INTERNAL TECHNICAL REPORT

Title: MANAGEMENT PLAN FOR FLUID SUPPLY AND INJECTION SYSTEM FOR THE RAFT RIVER 5 MW(e) PILOT POWER PLANT

Organization: GEOTHERMAL ELECTRIC PROGRAM

Author: ____________________________

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From: Dale J Claflin [Dale.Claflin@inl.gov]
Sent: Thursday, December 07, 2006 8:43 AM
To: Simmons, Patty
Cc: Claflin, Dale; Flynn, Vesta; Ponce, Linda
Subject: Re: EG&G Idaho Geothermal Reports
Attachments: EG&G Patent Docs.doc

Patty,

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Dale,

OSTI has been working on a project for the last year or so to collect geothermal documents. At the STIP meeting in April, I sent out a plea to the DOE labs to identify and send to OSTI any geothermal documents that we did not already have in our database. I have a problem with a group of reports from EG&G Idaho. I am not sure you are the person correct person to ask for help on this issue. If not, maybe you can direct me to the responsible individual.

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Please let me know if you can help me out with this problem, or advise if I should communicate with someone else.

12/7/2006
else - and who.

Thanks ahead for your help,
Patty

Patty Simmons
U.S. DOE Office of Scientific and Technical Information
simmons.p@osti.gov
865-576-1290
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MANAGEMENT PLAN FOR
FLUID SUPPLY AND INJECTION SYSTEM
FOR THE RAFT RIVER
5 MW(e) PILOT POWER PLANT

GEOTHERMAL ELECTRIC PROGRAM
EG&G IDAHO, INC.

January 9, 1978
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I. INTRODUCTION

This report details a plan for developing a fluid supply system for the First 5 MW(e) Pilot Power Plant at Raft River. The pilot plant has been specifically designed to use the medium-temperature geothermal water so common throughout the West. EG&G Idaho, Inc., the Department of Energy, Raft River Rural Electric Co-op, the United States Geological Survey (USGS), and the State of Idaho have worked together to develop a facility that will use an organic liquid as the working fluid.

Four wells have been drilled in the Raft River Valley, about ten miles South of Malta, in southern Idaho (see Figures 1 and 2). The completed well system will consist of seven wells: two conventional injection wells, three production wells, and a standby reserve well of each type. The additional three wells are to be drilled in FY-1978, in order to complete a coordinated test program before the First Pilot Power Plant is ready for operation. The system has been designed to meet the test-loop pilot plant's basic requirement: a 2450 gpm supply of geothermal fluid, at a nominal temperature of 290°F and with salinity of less than 5000 ppm.

Injection of cooled geothermal fluid into the Raft River reservoir will also require a network of monitor wells. The Idaho Department of Water Resources (IDWR), USGS, EG&G Idaho, and the Department of Energy will jointly select sites for two 1500-foot and five 500-foot monitoring wells.

This plan considers the work required to complete construction of the fluid supply system and obtain a preliminary check of its performance capability; the plan will discuss project management, costs, schedules, drilling, testing, environmental monitoring, and safety.
Figure 1 Raft River Valley with Drill Site Locations
II. RELATED DOCUMENTATION

This plan is part of a series of documents controlling the management and technical details of the Geothermal program at the Idaho National Engineering Laboratory. Long-range plans for the program are defined in both the INEL Institutional Plan (Final Draft November 10, 1977) and the INEL Long-Range Plan (January 31, 1977). These documents, which project program plans for a six-year period, are updated annually. Financial and technical highlights are summarized in the plans.

Technical details for each year are defined in Laboratory Program Authorization Documents (LPADs), which are written annually. This management plan is required by the LPAD titled "Facility Projects," dated November 1977. Interface requirements between the fluid supply system and the 5 MW(e) Pilot Power Plant are defined in Revision One of "System Specification and Description for the Raft River Thermal Loop Facility," and sub-tier documents which have evolved from this specification.

Management controls and procedures will be defined in two additional documents to be produced in FY 78. The "Raft River Test Loop Program Management Plan" will be written by DOE-ID. It will define management approaches for constructing, testing, and operating the Pilot Power Plant, and describe its relationship to the fluid supply and injection system. The second document, "Energy Technology Program Management Plan," will be prepared by EG&G Idaho. It will define management procedures to be used between EG&G Idaho and DOE-ID concerning the 5 MW(e) Pilot Plant and other energy projects. Other sub-tier documents that form an integral part of the fluid supply system management plan will be defined in sections of this plan.
III. REQUIREMENTS AND GUIDELINES

Specifications

The fluid supply and injection system for the First 5 MW(e) Pilot Power Plant should satisfy the following requirements:

1. Design temperature of the water provided to the power plant = 290°F
2. Minimum pressure of the supply = 140 psig at the power plant inlet, with 120 psig discharge.
3. Design facility flow rate = \(1.04 \times 10^6\) lbm/hr (2250 gpm at 290°F). (In addition, approximately 200 gpm will be required for plant regulation and 400 gpm for experiments related to advanced system components. The 400 gpm would be on an interruptible basis.)
4. Chemistry of water:
   a) Solids content less than 5000 ppm.
   b) Gas content a nominal 52 ppm by weight (41.3 mL STP/L), including CO₂, N, inert gases, and hydrocarbons.
5. Transients: The power plant must capable of accepting partial or complete fluid-supply shutdown caused by lightning or by failure of pump, power, or pipeline. Requirements for handling minor flow variations caused by the bypass line will be finalized after completion of simulated control studies.
6. Cooling tower makeup water will be extracted from the cooled plant geothermal fluid at a rate of 450 gpm. Present power-plant design calls for the 125 gpm blowdown to be injected with the cooled geothermal fluid.

The total injection requirement for the power plant is thus 2125 gpm (at 150°F and 120 psig). The untreated blowdown will be highly oxygenated and will carry a high content of dissolved solids; it will not be suitable for injection into wells. As of this time, a treatment has not been determined which will allow the blowdown to meet state and proposed federal injection standards and to prevent deterioration of the well casing.

7. Seven wells will be drilled. Four wells will be for production and three for injection, with one of each on standby.

More detailed specifications are contained in "System Specification and Description for the Raft River Thermal Loop Facility, Revision 1," an unpublished document submitted to ERDA-ID.

Guidelines for Well Field Development

The following basic guidelines have been agreed upon in principle by DOE and EG&G:
Any additional wells needed for the First 5 MW(e) Pilot Power Plant will be drilled on BLM land.

At least one full reserve well for production and one reserve well for injection will be on standby for the beginning of plant operation (summer or fall, 1979).

Well pumping rates will be established for plant operation, which will cover a period of at least five years.

Adequate monitoring of the near surface (above 1000 feet) aquifer shall be conducted to assure that the domestic and agricultural water supplies will not be adversely affected by the injection of used geothermal water. The criteria defining adverse effects shall be those established by the State of Idaho, Department of Water Resources.
IV. MANAGEMENT

Geothermal Electric, a new division of EG&G Idaho, Inc., is responsible for the design, construction, and testing of the fluid supply and injection system for the First Pilot Power Plant. Reservoir engineering and environmental monitoring support for the fluid supply system are the responsibilities of the Earth and Biological Sciences Branch of the EG&G Idaho Advanced Programs Division. A chart showing the relation of these divisions to EG&G management is provided in Figure 3. The Raft River facility, which is the responsibility of the Geothermal Electric Division, has in the past been operated as a hands-on facility for experimenters in the geothermal field. This approach has led to many innovative experiments that have made significant contributions to geothermal development. With the decision to build the 5 MW(e) Pilot Power Plant at Raft River, there is a need to establish formal management controls; this is also a requirement for the new EG&G organization.

The diverse Raft River experiments must be carefully integrated with the operation of the 5 MW(e) Pilot Power Plant. Operation of this plant will have top priority at Raft River, and all other experiments will be conducted on a non-interference basis. Procedures will be established to ensure that experiment schedules are compatible with the plant's requirements.

Procedures are being established for scheduling Raft River activities, reporting progress, identifying problem areas, analyzing costs, and--of considerable importance--defining change controls. Because a public power group will operate the power plant, and EG&G will operate the fluid supply and disposal system, tight control of interface requirements is mandatory. EG&G has considerable experience in developing these procedures and has demonstrated them by successfully bringing the LOFT program under control. Variations of the LOFT procedures will be used in managing the Geothermal Program. These will be defined in the Energy Technology Program Management Plan discussed in Section II.
Figure 3: EG&G Geothermal Organization
V. PROGRAM PLAN

A. Summary

Requirements for the fluid supply and injection system for the 5 MW(e) facility (see Section III) call for four production wells and three injection wells. Four of these wells currently exist and three must be drilled. DOE-ID has directed placement of the three additional wells, based on results of reservoir assessment tests and extensive use of consultants. The state of the art for geothermal reservoir engineering is such that there is considerable uncertainty associated with this decision; the Department of Energy would like an early demonstration to prove that the required volume of fluid can be successfully moved from the production wells to the injection wells.

To meet this objective, the schedules in this plan call for drilling the three additional wells as rapidly as normal engineering practices will permit. Plumbing necessary to begin the demonstration testing will also be rapidly installed. Details of the plans for accomplishing these objectives are discussed in Sections VI-A and VI-B.

Because of the considerable uncertainty concerning the proper placement of the three additional wells, a parallel reservoir assessment and environmental monitoring effort is planned to obtain early information on the performance of the fluid supply and injection system. Plans for these efforts are summarized in Section VI-C and VI-D.

The planning in this document terminates with a February 1979 test to demonstrate the ability of the system to flow 2450 gpm for a one-week period. Though this test will qualify the mechanical design of the system, it is anticipated additional testing will be required for reservoir qualification.
B. Schedule

Figure 4, a Management Summary Schedule, identifies the major activities that are required to complete the fluid supply and injection system. Each activity is discussed in Section VI, "Detailed Technical Plans." The chart schedules the drilling of one production and two injection wells, the drilling of monitor wells, pump tests, reservoir assessment, and construction of the control system and connecting pipelines and equipment. Relationships and constraints between activities are noted. This schedule is based on our best estimates, judging from experience. There is no management reserve in the schedule. The schedule also assumes a fixed drilling plan, with no options for alternate locations or drilling depths.

As the drilling progresses and the reservoir assessment tests provide data, it may be desirable or necessary to modify drilling plans for the wells. These decision-points for well drilling are discussed in detail in Section VI-A. If an optional drilling plan is selected, it will delay the entire schedule and increase costs. Also, many of the task relationships are critical; a delay in one task could affect a delay in the overall schedule. This is because the well-drilling contractor will probably drill the wells faster than the necessary piping and well-performance tests can be completed.

The critical path for completing the integrated reservoir development is shown as the dark line on Figure 4. The construction of pipelines and testing of the wells are the principal tasks which prevent test-completion at an earlier date. The design of the pipeline from well No. 3 to the Power Plant site could be started earlier (node 230), but this is an 8380-foot line estimated to cost $180,000. Before committing the construction contract, therefore, it was decided to wait for injection-test results on well No. 6, to be certain that this area would be acceptable for injection. If the design were started earlier, the critical path would shift to well drilling, logging, and testing, and about three weeks could be saved. It was not felt that the $180,000-risk was worth the three-week savings, and the decision was made to delay letting the construction contract until the completion of well No. 6 injection testing. Expediting the pipeline contracting or system operational testing, the other principle schedule constraints, is not considered feasible within current budget limits.

