GRUY FEDERAL, INC.

NVO-1528-4

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

APRIL 13, 1978

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

G

The Gruy Companies

...Since 1950

DISCLAIMER

GRUY FEDERAL, INC.
CONSULTANTS IN ENERGY SYSTEMS

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703/979-2955

April 13, 1978

Mr. Ronald T. Stearns
Engineering & Construction Division
DOE/Nevada Operations Office
Post Office Box 14100
Las Vegas, Nevada 89114

Dear Mr. Stearns:

With this letter we are forwarding the revised recommendation for the initial GEO^2 reentry well. The well, drilled as Superior Watkins-Miller No. 1, (WOO L-2) has been chosen for the first reentry test because of known hole conditions, favorable sand development in the area of interest (which became evidenced after the sonic log became available), and the favorable conditions for access. Whereas arrangements with other landowners appear to be time consuming and expensive, we do not doubt that we can come to favorable terms with Watkins-Miller and his lessee, Continental Oil Company.

Availability of drilling rigs capable of operating at this depth with sufficient hook load capacity continues to be a critical problem. One company has tentatively offered the use of a suitable rig, which is currently drilling in South Central Alabama and will be available to move to Louisiana on or about June 1. The cost of moving the rig will be approximately $80,000, which must be borne by the first well. Since rig availability is a critical item, it is incumbent upon the review committee to act quickly so that a binding agreement with a drilling contractor can be pursued.

The oil and gas rights to the Watkins-Miller acreage are currently under lease to Continental Oil Company. Conoco has assured us that they have no plans for the subject well and will cooperate with the experiment provided Gruy Federal assumes full liability for all land damages incurred during the test and indemnifies Conoco in this respect. No formal approval from Conoco has been received.

Negotiations with the landowner for the right of access to the well have begun. Mr. Miller has expressed a willingness to cooperate but no final agreement on the right-of-way fee has been reached. An offer of $5,000 for ninety (90) days was rejected and a cost estimate of $20,000 is included in the cost of the well.

The increase in total cost from that given in the original estimate is explained as follows:

1. The decision was made to tie the 7-inch OD casing rather than the 9-5/8-inch OD casing back to surface because the burst pressure of the larger pipe is too low if a leak in the tubing should occur.

2 The long string of 7-inch casing necessitates a larger rig with a higher day rate.

3. The full cost of the wellhead (Christmas tree, etc.) must be borne by the initial well and owing to the high temperature, high pressure environment a more expensive tree must be fabricated than the one initially proposed.

4. The cost of the rig move to Cameron Parish must be borne by the first well.

5. The landowners fee exceeded the initial estimate.

6. Perforating costs are higher than the initial estimate.

7. The earlier cost estimate did not include open hole logs and sidewall cores.

Much of this cost is applicable to future test wells and would be applicable to the second test well if a time lapse were to occur between the two operations, which would permit such material to be removed from Well No. 1 after the test period and before it would be necessary to use the material in a second well. Therefore, the timing of the second operation becomes important and we look forward to discussing this with you.

We will attempt to have the christmas tree and perhaps the tubular goods purchased by third parties and rented to us for the purposes of the overall program, but obviously, for the purposes of the cost estimate, it has been necessary to include the full purchase price.

Sincerely,

GRUY FEDERAL, INC.

