INVESTIGATION AND EVALUATION OF GEOPRESSURED-GEOTHERMAL WELLS

DETAILED REENTRY PROGNOSIS FOR GEOPRESSURE-GEOTHERMAL TESTING OF THE WATKINS-MILLER NO. 1 WELL CAMERON PARISH, LOUISIANA

GRUY FEDERAL, INC.
2500 TANGLEWILDE, SUITE 150
HOUSTON, TEXAS 77063

713/785-9200

AUGUST 1, 1978

PREPARED FOR THE
DEPARTMENT OF ENERGY
DIVISION OF GEOTHERMAL ENERGY
UNDER CONTRACT EG-77-C-08-1528

DISCLAIMER

GRUY FEDERAL, INC.
CONSULTANTS IN ENERGY SYSTEMS

August 1, 1978

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Mr. Ronald T. Stearns
Engineering and Construction Division
DOE/Nevada Operations Office
P. O. Box 14100
Las Vegas, Nevada 89114

Re: Contract No. EG-77-C-08-1528
Superior Oil Company
Watkins-Miller No. 1
"Wells of Opportunity" Program

Dear Mr. Stearns:

The following material contains a description of the known mechanical and geological condition of the Cameron Parish, Louisiana well site which was drilled as Superior Oil Company - Watkins Miller No. 1.

This well is recommended as a back-up test site if for any reason it is impossible to accomplish the objectives of obtaining Geo^2 test data from the two approved test sites. (Alice C. Plantation and Gladys McCall).

We have discussed the permit terms with the landowner and believe that the necessary arrangements can be made on short notice if it becomes necessary to utilize this well site.

Very truly yours,

Richard J. Dobson

Richard J. Dobson
Vice President
Special Programs

RJD:je
Enclosures

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GEOPRESSURED-GEOTHERMAL REENTRY PROSPECT L-2
GRAND CHENIER SOUTH PROSPECT
CAMERON PARISH, LOUISIANA
WATKINS-MILLER NO. 1

Introduction

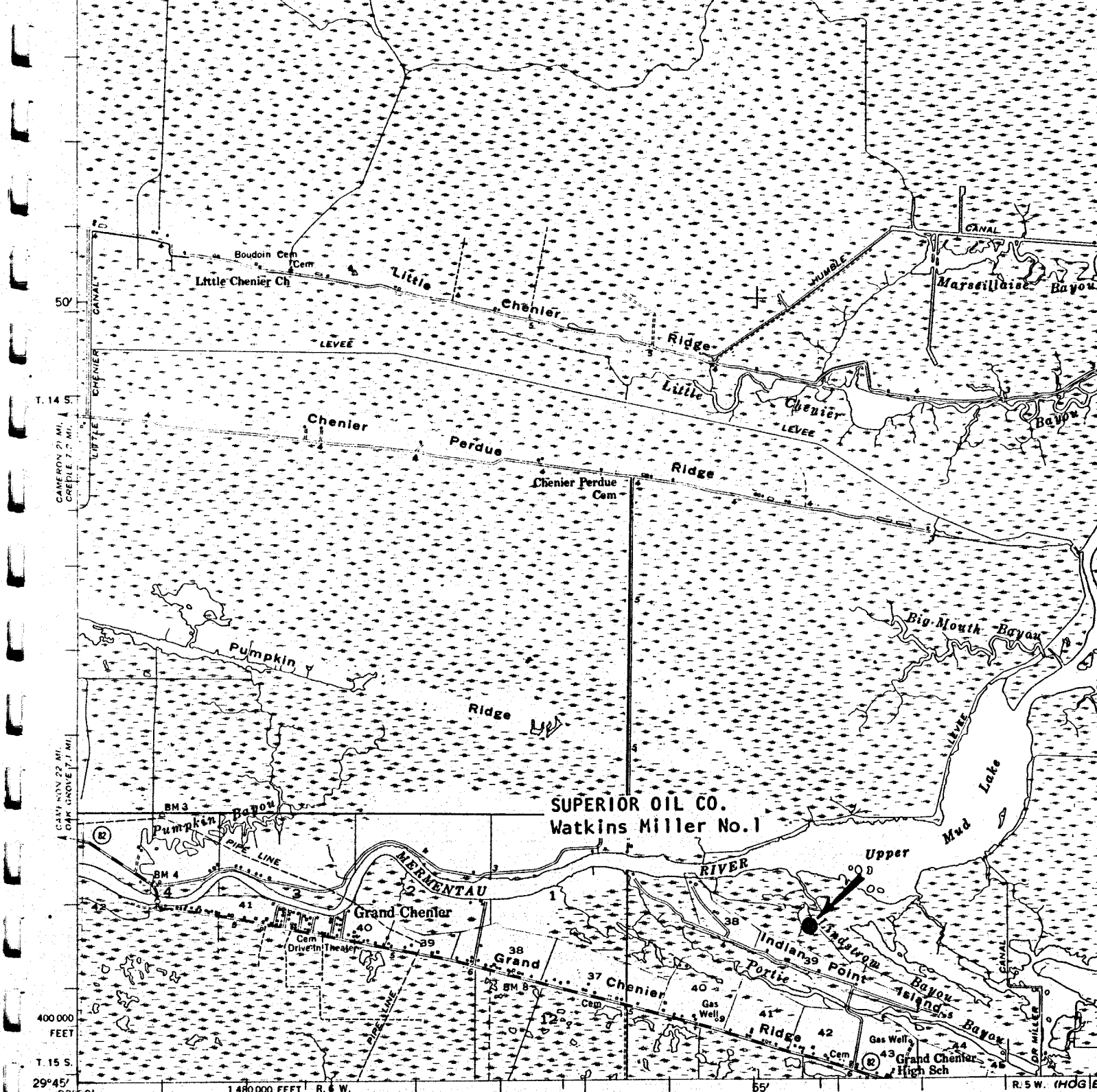
This prospect was drilled as the Superior Oil Company No. 1 Watkins-Miller, located in Section 5, T15S, R5W, Cameron Parish, Louisiana. The well site is just north of lot 39 on Indian Point Island and is readily accessible from State Highway 82 via a shell road which is in good condition. This location is shown on the lower portion of the USGS topographic sheet "Grand Lake West"; a portion of this sheet is included as Figure I. Superior Oil completed this well in late 1970 as a dual gas producer in sands between 11,150 and 11,250 feet and abandoned it in December 1974.

This well was initially selected as the first Geo^2 reentry candidate but was deferred when the landowner refused to grant reentry and test rights. He has, however, now indicated that he would be willing to grant those rights for a fee of $50,000. In view of our need for an alternate well to replace the State Lease 4183 No. 1, Gruy Federal has thoroughly reviewed alternate wells and concluded that the Watkins-Miller No. 1 requires minimal site preparation and is the reentry well of choice.

We are reluctant to file for the necessary state and local permits until a decision is made to consummate a deal with Mr. Miller. We are, however, in a position to expedite these applications at the appropriate time.

Geology

Figure II shows Gruy Federal's structural interpretation on top of the Geo^2 sands, based on a combination of regional geology and migration of the shallow sands depicted on the Cambe map. The accompanying overlay indicates the minimum net sand thickness through the aquifer. This interpretation is believed to be reasonable, and indicates that the Geo^2 aquifer available to this



ROAD CLASSIFICATION

Medium-duty ——— Light-duty ———

Unimproved dirt - - - - - -

State Route

QUADRANGLE LOCATION

This area also covered by larger scale maps of the Latania Lake, Lake Misere, Grand Cheniere, and Catfish Lake 7.5 minute quadrangles, surveyed 1934

GRAND LAKE WEST, LA.

N2945—W9245/15

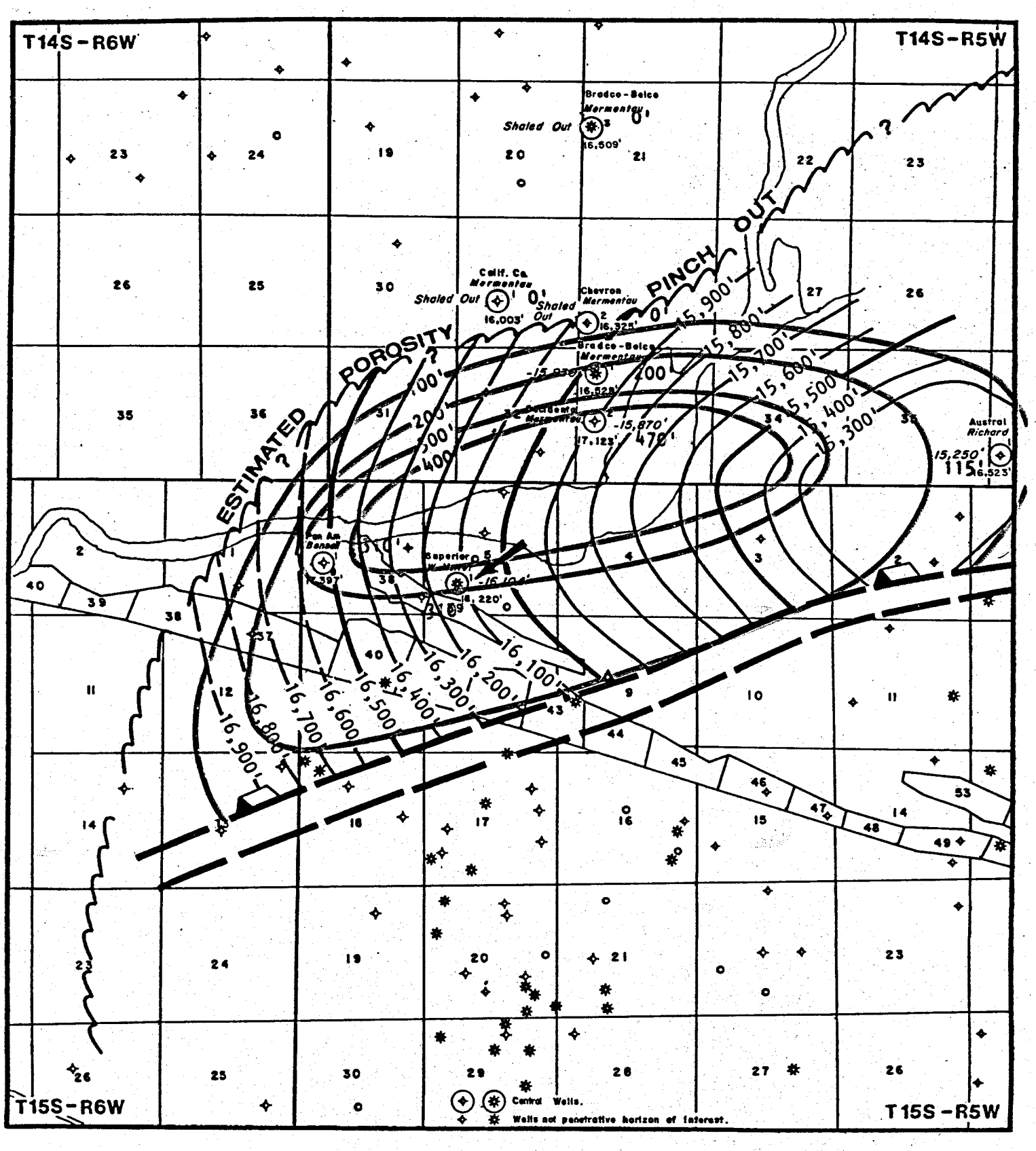
1955

AMS 7443 IV—SERIES V785

GRUY FEDERAL, INC.
Houston, Texas

LOCATION MAP
Grand Lake West
Cameron Parish, Louisiana

FIGURE 1



0 1 2 miles

NET SAND ISOPACHOUS MAP

GRUY FEDERAL, INC.
Houston, Texas

Crab Lake Field Area
Cameron Parish, Louisiana

STRUCTURE: TOP OF POROSITY
at First Geo^2 Sand
in Miocene Planulina Section

FIGURE 2

well extends over more than 7,500 acres. This Miocene Planulina sand appears to be shaled out to the northern and western aquifer extremities, and limited on the south by an inferred east-west striking fault. The absence of deep wells to the east makes it impossible to define the aquifer limits in that direction from the Watkins-Miller No. 1.