Table I lists the contracts requiring DOE approval. The dates on which DOE will receive the contracts and dates on which the contract must be approved are indicated for each contract. Delays in contract approval could delay the overall schedule.

C. Costs

Table II shows a summary of the costs associated with each major task. Breakdowns of these costs are provided in the sections which follow.
Figure 4
Management Summary Schedule

(See Inside Back Cover)
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**FY-77 RCE Costs**

| Process Control System | I-255 | 90 K |

*Funds not yet authorized by DOE.*
VI. DETAILED TECHNICAL PLANS

A. Well Drilling

This section describes the drilling program plan which will complete the required wells for an integrated production and injection system prior to power plant completion.

Three production and one injection well have previously been drilled and connected with pipelines. As stated in Section V-A, the "Program Plan Summary," DOE has directed and funded EG&G to drill the three additional wells as rapidly as possible. Figure 5 shows the path along which the drilling must proceed to comply with this requirement. Rig shortages and high move-in costs require that once the rig starts drilling it must keep working. Delays between wells would incur sizable standby charges (approximately $3K/day), and releasing the rig would create additional moving costs and necessitate finding another rig when needed.

There is always the chance, however, that one or more wells could be "dry holes." Major changes in the program would be necessary should one or more be encountered. Of the four existing wells, three have been successful and one marginally successful. Considerable thought has been given to such well failures as injection refusal around No. 3 area and a dry production hole at No. 5. Areas like that northeast of No. 2 should produce good shallow or deep injection wells with about the same total length of pipeline. Also, several production-well locations on public and private land have been picked as alternatives to the No. 5 site. Pipeline and well locations have been chosen considering various well configurations, including the future well needs for a second pilot power plant. Also, input from simultaneous reservoir assessment (Section VI-C) and environmental monitoring (Section VI-D) could require changes in the drilling plan as drilling proceeds. Figure 5 shows the basic drilling plan, as taken from Figure 4, and illustrates alternate paths.

A contractor will begin drilling RRGI-6 on approximately March 1, 1978, work on RRGP-5 will begin about April 21, with RRGI-7 following about July 1. This schedule is based on drilling RRGI-6 to 3500 feet with one leg, RRGP-5 to 5500 feet with three legs, and RRGI-7 to 3500 feet with one leg.
By the time No. 6 is completed (node 108, Figures 4 and 5), engineers will be able to examine initial injection and flow-test data from No. 6, injection test data from No. 4, and data from environmental monitoring wells. If no negative indicators exist, the rig will be immediately moved to RRGP-5 site and drilling initiated. Should any data be negative, EG&G will advise DOE-ID of optional methods and make a recommendation. Table III-a is a summary of plausible options, including relevant data and constraints. EG&G will wait up to one week for DOE-ID approval and then proceed.

A second key decision is concerned with the location-move from well No. 5 (node 116). Should additional data from continued injection into No. 4 be negative, alternatives to returning to No. 6 or moving on to No. 7 must be determined. The same decision pattern will apply as at the completion of well No. 6. A summary of possible options is shown in Table III-b.

A similar procedure will be used at the completion of No. 7 (node 126). The decision would be based on additional analysis of the pump and injection performances of wells No. 4, 5, 6, and 7 (see Table III-c). At this time, any proposed additional drilling would be cheaper because the rig would be on site. Nodes 130 and 132 on Figure 5 illustrate alternate drilling paths, and Tables III-d and III-e show the information relevant to the decisions. Figure 4 does not show nodes 130 and 132 because they are options which require rescheduling and additional funding. If any options are elected other than simple well completion, additional time and funding would be required.

All basic material procurement for the drilling has been completed. Due to unforeseen circumstances, however, some items will probably have to be obtained during drilling. An effort has been made to provide for procurement on an emergency basis. The drilling engineer will consider further requirements and make necessary procurement as drilling proceeds.

Because all well sites are on BLM land, and the BLM has not yet authorized the withdrawal of 5,000 acres for geothermal development, BLM must approve the Raft River activities. All requests are transmitted by DOE-ID legal. The approvals require two to three weeks and are needed prior to site preparation (nodes 102 and 122).

The environmental group is writing the environmental assessments for each proposed production and injection well and associated transfer pipelines. These assessments will be reviewed by Geothermal Electric Program management and DOE-ID. BLM approval of proposed land-use is contingent upon their review of the assessment. The pipelines, on the other hand, will cross both private and BLM land. The DOE legal staff will obtain the necessary easements before pipeline construction begins.
Table III

AVAILABLE INFORMATION AT WELL DRILLING DECISION POINTS
(see Figure 5)

a) Node 108: This decision point has two plausible paths: 1) drill two additional legs; or 2) delay the decision to drill any further legs until a later date, at which time the drill rig would be remobilized over the well. Data, constraints, and facts which will be available for decision are as follows:

1. Initial No. 4 test injection pressures.
2. Initial No. 4 test flows.
3. Increased 1500-ft aquifer pressure in both wells.
5. Water-chemistry change in shallow aquifer.
6. Injection pressure and flows during No. 6 test at end of drilling.
7. Funding constraints.
8. The lifetime of a triple-leg well is three times that of a single-leg well.
9. The injection pressure is halved with three legs.
10. Ease of deepening No. 6 with single leg.

b) Node 116: This decision point has only one possible path: the location of well No. 7. The decision will be made after the drilling and initial testing in well No. 6 and the drilling of No. 5. Data and facts which will help in determining the location for well No. 7 are as follows:

1. Extensive medium-depth flow testing in RRGI-3.
2. Extensive medium-depth air-lifting test in RRGI-3.
3. Initial No. 6 test, injection pressures and flows at end of drilling.
5. Increased 900-ft aquifer water level in the USGS-2 hole.
6. Water-chemistry change in monitor holes.
7. Change in the Crank well flow and chemistry.
8. Increased 1500-ft aquifer pressure in both wells.
c) Node 126: This decision point is similar to Node 108, but has three paths: 1) drill the additional two legs; 2) terminate drilling with only one leg; and 3) drill the well deeper into the production zone. If No. 7 is drilled deeper, then No. 6 will be drilled deeper for the same reasons. Data, constraints and facts which will influence this decision are as follows:

1. Injection pressures during No. 4 test.
2. Injection flows during No. 4 test.
3. Increased 1500-ft aquifer pressure in both wells.
5. Water-chemistry change in the shallow aquifer.
6. Pressure and flows during No. 6 full scale injection test.
7. Injection pressures and flows during No. 7 at end of drilling.
8. Funding constraints.
9. The lifetime of a triple-leg well is three times that of a single-leg well.
10. The injection pressure is halved with three legs.

11. The injection pressure is halved with three legs.

d) Node 130 (see Figure 5): This decision point has two paths: 1) drill two additional legs; or 2) complete well with one leg. The decision will likely be forced onto the first path because of the tighter formations at greater depths. If additional legs are drilled in No. 7, then they will be drilled in No. 6 for the same reasons. Data, constraints and facts which will influence this decision are:

1. Pressure and flow characteristics of RRGE-3.
2. Short injection tests in RRGE-3.
3. Injection pressures and flows into first leg of No. 7 at end of drilling.
4. Funding constraints.
5. The lifetime of a triple-leg well is three times that of a single-leg well.
6. The injection pressure is halved with three legs.
e) Node 132 (see Figure 5): This decision—to 1) leave No. 4 as is and use the well as a permanent injection well, or 2) deepen with three legs as a production well—is a critical point; several years are required to be certain that injection directly over the resource would not be detrimental. Since time is not available to prove the injection principle, this decision will most likely be forced along the second path, regardless of the available injection data. Data which would influence this decision will be gained from No. 4 injection tests, as well as from additional testing:

1. Increased 1500-ft aquifer pressures.
2. Water-level rise in shallow aquifer.
3. Changes in water chemistry of any monitor well.
4. Pressure changes in RRGE-1.
5. Flow, temperature, or water-chemistry changes in the Crank or BLM wells.
6. A marginal production from No. 5.
7. Any other negative effect on the shallow aquifer.
8. Funding constraints.
As with previous drilling and construction work, the Davis-Bacon committee will determine whether any proposed work amounting to more than $2,000 is experiment or construction. All construction work will be let out for bid, in accordance with the committee decision. Site preparation will involve negotiation of the contract and construction of the location, roads, cellar, and conductor. Design parameters have been established on the basis of previous construction experience as well as required needs.

Electricity and water must be supplied to the well site prior to drilling. The Raft River Electric Cooperative will provide power to the locations. EG&G will provide drilling water from either existing on-site wells or nearby irrigation wells. All necessary pipelines will be maintained by EG&G.

A meeting was held with Eastman Whipstock, Rocky Mountain District Manager and Casper Area Manager, to plan the directional drilling program for the wells. Discussions have also been held with Bill Maurer of Maurer Engineering and John Rowley of LASL on the use of the newly developed, high-temperature turbodrill for directional drilling. Field testing of the tool coincides with the scheduled directional drilling of RRGP-5, so that we may be able to use it for directional drilling. Eastman will be contracted as a backup for the turbodrill work and for any work required before the turbodrill is available. Maurer will provide special engineers for the turbodrill. This arrangement has two advantages: it will provide a comparison between conventional tools and techniques and the newly developed drill, and it will encourage direct industry involvement with geothermal research. Eastman will be able to evaluate a tool specifically developed for geothermal development, and they could eventually utilize it in the same manner as the Dynadrill.

To ensure successful award of the cementing contract, the field operations manager and the drilling engineer will carefully review the cementing techniques proposed by the bidders. We will meet with cement company personnel to plan procedures, with emphasis on prevention and correction of problem areas by February 1, 1978.

One contract will cover the drilling of all production and injection wells. Hopefully, the industry-wide scarcity of rigs will not cause any delay. Bid specifications have been written in a format familiar to the contractors, and time constraints for rig move-in will allow him as much flexibility as possible. The allowed move-in period is from February 1 to March 1, with the drilling of RRGI-6 scheduled to begin no later than March 1 (see Node 106, Figure 4). The Geothermal Electric Program office will attempt to make personal contact with the potential bidders to answer questions concerning the contract and to stimulate bid response, before bids are due on January 15, 1978. The bid specifications (see Appendix B) have been reviewed
by people outside of the company that are experienced in drilling: John Auten of Reynolds Engineering and Electric, and Lee Mueller of Energy Drilling Specialists. DOE-ID must approve the contract before it can be issued. Approval must be obtained by January 23 to ensure adequate bid response. Contractors will not bid if there is a three to four week approval period, as they would have to tie up their equipment while awaiting bid award.

The drilling supervisor will be a contract position to EG&G. This supervisor will serve on a continuous basis and act as a liaison between the contractor and other EG&G Geothermal personnel. Since the drilling supervisor is the key to a successful drilling operation, the EG&G field operations manager, drilling engineer, and mechanical systems manager will make a thorough investigation of the individual before contract negotiations begin. The job description requires expertise in directional drilling and, if possible, geothermal applications. The contracted drilling supervisor will report to the EG&G field operations manager or drilling engineer. All major contracts and procured items require DOE-ID approval (Table I, Section V-B). Normally at least three weeks is required for DOE-ID approval; however, in order to maintain the schedule, a much shorter approval time is now needed.