R. J. Dobson

Richard J. Dobson
Vice President
Special Programs

RJD:paw

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GEOPRESSURED-GEOTHERMAL REENTRY PROSPECT L-2

GRAND CHENIER SOUTH PROSPECT

CAMERON PARISH, LOUISIANA

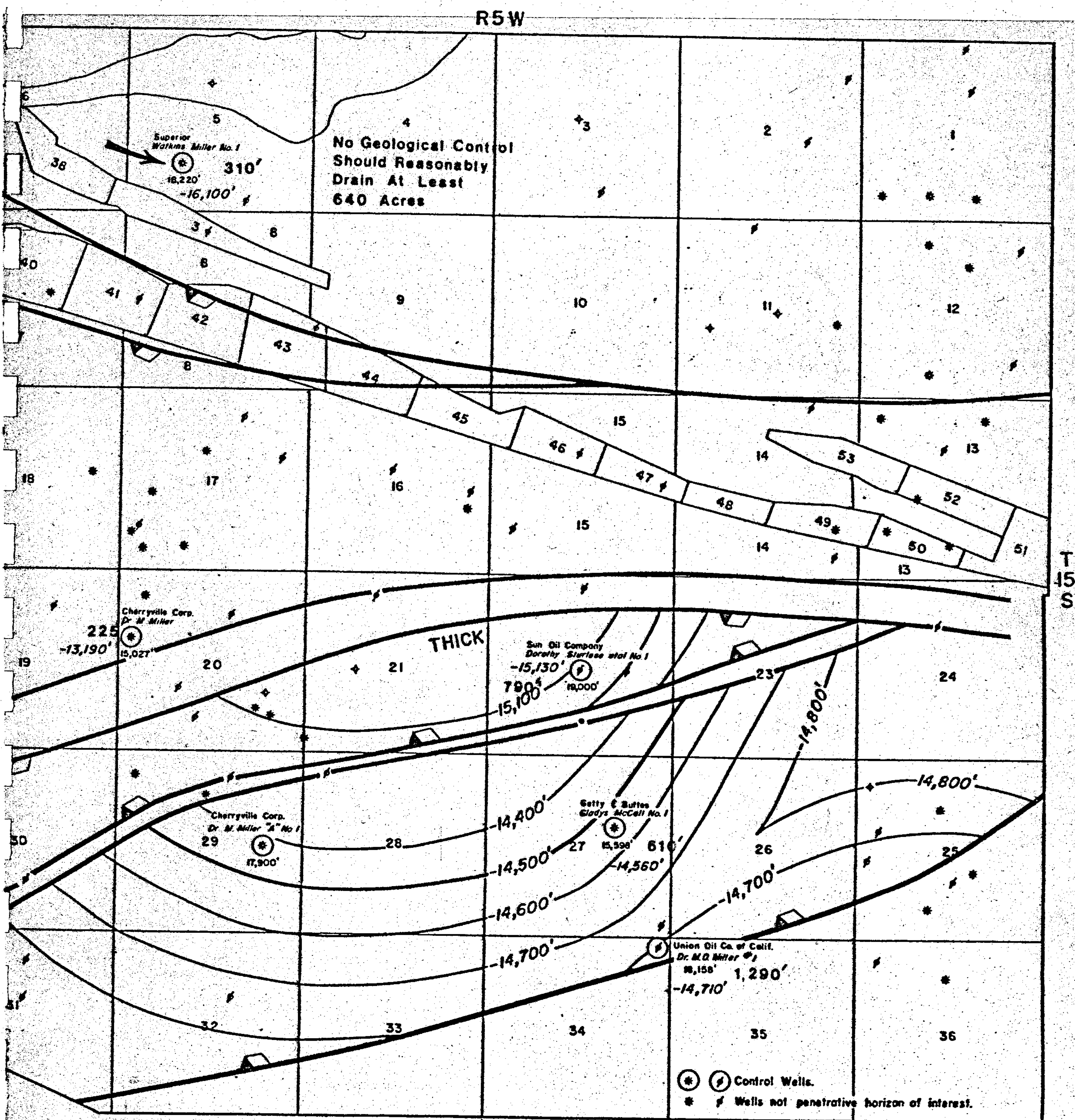
Introduction

This Gruy Federal Type II-B prospect was drilled as the Superior Oil Company No. 1 Watkins-Miller, API designation 17-023-20501 and is 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 Route 82 and a shell road in good condition. Superior Oil completed this well in late 1970 as a dual gas producer in sands between 11,150 and 11,250 feet but eventually abandoned the well in December, 1974. The cellar of the well is still visible on the site. This location is shown on the lower portion of USGS topographic sheet "Grand Lake West" in the map pocket of the Gruy Federal report "Investigation and Evaluation of Geopressured-Geothermal Wells, Prospective Test Wells in the Texas and Louisiana Gulf Coast", February 28, 1978.

Geology

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

A sonic log on the well was obtained from the operator (Superior Oil Company) and sent to H. J. Gruy and Associates in Dallas for analysis. 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



Designates Net Sand
Penetrated at 300° F+

GRUY FEDERAL, INC.
Houston, Texas

Crab Lake Field Area
Cameron Parish, Louisiana

STRUCTURE: TOP OF POROSITY
AT FIRST GEO^2 SAND
IN LOWER MIOCENE SECTION

SUPERIOR WATKINS MILLER NO. 1

upper section from 16,100 to 16,400 feet is higher than it is in the bottom 500 feet. Although selection of the final perforating interval will be deferred until additional logs have been run, it appears that the completed interval will be concentrated near the top of the sand.

Mechanical Condition

The enclosed diagrammatic sketch illustrates both the current mechanical condition of the well and the proposed configuration for testing. 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 7-inch liner at 11,300 feet. In 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 and the experience of prudent operators who have successfully penetrated and produced from geopressured-geothermal gas reservoirs in this area.

