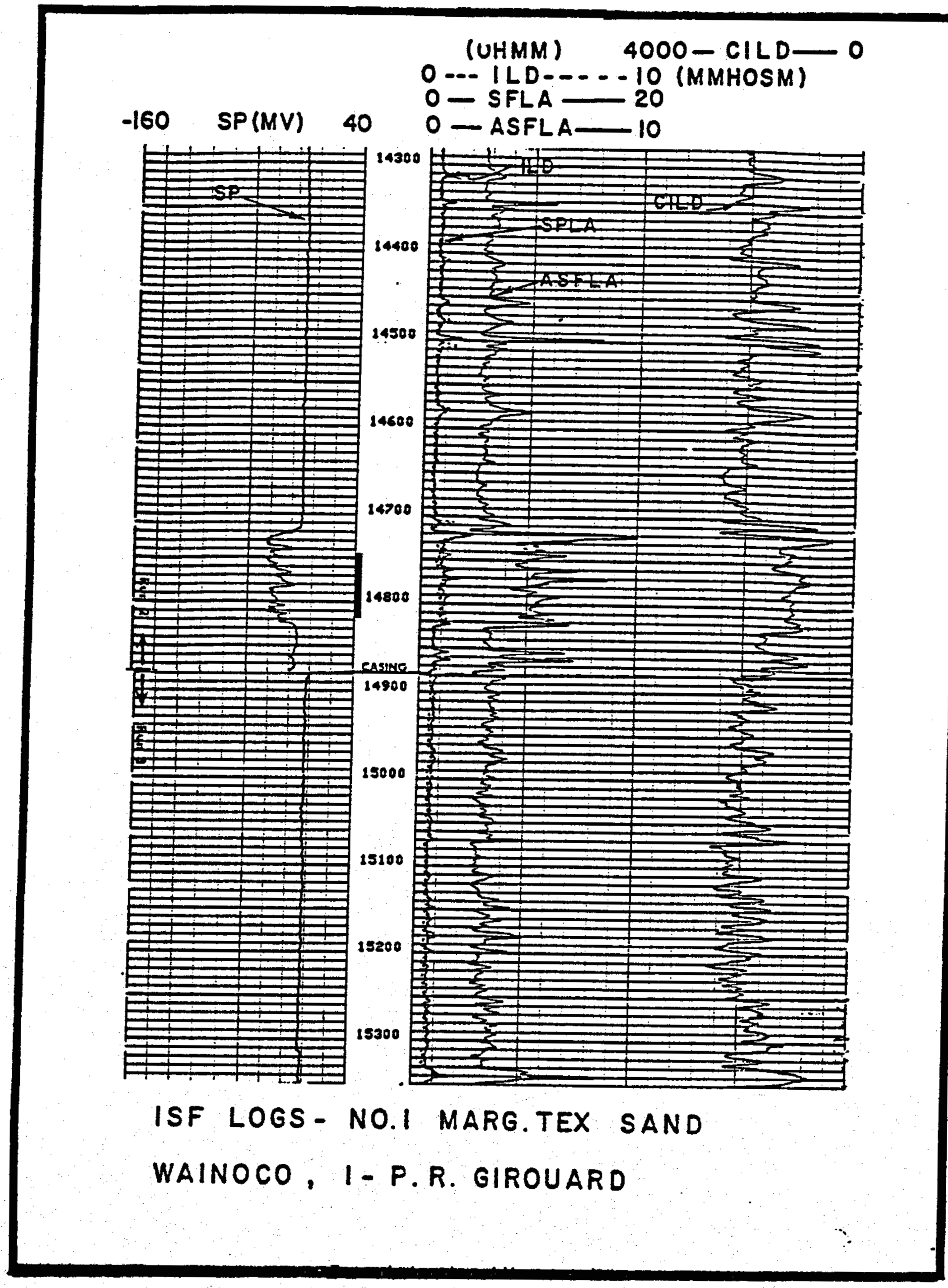


Figure 29. - - Electric log of the P.R. Girouard #1 test well showing the *Marg. Tex.* #1 sand which was tested (From Eaton Operating Co. Report, 1981).

TABLE 10

SUMMARY OF TEST RESULTS

P. R. GIROUARD WELL NO. 1
CADE FIELD
LAFAYETTE PARISH, LOUISIANA

Total Depth of Well	15,700 Feet
Formation	Oligocene Marginulina Texana No. 1
Gross Perforations.	14,744 - 14,819 Feet (8 HPF)
Original Reservoir Pressure	13,203 Psia
Original Reservoir Temperature.	274°F
Original Shut-In Surface Pressure	6,695 Psia
Average Porosity.	26% (Sonic Travel Time Log)

FLOW TESTS: (From 7-22-80 to 8-7-80)

Test No. 1	1.01 Day Reservoir Drawdown Test (Produced 4,117 Barrels of Water)
	2.18 Day Continuous Reservoir Build Up Test (BHP After 6.1 Days was 13,173 psia)
Test No. 2	1.36 Day Reservoir Drawdown Test (Produced 10,604 Barrels of Water)
Test No. 3	1.19 Day Flow Test (Produced 13,727 Barrels of Water)
Test No. 4	1.38 Day Flow Test (Produced 9,664 Barrels of Water)
Test No. 5	0.18 Day Flow Test For Sand Production (Produced 2,193 Barrels of Water)
Produced Dry Gas to Saltwater Ratio	40 SCF/BBL
Total Water Produced.	41,930 Barrels

ANALYSIS OF WATER:

Total Dissolved Solids . .	23,500 ppm
Chlorides.	13,300 ppm
Density.	1.017 g/cm³ at 24.0°C

ANALYSIS OF GAS:

Methane.	91.3 Mole Percent
Carbon Dioxide	6.0 Mole Percent
Heavier Hydrocarbons . . .	2.5 Mole Percent
Other.	0.2 Mole Percent
Heating Value	970 BTU/SCF

Highest Flow Rate Achieved.	18,460 BWPD
Highest Surface Temperature Observed.	255°F
Sand Production	Minimal; 0.5 to 1.7 lbs. Per 1000 BBLS.
Corrosion	None Observed
Scaling	Light; 0.03 Grams Per 1,000 BBLS Per SQ.IN.
Lowest Flowing Surface Pressure Observed. . .	490 Psia
Lowest Flowing Bottom Hole Pressure Measured.	11,242 Psia
Test Well Productivity Index.	3.0 to 4.0 BPD/Psi
Maximum Explored Volume of Reservoir Water .	Greater Than 5.2 Million Barrels
Maximum Distance Explored (BHP Instrument). .	A Radius of 1,540 Feet
Reservoir	Very Restricted, Lenticular with a Permeability Range of 200 to 240 Mds. and a Flow Angle of Less Than 50°
Disposal Well Gross Perforations.	2,870 to 3,000 Feet (4 HPF)
Disposal Well Pressure Range.	71 to 385 Psig

(From Eaton Operating Co., Report, 1981)

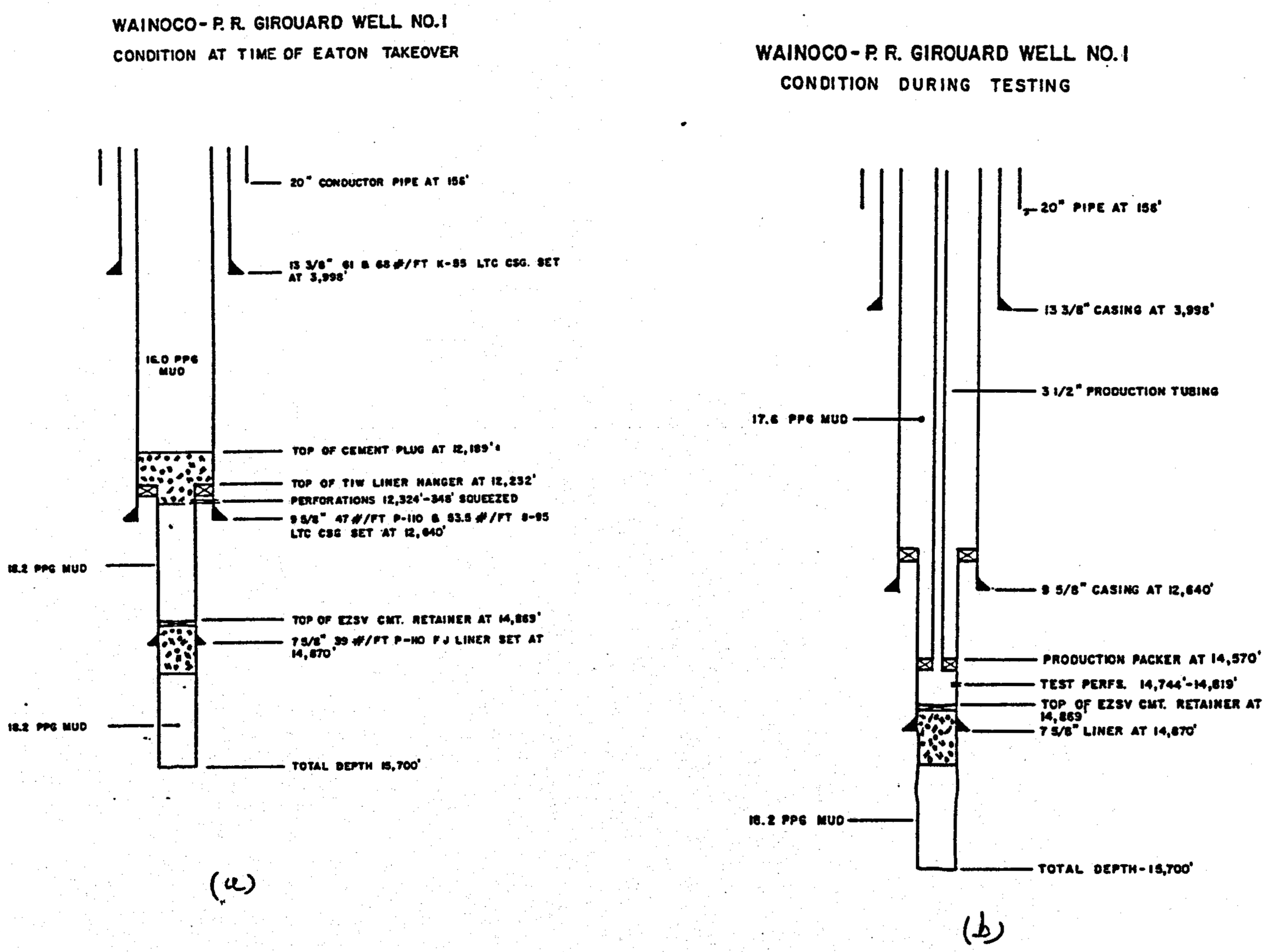


Figure 30. - - Schematic drawings of the test well showing conditions before and during testing (From Eaton Operating Co. Report, 1981).

was designed to have an injection capacity in excess of 15,000 BWPD at an injection pressure not to exceed 500 psi and for a temperature of up to 300°F. The minimum aquifer depth, as specified by the Louisiana Office of Conservation was 2,500 ft. Protection of the fresh and brackish water sands was achieved by setting two complete strings of casing through all such sands and circulating cement to the surface on both strings. Figure 31 shows a schematic diagram of the actual disposal well completion and the surface well head. An electric log run in the hole from 4,513 ft. to 1,518 ft. showed four potential disposal sands as follows:

Sand	Top	Bottom	Thickness	Average Porosity %
A	4,340'	4,420'	80'	39%
B	3,908'	4,020'	112'	43%
C	2,866'	3,010'	144'	37%
D	2,594'	2,772'	178'	37%

The well was completed in Sand 'A' and 'C' was considered the best alternate zone. After acid treatment the well accepted water at 14,400 BWPD at only 200 psi surface injection pressure without using any booster pumps.

Gas sampling and analyses was mostly done by IGT's Chicago laboratories. Other parties involved in collecting and analyzing gas samples on location included weatherly laboratories, McNeese State University, Lake Charles, La. and the U.S. Geological Survey at Menlo Park, California and at the NSTL Station, Mississippi. Details of all the gas, brine and other analyses are provided in the report by Eaton Operating Company (1981).

The test well was killed August 7, 1980 and after abandonment operations the rig was released on September 17, 1980. The abandonment work on the disposal well was completed on

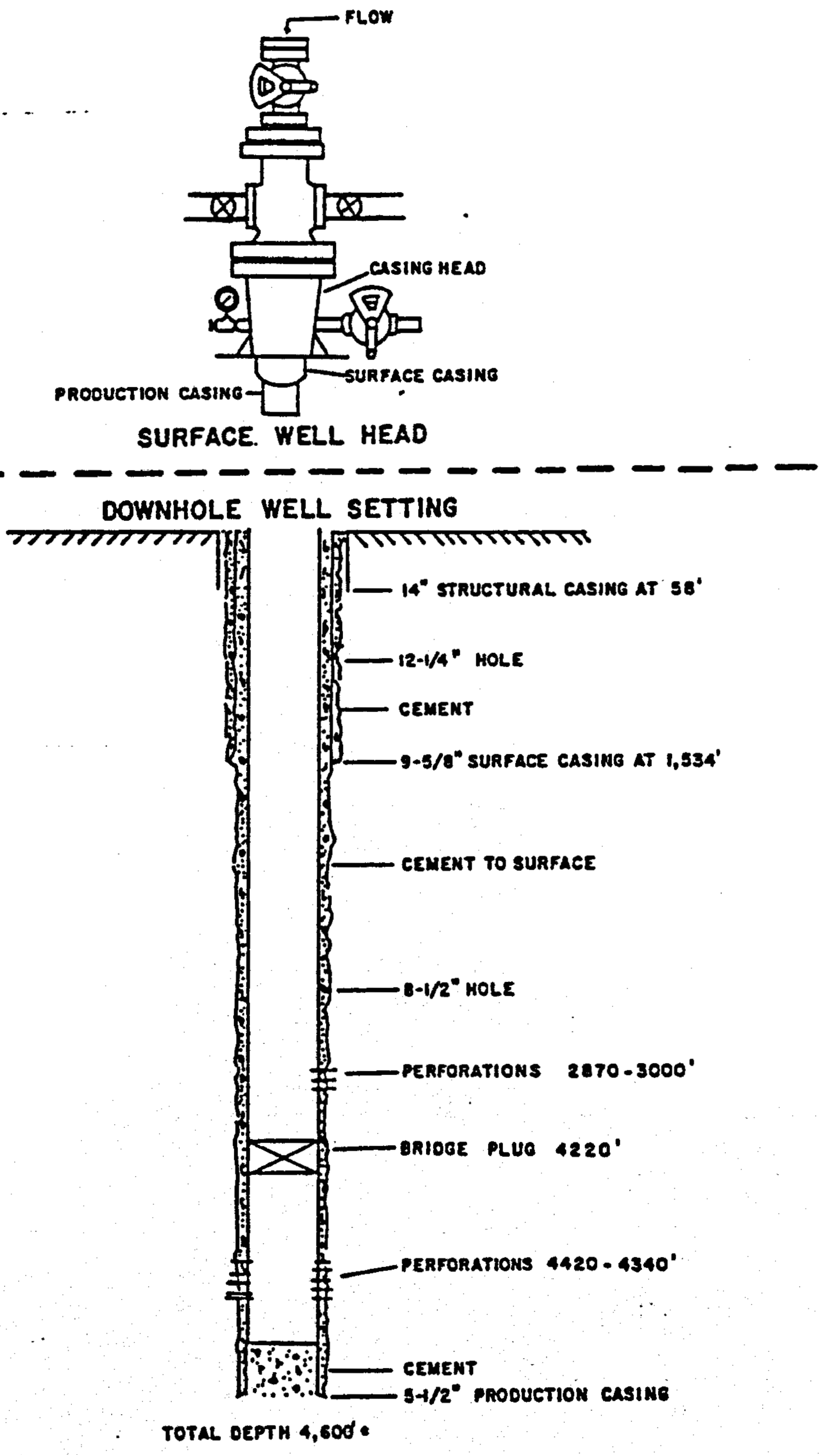


Figure 31. - - Schematic of the P.R. Girouard salt water disposal well #1 (From Eaton Operating Co., Report, 1981).

August 8, 1980. Data obtained by testing varied from pre-testing estimates in several cases as given below:

	Pretest	Actual Measured data
Original reservoir pressure	13,226 psia	13,203 psia
Original reservoir temperature	256°F	274°F
Salinity	36,000 ppm	23,500 ppm
Gas-to-water ratio	42 SCF /BBL	40, SCF /BBL
Reservoir size	3,520 acres	305 acres (minimum)

Though the reservoir limits could not be determined during drawdown flow tests it is projected as being much smaller than originally anticipated. Flow test data indicated a pinching out of the sand close to the well (Eaton Operating Co., Report, 1981).

PRAIRIE CANAL #1

The Prairie Canal Company, Inc., Well No. 1 is located approximately 8 miles south of the city of Lake Charles, Louisiana in Section 21, Township 11S, Range 8E, Calcasieu Parish, Louisiana. Eaton Operating Company, Inc., assumed control of the site on October 20, 1980, when Houston Oil and Minerals Corporation abandoned the well as a dry hole at a total depth of 15,636 ft. Complete details of all investigations concerned with the geopressured - geothermal testing of this well are provided in a final report by Eaton Operating Company, 1981, prepared for the U.S. Department of Energy, Nevada Operations office under Contract No. DE-AC08-80ET27081. Information provided herein is taken from this report.

The geopressured - geothermal zone of interest is in the Hackberry section of the Oligocene Frio formation. Hackberry sands in this area occur in a southward thickening sedimentary wedge containing deep water fauna and are therefore interpreted as being turbidite deposits. A small trapping fault immediately north of the well and a large fault approximately four miles south of the well are the only faults revealed during mapping and interpretation of the proprietary seismic data. The well penetrates the north flank of an east-west trending fault structure with an expansive drainage area dipping towards the south. Figure 32 shows a structure map of the Hackberry sand and an electric log of the section tested in this well. Initially, a sand was perforated and completed at 14,976 ft. to 15,024 ft. for flow testing. This primary zone however, produced a large amount of sand, shale, gravel and rocks during the earlier periods of flow testing and so it was abandoned in favor of a second zone perforated from 14,782 ft. to 14,820 ft. for testing. A cross section showing this test sand is shown in Figure 33. Log analysis indicated 25 ft. gross sand (14 ft. net) and a sonic derived porosity of 22.5%. Original formation pressure was 12,942 psia, formation temperature 294°F, and the total dissolved solids in the surface equipment was also detested.

Four pressure drawdown and three pressure buildup tests were performed during 12 days. A total of 36,505 barrels of brine was produced. The highest sustained flow rate was 7,100 bbl per day; highest flowing temperature was 250°F. Measured solution gas values ranged from 41 to 50 SCF /bbl. A disagreement among investigators concerning the gas saturation value of the brine (43.3 to 49.7 SCF /bbl) places the brine at or very near saturation. Flare gas content consisted of 88.4% mol % methane, 8.4% mol % CO_2 and 12-24 ppm H_2S. Pressure transient analysis detected two permeability barries which reduced the flow area to 40°. Permeability to

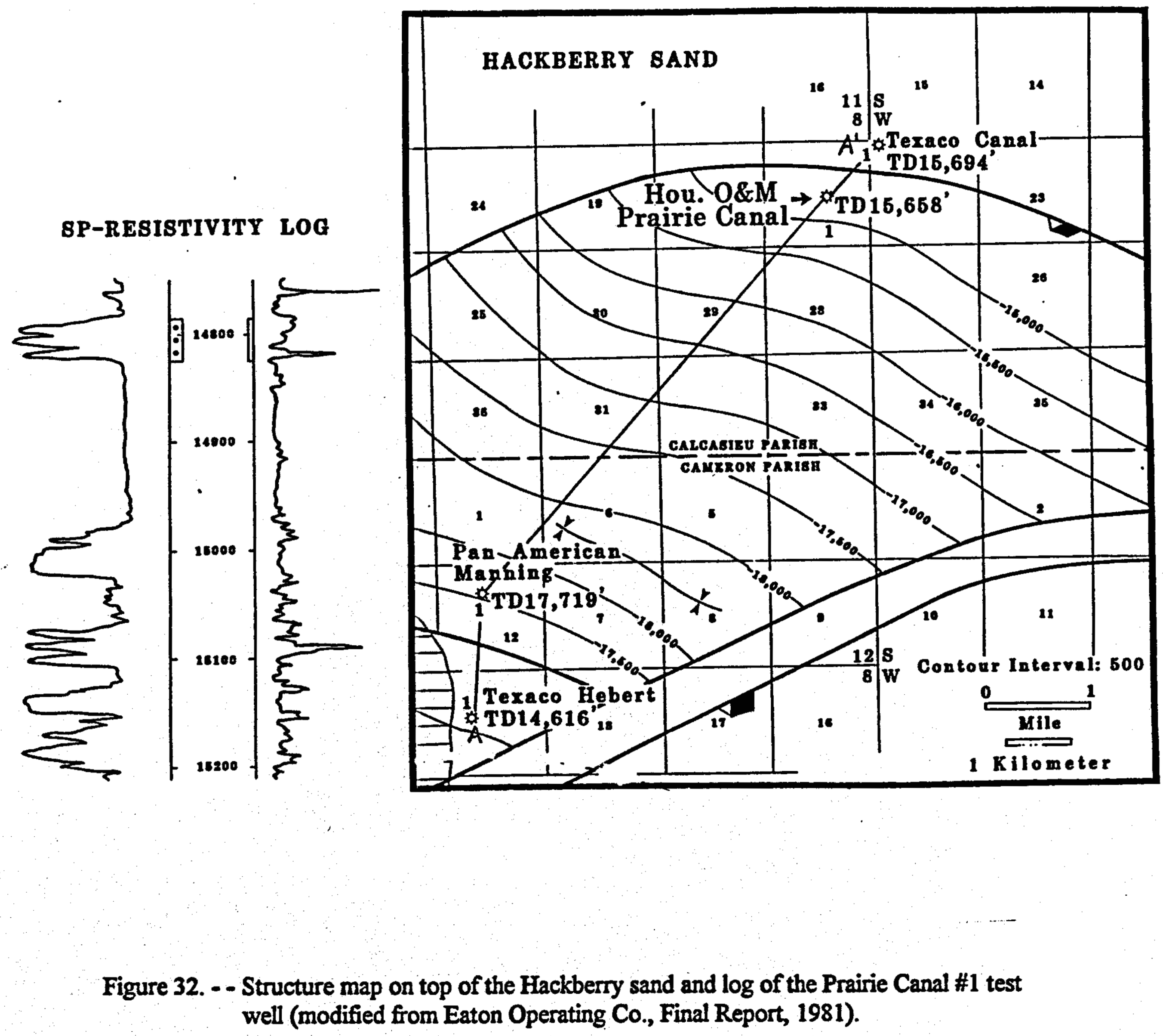


Figure 32. - - Structure map on top of the Hackberry sand and log of the Prairie Canal #1 test well (modified from Eaton Operating Co., Final Report, 1981).

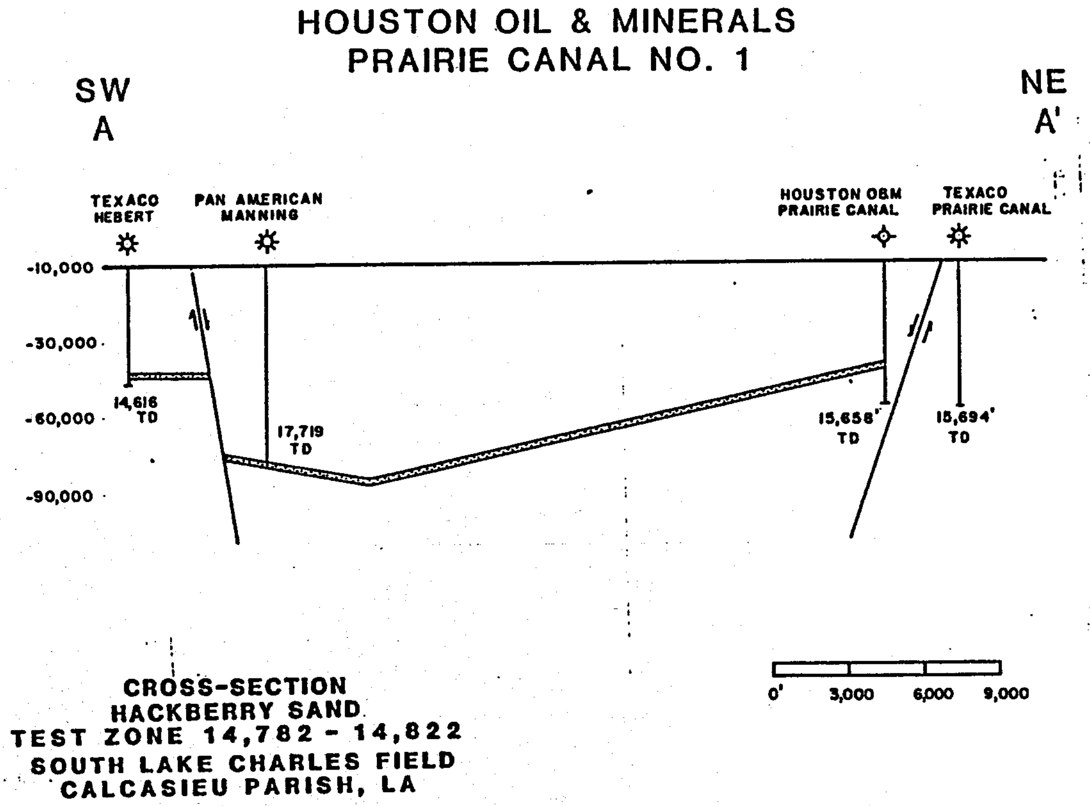


Figure 33. - - Cross section showing the Hackberry sand tested in the Prairie Canal #1 well. Cross section line shown on Figure 32. (From Eaton Operating Co., Inc., Final Report, 1981).

reservoir fluids was about 93 millidarcies. The pressure transient analysis was interpreted as indicating that this particular reservoir was not capable of the high sustained production rates which is essential if this resource were to become economically profitable. A summary of the test results of the Prairie Canal Company #1 well is provided in Table 11.

Schematic illustrations of the Prairie Canal #1 test well before testing, during testing and after being plugged and abandoned are shown in Figure 34.

The brine disposal well was located 90 feet southwest of the test well and was designed to have an injection capacity of up to 15,000 barrels per day at an injection pressure not to exceed 500 psi, with a temperature capability of up to 300°F. The fresh and brackish water sands were protected by setting two complete strings of casing through all such sands and circulating cement to the surface on both strings. Four potential disposal zones were identified in this well after running electric logs, ranging in depth between 2,312 ft. and 5,196 ft. The well was perforated from 4,570 ft. to 4,600 ft. and from 4,490 to 4,560 ft. However an injectivity test showed that well stimulation was necessary as the zones would only accept water at a rate of 1,400 BPD at 1,000 psi surface pump pressure. Acid stimulation was performed on the well. A schematic diagram of the disposal well completion and wellhead is shown in Figure 35. This shows three sets of perforations as the upper two were added during the test operations when additional capacity was required. This recompleted well performed satisfactorily, but injection pressures were in excess of 600 psi during times when disposal rates were higher than 6,500 BWPD. It was believed that formation plugging by solids in the brine was the main cause for the high injection pressure.

TABLE 11

SUMMARY OF TEST RESULTS

PRAIRIE CANAL COMPANY INC. WELL NO. 1

CALCASIEU PARISH, LOUISIANA

WELL DATA:

Total Depth of Well	15,636 Feet
Formation	Hackberry, Upper Frio
Gross Sand Interval	25 Feet
Net Sand	14 Feet
Perforations	14,782 - 14,820 Feet (8 HPF)
Original Reservoir Pressure	12,942 Psia
Original Reservoir Temperature	294°F
Original Shut-In Surface Pressure	6440 Psia
Average Porosity	22.5% (Log)
Average Permeability	(No sidewall cores)

ANALYSIS OF POST-SEPARATOR WATER:

Total Dissolved Solids	43,400 mg/l
Chlorides	24,800 mg/l
pH	6.0

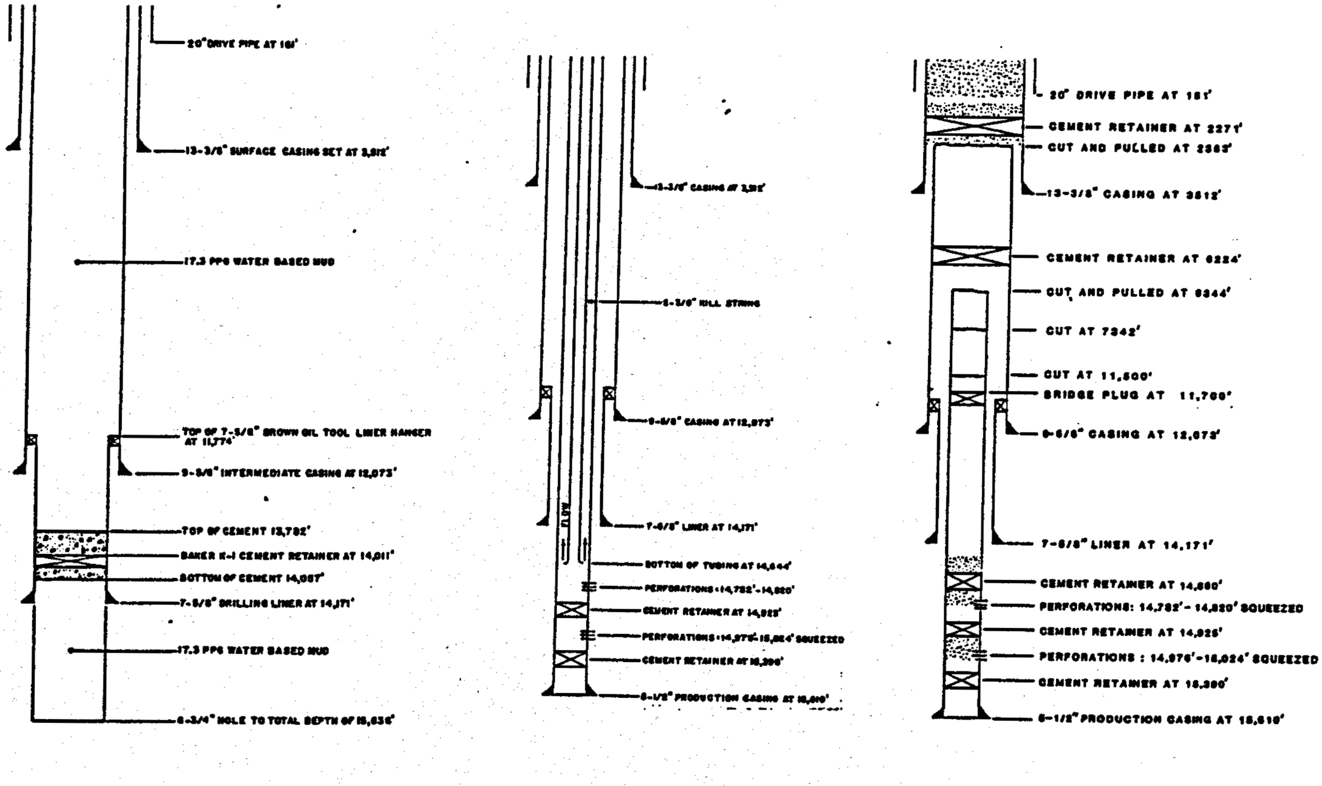
ANALYSIS OF FLARE LINE GAS:

Methane	88.4	Mole Percent
Carbon Dioxide	8.4	Mole Percent
Heavier Hydrocarbons	2.9	Mole Percent
Other	0.3	Mole Percent
Heating Value	949	BTU/SCF
H_2S in Gas	12-24	ppm

TESTS (From 2-21-81 to 3-05-81):

Test No. 1	A 2.51-day reservoir drawdown test, producing 4455 barrels of water, followed by a 0.14-day reservoir buildup period.
Test No. 2	A 1.21-day reservoir drawdown test, producing 4953 barrels of water, followed by a 0.93-day pressure buildup period.
Test No. 3	A 4.00-day flow test, producing 23,202 barrels of water, followed by a 2.00-day buildup period.
Test No. 4	A 1.17-day flow test, during which 3895 barrels of water were produced.
Produced Dry Gas-to-Saltwater Ratio	41 to 50 SCF/STB
Total Water Produced While Testing	36,505 Barrels
Highest Flow Rate Achieved	7100 BWPD
Highest Surface Temperature Observed	250°F
Solids Production	High, rough estimate is 100 to 200 lb per 1000 BBLS
Corrosion	Very light, not measurable
Scaling	Very light, not measurable
Lowest Flowing Surface Pressure Observed	805 psia
Lowest Flowing Bottom-hole Pressure Measured	7031 psia
Test Well Productivity Index	1.94 BBLS per day per psi
Maximum Explored Volume of Reservoir Water	22.4 million barrels
Maximum Distance Explored (BHP Instrument)	4741 Feet
Reservoir	A thin sand zone restricted in drainage area by close-by permeability barriers which reduce the flow area to 40°. The permeability to reservoir fluid is 93 mds.
Disposal Well Gross Perforations	Zone 1: 4490-4600 feet Zone 2: 3070-3130 and 3350-3410 feet
Disposal Well Pressure Range	100-1400 psi

(From Eaton Operating Co., Inc., Final Report, 1991).



(a) (b) (c)

Figure 34. - - Schematic drawings of the Prairie Canal #1 test well showing: (a) condition at time of Eaton takeover of well (b) condition during well testing, and (c)plugged and abandoned condition.