Testing will be conducted on both production and injection wells as they are drilled. To acquire a lithology log for the wells, Rocky Mountain Engineering will gather and analyze drill cuttings. INEL personnel will run geophysical logs (temperature, caliper, gamma, self-potential, resistivity, and sonic) in order to determine casing setting depths and near-surface aquifer characteristics for cementing operations. Commercial geophysical logs will also be run as determined by the Reservoir Engineering Program. That companion program will also be responsible for obtaining two or three cores from each well, using the Joides Tricone coring system. Rock properties will be cross-referenced to the lithology and geophysical logs.

Brief flow tests will be conducted to determine water temperature and quality at selected depths. The condition of the wells (taking or producing water) will be monitored continually during trips in and out of the hole with the drill string. The flow tests will be conducted using eight-inch flow line, valves, orifice plates, and other existing equipment.

At the completion of drilling, before the rig is removed, each well will be air-lift pumped to clean out and develop the well. A shut-in period and a step-flow test will follow the pumping. The injection wells will
have an additional test run to measure the injection characteristics over the full range of the mud pumps, using reserve pit water. This information from each well will assist management in making the decisions outlined in Figure 5, especially Node 116, concerning the location of well No. 7.

As the project stands now, drilling funded by I-475 includes:

<table>
<thead>
<tr>
<th>Well</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>RRGP-5</td>
<td>$722.0 K</td>
</tr>
<tr>
<td>RRGI-6</td>
<td>449.5 K</td>
</tr>
<tr>
<td>RRGI-7</td>
<td>449.5 K</td>
</tr>
</tbody>
</table>

$1,621.0 K

In addition, two 1500-foot monitor wells are funded for a total of $159 K, and $60 K has been provided for drilling labor.

Other obligations for this fund are accounted for in Section VI, "Support Systems." The total I-475 budget is $2,550 K.
B. Support Systems

This section describes the support system required for the Fluid Supply and Injection System, and discusses plans for the procurement and installation of its components. The system consists of wellhead equipment, pumps, pipelines, instrumentation, controls, and power supply. The parts must work together to supply geothermal brine to the Power Plant and return the cooled brine to the injection wells.

The system must supply 2450 gpm for the Power Plant and 400 gpm interruptible for experiments. The 290°F water will come from three wells (with one production well on standby), and must be disposed of into two injection wells (with one injection well on standby). A remote control system will provide monitoring and control over the entire supply and injection system. Also, each production well will require a reserve pit and bypass line to allow for well bypass during heatup and cooldown. In addition, a bypass system and reserve pit will be needed at the power plant itself to allow for bypass and temperature control.

1. Pipelines

Pipelines now connect wells No. 1, 2, and 3 with well No. 4, on which injection testing will begin in March 1978. The piping network that will ultimately connect the Power Plant to the wells will consist of approximately 5-1/4 miles of buried asbestos-cement pipe. About two miles of the required piping are already installed, as shown in Figure 6.

Though the primary function of the system is to supply water to the Power Plant and return the water to the injection wells, the systems must first provide a flow path for well production and injection testing. Construction will proceed according to the sequence dictated by well-test requirements. The following description is arranged in accordance with that planned schedule, which appears in series 200 and 400 of the Management Summary Schedule, Figure 4. Test results may require later adjustments in the sequence, however.

a. Pipeline - No. 3 to No. 6

Approximately 3200 ft of buried 10-inch asbestos-cement pipe will connect wells No. 3 and No. 6. EG&G or a subcontractor will begin design by February 1, 1978. Allowing six weeks for design and four weeks to select a construction subcontractor, construction would begin the second week in April and conclude June 15, 1978.

The necessary asbestos-cement pipe is on hand. Other government-furnished equipment will include long-lead items that would delay construction if they were furnished by a subcontractor. As soon as the design identifies these items, they will be ordered; the same procedure will be followed with each pipeline.
b. Pipeline - No. 5 to Line

Approximately 2200 ft of buried asbestos-cement pipe will connect well No. 5 to the Power Plant and to the existing pipeline from well No. 1 to well No. 4. From well No. 5 to the Power Plant tie-in, the 10-inch pipe will be used. From there to the junction with the No. 1-to-No. 4 line, the pipe will be 12-inch. All piping will be insulated with one inch of urethane foam.

EG&G or a subcontractor will design the pipeline. Design will be completed by April 1, 1978. Allowing four weeks to select a construction subcontractor and five weeks for construction, the line would be completed by July 15, 1978. All of the required 10-inch asbestos-cement pipe is on hand. The 12-inch asbestos-cement pipe and other long-lead items will be ordered as soon as they are identified by the design.

c. Pipeline - No. 3 to No. 7

If the testing of well No. 6 indicates that well No. 7 should be drilled at its planned location, another 2600 ft of buried 10-inch asbestos-cement pipe will be required to connect No. 7 to the line at well No. 3. Design by EG&G or a subcontractor should be completed by June 21, 1978, and construction completed by the first week in August. The necessary asbestos-cement pipe is on hand.

d. Pipeline - No. 3 to Thermal Loop Site

If wells No. 6 and No. 7 are used for injection, additional piping will be required from the junction at well No. 3 to the Pilot Plant Site. This line would consist of approximately 3900 ft of 14-inch pipe, running east from the Pilot Plant Site to the existing line between wells No. 1 and 3. The new line would then connect with the existing line, and a second 10-inch line would run parallel with the existing line to site No. 3, a distance of approximately 5000 feet. All piping would be buried. The approximate route is shown in Figure 6. Most of the east-west run would cross private property, while the north-south run to site No. 3 would use existing right-of-way on BLM land.

Design by EG&G or a subcontractor should be completed by June 15, 1978. Allowing four weeks to select a construction subcontractor and seven weeks for construction, the job would be completed by September 1, 1978. The necessary 10-inch asbestos-cement pipe is on hand. The 14-inch pipe and other long-lead items would be government-furnished.

e. Thermal Loop Interface

Since the piping system will be completed before the Power Plant is constructed, a temporary junction will be required for test purposes.
A section of linking pipe containing valves will be used to simulate pressure drop and flow demand. The test connection will be above-ground, carbon-steel pipe, located so as not to interfere with Thermal Loop construction. When it is installed, the permanent piping will consist of a cross-over line and pressure-control valve between the main pipelines and the valves on the injection line. The injection-line valves will divert water to the power plant holding pond. Bypass Loop Piping will be completed by December 1978.

f. Testing

As each section of piping is completed, the components will be hydro-tested; cement-asbestos pipe at 200 psi, steel piping at 700 psi. Each production and injection well will also be individually tested for both remote and wellhead operation.

The system will be step-tested by starting one production and one injection well and adding single wells until all wells are operational and the flow, pressure, and temperature requirements of the thermal loop are fulfilled.

A detailed test procedure for this S.O. testing will be completed before November 1979 (node 238).

2. Production Pumps

The new production well will be pump-tested with a temporary pump as soon after drilling and clean-out as possible. When pump tests are completed, permanent pumps of correct size will be ordered and installed.

Two REDA pumps are now being tested, and a Peerless lineshaft pump has been ordered. REDA pump No. 1 is rated at 1400 gpm at a total head of 580 feet, and is driven by tandem 160 HP 2300V motors. It was tested on well No. 1 for thirty days and was returned to the vendor for inspection and repair when the lower motor developed a leaky seal. It has now been returned to Raft River and will be used for production and pump tests on RRGP-5.

REDA pump No. 2 is now undergoing reliability tests on RRGE-3. After five months of testing, the pump will be returned to the vendor for disassembly and inspection. An evaluation of its condition will help to predict the lifetime of other pumps. The REDA-2 will pump 750 gpm at a total head of 850 feet, and is also driven by tandem 160HP 2300V motors.

A Peerless lineshaft pump has been ordered for testing on RRGE-2. All hardware is scheduled to be shipped on February 14, 1978, and pump testing will begin in March 1978. This testing will provide a performance comparison between lineshaft and submersible pumps. Certain factors already favor purchase of the REDA models, however.

<table>
<thead>
<tr>
<th></th>
<th>REDA Submersible</th>
<th>Peerless Lineshaft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Cost of Pump</td>
<td>$48,000</td>
<td>$92,000</td>
</tr>
<tr>
<td>Delivery of Complete Pump</td>
<td>4 weeks</td>
<td>22 weeks</td>
</tr>
<tr>
<td>Parts Availability</td>
<td>Shelf Item</td>
<td>8 to 10 weeks</td>
</tr>
</tbody>
</table>
3. Injection Pumps

Injection pumps and piping are being installed between the end of the asbestos-cement pipeline and the wellhead at RRGI-4. Dual filters are also being installed to prevent particulates of a diameter larger than 20 microns from entering the well. Injection tests which will determine the feasibility of intermediate-depth injection will begin in March 1975. A range of injection flow rates (outlined in Section VI-C) and wellhead pressures will be used for this test, and results will indicate whether other pumps already at Raft River can be used for test injection into wells RRGI-6 and 7. After each injection test an appropriate pump will be ordered and installed.

4. Wellhead Equipment

The wellhead equipment, usually called the Christmas Tree, consists of a series of flanges, valves, and spools used during both drilling and production. They are high-strength components which can handle the pressures and vibration from drilling and pumping. Except for the pump-landing spools, all wells are similarly equipped - as shown in Figures 7 and 8.

All equipment shown in Figure 7 is on location at Raft River or has been ordered and will be delivered by April 1978. Wells 1, 2, and 3 are complete, and equipment for well No. 4 is on location and ready for installation during January 1978. Equipment for wells No. 5 and 6 is on location at Raft River; equipment for well No. 7 is on order, to be delivered April 1, 1978.

5. Instrumentation, Controls, Power, and Costs

Preliminary design of the instrumentation and control system is complete. The power plant modeling group is modeling this system for compatible operation with the power plant; their task should be completed by April 21. The EG&G Electrical Design Group should complete the design of electrical control and instrumentation circuitry input to the microprocessor by April 15.

The EG&G Radio and Alarm Group is completing specifications for the microprocessor system, which will collect and record data from the wells and pipelines. The system will also control supply, and will take corrective action in case of an emergency such as pipeline failure or power outages. Construction will be completed by November 15.

Power Requirements for the system have been estimated by EG&G and FSEC personnel. Nameplate horsepower ratings have been used for the power plant. Actual power usage should be less. Figure 9 is a breakdown of power needs at the Raft River site through the year 1981. It shows the power needed by the plant and well system separate from the needs for experiments and testing programs.
12-IN., 3000# HYDRIL SPHERICAL SHAFFER

12-IN., 3000# SHAFFER BOP DOUBLE RAMS

12-IN. x 8-IN. FLOW SPOOL

CELLAR HEIGHT

12-IN. WKM VALVE (MASTER VALVE)

20-IN. x 12-IN. EXPANSION SPOOL

20-IN., 2000# CASING HEAD

3-IN., 2000# FLANGED OUTLETS- 4 PLACES (BRADEN HEAD)

FIG. 7 P.O.P. STAGE, DRILLING OUT 13-3/8-INCH CASING
Fig. 8 Christmas Tree Assembly
NOTE: It is estimated that between 250 and 500KW of power need to be uninterruptable to run heaters, fire pump and critical instruments and controls.

