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memorandum

TO: Distribution

THRU: H. Murphy RHH for HD
CH BH

FROM: Don Dreesen and Bob Hand

SUBJECT: REDRILLING PLAN FOR EE-3

DATE: 14 November 1984

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Attached is the 3rd draft copy of the EE-3 redrilling plan. We believe that we have taken the document as far as we can and feel that it is ready for distribution as soon as the trajectory question is resolved and necessary changes in wording that ~~results~~ result are made. The figures are presently being redrawn by John Paskiewicz and should be ready in about one week.

Suggestions and short write ups for the plan were received from Bob Nicholson, Fritz Waters, George Cocks, Morton Smith, and Ron Aguilar. Hugh Murphy, George Cocks, Fritz Water, Bob Potter, Bob Nicholson, Bob Hendron, and Kenio Seo have critiqued the plan at various stages in the preparation of the document.

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1.0 INTRODUCTION

In 1977, the world's first hot dry rock (HDR) geothermal energy system was completed at Fenton Hill in northern New Mexico. Identified as the "Phase I (Research) System," it was operated successfully as a recirculating pressurized-water loop through an injection well, hydraulically fractured reservoir, production well and surface heat extraction system. Heat was extracted from a granodiorite intrusive at depths around 9000 ft where the initial rock temperature was about 365°F. Up to 5.1 MW thermal heat was brought to the surface in superheated water at temperatures of about 275 to 285°F, under sufficient pressure to prevent boiling. Water quality remained benign and, during a nine-month flow test, rate of water loss decreased to less than 8% of the flow rate through the system. Because of thermal contraction of the rock as heat was extracted from it, volume of the fracture system increased about 25% with a proportionate increase in effective heat transfer area.

In constructing the Phase I system, a slightly inclined injection well was drilled into the hot rock, a large hydraulic fracture was extended from it, and a production well was drilled to intersect the fracture. Several hydraulic-fracturing operations and two redrillings of the production well were required to complete a connected system with satisfactorily low pressure drop. The hydraulic fractures produced were substantially vertical with a north-northwest strike. Modeling of system behavior indicated that heat extraction occurred principally in that part of the fracture system best represented by a circular region between the source at the injection well and the sink at the production well.

The Phase I system demonstrated the technical feasibility of creating and operating HDR energy systems. It did not produce heat at a temperature or rate that would support a commercial-scale electrical power plant. Therefore, in 1978, planning began for construction of a larger, hotter Phase II ("Engineering") System that would more nearly approach those requirements. Extrapolation of the Phase I temperature gradient projected a temperature of 480 to 525°F would be reached at a depth of 13,000 ft. It was assumed that, at that depth, hydraulic fractures would be planar and vertical with a north-northwest strike, and it was also assumed that heat extraction would occur in a roughly circular area within those fractures connecting the injection and production wells. It was believed that impedance to fluid flow would be excessive if well separation was much greater than the 1000 ft separation in the Phase I system. To sustain energy production of 35 MW thermal about seven connecting fractures of 1000 ft effective vertical height would be required. To thermally isolate parallel, vertical fractures for a period of ten years requires a horizontal distance between them of about 165 ft. The Phase II system was designed with the lower 3000 ft of each well inclined at 35° to provide about 1000 ft of horizontal space for hydraulic fracturing, and the inclined section of the production well was to be about 1000 ft directly above the injection well. The wells were to be drilled toward the east-northeast, normal to the expected strike of the fractures. Finally, to avoid the difficulties expected in trying to drill through a succession of fractures that were separated both horizontally and vertically, it was decided this time to drill the two holes first and then extend the hydraulic fractures from one to the other.

Well EE-2, the injection well of the Phase II system was completed as planned between April 1979 and May 1980. Its total depth was 15,289 ft with 9-5/8 in. injection casing set at 11,580 ft. Well EE-3, the production well, was drilled between May 1980 and August 1981 from a surface location about 150 ft from the EE-2 wellhead. It reached a total depth of 13,933 ft with 9-5/8 in. production casing set at 10,374 ft. In its inclined section EE-3 was drilled about 1215 ft above EE-2. By careful directional drilling, EE-3 was kept within 165 ft of the vertical plane containing EE-2, the largest departure being at the bottom of the hole where no directional corrections were made.