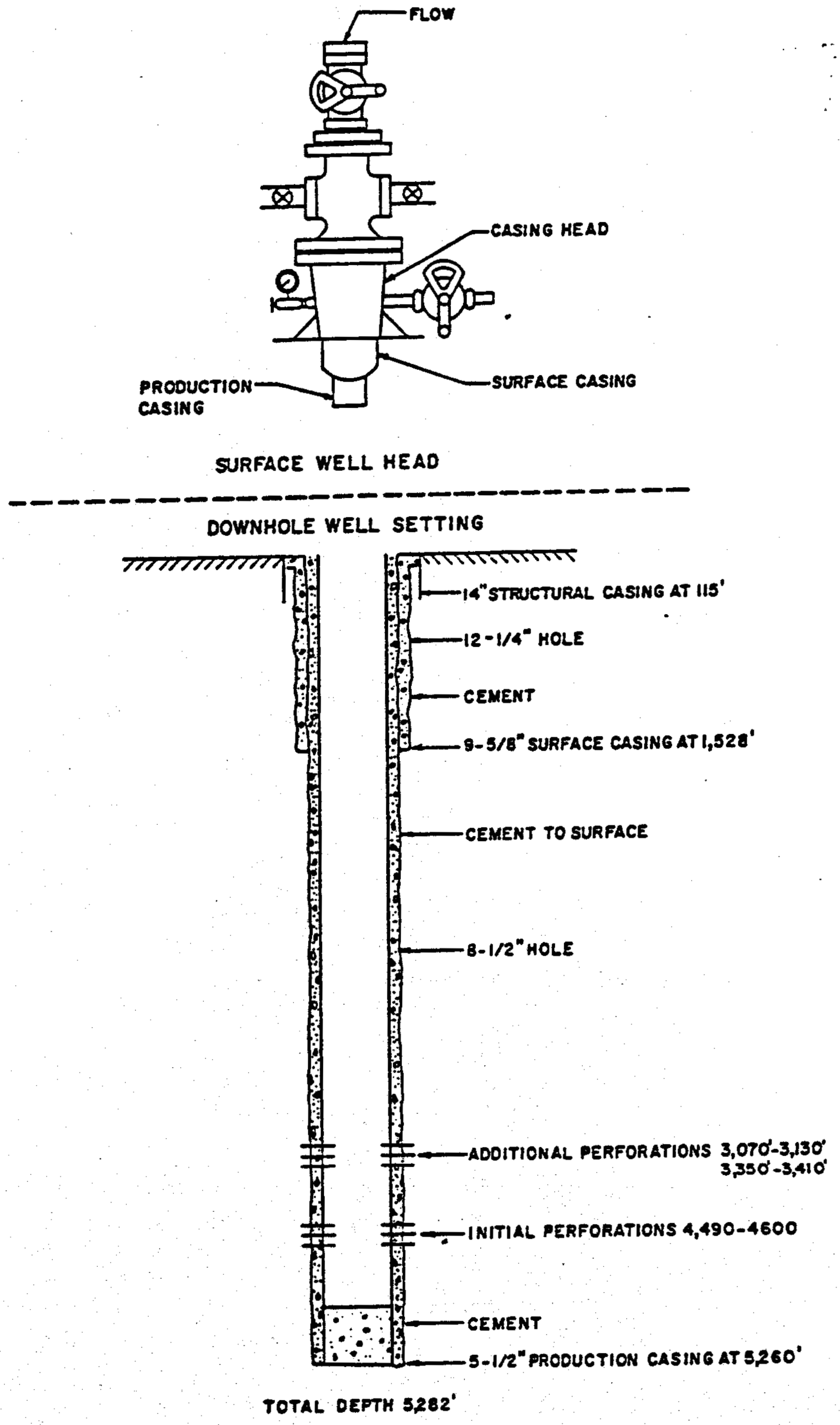


Figure 35. - - Schematic illustration of the disposal well completion and wellhead (From Eaton Operating Co., Inc., Final Report, 1991).

Brine and gas sampling and analyses were carried out by IGT, Weatherly Laboratories, Lafayette, LA., McNeese State University, Lake Charles, LA., Rice University and the U.S. Geological Survey, Menlo Park, CA., and the NSTL Station, Miss. Other groups invited to participate in the sampling and analysis included the University of Texas at Austin, Lawrence Berkeley Laboratory, and Louisiana State University.

One of the points to be noted as a result of this well testing was that this well produced more solids than any of the wells previously tested under the Wells of Opportunity (WOO) program. It was concluded that the high amounts of solids produced (100 - 200 pounds per 1,000 barrels) precluded long term operation unless sand control could be successfully done at the perforations: Further, the mercury concentrations in the brine averaged 0.75 micrograms per liter, and boron averaged 55 milligrams per liter. Both of these volumes are higher than that recommended by the U.S. Environmental Protection Agency. These analyses therefore precluded any plans for long term surface disposal of the produced brine.

The test well was killed on March 6, 1981 by pumping mud down the tubing and the casing-tubing annulus, and the rig was released on March 24, 1981. No workover rig was required to plug the disposal well, since a tubing string was not in the hole, and all casing was cemented in place. Abandonment work on the disposal well was completed on March 22, 1981.

CROWN ZELLERBACH #2

The Crown Zellerbach Well #2 is located approximately 23 miles east of Baton Rouge, Louisiana and about 3 miles north of Interstate 12 near the town of Livingston, Louisiana in Section 19, Township 6 South, Range 5 East. Eaton Operating Company, Inc., took over control of the well on February 20, 1981 after Martin Exploration Company abandoned the well as a dry hole at a total depth of 17,000 ft. Complete details of the geopressured - geothermal testing analyses, and other data obtained from the Crown Zellerbach #2 well is contained in the Final report of the Eaton Operating Company, Inc., Houston, Texas (1981). Information provided here on this well is taken from this final report which was prepared for the U.S. Department of Energy, Nevada Operations office under DOE Contract No. De-AC08-80ET27081.

The prospective geopressured - geothermal test sands lie in the lower Tuscaloosa Trend of Upper Cretaceous age. In general the Lower Tuscaloosa is composed of alternating sands and shales and the trend extends across Louisiana from St. Tammany Parish on the east to Beauregard Parish on the west. The Tuscaloosa sediments are found below a depth of 16,000 ft. where temperatures approach 400°F and pressure gradients vary from 0.459 psi/ft. to 0.96 psi/ft. The Tuscaloosa sands are believed to have been deposited in highly constructive deltaic systems in a fluvial to shallow marine environment. Since the area has poor well control the structure map on top of the Tuscaloosa sand (Figure 36) was drawn mainly based on seismic data. The map places the well between two subparallel trending faults on the north flank of a faulted anticlinal structure. Approximate fault displacements are 900 ft. for the north bounding fault and 450 ft. on the south bounding fault. Two cross sections drains through the Crown Zellerbach #2 test well based on seismic data are shown in Figure's 37 and 38.

An electric log of the Crown Zellerbach #2 well showing the two sands which were tested is shown in Figure 39. These two Tuscaloosa sands occur at a depth of 16,718 - 16,754 ft. (Sand A) and 16,462 to 16,490 ft. (Sand B). Flow testing was conducted on two sands. Sand A was tested initially for 13 days. Sand B was then perforated and fluids from both zones commingled

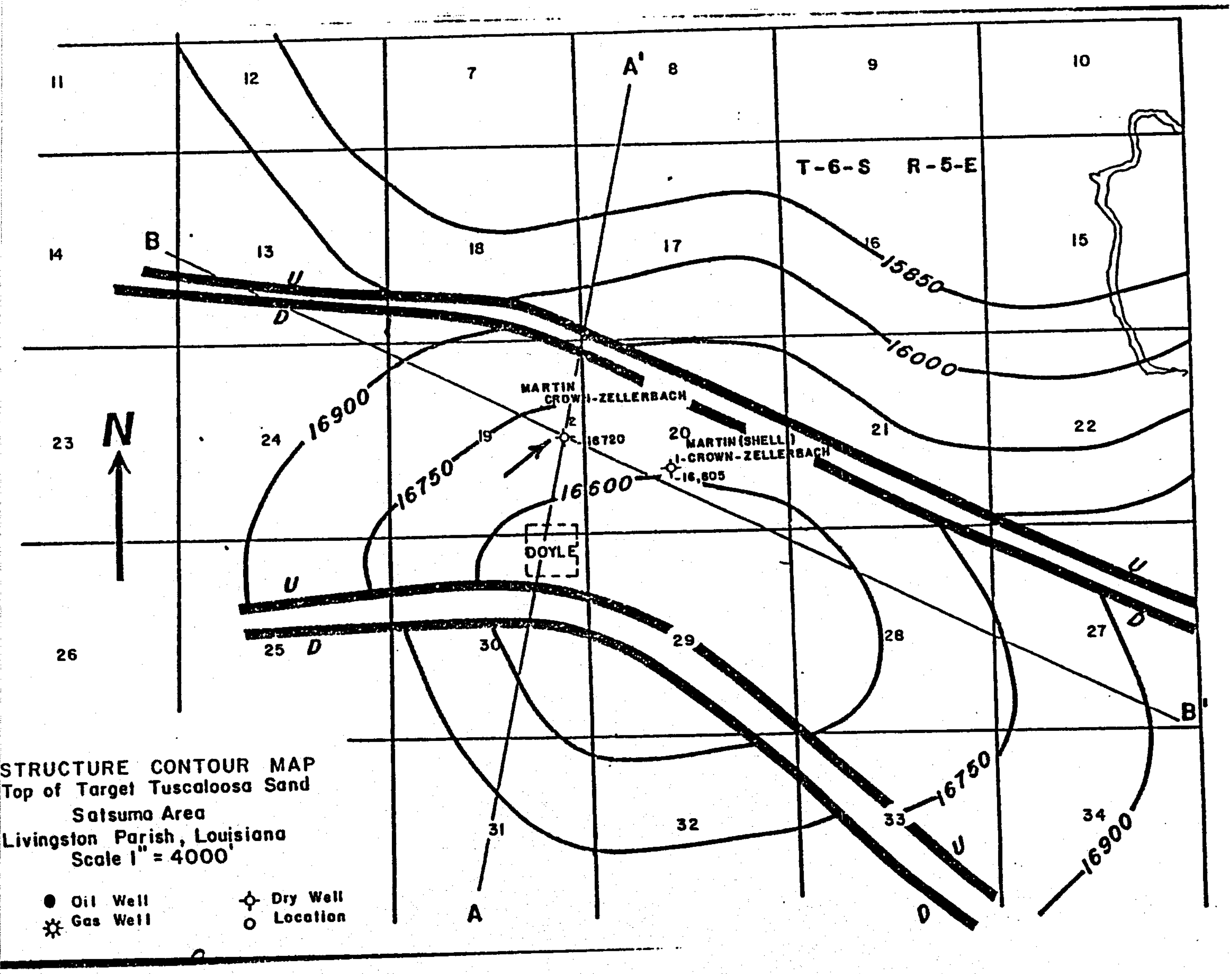


Figure 36. - - Seismic Structure map of the Tuscaloosa sand in the area of the Crown Zellerbach testwell (From Eaton Operating Co., Final Report, 1981).

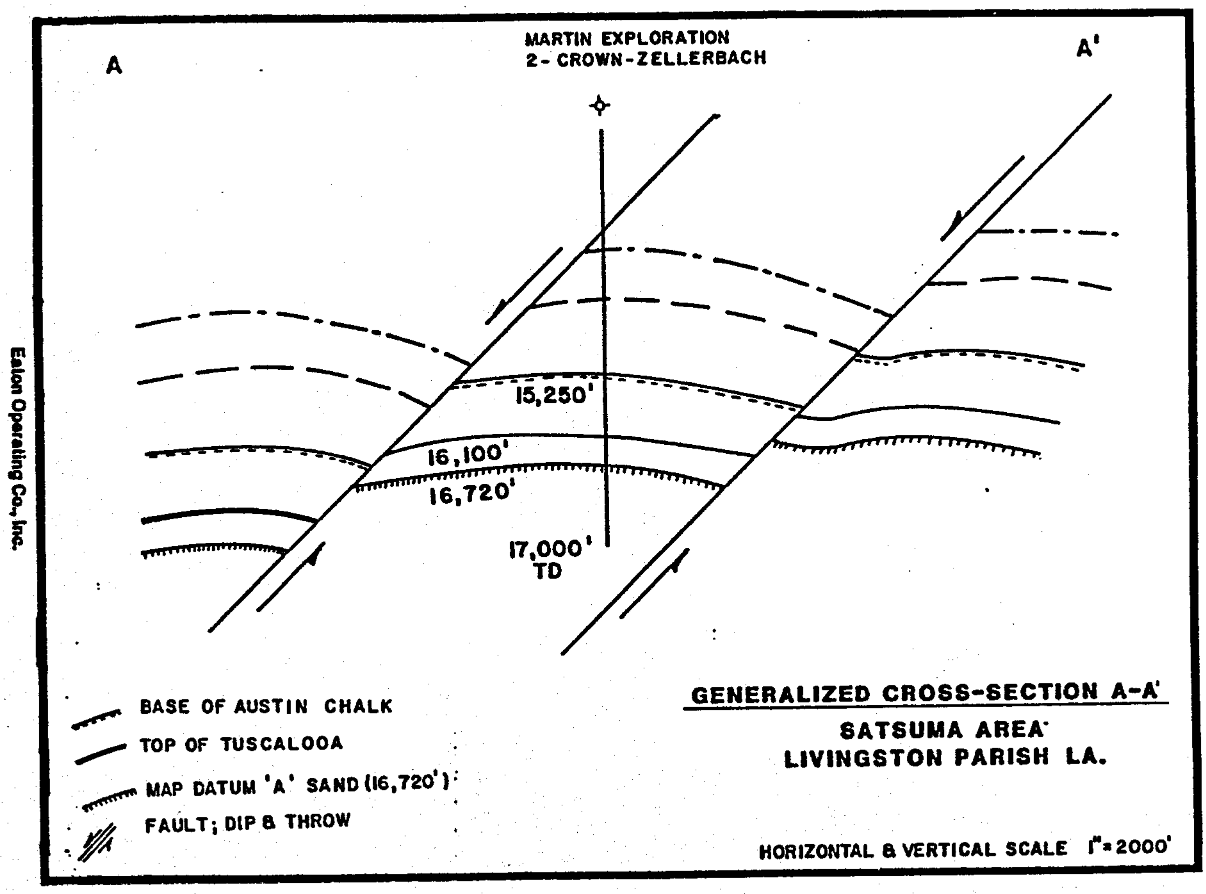


Figure 37. - - A generalized north south cross section in the area of the Crown Zellerbach #2 well based on seismic data. Cross section line is shown in Figure 36 (From Eaton Operating Company Final Report, 1981).

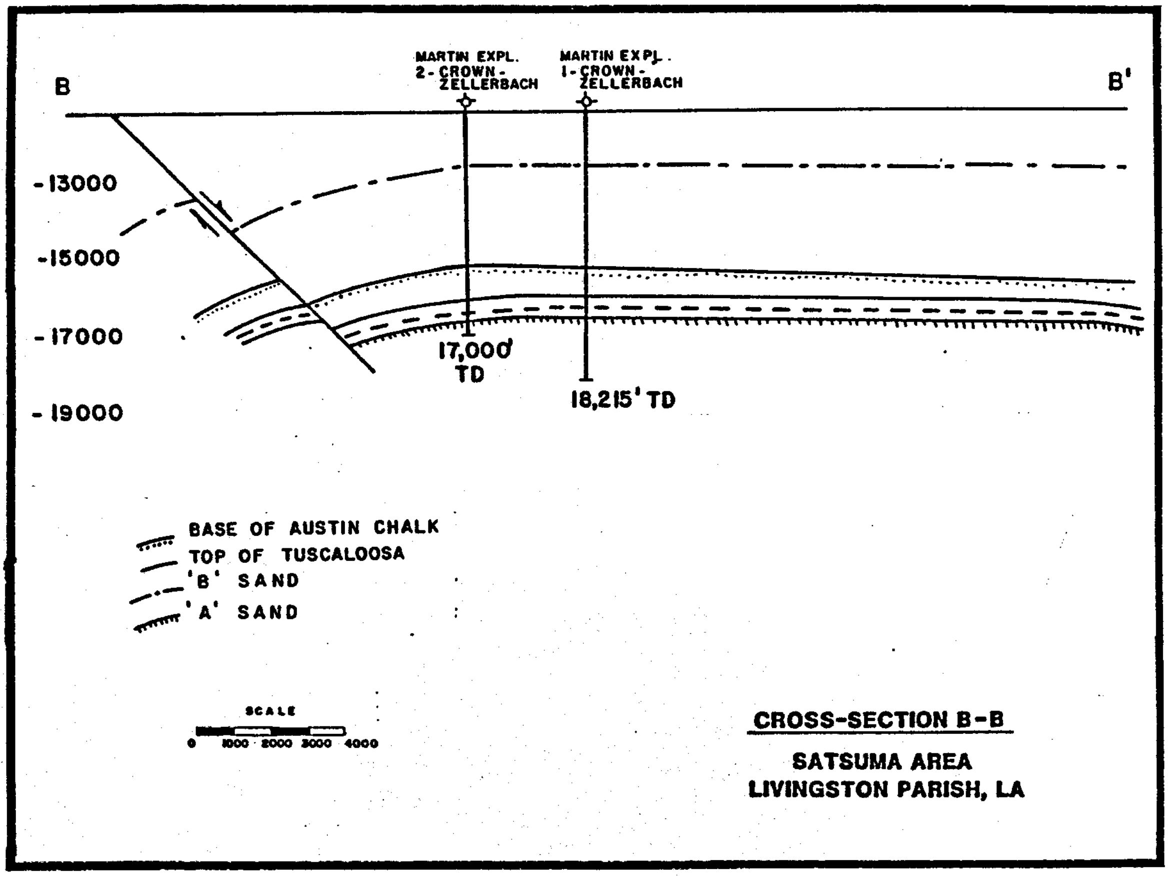


Figure 38. - - A generalized east-west cross section in the area of the Crown Zellerbach #2 well based on seismic data. Refer to Figure 36 for location of cross section line (From Eaton Operating Co., Inc., Final Report, 1981).

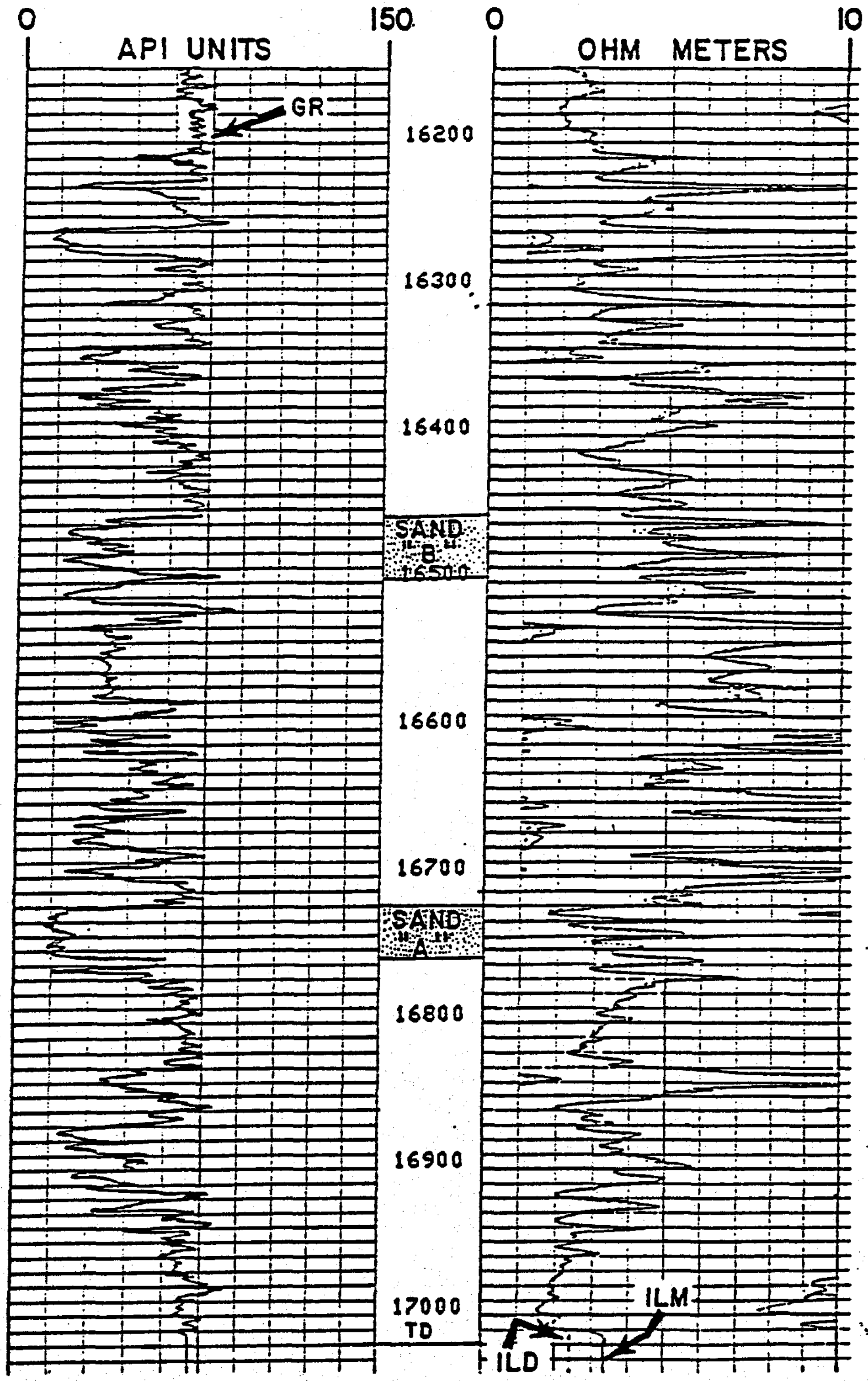


Figure 39. - - An electric log (dual induction/borehole compensated sonic log) of the Crown Zellerbach #2 well showing the two sands tested (Sands A and B) (From Eaton Operating Co., Final Report, 1981).

for two days of flow testing. Sand A has a gross thickness of 36 ft. (35 ft. net thickness) and a log derived average porosity of 17% and was perforated from 16,720 ft. to 16,750 ft. Original formation pressure was 10,114 psia, temperature 330°F, and total dissolved solids was 31,700 mg/l. During flow testing, the highest flow rate achieved was 3,887 BWPD. A total of 12,489 barrels of water was produced. Pressure transient analysis indicated a reservoir permeability of 14.1 md., a permeability barrier at 197 ft. and an increase in sand thickness away from the wellbore. Solids production was high (20 - 190 lb./1,000 BW). Corrosion and scaling were slight. Measured gas in solution was 32 SCF /bbl. Gas analyses showed the flare line gas to be composed of 71 mol % methane, 23.5 mol % CO_2 content higher in relation to the earlier tested geopressure - geothermal wells. A summary of the test results of the Sand A is provided in Table 12.

Sand B. was perforated from 16,462 ft. to 16,490 ft. It has a grass thickness of 28 ft. (23 ft. net) and an average log derived porosity of 13.7%. Original formation pressure was estimated to be 10,007 psia, with formation temperature ranging from 324°F to 330°F. A three day flow test was conducted with commingled production from the two sands (A and B). Maximum flow rate achieved during testing was 3,000 BWD and a total of 4,739 barrels of water was produced. Solution gas ratio, gas content, and other fluid values showed very little change from that observed for Sand A tests. Solids production with the commingled test was lower than that observed during testing of Sand A alone. No particular explanation was provided for the low solids production when the liquids from the two Sands (A and B) were commingled. A summary of the test results of the combined A and B sands is provided in Table 13.

TABLE 12

SUMMARY OF TEST RESULTS

CROWN ZELLERBACH WELL NO. 2

LIVINGSTON PARISH, LOUISIANA

(Lower Zone)

(SAND A)

WELL DATA:

Total Depth of Well	17,000 Feet
Formation	Upper Cretaceous, Tuscaloosa Trend
Gross Sand Interval	36 Feet
Net Sand	35 Feet
Perforations	16,720-16,750 (8 HPF)
Original Reservoir Pressure	10,114 Psia
Original Reservoir Temperature	330°F
Original Shut-In Surface Pressure	2900 Psia
Average Porosity	17% (Density/Neutron Log)
Average Permeability	(No sidewall cores)

ANALYSIS OF POST-SEPARATOR WATER:

Total Dissolved Solids	31,700 mg/l
Chlorides	18,300 mg/l
pH	5.6

ANALYSIS OF FLARE LINE GAS:

Methane	71.0	Mole Percent
Carbon Dioxide	23.5	Mole Percent
Heavier Hydrocarbons	5.0	Mole Percent
Other	0.5	Mole Percent
Heating Value	823	BTU/SCF
H_2S in Gas	12-56	ppm

TESTS (From 6-5-81 to 6-17-81):

Test No. 1	A 4.55 day reservoir drawdown test producing 10,109 barrels of water followed by a 1.64 day reservoir buildup test.
Test No. 2	A 0.88 day flow test producing 2380 barrels of water.
Produced Dry Gas-to-Saltwater Ratio	32.0 SCF/STB
Total Water Produced While Testing	12,489 Barrels
Highest Flow Rate Achieved	3837 BWPD
Highest Surface Temperature Observed	201°F
Solids Production	High; at least 20 to 190 lb/1000 barrels
Corrosion	Very light, not measurable
Scaling	Very light, not measurable
Lowest Flowing Surface Pressure Observed	449 psia
Lowest Flowing Bottom-hole Pressure Measured	7378 Psia (extrapolated to perforations)
Test Well Productivity Index	2.09 barrels per day per psi
Maximum Explored Volume of Reservoir Water	16.4 million barrels
Maximum Distance Explored (BHP Instrument)	2971 Feet
Reservoir	Relatively tight with increasing sand thickness. At least 1 permeability barrier about 197 feet from the wellbore. Permeability to reservoir fluids is 14.1 millidarcies.
Disposal Well Gross Perforations	4833-4908 Feet (4 HPF)
Disposal System Pressure Range	40 to 175 psi

(From Eaton Operating Co., Inc., Final Report, 1981).

TABLE 13

SUMMARY OF TEST RESULTS

CROWN ZELLERBACH WELL NO. 2

LIVINGSTON PARISH, LOUISIANA

(Lower and Upper Zones)
(SANDS A & B)

WELL DATA:

Total Depth of Well	17,000 Feet
Formation	Upper Cretaceous, Tuscaloosa Trend
Gross Sand Interval	64 Feet (36 + 28)
Net Sand	58 Feet (35 + 23)
Perforations	16,720-16,750 (8 HPF) and 16,462-16,490 (4 HPF)
Original Reservoir Pressure	10,007 Psia (estimated)
Original Reservoir Temperature	330° to 324°F
Original Shut-In Surface Pressure	2389 Psia
Average Porosity	17 and 13.7% (Density/Neutron Log)
Average Permeability	(No sidewall cores)

ANALYSIS OF POST-SEPARATOR WATER:

Total Dissolved Solids	29,900 mg/l
Chlorides	17,600 mg/l
pH	5.6

ANALYSIS OF FLARE LINE GAS:

Methane	70.0	Mole Percent
Carbon Dioxide	24.6	Mole Percent
Heavier Hydrocarbons	4.9	Mole Percent
Other	0.5	Mole Percent
Heating Value	813	BTU/SCF
H_2S in Gas	60	ppm

TESTS (From 6-23-81 to 6-25-81):

Test No. 1	A 2.36 day flow test producing 4,739 barrels of water. Followed by a 3.01 day pressure buildup period. (This is described as the third flow test in the text.)
Produced Dry Gas-to-Saltwater Ratio	33.0 SCF/STB
Total Water Produced While Testing	4739 Barrels
Highest Flow Rate Achieved	3000 BWPD
Highest Surface Temperature Observed	197°F
Solids Production	Low; about 7 to 23 lb/1000 barrels
Corrosion	Very light, not measurable
Scaling	Very light, not measurable
Lowest Flowing Surface Pressure Observed	280 psia
Lowest Flowing Bottom-hole Pressure Measured	Not applicable
Test Well Productivity Index	Not applicable
Maximum Explored Volume of Reservoir Water	42.8 million barrels
Maximum Distance Explored (BHP Instrument)	Not applicable
Reservoir	Surface pressure drawdown data apparently indicates a much higher productivity of 2218 md-ft as compared to a productivity of 495 md-ft for the bottom zone alone.
Disposal Well Gross Perforations	4833-4908 Feet (4 HPF)
Disposal Well Pressure Range	Produced to reserve pit

(From Eaton Operating Co., Inc., Final Report, 1981).

Liquid hydrocarbons were recovered during testing at an average rate of 5.3 liters /MCF and was considered to be rather high production of liquid hydrocarbons in the WOO program. Chemical analysis of the recovered liquids indicated the C_7 compounds exclusive of toulene are 70 - 85% cyclic hydrocarbons. This differs from normal crude oil, which usually contains only a small fraction of cyclic compounds which suggested that the recovered liquid hydrocarbons could have been in solution in the brine and not from a free oil phase. Extrapolated laboratory data indicated a brine gas saturation value of 55.7 SCF /bbl at reservoirs conditions. The recovered gas solubility value of 32.0 SCF /bbl suggested that the brine is very undersaturated. However, it is suggested that the combined effects from the relatively high CO_2 and the liquid hydrocarbons present in this well may suppress the methane solubility values are saturated (from Miller, 1991 in Groat, 1991).

The test equipment and procedures carried out for geopressured - geothermal testing for the Crown Zellerbach #2 well were designed to obtain the maximum specific information with the time and funds allotted. Specific information was sought for (1) gas content and solubility, (2) well deliverability, (3) formation flow capacity, (4) aquifer geometry, (5) distance to existing boundaries, (6) chemical composition of produced fluids, (7) performance of down hole equipment, (8) performance of surface test equipment, (9) scaling and corrosia potenital, (10) formation sand production, and (11) disposal well injectivity. A schematic drawing of the test well condition at the time of Eaton takeover from Martin and the well condition during testing is shown in Figure 40. The well was tested through the annulus between 7-inch casing and 2⅜ inch tubing.

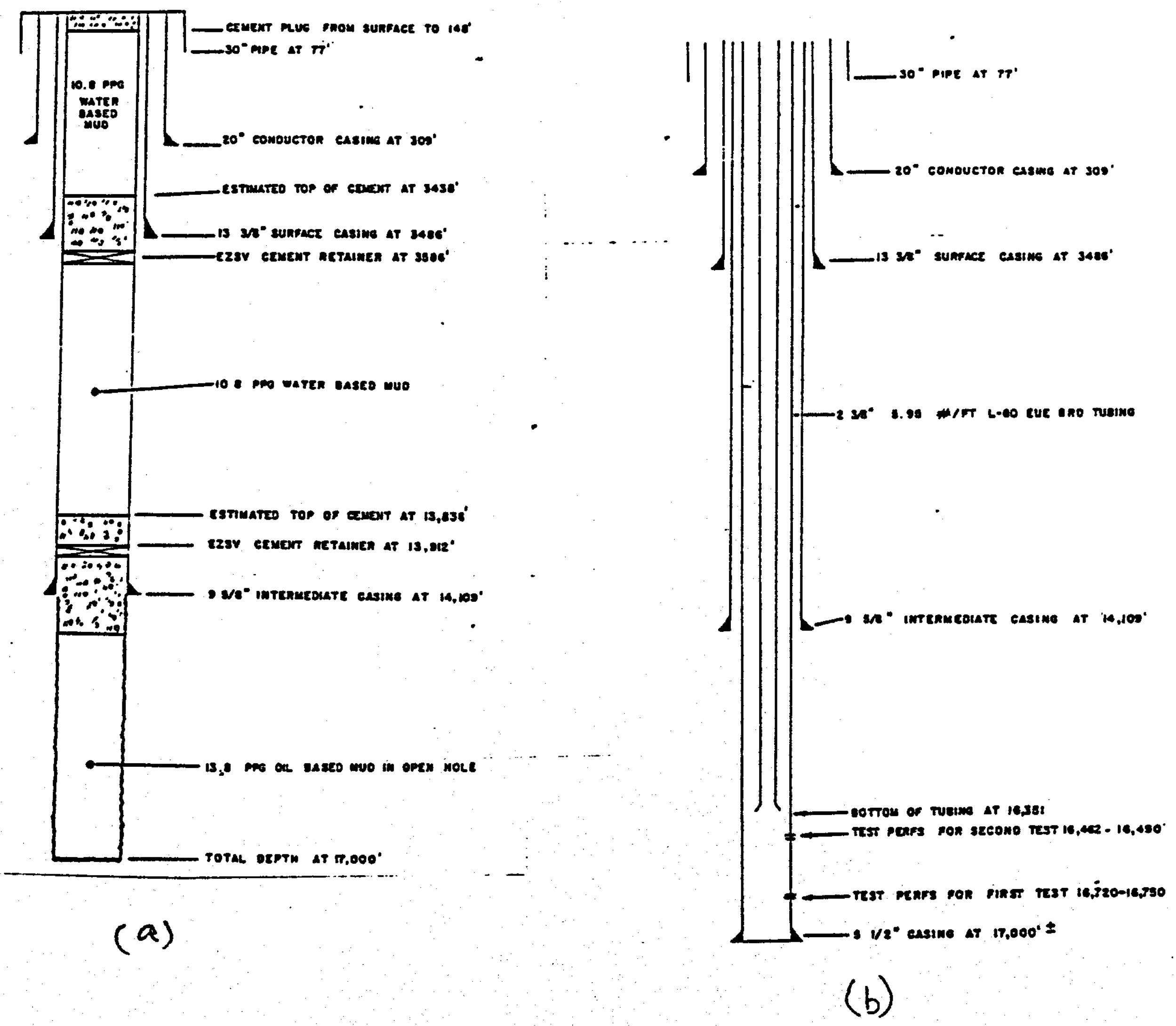


Figure 40. - - Schematic illustration of the tubular configuration of the well condition (a) at time of Eaton takeover; and (b) during testing. (From Eaton Operating Co., Final Report, 1981).