- **SPARE INJECTION WELL** 220KW TOTAL (Possibly for Testing Needs)
- **SPARE PRODUCTION WELL** 220KW TOTAL (Possibly for Increased Testing Needs)
- **MISCELLANEOUS & UNKNOWN LOADS** 300 KW (Possibly for Increased SPARE PRODUCTION WELL 220KW TOTAL)
- **INJECTION WELL NO. 1 200KW TOTAL**
- **INJECTION WELL NO. 2 200KW TOTAL**
- **MAINTENANCE SHOPS 175KW TOTAL**
- **60KW UNIT 120KW TOTAL**
- **EXP & TESTING 220KW TOTAL**
- **5MW UNIT OPERATING PHASE 1800 KW**
- **PRODUCTION WELL NO. 1 220 KW TOTAL**
- **PRODUCTION WELL NO. 2 220 KW TOTAL**
- **PRODUCTION WELL NO. 3 220 KW TOTAL**

Fig. 9
Rough estimate of power demand of Raft River Geothermal Site thru the year 1981 Est. Nov.22, 1977
Funding for the support systems will come from both I-475 and I-255:

<table>
<thead>
<tr>
<th>Instrumentation and Control System</th>
<th>I-475</th>
<th>I-255</th>
<th>RCE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pumps</td>
<td>130 K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wellhead</td>
<td>48 K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wellhouses</td>
<td>11 K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Injection System</td>
<td>113 K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Plugs, Pump Set, Misc.</td>
<td>91 K</td>
<td>25 K</td>
<td></td>
</tr>
<tr>
<td>Pipeline 5, 6, 7</td>
<td>284 K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pipeline 1-4, 1-TL</td>
<td>51 K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Labor</td>
<td>42 K</td>
<td>57 K</td>
<td></td>
</tr>
<tr>
<td>Power Costs</td>
<td>38 K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Supply Field and Interface Modelling</td>
<td>15 K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well Pumps and Pipeline Test Programs</td>
<td>43 K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pipeline Tie Line</td>
<td>770 K</td>
<td>52 K</td>
<td>90K</td>
</tr>
</tbody>
</table>
C. Reservoir Assessment Test Plan

This section outlines the reservoir assessment test plan, which will provide industry and the Department of Energy with a case study for geothermal reservoir assessment and utilization. The plan will give management the information necessary to make valid decisions regarding the drilling program (see Figure 5). For example, lithological and geophysical logging will be used primarily to determine where to set the casing and how deep to drill the wells. This plan contains the elements necessary to:

1. Evaluate the injection characteristics of RRGI-4, RRGI-6, and RRGI-7.
2. Evaluate the disposition of RRGI-4 (retain as injection well or deepen for a production well).
3. Evaluate the siting of RRGI-7 and recommend an injection-zone depth (intermediate or deep).
4. Evaluate reservoir boundaries and recharge effects by accurate triangulation and drawdown measurements.
5. Evaluate the reservoir response under short-term (one to three week), integrated, production and injection conditions (to support the 5 MW(e) pilot power plant).
6. Continue to monitor reservoir performance once power plant operation commences.

Reservoir testing and assessment have indicated that with a pump set above the Baker plug, expected 10-year flow-rates from the present three wells will be:

<table>
<thead>
<tr>
<th>Pump Inlet Depth (ft)</th>
<th>Flow Rate (gpm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RRGE-1 790</td>
<td>1000</td>
</tr>
<tr>
<td>RRGE-2 1190</td>
<td>830</td>
</tr>
<tr>
<td>RRGE-3 1115</td>
<td>400</td>
</tr>
</tbody>
</table>

Flow rates only slightly higher can be maintained for a five-year period. Ninety psi must be maintained at the pump inlet to prevent off-gassing (loss of CO₂) and pump cavitation.

These flow rates are approximate and are based on certain assumptions: 1) there are no nearby boundaries, and 2) there is no blockage or adverse perturbation of the well-bore formation, either from chemical or mechanical (sloughing) effects. If the produced water is injected and finds a direct conduit to a production well, some temperature degradation might occur. Should the wells experience a temperature reduction later in the program, an additional production well will be required.

All tests to date have been conducted with a single well flowing, so as to evaluate the responses of the individual well and reservoir. Similar single-well drawdown and interference tests will be conducted on each new well when drilling is completed (see nodes 412, 426, 446, and 452 on Figure 4).
A computer model has confirmed the reservoir pressure response observed in the testing. The model indicates that injection will have a beneficial effect on the reservoir pressure response (perhaps as much as 100 feet of head) if the injection zone has good pressure communication with the production zone. This model will be updated with the test data to be gathered from the new wells.

During the drilling of each well, engineers and geologists will examine data concerning rock properties and aquifer characteristics, and will study short flow tests, water chemistry, and geophysical logs to determine casing-setting depths, core intervals, probable production zones, and final hole depths (see nodes 420, 433, and 444 on Figure 4).

After completion of each well, geophysical logs and flow and injection tests will be conducted to study well-pressure responses, water chemistry, reservoir boundaries, geological structure control, fluid movement, well performance, and total reservoir response (see nodes 412, 422, and 435 on Figure 4). The results of these tests, when combined with the reservoir parameter analysis, should satisfy objectives one, two, three and four. For the third objective, a full-scale injection test on well No. 6 cannot be started before site No. 7 preparation has begun. This means that the location of No. 7 will be determined without the test data from RRGI-6 injection tests.

Test data will be available, however, before it is necessary to commit funds for constructing the pipeline to well No. 7. An interim report on well No. 6 injection performance will be prepared (node 429) before committing the $180,000 for constructing the pipeline (see critical path discussion, Section V).

After initial testing, production and injection testing will be conducted individually and concurrently. The tests will determine the reservoir parameters and study the effects of injection upon the medium depth reservoir, the upper aquifers, and the deep production zone. Monitor wells and static production and injection wells will be used to measure the pressure responses (see nodes 430, 436, and 460 in Figure 4). The above tests and the integrated tests indicated in node 464 will complete the preliminary well-testing program and accomplish the fifth objective. A summary of the flow tests which will be complete at the end of the preliminary well-test program is shown in Table IV. Additional flow tests will be planned prior to power plant operation in order to continue the reservoir evaluation.

After completion of the test program, the long-range reservoir monitoring program will begin. It will continue throughout the life of the pilot power plant. Water samples will be gathered for chemical analyses. There samples will be used to track, compare, and interpret the chemical environment of the reservoir. Isotope analysis of D/H and 018/016, plus tritium will
### TABLE IV
**SUMMARY OF RESERVOIR TESTS TO BE CONDUCTED AT RAFT RIVER**

<table>
<thead>
<tr>
<th>Well</th>
<th>Nodes (Fig. 4)</th>
<th>Type</th>
<th>Rate (gpm)</th>
<th>Duration</th>
<th>Use</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>RRGI-4*</td>
<td>Flow</td>
<td>109,137,190</td>
<td>6 days</td>
<td>Drawdown/Interference</td>
</tr>
<tr>
<td>2.</td>
<td>RRGE-3*</td>
<td>Flow</td>
<td>600</td>
<td>24 days</td>
<td>Drawdown/Interference</td>
</tr>
<tr>
<td>3.</td>
<td>RRGE-3*</td>
<td>Flow</td>
<td>600</td>
<td>24 days</td>
<td>Drawdown/Interference</td>
</tr>
<tr>
<td>4.</td>
<td>RRGE-4</td>
<td>Inject.</td>
<td>600,1200</td>
<td>5 days (each rate)</td>
<td>Buildup/Interference</td>
</tr>
<tr>
<td>5.</td>
<td>RRGI-6</td>
<td>Flow</td>
<td>200,350</td>
<td>2 days (each rate)</td>
<td>Drawdown/Interference</td>
</tr>
<tr>
<td>6.</td>
<td>RRGI-6</td>
<td>Inject.</td>
<td>600,1200</td>
<td>5 days (each rate)</td>
<td>Buildup/Interference</td>
</tr>
<tr>
<td>7.</td>
<td>RRGE-5</td>
<td>Flow</td>
<td>200,350</td>
<td>2 days (each rate)</td>
<td>Drawdown/Interference</td>
</tr>
<tr>
<td>8.</td>
<td>RRGE-5</td>
<td>Flow</td>
<td>800</td>
<td>10 days</td>
<td>Drawdown/Interference</td>
</tr>
<tr>
<td>9.</td>
<td>RRGI-7</td>
<td>Flow</td>
<td>200,350</td>
<td>2 days (each test)</td>
<td>Drawdown/Interference</td>
</tr>
<tr>
<td>10.</td>
<td>RRGI-7</td>
<td>Inject.</td>
<td>600,1200</td>
<td>5 days (each test)</td>
<td>Buildup/Interference</td>
</tr>
<tr>
<td>11.</td>
<td>Multiple</td>
<td>Flow/ Inject.</td>
<td>2450,2450</td>
<td>7 days</td>
<td>Demonstration</td>
</tr>
</tbody>
</table>

**NOTE 1:** Several flow tests have already been conducted at RRGE-1, RRGE-2, and RRGE-3.

**NOTE 2:** Additional long-term (one to three month) testing and monitoring is needed during power plant construction in order to refine the field boundaries and potential productivity.

**NOTE 3:** Tests include gathering of recovery data.

*Measurement made prior to January 9, 1978.*
be completed after well flow is fully developed. Water sampling and isotope analysis will be conducted and reported annually. Changes in production-well drawdown, monitor and static-well pressures, and chemical and dissolved-gas compositions will be monitored and reported monthly.

All new data gathered during the reservoir assessment and long-term monitoring efforts will be reduced, analyzed, and integrated into the existing reservoir model. The model will be updated and strengthened for making future predictions concerning the reservoir, and will become a management tool for reservoir development.

A final report will be prepared at the end of the first year of Pilot Plant operation. It will summarize the exploration, drilling, assessment and long-term utilization of the Raft River medium temperature geothermal resource. The report will be updated at the termination of DOE funded plant operation. The above outlined work accomplishes the sixth objective.

Funding for this program effort will be derived from the Hydrothermal Reservoir Assessment Program, I-430. A breakdown of the funding for FY-1978 is as follows:

<table>
<thead>
<tr>
<th>Activity</th>
<th>Funding</th>
</tr>
</thead>
<tbody>
<tr>
<td>Report Preparation</td>
<td>$20 K</td>
</tr>
<tr>
<td>Pressure/Flow Testing</td>
<td>60 K</td>
</tr>
<tr>
<td>Well Logging and Coring</td>
<td>60 K</td>
</tr>
<tr>
<td>Analysis and Reservoir Modeling</td>
<td>10 K</td>
</tr>
<tr>
<td>Program Management</td>
<td>50 K</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$200 K</strong></td>
</tr>
</tbody>
</table>
D. Environmental Monitoring Plan

This section outlines plans for establishing a network of shallow and intermediate depth wells that will monitor the effects of injection in the Raft River Valley. One of the major environmental concerns associated with the development of geothermal resources in the Raft River Valley is the possibility of contaminating shallow aquifer systems that are being used for agricultural and domestic purposes. The Idaho Department of Water Resources (IDWR) has declared the basin a critical groundwater area and has closed it to further groundwater development, as local users want to protect the adequacy and quality of their limited supplies of water.

Because the IDWR is concerned with protecting existing water rights, they are now also reluctant to approve proposed supply-injection plans. An injection test on RRGI-4 will be performed to provide data on possible interference with other wells - both the deep geothermal wells and the shallow domestic and irrigation wells. Under IDWR's proposed "Regulations for the Construction and Use of Waste Disposal and Injection Wells," approval of injection will be based on the applicant's ability to "clearly demonstrate" that such injection would not result in contamination of domestic or agricultural water supplies.

To allay these concerns and satisfy the regulations, a monitoring program has been developed. The objectives of this program are:

1. To determine if geothermal development in the Raft River Valley degrades the quality of domestic and agricultural water supplies.