The potential Geo^2 aquifer in this well is the Planulina (lower Miocene) section from 16,100 to 16,900 feet, having a net sand thickness of 310 feet. No hydrocarbon saturation is evident on the resistivity log. During drilling operations through these sands, the mud weight was 17.6 pounds per gallon, indicating a static aquifer pressure of approximately 14,000 psi (assuming 1,000 psi overbalance). The maximum recorded mud temperature during logging in this interval was 285 degrees Fahrenheit (141 degrees Centigrade), which would indicate an aquifer temperature of 311 degrees Fahrenheit (155 degrees Centigrade) based on correction factors developed for south Louisiana by the AAPG.

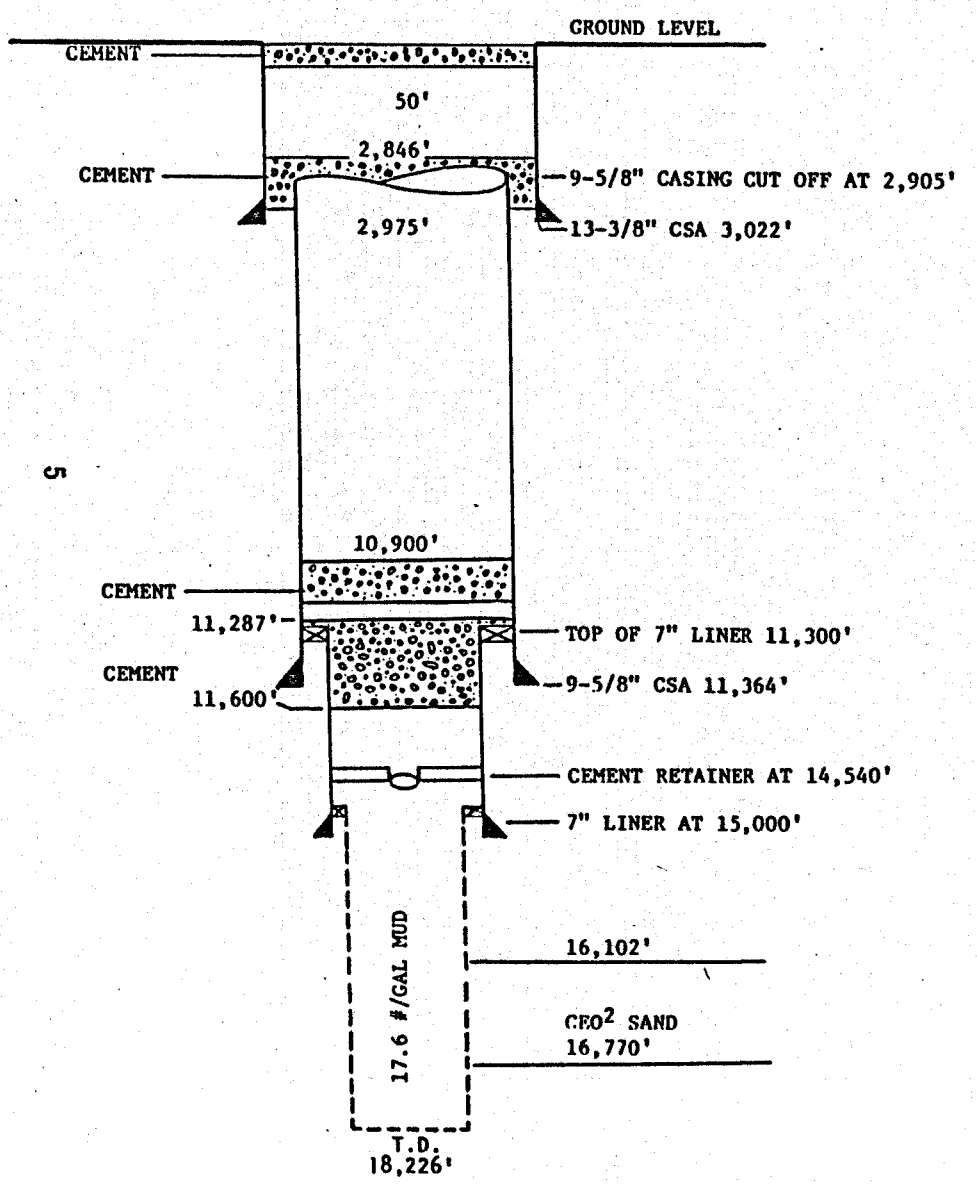
A sonic log on the well was obtained from Superior Oil Company and analyzed by H. J. Gruy and Associates. An average cementation factor of 2.3 was computed for the sand section, which suggests that the sand is well consolidated. Although the porosities of the sands are fairly uniform at 20 percent, the sand/shale ratio in the upper section from 16,100 to 16,400 feet is higher than in the bottom 500 feet. Selection of the final perforating interval will be deferred until additional logs have been run.

Mechanical Condition

Figure III illustrates the present condition of the well and the proposed condition for testing. Information on the present condition of the well was obtained from the plugging and abandonment report filed with the Louisiana Department of Conservation and verified from the drilling, completion, and plugging reports in the well file of the operator. It will be necessary to run a 7-inch OD string of casing and tie into the existing 7-inch liner at 11,300 feet. In

CURRENT STATUS

SUPERIOR OIL COMPANY
WATKINS MILLER NO.1
SOUTH GRAND CHENIER



PROPOSED COMPLETION

SUPERIOR OIL COMPANY
WATKINS MILLER NO. 1
SOUTH GRAND CHENIER

Datum = 24.58' ASL

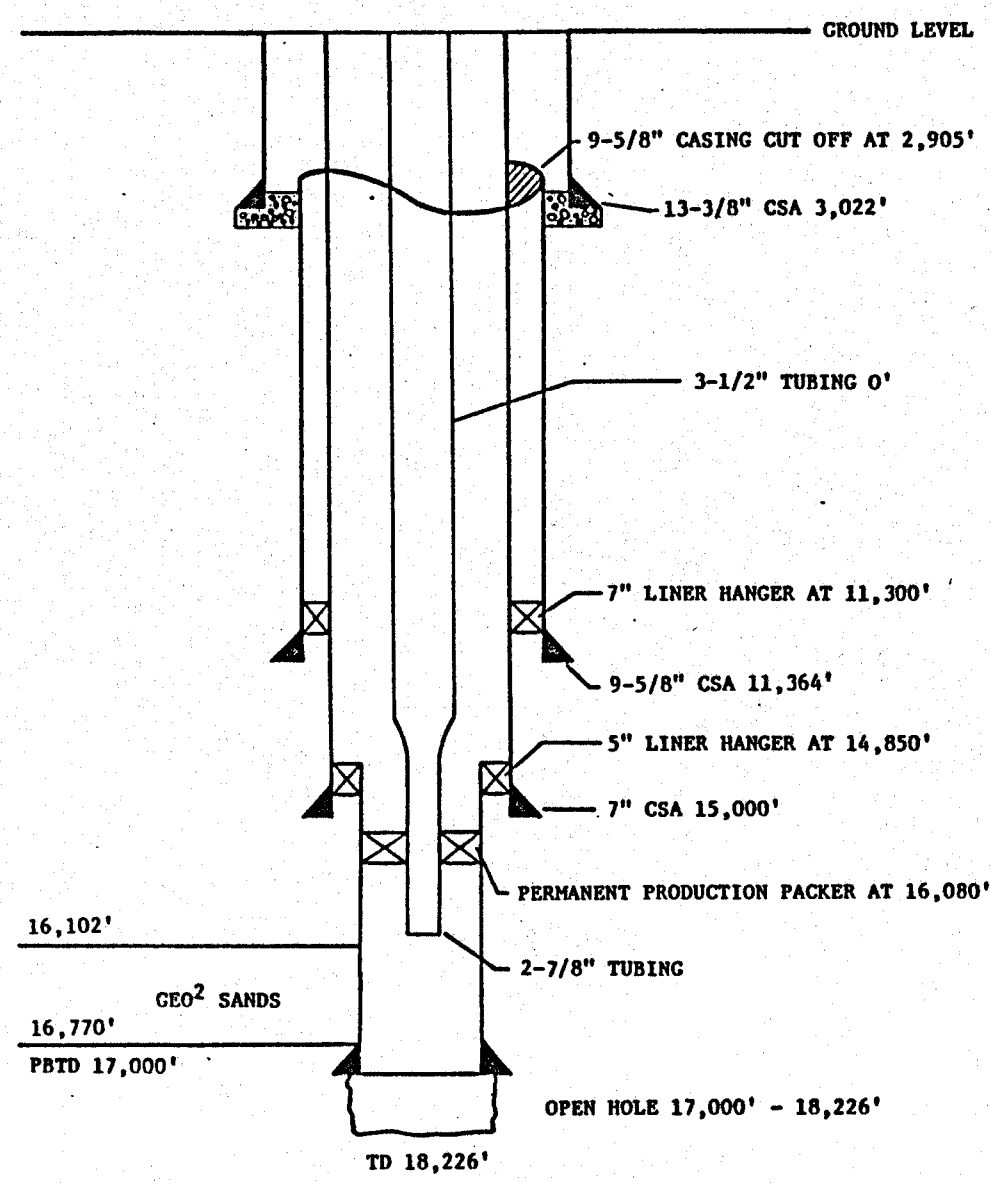


FIGURE III

addition, the open hole below the 7-inch liner must be cleaned out from 15,000 to 17,000 feet and a 5-inch liner run and cemented.

Reentry Technique

A detailed reentry and recompletion prognosis is attached. In designing the equipment and specifying the procedures, the primary consideration was the safety of the operation, taking into account the experience of prudent operators who have successfully penetrated and produced from geopressured-geothermal gas reservoirs in this area.

Casing Design

The 7-inch OD tie back casing string to 11,300 feet was designed with two considerations in mind: (1) capability to withstand the maximum internal pressure anticipated from the well, and (2) providing essentially all of this casing from that recovered from the Alice C. Plantation No. 2 well.

Tubing Design

The tubing design selected consists of a tapered string of 2-7/8", 8.70# P-105 from the Intracoastal City inventory to run inside the 5" OD casing liner, and a combination string of 3½" OD, 12.70#, P-105, PH6 Hydril threaded and IJ3SS tubing from the Alice C. Plantation well.

The 2-7/8" OD tubing is necessary to enter the 5" OD liner and still allow clearance for the tubing gun to pass through the seal assembly and landing nipples. The portion of the tubing which seats in the packer will be equipped with a seal assembly to allow for approximately 10 feet of expansion and contraction during flowing and plugging operation. A landing nipple and a circulating valve will be placed above the seals to permit communication between the tubing and casing. Figure IV is a diagram of the bottom hole tubing assembly.

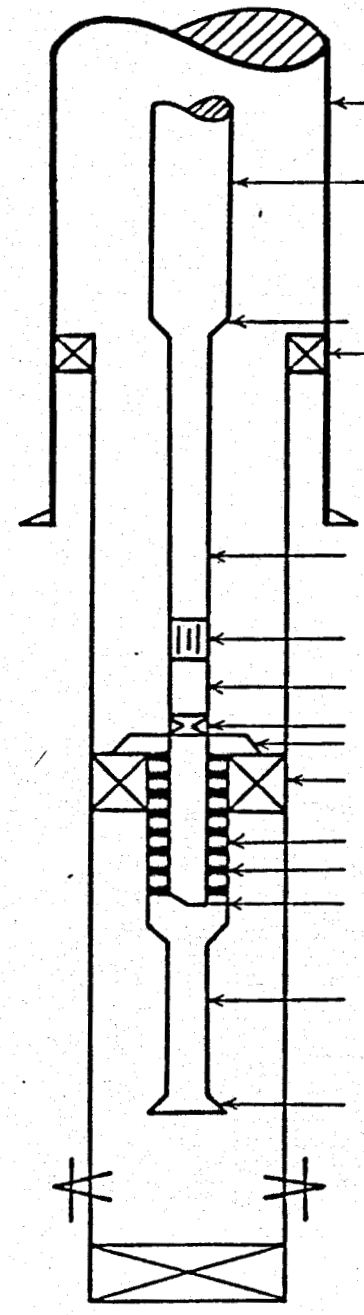
SUPERIOR OIL COMPANY

WATKINS-MILLER NO. 1

SOUTH GRAND CHENIER AREA

CAMERON PARISH, LOUISIANA

BOTTOM HOLE TUBING ASSEMBLY



1) 7" CASING

2) 3-1/2" 12.8# P-105 PH-6 TUBING - 2.764" I.D.; 2.639" DRIFT

3) 3-1/2" 12.8# CROSSOVER TO 2-7/8" 7.9# PH-6 TUBING

4) 5" 18# LINER - 4.276" I.D.; 4.151" DRIFT

5) 2-7/8" 7.9# PH-6 TUBING - 3.433" O.D.; 2.265" I.D.