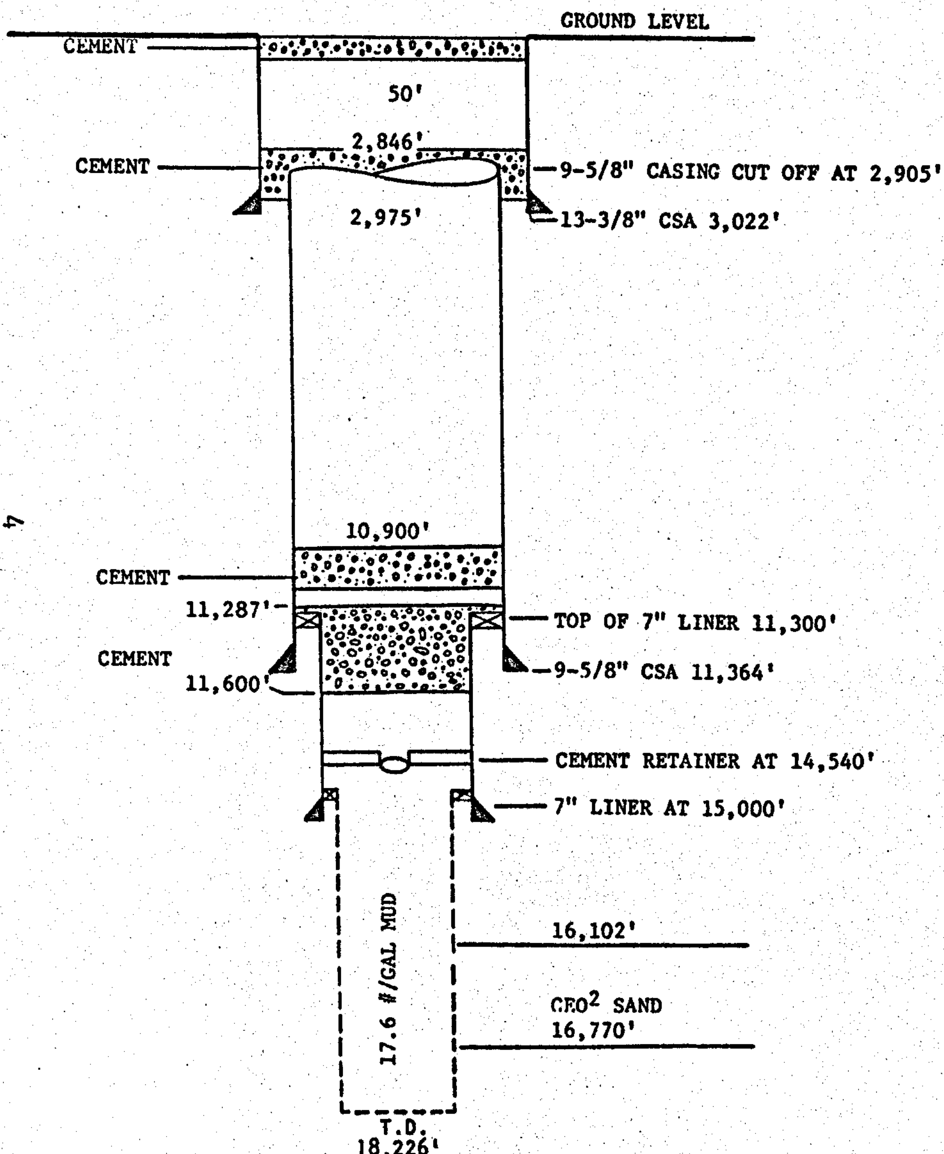
Casing Design: The 7-inch tie back string was designed using the following design factors:

Burst = 1.10
Collapse = 1.13
Joint strength = 1.60
Yield = 1.50

The burst pressure under operating conditions was computed by assuming that the casing would be exposed internally to the static aquifer pressure with no fluid outside the casing. Similarly the collapse pressure under operating conditions was calculated assuming that the pipe was exposed externally to the column of 17.6 pound per gallon mud with the casing empty.