The Crown Zellerbach Well No. 1, located about 3,000 ft. Southeast of the test well, which was plugged and abandoned by Martin was selected for use as the brine disposal well. Electric logs of this well indicated three potential sands suitable for disposal: Sand A (4,390 - 4,900 ft.), Sand B (4,120 - 4,230 ft.) And Sand C (3,625 - 3,710 ft.). A schematic drawing of the tubular configuration of the disposal well before re-entry and completion as a salt water disposal well by Eaton Operating Co., Inc., is shown in Figure 41a and the well configuration when completed for brine disposal is shown in Figure 41b. The disposal well was completed in Sand A from 4,833 to 4,908 ft. which had the following log derived parameters: net sand - 75 ft., Porosity - 33% pressure - 2,279 psi, temperature 133°F, and salinity - 110,000 ppm. Companies and institutions (other than Eaton Operating Co., Inc.) contracted to obtain various types of data and perform brine and gas analyses included the Institute of Gas Technology (IGT), Chicago, Weatherly Laboratories, Inc., Lafayette, LA., McNeese State University, Lake Charles, LA., United States Geological Survey Gulf Coast Hydroscience Center, NSTL Station, MS., and the USGS Federal Center, Lakewood, CO., and Rice University, Houston, TX.

In general, well testing indicated that the methane content of the produced gas was the lowest when compared to other wells tested in the WOO program and the CO_2 content was the highest. Liquid hydrocarbon production was also higher relative to the brine production with the exception of the Koolemay Well #1 which is described later in this report. Scaling and corrosion was very light in this well. Though the mercury content of the produced water was less than 0.2 micrograms per liter which is considered as non-hazardous for surface disposal, the boron concentration averaged 48 milligram per liter. This value for boron is considered as extremely

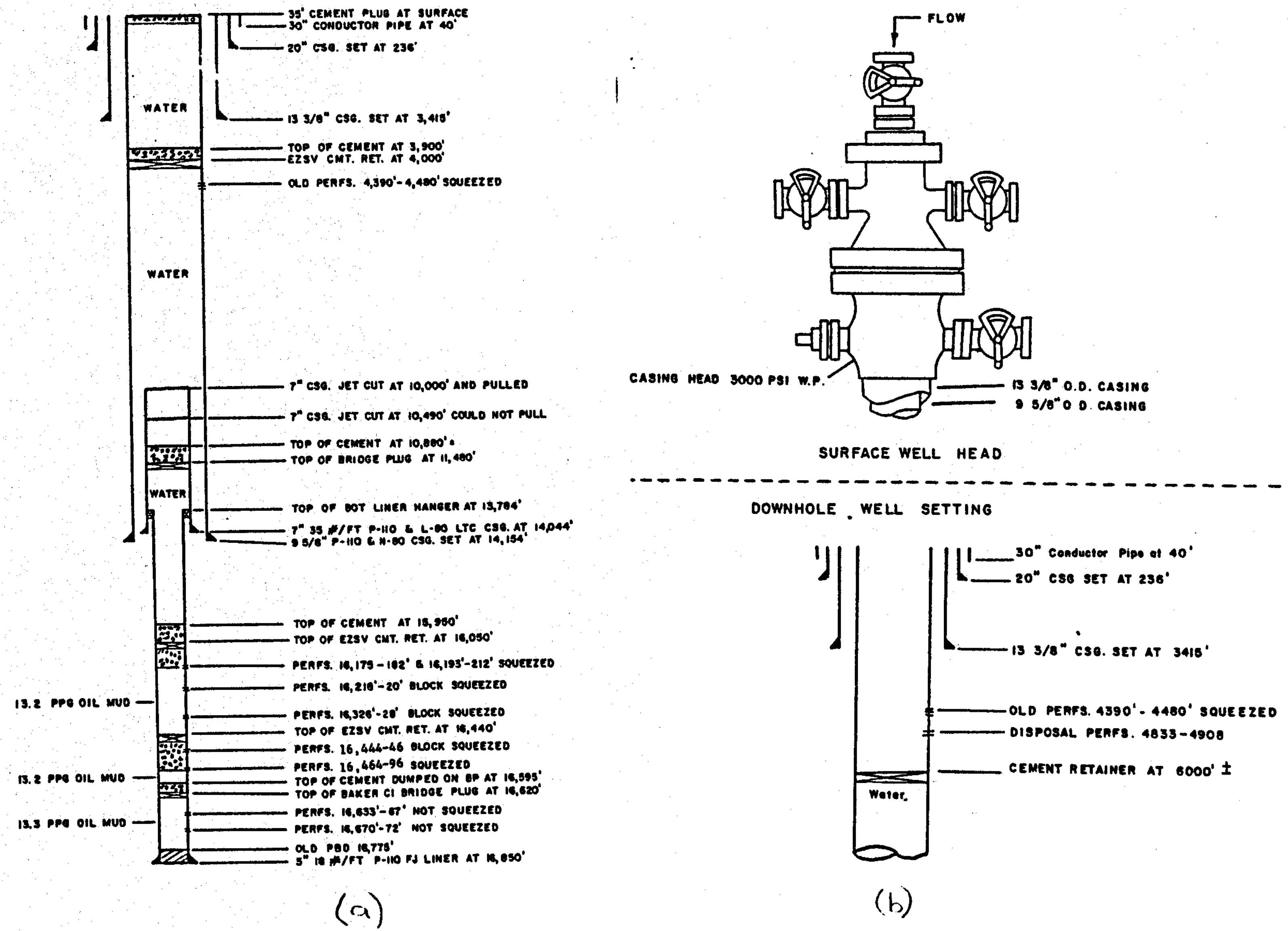


Figure 41. - - Schematic drawing of the disposal well showing (a) condition when Eaton took over operations from Martin; and (b) disposal well tubular configuration as completed for brine disposal and the well head design. (From Eaton Operating Co., Inc., Final Report, 1981).

toxic to plant life by the U.S. Environmental Protection Agency and therefore precludes any consideration for the surface disposal of untreated brine.

The test well was killed on October 24, 1981, by pumping mud down the tubing and around the annulus. The well was then plugged and abandoned and rig was released on November 5, 1981. The salt water disposal well was abandoned on December 23, 1981.

ALICE C. PLANTATION #2

The Alice C. Plantation #2 well is located in Section 2, Township 16-S, Range 10-E, in St. Mary Parish, Louisiana. This well was originally drilled by Sun Oil Company to a total depth of 19,000 ft. and abandoned as a dry hole in January, 1964. A detailed report of all investigations and operations conducted on this well is provided in the Gruy Federal, Inc., final report (Dec., 1978) on the well performed under U.S. DOE, Division of Geothermal Energy Contract No. EG-77-C-08-1528. Information complied here on this well is taken from this report.

The potential geopressured aquifers penetrated by the Alice C. Plantation #2 well belong to the lower *Marginulina ascensionensis* sand series at depths from 16,810 - 16,990 ft., 17,090 - 17,230 ft., and from 17,700 - 17,900 ft. An electric log through this section (Figure 42) shows that these sands contained 95 ft., 100 ft., and 120 ft., of net porous sand. These sands were drilled using a mud weight of 16.9 pounds per gallon. According to the Gruy Federal Report (1978) this indicated the stabi aquifer pressure to be 14,650 psi at 17,800 ft. on the assumption that the overbalance was 1,000 psi. The maximum recorded mud temperature through these sands was 277°F (136°C) which indicated an aquifer temperature of 305°F (152°C) based on correction factors developed by the AAPG (American Association of Petroleum Geologists) for

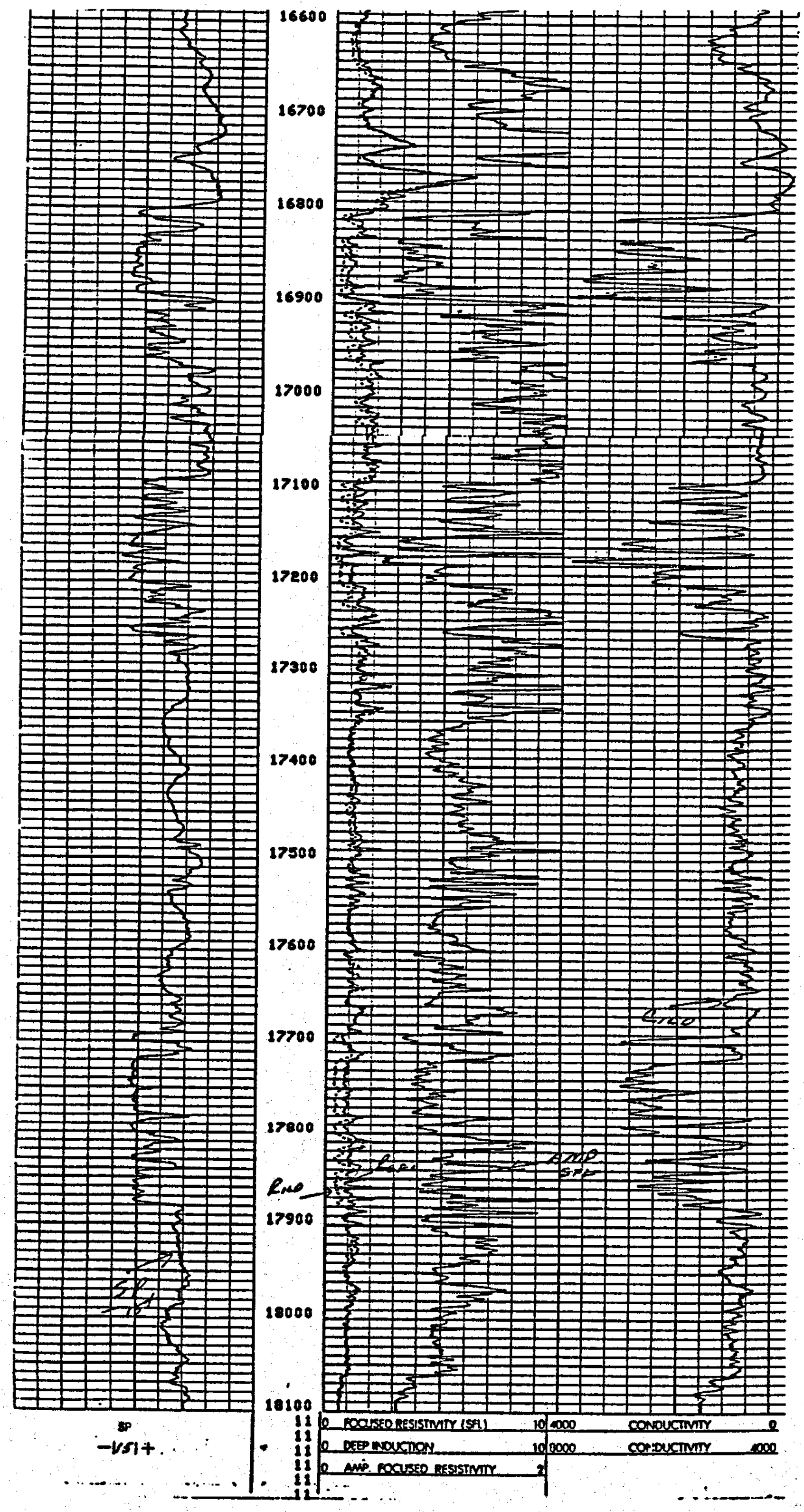


Figure 42. - - Electric log (ISF-Sonic) of the Alice C. Plantation #2 well showing the *Marginulina Ascensionensis* sands targeted for geopressured - geothermal testing from 16,810 ft. - 16,990 ft., 17,090 ft. - 17,230 ft., and from 17,700 ft. to 17,900 ft.

South Louisiana [Gruy Federal, Inc., 1978]. A structure map on top of the potential sand series proposed to be tested is shown in Figure 43.

A schematic illustration of the mechanical condition of the well and the completion proposed by Gruy Federal, Inc. for testing in shown in Figure 44. The Alice C. Plantation #2 re-entry project proceeded without unusual mechanical difficulty until the mud column became unbalanced causing salt water to flow in before casing could be run to contain the lowermost portion of the hole. After the salt water flow was contained by natural bridging, it was found that the intermediate casing had collapsed and the operation was then abandoned (Hartsock and Rodgers, in, Gruy Federal, Inc., Report, 1980).

TENNECO FEE "N" No. 1

The Tenneco Fee "N" No. 1 well is located approximately 20 miles from Houma, Louisiana in Section 38, Township 19 S, Range 19 E in Terrebonne Parish, Louisiana. The site is in a lowland marsh and is accessible by boat through canal and inland waters. This well was originally drilled for Tenneco Exploration and Production Company by Two-R Drilling Company, to a depth of 17,276 ft. after which a 4½ liner was run to total depth. It was abandoned as a dry hole in January 1979. As the well had penetrated a series of well developed geopressured - geothermal sands which met the DOE criteria for selection as a test well in the WOO program Gruy Federal Inc. recommended this well for testing to DOE in January 1979. After DOE approval of the Gruy Federal Inc., plans, they started recompletion operations in January 1980 in joint arrangement with Tenneco, whereby Tenneco provided on site operation and supervision and Gruy Federal, Inc., provided the purchasing services, liaison with DOE, and on-site

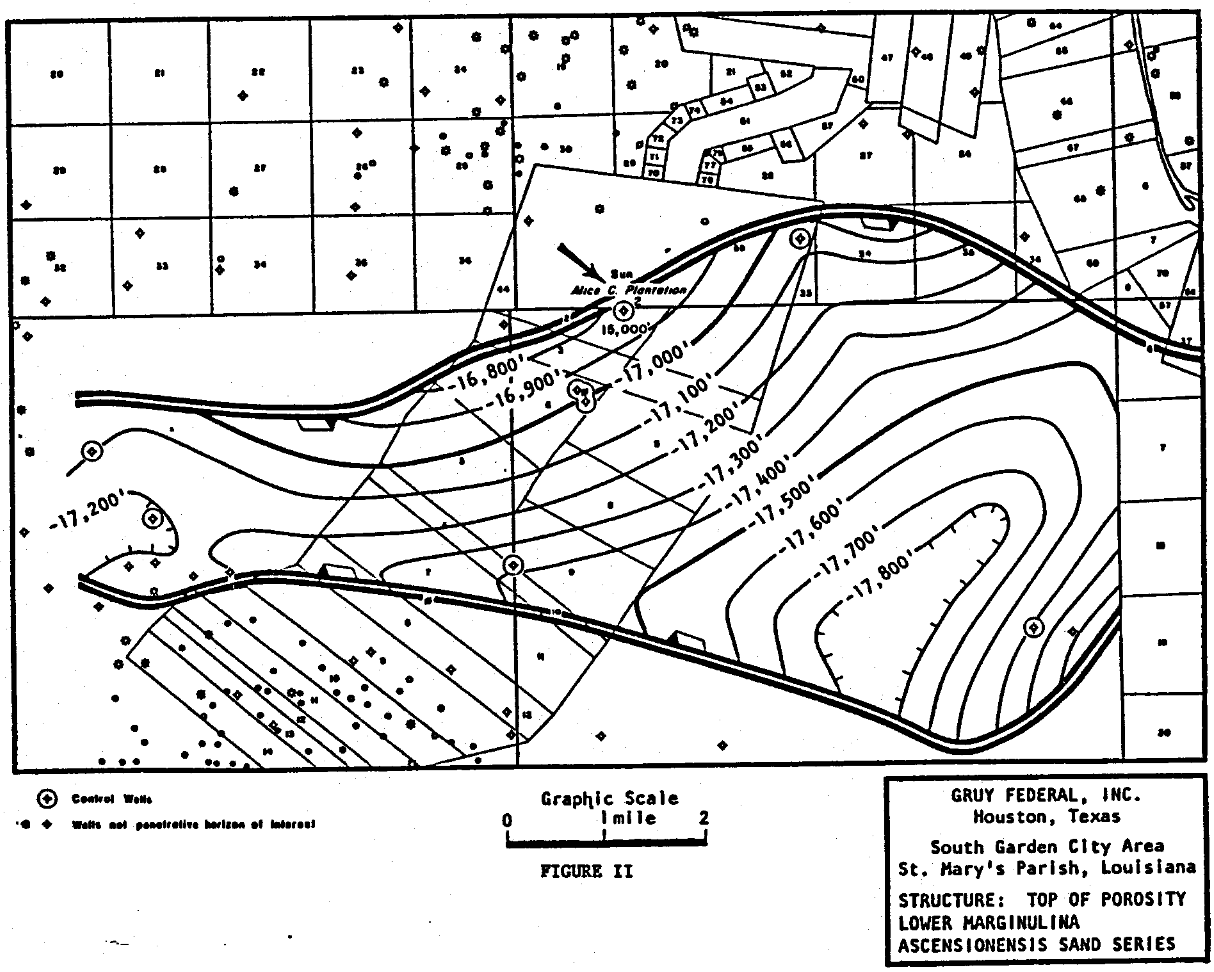


Figure 43. - - Structure map on top of the lower *Marginulina Ascensionensis* sand series (from Gruy Federal Inc., Final Report, Dec. 1978).

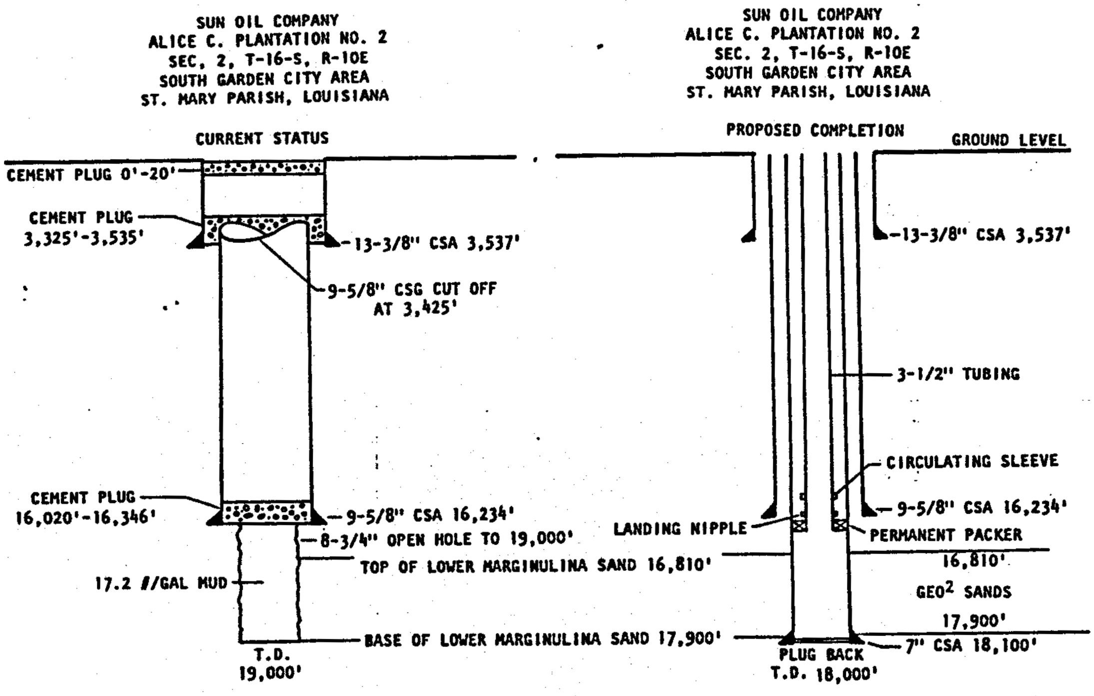


Figure 44. - - Schematic illustration of the Alice C. Plantation #2 well configuration at the time it was plugged and abandoned by Sun Oil Company and the proposed completion for geopressured - geothermal testing by Gruy Federal Inc., (from Gruy Federal Inc., Fiinal Report, 1978).

observations and advisory services. This was the first case of active participation by a industry (Tenneco) in the well-of-opportunity program. Complete details of all investigations and work carried out on this well are provided in the reports by Gruy Federal Inc., Houston, Texas (Sept. 1980) under contracts No. AC08-77ET28460 written by Dobson et al. (1980), and under contracts No. DE-AC08-78ET28373 (June, 1979) and No. EG-77-C-08-1528 (January 1979) for the Department of Energy, Division of Geothermal Energy. Information on this well provided here has been compiled and taken from these reports.

The Tenneco Fee "N" No. well penetrated a series of thick Miocene *Marginulina Textularia Warreni* sands starting from 14,750 ft. to 17,245 ft. (Figure 45). These geopressured - geothermal aquifer sands were characterized by an estimated drainage area of approximately 10 square miles uncomplicated by major faulting, about one cubic mile net sand volume, seven distinct sands varying in thickness from 61 ft. - 83 ft. and apparent depositional continuity, uniform dip and structural continuity.

Other reservoir characteristics of the geopressured - geothermal sands penetrated by this well are given in Table 14. A structural map drawn on the top of the first geopressured - geothermal sand encountered in this well is shown in Figure 46. This map also incorporated seismic data interpretation by Tenneco which was adjusted using the actual well control in the area.

The first sand scheduled to be tested in this well was the MG Tex 5D Sand (Figure 45) which was at a depth from 17,098 ft. to 17,185 ft. The initially test was proposed to last for about 60 days until a sustained producing capacity of at least 20,000 B/D was obtained. However, due to mechanical reasons, probably associated with the failure to obtain a cement shut-

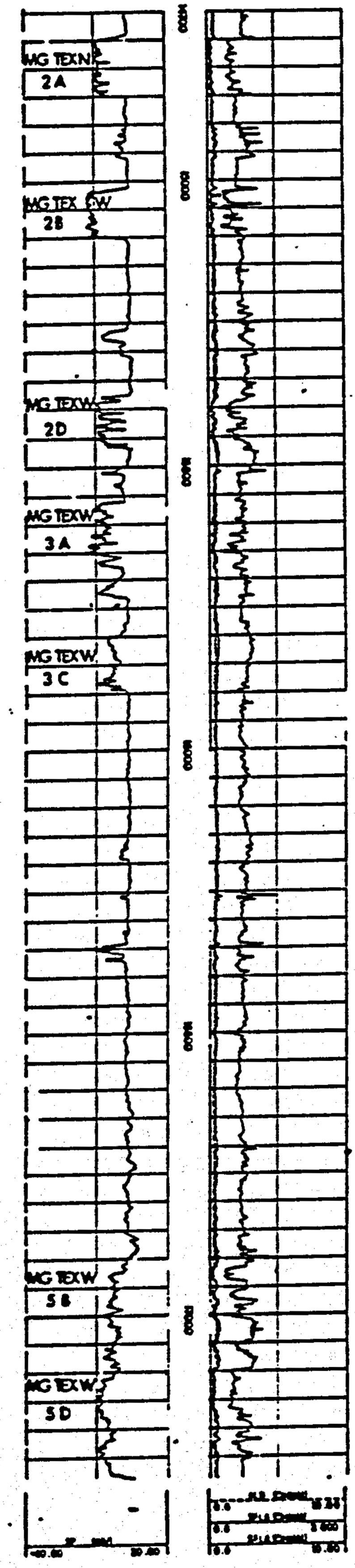


Figure 45. - - Electric log of the Tenneco Fee "N" #1 well (From Dobson et.al., in, Gruy Federal, Inc., Final Report, 1980).

TABLE 14

Reservoir characteristics of the geopressured - geothermal sands in the Tenneco Fee "N" No. 1 well

Depth, ft		Geo^2 sand	Shale Content (Vsh)	Calculated Average Porosity, %	Net Sand Thickness, ft	Estimated Pressure Gradient, psi/ft
From	to					
14,750	14,850	MG TexW 2A	10.2	25.2	82	0.92
15,018	15,100	MG TexW 2B	5.0	23.0	62	0.910
15,375	15,460	MG TexW 2D	8.5	23.6	65	0.900
15,560	15,660	MG TexW 3A	12.5	23.6	83	0.920
15,810	15,880	MG TexW 3C	13.8	21.3	61	0.926
16,906	17,005	MG TexW 5B	2.3	22.6	61	0.936
17,098	17,185	MG TexW 5D	1.0	21.6	72	0.936
					486	

(From Dobson et.al., in, Gruy Federal, Inc., Final Report, 1980).

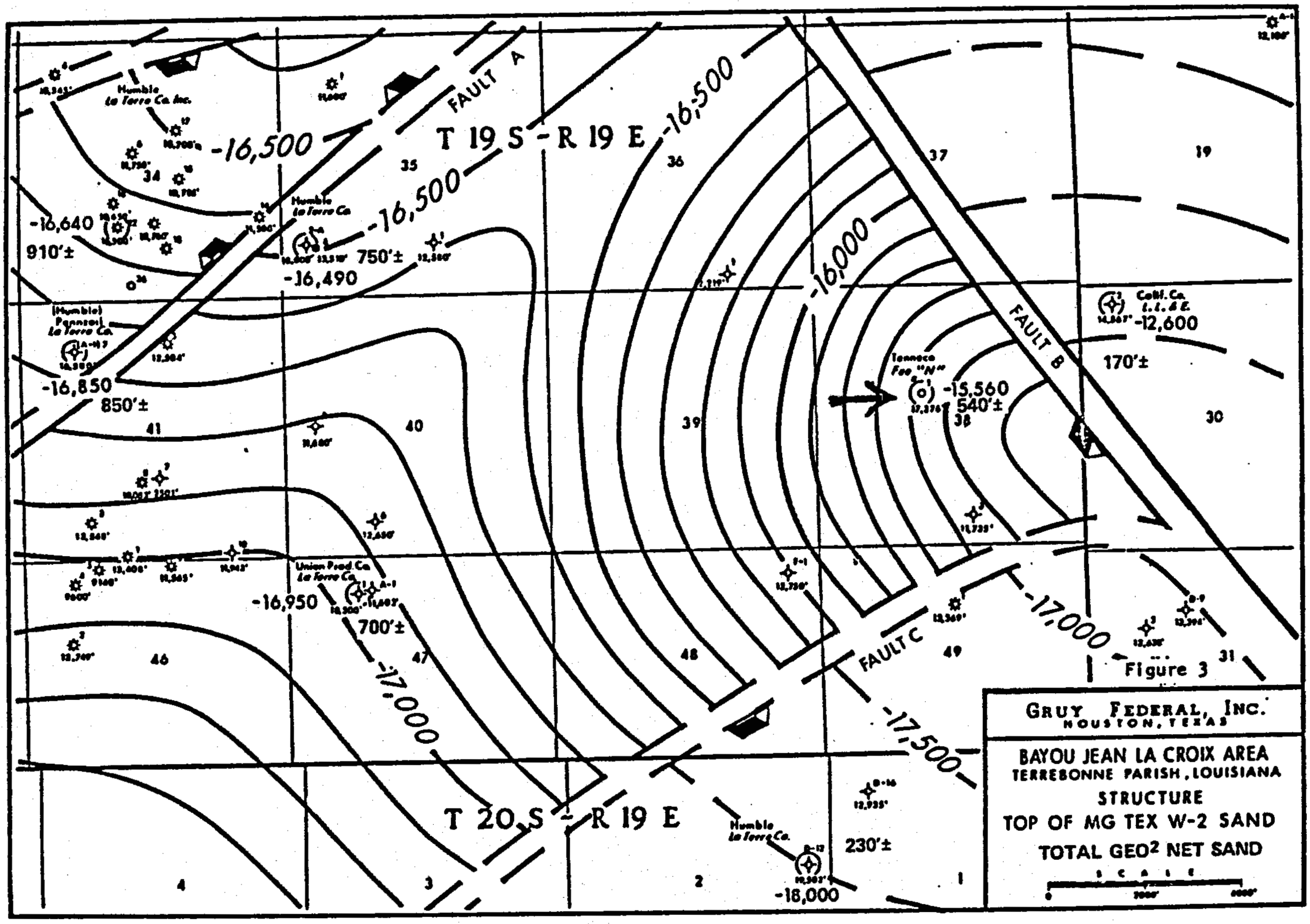


Figure 46. - - Structure map on top of the *Marginulina Textularia Warreni* age W-2 Sand (Miocene) in the area of the Tenneco Fee "N" No. 1 well. (From Gruy Federal, Inc., Final Report, Sept. 1980).

off when the liner was originally installed was not possible to conduct the proposed production test of the geopressured - geothermal sand aquifers.

Repeated attempts were made to re-cement and seal off the top of the 4½ inch liner and to clean it out to total depth prior to perforating for the first production test. Due to the development of a hole in the liner at 13,920 ft. which caused shale, gas and salt water to enter the well it became unpractical to attempt further cementing operations inside the small liner to correct this condition and it was decided to abandon the well. The condition of the Tenneco Fee "N" No. 1 well at the time of re-entry and after plugging and abandonment is shown in Figure 47. It was generally concluded after evaluating the events leading to abandonment of this well that the mechanical conditions leading to the problem encountered during re-entry and attempted completion were present at the start of the operations and was aggravated to the eventual failure experienced from the long exposure period during the clean out effort. Gruy Federal Inc. concluded that the net cost of this aborted test attempt was approximately $4,227,000. The drill barge was released on April 22, 1980 after having plugged the well in accordance with state regulations.

PAULINE KRAFT NO. 1

The Pauline Kraft Well No. 1 is located about 6 miles south of Corpus Christi, Texas, north of Chapman Ranch. The specific well location is 467 ft. from the north line and 990 ft. from the west line of Section 4, Laurels Farm Tracts, in E 1 Rincon De Corpus Christi Grant, Survey A - 411. The area is about 32 ft. above sea level with a flat terrain. The Pauline Kraft Well #1 which was originally drilled by Coastal States Gas Corporation to a depth of 13,000 ft.

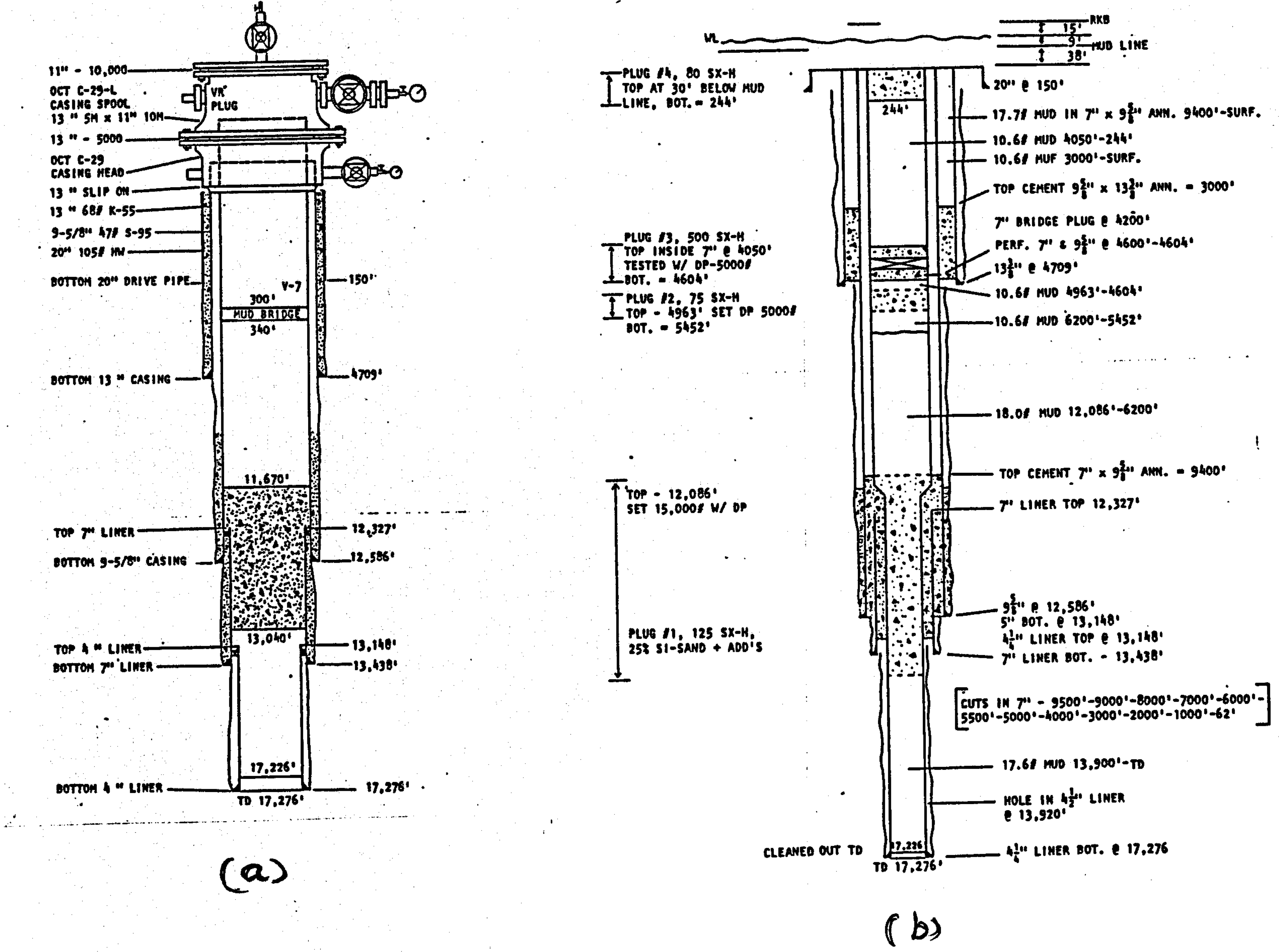


Figure 47. - - Condition of Tenneco Fee "N" No. 1 well at (a) time of re-entry and (b) after plugging and abandonment. (From Dobson et.al., in, Gruy Federal, Inc., Final Report, 1980).

and was abandoned as a dry hole in August 1971. It was originally proposed as a WOO prospect by the late Dr. Myron H. Darfman of the University of Texas at Austin based on his studies of the area geology and the well itself. Later the well was re-entered by Ross - Pope Drilling Equipment Company in an effort to obtain a source of geopressured - geothermal energy for a proposed gasahol manufacturing plant. Eaton Operating Company, Houston, Texas assumed control of the site on December 19, 1980 to conduct geopressured - geothermal testing under a contract with DOE under the WOO testing program. Details of all tests conducted on this well are to be found in the Final Well Report by Eaton Operating Company, Inc., (1981) prepared for the U.S. Department of Energy, Nevada Operations Office under Contract No. DE-AC08-80ET27081. Information provided in this compilation is taken from this report.