6) 2-7/8" 7.9# "RA" SLEEVE - 2.188" I.D.

7) 2-7/8" 7.9# PH-6 ONE JOINT OF TUBING

8) 2-7/8" 7.9# PH-6 "RN" NIPPLE - 2.010" I.D.

9) PACKER LOCATOR MANDREL WITH 2-7/8" 7.9# PH-6 BOX

10) 5" 18# "WB" PERMANENT DRILLABLE PACKER - 2.55" I.D.

11) PACKER BORE EXTENSIONS - 16' LENGTH; 2.55" I.D.

12) EXTRA SEALING UNITS - 16' LENGTH; 1.80" I.D.

13) MULE SHOE GUIDE

14) 2-3/8" 5.95# "CS" PUP JOINT - 6' LENGTH

15) RE-ENTRY GUIDE

Perforations

FIGURE IV

Blowout Preventers

The well prognosis sets out the necessary safeguard specifications and procedures for surface blowout prevention as adopted by IADC, API, and prudent operators in the Geo^2 areas. Figure V is a diagram of the proposed BOP hookup and choke manifold assembly.

Logging

The reentry prognosis recommends that the following open hole logs be run:

(1) Induction electric log
(2) Caliper
(3) Sonic

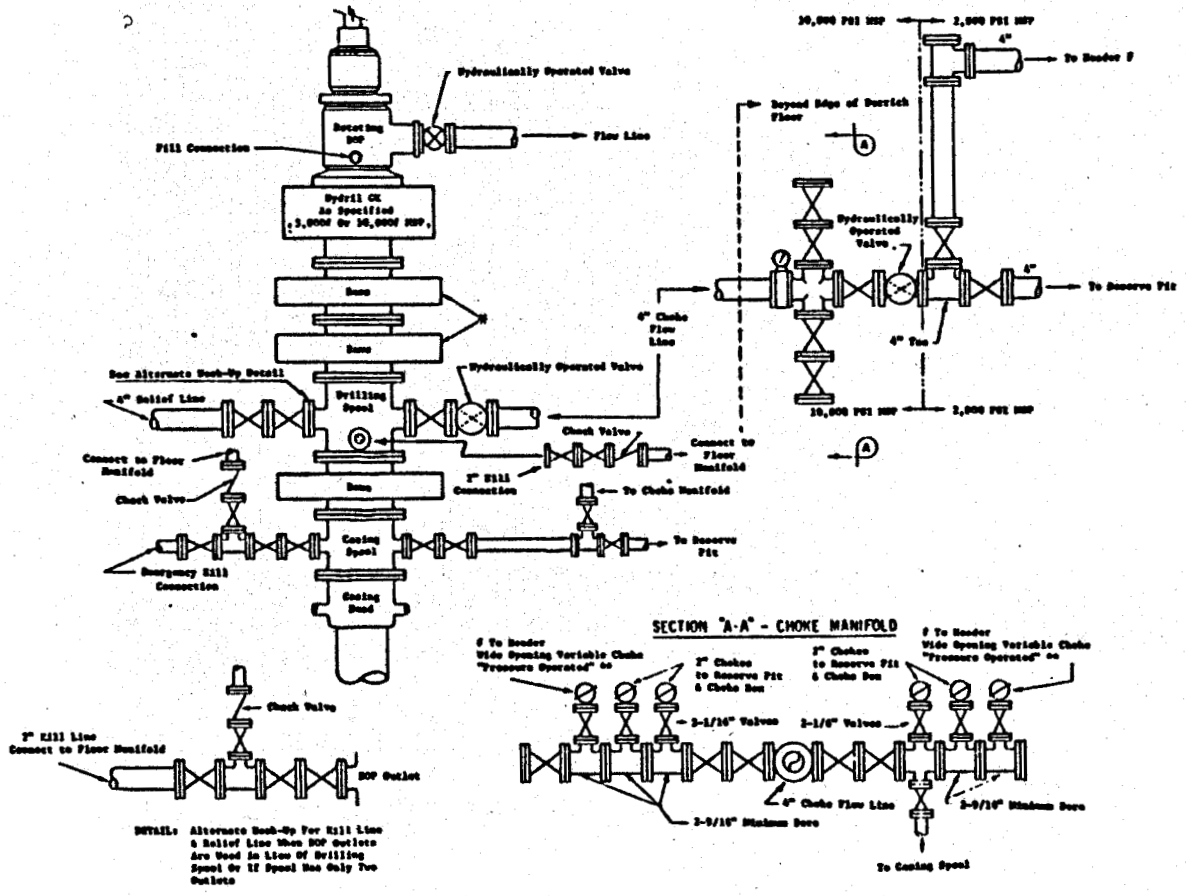
Although an induction electric log and a sonic log have previously been run, they should be rerun in order to evaluate any invasion that has occurred since the well was first completed. The cased hole logs (gamma ray, cement bond, and collar locator) are desirable to establish the integrity of the cement and to provide a benchmark for perforating.

Perforating

The perforating will be accomplished with a 1-11/16" high-temperature, through tubing jet perforating gun with four shots per foot and zero phasing. This jet creates a casing entry diameter of approximately 2" beyond the cement sheath. Assuming 100 percent firing efficiency, this configuration should provide a productivity equal to 70 percent of the open hole productivity.

The perforated interval length will be designed to achieve a productivity equal to 1/3 of open hole productivity. In the Watkins-Miller No. 1 well, this can be accomplished by perforating approximately 92 feet. The exact

BLOWOUT PREVENTER DESIGN



Minimum operating equipment for preventers will be as follows: (1) multiple pumps, driven by a continuous source of power, capable of fluid charging the total accumulator volume within twenty minutes; and (2) accumulators with a pre-charge of nitrogen at not less than 750 psi and capable of receiving a fluid charge from the (charging) pumps. Fluid charge volume shall be the amount required to increase accumulator pressure from nitrogen pre-charge pressure to rated pressure. Charging pumps are to be connected to the hydraulic operating system which is to be a closed system. When requested, an additional remote and equivalent source of power shall be available to operate the pumps. The pressurized fluid volume stored in the accumulators shall be sufficient to close all pressure operated devices simultaneously within 20 seconds with charging pumps shut down. Minimum accumulator pressure shall be 1500 psi initially and not less than 1200 psi when all preventors are closed.

The closing manifold and remote closing manifold (floor-mounted) will have a separate control for each pressure operated device. Each control will be labeled to designate which pressure device it controls and to show open and closed positions. A pressure reducer and regulator is to be provided for the Hydril GK. Hydraulic oil shall be used as the operating fluid. One-inch size seamless steel piping shall be used to connect the closing unit to the preventors. Piping is to be tested to maximum rated pump pressure. The choke manifold, the four-inch choke flowline and the four-inch relief line shall be supported by metal stands or reinforced concrete. The choke lines shall be anchored. No sharp bends or curves will be permitted in the choke flowline from the preventers to the pits. Header to have three way outlet: (1) to reserve pit, (2) to choke box, (3) to separator. Easy and safe access will be maintained to the choke manifold. If deemed necessary, walkways and stairways will be provided in and around choke manifold. All valves throughout the assembly shall be selected for operation in the presence of oil, gas and drilling fluids. Valves connected adjacent to the drilling spool and all ram-type preventers will be equipped with stem extensions, universal joints, if needed, and operating wheels which are to extend beyond edge of derrick substructure. Any other valves within the limits of the derrick substructure will be so equipped when requested.

FIGURE V

interval finally chosen will be contingent upon the analysis of the additional open hole logs that will be run.

The well will be perforated with $CaCl_2$ water in the hole so that a pressure differential from the formation to the well bore will exist. When the first gun is fired, water from the formation will expand into the well bore, equalizing the pressure on both sides of the casing. Perforating in this manner will prevent mud filtrate from entering the formation with a simultaneous buildup of mud cake on the wall of the perforation.

Wellhead Design

Figure VI is a sketch of a Geo^2 christmas tree designed by the WKM Wellhead Systems Division. The tree is rated at a working pressure of 10,000 psi. All valves have T-24 steel vertical runs with packing and seals for high-temperature fluids (360 degrees Fahrenheit). The tree consists of two 3-1/16" master gate valves and a 3-1/16" swab valve. Between the master gate valve and the swab valve is a double wing assembly to house the choke bodies. One wing contains a positive choke, the other an adjustable choke. Each wing consists of a Hi-Lo safety valve and a conventional wing valve. This specific design protects the tree assembly from the maximum pressures expected in the well.

During squeeze cementing to plug and abandon the well, the wellhead pressure may exceed 10,000 psi. To circumvent this problem, it is planned to utilize a wellhead isolation tool developed by Halliburton. This tool is attached to the top of the swab valve on the tree and a mandrel is hydraulically positioned through the master gate valves until it is locked in the production tubing. This device, rated at 20,000 psi working pressure, isolates the wellhead from the treating fluid pressure. The tubing in the well will accommodate all anticipated pressures.

The casinghead used to set the production string has been designed to accept casing of any size from all the wells under consideration, and to be compatible with both the blowout preventers and the upper christmas tree assembly.

GEO^2 CHRISTMAS TREE
TO BE ADAPTED FOR ALL REENTRY WELLS
BY GRUY FEDERAL, INC.

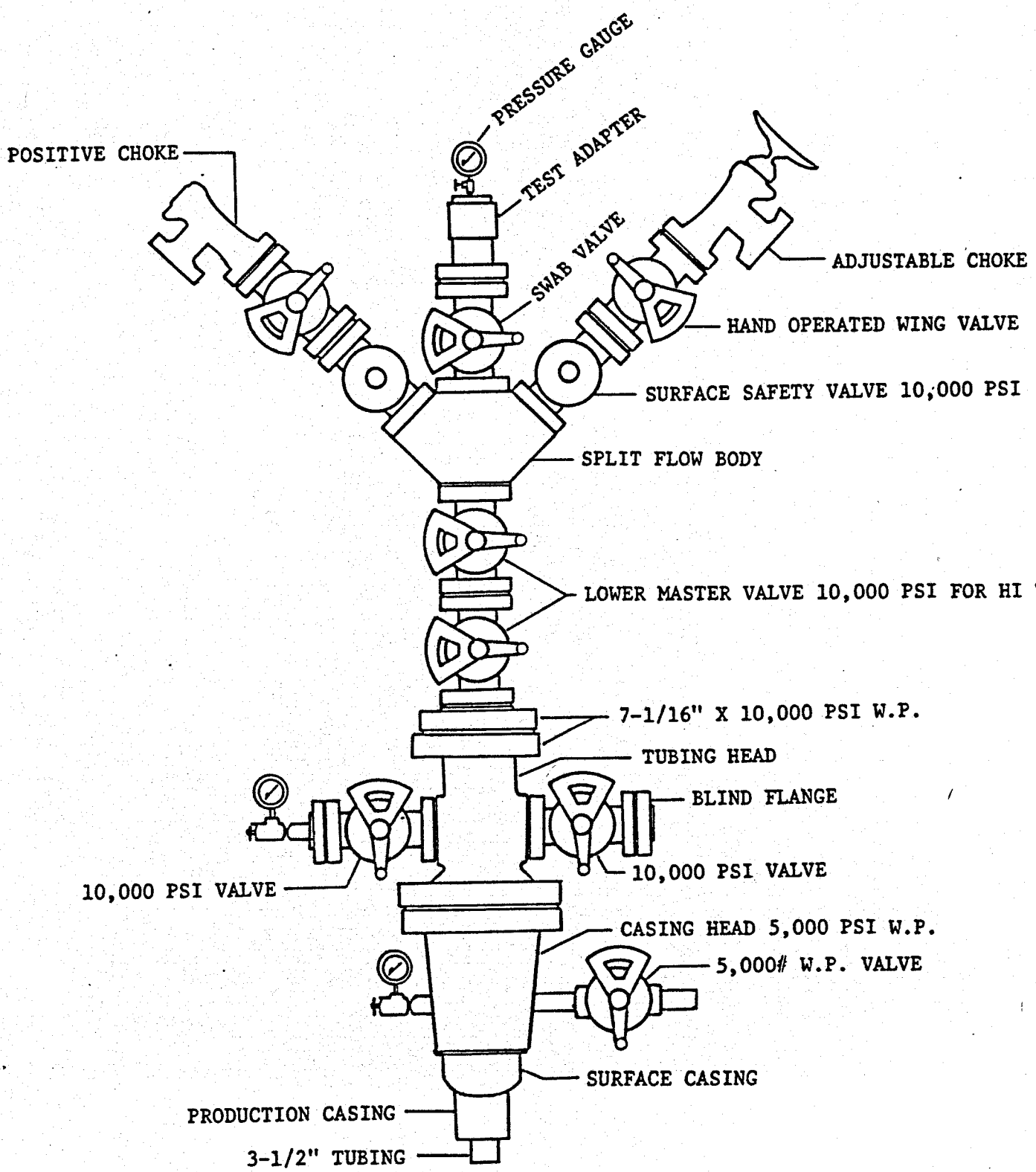


FIGURE VI

General Comments

The Watkins-Miller No. 1 well has been recommended as a Geo^2 candidate for the following reasons:

(1) It is located in a recognized geothermal fairway identified by the Petroleum Engineering Department of Louisiana State University under contract to DOE.