CURRENT STATUS

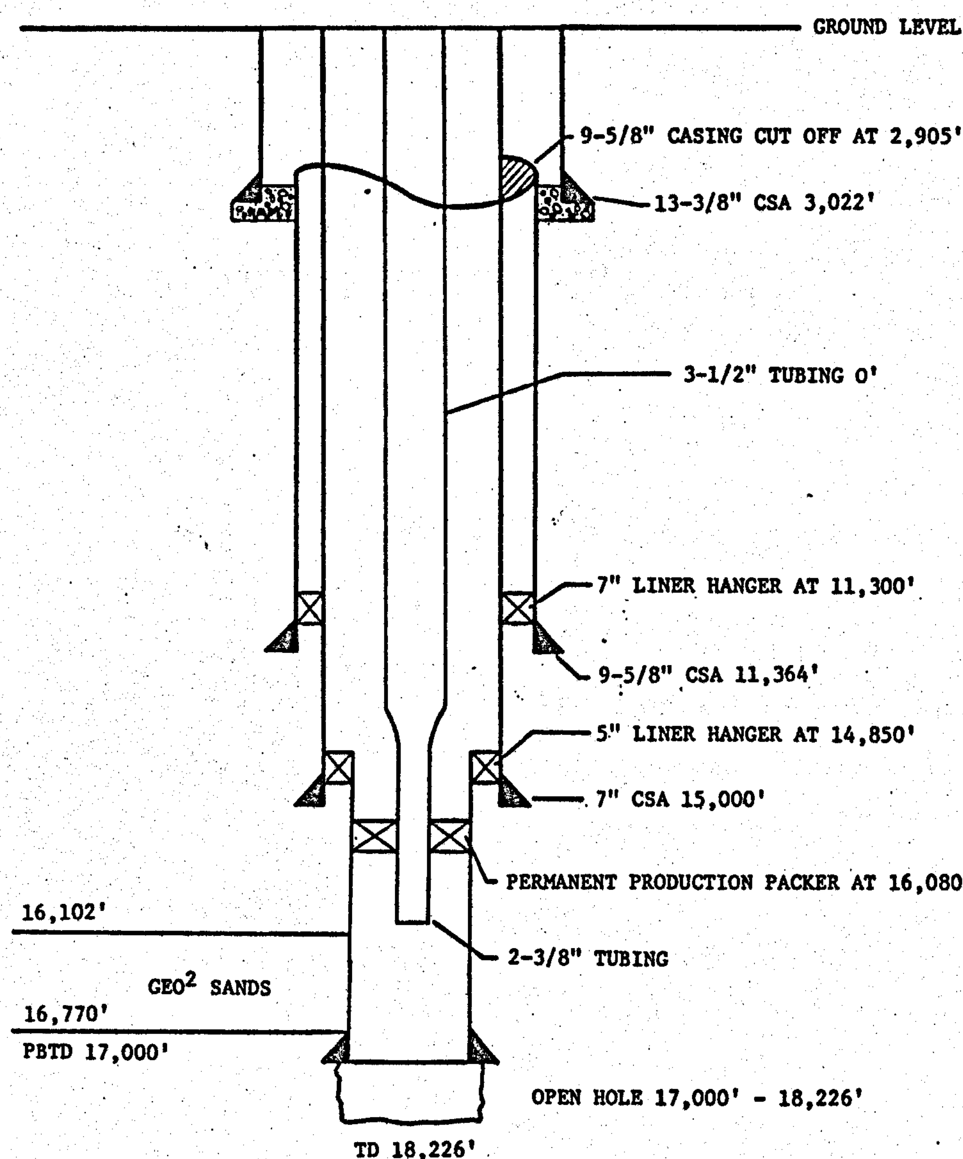
SUPERIOR OIL COMPANY
WATKINS MILLER NO.1
SOUTH GRAND CHENIER



PROPOSED COMPLETION

SUPERIOR OIL COMPANY
WATKINS MILLER NO. 1
SOUTH GRAND CHENIER

Datum = 24.58' ASL



The loss in collapse resistance as a function of tensile loading was incorporated into the casing design.*

<u>Tubing Design:</u> The tubing selected was a tapered string consisting of 2-3/8 inch, 4.70 pound per foot to run inside the 5-inch OD casing liner and 3-1/2 inch, 12.70 pound per foot, P-105, PH6 Hydril threaded tubing. In this design, Gruy Federal has adopted the philosophy consistent with industry practice to run only those size pipes and tools which can be washed over if a fishing operation is required. 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 operations. A landing nipple and a circulating valve will be placed above the seals to permit communication between the tubing and casing if it becomes necessary.

<u>Blowout Preventers:</u> The enclosed well prognosis sets out the necessary safeguard specifications and procedures for surface blowout prevention as they have been adopted and gathered by IADC, API and most prudent operators in the Geo^2 area. A diagrammatic sketch of the BOP hook-up and choke manifold which we propose for use is also enclosed.

<u>Logging:</u> The reentry prognosis recommends that the following open hole logs be run:

* Standard API threads were selected rather than Hydril threads for the following reasons:

1. They satisfied all the design constraints.
2. The 7-inch casing will not be exposed to the aquifer pressure except in the case of a tubing leak.
3. Hydril threads will add $80,000 to the cost of the well.
4. The double make-up required for running Hydril will add to the rig time.
5. The higher joint loss owing to thread damage that will occur during the recovery of the Hydril pipe.
6. Hydril pipe is not available immediately.

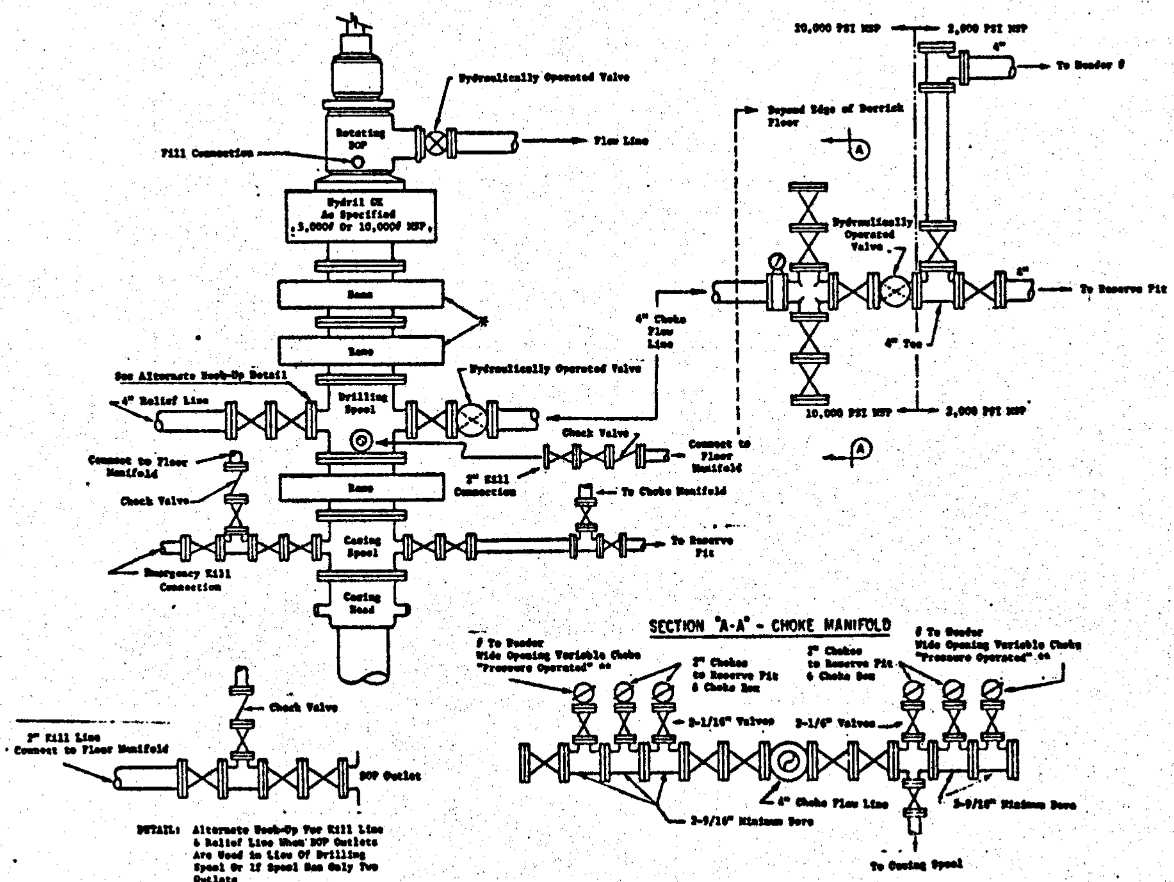
(1) Induction electric log
(2) Compensated neutron and compensated density logs
(3) Caliper
(4) Sonic