2. To determine, through pressure monitoring, if geothermal development affects the quantity of existing domestic and agricultural supplies.

An environmental monitoring program initiated in 1974 included semiannual sampling of 22 irrigation wells near the Raft River geothermal development. This has provided very useful baseline data, and valuable data have been gathered as the program has developed. However, the data do not present conclusive evidence that geothermal development will not eventually interfere with shallow aquifers. Several problems have been encountered during the monitoring program; for example, access to the wells has been limited to the irrigation season (May to September), certain wells that were sampled one year could not be sampled the next, seasonal variations in pumping rates resulted in variations in water quality, and information about the construction and production zones of the private wells is scarce. As a result, only tentative conclusions can be drawn from the data.

To obtain more conclusive data on the effects of injection, the first two monitoring wells will be drilled before the RRGI-4 injection test begins on March 1. These wells, one to 500 feet and one to 1500 feet, are specifically designed to monitor injection tests on RRGI-4. A schedule for the drilling and baseline testing of all monitor wells is given in the 300 series of the Management Summary Schedule, Figure 4. A 1500-foot well and
four more 500-foot wells are tentatively planned for the spring of 1978. The final well designs will not be determined, however, until preliminary results from injection tests on RRGI-4 have been examined.

The first 500-foot well will consist of at least a six-inch cased hole, the bottom 80 feet of which will be slotted. An eight-inch gate valve set at the surface will provide containment. The well will be drilled by a local water-well driller using a cable-tool rig.

The 1500-foot well will be cased to total depth with either eight-inch or six-inch casing. This will accommodate any sampling or downhole, pressure instrumentation and, if necessary, a small submersible pump. Because anticipated artesian flow must be contained, a gate valve will be set on the surface pipe.

The RRGI-4 monitor wells will be located in the probable area of injection influence. The 500-foot well is located in the southwest corner of the Crook property, approximately 100 feet west of the greenhouse hot well and 1870 feet east of RRGI-4. The 1500-foot well will be drilled on BLM land, 470 feet southeast of RRGI-4. The USGS No. 3 hole, 2200 feet west of RRGI-4, will also be monitored during the tests. All three wells are shown in Figure 10.

Monitoring of the two wells will begin as soon as they are completed, in order to obtain at least three weeks of baseline data before the injection tests begin. The aquifer's first response to influence from injected fluids would probably be a pressure change; therefore, each well will be equipped with either a recording pressure transducer or a water level recorder. Samples for pH, conductivity, temperature, and redox potential will be taken daily during injection tests. Weekly or semimonthly samples from all wells will be analyzed for Ca, K, Li, Mg, Na, SiO2, Sr, Cl-, HCO3, F-, NH4, SO4, and total dissolved solids. All the monitor wells are expected to have artesian flow at the surface; however, a small pump will be available for sampling during non-artesian conditions.

The baseline chemistry of each of the injection wells will be determined prior to injection tests. This information, in conjunction with studies of the chemistry of the injected fluids and studies of any changes in aquifer chemistry, will be used to determine a limiting water chemistry for injected fluids. The limitations will comply with state and proposed federal regulations. This will determine whether or not treated or untreated blowdown fluids can be injected.

The Earth and Biological Sciences Branch will manage the monitoring program. DOE-ID and IDWR will review all proposed monitor well plans.

Drilling of the first monitor well, which began in December 1977, was completed January 6, 1978. The first 1500-foot well will be completed by February 15, so that baseline tests can be run on the well before the RRGI-4 injection test begins. Drilling and baseline testing of the remaining monitor wells will be completed by August 21. The decisions regarding the acceptability of intermediate injection in RRGI-6 and RRGI-7 will be made by August 15 and December 30, respectively. These decisions will be coordinated with the Idaho Department of Water Resources.
FIGURE 10
Location of Monitor Wells
A total of $264,000 ($105,000 under I-461 and $159,000 under I-475) has been funded for the monitor wells. The following is a breakdown of that funding:

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling and Well Completion</td>
<td>$209K</td>
</tr>
<tr>
<td>($79,500 each for two 1500-foot wells; $10,000 each for five 500-foot wells)</td>
<td></td>
</tr>
<tr>
<td>Monitor Equipment</td>
<td>26K</td>
</tr>
<tr>
<td>Chemical Analyses</td>
<td>11K</td>
</tr>
<tr>
<td>Technical Support (4.4 mm)</td>
<td>17K</td>
</tr>
<tr>
<td>Travel</td>
<td>1K</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$264K</strong></td>
</tr>
</tbody>
</table>
VII. SAFETY

The DOE contractor company, EG&G, is responsible for implementing safety programs at the Raft River site. The company must issue standard procedures for safe site operation, and train and qualify operating personnel for job assignments. Interfaces with respect to safety communication exist among DOE-ID, the contractor company, Raft River Geothermal Development Cooperative, subcontractors, and other participating organizations—both government and non-government. Safety interfaces also exist among the various divisions of the contractor company. With the exceptions of power plant construction and operation, ultimate responsibility for site safety thermal Electric Division of EG&G. DOE-ID will contract for power plant construction and operation. The safety responsibility for these tasks has not been defined.

Site operating crews are trained on the job and in formal training sessions with informed management and engineering personnel. All training is highly safety oriented. Safety meetings are also routinely scheduled to discuss pertinent safety topics and reinforce safety consciousness, and several company employees are qualified Emergency Medical Technicians.

The site manager and the site safety coordinator are responsible for safety, and have the authority to close down any unsafe activities, including those undertaken by subcontractor employees. All personnel also have the responsibility to report any unsafe condition to site management.

Semimonthly safety inspections are made by qualified safety inspectors from the Safety Division of the company. These inspections are documented, and site management response and timely corrective action are required on any unresolved safety items. In addition, safety is considered in the new-construction inspections performed by the Construction Management Branch of the company.

An Emergency Procedure Document defines the emergency responsibility at the site. A site emergency director is responsible for declaring emergencies and is in charge throughout any declared emergency period. The document also provides for an emergency planning group that is responsible for developing emergency procedures, tests, and training exercises. In addition, the document lists emergency equipment that must be maintained at the site.

From time to time subcontractors perform certain functions at the site. These include drilling and logging wells, trenching and laying pipelines, installing pumps, constructing buildings and other facilities, maintaining equipment, and other activities. Safety procedures and practices are controlled by the DOE site contractor through formal contracts which specify, as part of the contract, that all operations will be carried out in a safe manner. This feature of the contract is also binding on any subcontractors. Specifically, the contract requires:
1. Adherence to OSHA standards of safety.

2. Acceptance of overall site safety responsibility by the DOE site contractor.

3. Authority of site management or the site safety officer to shut down or stop any operation or procedure he deems unsafe.

4. Safety training of personnel specified by the DOE site contractor.

All operations at the site are subject to OSHA regulations, and it is the responsibility of the site management to see that all activities conform to OSHA requirements.

In addition, all sensitive operations are controlled by procedures documented in Standard Practices. Standard Practices are official company control documents and receive independent engineering and safety review. All changes to Standard Practices must go through the same review chain.

Safety analysis documents (SADs) are also prepared for site activities. An SAD has been prepared for general site activities and covers well safety, the geothermal fluid distribution system, and general industrial safety. This SAD is now in the approval process. Additional SADs will be prepared for various utilization systems. The SAD gives management a definition and review of all identifiable risks, together with risk magnitudes, so that intelligent risk-acceptance decisions can be made.

Finally, workers and management perform informal job safety analyses. They discuss the risks of a new job where unreviewed safety problems may be involved. These analyses may be either documented or undocumented, but the purpose is the same as the formal SAD: to define and review the risks involved in doing a particular job.
APPENDIX A

DRILLING PROCEDURE
A. **Production Well** (See Figure 11)

1. Prepare location

2. Using rat-and-mouse hole drill, drill 26-inch hole for 20-inch conductor pipe to 150 feet. Cement conductor pipe with collars from 150 feet to surface.


4. Move in and rig up drilling rig.

5. Install 20-inch spool, 20-inch single gate valve, and nipple-up.

6. Drill 17-1/2-inch hole to 1,500 feet with mud. Run single-shot directional survey every bit trip, or as required. Treat fluid-loss zones as they occur with mud additives, and, if necessary, with cement plugs. Condition hole to log and run casing.

7. Mud logging services will be used below 500 feet, or as required by EG&G.

8. Run caliper log and temperature log 1,500 feet to 150 feet. Additional logs to be run as determined and directed by EG&G Idaho, Inc.

9. Condition hole and run 1,500 feet of 13-3/8-inch, 54.5-lb./ft. casing. Run guide shoe, float collar, centralizers and stage cementing (DV) collar, if required. (The optional running and subsequent use of the DV collar will be based on an evaluation of drilling data, open-hole logs, and the cementing operation experience.) Install centralizer for wellhead equipment before any cement is pumped in hole.

   **Cementing without DV collar:**

   Circulate and condition hole and cement through shoe to the surface, using water to displace cement. If cement is not displaced to the surface, determine the top of cement, perform work under Item 9 below, then perform remedial cementing through the 20-inch casing head down the annulus. WOC 12 hours and proceed to Item 10.

   **Cementing with DV collar:**

   Circulate and condition hole and cement first stage, open DV collar and circulate out excess cement above DV collar. WOC 12 hours while circulating hole, then cement second stage to the surface, using water to displace cement.
If remedial cementing is required because the first stage cement did not circulate to the surface, WOC 12 hours while circulating, close DV collar, perform work under Item 9 below, then cement through the 20-inch casing head down the annulus. WOC 12 hours and proceed to Item 10.

If remedial cementing is required because the second stage cement was not displaced to the surface, determine the top of cement, perform the work under Item 9, then cement through the 20-inch casing head down the annulus. WOC 12 hours and proceed to Item 10.

Mud and cement "returns" will be monitored during cementing operations. Diagnostic logs will be run in the event of any remedial cementing to determine cement top or determine if additional remedial cementing is required as directed by EG&G.

10. WOC 24 hours, remove 20-inch B.O.P. Cut off 13-3/8-inch casing 10 inches above 20-inch casing head and install 20-inch x 12-inch WH expansion spool, 12-inch double-gate valve, 12-inch x 12-inch flow spool, 12-inch double-gate Shaffer BOP, and 12-inch Hydri BOP (with kill and choke lines, Grant rotating head, and nipple-up flow lines). Use dual controls on BOPs. Pressure test BOPs and casing with 300 psig surface pressure. (EG&G-Idaho will notify the State of Idaho of scheduled B.O.P. pressure tests.)

11. After displacing mud with water, tag top of cement and drill out to above casing shoe. If a DV collar was used, pressure-test the collar to 300 psig surface pressure.

12. Drill out shoe and drill formation with 12-1/4-inch bit using water. Use a centralized and stabilized assembly for drilling the 12-1/4-inch hole. Run single-shot magnetic survey every trip, or as requested. Drill to 3,500 + feet and run tests as directed by EG&G to determine the 9-5/8-inch casing setting depth. If a resource zone has been bypassed, plug back with sand, barite, and/or cement plug to the appropriate casing setting depth as determined by EG&G.

13. Condition hole for logging and running casing. Treat hole for fluid losses if necessary.

14. Condition hole for logs. Run open-hole logs as directed by EG&G, i.e., dual induction, gamma ray, sonic, compensated neutron, density, and spectralog.