(2) The geopressured objective sand has the highest indicated temperature (311 degrees Fahrenheit) of any available candidates that have been screened.

(3) Available data indicate that the Geo^2 sections are capable of producing salt water in sufficient quantities for the scheduled test period.

(4) Modern logging equipment can be run in the open hole interval of interest. Sidewall core sampling may be possible, but is not recommended, since recovery at this depth is poor and it might cause mechanical hole problems.

(5) The site can be prepared within 10 days from the time all clearances are received.

WELL PROGNOSIS
FOR
SUPERIOR OIL COMPANY
WATKINS-MILLER NO. 1
SOUTH GRAND CHENIER

Operational Day

1. Prepare location.

2. Dig out and inspect 13-3/8" surface casing, extend to proper elevation, and weld on casinghead.

1st 3. Move in rig, rig up, and install BOP's.

4th 4. Clean out 13-3/8" OD casing with 12¼" rock bit on drill string and drill out cement to the top of the cut-off 9-5/8" OD casing at approximately 2905 feet. Pull out of hole.

5. Run 11½" OD lead impression block on top of 9-5/8" casing to observe its position and mechanical condition. Pull out of hole.

5th 6. If required from appearance of lead impression block, run 8-3/4" OD long tapered carboloy junk mill to dress out top of cut-off 9-5/8" OD casing. Dress out top to permit working through to top 7" OD casing. Run mill, 6½" OD drill collars, 3½" OD drill pipe. Pull out of hole.

6th 7. Clean out cement plugs in 9-5/8" OD casing with 8-3/4" OD rock bit to the top of the 7" OD liner at 11,300 feet.

7th 8. Run 8½" OD lead impression block on bottom of 6½" OD drill collars and 3½" OD drill pipe to check condition of 7" OD tie back sleeve. Pull out of hole.

9. If required from appearance of lead impression block, run 6" OD long tapered carboloy junk mill to dress out top of 7" OD tie back sleeve.

8th

10. Run mill, 4½" OD drill collars, 3½" OD drill pipe. Dress out top of 7" OD tie back sleeve and clean out approximately 25 feet below top of sleeve. Pull out of hole.

9th

11. Go in hole with two joints 8-5/8" OD 36# Hydril. FJWP washover pipe; 8-3/4" OD tooth type carboloy rotary shoe, top bushing, and 4½" API IF Johnston hydraulic oil jars on bottom of 6½" OD drill collars and 3½" OD drill pipe. Wash over and dress off entire tie back sleeve plus 10 feet of casing. Pull out of hole.

10th

12. Go in hole with 7" OD tie back sleeve and 11,300 feet of 7" casing as follows:

7" OD TIEBACK CASING STRING

From	To	weight, #/ft.	Grade	Type Ends	Section Length
11,300'	10,150'	35.0	P-110	LT&C	1,150 ft.
10,150'	0	32.0	P-110	LT&C	10,150 ft.

Centralizers on bottom 500' if tie back sleeve centralized.

12th

13. Nipple up 7" casing.

14. Continue in hole to top of remaining cement plug at 11,325 feet and test casing above this point to 7,500 psi. Repair casing or tie back if necessary by cement squeeze.

13th

15. Condition mud to 17.6#/gallon, then drill cement from 11,325 feet to 11,600 feet, the cement retainer at 14,540 feet, and the cement below the retainer.

14th

16. Continue drilling cement with every precaution not to sidetrack hole below 7" liner set at 15,000 feet. Wash and ream old hole to a total depth of 17,000 feet.

18th

17. Run IES electric log and sonic log from total depth of 17,000 feet to the bottom of the 7" casing at 15,000 feet.

19th

18. Rig up and run 2,200 feet of 5" OD 18# P-110 FJ casing to total depth of 17,000 feet and cement with sufficient cement to circulate the full annular space behind the liner. the liner is to be equipped with a casing shoe on bottom, a float collar 2 joints above bottom, and centralizers every 100 feet from the bottom of the 7" casing to total depth.

21st

19. Pick up 2,300 feet of 2-7/8" work string and go in hole to the float collar on the 5" casing and condition hole.

20. Rig up and run a gamma ray, cement bond log from total depth to top of 5" OD liner and block squeeze, if necessary. Squeeze top of liner, if necessary.

23rd

21. Drill out cement and condition hole to top of 5" OD float collar at about 16,900 feet. Displace the mud in the hole with 10#/gallon $CaCl_2$ water and observe the hole for back flow and pressure increase at the surface. If none occurs, lay down drill pipe.

24th

22. Rig up and set permanent packer at 16,000 feet inside 5" liner.

23. Make up completion assembly on bottom of tubing (see enclosed drawing). Pick up 1300 feet of 2-7/8" OD 8.7# P-105 PH6 Hydril tubing, or combination string of said

Hydril and IJ3SS, if available. Space out tubing and set stinger with seals in packer. Pressure test the packer with 6,500 psi differential from the bottom and 5,000 psi from the top. Each joint of tubing is to be tested to 10,000 psi while going in the hole for completion.

27th 24. Hang tubing with wrap-around hanger, remove the BOP's, and nipple up christmas tree. Test tree to 10,000 psi.

25. Release rig and rig down.

30th 26. Finish moving out rig.

31st 27. Move in and rig up wireline lubricator on well and test same to 10,000 psi. Perforate the interval to be selected from the new logs obtained with 4 shots per foot. Most likely, the interval will be within the sand occurring from 16,500 feet to 16,770 feet. Since the initial perforating gun will be fired with a differential to the well bore, observation shall be made of the increased tubing pressure for leak off of static fluid pressure in the casing to make sure there are no leaks in the tubing or packer.

32nd 28. Rig down wireline unit and connect the test unit for production tests.

GENERAL PROCEDURE FOR BLOWOUT PREVENTION

1. Use BOP design as attached. The minimum assembly will consist of three preventers. The bottom and middle preventers may be Cameron QRC, Cameron Type F or Shaffer Hydraulic Single, and the upper preventer will be Hydril GK. Double preventers or space savers may be used if approved by the company supervisor. An accumulator with a closing unit is required. Accumulator reservoir pressure shall be sufficient to close all preventers simultaneously in 20 seconds with the charging pumps closed down. Minimum accumulator pressure shall be 1,500 psi initially and not less than 1,200 psi when all preventers are closed.

2. When nippling up production casing, test BOP's and choke manifold to 7,500 psi with cold water, or as specified by the company representative. BOP's will be tested at least once each day thereafter when working in open hole and once each week otherwise.

3. Have a full opening safety valve and Gray inside BOP with drill pipe connections on the rig floor.

4. Have extra pipe rams on location at all times when drilling or completing.

5. Locate all choke manifolds, lines, and valves at the side of and away from the substructure. Adequately support and tie down the choke assembly.

ESTIMATED REENTRY COST
FOR
WATKINS-MILLER NO. 1

	Activity	Est. Amount
1.	Lease aquisition and legal fees	$ 55,000
2.	Rig transportation cost	35,000
3.	Location preparation	65,000
4.	Rig time - 30 days @ $6,000/day	180,000
5.	Bits	2,000
6.	Mud and chemicals (part from previous well)	55,000
7.	Casinghead from previous well	200(1)
8.	Christmas tree, including surface safety controls (from inventory)	500(1)
9.	Casing patch, mills, equipment & service	20,000
10.	Rental tools and equipment	15,000
11.	3½" drill pipe rental	20,000
12.	Trucking (other than rig and tubular goods)	10,000
13.	Cement and services	25,000
14.	Logging and coring	37,600
15.	Perforating	28,500
16.	14,800' of new 3½" P-105 12.95# tubing (from previous well after inspection)	5,000(1)
17.	1,300' of 2-7/8" P-105 8.7# IJ3SS tubing (from invenrory after DelCrombe well)	1,000
18.	Packer and subsurface equipment (part from previous well)	3,500
19.	11,300' of 7" OD tieback casing per prognosis (from previous well)	10,000(1)
20.	2,200' of 5" OD 18# P-110 F. J. liner	29,350

21.	Supervision	10,000
22.	Miscellaneous	20,000
23.	Contingencies	45,000
24.	Material handling @ 1.3% of all except items 1, 21, and 22	9,900
25.	G & A @ 18% of items 1 and 21	15,300
	TOTAL	$697,850

(1) If timing on well operations do not permit salvaging casinghead, christmas tree, 7" casing and 3½" OD tubing from previous well, we must add $565,400 to cost of well for new items of material.

SALT WATER DISPOSAL WELL
FOR
WATKINS-MILLER NO. 1
SOUTH GRAND CHENIER AREA

The available electric logs covering the shallow sands from the conductor pipe to a depth of 5,000 feet indicate that the fresh water sands extend to a depth of approximately 900 feet and that sands capable of accepting high flow rate salt water occur above 4,000 feet. Detailed electric logs on the specific well will isolate the exact sand to be perforated.

The basic design of the casing program conforms with the requirements of the Department of Conservation. Tubing is not recommended for the well because it acts to increase the surface injection pressure and would be utilized only if backflushing is required. The need for backflushing appears to be remote for the following reasons: (1) a volume of less than 200,000 barrels will be injected; (2) filters are provided downstream from the pumps to reduce solid and scale build-up; (3) the closed system prevents bacterial growth; and (4) two injection pumps (one of which is a standby) capable of delivering 10,000 barrels per day at an injection pressure of 500 psi.

In the event that formation plugging prevents disposal of the water, coiled tubing can be lubricated into the well and the sand backwashed using nitrogen.

For scheduling purposes, the drilling of the salt water disposal well is contemplated to be concurrent with reentry operations on the Watkins-Miller No. 1 Geo^2 well.

Operational Day

1st	1.	Move in and rig up water well rig.
	2.	Drive 13-3/8' OD casing to refusal or ± 125 feet.
3rd	3.	Drill 12-1/4" hole to 1,200 feet.

5th	4.	Run 1,200 feet of 9-5/8", 36.0#, H-40 casing with guide shoes on bottom and a float collar one joint above bottom. Use one centralizer per 100 feet of casing for bottom 500 feet and cement casing to surface.
	5.	Drill 8-3/4" hole below surface casing to 4,000 feet.
9th	6.	Run Induction Electric and Sonic logs; take sidewall cores, if desired.
10th	7.	Run 4,000 feet of 5-1/2" OD, 15.5#, J-55 casing with guide shoe on bottom and float collar two joints above bottom. Run centralizers on every other joint of casing for bottom 500 feet. Cement casing with sufficient cement to get returns at the surface.
	8.	Nipple up 5-1/2" casing and install christmas tree.
11th	9.	Make trip with 2-7/8" work string, condition hole to float collar, and displace mud in hole with water. Test casing and tree to 2,000 psi.
12th	10.	Run gamma ray - cement bond log from total depth to 1,200 feet and block squeeze with cement, if necessary, to obtain good bond.
14th	11.	Rig down and move out water well rig.
	12.	Perforate approximately 50 feet of the lowest clean sand (determined from electrical logs) with four shots per foot using a casing bullet gun and rig down wireline unit.
	13.	Test injectivity of well with rig pumps or pump truck to achieve 10,000 barrels per day injection rate at 150 psi or

less. If injection rate is not sufficient, select and perforate additional sand interval or consider treatment with mud cleanout acid, or both, if deemed necessary.