The prospective geopressured - geothermal sand tested is at a depth of 12,750 ft. to 12,860 ft. and is known as the Frio - Anderson sand of Mid-Oligocene age. These sands were deposited in a strand plain type environment and were reworked by marine processes and deposited in narrow bands, parallel to strike, occurring as complexes of ridges and bars. Locally, the structure is broadly anticlinal being bounded towards the northwest by a northeast - southwest trending fault (Figure 48). The fault lies apart 250 ft. northwest of the test well in the Anderson sand and has a displacement of about 450 ft. A cross section of the area through the Pauline Kraft #1 Well is shown in Figure 49. The grass sand thickness over the geopressured - geothermal reservoir interval of 12,750 ft. to 12,860 ft. is 110 ft. and the net sand thickness is estimated to be 109 ft. These values were derived from an analysis of the electric log shown in Figure 50, using a porosity cut off of 10%.

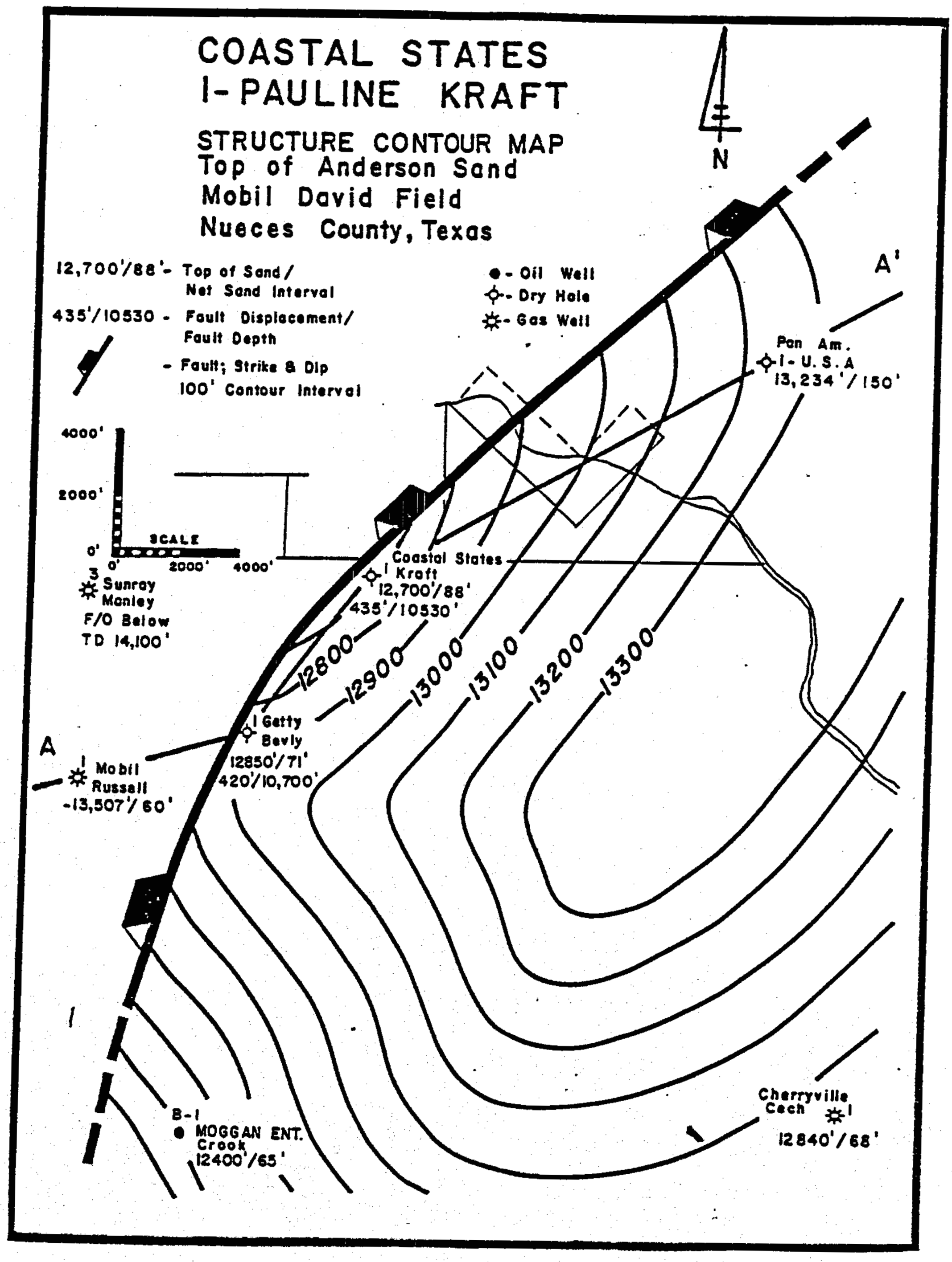


Figure 48. - - Structure map drawn on top the geopressure - geothermal sand (Anderson Sand) tested in the Pauline Kraft #1 Well (From Eaton Operating Co., Inc., Final Report, 1981).

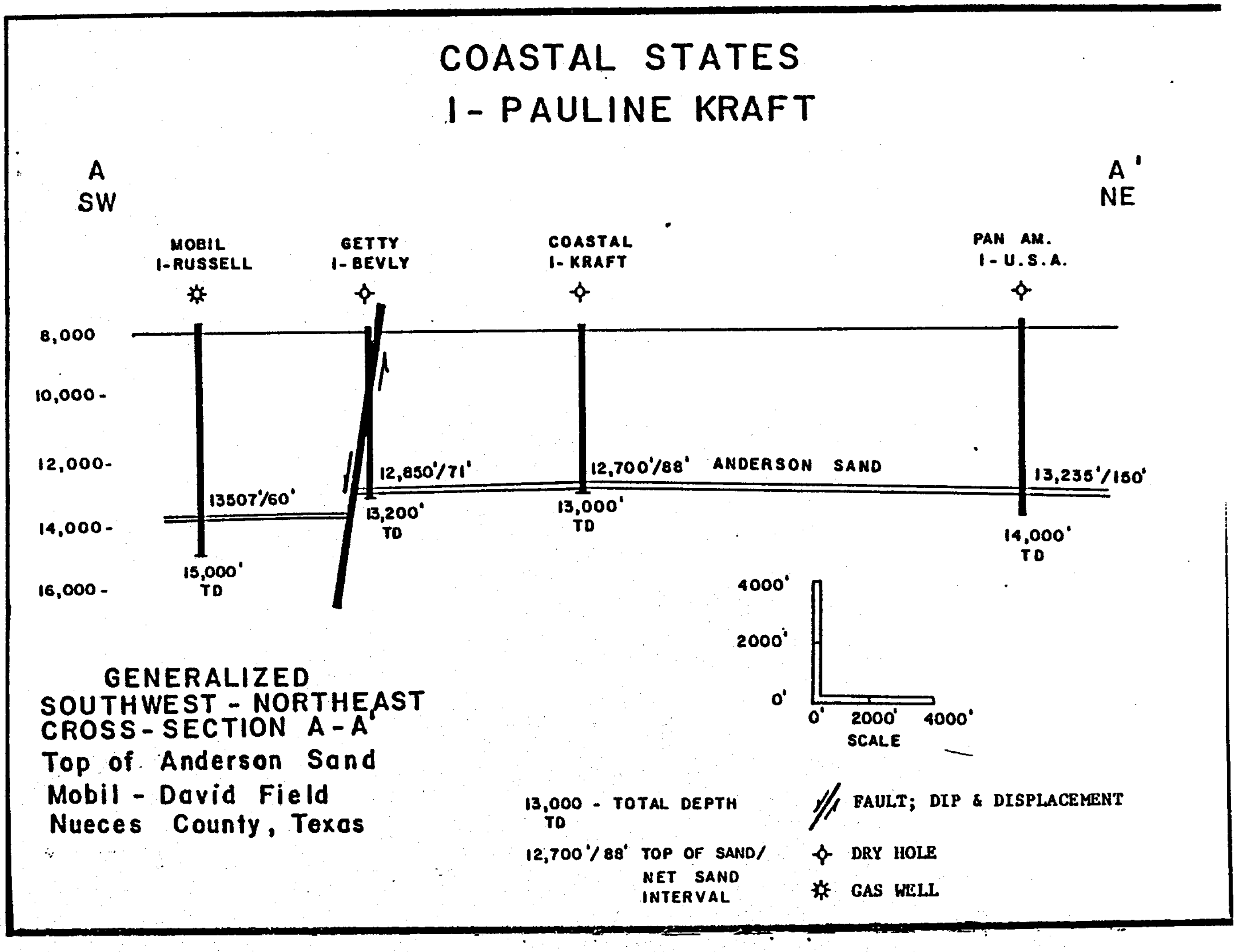


Figure 49.- - Generalized cross section across the Pauline Kraft #1 Well showing the sand tested See Figure 48 for cross section line (From Eaton Operating Company, Final Report, 1981).

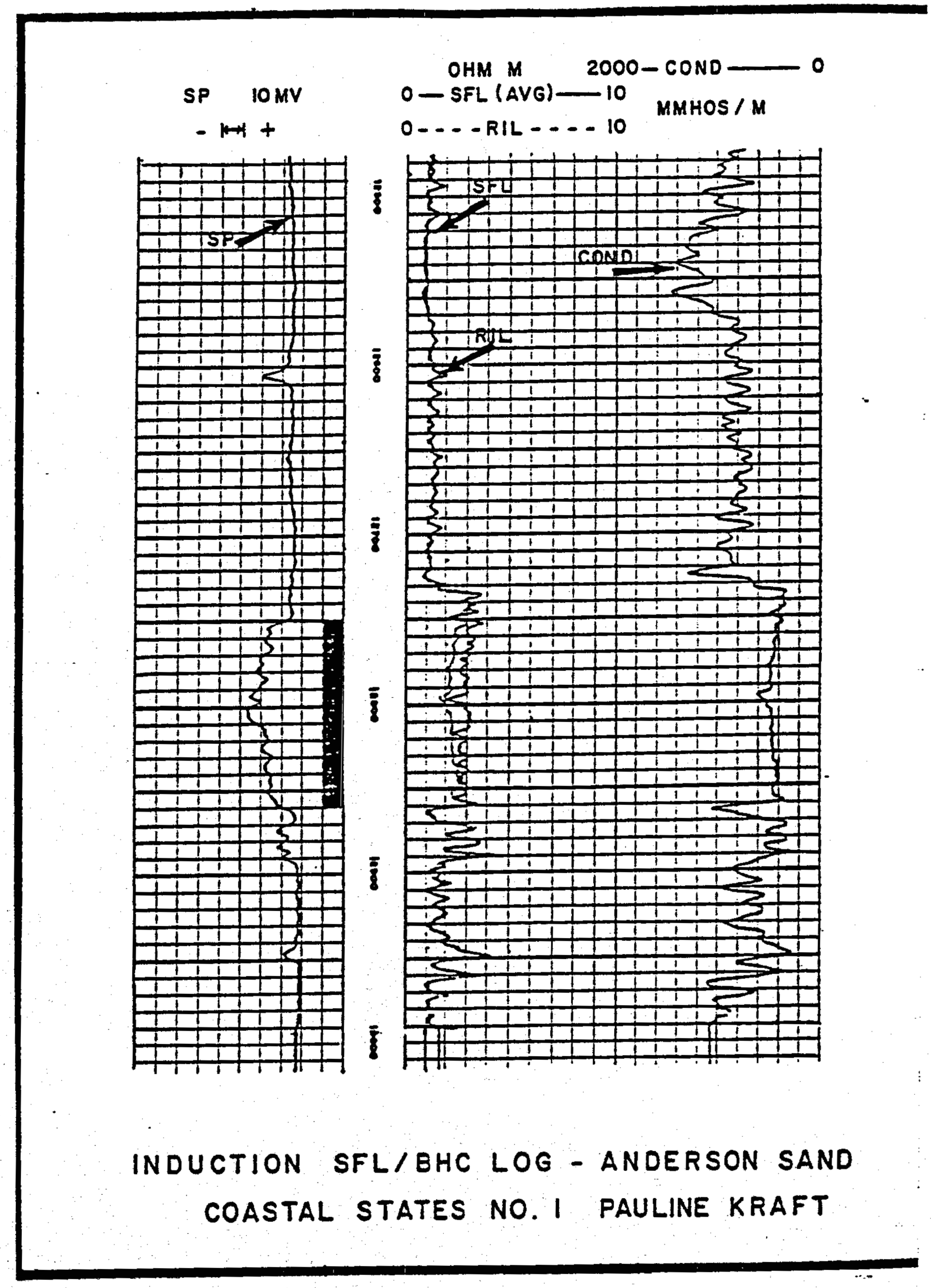


Figure 50. - - Electric log of the Pauline Kraft #1 Well showing the sand tested for geopressured - geothermal data (From Eaton Operating Co., Inc., Final Report., 1981).

The mean porosity on the basis of sidewall core analysis was determined to be 23% with a range between 10% - 20%. The mean permeability of the Anderson Sand was calculated to be 39 md with a range of 10 to 83 md based on sidewall core data. The formation water salinity was estimated to range from 2,000 ppm to 48,000 ppm based on well log analysis.

A schematic drawing of the test well showing its condition at the time Eaton took over operations from Ross-Pope Drilling Equipment Company., Inc., and as later completed for testing is shown in Figure 51. The completion interval was first perforated on March 17, 1981 the first interval perforated being from 12,820 ft. to 12,860 ft. with a shot density of four holes per foot. Later the well was opened to flow to clean perforations and flowed approximately one barrel while the pressure dropped from 4,000 to 700 psi. It was then shut in and the same interval was perforated with an additional four holes per foot. The well was flowed to the reserve pit while perforating from 12,820 ft. to 12,750 ft. At this time the flowing well pressure was 100 psi, with an estimated 35 barrels of water per day producing rate. During perforating operations the well produced about 30 barrels of water. Perforating was performed during only daytime during which time the well flowed and it was shut in at night. On March 19, 1981 a Haliburton high pressure pump was connected to the tubing value on the Christmas tree and water was pumped into the well at a rate of ½ barrel a minute. The surface pressure increased from 2,000 psi to 7,100 psi when 5 barrels of water was pumped. The pressure was then released allowing the well to "back surge" into the well bore. This operation was then repeated and a large amount of muddy water was removed from the casing as a result of this circulation. Later eleoen barrels of water were pumped at a rate of 1 barrel a minute. The surface pressure increased to 6,900 psi and when it was released the well flowed approximately 93 barrels of water per day. However,

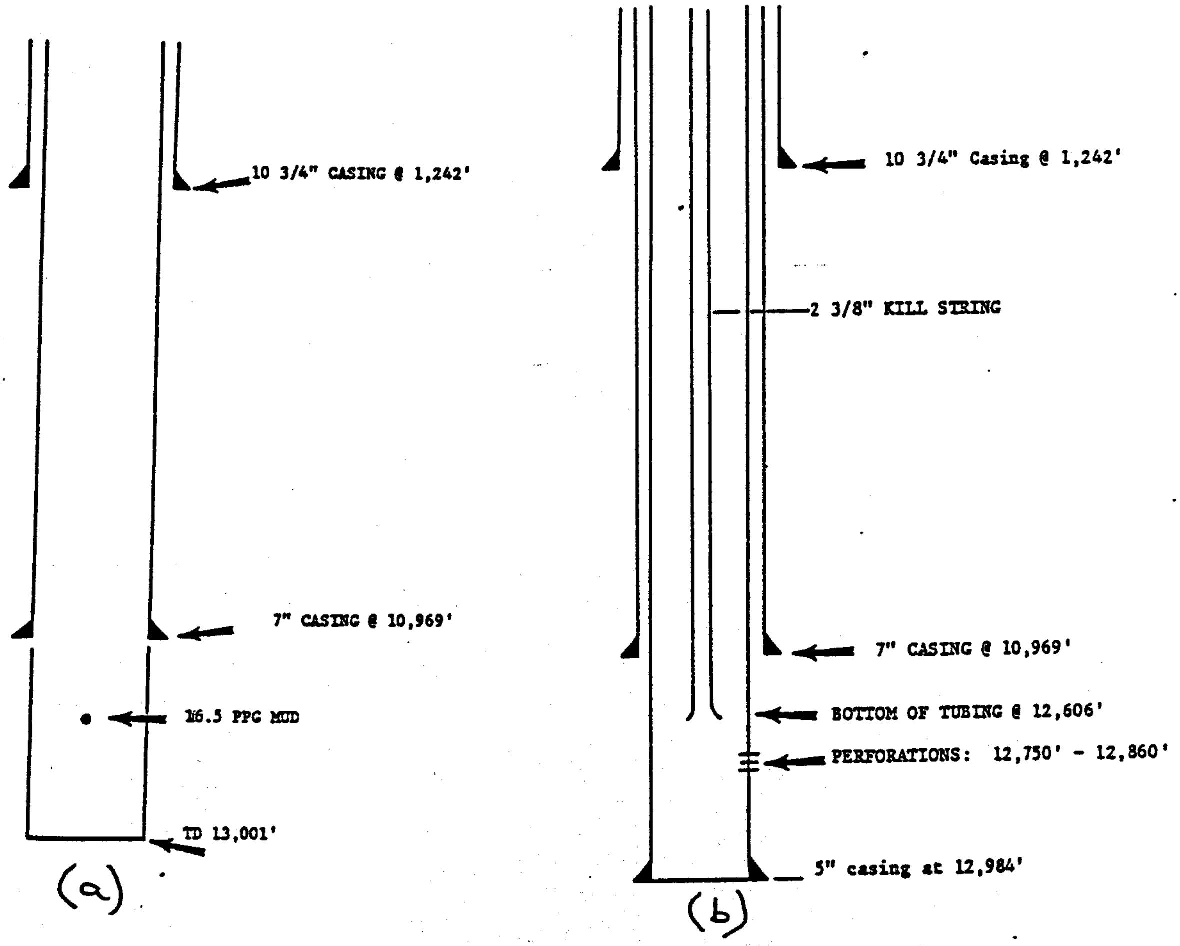


Figure 51. - - Schematic diagram of the test well at (a) the time of Eaton takeover, and (b) during testing (From Eaton Operating Co., Final Report, 1981).

the flow decreased from 93 to 35 BWPD over the next 24 hours. As formation damage was suspected the well was acidized on March 20, 1981. No improvement of injectivity was apparent during the entire acid job of 20,000 gallons. The first 19,000 gallons were pumped at a rate of 42 gallons per minute with 5,900 psi surface pressure and the last 1,000 gallons were pumped at 84 gallons per minute with 6,200 psi, including 1,722 gallons of displacement water.

When only 420 gallons of displacement water was left to pump, the wellhead jumped up about 4 inches and fell back to its original position and mud sprayed out of the 7" casing valve. Pumping was stopped and the 5" annulus was flowed to the put after the 7" casing valve was closed. The surface flowing pressure decreased from 6,200 to 0 psi in 15 minutes and the well was then produced to a tank for 2½ hours and was gauged at 132 BWPD. These events indicated to the operators that a casing failure had occurred in the 5" casing close to the surface. After an analysis of the situation it was decided that the estimated cost to repair the 5 inch casing and to perform the frac treatment could not be justified.

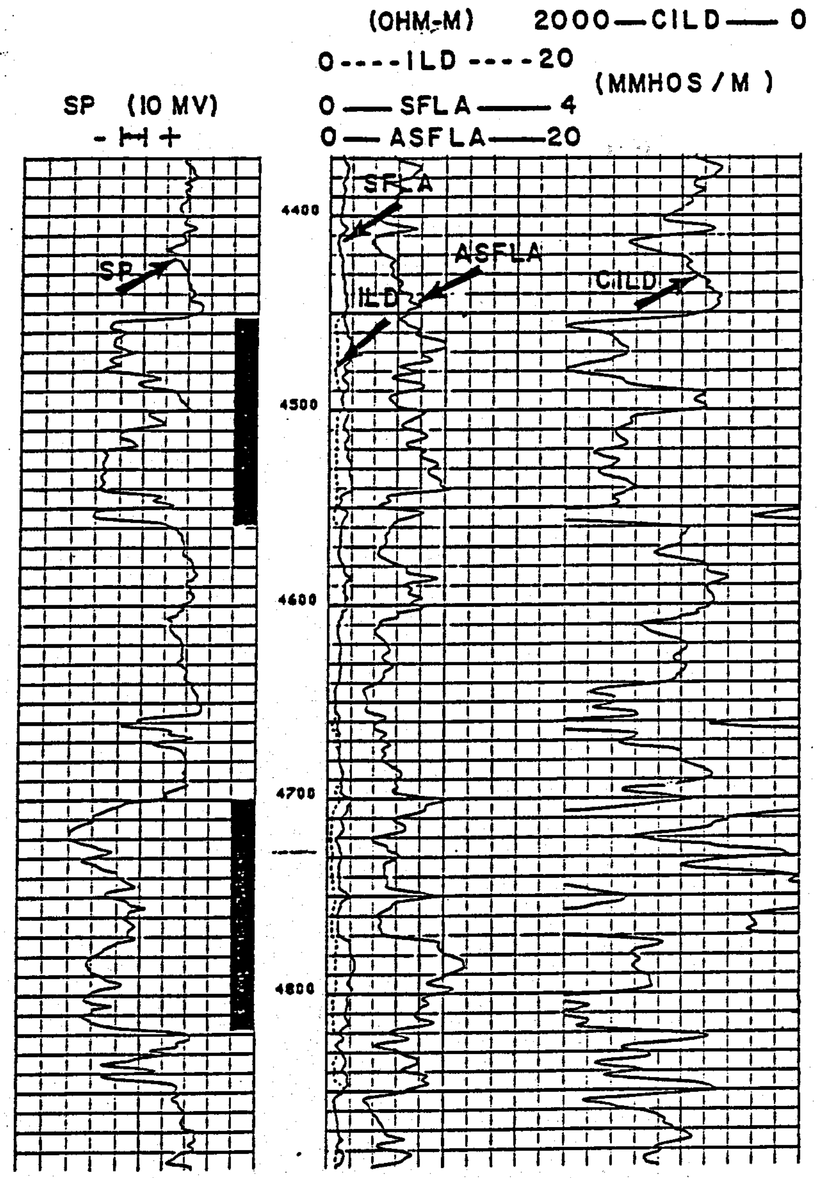
The Pauline Kraft Well No. 1 was killed on March 22, 1981 by circulating 16.5 ppg mud down the tubing and out of the casing. The well was then plugged and abandoned and the workover rig was released on March 27, 1981.

The Pauline Kraft Salt Water Disposal Well was drilled to a depth of 5,275 ft. Electric logs indicated four potential disposal zones (1) Sand A - 4,702 ft. to 4,816 ft.; (2) Sand B - 4,453 ft. to 4,550 ft., (3) Sand C - 3,872 ft. and (4) Sand D - 3,748 ft. to 3,820 ft. The disposal well was completed in Sand A and Sand B (Figure 52). These sands had the following log derived parameters:

	Sand A	Sand B
Net Sand	93'	97'
Porosity	26%	25%
Salinity	45,000 ppm	32,000 ppm
Temperature	160°	156°F
Pressure	2,228 psi	2,109 psi

The disposal well was stimulated with 15,000 gallons of acid after which it accepted brine at 32,400 BWD at 150 psi injection pressure. It was therefore completed to be capable of accepting all production from the test well. The schematic diagram of the actual well completion and the surface well head is shown in Figure 53.

The low productivity of the Anderson sand in the Pauline Kraft #1 Well was surprising to all parties concerned. Reasons suggested for the low productivity included formation damage which may have occurred during reaming out and completion operations, and a low mean porosity of 16% determine from a sonic log run by Eaton Operating Company, which may have been due to formation damage or just a more accurate log reading from logs run earlier. The Anderson sand had a high lime content (determined from sidewall cases) and this could have acted as a cementation agent reducing effective reservoir permeability. The 5-inch casing failure areas



INDUCTION - SFL LOG — CATAHOULA SANDS
COASTAL STATES NO. 1 - SWD PAULINE KRAFT

Figure 52. - - Electric log of the salt water disposal wells showing the two sands perforated for brine disposal (From Eaton Operating Co., Inc., Final Report, 1981).

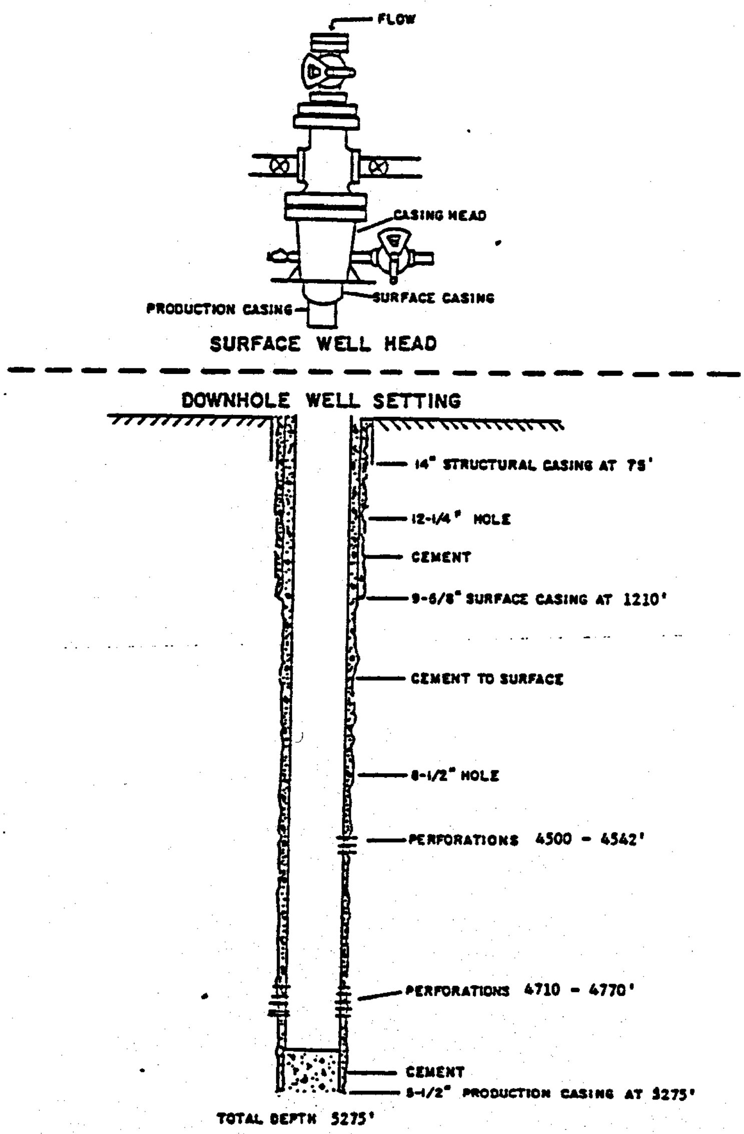


Figure 53. - - Schematic diagram of the actual well completion and surface wellhead of the salt water disposal well (From Eaton Operating Co., Final Report, 1981).

attributed to be probably due to the cooling effect of the acid job and the high surface temperatures encountered during the acidizing operations.

SALDANA WELL NO. 2

The Saldana Well No. 2 is located in South Texas approximately 35 miles southeast of the city of Laredo and about five miles northeast of Escoban, Texas, in the Martinez Field area, Zapata County. The well location is 300 ft. from the south line and 2,200 ft. from the east line of the A. Stehle Survey, A-497, in the first quadrant of the Tobin township 24-S, Range 9-E grid system. This well was originally drilled by Riddle Oil Company in March 1980 and abandoned as a dry hole at a total depth of 11,171 ft. Eaton Operating Company assumed control of the well on October 8, 1980 for testing under the DOE geopressured - geothermal wells of Opportunity (WOO) program. Eaton also acquired the Saldana Well No. 1 from Riddle, also a dry hole, for use as a brine disposal well. Actual field operations at the well site were initiated by Eaton Operating Co., Inc., Houston, Texas, on October 23, 1980. A detailed account of all the investigations and analyses on this well are provided in the final well report by Easton Operating Co., Inc., (1981). This work was performed by Eaton under DOE contract No. DE-AC08-80ET27081 with the Nevada Operations Office. Information compiled herein is taken from this report.

The geologic section tested is at a depth of 1,745 ft. to 9,820 ft. and is named as the 1st Hinnant Sand which is the upper member of the Wilcox Group. Generally the Wilcox Group sediments were deposited in a deltaic environment during the early Eocene/late Paleocene age. It consists of a wedge of coarsening upward sandstone and shale sequences, dipping towards the

Gulf (Coast) across a complex growth fault system. The Saldana No. 2 Well lies in the Zapata delta complex within the Rosita delta system in the Upper Wilcox of South Texas.

A structure map of the area is shown in Figure 54. The area structurally is composed of a faulted dome with moderate relief. The Saldana No. 2 test well is located in the central area and is bounded by arcuatc northeast - south and southwest trending faults which are typically down to the coast. These faults limit the reservoir extent approximately 1,600 ft. to the last and 1,500 ft. to the west of the Saldana No. 2 test well. These appear to be no apparent reservoir limiting barriers to the north or to the south of the test well. Two geologic cross sections north-south, and east west through the Saldana No. 2 test well show the domal and faulted depositional trend of the 1st Hinnant sand tested in the well (Figure's 55 and 56).

An electric log of the Saldana No. 2 test well showing the test sand (Figure 57) indicates the net sand thickness of the tested zone to be 79 ft. This value has been based on an analysis of both the indiction and density logs gross interval of 90 ft. to which a porosity cutoff of 10% was applied to yield the net value. The mean porosity of the tested sand was 20% and ranged between 18.1% to 22.5%. This value was obtained from sidewall cores taken from the 1st Hinnant test sand in the Saldana No. 2 Well.

One pressure drawdown flow test and one pressure buildup test were conducted during a ten day testing period. During this time a total of 9,328 barrels of water was produced, and the highest sustained flow rate was 1,950 BWPD. The gas to water ratio ranged from 47 to 54 SCF/BBL. However, recombination studies determined a saturation value of 40.9 SCF/BBL. This indicated that the gas production was higher than that due to gas solubility in brine at reservoir conditions. Analysis of bottom hole fluid samples indicated a gas to water content of

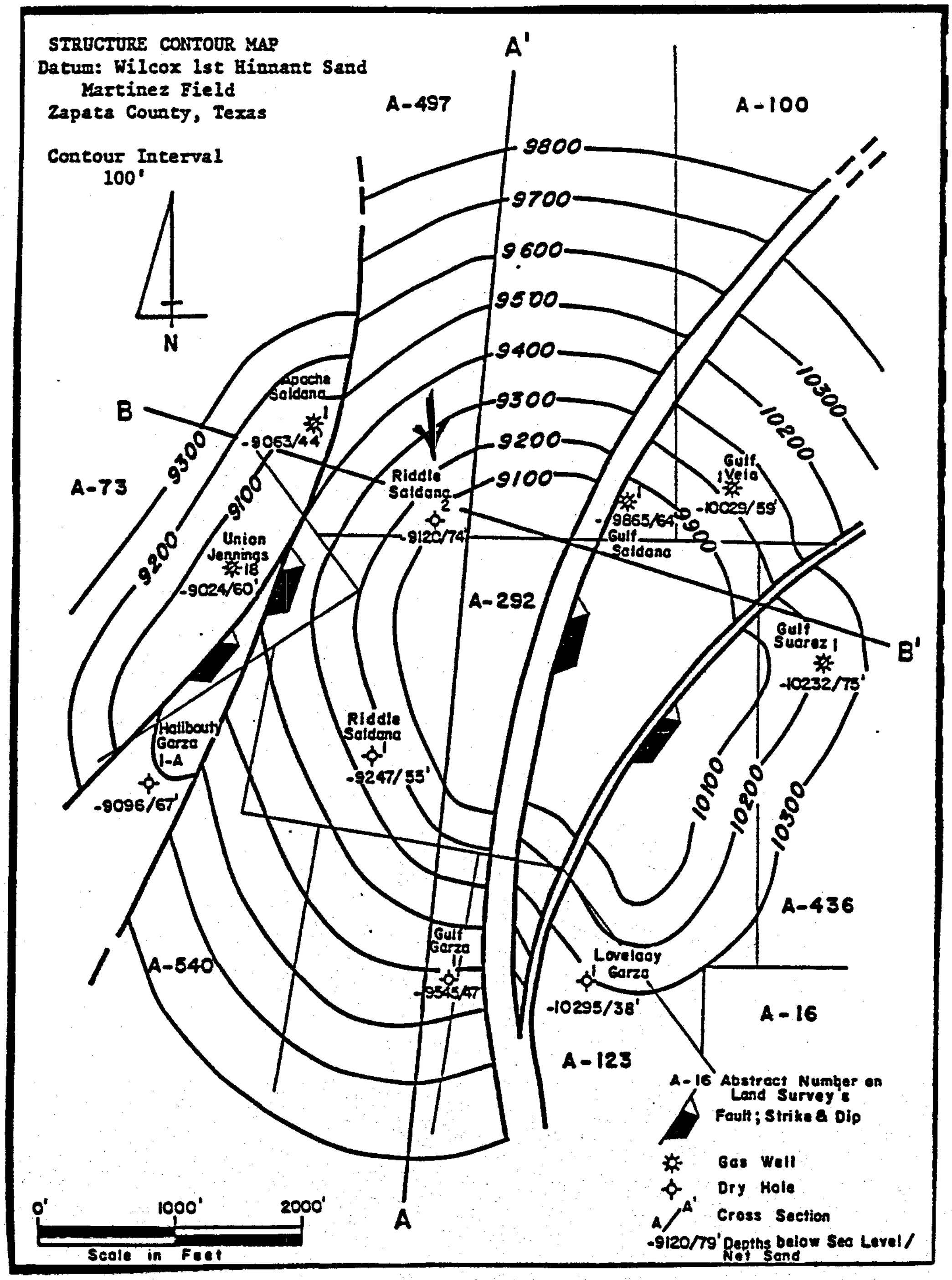


Figure 54. - - Structure map drawn on top of the Wilcox 1st Hinnant Sand in the Martinez Field Area (From Eaton Operating Co., Final Report, 1981).