15. Condition hole and run 9-5/8-inch, 36-lb./ft. buttress thread casing and set in 13-3/8-inch casing with casing liner hanger, with approximately 200 feet of casing overlap. Run a differential-fill-up shoe and collar, centralizers, and cement baskets, as required.
Cement 9-5/8-inch casing through drill pipe latched into casing liner hanger. Displace cement with water. Monitor returns during cementing operations. In the event cement is not circulated to the surface, locate top of cement and perform remedial cementing by squeezing down through the liner hanger ports.

16. NOC 48 hours while nippling up, and run CBL logs if remedial cementing is required. Pressure test BOP, casing, and wellhead to 300 psi.

17. Drill out shoe with 8-3/4-inch bit with water as the drilling fluid. Alternately drill and core (approximately three) at intervals determined by EG&G, to a total depth of approximately 5,500 feet, or as determined by EG&G. Run single-shot magnetic surveys every 90 feet between 3,500 feet and 4,000 feet, and every 180 feet from 4,000 feet to T.D.

18. Run logs as in Section 14 above. Run flow and/or injection tests as determined by EG&G.

19. If directed by EG&G as a result of its evaluation of the geothermal resource potential, sidetrack an 8-3/4-inch hole from below the 9-5/8-inch casing shoe KOP, using a turbodrill with water as a drilling fluid. EG&G will establish the bearing of the sidetrack hole from true north. Hole deviation will be maintained so as to reach a total horizontal displacement of at least 400 feet between the two holes at T.D. Magnetic single-shot surveys will be taken approximately every 30 feet while drilling with the turbodrill, or as directed by the directional driller, and every 60 feet until the required 400-foot hole displacement has been achieved, and thereafter every 180 feet to T.D.

20. Run logs as in Section 14 above. Run flow and/or injection tests.

21. If directed by EG&G, sidetrack one additional 8-3/4-inch hole as in Item 19 above.

22. Run logs, as in Section 14 above. Run flow and/or injection tests as directed by EG&G.

23. Move or release rig.
Fig. 11 Production Well Design
B. Injection Well (See Figure 12)

1. Prepare Location

2. Using rat-and-mouse hole drill, drill 26-inch hole for 20-inch conductor pipe to 150 ± feet. Cement conductor pipe with collars from 150 feet to surface.

3. Construct a concrete-lined cellar, approximately 8 feet wide, 10 feet long, and 10 feet deep. Cut off 20-inch casing and install 20-inch casing head.

4. Move in and rig up drilling rig.

5. Install 20-inch spool, 20-inch single gate valve and nipple-up.

6. Drill 17-1/2-inch hole to 2,000 ± feet with mud. Run single shot directional survey every bit trip, or as required. Treat fluid loss zones as they occur with mud additives, and, if necessary, with cement plugs. Condition hole to log and run casing.

7. Mud logging services will be used below 500 feet, or as required by EG&G.

8. Run caliper log and temperature log 1,400 feet to 120 feet. Additional logs to be run as determined and directed by EG&G Idaho, Inc.

9. Condition hole and run 2000 ± feet of 13-3/8-inch, 54.5-lb./ft. casing. Run guide shoe, float collar, centralizers and stage cementing (DV) collar, if required. (The optional running and subsequent use of the DV collar will be based upon an evaluation of drilling data, open-hole logs, and the cementing operation experience.) Install centralizer for wellhead equipment.

   **Cementing without DV collar:**

   Circulate and condition hole and cement through shoe to the surface, using water to displace cement. If cement is not displaced to the surface, determine the top of cement, perform work under Item 9 below then perform remedial cementing through the 20-inch casing head down the annulus. WOC 12 hours and proceed to Item 10.

   **Cementing with DV collar:**

   Circulate and condition hole and cement first stage, open DV collar and circulate out excess cement above DV collar. WOC 12 hours while circulating hole, then cement second stage to the surface, using water to displace cement.
If remedial cementing is required because the first stage cement did not circulate to the surface, WOC 12 hours while circulating, close DV collar, perform work under Item 9 below, then cement through the 20-inch casing head down the annulus. WOC 12 hours and proceed to Item 10.

If remedial cementing is required because the second stage cement was not displaced to the surface, to determine the top of cement, perform the work under Item 9. Then cement through the 20-inch casing head down the annulus. WOC 12 hours and proceed to Item 10.

Mud and cement "returns" will be monitored during cementing operations. Diagnostic logs will be run in the event of any remedial cementing to determine cement top or determine if additional remedial cementing is required as directed by EG&G.

10. WOC 24 hours, remove 20-inch B.O.P. Cut off 13-3/8-inch casing 10 inches above 20-inch casing head and install 20-inch x 12-inch WKM expansion spool, install 12-inch 400# WKM gate valve, 12-inch x 12-inch flow spool, 12-inch double-gate Shaffer BOP, and 12-inch Hydrid BOP (with kill and choke lines, Grant rotating head, and nipple-up flow lines). Use dual controls on BOPs. Pressure-test BOPs and casing with 300 psig surface pressure. (Appropriate notifications to state of scheduled BOP pressure tests will be made by EG&G.)

11. After displacing mud with water, tag top of cement and drill out to above casing shoe. If a DV collar was used, pressure test the collar to 300 psig surface pressure.

12. Drill out shoe formation with 12-1/4-inch bit using water. Use a centralized and stabilized assembly for drilling the 12-1/4-inch hole. Run single-shot magnetic survey every trip, or as required. Drill to 3,500 feet, or as directed by EG&G.

13. Condition hole for logs. Run open-hole logs as directed by EG&G, i.e., dual induction, gamma ray, sonic, compensated neutron, density, spectalog. Run flow and/or injection tests as directed by EG&G.

14. Option: If injection testing of the intermediate aquifer indicates multiple legs are necessary for adequate injection, directionally drill 8-3/4-inch hole from below the 13-3/8-inch casing shoe KOP, using a turbodrill with water as a drilling fluid. EG&G will establish the bearing of the sidetrack hole from true north. Hole deviation will be maintained so as to reach a total horizontal displacement of at least 400 feet between the two holes at T.D. Magnetic single-shot surveys will be taken approximately every 30 feet while drilling with the turbodrill, or as directed by the directional driller, and every 60 feet until the required 400 foot hole displacement has been achieved, and thereafter every 180 feet to T.D.
15. Run logs as in Section 13 above. Run flow and/or injection tests.

16. If directed by EG&G, sidetrack one additional 8-3/4-inch holes as in Item 14 above.

17. Run logs, as in Section 13 above. Run flow and/or injection tests as directed by EG&G.

18. Drill a 12-1/4-inch hole as nearly vertical as possible, utilizing the turbodrill for direction and angle. This will allow for the setting of a 9-5/8-inch liner if the well should need to be deepened for deep injection in the future.

19. Run logs as in Section 13 above. Run flow and/or injection tests as directed by EG&G.

20. Move or release rig.
Fig. 12 Proposed Injection Well
APPENDIX B

WELL SPECIFICATIONS FOR BID
### SCHEDULE A
Daywork Payment for Four Geothermal Wells

<table>
<thead>
<tr>
<th>Work</th>
<th>Quantity &amp; Unit</th>
<th>Unit Price</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Mobilization</td>
<td>Lump sum</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Location to Location Move**</td>
<td>3 ea.</td>
<td>Each</td>
<td></td>
</tr>
<tr>
<td>3. Operating Day Rate (w/o drill pipe)</td>
<td>6 days</td>
<td>Per Day</td>
<td></td>
</tr>
<tr>
<td>4. Operating Day Rate (with drill pipe)**</td>
<td>142 days*</td>
<td>Per Day</td>
<td></td>
</tr>
<tr>
<td>5. Standby rate (with crews)</td>
<td>1 day</td>
<td>Per Day</td>
<td></td>
</tr>
<tr>
<td>6. Standby rate (w/o crews)</td>
<td>1 day</td>
<td>Per Day</td>
<td></td>
</tr>
<tr>
<td>7. Demobilization</td>
<td>Lump sum</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>$</td>
</tr>
</tbody>
</table>

*This figure represents combined daywork for all 4 wells to be drilled.

**Includes option of deepening RRGI-4.
SECTION
BID PROPOSAL & SPECIFICATION
FOR DRILLING RAFT RIVER WELLS

1.0 DRILLING PROGNOSIS

1.1 Contractor (Operator):
EG&G Idaho, Inc.

1.2 Work Scope

1. Raft River Geothermal Production Well No. 5 (RRGP-5) + 5500 ft.
   0-60 36" hole 0-60 26" casing
   0-150 26" hole 0-120 20" casing
   150-1500' 17-1/2" hole 0-1500 13-3/8" casing
   1500-4000' 12-1/4" hole 1300-4000' 9-5/8" liner
   4000-5500' 3 directionally drilled 8-3/4" open holes

2. Raft River Geothermal Injection Well No. 6 (RRGI-6) + 3500 ft.
   0-150 26" hole 0-150 20" casing (set by Rat and Mouse Hole Driller)
   150-2000' 17-1/2" hole 0-2000' 13-3/8" casing
   2000-3500' 12-1/2" open hole*

3. Raft River Geothermal Injection Well No. 7 (RRGI-7) + 3500 ft.
   0-150 26" hole 0-150 20" casing (set by Rat and Mouse Hole Driller)
   150-2000' 17-1/2" hole 0-2000' 13-3/8" casing
   2000-3500' 12-1/2" open hole*

4. OPTION: Raft River Geothermal Injection Well No. 4 (RRGI-4)
   Deepening 2800 ft. to ±5,500 ft.
   2840-3700' 12-1/4" hole 1700'-3700' 9-5/8" liner
   3700-5500' 3 directionally drilled 8-3/4" open holes

1.3 Location:
Cassia Co., Idaho - RRGP-5 NESW Sec. 22 T15S R26E
RRGI-6 NE SE NE Sec. 23 T15S R26E
RRGI-7 Proposed NE SW SE Sec. 23 T15S R26E
RRGI-4 SW¼ Sec. 23 T15S R26E

1.4 Elevation:
RRGP-5  4988'
RRGI-6  4815'
RRGI-7  4855 (anticipated)
RRGP-4  4840'

1.5 Estimated Formation Tops: (See attached sample logs)
   Alluvium    Surface
   Raft River Formation  100 ± feet

*Option of two additional directionally drilled legs.
1.5 Estimated Formation Tops: (Continued)

- Salt Lake Formation: 1000 ± feet
- PC Shist: 5000 ± feet
- PC Elba Quartzite: 5300 ± feet
- PC Quartz Monzonite: 5600 ± feet

1.6 Anticipated Drilling Problems

Possible drilling fluid loss.
Possible loss of cement returns.

2.0 PROGRAM

2.1 Hole Size:

<table>
<thead>
<tr>
<th>Production Well</th>
<th>Injection Well</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 - 150'</td>
<td>0 - 150'</td>
</tr>
<tr>
<td>150 - 2000'</td>
<td>17-1/2&quot;</td>
</tr>
<tr>
<td>1200 - 1500'</td>
<td>12-1/4&quot;</td>
</tr>
<tr>
<td>1500 - 4000'</td>
<td>8-3/4&quot; (open hole completion)</td>
</tr>
<tr>
<td>4000 - 5500'</td>
<td></td>
</tr>
</tbody>
</table>

2.2 Casing Program:

- Conductor: 20" conductor
- Surface Casing*: 13-3/8" 54.5#, K55, ST&C
- Production Liner*: 9-5/8" 36#, K55, 1300-4000' Buttress

* Casing to be run with power tongs.