ESTIMATED COST
OF
SALT WATER DISPOSAL WELL
FOR
WATKINS-MILLER NO. 1

Activity		Estimated Amount
1.	Move in rig, drill to 4,000 ft., 14 days @ $4,200	$ 58,800
2.	Location preparation	5,000
3.	130 feet of 13-3/8" 65# J-55 plain end casing	4,000
4.	1,200 feet of 9-5/8" 36# H-40 casing ST & C or LT & C	14,000
5.	4,000 feet of 5-1/2" 15.5# J-55 ST & C or LTC	21,400
6.	Standby rig time	4,200
7.	Cement and Services	14,000
8.	Electric logging	12,000
9.	Perforating	8,000
10.	Wellhead equipment from previous well, inspected	500
11.	Stimulation	2,500
12.	Supervision	4,200
13.	Miscellaneous supplies and rentals	7,500
14.	Trucking	3,000
15.	Contingencies	14,000
16.	Material handling at 1.3% on all items except 12 and 15	2,050
TOTAL WELL COST		$175,150

WELL TEST PROCEDURE

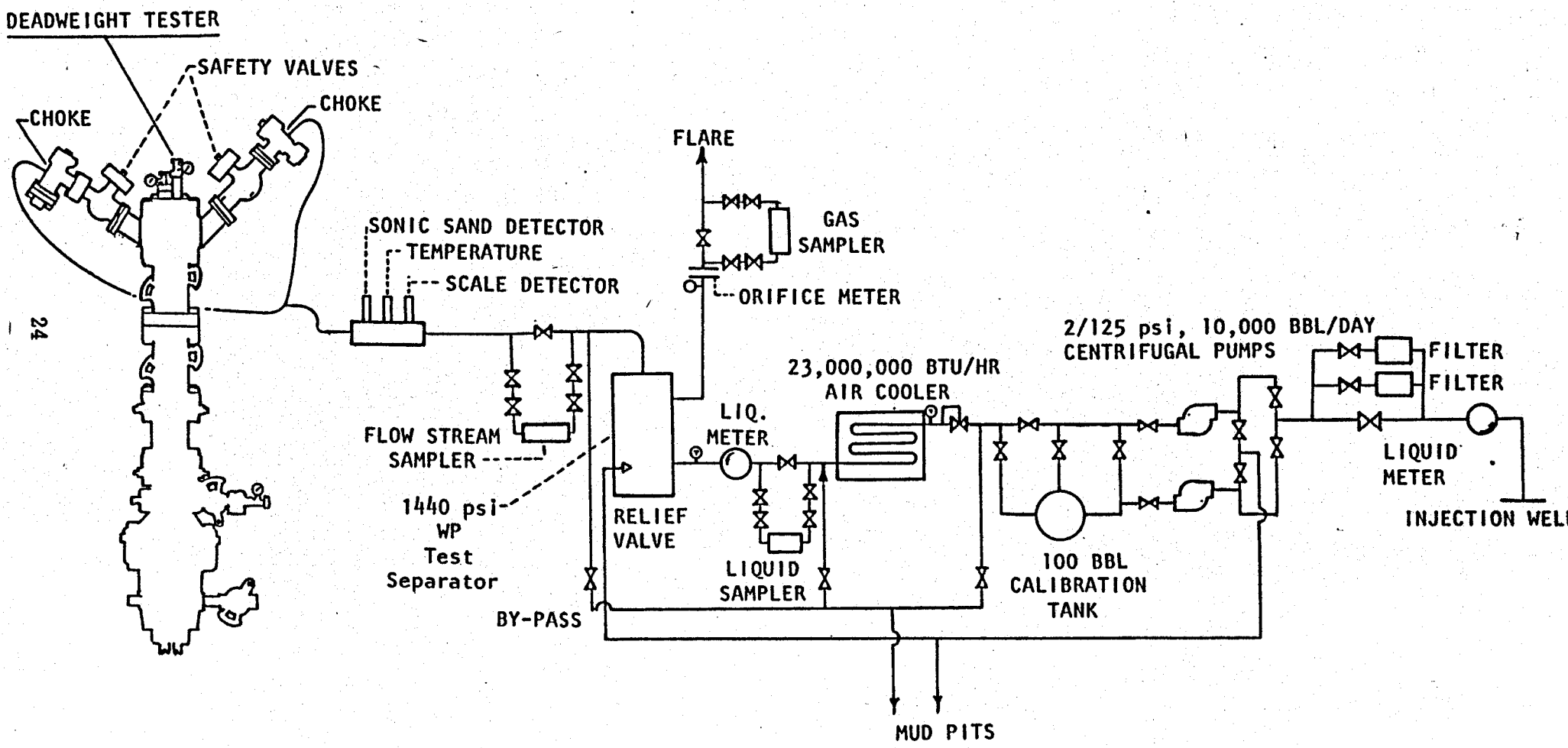
The well test procedure was established to provide the maximum amount of reservoir rock and fluid information obtainable within the fixed time frame and the limitations of available equipment. The only bottomhole pressure device capable of operating at these temperatures and pressures is a 15,000 psi (full scale deflection) Amerada RPG-3 bourdon tube pressure gauge. This gauge has no surface readout capability and has 3, 5, and 7 day clocks; its maximum acuuracy is $\pm$ 0.25% (37.5 psi) under controlled calibration conditions. These limitations affect the scope of meaningful transient tests that can be conducted.

Before testing commences it will be necessary to flow the well into a reserve pit to clean the perforations of mud and foreign solids. After this has been accomplished, the well will be shut in to measure static reservoir pressure. The well will then be placed on production at a low rate through the test equipment (Figure VII) in order to establish the drawdown characteristics at a safe level. Every 24 hours the rate will be increased until the choke size that allows flow at 10,000 barrels is determined. The well will then be shut in and the pressure buildup recorded. These data will be analyzed to determine the flow capacity of the formation and the skin effect or formation damage.

During each flow period, full flow stream samples will be taken and analyzed for chemical composition. Separator gas-water ratios will be carefully metered to detect changes as a function of flow rate.

After the well bore pressure has returned to static conditions, the well will be flowed at a rate of 10,000 barrels per day for approximately 2 weeks. The pressure data from this flow can be used to verify the reservoir parameters computed from the buildup analyis.

At selected intervals throughout the flow periods, separator gas and liquid samples will be taken for laboratory recombination studies to be conducted.



SURFACE TESTING FACILITIES
Gruy Federal, Inc.

FIGURE VII

TEST PROGNOSIS
FOR
WATKINS-MILLER NO. 1

Operational Day

39th

1. Move in and nipple up test equipment. Hydraulically test all systems with water to 400 psi.

42nd

2. Run two Amerada RPG-3 pressure gauges with 24-hour clocks and 15,000 psi full-scale deflection to 16,000 feet, stopping for 15 minutes each 3,000 feet. Hang bombs for 2 hours and record surface pressure with deadweight tester. Retrieve pressure bombs.

3. Hook up two-pen pressure recorder to tubing upstream from the choke and to the casing to observe for tubing or packer leaks.

4. Place well on production through adjustable choke at low setting and record surface flowing pressure every 30 minutes by deadweight tester.

5. Record gas and liquid flow rates by calibrating the liquid turbine meter with the test tank.

43rd

6. Gradually increase the flow rate in increments until either the maximum flow rate or 10,000 barrels per day is achieved. Continue to flow at this rate for 24 hours while recording surface temperature, pressure, and gas and liquid production. If maximum flow rate of well is not sufficient, do one of the following:

   (1) acidize, or
   (2) perforate more interval.

44th 7. Shut in well and measure surface pressure buildup with deadweight tester.

45th 8. When wellbore pressure has stabilized, run two Amerada RPG-3 pressure bombs with 5-day clocks and latch into landing nipple at bottom of tubing.

46th 9. Place well on production at 1,000 barrels per day for 24 hours. Monitor surface pressure, temperature, and flow rates, and take the following samples:

(a) Two one-liter, full well stream samples for chemical analysis;
(b) Three one-liter separator liquid samples;
(c) Two one-liter separator gas samples.

47th 10. Increase flow rate to 4,000 barrels per day for 24 hours and sample as before.

48th 11. Increase flow rate to 7,000 barrels per day for 24 hours and sample as before.

49th 12. Increase flow rate to 10,000 barrels per day for 24 hours and sample as before.

50th 13. Shut well in, measure buildup for 24 hours, then retrieve pressure bombs.

51st 14. Place well on production at low rate and gradually increase rate over a 12-hour period until it reaches 10,000 barrels per day.

15. Flow well at this rate for 9 days while measuring surface pressure, temperature, and flow rates.

16. Sample as before prior to shutting well in.

62nd 17. Shut well in, run two pressure gauges to 16,000 feet, and record until deadweight tester at surface indicates static conditions have been reached.

63rd 18. Pull pressure gauges, release test equipment, and move same out.

19. Proceed with plug and abandonment operations.

ESTIMATED TESTING COST
FOR
WATKINS-MILLER NO. 1

	Activity	Estimated Amount
1.	Two data headers	$ 108
2.	Two-phase separator	3,780
3.	100-barrel tank	1,090
4.	Two 10,000 BPD centrifugal pumps	1,940
5.	23,400,000 BTU/hr air cooler	3,459
6.	Piping	740
7.	Sonic sand detector	300
8.	Wireline unit w/ pressure gauge	1,440
9.	Gate valve w/ activator	500
10.	House trailer w/ power plant	850
11.	Generator	20,000
12.	Expansion loops	900
13.	Supervision and labor	46,200
14.	Material handling @ 1.3% on all items except 14	457
15.	Test accessories	200
	TOTAL	$81,964

TABLE 1

WATKINS-MILLER NO.1
CAMERON PARISH, LOUISIANA

Analysis Required for Geo^2 Water and Gas

Chemical Analysis of Water

A. Metals
   1. Copper
   2. Zinc
   3. Boron
   4. Arsenic
   5. Chromium
   6. Mercury
   7. Lead
   8. Cadmium

B. Solids
   1. Dissolved
   2. Total

C. Hardness
   1. Calcium carbonate
   2. Magnesium carbonate

D. Others
   1. Carbonate
   2. Bicarbonate
   3. Chloride
   4. Iron
   5. Sulfate
   6. Dissolved silicate

Chemical Properties of Water

1. Density
2. Compressibility
3. Conductivity
4. Viscosity
5. pH

Chemical Analysis of Vapor

A. Hydrocarbons (percent)

1. Methane
2. Ethane
3. Propane
4. Isobutane
5. Normal butane
6. Isopentane
7. Normal pentane
8. C_6 +

B. Other

1. Hydrogen sulfide
2. Carbon dioxide
3. Radon

Recombination PVT analysis

1. Solution gas-water ratio
2. Formation volume factor for water
3. Supercompressibility factor of gas

WATKINS-MILLER NO. 1 WELL
CAMERON PARISH, LOUISIANA

Analytical Costs for Geo^2 Water and Gas

Recombination 2 samples per well		$10,000
Chemical Analysis of Water 5 samples per well		750
Material Handling at 1.3%		140
	TOTAL	$10,890

PLUGGING AND ABANDONMENT PROCEDURE
FOR
THE SUPERIOR OIL COMPANY
WATKINS-MILLER NO. 1

1. Move in and rig up pulling unit capable of plugging and abandonment.

2. Nipple up pump trucks to wellhead.

3. Squeeze cement perforations.

4. If squeeze pressure is not obtained, overdisplace cement into formation with water and repeat squeeze cementing until successful.

5. When squeeze pressure is obtained, unbolt christmas tree from tubing hanger, pick up tubing out of packer, and reverse excess cement.

6. Remove tree and install BOP's.

7. Run in hole with tubing.

8. Cut 7" OD casing at approximately 11,260 feet (one joint above tie back sleeve) and lay down casing.

9. Make trip with open ended tubing and spot cement plug 100 feet in and out of cut off casing, another cement plug 100 feet in and out of the 9-5/8" casing which is cut off at 2,905 feet, then set 50 foot cement plug from 50 feet to the surface. Simultaneously with these cement operations, tie into disposal well and displace 200 feet of cement to bottom of 5" casing, then displace 50 foot cement plug from surface to 50 feet.