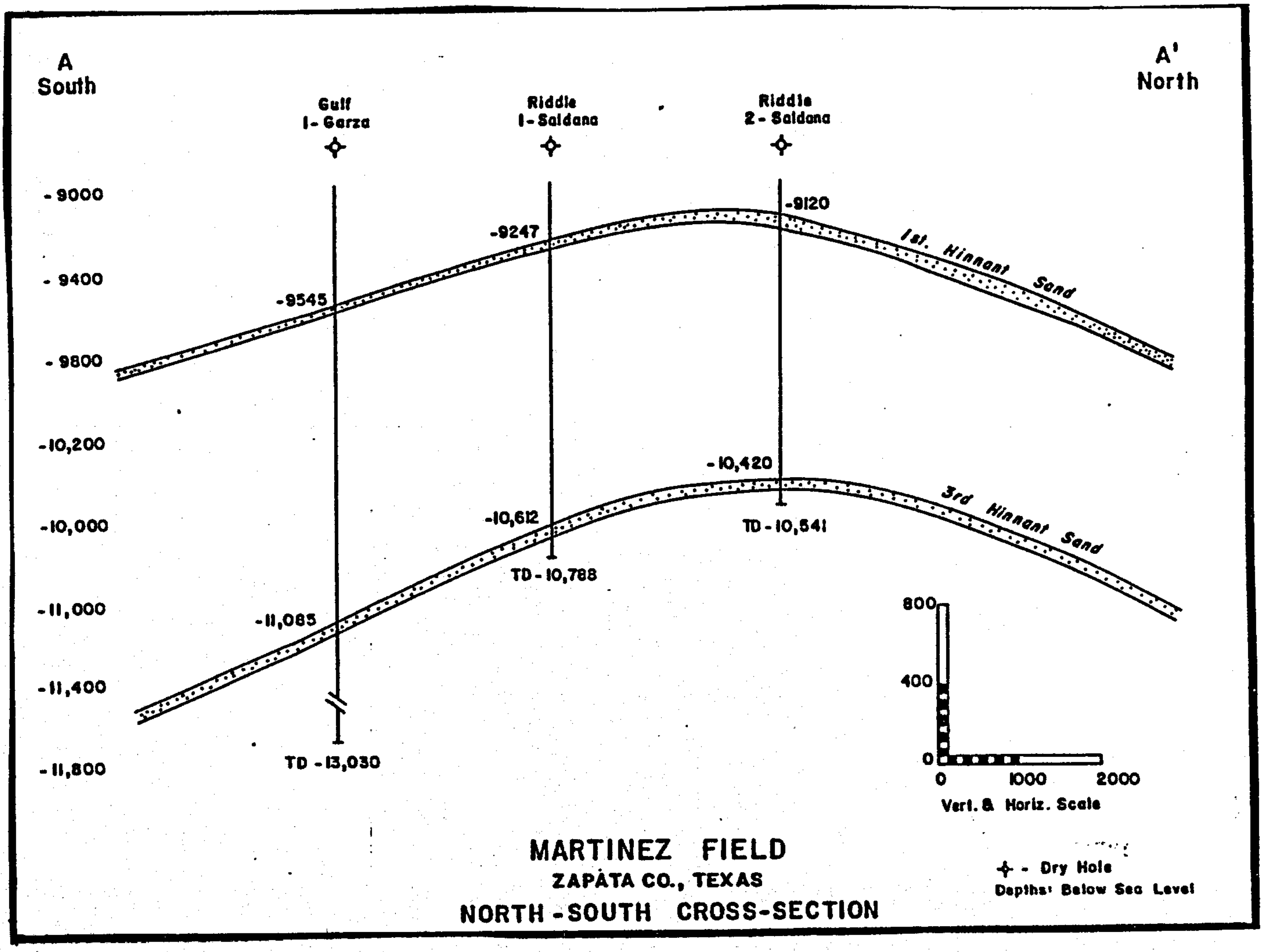


Figure 55. - - A north-south geologic cross section through the Saldana Well No. 2. The cross section line is shown in Figure 54 (From Eaton Operating Co., Inc., Final Report, 1981).

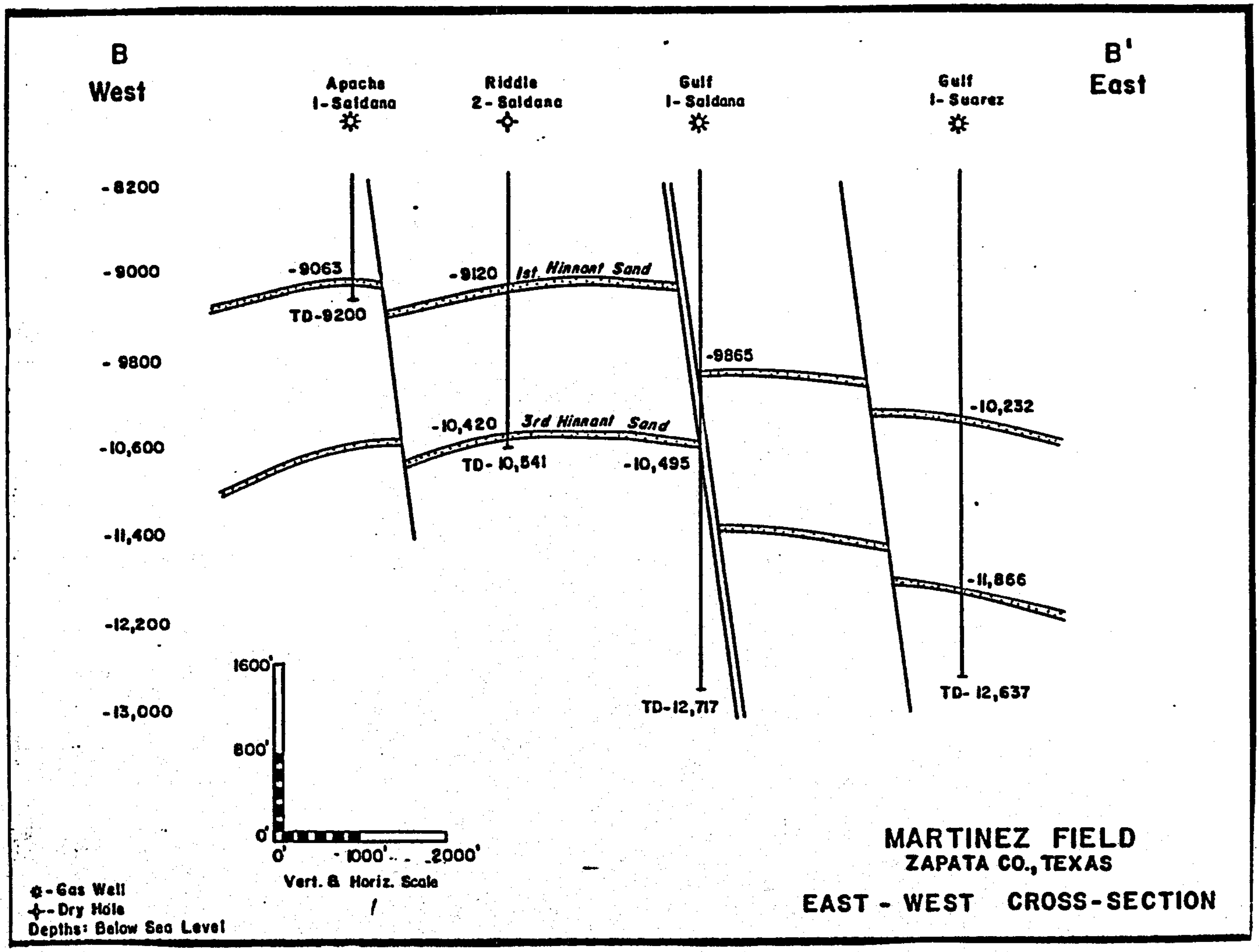


Figure 56. - - An east-west geologic cross section in the Martinez Field area incorporating the Saldana #2 geopressured - geothermal test well. The cross section line is shown in Figure 55 (From Eaton Operating Co., Inc., Final Report, 1981).

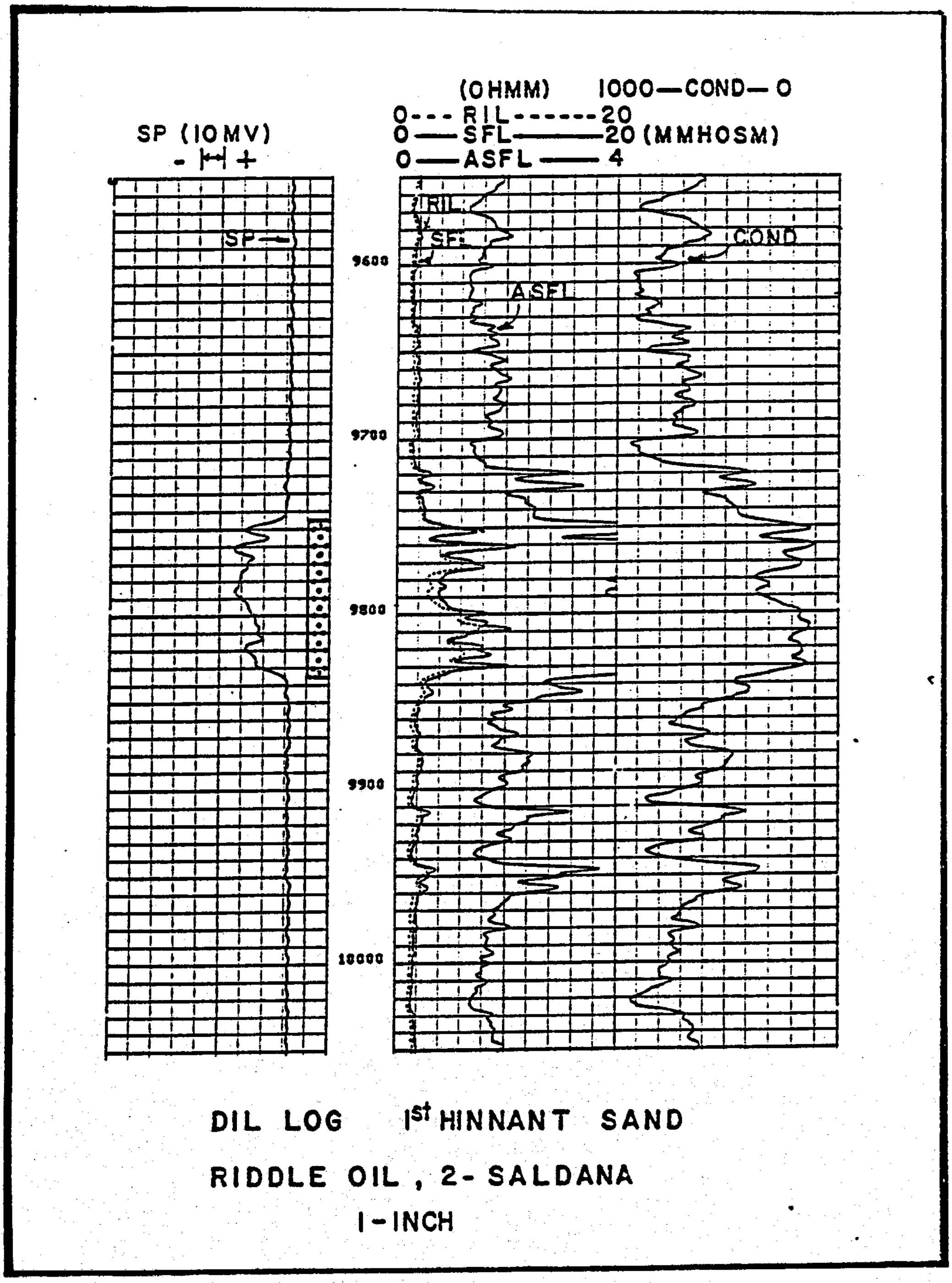


Figure 57. - - Electric log of the Saldana #2 geopressured - geothermal test well showing the testing sand perforated from 9,745 ft. - 9,820 ft. (From Eaton Operating Co., Inc., Final Report, 1981).

38.8 SCF/BBL which supported the recombination data. The CO_2 content ranged from 26.4 - 16.4 mol %, and H_2S values ranged from 57 - 93 ppm, which was much higher than that of other wells tested. The bottom hole pressure was measured to be 6,627 psia with the corresponding original surface pressure was 2,443 psia. The reservoir temperature was 300°F and the highest surface temperature observed during testing was 220°F. The reservoir had a permeability to reservoir fluid of 12.5 md. Testing indicating two permeability barriers within 265 ft. Of the well bore, restricting the drainage area to approximately 111°. The total dissolved solids in the produced brine averaged 12,800 mg/l. There was light scaling during the test period (.0050 gms. per square inch per 1,000 barrels of water) and only slight corrosion of surface test equipment was observed. During testing, about 488 lbs. of five solids were produced of which 37% was drilling mud residue, 34% was formation material, and 29% were products precipitated from the brine. A summary of test results from the Saldana No. 2 Well is given in Table 15.

A schematic illustration of the test well showing the down hole configuration at the Eaton takeover of the well from Riddle, and as completed by Eaton for testing is shown in Figure 58. The original well was drilled to a depth of 11,171 ft. Eaton Operating Co., Inc., perforated the target zone from 9,745 ft. to 9,820 ft. with 8 holes per foot for geopressured -geothermal testing.

The Saldana Well No. 1 which is located about 2,900 ft. south - southwest of the test well was used as the salt water disposal well. The electric log of the Saldana No. 1 obtained by Eaton from Riddle indicated that there were four potential disposal sands available for brine injection (Figure 59) (1) Sand A (3,005 ft. - 3,097 ft., thickness 92 ft., average porosity 25%), (2) Sand B (2,825 ft. - 2,885 ft., thickness 60 ft., average porosity 30%), (3) Sand C (2,695 ft. - 2,785 ft.,

TABLE 15

SUMMARY OF TEST RESULTS

SALDANA WELL NO. 2

ZAPATA COUNTY, TEXAS

WELL DATA:

Total Depth of Well	11,171 Feet
Formation	Upper Wilcox, First Hinnant Sand
Gross Sand Interval	90 Feet
Net Sand	79 Feet
Perforations	9745 - 9820 Feet (8 HPF)
Original Reservoir Pressure	6627.2 Psia
Original Reservoir Temperature	300.2°F
Original Shut-In Surface Pressure	2442.9 Psia
Average Porosity	20% (Sidewall Cores)
Average Permeability	20 md (Sidewall Cores)

ANALYSIS OF POST-SEPARATOR WATER:

Total Dissolved Solids	12,800 mg/l
Chlorides	6,630 mg/l
pH	6.5

ANALYSIS OF FLARE LINE GAS:

Methane	70.9	to	78.8	Mole Percent
Carbon Dioxide	26.4	to	16.4	Mole Percent
Heavier Hydrocarbons	2.5	to	4.7	Mole Percent
Other	0.2	to	0.1	Mole Percent
Heating Value	790	to	893	BTU/SCF
H_2S in Gas	57	to	93	ppm

TESTS (From 11-16-80 to 11-25-80):

Flow test	6.0-day reservoir drawdown and flow test during which 9328 barrels of water were produced.
Build-up Test	3.1-day reservoir pressure buid-up test.
Produced Dry Gas-to-Saltwater Ratio	47 to 54 SCF/STB (49.15 average)
Total Water Produced	9328 Barrels
Highest Flow Rate Achieved	1950 BWPD Sustained
Highest Surface Temperature Observed	220°F
Solids Production	High; 50 pounds per 1000 barrels
Corrosion	Light; 0.0046 Grams/1000 BBLS/IN^2
Scaling	Light; 0.0050 Grams/1000 BBLS/IN^2
Lowest Flowing Surface Pressure Observed	424 Psia
Lowest Flowing Bottom-hole Pressure Measured	4237 Psia
Test Well Productivity Index	1.51 BPD per psi
Maximum Explored Volume of Reservoir Water	Approximately 18 Million Barrels
Maximum Distance Explored (BHP Instrument)	2768 Feet
Reservoir	Relatively tight with a permeability to reservoir fluid of 12.5 mds. and a gas saturation in excess of solubility. Two permeability barriers were found within 265 feet of the wellbore, restricting the drainage area to about 111 degrees.
Disposal Well Gross Perforations	3005 to 3100 feet (4 HPF)

(From Eaton Operating Co., Inc., Final Report, 1981)

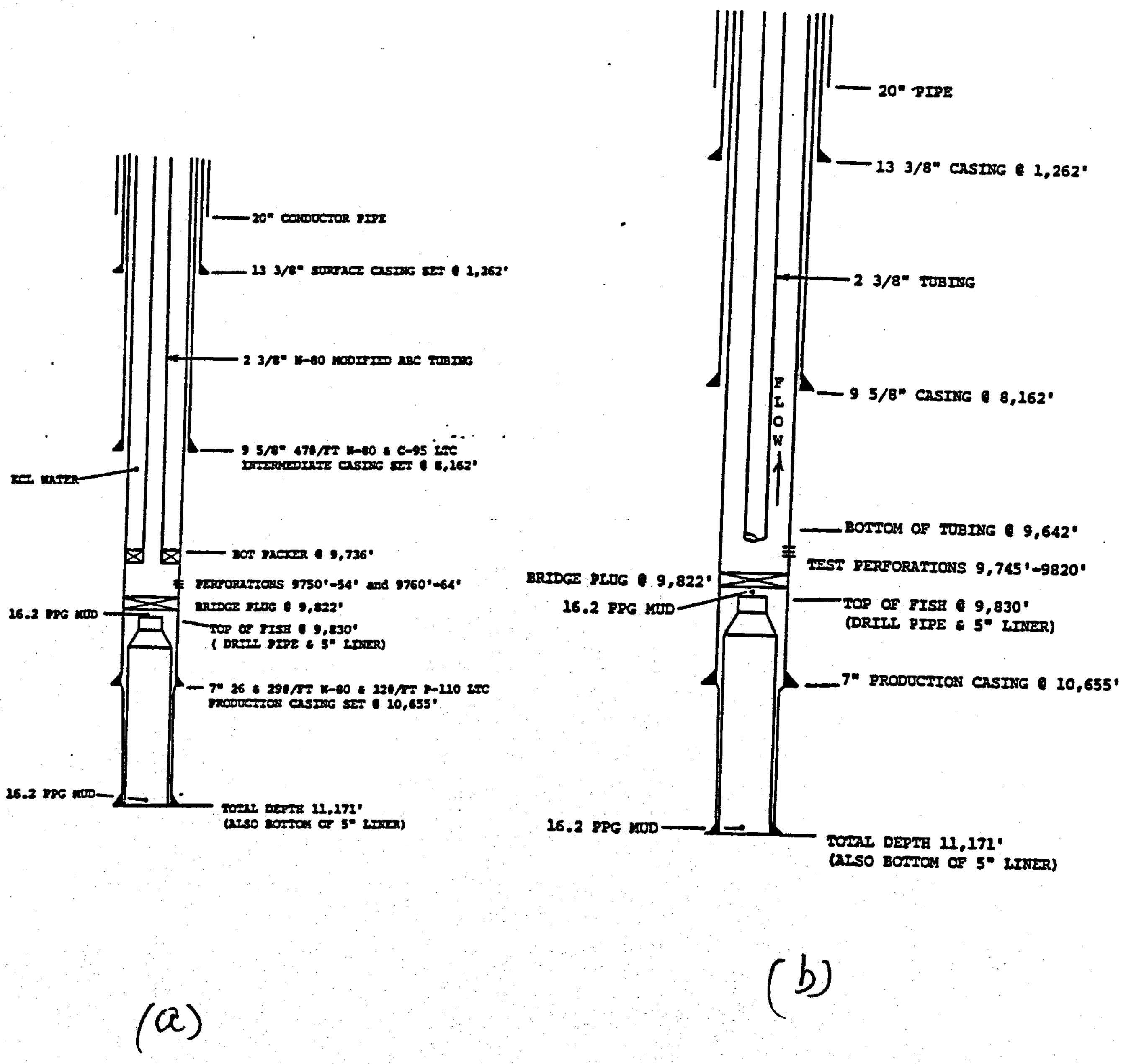
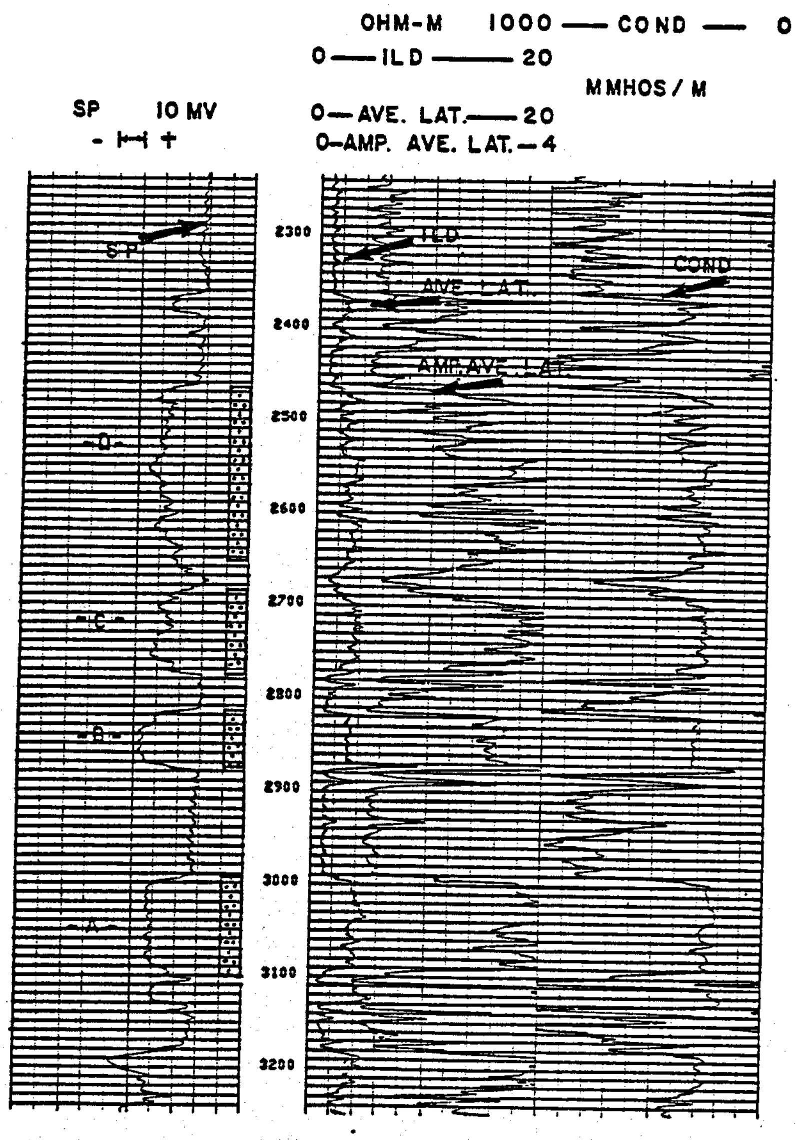


Figure 58. - - Schematic diagram of the test well showing (a) the downhole configuration at the time of Eaton takeover of the well, and (b) during geopressure - geothermal testing. (From Eaton Operating Co., Inc., Final Report, 1981).



DUAL INDUCTION LATEROLOG - YEGUA SANDS

RIDDLE NO. I SALDANA

Figure 59. - - Electric log of the salt water disposal well showing the four potential sands deemed suitable for brine disposal (From Eaton Operating Co., Inc., Final Report, 1981).

thickness 90 ft., average porosity 20%), and (4) Sand D (2,475 ft. - 2,662 ft., thickness 187 ft., average porosity 31%). The well was completed in Sand A and B for brine disposal.

A schematic drawing of the brine disposal well showing its tubular configuration at the time it was acquired by Eaton Operating Company, Inc., from Riddle and as completed by Eaton is shown in Figure 60. No stimulation treatment was necessary for the disposal well. After injectivity tests it was determined that the disposal well was capable of accepting more than 8,000 BWPD with a maximum surface injection pressure of 500 psi (Figure 61).

Pressure and temperature data and same chemical analyses performed during testing were carried out by the Institute of Gas Technology (IGT) and Weatherly Laboratories, Lafayette, LA. Other parties involved in the investigations were McNeese State University, Lake Charles, LA, U.S. Geological Survey at the NSTL Station, Miss., and Menlo Park, California, and Matsen and Associates, Houston, Texas.

The rig was moved on location on December 4, 1980 to start plugging and abandonment operations on the Saldana No. 2 test well. These operations were completed on December 17, 1980 after which the same rig was moved to the disposal well. The plugging of the disposal well was completed and the rig was released on December 20, 1980.

Concentrations of mercury in the produced brine averaged 2.0 micrograms per liter which is much higher than the upper limit (0.10 micrograms per liter) set by the U.S. Environmental Protection Agency for protection of aquatic organisms. Toxic concentrations of baron (88 milligrams per liter) were also present in the produced brine. These factors would preclude any long term surface disposal of the produced brine. In the testing of the Saldana No. 2 Well, free gas in the reservoir was evident.

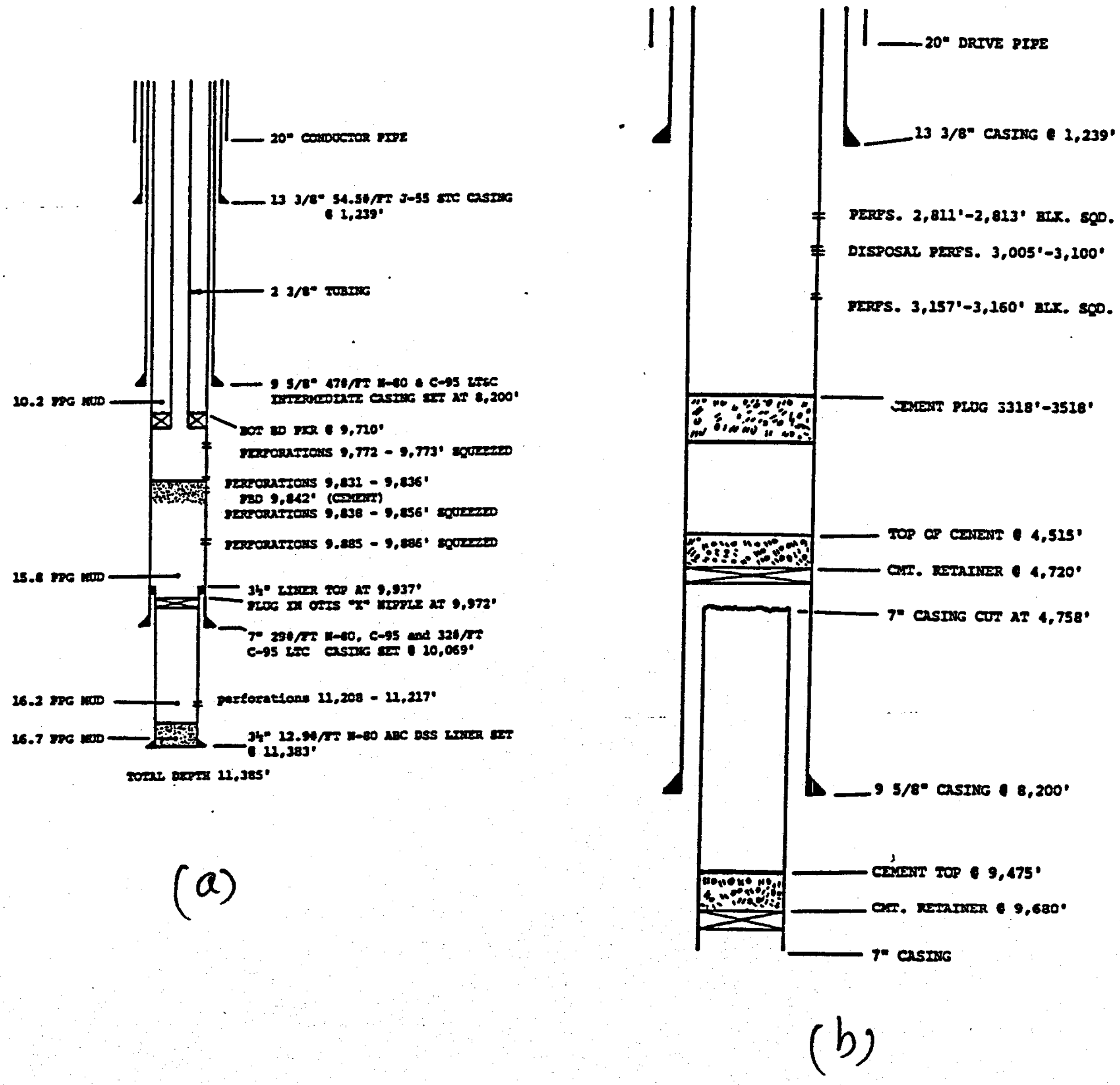


Figure 60. - - Schematic drawing of the brine disposal well showing its tubular configuration at (a) the time when Eaton took over operations from Riddle, and (b) when completed for brine disposal from the test well (From Eaton Operating Co., Inc., Final Report, 1981).

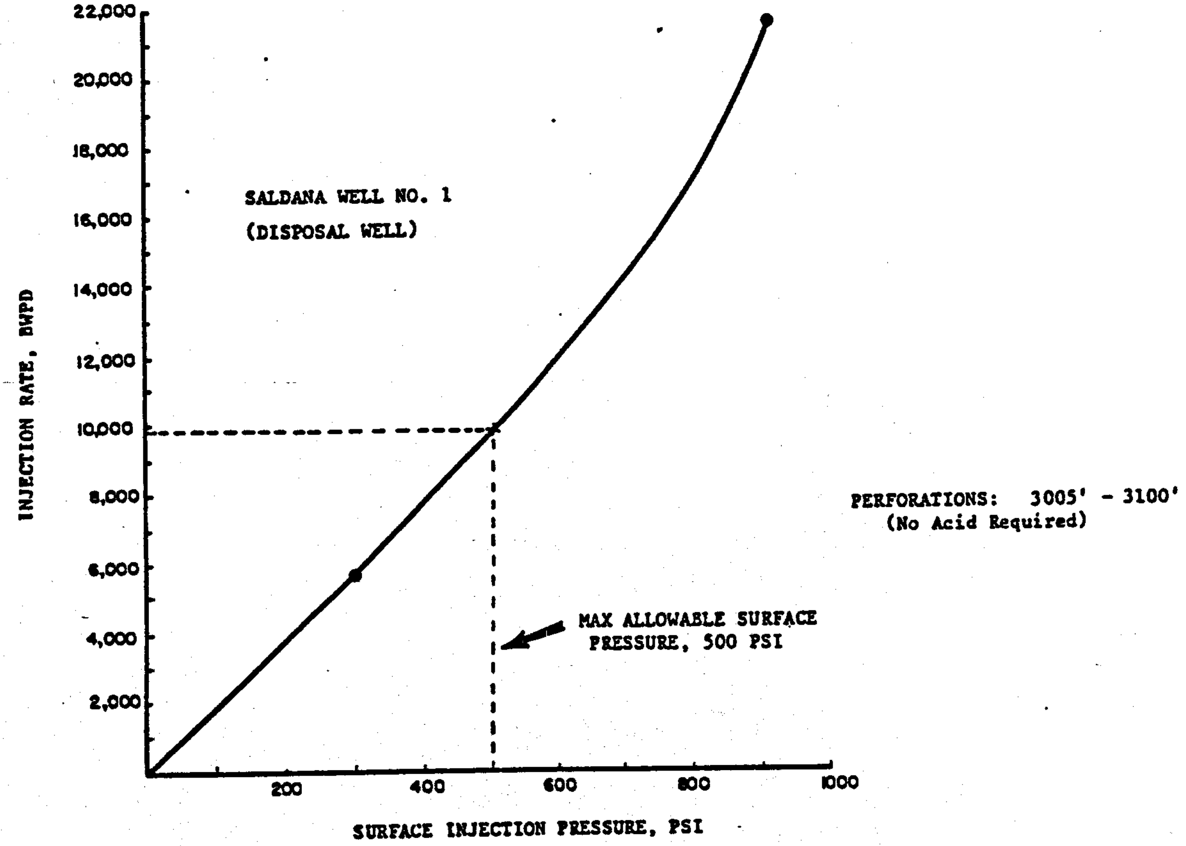


Figure 61. - - Graph showing the injection rate vs. surface injection pressure for the brine disposal well (From Eaton Operating Co., Inc., Final Report, 1981).

Produced hydrocarbon gas was in excess of the amount that could have been in solution in the produced reservoir brine. It was suggested that the free gas originated at a depth greater than the tested reservoir depth. The high amount of solids produced during short term testing, indicates potential problems associated with long term testing and solids processing. The test separator was found to be a very effective device for removing produced gas from the brine. The produced water contained less than 2 SCF /BBL gas at a separator operating pressure of 200 psi. This gas composition was 42.50% methane and 53.87% CO_2 and is not marketable. The Saldana No. 2 Well reservoir tested had a limited flow capacity (985 milldarcy-feet) which is within the economical range for petroleum production, but much too low for geopressured - geothermal gas production economics (from Eaton Operating Co., Inc., Final Report, 1981).