2.3 Cementing Program:

20" and 13-3/8" casing shall be cemented to surface, 9-5/8" liner will be cemented to liner hanger as provided for and directed by EG&G Idaho, Inc.

2.4 Casing Equipment:

Shall include guide shoe, float collar, centralizers, liner hanger and cementing manifold as required, provided for and directed by EG&G Idaho, Inc.

2.5 Drilling Fluid Program:

- 0 - 1500': Spud mud Wt. 8.8-9.2 Vis. 40-60
- 1500 - TD: Water

Squeeze techniques will be used for severe lost circulation zones.
2.6 Logging:

Caliper and temperature logs will be run prior to cementing; diagnostic borehole logs shall be taken at casing intervals and/or at completion as directed and provided for by EG&G.

2.7 Samples:

0 - TD - Two each at 20' intervals or as directed by EG&G. Cuttings to be washed and placed in legibly-labeled sample bags provided by EG&G.

2.8 Sample Logging:

As provided for and directed by EG&G.

2.9 Deviations:

Deviation not to exceed 1° change per 100 feet drilled and not to exceed a maximum of 7° deviation from vertical at total depth. Surveys to be run every 90 feet or as directed by EG&G.

2.10 Cores and DST's:

As directed and provided for by EG&G.

2.11 Drilling Records:

1. Record with 6-pen recorder:
   a. Weight on derrick
   b. One ft. drilling time
   c. Rotary torque
   d. Standpipe pressure
   e. Pump strokes on #1 pump and #2 pump

2. Daily drilling report shall be kept on standard IADC-API Report form or equivalent. Record all pertinent information (i.e., trips, cementing, DST's etc.).

3. Bit weight and pump pressure to be continuously recorded.

4. An accurate drill string tally and record shall be maintained at all times. Measured drill pipe and bottom hole assembly tallies shall be made prior to coring and/or casing running operations or as directed by EG&G.

5. Bit record shall be kept on standard forms.

2.12 BOP Equipment: (See attached BOP stack drawing)

Minimum - 1-20" 2000# Manual Gate Valve BOP
1-12" 900 Series Double with blind and pipe rams
1-12" Hydril (Spherical)
1-12" Grant rotating head 55
All BOP equipment and casing shall have working pressure of 1,000 psi and hold 300 psi surface pressure for 15 minutes. All BOP equipment shall be tested prior to drilling out casings.

2.13 Reporting:

Drilling subcontractor supervisor shall report to EG&G Drilling Supervisor.
3.0 SPECIAL CONDITIONS

3.1 Bradenhead and guide bushing shall be set on 20" casing prior to cementing the 13-3/8" casing as provided for and directed by EG&G. Wellhead equipment shall be installed after the 13-3/8" casing is set prior to drilling out casing as directed by EG&G.

3.2 Work shall include setting a downhole pump if required, provided for and directed by EG&G Idaho, Inc.

3.3 Drilling subcontractor shall provide with bid submittal:
   1. Rig and equipment inventory.
   2. Rig layout dimensions and substructure height.
   3. Rat and mouse hole locations from center hole.
   4. Previous operator that subcontractor's rig worked for.

3.4 At the time of bid award, successful bidder will be required to show documented evidence that all drill pipe has been electronically inspected (i.e., Tubescope) and that drill collars, lifting subs, all subs, placed in drill string, etc. have been magnafluxed. All drill pipe shall be classified Grade 2 or better as specified in AP-I RP7G.

4.0 PROPOSAL

The following is in accordance with IADC Rotary Drilling Proposal and Contract.

4.1 Depth:

Well Depth: The well(s) shall be drilled to depth of approximately 5,500 feet, or to the PC Quartz Monzonite, whichever is deeper, but subcontractor shall not be required hereunder to drill said well(s) below a maximum depth of 6,000 feet, unless subcontractor and contractor mutually agree to drill to a greater depth. Injection wells will be drilled to ± 3500 feet.

4.2 Daywork Rates:

Subcontractor shall be paid on the following basis for the work performed hereunder.

1. Mobilization - Demobilization - Contractor shall pay subcontractor a lump sum for mobilization and demobilization in accordance with Schedule A.
2. Location to Location Move - Contractor will pay subcontractor a lump sum for each location to location move in accordance with Schedule A.

3. Operating Day Rate - For work performed per twenty four (24) hour day with full crews the operating rate will be in accordance with unit prices, with or without drill pipe as set in Schedule A. Partial day payment will be based on that fraction of the twenty-four (24) hour day rate.

Drill pipe shall be considered in use not only when in actual use but also while it is being picked up or laid down. When drill pipe is standing in the derrick, it shall not be considered in use, provided, however, that if subcontractor furnishes special strings of drill pipe, drill collar, and handling tools as provided for in Exhibit "A", the same shall be considered in use at all times when on location or until released by contractor. In no event shall fractions of an hour be considered in computing the amount of time drill pipe is in use but such time shall be computed to the nearest hour, with thirty minutes or more being considered a full hour and less than thirty minutes not to be counted.

Operating rate will begin when the drilling unit is rigged up at the drilling location, and ready to commence drilling operation; and will cease when the rig is ready to be moved off the location.

4. Repair Rate - In the event it is necessary to shut down subcontractors rig for repairs, excluding routine rig servicing, while subcontractor is performing daywork, subcontractor shall be allowed compensation at the applicable daywork rate up to a maximum of 8 hours total per well.

4.3 Standby Time Rate with or without Crews:

Standby time shall be defined to include time when the rig is shut down although in readiness to begin or resume operations but subcontractor is waiting on orders of contractor or on materials, services or other items to be furnished by contractor, per Schedule A.

4.4 Reimbursable Costs:

Contractor shall reimburse subcontractor for the costs of material, equipment, work or services which are to be furnished by contractor as provided for herein but which for convenience are actually furnished by subcontractor at contractor's request.

4.5 Time of Payment:

Subject to Contractor's right to require that subcontractor furnish him with satisfactory evidence that subcontractor has paid all labor and material claims chargeable to subcontractor, payment becomes due by contractor to subcontractor as follows:
Payment for mobilization, drilling and other work performed at applicable day rates, and all other applicable charges shall be due upon acceptance by contractor of the work performed in accordance with this contract, upon presentation of invoice therefore at the end of the month in which such work was performed or other charges are incurred.

4.6 Duration of Contract:

This contract shall remain in full force and effect until drilling operations are completed on the well or wells specified in Par. 1.2 above or as otherwise specified by contractor (see Par. 4.7).

4.7 Early Termination:

1. By Either Party - Upon giving of written notice, either party may terminate this contract when conditions of total loss or destruction of the rig or a major breakdown with indefinite repair time necessitate stopping operations hereunder.

2. By Contractor - Notwithstanding the provisions of Paragraph 4.1 with respect to the depth to be drilled, contractor shall have the right to direct the stoppage of the work to be performed by subcontractor hereunder at any time prior to reaching the specified depth, and even though subcontractor has made no default hereunder. In such event contractor shall reimburse subcontractor only for work completed including demobilization.

4.8 Casing Program:

Subcontractor shall drill a hole sufficient in size to set, at the approximate depths indicated, the size casing specified in the casing program provision of Schedule A. Contractor shall have the right to designate the points at which casing will be set and the manner of setting, cementing, and testing.

4.9 Drilling Methods and Practices:

1. Subcontractor shall maintain well control equipment in good condition at all times and shall use all reasonable means to control and prevent fires and blow-outs and to protect the hole.

2. Subject to the terms hereof, and at contractor's cost, at all times during the drilling of the well, contractor shall have the right to control the mud program, and the drilling fluid must be of a type and have characteristics and be maintained by subcontractor in accordance with the specifications shown in Par. 2.5.

3. Subcontractor will conduct operations to comply with all laws, rules, orders, and regulations, Federal, State and Local, which are applicable to subcontractor, subcontractor's business, equipment, and personnel engaged in operations covered by this contract.

4. Subcontractor shall keep and furnish to contractor an accurate record of the work performed and formations drilled on the IADC-API Daily
Drilling Report Form or other form acceptable to contractor. A legible copy of said form signed by subcontractor's representative shall be furnished by subcontractor to contractor.

5. Subcontractor shall furnish contractor with copy of delivery tickets covering any material or supplies provided by contractor and received by subcontractor.

4.10 Ingress, Egress, and Location:

Contractor hereby assigns to subcontractor all necessary rights of ingress and egress with respect to the tract on which the well is to be located for the performance by subcontractor of all work contemplated by this contract. Should subcontractor be denied free access to the location for any reason not reasonably within subcontractor's control, any time lost by subcontractor as a result of such denial shall be paid for at the applicable rate.

4.11 Sound Location:

Contractor shall prepare a sound location adequate in size and capable of properly supporting the drilling rig, and shall be responsible for a conductor pipe program adequate to prevent soil and sub-soil washout. It is recognized that subcontractor has superior knowledge of the location and access routes to the location, and must advise subcontractor of any sub-surface conditions, or obstructions which subcontractor might encounter while en route to the location or during operations hereunder. In the event sub-surface conditions cause a cratering or shifting of the location surface, and loss or damage to the rig, its associated equipment or personnel results therefrom, contractor shall, without regard to other provisions of this Contract, reimburse subcontractor to the extent not covered by subcontractor's insurance, for all such loss or damage during repair and/or demobilization if applicable.

4.12 Termination of Location Liability:

When subcontractor has complied with all obligations of the contract regarding restoration of contractor's location, contractor shall thereafter be liable for damage to property, personal injury or death of any person which occurs as result of condition of the location and subcontractor shall be relieved of such liability; provided, however, if subcontractor shall subsequently reenter upon the location for any reason including removal of the rig, any term of the Contract relating to such reentry activity shall become applicable during such period.

4.13 Insurance:

During the life of this contract, subcontractor shall at subcontractor's expense maintain, with an insurance company or companies authorized to do business in the state where the work is to be performed or through a self-insurance program, insurance coverages. Subcontractor shall, if requested to do so by contractor, procure from the company or companies writing said insurance a certificate or certificates that said insurance is in full force and effect and that the same shall not be cancelled or materially changed without ten (10) days prior written notice to contractor.
4.14 Responsibility for Loss or Damage:

1. Subcontractor's Surface Equipment - Subcontractor shall assume liability at all times, for damage to or destruction of subcontractor's surface equipment, including but not limited to all drilling tools, machinery, and appliances for use above the surface, regardless of when or how such damage or destruction occurs, and contractor shall be under no liability to reimburse subcontractor for any such loss except loss or damage under the provisions of Paragraph 4.11 and Paragraph 4.14.7.

2. Subcontractor's In-Hole Equipment - Contractor shall assume liability only in excess of fair wear and tear for damage to or destruction of subcontractor's in-hole equipment, including but not limited to, drill pipe, drill collars, and tool joints, and contractor shall reimburse subcontractor for the value of any such loss or damage; the value to be determined by agreement between subcontractor and contractor repair cost or percentage of current new replacement cost of such equipment caused by exposure to highly corrosive or otherwise destructive elements, including those introduced into the drilling fluid.

3. Contractor's Equipment - Contractor shall assume liability at all times for damage to or destruction of contractor's equipment, including but not limited to casing, tubing, wellhead equipment, and platform if applicable, and subcontractor shall be under no liability to reimburse Operator for any such loss or damage.

4. The Hole - In the event the hole should be lost or damaged, contractor shall be solely responsible for such damage or loss to the hole, including the casing therein.