10. Release rig.

11. Send tubing and casing to pipe yard for inspection and repair.

12. Send christmas tree to shop for servicing.

ESTIMATED PLUGGING COSTS FOR WATKINS-MILLER NO. 1

Activity		Amount
1.	Pulling unit at $1,000/day	$ 8,000
2.	Rental tools at $500/day	4,000
3.	Trucking	3,000
4.	Cement and services	4,000
5.	Supervision	2,000
6.	Contingencies	2,400
7.	Material handling on all but supervision and contingencies @ 1.3%	300
8.	G & A at 18% of item 5	400
	TOTAL	$ 24,100

SITE-SPECIFIC ENVIRONMENTAL INFORMATION CHECKLIST
GEOPRESSURED-GEOTHERMAL WELL TEST PROGRAM
GRUY FEDERAL, INC.
NO. L-2

(Drilled as Superior Oil Company - Watkins Miller No. 1)
Cameron Parish, Louisiana

A. GENERAL

1. Is the proposed site located in the area covered by the "Gulf Coast Programmatic Environmental Assessment, Geothermal Well Testing, the Frio Formation of Texas and Louisiana October 1977"?

   Yes X No____ If no explain.

2. Has a federal, state and/or local environmental assessment been conducted previously for the proposed test well or other wells in the area?

   Yes____ No X If yes, provide a copy, if available.

3. Have all required permits, licenses, and/or agreements for proposed project been obtained?

   Yes____ No X If no, explain.

   These will be applied for immediately upon completion of arrangements with the landowner.

4. Does the project site fall within the habitat of rare or endangered species?

   Yes____ No X If yes, explain.

5. Are known archeological sites, historic sites, or natural landmarks within or visible from the site area?

   Yes_____ No X___ If yes, explain.

6. Will expected continuous noise levels from site operations be 65 dBA or less at the nearest residence?

   Yes_x___ No_____ If no, explain.

B. SITE CONSTRUCTION

1. Will additional land clearing be required for the test well (e.g., drill pad, road construction, mud reserve pits, pipeline)?

   Yes_____ No_X___ If yes, describe.

2. Will additional land clearing be required for the disposal well (e.g., drill pad, reserve pits, utilities, road construction, pipeline)?

   Yes _____ No X___ If yes, describe.

3. Will the site and related roads be treated to minimize dust?

   Yes_____ No_X___ If no, explain.

4. Are portable sanitary facilities or an approved septic system to be used at the site?

   Yes_X___ No_____ If no, explain.

5. Will liquid and solid wastes be disposed in accordance with local regulations?

   Yes_X___ No_____ If no, explain.

6. Will erosion control be required for excavated areas?

   Yes_____ No_X___ If yes, explain.

7. Will dredge spoil be deposited in swamp forest or marshland?

   Yes_X___ No_____ If yes, explain.

   Well is in marsh, but dredge spoil levee has been in place since 1970 when well originally drilled. Only minor repairs to existing levees will be required.

8. Upon completion of proposed test program, will the site be restored to as natural a condition as possible by regrading, filling, and reseeding?

   Yes_X___ No_____ If no, explain.

C. WELL TESTING AND SAFETY

1. Is fluid production from the well during testing expected to be 2 weeks or less in duration per formation?

Yes_____ No_X_ If no, explain.

2. Is the total dissolved solids of the produced geopressure fluid expected to be 90,000 mg/l or less?

Yes_X_ No_____ If no explain.

3. Is the volume of geopressure fluid to be produced and injected expected to be 3,000,000 barrels or less?

Yes_x_ No_____ If no, explain

4. Is the temperature of produced geopressured fluid expected to be 260°C or less?

Yes_X_ No_____ If no, explain.

5. Will the gas content of the produced fluid be flared?

Yes_X_ No_____ If no, explain.

6. Will blowout preventers rated to at least 10,000 PSI be used?

Yes_X_ No_____ If no, explain.

GRUY FEDERAL, INC.

7. Will production tubing rated to at least 20,000 PSI, be used?

Yes_____ No_X_ If no, explain.

Maximum burst pressure for 3-1/2" O.D. tubing to be used is 18,000 psi at 80% yield strength.

8. Can safety valves be operated from remote locations?

Yes_X_ No_____ If no, explain.

9. Will the test tree be rated to at least 10,000 PSI?

Yes_X_ No_____ If no, explain.

10. Will a test well directional survey be conducted?

Yes_____ No_X_ If yes, at what interval? _____Feet.
If no, explain.

Well is already drilled. Proposed work is reentry into existing well.

11. Will a lined pond be used to hold all liquid effluents and production fluids that are not injected?

Yes_X_ No_____ If no, explain.

12. Has an injection permit been obtained?

Yes_____ No_X_ If no, explain.

Permit will be applied for in conjunction with all other applicable premits after arrangements are completed with landowner.

GRUY FEDERAL, INC.

13. Will H_2S monitors be located onsite?

Yes_____ No X___ If no, explain.

No history of H_2S in this formation or area.

14. Will fire extinguishers be located onsite?

Yes X_____ No_____ If no, explain.

15. Do contingency plans exist for evacuating personnel should a blowout occur or high levels or H_2S be detected?

Yes__X__ No_____ If no, explain.

16. Will high-pressure engineering and mud logging personnel be onsite during production well drilling operations?

Yes_____ No X___ If no, explain.

Mud logging personnel will not be present since this is a reentry and not a drilling operation. However, experienced high pressure drilling and mud engineers will be on site.

GRUY FEDERAL, INC.

WATKINS-MILLER NO. 1

Attached are copies of revised or additional data sheets for the Watkins-Miller No. 1 well per instructions.

In the future, all reports will be complete prior to leaving Gruy Federal's office.

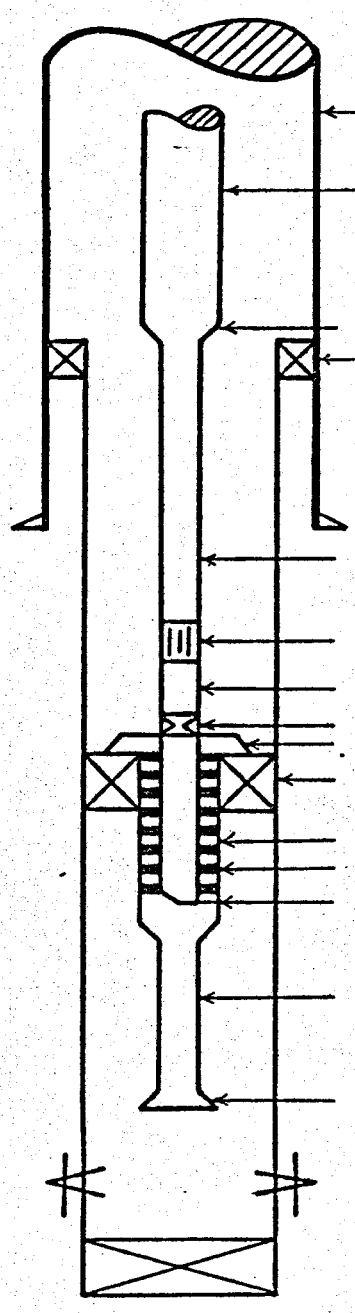
SUPERIOR OIL COMPANY

WATKINS-MILLER NO. 1

SOUTH GRAND CHENIER AREA

CAMERON PARISH, LOUISIANA

BOTTOM HOLE TUBING ASSEMBLY



1) 7" CASING

2) 3-1/2" 12.8# P-105 PH-6 TUBING - 2.764" I.D.; 2.639" DRIFT

3) 3-1/2" 12.8# CROSSOVER TO 2-7/8" 7.9# PH-6 TUBING

4) 5" 18# LINER - 4.276" I.D.; 4.151" DRIFT

5) 2-7/8" 7.9# PH-6 TUBING - 3.433" O.D.; 2.265" I.D.

6) 2-7/8" 7.9# "RA" SLEEVE - 2.188" I.D.

7) 2-7/8" 7.9# PH-6 ONE JOINT OF TUBING

8) 2-7/8" 7.9# PH-6 "RN" NIPPLE - 2.010" I.D.

9) PACKER LOCATOR MANDREL WITH 2-7/8" 7.9# PH-6 BOX

10) 5" 18# "WB" PERMANENT DRILLABLE PACKER - 2.55" I.D.

11) PACKER BORE EXTENSIONS - 16' LENGTH; 2.55" I.D.

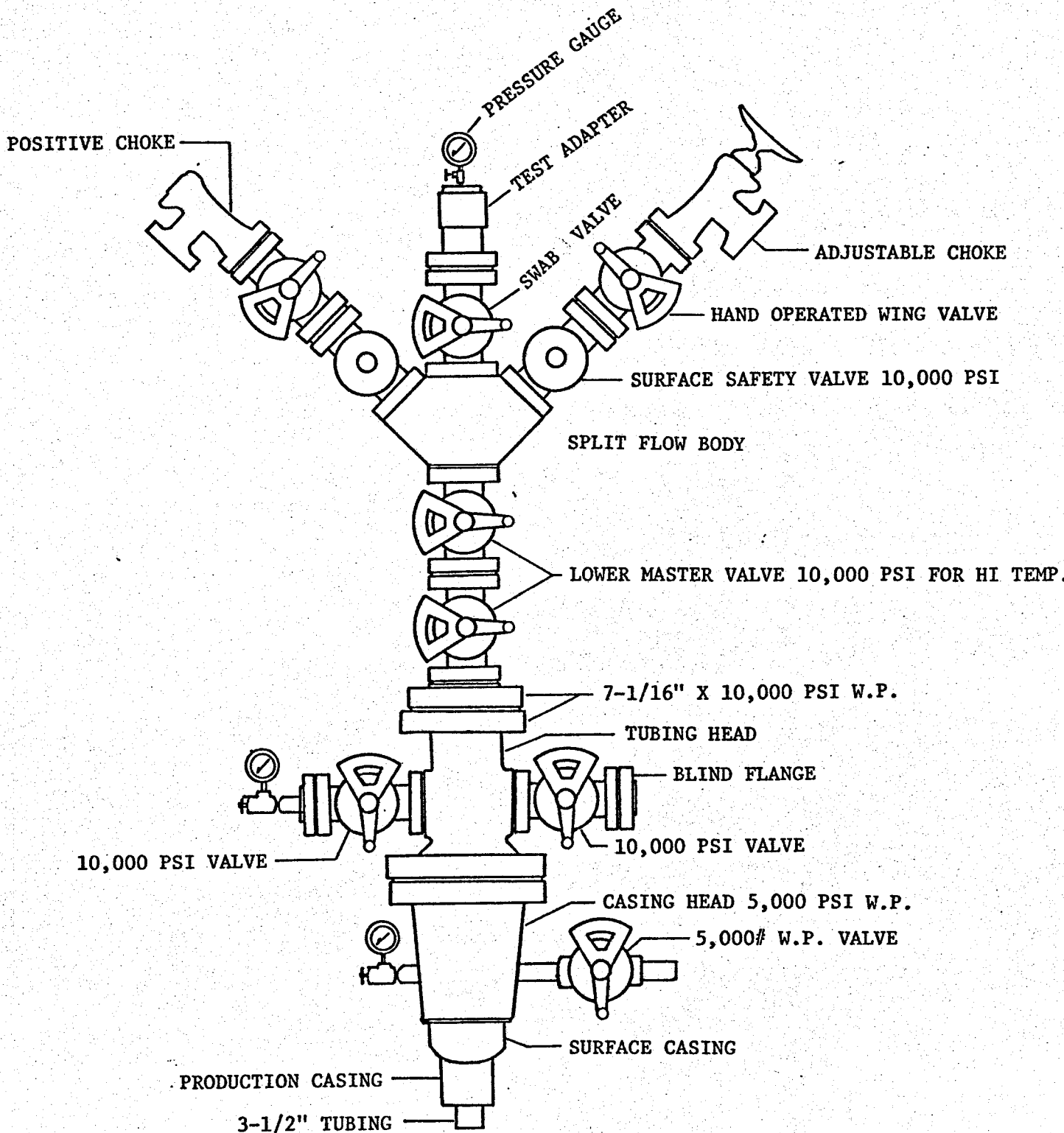
12) EXTRA SEALING UNITS - 16' LENGTH; 1.80" I.D.