G.M. KOELEMAY WELL NO. 1

The G.M. Koelemay Well No. 1 was originally drilled by Lear Petroleum Exploration, Inc., to a total depth of 14,885 ft. and was temporarily abandoned as a dry hole. It was later acquired by Eaton Operating Company, Inc., by contract with lear on May 21, 1980. Eaton Operating Company initiated field operations on June 20, 1980. The well is located approximately 19 miles west of Beaumont, Texas, and about 4 miles north of U.S. Highway 90. It's specific location is 8,000 ft. south and 26,600 ft. east of the northwest corner of Geomap Township 1 N, Range 46 E, in Jefferson County, Texas. Complete details of completion and testing, well test data and chemical analyses etc. are provided in Eaton Operating Company, Inc. (1981), Final Well Report on this well. This work was performed by Eaton Operating Company, Inc., under a DOE contract No. DE-AC08-80ET27081, with the Nevada Operations Office.

Information compiled in this report is directly taken from Eaton's report.

The geopressure - geothermal section tested is of Mid-Eocene age and a member of the Yegua formation called the "Leger" sand. The interval tested is from 11,639 ft. to 11,780 ft. (Figure 62). The Yegua formation is primarily a continental deposit consisting of fluvial sands, along with lignites and clays which originated in swamps and lakes, respectively. The G.M. Koelemay No. 1 test well is located on the western flank of the Doyle Field. This field is broken up into several faulted blocks by east - west trending and south dipping faults. The "Leger" sand reservoir is approximately 3,800 ft. from the north bounding fault (Figure 63). A north - south cross section through the test well is shown in Figure 64. The cross section show that the "Leger" sand thins updip and has a gross thickness of 135 ft. Faulting in the area can also be seen on the cross section. The Yegua "Leger" sand appears to have been deposited in a high constructive delta type depositional environment.

The mean porosity of the test sand was 20% ranging between 16% to 25%. This value was determined using a neutron density log. Using a porosity cut off value of 10% for clear sand the net thickness of the sand was estimated to be 77 ft. and gross thickness was 139' ISF/sonic logs were used to determine sand thickness.

Three flow tests were conducted on the test well from 12 September, 1980 to 25 September, 1980. Total brine produced during the tests was 30,030 barrels: chemical analyses of the post separator brine showed a total dissolved solids value of 15,000 mg/l with chlorides being 7,500 mg/l. Hare line gas analysis showed methane to constituent 87.2 to 75.6 Mol. %, carbon dioxide 7.2 to 2.7 Mol. %, heavier hydrocarbons ranged from 5.4 to 21.4%. A summary of the test results of the G.M. Koelemay Well No. 1 is shown in Table 16.

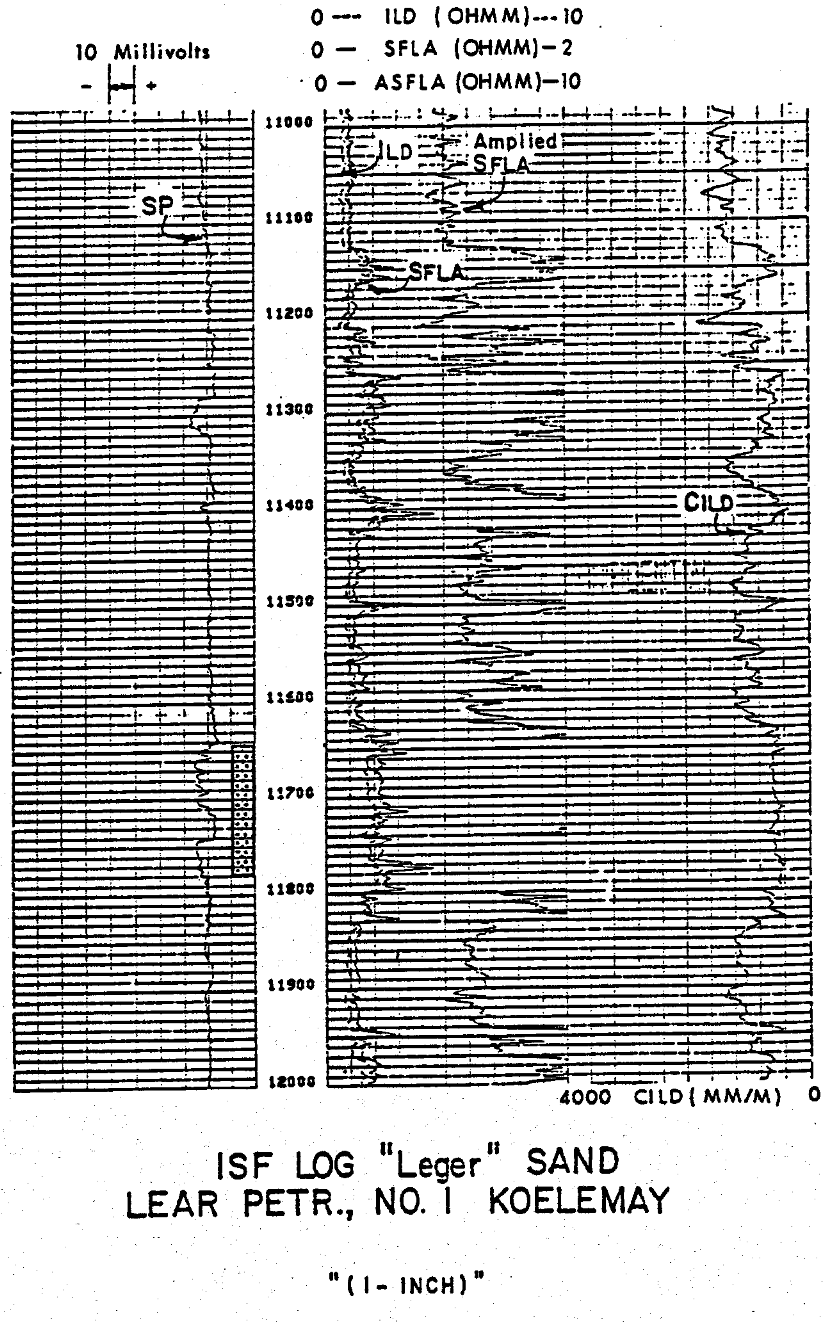


Figure 62. - - Electric log from the G.M. Koelemay #1 Well showing the tested sand (From Eaton Operating Co., Inc., Final Report, 1981).

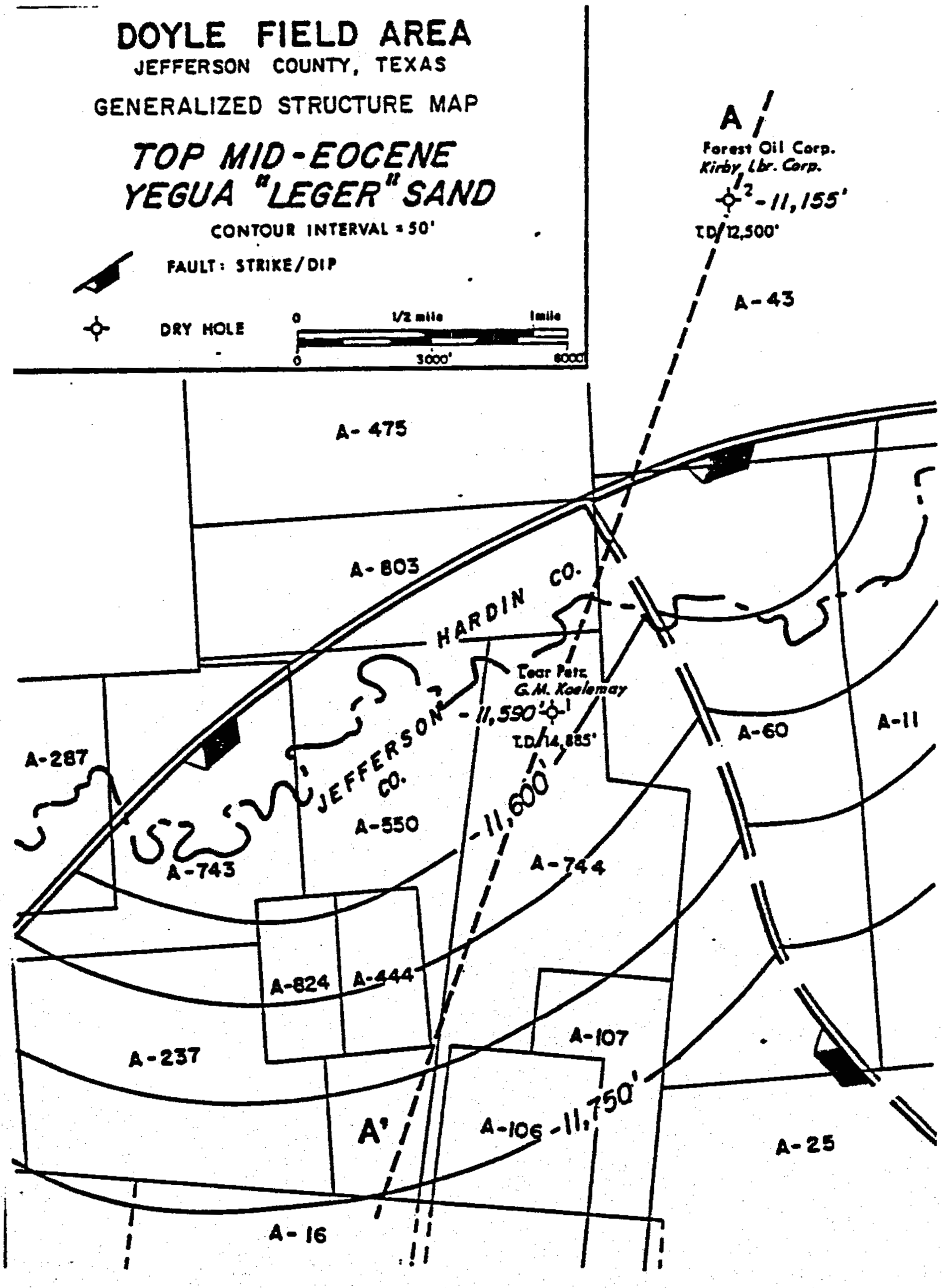


Figure 63. - - Structure map drawn on top of the "Leger" Sand tested to obtain geopressured - geothermal data in the G.M. Koelemay Well #1 (From Eaton Operating Co., Final Report, 1981).

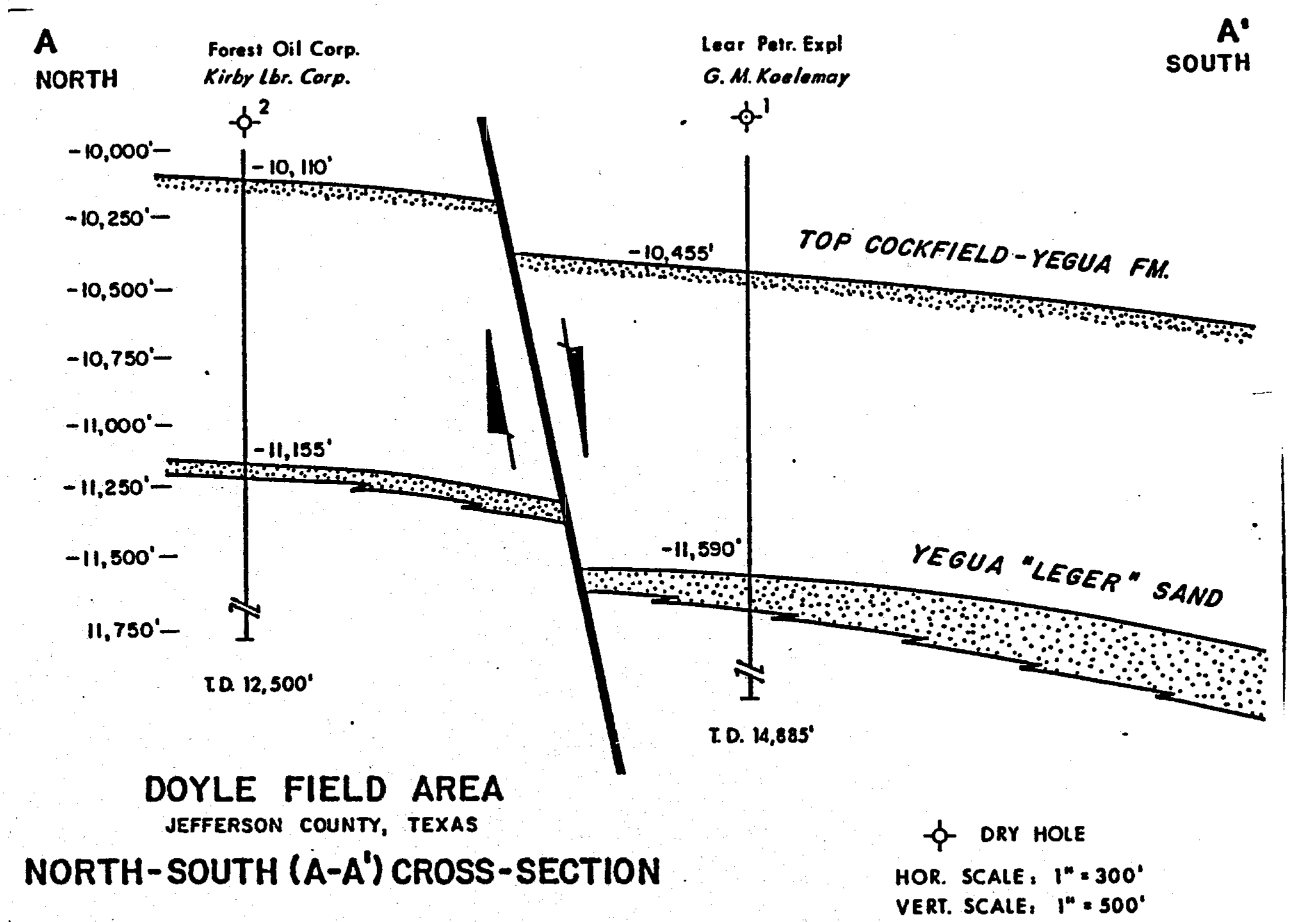


Figure 64. - - Structural cross section drawn through the G.M. Koelemay No. 1 Well showing the geopressure - geothermal "Leger" Sand. The cross section line is shown in Figure 63 (From Eaton Operating Co., Final Report, 1981).

TABLE 16

SUMMARY OF TEST RESULTS

G. M. KOELEMAY WELL NO. 1

JEFFERSON COUNTY, TEXAS

Total Depth of Well	14,885 Feet
Formation	Middle Eocene, Yegua "Leger"
Gross Sand Interval	139 Feet
Net Sand	77 Feet
Perforations	11,639 - 11,780 Feet (8 HPF)
Original Reservoir Pressure	9450 Psia
Original Reservoir Temperature	260°F
Original Shut-In Surface Pressure	4373 Psia
Average Porosity	20% (Density Log)
Average Permeability	85 md (Sidewall Cores)

FLOW TESTS: (From 9-12-80 to 9-25-80)

Test No. 1	1.05-Day Reservoir Drawdown Test (Produced 2243 Barrels of Water) Followed by a 3.16-Day Continuous Reservoir Buildup Test.
Test No. 2	0.43-Day Reservoir Drawdown Test (Produced 1638 Barrels of Water) Followed by a 1.40-Day Reservoir Buildup Period.
Test No. 3	7.27 Day Flow Test (Produced 26,149 Barrels of Water).
Produced Dry Gas-to-saltwater Ratio	30 to 318 SCF/STB
Total Water Produced	30,030 Barrels (At standard conditions)

ANALYSIS OF POST-SEPARATOR WATER:

Total Dissolved Solids	15,000 mg/l
Chlorides	7,500 mg/l
pH	6.6

ANALYSIS OF FLARE LINE GAS:

Methane	87.2 to 75.6 Mole Percent
Carbon Dioxide	7.2 to 2.7 Mole Percent
Heavier Hydrocarbons	5.4 to 21.4 Mole Percent
Other	0.2 to 0.3 Mole Percent
Heating Value	987 to 1246 BTU/SCF
H_2S in Gas	7.4 ppm

Highest Flow Rate Achieved	6677 BWPD (Instantanious), 3200 BWPD (Sustained)
Highest Surface Temperature Observed	206°F
Solids Production	High; 28 pounds per 1000 barrels of water
Corrosion	None Observed
Scaling	Light; 0.0065 Grams/1000 BBLS/SQ. In.
Lowest Flowing Surface Pressure Observed	426 Psia
Lowest Flowing Bottom Hole Pressure Measured	4262 Psia
Test Well Productivity Index	1.023
Maximum Explored Volume of Reservoir Water	Approximately 6.2 Million Barrels
Maximum Distance Explored (BHP Instrument)	1972 Feet
Reservoir	Lenticular sand pinch-out with very restricted flow area and an updip attic-type hydrocarbon saturated zone. Fluid permeability, in the order of 100 to 200 millidarcies, could not be determined due to two-phase saturation near the well bore.
Disposal Well Gross Perforations	3420 to 3520 (4 HPF)
Disposal Well Pressure Range	190 to 490 Psi

(From Eaton Operating Co., Inc., Final Report, 1981).

Unlike the other well tests, during the testing the well began to produce gas and oil. Eaton Operating Company, Inc., stated that attic production through coning of an oil rim with a gas cap was perhaps the best explanation for the hydrocarbon production.

The initial pressure drawdown flow test lasted 1.05 days during which 2,243 bbl's of water were produced. This was followed by a 3.16 day continuous reservoir pressure build up test which provided information on reservoir parameters. The second reservoir pressure drawdown flow test lasted .43 days during which 1,638 barrels of water were produced. The short flow period of this test was because the disposal well was plugged up with solids and the reserve pit was full. The test well was shut in for 1.4 days while the disposal well, was recompleted in Sand E. The third flow test lasted 7.27 days and produced 26,149 barrels of water. During this test, the well started producing significant amounts of oil and gas. At this point the decision was made to terminate geopressured - geothermal testing as very little additional useful information concerning the brine aquifer could be obtained. Testing ended on September 26, 1980. Lear then took over operations on the site and continued testing the well which eventually became a commercial oil and gas well. Lear continued Eaton's third flow test for 12.11 more days for a total flow testing lasting 19.34 days of flow. During Lear's 12.11 day flow test the well produced 32,389 barrels of water, 2,055.5 barrels of oil, and 18,671 MCF of gas. This event was reported in an article which was published in Drilling - DCW, January, 1981 and is reproduced below: — Removed for separate processing

A schematic illustration of the tubular configuration in the test well at the time of Eaton Operating Company, Inc., takeover from Lear is shown in Figure 65a. The lower portion of the well was abandoned by setting a cement plug at 11,184 ft., after cement squeezing. The tubular configuration of the well as completed by Eaton for testing is shown in Figure 65b. A string of 2⅜ inch tubing was run without a packer to 11,533 ft. After displacing heavy mud with salt water the well was perforated in the "Leger" sand from 11,639 ft. to 11,780 ft.; using wireline perforating guns through the tubing. Details of the re-entry operations are provided in Eaton Operating Company, Inc., Final Report (1981).

The salt water disposal well was located about 85 ft. southeast of the test well. The primary design requirements for the well included an injection capacity in excess of 15,000 barrels per day at an injection pressure not to exceed 500 psi, high temperature capability of up to 300°F, minimum disposal depth of 1,250 ft., and the setting of two complete casing strings through fresh and brackish water sands, and circulating cement to the surface on both strings. The design parameters were made in compliance with the specifications required by the Texas Railroad Commission.

Electric logs run in the disposal well identified five potential disposal sands (Figure 66): (1) Sand A (4,242 ft. to 4,368 ft.; net thickness 118 ft., porosity 44%); (2) Sand B (4,100 ft. to 4,175 ft.; net thickness 75 ft., porosity 44%); (3) Sand C (3,803 ft. to 3,891 ft., net thickness 88 ft., porosity 48%); (4) Sand D (3,648 ft. to 3,726 ft., net thickness 77 ft., porosity 42%); and (5) Sand E (3,416 ft. to 3,529 ft., net thickness 133 ft., porosity 38%).

The Sand A was perforated from 4,336 ft. to 4,366 ft., 4,299 ft. to 4,329 ft., and 4,242 ft. to 4,292 ft. using 3⅛ inch casing guns, with four shots per foot. Injectivity tests were performed

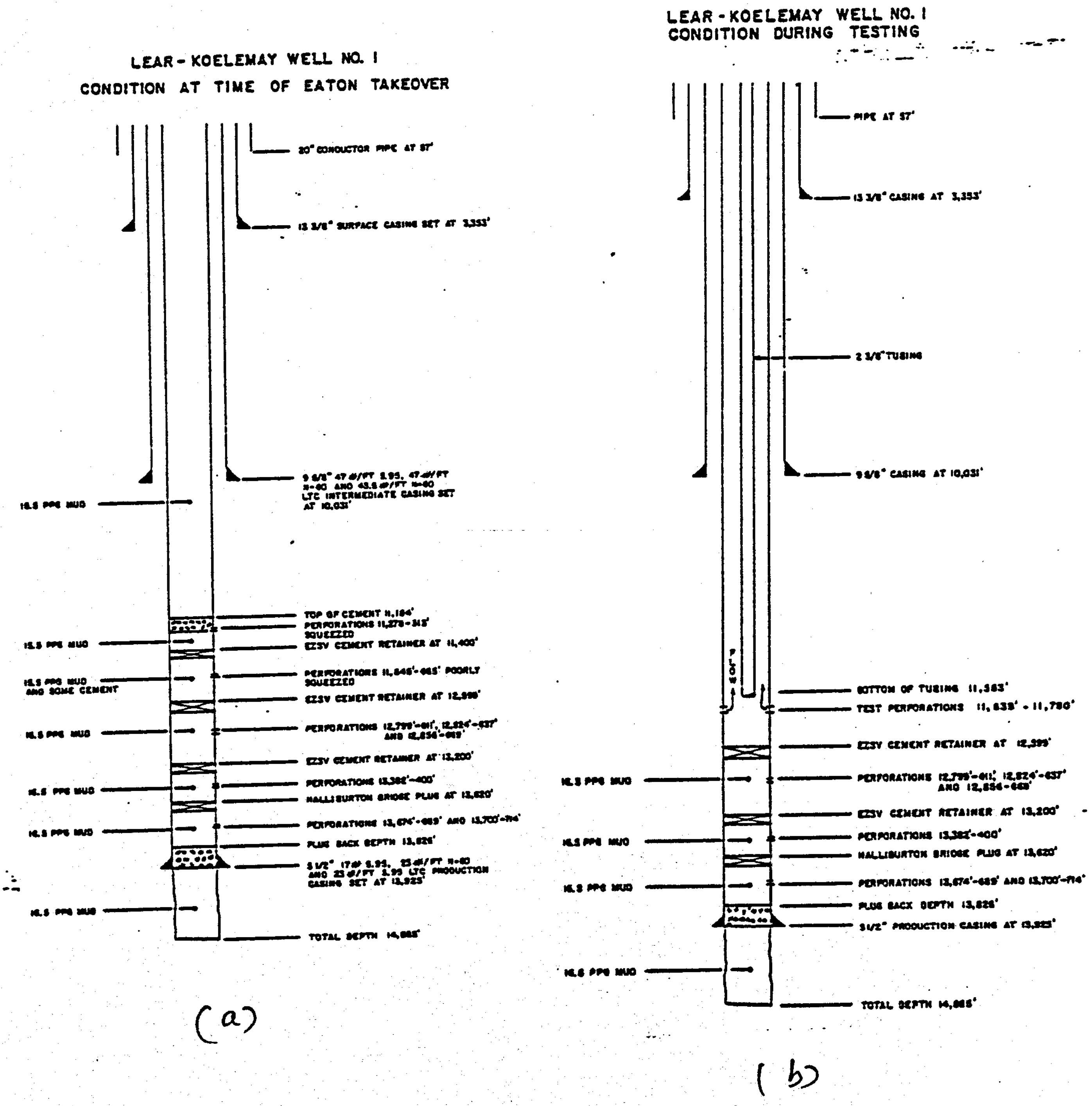
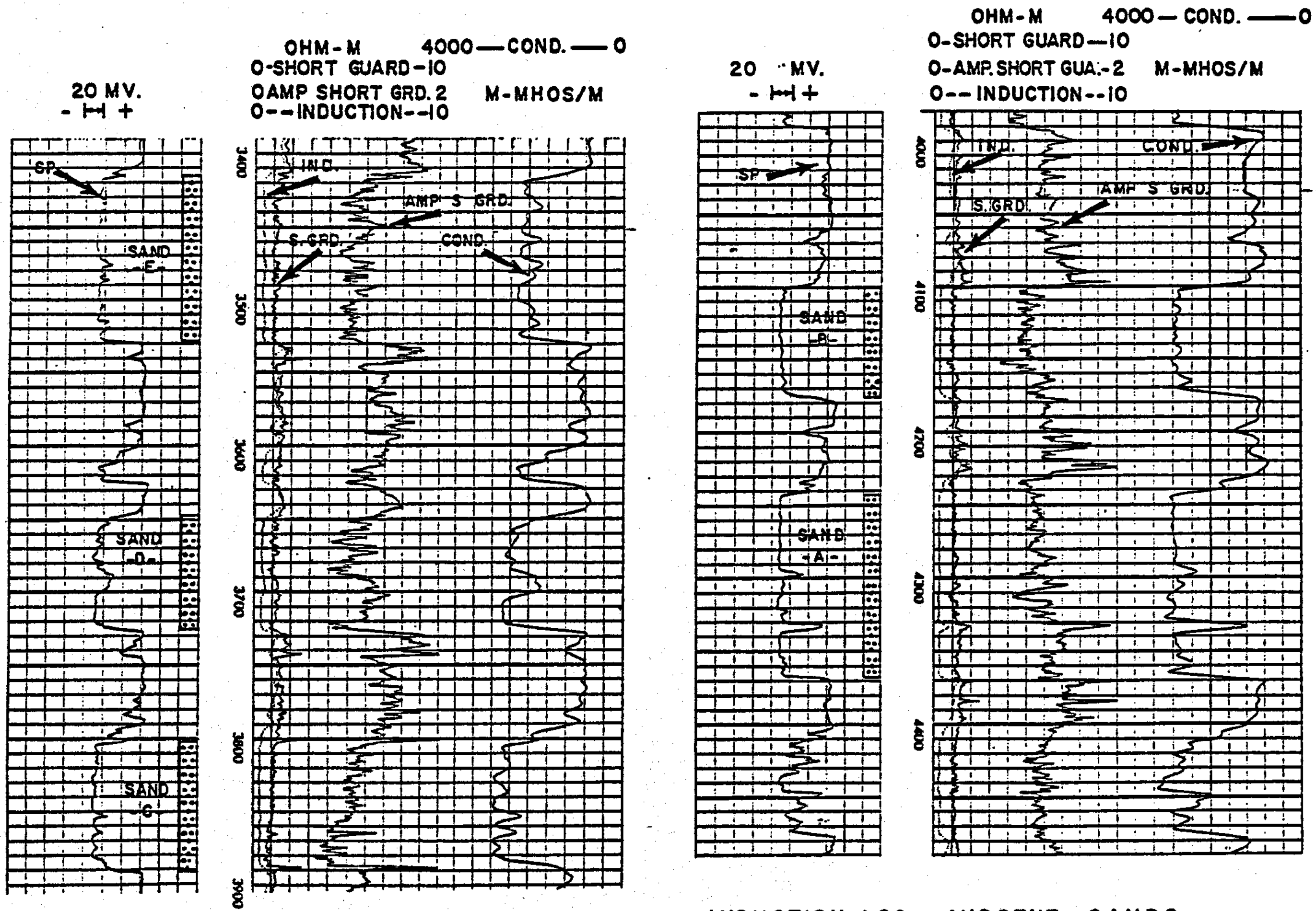


Figure 65. - - Schematic drawing of the test well showing (a) conditions when Eaton took over operations from Lear, and (b) well configurations as completed for testing (From Eaton Operating Co., Inc., Final Report, 1981).



INDUCTION LOG - MIOCENE SANDS
LEAR PETR. NO. I - SWD KOELEMAY

INDUCTION LOG - MIOCENE SANDS
LEAR PETR. NO. I - SWD KOELEMAY

Figure 66. - - Electric log of the brine disposal well showing the five potential disposal sands (A,B,C,D, & E). Sand E was completed for salt water disposal (From Eaton Operating Co., Final Report, 1981).

and the highest injection rate achieved was 8,640 BWPD at 2,000 psi which showed that acid stimulation of the disposal well was required. A graph of injection rate versus surface injection pressure before stimulation is shown in Figure 67a. After acid treatment the well accepted water at a rate of 12,260 BWD at an injection pressure of only 175 psi. At this point, the well was capable of accepting all the brine produced from the test well without using any surface pumps. A schematic illustration of the actual disposal well configuration after completion is shown in Figure 67b. As the perforated zone (Sand A) get plugged up with solids during testing, the well was later perforated in Sand E (3,420 ft. to 3,520 ft.) With 4 holes per foot and was then subjected to acid stimulation. This zone was then used for brine disposal for the remainder of the testing.

Subcontractors for data recording included the Institute of Gas Technology (IGT), Reservoir Data, Inc. (RDI) and Weatherly Engineering, Inc. (Weatherly). IGT gathered data on wellhead temperature, wellhead pressure (annulus and tubing), wellhead brine production rate, sand detection, separator pressure, orifice meter differential pressure, gas temperature, separator brine production rate, filter differential pressure, disposal well pressure and temperature. RDI was responsible for gathering data on pre-production temperature, and pressure gradients, bottomhole pressure, wellhead tubing pressure and wellhead brine production rate. Weatherly recorded data on separator pressure, orifice meter differential pressure, gas temperature and sand detection: All the raw data collected during the testing operations are presented in Eaton Operating Company, Inc., Final Well Report, 1981.

In addition to IGT and Weatherly, gas brine samples were collected and analyzed by McNeese State University, Lake Charles, La., U.S. Geological Survey, NSTL Station, Miss., and

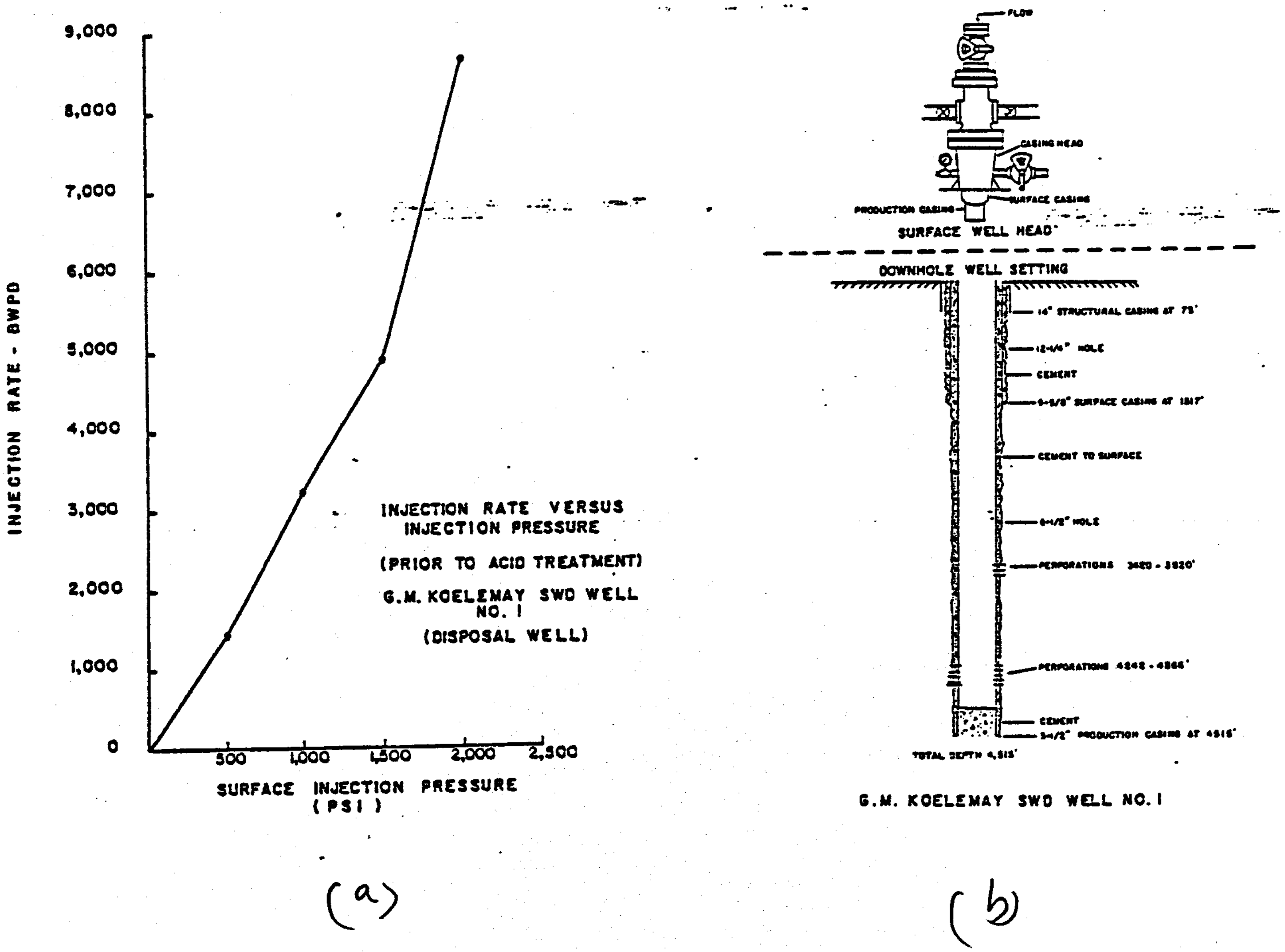


Figure 67. - - (a) Graph of injection rate versus surface injection pressure before acid stimulation of the disposal zone (b) Schematic diagram of the disposal well completion and wellhead. Two sets of perforations are shown as the lower zone was plugged with solids during early testing requiring perforation of the upper zone (From Eaton Operating Co., Inc., Final Report, 1981).