Although an induction electric log and a sonic log have been run previously on the well, an alignment error as much as 10 feet was experienced. These logs should be rerun in order to evaluate any invasion which has occurred since the well was completed initially and to provide an accurate depth correlation with the sidewall samples. The cased hole logs; namely, the gamma ray, cement bond, and collar locator, are desirable to establish the integrity of the cement and as a benchmark for perforating.

Perforating: The perforating will be accomplished with a 1-11/16 inch high-temperature, through tubing jet perforating gun with four shots per foot and zero phasing. When fired this jet creates a casing entry diameter of approximately 1/4-inch and an effective core penetration of approximately two inches beyond the cement sheath. Assuming 100 percent firing efficiency, this configuration should provide a productivity equal to 70 percent of the open hole productivity.

In selecting the fraction of the net sand to perforate, the perforated interval length was designed to achieve a productivity equal to 1/3 of the open hole productivity. In the Watkins-Miller No. 1 well, this productivity can be accomplished by perforating approximately 92 feet. The final interval will be contingent upon the analysis of the additional open hole logs that will be run.

Wellhead Design: The wellhead has been designed and a detailed sketch will follow in one of the additional submittals. The tree is rated to a working pressure of 15,000 psi and all valves have stainless steel vertical runs with packing and seals for high temperature fluids. The tree consists of two 3-1/2 inch master gate valves and a 3-1/2 inch swab valve. Between the master gate valve and the swab valve is a double wing assembly to house the choke bodies. One wing will contain a positive choke



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.

and the other will contain an adjustable choke. Each wing will consist of a Hi-Lo safety valve and a conventional wing valve. This specific design limits the anticipated high pressures to the tree assembly, thus permitting lighter weight pipe for all surface pipes and fittings.

General Comments

Watkins-Miller has been chosen as the first Geo^2 test for the following reasons:

(1) It appears that a timely and reasonable arrangement can be made with the landowner and Conoco has indicated a willingness to cooperate.

(2) Access problems will be minimal.

(3) The most modern logging tools can be run in the open hole interval of interest. Sidewall sampling is possible.

(4) The available porosity logs indicate that geopressured section should be capable of producing salt water in sufficient quantities.

REENTRY PROGNOSIS
FOR
SUPERIOR OIL COMPANY
No. 1 Watkins Miller
South Grand Chenier Area

1. Prepare location.

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

3. Move in and rig up.

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 grade "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'.

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'.

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

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

From	To	Size	Weight Ft.	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'

From	To	Size	Weight Ft.	Grade	Type Ends	Section Length
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.

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 replacement.

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.

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 inch) 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.

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.

14. Make trip with bit and condition hole to 16,850'.

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.

16. Make trip, run tapered work string and condition hole to float collar on 5" OD liner at ± 16,920'.

17. Run work string and test tool and test top of liner. Squeeze liner top, if necessary.

18. Run Gamma Ray - Cement bond log from TD to 11,300'.

19. If bond log indicates it necessary, block squeeze above and below probable completion zones. Condition hole to PBTD.

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. $CaCl_2$ water. Test for leaks for 1 hour. If OK pull out of hole and remove the 700' of 2-3/8" OD work string.

21. Rig up wire line unit and set production packer at 16,080'.

22. Make up bottom hole completion equipment as shown on enclosed diagramatic 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 xmas tree.

24. Release drilling rig, rig down and move out same.

25. Perforate (through tubing) a minimum of 92 ft. of sand in the interval from 16,102' to 16,770' as set out in step 26, 27 and 28 below. The final selection of the completion interval is to be made after review of the electric logs to be obtained on the well.

26. Rig up wire line company high pressure lubricator on well and test same to 10,000 psi for 30 minutes.

27. Run through tubing perforating gun with collar locator and perforate lowest 46 ft. of completion interval to be selected with 4 holes per foot after final review of all available logs on the well. Observe increased surface pressure (after perforating) for leak off or 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 feet - 4 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 3 preventors. 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. Accumlator reservoir pressure shall be sufficient to close all preventers simultaneously in 20 seconds with the charging pumps closed down. Minimum accumulator pressure shall be 1500 psi initially and not less than 1200 psi when all preventers are closed.

2. When nippling up production casing, test BOP's and choke manifold to 7500 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.