13) MULE SHOE GUIDE

14) 2-3/8" 5.95# "CS" PUP JOINT - 6' LENGTH

15) RE-ENTRY GUIDE

GEO^2 CHRISTMAS TREE
TO BE ADAPTED FOR ALL REENTRY WELLS
BY GRUY FEDERAL, INC.



REENTRY PROGNOSIS

for

SUPERIOR OIL COMPANY WATKINS-MILLER NO. 1
SOUTH GRAND CHENIER AREA

Operational Day

1. Prepare location.

2. Dig out and inspect 13-3/8" casing, extend to proper elevation and weld on casinghead.

1st 3. Move in and rig up.

4th 4. Pick up 3-1/2" DP and bit and drill out cement plug from surface to 50'. Nipple up 13-3/8" surface casing and install BOP.

5. Continue in hole and drill cement plug from 2846' to top of 9-5/8" casing using drill collars and 3-1/2" OD grand "S" drill pipe work string.

6. Change bits and continue in hole inside 9-5/8" casing to condition mud to 10.0#/gal. and drill cement plug from 10,900' to top of 7" OD liner at 11,300'.

5th 7. Make trip to change bits and continue in hole inside 7" OD casing to drill cement to 11,600' and condition hole to top of cement retainer at 14,540'.

6th 8. Make trip and dress out tieback sleeve on top of 7" OD liner at 11,300'. Lay down work string.

7th. 9. Rig up and run 7" OD casing string as follows:

From	To	Size	Weight Feet	Grade	Type Ends	Section Length
11,300'	10,150'	7" OD	35.0	P-110	LT & C	1,150'
10,150'	9,550'	7" OD	38.9	N-80	LT & C	600'
9,550'	9,150'	7" OD	38.0	N-80	LT & C	400'
9,150'	8,450'	7" OD	32.0	P-110	LT & C	700'
8,450'	7,950'	7" OD	32.0	YS-95	LT & C	500'
7,950'	7,450'	7" OD	35.0	N-80	LT & C	500'
7,450'	6,850'	7" OD	32.0	YS-95	LT & C	600'
6,850'	5,250'	7" OD	29.0	YS-95	LT & C	1,600'
5,350'	4,200'	7" OD	29.0	P-110	LT & C	1,050'
4,200'	3,950'	7" OD	26.0	P-110	LT & C	250'
3,950'	200'	7" OD	29.0	P-110	LT & C	3,750'
200'	0	7" OD	38.9	P-110	LT & C	200'

Hang 7" casing string in maximum tension in slips in order to allow for thermal expansion under dynamic flow conditions.

Operational Day	
9th	10. Pick up 3-1/2" DP and condition hole to cement retainer at 14,540'. Build mud weight to 17.6#/gal. Make trip and run retrievable packer to approximately 14,500' and test casing patch to 7,500 psi surface pressure for 30 minutes. Repair casing, if necessary, by cement placement.
10th	11. Go in hole with 3-1/2" drill pipe work string and drill up cement retainer at 14,540' and cement to 15,000' or to the bottom of the 7" OD casing liner and condition mud.
12th	12. Run 3-1/2" work string with 2,200' 2-3/8" IF grade "S" drill pipe and drill collars. Drill cement, wash and ream hole (6" bit) to 17,000'. Do this in stages so that full returns from bottom can be received as each successive 100' of hole is washed down.
15th	13. Condition 17.6#/gal. mud, pull out of hole and run the following electric logs in open hole below 7" liner at 15,000'. Take side wall cores if hole conditions permit: Induction electric log Compensated neutron and compensated density log Caliper log Sonic log
16th	14. Make trip with bit and condition hole to 16,850'.
17th	15. Rig up and run 2,200' of 5" OD 18# P-110 FJ casing for liner equipped with one centralizer per 100' of liner. Hang liner top at 14,850' and cement liner with sufficient cement to fill all of liner annulus space. Reverse out excess cement, set liner hanger, release same and pull out of hole with work string. WOC 12 hours.
18th	16. Make trip, run tapered work string and condition hole to float collar on 5" OD liner at $\pm$ 16,920'.
19th	17. Run gamma ray - cement bond log from TD to 11,300'.
	18. Run work string and test tool and test top of liner. Squeeze liner top, if necessary.
	19. If bond log indicates it necessary, block squeeze above and below probable completion zones. Condition hole to PBTD.
21st	20. Lay down work string and pick up 14,800' of 3-1/2" 12.70# P-105 PH-6 Hydril tubing and 1,300' of 2-3/8" 5.80# P-105 Hydril tubing and 700' of 2-3/8" work string. Condition hole to PBTD and displace mud in hole with 10#/gal. CaCl2 water. Test for leaks for one hour. If OK, pull out of hole and remove the 700' of 2-3/8" OD work string.

Operational Day	
23rd	21. Rig up wire line unit and set production packer at 16,080'.
	22. Make up bottom hole completion equipment as shown on enclosed diagrammatic sketch and go in hole. Test each joint of tubing to 10,000 psi while going in hole. Space out tubing and test packer to 6,500 psi differential from bottom and 5,000 psi on top.
	23. Hang tubing with wrap-around hanger and nipple up christmas tree.
24th	24. Release drilling rig, rig down and move out same.
26th.	25. Suspend operations while drilling salt water disposal well.
37th	26. Rig up wire line company high pressure lubricator on well and test same to 10,000 psi for 30 minutes. Perforate (through tubing) a minimum of 92 feet of sand in the interval from 16,102' to 16,770' as set out in step 27. The final selection of the completion interval is to be made after review of the electric logs to be obtained on the well.
	27. Run through tubing perforating gun with collar locator and perforate lowest 92 feet of completion interval to be selected with four holes per foot after final review of all available logs on the well. Observe increased surface pressure (after perforating) for leak off of static fluid in hole for 30 minutes. Pull gun out of hole. Make successive runs with perforating gun until full objective perforating interval is accomplished. (Maximum loading on gun is 46', four shots per foot)
	28. Rig down wire line unit and lubricator, then proceed to hook up well to test unit.

GENERAL PROCEDURE FOR BLOWOUT PREVENTION:

1. Use BOP design as attached. The minimum assembly will consist of three preventers. The bottom and middle preventers may be Cameron QRC, Cameron Type F or Shaffer Hydraulic Single, and the upper preventer will be Hydril GK. Double preventers or space savers may be used if approved by the company supervisor. An accumulator with a closing unit is required. Accumulator reservoir pressure shall be sufficient to close all preventers simultaneously in 20 seconds with the charging pumps closed down. Minimum accumulator pressure shall be 1,500 psi initially and not less than 1,200 psi when all preventers are closed.

2. When nippling up production casing, test BOP's and choke manifold to 7,500 psi with cold water, or as specified by the company representative. BOP's will be tested at least once each day thereafter when working in open hole and once each week otherwise.

3. Have a full opening safety valve and Gray inside BOP with drill pipe connections on the rig floor.

4. Have extra pipe rams on location at all times while drilling or completing.

5. Locate all choke manifolds, lines and valves at the side of and away from the substructure. Adequately support and tie down the choke assembly.

SUPERIOR OIL COMPANY WATKINS-MILLER NO. 1
CAMERON PARISH, LOUISIANA

Analyses Required for Geo^2 Water and Gas

Chemical Analysis of Water

A. Metals
   1. Copper
   2. Zinc
   3. Boron
   4. Arsenic
   5. Chromium
   6. Mercury
   7. Lead
   8. Cadmium

B. Solids
   1. Dissolved
   2. Total

C. Hardness
   1. Calcium Carbonate
   2. Magnesium Carbonate

D. Others
   1. Carbonate
   2. Bicarbonate
   3. Chloride
   4. Iron
   5. Sulfate
   6. Dissolved Silicate

SUPERIOR OIL COMPANY WATKINS-MILLER NO. 1
CAMERON PARISH, LOUISIANA

Chemical Analysis of Vapor

A. Hydrocarbons (percent)
   1. Methane
   2. Ethane
   3. Iso-propane
   4. Normal Propane
   5. Iso Butane
   6. Normal Butane
   7. Pentane
   8. C_6+

B. Other
   1. Hydrogen Sulfide
   2. Carbon Dioxide
   3. Fadon

Chemical Properties of Water

1. Density
2. Compressibility
3. Conductivity
4. Viscosity
5. pH

Recombination PVT Analysis

1. Solution gas-water ratio
2. Formation volume factor for water
3. Supercompressibility factor of gas

SUPERIOR OIL COMPANY WATKINS-MILLER NO. 1

CAMERON PARISH, LOUISIANA

Analytical Costs for Geo^2 Water and Gas

Recombination	
2 samples per well	$ 10,000
Chemical Analysis of Water	
5 samples per well	750
Total	$ 10,750

SITE-SPECIFIC ENVIRONMENTAL INFORMATION CHECKLIST
GEOPRESSURED-GEOTHERMAL WELL TEST PROGRAM
GRUY FEDERAL, INC.
NO. L-2
(Drilled as Superior Oil Co.-Watkins-Miller No. 1)
Cameron Parish, Louisiana

A. GENERAL

1. Is the proposed site located in the area coverd by the "Gulf Coast Programmatic Environmental Assessment, Geothermal Well Testing, the Frio Formation of Texas and Louisiana, "October 1977?

   Yes X No ____ If no, explain

2. Has a Federal, state and/or local environmental assessment been conducted previously for the proposed test well or other wells in the area?

   Yes ____ No X If yes, provide a copy, if available.
   Not to knowledge of Gruy Federal, Inc.

3. Have all required permits, licenses, and/or agreements for proposed project been obtained?

   Yes ____ No X If no, explain.
   These are in progress of preparation and will be obtained when well is approved for reentry by Department of Energy and when arrangement with landowner have been finalized.

4. Does the project site fall within the habitate of rare or endangered species?

   Yes ____ No X If yes, explain.

5. Are known archeological sites, historic sites, or natural landmarks within or visible from the site area?

   Yes ____ No X If yes, explain.
   This site is an area of marshland which has been built-up by a earth and shell fill when the existing well bore was drilled in 1970. The general area is near or within an area of approximately 10 x 30 miles, corresponding to the configuration of the Mermentau River and Grand Lake, which 300 (acre) area contains approximately 10 archeological sites (Plate No. 12 of Atlas prepared by Coastal Environments, Inc.). However, there is no evidence of any archeological site at this location since this was originally in the marsh.

6. Will expected continuous noise levels from site operations be 65 dBA or less at the nearest residence?
   Yes X No ____ If no, explain.
   Nearest residence is that of landowner, whose permission to do this work is prequisite to its commencement. This residence is approximately 1/2 mile distant, where the noise level is expected to be less than this amount.

B. SITE CONSTRUCTION

1. Will additional land clearing be required for the test well (e.g., drill pad, road construction, mud reserve pits, pipeline)?
   Yes ____ No X If yes, describe.

2. Will additional land clearing be required for the disposal well (e.g., drill pad, reserve pits, utilities, road construction, pipeline)?
   Yes ____ No X If yes, describe.

3. Will the Site and related roads be treated to minimize dust?
   Yes ____ No X If no, explain.
   Hard packed shell road and boarded work area make this unnecessary.

4. Are portable sanitary facilities or an approved septic system to be used at the site?
   Yes X No ____ If no, explain.

5. Will liquid and solid wastes be disposed in accordance with local regulations?
   Yes X No ____ If no, explain.

6. Will erosion control be required for excavated areas?
   Yes ____ No X If yes, explain.

7. Will dredge spoil be deposited in swamp forest or marshland?
   Yes X No ____ If yes, explain.
   Well is in marsh, but little or no dredge spoil is expected. Spoil, if any, will be applied to ring levy or road levy.

8. Upon completion of proposed test program, will the site be restored to natural a condition as possible by regrading, filling, and reseeding?

   Yes _X_ No ____ If no, explain.

C. WELL TESTING AND SAFETY

1. Is fluid production from the well during testing expected to be 2 weeks or less in duration per formation?

   Yes ____ No _X_ If no, explain.

   Testing period is expected to extend over approximately 4 weeks.