Menlo Park, California, and Jack V. Matson, P.E. whose firm collected samples in relation to scale and corrosion studies.

Very little scaling or corrosion occurred during the testing of the G.M. Koelomay No. 1 Well, though significant amounts of solids were produced. These solids were over 95% acid insoluble, unlike the solids in the earlier tested P.R. Girouard Well No. 1. The high amount of solids production is significant as it has the potential of plugging up brine disposal zones if long term production is attempted. The brine produced average 0.34 microgram per liter of mercury and 45 milligrams per liter of boron. Both these values are higher than the upper limits recommended by the U.S. Environmental Protection agency and are toxic for aquatic organisms, humans, and plant life. Hence any considerations for surface disposal would have to be produced. The production of commercial oil and gas as testing proceeded was unexpected. Though sidewall came data indicated possibility of free hydrocarbons updip in the reservoir, without producing the large amounts of brine in the test well, the updip hydrocarbons would not have reached the well bore of the G.M. Koelemay No. 1 test well. Finally, though the reservoir limits were not found during the flow tests, it is projected to be smaller than originally anticipated, as flow test data indicated a pinching out of the sand and a very restricted flow area.

WILLIS HULIN NO. 1 WELL

The Willis Hulin No. 1 Well was obtained by DOE from Superior Oil Company in 1984 for testing under the geopressured - geothermal Well of Opportunity testing program. The Willis Hulin #1 Well was drilled by Superior Oil Company in 1978 in Section 2, Township 14 S, Range 4 E, to a total depth of 21,549 ft. The well site is located approximately 7 miles south of Erath in

Vermilion Parish, Louisiana. Information on investigation conducted on this well are mainly provided in the monthly reports by Eaton Operating Co., in the Final Contract report (1986-1990) by Eaton under DOE Contract No. DE-AC07-85ID12578, in annual report on technical support for geopressured - geothermal well activities in Louisiana under DOE Contract No. DE-FC07-85NV10425 by the Louisiana State University (1988-1990) and in reports by Institute of Gas Technology to Eaton Operating Company under Eaton's subcontract to IGT No. IGT/EOC-85-4. Information provided here is taken directly from these reports.

A maximum log recorded temperature of 338°F, and a thick (600 ft. gross) geopressured - geothermal sand aquifer between 20,100 ft. And 20,700 ft. made this well an excellent candidate for testing. The well was perforated by Superior Oil Company between 21,059 ft. and 21,094 ft. in a poorly developed sand and produced 0.3 BCF of gas during 19 months of production. Declining wellhead pressure resulted in efforts to restore production, which led to packer/tubing failure. At this point Superior Oil Company decided to abandon the well, once it was acquired by DOE for testing under its geopressured - geothermal program. Eaton Operating Co., Inc., Houston, Texas, was contracted by DOE to clean and recomplete the well and to correct problems that were causing a pressure buildup in the well. This process was completed in February 1989, and the well was plugged back to 20,725 ft. just below the geopressured - geothermal aquifer which was later tested.

The geopressured - geothermal prospects identified for testing in Louisiana were originally selected based on regional geologic studies conducted at the Louisiana Geological Survey (LGS) in the early stages of this project by D.G. Bebout (1982) and others (Bebout and Gutierrez, 1981; Bebout et.al., 1983; Wallace, 1982; McCulloh et.al., 1984). These studies provided valuable data concerning subsurface structure, geopressured - geothermal sandstone distribution, porosity, permeability, temperature, brine salinity, formation pressures, and the distribution and depths to the top of the geopressured sandstones in South Louisiana (Figure 68). The Hulin prospect lies in the Miocene geopressured - geothermal fairway as defined by the regional studies.

Regional studies performed by Conover (1987) and Hamlin and Tyler (1988) at the Bureau of Economic Geology, the University of Texas at Austin, indicated that the geopressured - geothermal section sands in the Hulin well represented elongated canyon sandstone facies. A net sandstone isopach map of the Planulina zone in the Hulin prospect area and its depositional setting is shown in Figure 69 and a generalized representative cross section of this area is presented in Figure 70. Another possible depositional setting was described by Johns (1991, in LSU Annual Report 1988-1990) as possibly being deposition in an unstable shelf delta system where sand deposition on a subsiding shelf would account for the great thickness of the sand.

The Willis Hulin No. 1 Well is the deepest well in the area and is the hottest and highest pressured well to be tested in the DOE's geopressured - geothermal program. The geopressured - geothermal aquifer tested is about 600 ft. thick with the top at about 20,100 ft. (Figure 71). It is generally a clean sand with occasional intervening layers of shale. Paleontological analysis by Paleodata Inc., showed that the Hulin Well penetrated the Lower Miocene *Planulina* zone and was in it at 13,090 ft. Regionally the *Planulina* zone is characterized by complex structural configuration and heterogeneous facies distribution that generally make correlation difficult. A structure map of the Hulin prospect area contoured at the top of the 15,400 ft. sand in the Lower *Planulina* section used by DOE in its discussions on the Hulin prospect is shown in Figure 72. The Erath field situated to the north of the Hulin Well, the Boston Bayou field to the south, and

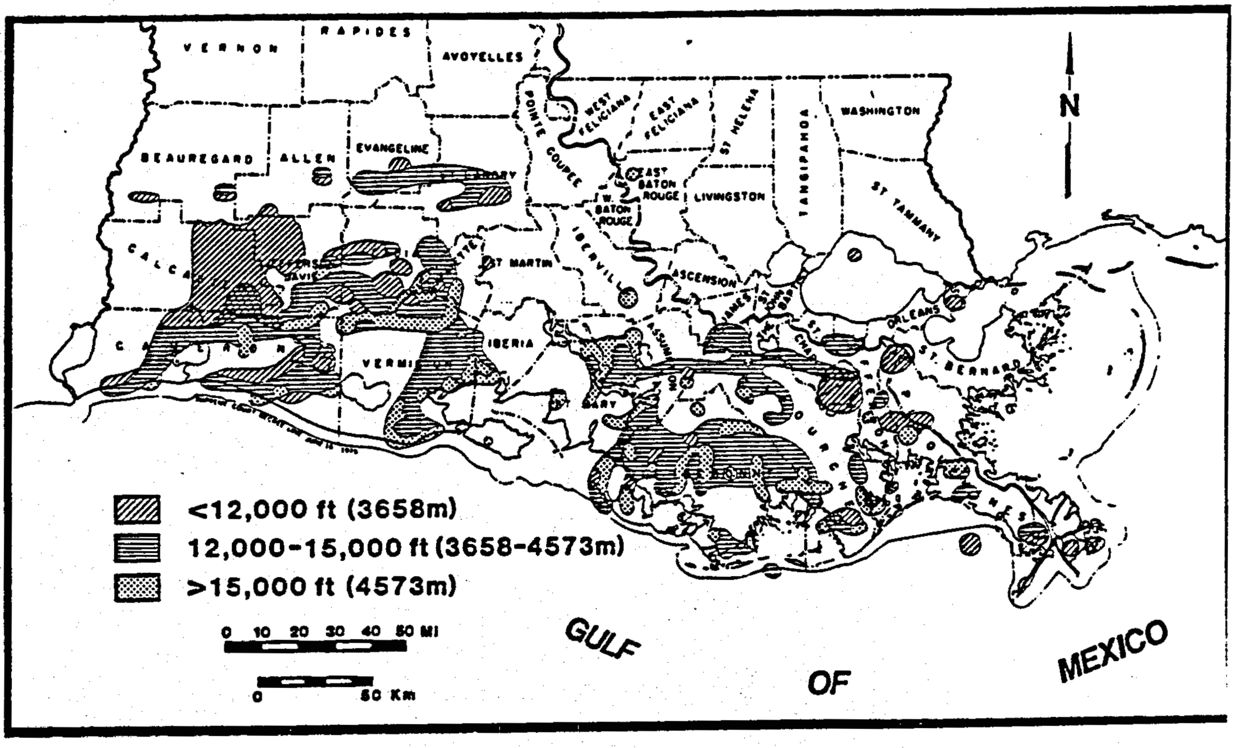


Figure 68. - - Distribution and depths to Tertiary geopressured - geothermal sandstones in South Louisiana (modified from McCulloh et.al. 1984, from John, 1991, in Groat, 1991, Louisiana State University Technical Support Report 1988 - 1990).

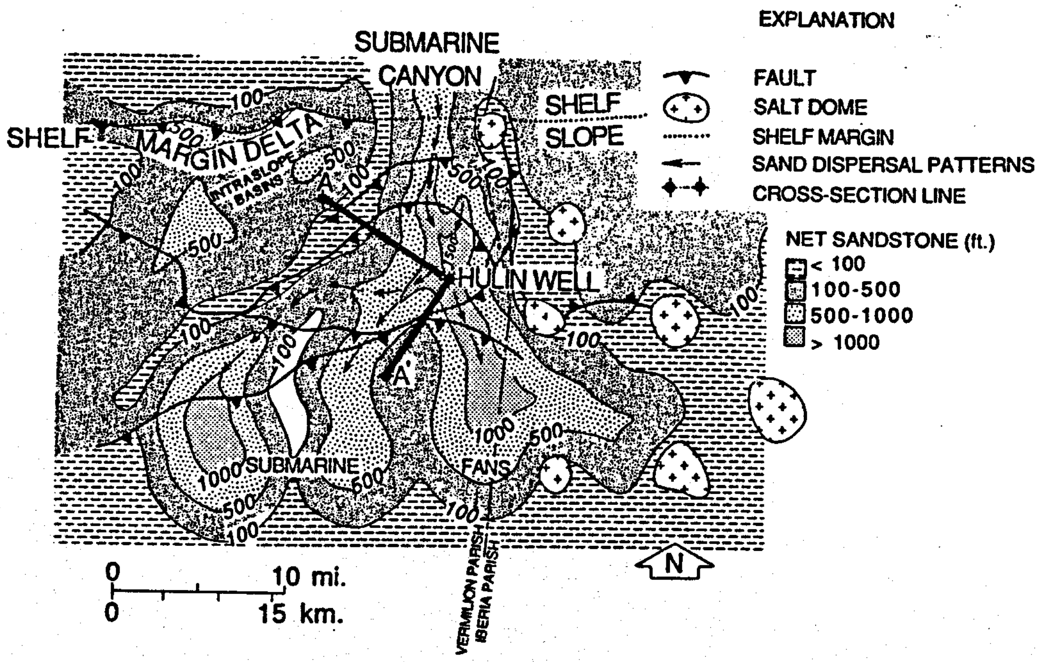


Figure 69. - - Depositional setting and sandstone thickness of the *Planulina* zone of the Hulin prospect area (modified from Hamlin and Tyler, 1988; Bureau of Economic Geology, Annual Report).

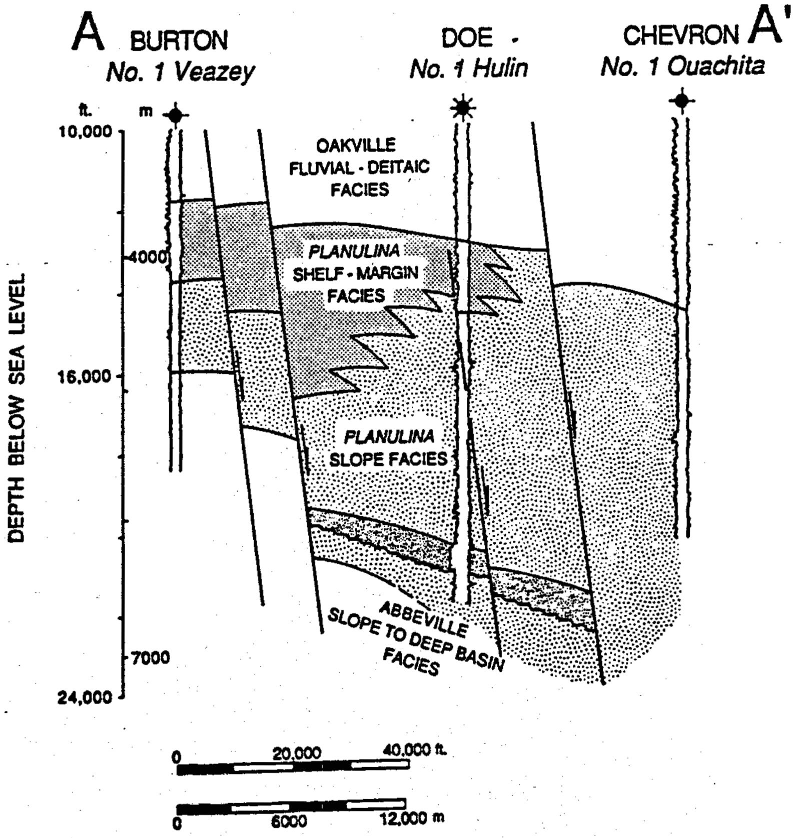


Figure 70. - - Representative dip cross section of the depositional setting shown in figure 69. Line of cross section is also shown in figure 69 (from Hamlin abd Tyler, 1988, Bureau of Economic Geology, Annual Report).

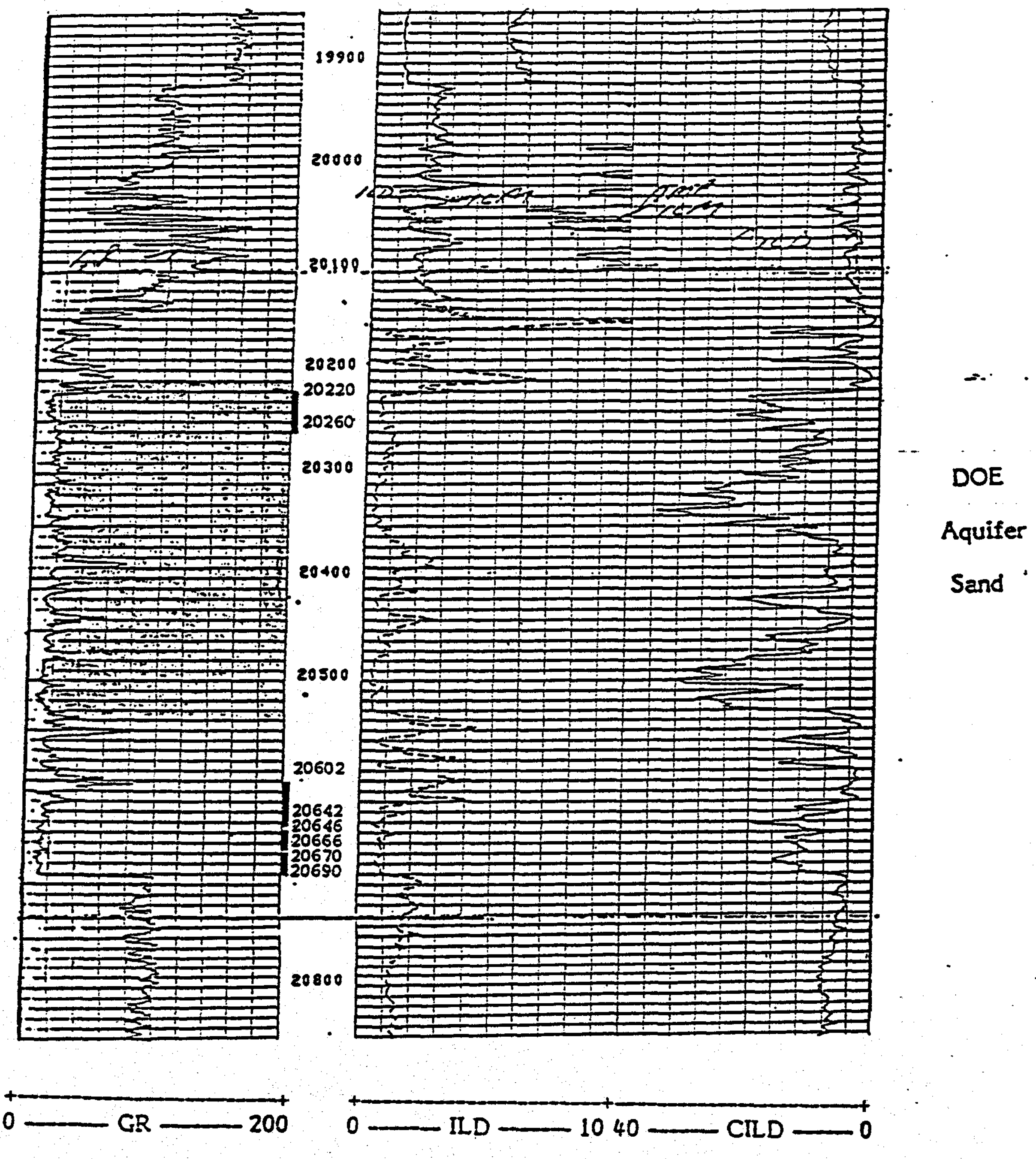


Figure 71. - - Electric log of the Superior Hulin No. 1 geopressured - geothermal aquifer sand showing the perforation depths (From Eaton Operating Company, Final Contract Report, 1986 - 1990).

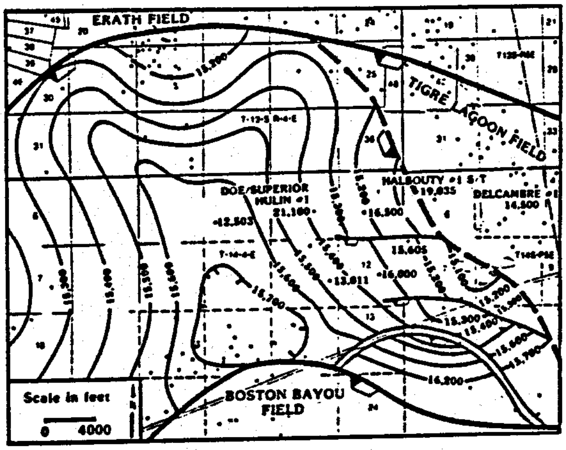


Figure 72. - - Lower *Planulina* structure map of the Hulin prospect area (adapted from U.S. Department of Energy, 1988, Hulin test plan memorandum dated Sept. 19, 1986, Idaho Falls, Idaho).

the Tigre Lagoon field to the northeast are all fault separated by major regional down to the basin (south dipping) faults. No major faulting is indicated west of the Hulin Well. The Hulin Well, as mapped here, is located in a fault block that is approximately 12 miles long (east - west) by about 5 miles wide (north - south) and bounded by large arcuate faults with smaller faults within the block.

A dip and strike section of the Hulin prospect through the Hulin #1 Well are shown in Figures 73 and 74. The top of geopressure is located approximately at the base of the main series of Miocene sands and is at about 12,500 ft. in the Hulin No. 1 Well. Before testing began a detailed well log analysis by the Petroleum Engineering Department of the University of Texas at Austin indicated that the aquifer may contain free gas and solution natural gas in several zones, but the short term tests, described later here, did not provide evidence of any free gas.

The Louisiana Geological Survey (Louisiana State University) acquired some proprietary seismic data in the Hulin prospect area. Using this data a new seismic structure map was constructed at the top of the geopressured - geothermal test sand (Figure 75). Using this map interpretation an estimate of 1 billion barrels of brine reserves in the Hulin test reservoir was made. Earlier estimates of 14 billion barrels of brine were based on a different structural interpretation at a much higher level in the section. However, it was stated that factors including no fault closure on the west side, lateral and vertical stratigraphic relationships between adjoining reservoirs, fluid communication between reservoirs, induced faulting due to high volume brine production, etc., which are difficult to quantify accurately, probably make these estimations of brine volume inaccurate. Long term, high volume production testing could cause virtually unlimited recharge of the reservoir.

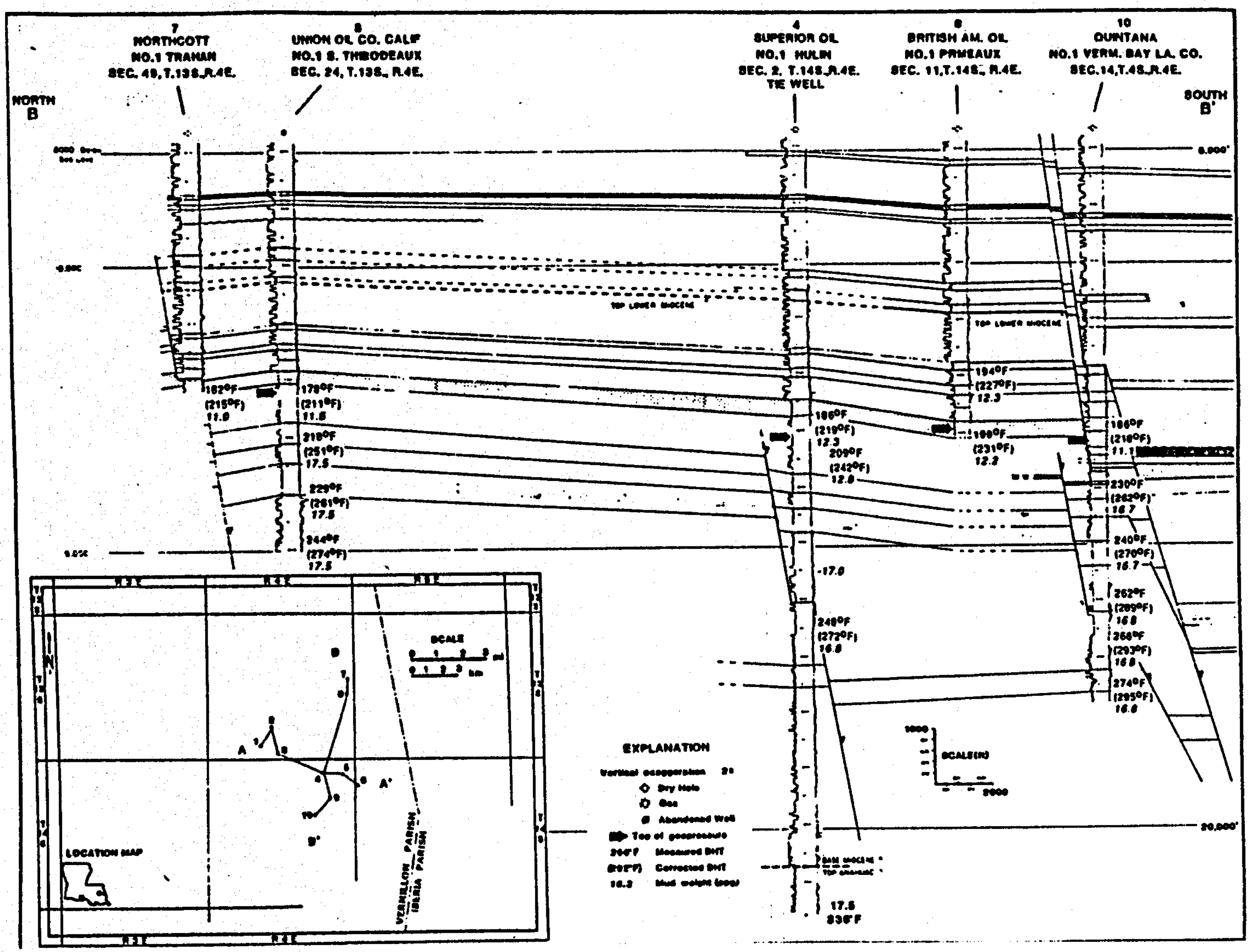


Figure 73. - - A north - south (dip) cross section of the Hulin prospect area (modified from McCullon and Pino, 1983, in, Louisiana State University, Annual Report 1981 - 1982).

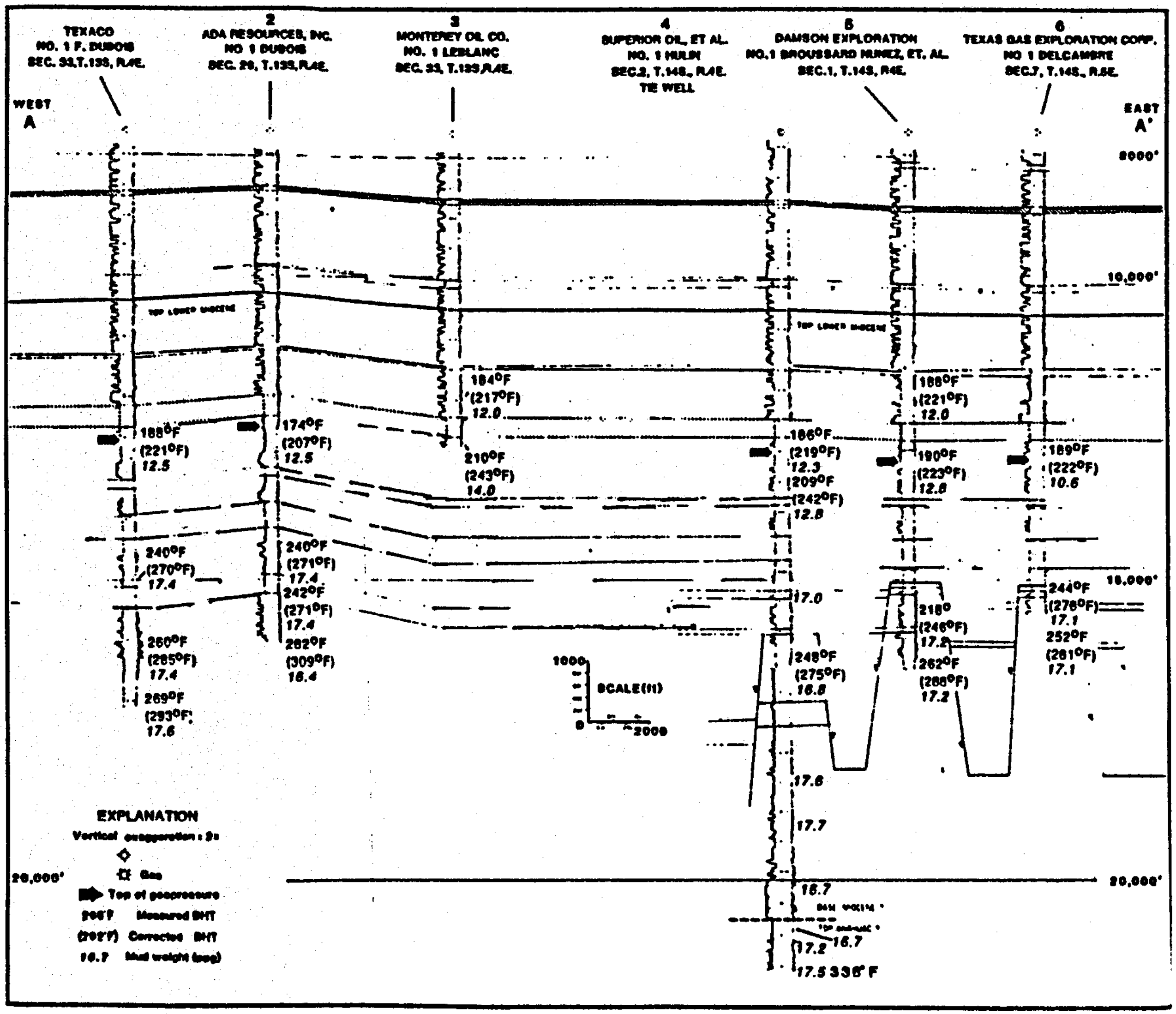


Figure 74. - - A strike (east - west) cross section through the Superior Hulin #1 Well (adapted from McCulloh and Pino, 1983, in, Louisiana State University, Annual Report 1981 - 1982). The cross section line (A-A') is shown in figure 73 (inset).

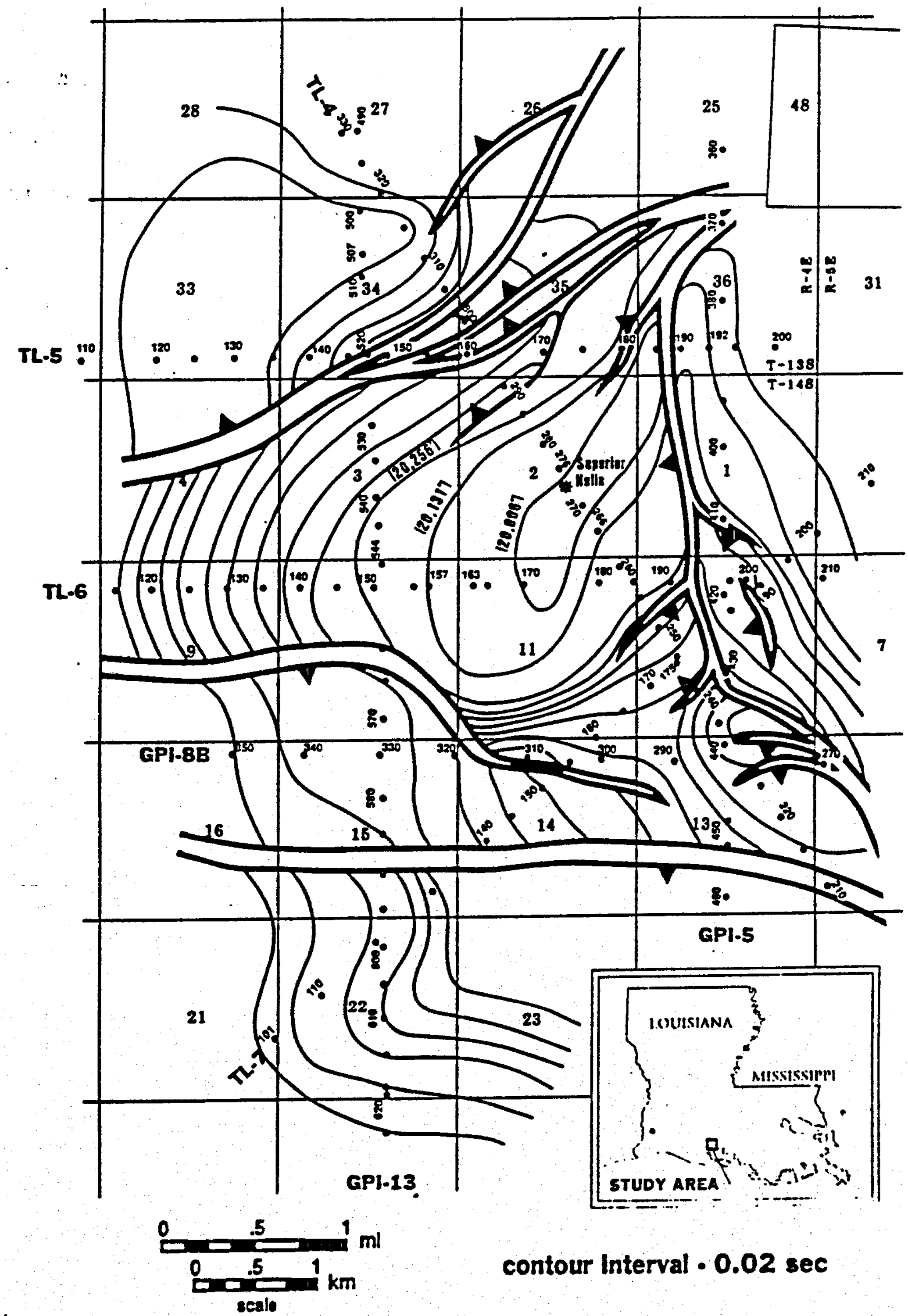


Figure 75. - - Seismic structure map of the Hulin prospect contoured at the top of the geopressured - geothermal reservoir tested (map by Don Stevenson; from John 1991, in Groat 1991, Louisiana State University Technical Support Report 1988 - 1990).

During original drilling of the well by Superior Oil Company, beginning in 1978, the drill pipe got stuck at 21,000 ft. Attempts to recover the drill pipe failed leaving a fish in the original hole. The well was then side tracked around it to 21,546 ft. and completed as a gas well in the interval 21,059 ft. to 21,094 ft. in 1981. Gas production ceased in 1983. Attempts to restore production failed due to mechanical problems. Due to the high costs involved in cleaning or recompleting the well, or to plug and abandon it, Superior offered the well to DOE for testing as a Well of Opportunity. As the well had excellent geopressured - geothermal sands which met all the criteria established by DOE for a test well under this program, and further as drilling a new well would be much more expensive than an extensive workover on this well, DOE accepted the well from Superior in 1984. The well configuration at this time is shown in Figure 76. Eaton Operating Company, performed an extensive workover on this well for DOE under contract and a cement plug was set from 20,725 ft. to 20,785 ft. with a cost iron retainer on top to isolate the old production interval. During workover operations the latest logging tools were run to log the well but two logging tools collapsed at pressures of ± 17,500 psi due to the time exposure to the high temperature, inspite of having pressure ratings of 22,000 psi. As a result, only a partial density, neutron, gamma ray, caliper electric well logs were obtained. The schematic illustration of the well as completed by Eaton Operating Company is presented in Figure 77.