ESTIMATED REENTRY COST
FOR
SUPERIOR OIL COMPANY
No. 1 Watkins Miller

ACTIVITY:	ESTIMATED AMOUNT:	
1. Lease aquisition and legal fees	$ 22,000	
2. Rig transportation cost	80,000	
3. Location preparation	30,000	
4. Rig time - 26 days	124,800	
5. Bits	3,000	
6. Mud and chemicals	30,000	
7. Casinghead	2,000	
8. Xmas tree	150,000	(1)
9. Casing patch	6,000	
10. Rental tools and equipment	12,000	
11. 3-1/2" drill pipe rental	20,000	
12. Trucking	7,000	
13. Electric logs and sidewall cores	37,000	
14. Liner setting	4,500	
15. Cement and services	7,000	
16. Cement bond log	5,000	
17. Perforating	39,000	
18. 1300' of 2-3/8" P-105 4.7# PH-6 Hydril tubing	15,300	(2)
19. 15,000' of 3-1/2" P-105 12.95# PH-6 Hydril tubing	307,500	(4)
20. Packer	3,500	
21. 11,400' of 7" tieback casing per prognosis	165,100	(3)
22. 2200' of 5" P-110 18# SFJ casing	26,700	

GRUY FEDERAL, INC.

ACTIVITY:	ESTIMATED AMOUNT:
23. Supervision	$ 7,500
24. Miscellaneous	6,000
25. Contingencies	45,000
TOTAL	$ 1,155,900

(1). Requires minor shopping to reuse on other Geo^2 wells.

(2). 90% can be reused on other Geo^2 wells.

(3). Approximately 80% can be reused on other Geo^2 wells.

(4). Will incorporate all available tubing in stock at Intracoastal City, Louisiana and effectively reduce cost requirements.

SALT WATER DISPOSAL WELL
FOR
NO. 1 WATKINS MILLER

The available electrical logs covering the shallow sands from ground surface through a depth of 5,000 feet indicate the fresh water sands to extend to approximately 900 feet and that adequate sand to accomodate salt water disposal occur above 2,500 feet. In view of these data the following well prognosis and estimated cost is submitted.

1. Drive 13-3/8" OD casing to refusal of ± 125 feet.
2. Move in and rig up water well rig.
3. Drill 12-1/8" hole to 1,200 feet.
4. Run 1,200 feet of 9-5/8" 36.0# H-40 casing with guide shoe 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 2,500 feet.
6. Run induction electric and density logs.
7. Run 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. Make trip with 2-7/8" workstring and condition hole to float collar at approximately 2,420 feet and displace mud in hole with water.
9. Run gamma ray - cement bond log from total depth to 1,200 feet and block squeeze with cement, if necessary to obtain good bond.
10. Nipple up 5-1/2" casing and install christmas tree.
11. Test casing and tree to 2,000 psi surface pressure with water in hole.
12. Rig up wireline unit and run gamma ray-collar log from bottom to 1,200 feet.
13. 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.
14. 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.

15. Rig down and move out water well rig.

Estimated Cost

1.	Move in rig, drill to 2,500 feet and set two casing strings.	$ 30,000
	130 feet of 13-3/8" 65# J-55 plain end casing	3,600
	1,200 feet of 9-5/8" 36# H-40 casing ST & C or LT & C	18,200
	2,500 feet of 5-1/2" 15.5# J-55 ST & C or LT & C	17,200
	Stand by rig time	3,000
	Cement and Services	14,000
	Electric logging	8,000
	Perforating	4,000
	Wellhead equipment	3,000
	Stimulation	2,500
	Supervision	2,000
	Miscellaneous supplies and rentals	5,000
	Trucking	1,500
	Contingencies	10,000
	TOTAL WELL COST	$ 122,000

TEST PROGNOSIS
FOR
No. 1 Watkins Miller
South Grand Chenier Area

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

2. Run two Amerada RPG-3 pressure gauges with 24 hour clocks and 15,000 psi full-scale deflection to 16,060 feet, stopping for fifteen minutes each 3,000 feet. Hang bombs for two 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 thirty minutes by deadweight tester.

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

6. Gradually increase the flow rate in increments until either the maximum flow rate from the well 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 not sufficient, do one of the following:

   (1) Acidize
   (2) Perforate more interval

7. Shut well in and measure surface pressure build-up with deadweight tester.

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

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

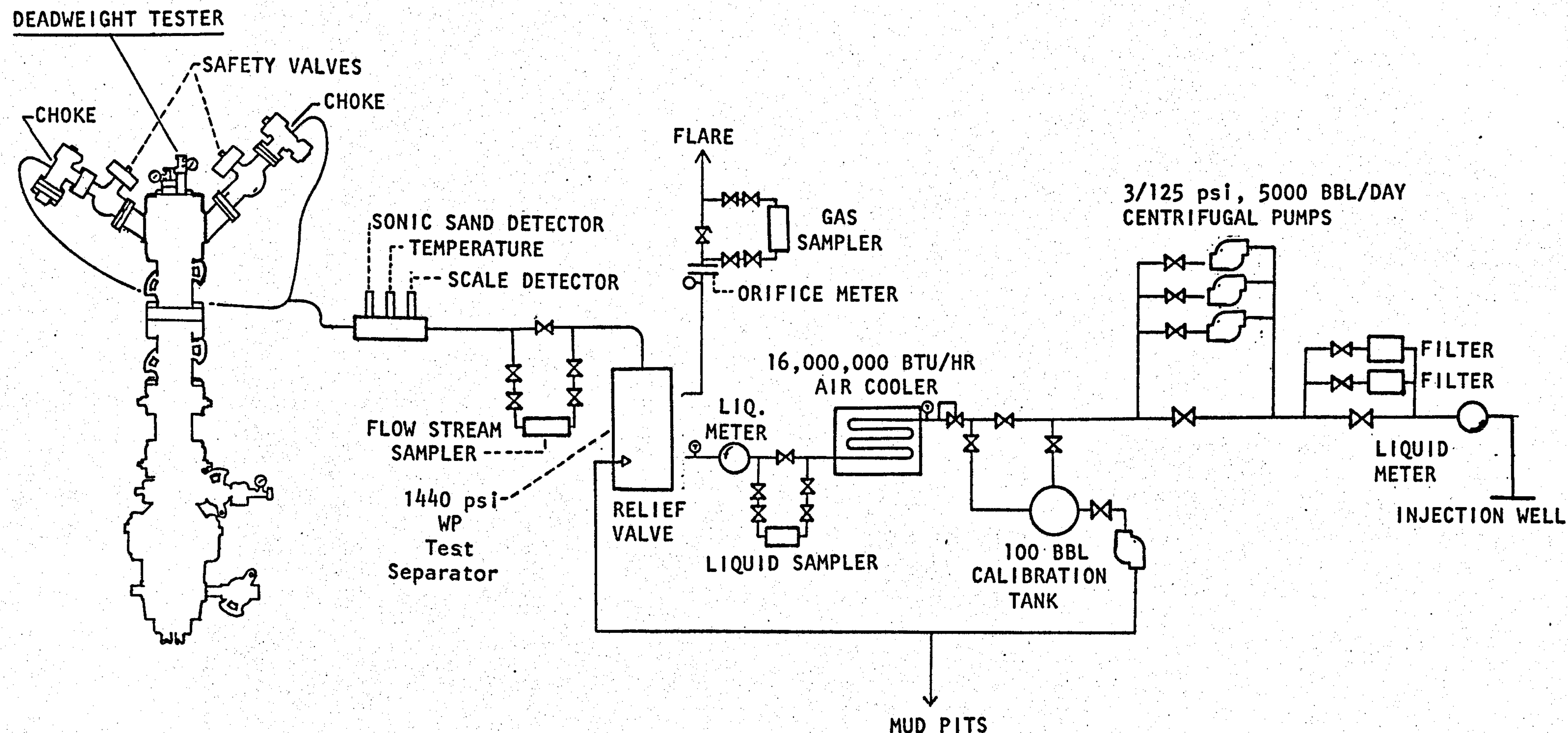
   (a) Two, one liter, full well stream samples for chemical analysis.
   (b) Three, one liter, separator liquid samples.
   (c) Two, one liter, separator gas samples.

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

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

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

13. Shut well in, measure build-up for 24 hours, then retrieve pressure bombs.
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 two weeks while measuring surface pressure, temperature and flow rates.
16. Sample as before prior to shutting well in.
17. Shut well in and run two pressure gauges to 16,060 feet and record until deadweight tester at surface indicates static conditions have been reached.
18. Pull pressure gauges, release test equipment and move same out.
19. Proceed with plug and abandonment operations.



SURFACE TESTING FACILITIES

Gruy Federal, Inc.

GRUY FEDERAL, INC.

ESTIMATED TESTING COST
FOR
SUPERIOR OIL COMPANY
No. 1 Watkins Miller

ACTIVITY	ESTIMATED AMOUNT
Two phase separator	$ 16,800
Air cooler	12,600
3 centrifugal pumps	4,200
110 bbl. calibration tank	60
Sand detector and manifold	3,900
200' of 3" flow lines	2,850
2 3" expansion loops w/unions	900
2 pen 10,000 psi recorder	600
Deadweight pressure gauge	600
Portable quartz iodide lights	600
Temperature recorder 0-400^{o}	600
Trailer house for personnel	900
Supervision and labor	39,600
Sampling	1,500
Pressure gauges and wireline units	10,000
TOTAL	$ 95,710

PLUGGING AND ABANDONMENT PROCEDURE
FOR
Superior Oil Company
No. 1 Watkins Miller
South Grand Chenier Area

1. Move in and rig up pulling unit capable of plugging and abandonment.
2. Nipple up pump trucks to well head.
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. Pull and lay down tubing.
8. Run free point indicator and cut off 7" OD casing with chemical cutter above indicated free point.
9. Pull and lay down 7" casing.
10. Pick up tubing and run in hole.
11. Set cement plug 100' in and 100' out of 7" OD casing.
12. Pull tubing and set a plug from 50' to surface.
13. Cut off 13-3/8" casing 3' below ground level and weld on plate.
14. Release rig.
15. Send tubing and casing to pipeyard for inspection and repair.
16. Senc christmas tree to shop for overahul.

ESTIMATED PLUGGING COSTS
FOR
Superior Oil Company
No. 1 Watkins Miller
South Grand Chenier Area

Activity	Amount
Pulling unit at $1,000/day	$ 10,000
Rental tools at $500/day	5,000
Trucking	3,000
Cement and Services	4,000
Supervision	2,000
Contingencies	2,400
TOTAL	$ 26,400

GRUY FEDERAL, INC.