2. Is the total dissolved solids of the produced geopressure fluid expected to be 90,000 mg/1 or less?

   Yes _X_ No ____ if no, explain.

3. Is the volume of geopressure fluid to be produced and injected expected to be 300,000 barrels or less?

   Yes _X_ No ____ If no, explain.

4. Is the temperature of produced geopressured fluid expected to be 260°C or less?

   Yes _X_ No ____ If no, explain.

   Expect aquifer temperature of approximately 155°C, but cooler will reinject water at 190°F.

5. Will the gas content of the produced fluid be flared?

   Yes _X_ No ____ If no, explain.

6. Will blowout preventers rated to at least 10,000 PSI be used?

   Yes _X_ No ____ If no, explain.

7. Will production tubing rated to at least 20,000 PSI, be used?

   Yes ____ No _X_ If no, explain.

   Burst pressure max for 3-1/2 P-105 tubing is 18,000 psi.

8. Can safety valves be operated from remote locations?

   Yes _X_ No ____ If no, explain.

9. Will the test tree be rated to at least 10,000 PSI?
   Yes X No ____ If no, explain.

10. Will a test well directional survey be conducted?
    Yes ____ No X If yes, at what interval? ____ Feet,
    If no, explain.
    Well is already drilled.

11. Will a lined pond be used to hold all liquid effluents and production fluids that are not injected?
    Yes X No ____ If no, explain.

12. Has an injection permit been obtained?
    Yes ____ No X If no, explain.
    This is being applied for in connection with all other applicable permits, which cannot be done until arrangements are completed with landowner.

13. Will H_2S monitors be located onsite?
    Yes ____ No X If no, explain.
    No history of H_2S in this formation or area.

14. Will fire extinguishers be located onsite?
    Yes X No ____ If no, explain.

15. Do contingency plans exist for evacuating personnel should a blowout occur or high levels of H_2S be detected?
    Yes X No ____ If no, explain.

16. Will high-pressure engineering and mud logging personnel be onsite during production well drilling operations?
    Yes ____ No X If no, explain.
    Mud logging personnel wil not be present since this is a reentry and not a drilling operation. However, experienced high pressure drilling and/or engineering personnel will be on site.

Dresser Atlas

BHC Acoustilog

FILE NO.

SERIAL#133987
PERMIT#117921
API# 170232050

COMPANY THE SUPERIOR OIL COMPANY

WELL WATKINS MILLER NO. 1

FIELD SOUTH GRAND CHENIER

COUNTY CAMERON STATE LOUISIANA

LOCATION: BG. @NW/C. SW/4 OF SEC. 5, T-15S, R-5W THENCE S1°19'44" W 1358', THENCE S88°40'16", E1593' TO LOCATION

SEC 5 TWP 15-S RGE 5-W

Other Services: IEL, DIPLOG, CG

Permanent Datum B.H.F. Elev. 1.58'

Log Measured from R.K.B. 23.0 Ft. Above Permanent Datum

Drilling Measured from R.K.B.

Elevations: KB * DF * GL *

Date	8-30-70	12-3-70		
Run No.	ONE	TWO		
Depth—Driller	11315	18220		
Depth—Logger	11323	18223		
Bottom Logged Interval	11321	18217		
Top Logged Interval	8350	14985		
Casing—Driller	13 3/8 @ 3022	7" @ 15010	@	@
Casing—Logger	3022	14985		
Bit Size	12 1/4	6"		
Type Fluid in Hole	LOW PH MUD WATERBASE	LIGNO'SULFONATE 10% WALL COAT		
Density and Viscosity	10.5 / 40	17.6 / 48		
pH and Fluid Loss	8.0 / 9.1 cc	10.5 / 5.6 cc	cc	cc
Source of Sample	FLOWLINE	PIT		
Rm @ Meas. Temp.	1.06 @ 90 °F	.65 @ 78 °F	@ °F	@ °F
Rmf @ Meas. Temp.	0.91 @ 89 °F	.36 @ 78 °F	@ °F	@ °F
Rmc @ Meas. Temp.	1.62 @ 89 °F	1.5 @ 78 °F	@ °F	@ °F
Source of Rmf and Rmc	M / M.	M. / M.		
Rm @ BHT	0.53 @ 180 °F	.16 @ 320 °F	@ °F	@ °F
Time Since Circ.	5 HRS.	16HRS.		
Max. Rec. Temp. Deg. F.	180 °F	320 °F	°F	°F
Equip. No. and Location	6024 / L.C.	1217 / LAF.		
Recorded By	DAVIS	H.L.SMITH		
Witnessed By	MILLER	MILLER		

FOLD HERE

THIS HEADING AND LOG CONFORMS TO API RECOMMENDED STANDARD PRACTICE RP-31

REMARKS NOTES: RUN#1 CALIPER RECORDED 14' DEEP ON REPEAT SECTION
SP ON RUN#2 DRAFTED OFF OF IEL LOG
RUN#2 LOG WAS NOT TIED IN DUE TO HOLE CONDITIONS, THE LOG ON BOTTOM IS 10' HIGH TO IEL, LOSS OF 10' DUE TO LINE SLIPPAGE WHEN PULLING

*INFORMATION NOT AVAILABLE

Changes in Mud Type or Additional Samples

Date / Sample No.		
Depth-Driller		
Type Fluid in Hole		
Dens. / Visc.		
pH / Fluid Loss	cc	cc
Source of Sample		
Rm @ Meas. Temp.	@ °F	@ °F
Rmf @ Meas. Temp.	@ °F	@ °F
Rmc @ Meas. Temp.	@ °F	@ °F
Source Rmf / Rmc		
Rm @ BHT	@ °F	@ °F
Rmf @ BHT	@ °F	@ F
Rmc @ BHT	@ °F	@ °F

Scale Changes

Type Log	Depth	Scale Up Hole	Scale Down Hole

Equipment Data

Run No.	Tool Type	Pad Type	Tool Position	Other
ONE	625	--	W16"C	--
TWO	625	--	FREE	--

Electrolog®

FILE NO.

PERMIT #117921
SERIAL #133987
API #1702320501

COMPANY THE SUPERIOR OIL COMPANY

WELL WATKINS MILLER NO. 1

FIELD SOUTH GRAND CHENIER

COUNTY CAMERON STATE LOUISIANA

GUY FEDERAL, INC.
HOUSTON
LOG LIBRARY

LOCATION BEG. @ NW/C SW/4 OF SEC. 5 T15S, R5W, THENCE S1° 19' 44" W 1357' THENCE S88° 40' 16" E 1593' TO LOG.
SEC 5 TWP 15S RGE 5W

Other Services
ACOUSTILOG
DIPLOG
CG

Elevations:
KB #
DF #
GL #

Permanent Datum B. H. F. Elev. 1.58'
Log Measured from R. K. B. 27.0 Ft. Above Permanent Datum
Drilling Measured from R. K. B.

Date	8/30/70	9/22/70	10/7/70	10/16/70
Run No.	ONE	TWO	THREE	FOUR
Depth—Driller	11315	12240	14115	15000
Depth—Logger	11324	12248	14121	15010
Bottom Logged Interval	11318	12242	14115	15004
Top Logged Interval	3022	11367	12248	13900
Casing—Driller	13 3/8@3022	9 5/8@11364	9 5/8@11364	9 5/8 @11364
Casing—Logger	3022	11367	11367	NOT LOGGED
Bit Size	12 1/4	8 1/2	8 1/2	8 1/2
Type Fluid in Hole	LOW PH MUD	CLS POLYTONE	CLS POLYTONE	CLS POLYTONE
	WATERBASE	3% OIL	3% OIL	2% OIL
Density and Viscosity	10.5 40	16.0 58	17.0 51	17.5 48
pH and Fluid Loss	8.0 19 cc	11.5 4.5 cc	11.5 3.2 cc	11.5 2.8 cc
Source of Sample	FLOWLINE	FLOWLINE	FLOWLINE	FLOWLINE
Rm @ Meas. Temp.	1.06 @90 °F	0.174@ 97 °F	0.93@ 108 °F	0.78@ 68 °F
Rmf @ Meas. Temp.	0.91 @90 °F	0.136@ 80 °F	0.31@ 76 °F	0.28@ 65 °F
Rmc @ Meas. Temp.	1.62 @89 °F	0.210@ 80 °F	1.87@ 76 °F	2.55@ 65 °F
Source of Rmf and Rmc	M M	M M	M M	M M
Rm @ BHT	0.53 @180 °F	0.34@ 215 °F	0.41@ 246 °F	0.21@ 257 °F
Time Since Circ.	5 HOURS	5 HOURS	5 HOURS	5 HOURS
Max. Rec. Temp. Deg. F.	180 °F	215 °F	246 °F	257 °F
Equip. No. and Location	6024 L.C.	6029 L.C.	6029 L.C.	6029 L.C.
Recorded By	DAVIS	HARLTON	DAVIS	WARMKE
Witnessed By	MILLER	STOVER	OERTLIND	OERTLIND

Depth—Logger	16026	16262	17235	17894
Bottom Logged Interval	16020	16255	17229	17889
Top Logged Interval	15010	16020	16255	17229
Casing—Driller	7" @15010	7" @15010	7" @15010	7" @15010
Casing—Logger	15010	15010	NOT LOGGED	-
Bit Size	6"	6"	6"	6"
Type Fluid in Hole	CLS POLYTONE	CLS POLYTONE	CLS POLYTONE	LTGNO SULF
	2.5% OIL	3% O.E.	2% OIL	2% OIL
Density and Viscosity	17.6 55	17.6 50	17.6 50	17.6 55
pH and Fluid Loss	10.5 2.5 cc	11.0 2.8 cc	11.0 2.0 cc	11.0 1.8 cc
Source of Sample	FLOWLINE	CIRCULATED	FLOWLINE	MUD PIT
Rm @ Meas. Temp.	0.83 @74 °F	1.01@ 2.8 °F	1.02@ 88 °F	.8 @88 °F
Rmf @ Meas. Temp.	0.33 @70 °F	0.34@ 76 °F	0.36@ 64 °F	.42 @73 °F
Rmc @ Meas. Temp.	1.92 @70 °F	2.12@ 76 °F	2.19@ 64 °F	1.6 @73 °F
Source of Rmf and Rmc	M M	M M	M M	M M
Rm @ BHT	0.22 @280 °F	0.41@ 285 °F	0.36@ 308 °F	.22 @320 °F
Time Since Circ.	10 HOURS	14 1/2 HRS	9 HOURS	7 HOURS
Max. Rec. Temp. Deg. F.	280 °F	285 °F	308 °F	320 °F
Equip. No. and Location	6023 LAF.	6023 LAF.	6029 L.C.	6005 LAF.
Recorded By	ELKINS	ELKINS	HARLTON	HEARD
Witnessed By	STOVER	STOVER	COMEAUX	COMEAUX

Date	11/30/70	12/3/70		
Run No.	NINE	TEN		
Depth—Driller	18115	18220		
Depth—Logger	18121	18228		
Bottom Logged Interval	18116	18224		
Top Logged Interval	15700	17800		
Casing—Driller	7" @15010	7" @15010	@	@
Casing—Logger	-	NOT LOGGED		
Bit Size	6"	6"		
Type Fluid in Hole	LTGNO SULF	LTGNO SULF		
	2% O.E.	10% WALL COAT		
Density and Viscosity	17.7 64	17.6 48		
pH and Fluid Loss	10.0 2.3 cc	10.5 5.6 cc	cc	cc
Source of Sample	MUD PIT	PIT		
Rm @ Meas. Temp.	.7 @ 84 °F	.65 @ 78 °F	@ °F	@ °F
Rmf @ Meas. Temp.	.4 @ 70 °F	.36 @ 78 °F	@ °F	@ °F
Rmc @ Meas. Temp.	1.4 @ 70 °F	1.5 @ 78 °F	@ °F	@ °F
Source of Rmf and Rmc	M M	M M		
Rm @ BHT	.18 @220 °F	.16 @ 320 °F	@ °F	@ °F
Time Since Circ.	8 HOURS	12.5 HOURS		
Max. Rec. Temp. Deg. F.	320 °F	320 °F	°F	°F
Equip. No. and Location	6005 LAF.	1217 LAF.		
Recorded By	HEARD	SMITH		
Witnessed By	STOVER	MILLER