Short term flow testing of the Hulin #1 Well was done in December 1989 and January 1990. The first interval tested was the lowermost 20 ft. of the lowest sand member from 20,670 ft. to 20,690 ft. During later testing additional intervals were perforated from 20,602 ft. to 20,642 ft., 20,646 ft. to 20,666 ft., and 20,220 ft. to 20,260 ft. The following account of the flow tests is

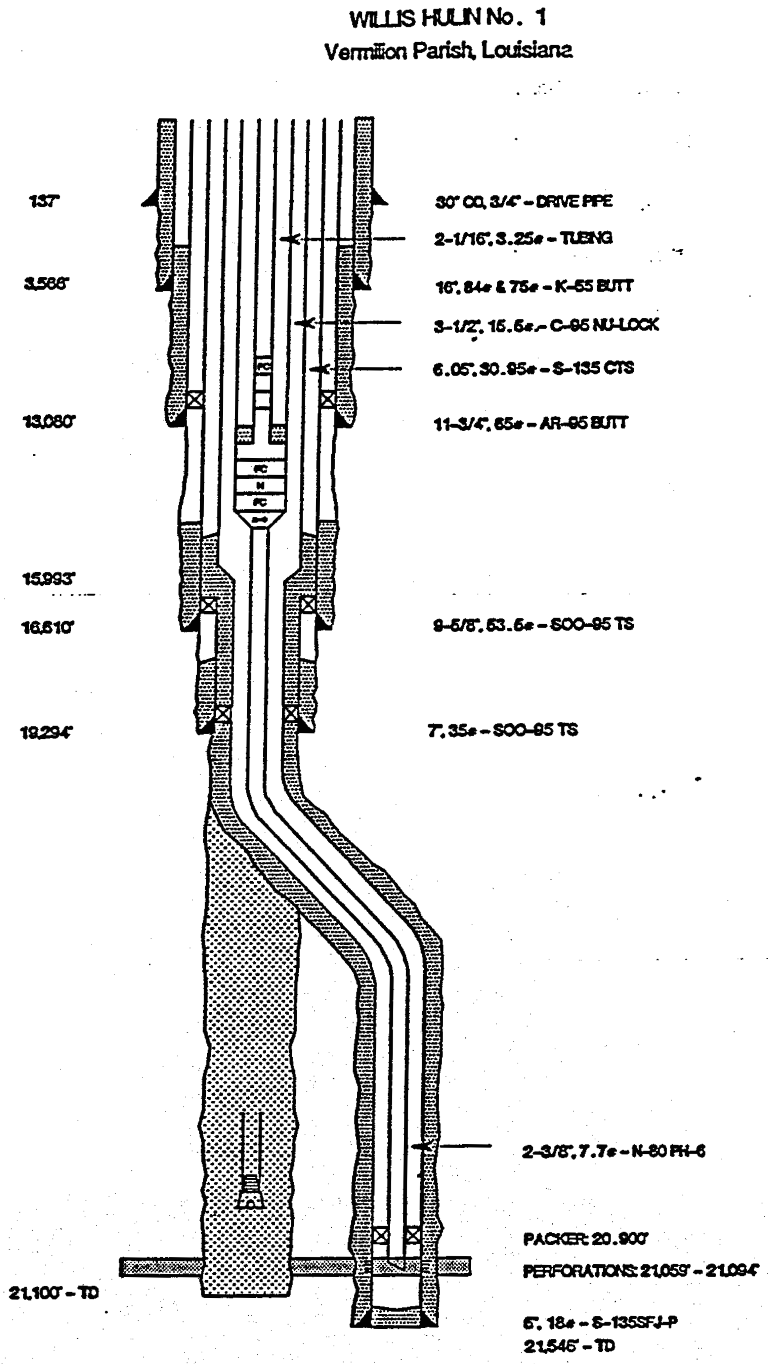


Figure 76. - - Schematic illustration of the Willis Hulin No. 1 Well completion at the time it was taken over by DOE (Eaton Operating Company, Inc.) From Superior Oil Company in 1984. (From Eaton Operating Company, Inc., Final Contract Report, 1986 - 1990).

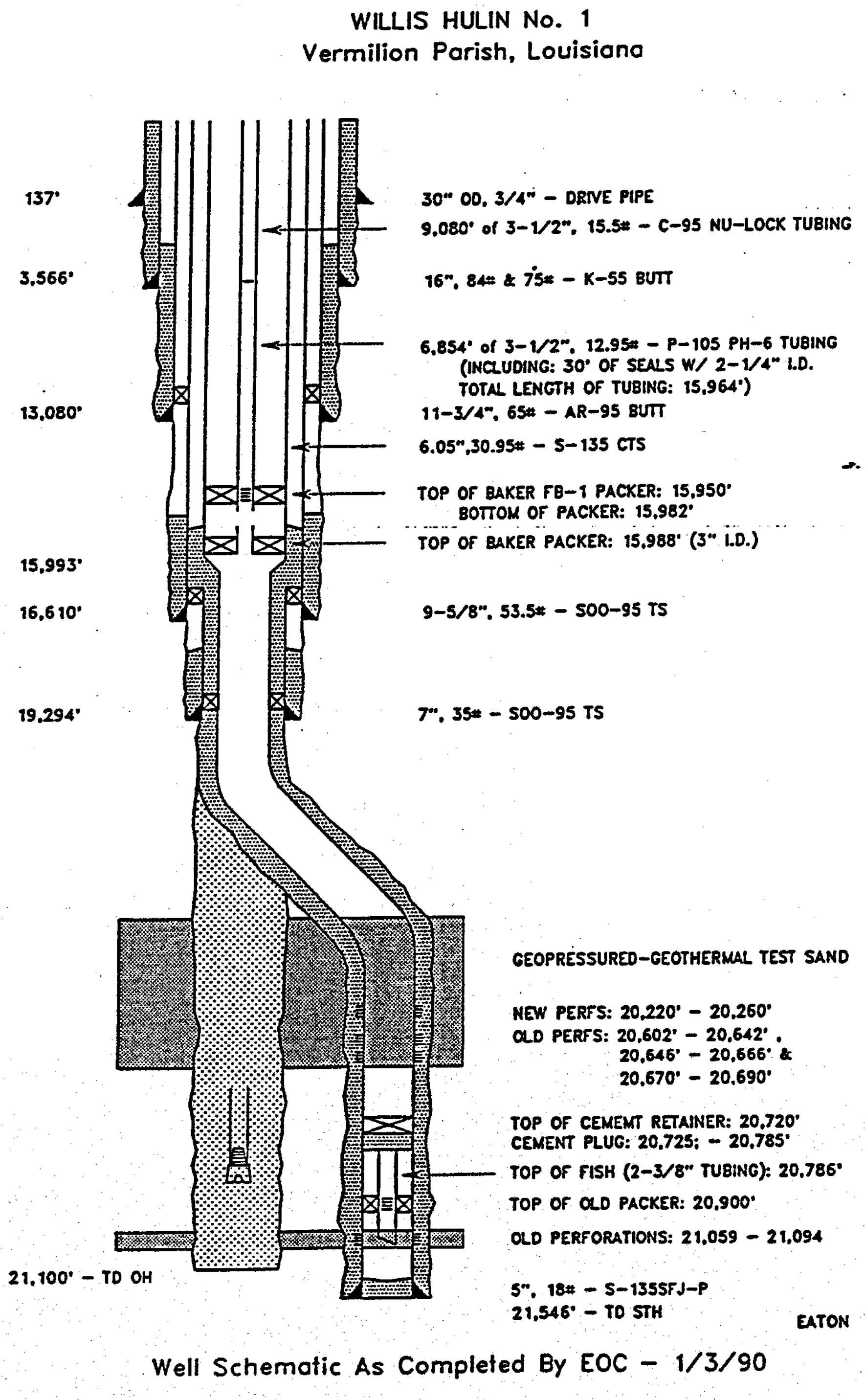


Figure 77. - - Schematic illustration of the Willis Hulin No. 1 Well as completed by Eaton Operating Company, Inc., for testing (From Eaton Operating Company, Inc., Final Contract Report, 1986 - 1990).

taken from the IGT, Final Report, Volume III dealing with flow tests of the Willis Hulin Well prepared under their subcontract with Eaton Operating Company.

The first instrumented test was a 1-day flow test to obtain brine and gas samples and to obtain a first indication of the reservoir properties. A bottomhole pressure gauge was in the hole for 5 days to record both the pressure draw-down and following buildup. The remaining part of the lowest sand member (20,622 to 20,666 feet) was then perforated, and the entire 80-foot interval was tested with a 4-day flow and 12-day buildup test. The bottomhole pressure was also recorded for this test. The static bottomhole pressure (at 20,600 feet) was 17,308 psia prior to the 1-day flow test and 17,283 psi prior to the 4-day flow test. The bottomhole temperature was 339°F and the initial wellhead pressure was 7,460 psi. The produced brine had a total dissolved solids content (mostly sodium chloride) of 207,000 mg/L and was at or near saturation with gas at 31-32 SCF/STB. The gas was leaner in the heavy hydrocarbons than the gas from other geopressured - geothermal wells, and was about one-sixth carbon dioxide. No free gas was detected in the reservoir. The amounts, if any, of produced condensate or oil was small compared to the amount of diesel pumped into the wellhead to prevent hydrates after shut-ins.

Analysis of bottomhole pressure data for the lowermost sand member by S-Cubed gave a transmissivity of about 1050 md-ft (millidarcy-feet). From this, a permeability of 13 md was calculated for the reservoir. The lateral extent of the reservoir was not determined, although the analysis of the data indicated a fault at a distance of 100 to 200 feet from the well. A skin factor of 15 was found with the entire 80-foot interval perforated. That indicated low flow efficiency for the perforations. The decreasing initial static bottomhole pressure prior to each test suggests that this sand member is not large.

In January 1990 the upper most sand member in the zone of interest (20,220 to 20,260 feet) was perforated and tested in a 7-day flow test during which the brine produced from this interval was commingled with that from the lower sand. No free gas was found. The brine and gas compositions of the commingled flow changed slightly compared to the lower zone along, which indicated that the brine in the upper zone was also saturated with gas but isolated from the lower zone. Bottomhole pressures were not measured and the reservoir characteristics of the upper zone were not determined. But, substantially lower drawdown for the commingled zones suggests either higher permeability or lower skin for the shallower perforated interval.

Although production of free gas from the reservoir was not observed for either the upper or the lower sand members, this does not preclude the possibility of free gas production after additional flow.

Hydrate formation in the wellhead and near surface tubing was a problem. To circumvent this problem, about 10 barrels of diesel were pumped into the well after each flow period to displace the brine in the wellbore down to a point where the temperature was sufficient to prevent hydrate formation. Calcium carbonate scale formation in the brine lines was a potential problem, but was avoided by conducting the flow tests only in pressure- and flow-rate ranges where scale would not form in the well. The surface equipment was protected from scaling by injecting scale inhibitor into the surface flow lines.

Total production for the December 1989 through January 1990 testing of the well was 16,805 barrels of brine and 536,700 SCF of gas.

A comparison of the gas analyses from the Hulin #1 Well with those from other wells tested before is presented in Table 17. Brine analyses were conducted by the Bureau of

TABLE 17

TYPICAL GEOPRESSURED-GEOTHERMAL WELL GAS ANALYSES*

Well	Hulin	Girouard	Koelemay	Saldana	Prairie Canal	Crown Zellerbach	Amoco Fee	Gladys McCall	Pleasant Bayou
Date	1/7/90	7/80	9/80	11/80	2/81	6/81	8/81	6/87	2/90
Pressure (psia)	295	277	260	218	272	283	236	1015	693
Gas Temp (°F)	185	189	165	179	160	110	-	300	292
Brine Temp (°F)	221	215	201	216	229	197	160	294	271
Mole Percent of:									
Helium	0.01	0.01	0.01	<0.01	<0.01	0.03	<0.01	<0.01	0.01
Hydrogen	0.05	NA	NA	NA	NA	NA	0.01	<0.01	0.02
Nitrogen	0.11	0.20	0.27	0.10	0.11	0.44	0.20	0.28	0.52
Carbon Dioxide	16.70	6.00	7.50	17.18	10.06	25.00	8.13	8.47	10.40
Methane	81.20	91.50	83.87	78.75	86.94	69.10	89.28	88.04	84.70
Ethane	1.68	1.80	4.67	2.97	2.29	4.03	1.74	2.41	2.88
Propane	0.16	0.29	2.19	0.66	0.30	0.76	0.39	0.52	0.97
Iso-Butane	0.01	0.12	0.38	0.07	0.03	0.10	0.02	0.08	0.15
n-Butane	0.01	0.08	0.58	0.10	0.02	0.10	0.05	0.07	0.14
Pentanes	<0.01	<0.01	0.24	0.07	<0.01	0.04	0.01	0.03	0.06
Hexanes plus	0.02	<0.01	0.25	0.06	<0.01	0.03	<0.01	0.03	0.06
Benzene	0.03	0.01	0.02	0.07	0.02	0.18	0.10	0.05	0.07
Toluene	0.01	<0.01	0.02	0.06	0.01	0.18	0.07	0.01	0.04
C2 Benzenes	<0.01	<0.01	<0.01	0.01	<0.01	0.01	<0.01	<0.01	0.02
Heating Value**	860	970	1040	892	928	815	-	960	951
Gravity (air=1)	0.728	0.631	0.698	0.766	0.667	0.838	-	0.660	0.691

*Analyses performed at IGT, by mass spectrometry or gas chromatography
** heating value in (BTU/SCF) Dry, 14.7 psia, 60°F

(From IGT Final Report, 1985 - 1990, Volume 3, for Eaton Operating Company).

Economic Geology, The University of Texas at Austin, and results of some of the analyses are shown in Table 18.

A salt water disposal well was drilled and completed in the vicinity of the test well. A schematic illustration of the salt water disposal well completion is presented in Figure 78. An electric log was run on this well and is shown in Figure 79. It was perforated from 6,530 ft. to 6,590 ft. with 4 shots per foot. This one zone was considered as adequate for the short term testing conducted on the Hulin #1 Well.

After perforating an attempt to inject produced brine resulted in rapid pressure buildup to 1,400 psi with about a barrel of fluid. The pressure then dropped to 300 psi in about 5 minutes with the pump off. Acid treatment of the disposal zone was followed with 400 barrels of produced brine from the second of the two frac tanks filled on the previous day. A pressure of 1,000 psi was held on the 5½ x 9⅝ inch annulus during the acid treatment and subsequent injection. Disposal well injection pressure at a brine rate of about 3,800 STB/d increased from 40 psi to 235 psi over 3 days. The value leveled out at 235 psia, but broke back and then built back up during the last night of operation. Assuming a gradient of 0.48 psi/ft. above the fluid level of 476 ft. below the wellhead pressure transmitter (measured on December 5, 1989, before heating with injection), the wellhead pressure of 235 psia at 3,800 STB/d corresponds to an injectivity of 8.2 STB/d/psi. This is consistent with the value of 10 STB/d/psi characteristic of the end of the test on December 6-8, because that test did not last long enough for the injection pressure to level out.

When operations were resumed on January 2nd there was approximately 44 psi of gas pressure on the disposal wellhead remaining from the previous flow test. The pressure was a

TABLE 18

BRINE ANALYSES, BEG*

Date	02/09/89	12/06/89	12/06/89	12/07/89	12/07/89	01/06/90	01/06/90
Time, h		1930	2340	0800	0800		
Dilution				•	1:1		1:1
Brine Temp, °F	280						
Total Dissolved Solids, mg/L	201600	209540	206040	208140	204700	200780	201440
Alkalinity as mg CaCO3/L	32	126	137	139	NA**	246	NA
Ammonia				176	177	165	164
Barium	180	198	125	114	131	24	38
Boron	67	62.9	62.2	62.6	63.6	65.5	70.6
Bromide	76	NA	NA	76.2	75.6	89.1	92.2
Calcium	16830	18100	18400	18400	18300	16200	16600
Chloride	115400	114400	115000	116300	NA	114600	NA
Fluoride	2.1	NA	NA	2.61	2.98	2.99	2.78
Iodide	12	NA	NA	14.3	13.9	14.6	13.2
Iron	415	219	222	203	203	160	176
Lithium	29	28.0	30.2	27.8	27.8	30.1	32.6
Manganese	56	49.2	50.9	48.4	48.1	30.0	32.2
Magnesium	892	989	995	1000	992	829	830
Potassium	420	535	513	570	568	358	376
Silica (SiO2)	150	126	126	121	125	104	134
Sodium	52200	54400	55200	56200	55200	51200	51700
Strontium	1020	1040	1080	1090	1150	1028	1054
Sulfate	NA	NA	NA	<5	6.8	22	32
Zinc	11	9.48	10.00	9.49	9.47	8.0	8.6

* All results in milligrams per liter unless otherwise specified.
Samples are collected just after the separator. The samples are cooled by passing through a water bath prior to flashing to atmospheric pressure, and are collected under carbon dioxide.
Certain elements are looked for but have not been seen using our established procedures. These elements, and the minimum detection limits for each, are:

Arsenic, less than 0.5 mg/L	Cadmium, less than 0.1 mg/L
Chromium, less than 0.1 mg/L	Copper, less than 0.1 mg/L
Lead, less than 1 mg/L	Mercury, less than 0.005 mg/L
Nickel, less than 0.25 mg/L	Tin, less than 0.25 mg/L

** NA = Not Analyzed

(From IGT Final Report, 1985 - 1990, Volume 3, for Eaton Operating Company).

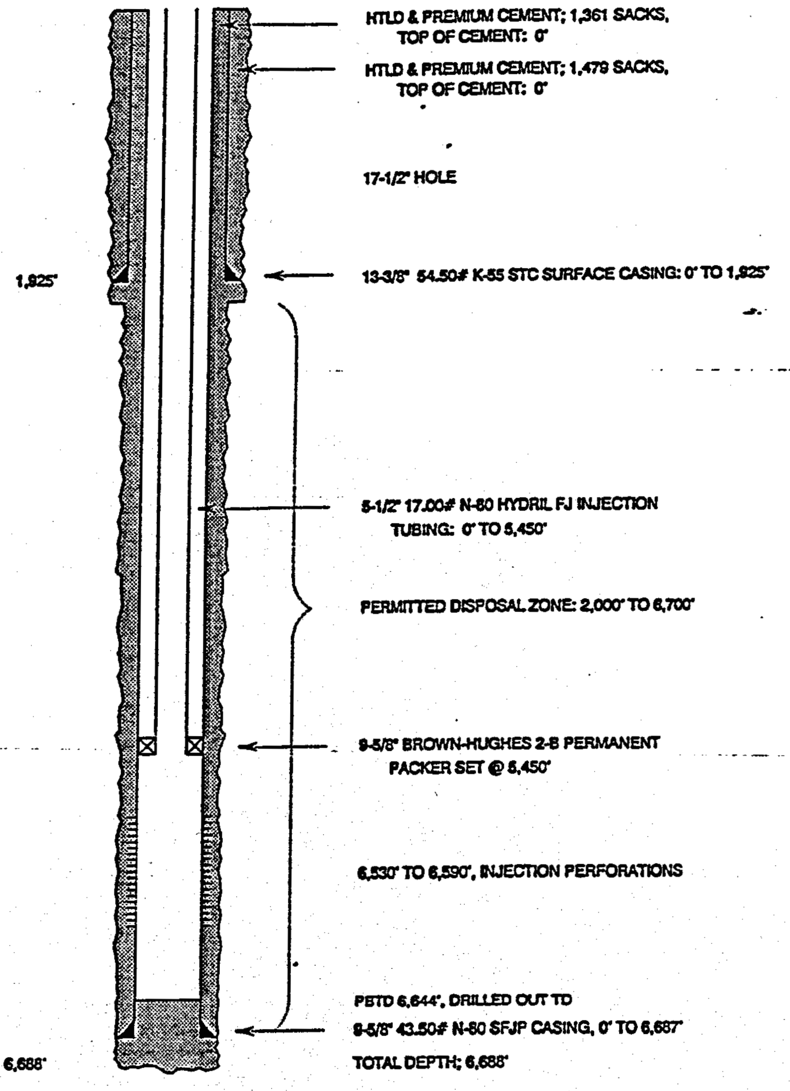


Figure 78. - - Schematic illustration of the salt water disposal well as completed by Eaton Operating Company, Inc. (From Eaton Operating Company, Inc., Final Contract Report 1986 - 1990).

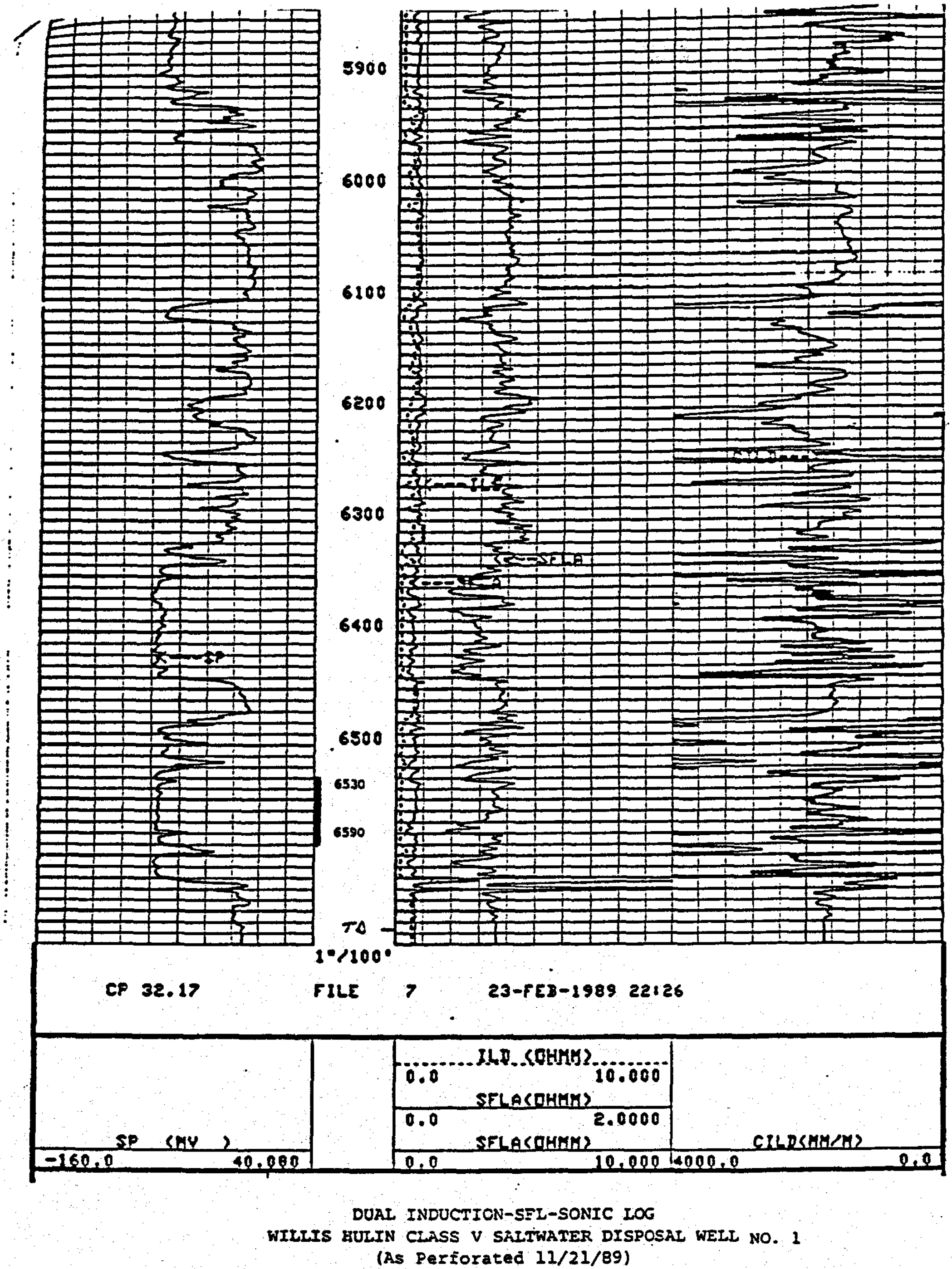


Figure 79. - - Electric log of the brine disposal well for brine produced from the Superior Hulin #1 test well (From Eaton Operating Company, Inc., Final Contract Report 1986 - 1990).

result of the gas trapped in the well on top of the brine, depressing the brine below its static level. The pressure was bled off. When flow to the disposal well was resumed, the wellhead pressure in the disposal well continued to increase with production. Accurate measurement of the pressure was not made on January 4th and 5th, because gas was being vented from the instrument tubing as part of the test to determine the amount of free gas going into the disposal well. This caused the gauges to read low. Near midnight on the 5th, the pressure of 320 psia in the large separator could no longer drive all of the brine into the disposal well, causing the separator to flood and send brine over the top through the gas line to the small separator. Increasing the back pressure in the large separator to 400 psia restored the ability to drive all of the brine from the separator into the disposal well continued to increase with production. Accurate measurement of the disposal wellhead pressure was restored on the 6th by changing the disposal well pressure gauge to read the pressure in the flow line ahead of the disposal well where gas was not being bled through the line (from IGT Final Report, 1985-1990, Volume 3, for Eaton Operating Company, Inc.).

The short term flow test on the Willis Hulin No. 1 Well was finished in January 1990 after which the well was shut in. Plugging and abandonment operations were initiated in February 1994 and completed on April 13, 1994. More information in the well site restoration work is provided later in this report.

INVESTIGATIONS OF OTHER WELLS OF OPPORTUNITY

(NOT TESTED)

CLOVIS A. KENNEDY NO. 1 WELL

This well is considered as a prospective well of opportunity and was originally drilled and completed as a gas producer by Wrightsman Investman Company in early 1973. It is located in the Perry Pointe Field, Vermilion Parish, Louisiana. The original producing interval was from 15,210 ft. to 15,238 ft. Later, IMC Exploration Company, Inc., acquired the property from Wrightsman. An option to acquire the Clovis Kennedy No. 1 Well for geopressured - geothermal testing was obtained by Eaton Operating Company, Inc., on May 12, 1980. This well would have tested the Oligocene Frio *Bolivina Mexicana* (Bol. Mex.) F-1 sand which was at a depth of 15,826 ft. to 15,942 ft. A testing and detailed completion prognosis report on the Clovis A. Kennedy No. 1 Well was done by Eaton Operating Company, Inc., under the U.S. Department of Energy Contract No. DE-AC08-80ET27081. However, in the Final Wells of Opportunity Contract report done under the same contract, it is stated that testing of this well was declined based on the relatively high salinities of the sand to be tested (Bol. Mex. F-1) which ranged from 80,000 to 130,000 ppm.

WATKINS - MILLER NO. 1 WELL

This well was originally drilled by Superior Oil Company who completed it in late 1970 as a dual gas producer in sands between 11,150 ft. and 11,250 ft.; and later abandoned it in December 1974. It is located in Section 5, T 15 S, Range 5 W, Cameron Parish, Louisiana. Investigation s evaluation of this well as a suitable candidate for geopressured - geothermal testing under DOE's Wells of Opportunity program was performed by Gruy Federal, Inc. who also prepared a detailed re-entry prognosis on this well which was presented in reports to DOE dated April, 1978 and August 1978. These were prepared under a Department of Energy, Division of Geothermal Energy contract No. EG-77-C-08-1528 with Gruy Federal, Inc., Houston, Texas. The potential geopressured - geothermal aquifer to be tested belonged to the lower Miocene *Planulina* section from 16,100 ft. to 16,900 ft. and had a net sand thickness of 310 ft. The maximum temperature recorded during drilling of the original well was 285°F. Gruy Federal Inc., stated in their report that the aquifer to be tested extended more than 7,500 acres. No reasons have been stated in Gruy Federal Inc. reports as to why this well was not tested, but it may have been due to a lack of agreement on terms of the contract with the landowner.

LUCIEN J. RICHARD et al NO. 1 WELL

This well was originally drilled to a total depth of 16,000 ft. by Enterprise Oil Company as the Lucien J. Richard et al No. 1 Well. It is located in Section 47, T 15 S, R 17 E, Lafourche Parish, Louisiana. It is approximately midway between the towns of Thibodaux and Racecard and accessible by Louisiana State Highway 1 and FM 308. The well was a dry hole and was subsequent by offered to Gruy Federal Inc., on September 14, 1978. Gruy Federal Inc., prepared a detailed completion prognosis report on this well, dated September 20, 1978 under a Department of Energy, Division of Geothermal Energy, Contract No. EG-77-C-08-1528. The sand aquifer proposed to be tested is of mid - Miocene age and lies between depths of 13,610 ft. and 13,710 ft. Gruy Federal Inc., stated that the net sand thickness was approximately 80 ft. and expected the reservoir to be capable of producing over 10,000 barrels per day. The maximum recorded temperature during logging was 262°F. The areal extent of the aquifer was estimated to be 4,000 acres: Drilling data from the well showed that 17.5 lb/gallon mud was used while drilling through the proposed test section and the reservoir bottom hole pressure was estimated to be approximately 12,500 psi at 13,650 ft. depth as opposed to a normal pressure of about 6,375 psi. No reason was stated anywhere, as for as we can determine, for not testing this well.

C & K - FRANK A. GODCHAUX, III, WELL NO. 1

This well was originally drilled by C & K Petroleum to a total depth of 16,000 ft. It is located in Live Oak Field, Vermilion Parish, Louisiana, in the irregular Section 88, Township 14 S and Range 3 E. A detailed report on the proposed testing and a completion prognosis for this well is provided in a report by Eaton Operating Company, Inc. under U.S. Department of Energy Contract No. DE-AC08-80ET27081. Eaton Operating Company, Inc. acquired the well from C & K Petroleum, Inc. on March 20, 1981, after it was abandoned as a dry hole. The proposed primary target prospective geopressured - geothermal sand is of Lower Miocene age (*Planulina* sand series) at a depth of 15,455 ft. to 15,963 ft. and the alternate target sand interval is at a depth of 14,904 ft. to 15,275 ft. Based on log analysis, Eaton Operating Company, Inc., reported that the gross sand thickness of the target interval is 508 ft. (360 ft. net sand thickness), porosity 27%, permeability 144 millidarcy's, pressure approximately 14,775 psi at a depth of 15,963 ft., temperature 298°F, salinity 75,000 ppm and gas content, assuming saturation, to be 44 SCF/bbl (Figure 80). No tests were conducted on this well as it was lost due to mechanical failure of the 9⅝ inch intermediate casing during open hole entry.

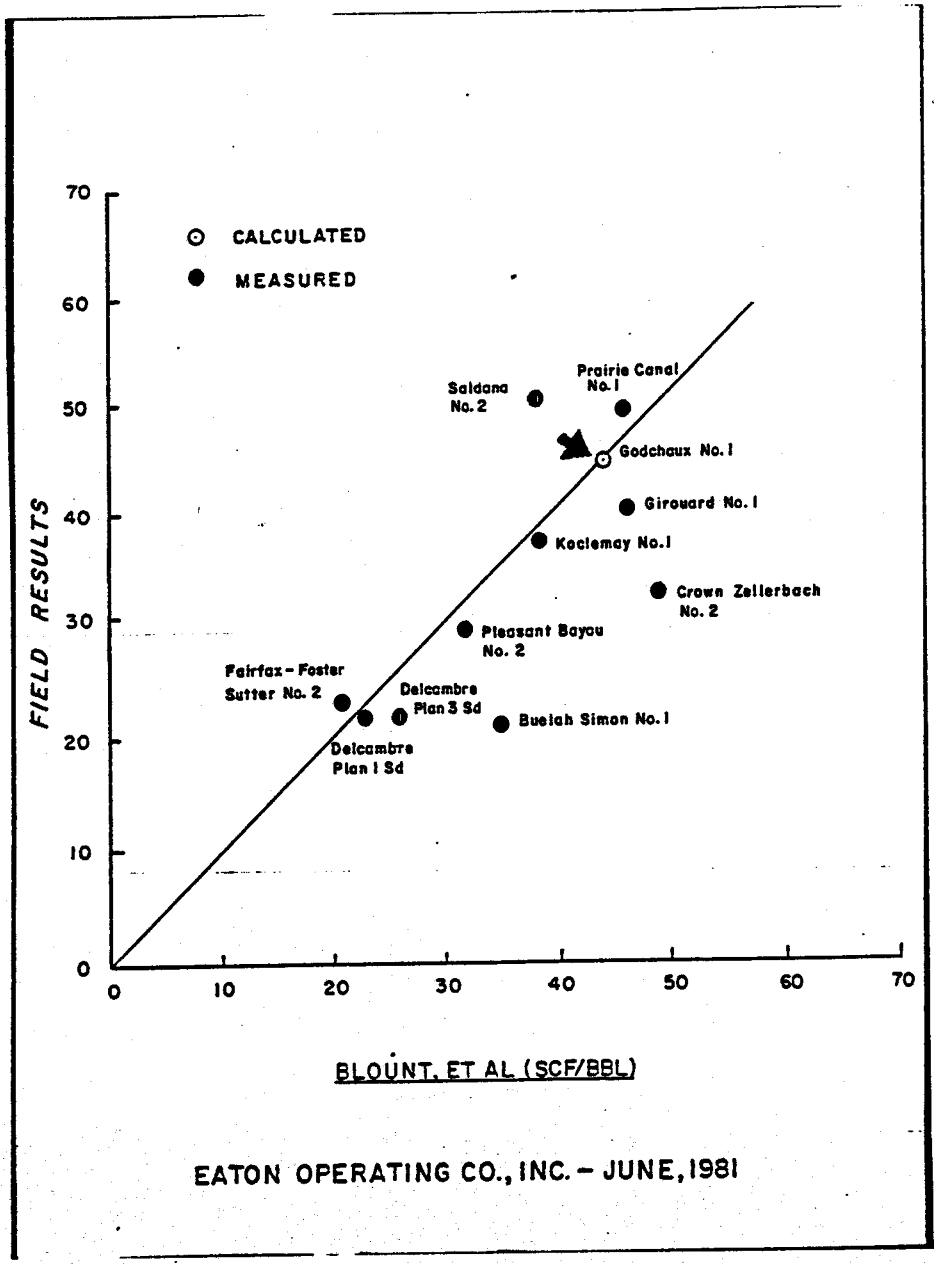


Figure. - - 80. Graph showing the estimated gas content of brine in the C & K - Frank A. Godchaux III, Well No. 1 as compared with the field measurements of gas contents in previously tested wells (From Eaton Operating Company, Inc., 1981).