5. Inspection of Materials Furnished by Contractor - Subcontractor agrees to visually inspect all materials furnished by contractor before using same and to notify contractor of any apparent defects therein. Subcontractor shall not be liable for any loss or damage resulting from the use of materials furnished by contractor.

6. Subcontractor's Indemnification of Contractor - Subject to the provisions of Par. 4.12 hereof, subcontractor agrees to protect, defend, indemnify and save contractor harmless from and against all claims, demands, and causes of action of every kind and character, without limit and without regard to the cause or causes thereof or the negligence of any party, arising in connection herewith in favor of subcontractor's employees. Subcontractor's or their employees, on account of bodily injury, death or damage to property.

7. Liability for Wild Well - Contractor shall be liable for the cost of regaining control of any wild well, as well as for cost of removal of any debris, and shall indemnify subcontractor in this regard.
8. Pollution and Contamination - Notwithstanding anything to the contrary contained herein, except the provisions of Paragraphs 4.10 and 4.12, it is understood and agreed by and between subcontractor and contractor that the responsibility for pollution and contamination shall be as follows:

A. Unless otherwise provided herein, subcontractor shall assume all responsibility for, including control and removal of, and protect, defend and save harmless contractor from and against all claims, demands and causes of action of every kind and character arising from pollution or contamination, which originates above the surface of the land or water from spills of fuels, lubricants, motor oils, normal water base drilling fluid, pipedope, paints, solvents, ballast, bilge and garbage, except unavoidable pollution from reserve pits, wholly in subcontractor's possession and control and directly associated with subcontractor's equipment and facilities.

B. Contractor shall assume all responsibility for, including control and removal of, protect, defend and save subcontractor harmless from and against all claims, demands, and causes of action of every kind and character arising from all other pollution or contamination which may occur during the conduct of operations hereunder, including but not limited to, that which may result from fire, blowout, cratering, seepage or any other uncontrolled flow of oil, gas, water or other substance, as well as, the use of disposition of oil emulsion, oil base or chemically treated drilling fluids, contaminated cuttings or cavings, lost circulation and fish recovery materials and fluids.

C. In the event a third party commits an act or omission which results in pollution or contamination for which either subcontractor or contractor, for whom such party is performing work, is held to be legally liable, the responsibility therefore shall be considered, as between subcontractor and contractor, to be the same as if the party for whom the work was performed had performed the same and all of the obligations respecting defense, indemnity, holding harmless and limitation of responsibility and liability, as set forth in (A) and (B) above, shall be specifically applied.

9. Consequential Damages - Neither party shall be liable to the other for special, indirect, or consequential damages resulting from or arising out of this Contract, including, without limitation, loss of profit or business interruptions, however same may be caused.

4.15 No Waiver Except in Writing:

It is fully understood and agreed that none of the requirements of this Contract shall be considered as waived by either party unless the same is done in writing, and then only by the persons executing this contract, or other duly authorized agent or representative of the party.
4.16 Information Confidential:

Upon written request by contractor, information obtained by subcontractor in the conduct of drilling operations on this well, including, but not limited to, depth, formations penetrated, the results of coring, testing, and surveying, shall be considered confidential and shall not be divulged by subcontractor or his employees, to any person, firm, or corporation other than contractor's designated representatives.

4.17 Subcontracts by Contractor:

Contractor may employ other subcontractors to perform any of the operations or services to be provided or performed by it according to Exhibit "A".
**DRILLING RIG**

Complete drilling rig, designated by Subcontractor as his Rig No. ______, the major items of equipment being: 

<table>
<thead>
<tr>
<th>Item</th>
<th>Make and Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drawworks</td>
<td></td>
</tr>
</tbody>
</table>

**Engines:**

<table>
<thead>
<tr>
<th>No. on Rig</th>
<th>Make, Model, and H.P.</th>
</tr>
</thead>
</table>

**Pumps:**

<table>
<thead>
<tr>
<th>No.</th>
<th>Make, Size, and Power</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
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<tr>
<td>2</td>
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</tbody>
</table>

**Mud Mixing Pump:**

<table>
<thead>
<tr>
<th>Make, Size, and Power</th>
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</thead>
</table>

**Boilers:**

<table>
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<tr>
<th>Number</th>
<th>Make, H.P. and W.P.</th>
</tr>
</thead>
</table>

**Derrick or Mast:**

<table>
<thead>
<tr>
<th>Make, Size, and Capacity</th>
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</thead>
</table>

**Substructure:**

<table>
<thead>
<tr>
<th>Size and Capacity</th>
</tr>
</thead>
</table>

**Rotary Drive:**

<table>
<thead>
<tr>
<th>Type</th>
</tr>
</thead>
</table>

**Drill Pipe:**

<table>
<thead>
<tr>
<th>Size</th>
<th>in.</th>
<th>ft.; Size</th>
<th>in.</th>
<th>ft.</th>
</tr>
</thead>
</table>

**Drill Collars:**

<table>
<thead>
<tr>
<th>Number</th>
<th>Size 8&quot;</th>
<th>Total Wt.</th>
<th>Number</th>
<th>Size 6&quot;</th>
<th>Total Wt.</th>
</tr>
</thead>
</table>

**Blowout Preventers:**

<table>
<thead>
<tr>
<th>Size</th>
<th>Series or Test Pr.</th>
<th>Make &amp; Model</th>
<th>Number</th>
</tr>
</thead>
<tbody>
<tr>
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</table>

**B.O.P Closing Unit:**

**B.O.P. Accumulator:**

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64
DRILLING RIG (Cont.)

<table>
<thead>
<tr>
<th>Min. Rig Requirements</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Hoist Capacity</td>
<td>300,000#</td>
</tr>
<tr>
<td>Engines</td>
<td>900 HP combined</td>
</tr>
<tr>
<td>Mud Pumps</td>
<td>500 HP</td>
</tr>
<tr>
<td></td>
<td>16&quot; stroke</td>
</tr>
<tr>
<td></td>
<td>#1 &amp; 2 with independent power</td>
</tr>
<tr>
<td></td>
<td>capable of pumping 450 gpm</td>
</tr>
<tr>
<td>Substructure</td>
<td>14'</td>
</tr>
<tr>
<td>Rotary Table</td>
<td>27&quot;</td>
</tr>
<tr>
<td>Drill Pipe</td>
<td>4-1/2&quot;</td>
</tr>
<tr>
<td>Drill Collars</td>
<td>40,000# 6&quot; min.</td>
</tr>
</tbody>
</table>
EXHIBIT A

EQUIPMENT, MATERIALS AND SERVICES TO BE FURNISHED BY Subcontractor:

The machinery, equipment, tools, materials, supplies, instruments, services and labor hereinafter listed, including any transportation required for such items, shall be provided at the location at the expense of Subcontractor unless otherwise noted hereon.

Derrick timbers.
Normal strings of drill pipe and drill collars specified above.
Conventional drift indicator.
Circulating mud pits.
Necessary pipe racks and rigging up material.
Normal storage for mud and chemicals.
Shale Shaker.


EQUIPMENT, MATERIALS AND SERVICES TO BE FURNISHED BY Contractor:

The machinery, equipment, tools, materials, supplies, instruments, services and labor hereinafter listed, including any transportation required for such items, shall be provided at the location at the expense of Contractor unless otherwise noted hereon.

Furnish and maintain adequate roadway and/or canal to location, right-of-way, including rights-of-way for fuel and water lines, river crossings, highway crossings, gates and cattle guards.
Stake location, clear and grade location, and provide turnaround, including surfacing when necessary.
Test tanks with pipe and fittings.
Mud storage tanks with pipe and fittings.
Separator with pipe and fittings.
Labor to connect and disconnect mud tank, test tank, and separator.
Labor to disconnect and clean test tanks and separator.
Drilling mud, chemicals, lost circulation materials and other additives.
Pipe and connections for oil circulating lines.
Labor to lay, bury and recover oil circulating lines.
Drilling bits, reamers, reamer cutters, stabilizers and special tools.
Contract fishing tool services and tool rental.
Wire line core bits or heads and wire line core catchers if required.
Conventional core bits and core catchers.
Diamond core barrel with head.
Cement and cementing service.
Electrical and Gamma-Neutron and Micro logging services.
Directional, caliper, or other special services.
Gun or jet perforating services.
Explosives and shooting devices.
Formation testing, hydraulic fracturing, acidizing and other related services.
Equipment for drill stem testing.
Mud logging services.
Sidewall coring service.
Welding service for welding bottom joints of casing, guide shoe, float shoe, float collar and in connection with installing of well head equipment if required.
Casing, tubing, lines, screen, float collars, guide and float shoes and associated equipment.
Casing scratchers and centralizers.
Well head connections and all equipment to be installed in or on well or on the premises for use in connection with testing, completion and operation of well.
Special or added storage for mud and chemicals.
Casinghead, API series, to conform to that shown for the blowout preventers specified in Paragraph 4.1 above.
Blowout preventer testing packoff.
Casing Thread Protectors and Casing Lubricants.
EQUIPMENT, MATERIALS AND SERVICES TO BE FURNISHED BY DESIGNATED PARTY:

The machinery, equipment, tools, materials, supplies, instruments, services, and labor listed as the following numbered items including any transportation required for such items unless otherwise specified, shall be provided at the location and at the expense of the party hereto as designated by an X mark in the appropriate column.

<table>
<thead>
<tr>
<th>Item</th>
<th>To Be Provided By and At The Expense Of</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cellar and runways</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Fuel (located at <strong>Burley or, Malta</strong>)</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Fuel Lines (length)</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Water at source, including required permits</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Water well, including required permits</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Water lines, including required permits</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Water storage tanks</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Labor to operate water well or water pump</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Maintenance of water well, if required</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Mats for engines and boilers, or motors and mud pumps</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Transportation of Contractor’s property</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Move in</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Move out</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Special strings of drill pipe and drill collars as follows:</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Kelly joints, sub, elevators and slips for use with special drill pipe</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Drill pipe protectors for Kelly joint and each joint of pipe</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>running inside of Surface Casing as required</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>for use with normal strings of drill pipe</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Drill pipe protectors for Kelly joint and drill pipe running</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>inside of Protection Casing</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Coring reel with wire line of sufficient length for coring</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>at maximum depth specified in Contract</td>
<td><strong>Contractor</strong></td>
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<tr>
<td>Wire line core barrel</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Conventional core barrel</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Rate of penetration recording device</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Extra labor for running and cementing casing</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Casing tools</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Power casing tongs</td>
<td><strong>Contractor</strong></td>
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<tr>
<td>Tubing tools</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Power tubing tong</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Swabbing unit with swabbing line</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Swab</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Swab lubricator</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Swab rubbers</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Crew Boats, Number</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Service Barge</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Service Tug Boat</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Helicopter service</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Rat Hole</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Mouse Hole</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Reserve Pits</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Erect and Dismantle Derrick</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Upper Kelly Cock</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Drilling hole for or driving for conductor pipe</td>
<td><strong>Contractor</strong></td>
</tr>
<tr>
<td>Charges, cost of bonds for public roads</td>
<td><strong>Contractor</strong></td>
</tr>
</tbody>
</table>
APPENDIX C

Additional information and illustrations were submitted with the bid specifications and contract. A list of these items is given below.

1. Production well design figure for RRGE-3.
2. BOP Stack required during drilling with 12-1/4-inch or smaller bits.
3. Site layout for Site No. 6.
4. Bit records for the four existing wells.
5. Cellar design drawing for Site No. 6.