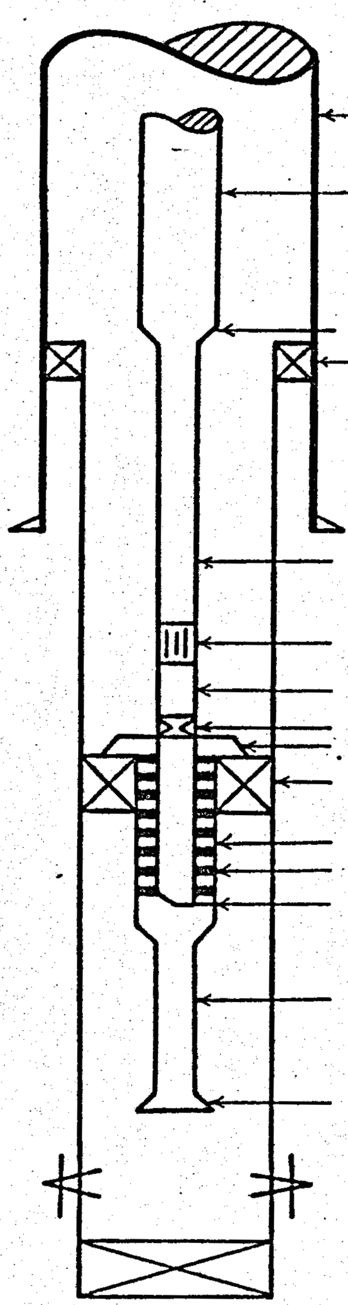
WATKINS-MILLER NO. 1

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

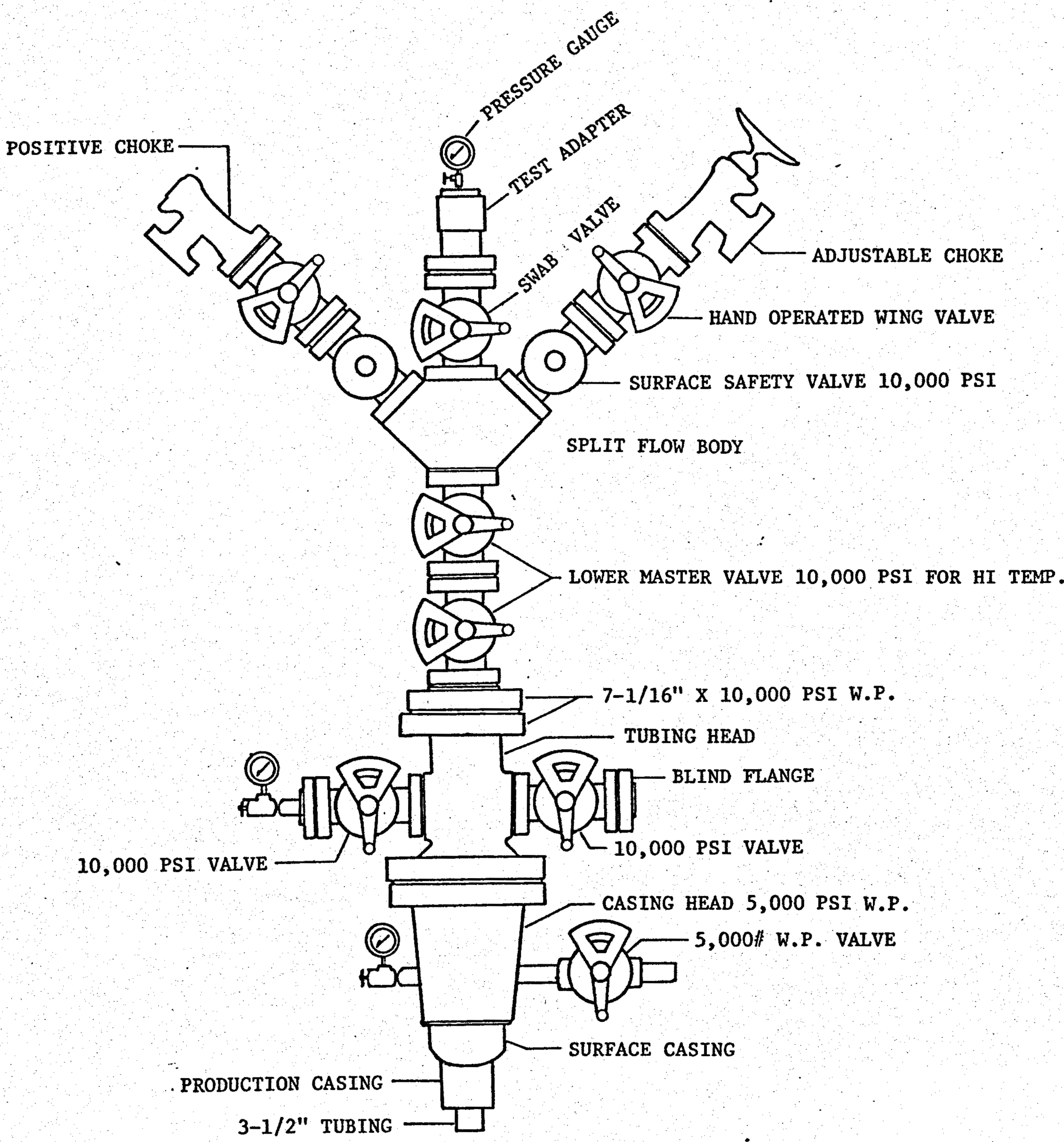
In the future, all reports will be complete prior to leaving Gruy Federal's office.

SUPERIOR OIL COMPANY
WATKINS-MILLER NO. 1
SOUTH GRAND CHENIER AREA
CAMERON PARISH, LOUISIANA

BOTTOM HOLE TUBING ASSEMBLY



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 ± 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. <u>SITE CONSTRUCTION</u>

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/l 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.