Since the Phase II well pair drilling was completed, activities at Fenton Hill have concentrated primarily on preparing the two boreholes and conducting hydraulic fracturing experiments. Four major reservoirs, two in each well, have been created using at least two large volume hydraulic fracturing treatments in each reservoir. More than two million gallons were pumped into the lower reservoir in EE-2 below a 4-1/2 in. liner at 14,700 ft. More than eight million gallons were pumped into the upper reservoir in EE-2 below the 9-5/8 in. casing shoe at 11,585 ft. Approximately two million gallons were pumped into the lower reservoir in EE-3 below a 4-1/2 in. liner at 11,390 ft. The three reservoirs were created at surface fracturing pressures in excess of 5000 psi (all pressures in this plan refer to wellhead injection pressure).

The upper reservoir in EE-3, just below the 9-5/8 in. casing shoe at 10,374 ft was treated with more than 1/2 million gallons of water at pressures below 2000 psi.

Hydraulic data and geophysical data showing micro earthquake locations, all show that: (1) no seismic overlap or hydraulic connection between an EE-2 reservoir and an EE-3 reservoir presently exists and (2) the upper and lower reservoirs in EE-3 overlap and are hydraulicly connected. In order to create a heat extraction loop, it is now planned to redrill from EE-3 into the upper reservoir in EE-2.

In the last pump-in in EE-2, Experiment 2032, 5.6 million gallons were pumped at an average injection rate of 40 BPM at an average treating pressure of 6950 psi. Mapping of the locations of micro earthquakes which occurred during the treatment provides the basis for tenative target and trajectory specified in this drilling plan. It is assumed that within the "cloud" depicted by plotting several hundred of the most accurately located earthquakes, there exists a region of hydraulicly communicative fractures. It is intended to sidetrack EE-3 and drill on a trajectory which has the maximum probability of penetrating the region of recently open fractures.

Many targets in each of the reservoirs and many trajectories have been considered prior to choosing the strategy outlined in this drilling plan. After it was decided to drill into the Experiment 2032 cloud from a 9300 ft depth in EE-3 the major remaining issues were to (1) chose a "target" in the seismic event cloud, (2) determine the wellbore angle as it penetrated the seismic event cloud and (3) to determine the desired closest point of approach to the Experiment 2032 injection zone, 11,578 - 11,645 ft in EE-2. The "final" trajectory will be selected to allow, if needed, the penetration of as much of the seismic region as possible and to provide sufficient flexibility to modify the trajectory, if it is logical to do so after 600 ft of the seismic region has been drilled.

2.0 SUMMARY OF EACH PLANNED EE-3 OPERATION

The present configuration of the EE-3 wellbore is shown in Figure 1 and described in more detail in the General Plugback and Redrilling Program.
A procedure is set forth to sidetrack EE-3 at 9290 ft and directionally drill an 8-1/2 in. hole into the seimic cloud around the EE-2 casing shoe as mapped during Experiment 2032. A single flow connection to the EE-2 wellbore is the main objective of the plan, but completion techniques which provide a mechanism for multiple flow paths are also proposed. It is also important that as much as possible be learned about the reservoir structure and flow characteristics during the drilling to lead to a completion design which complements the reservoir.

2.1 Plugback of Openhole

Based on the Phase I reservoir there is a strong possibility that the connecting fracture system will grow significantly with heat extraction. Effective plugback of the existing EE-3 openhole wellbore is considered to be critical to prevent crossflow or water loss through the old wellbore if it is ever intercepted by the growing reservoir. The plugback of the two openhole sections will be performed with barite plugs or cement using a bullheading technique if possible.

2.2 Sidetrack Operation

A 40 ft section will be milled out of the 9-5/8 in. casing and an A-Z International Packstock Whipstock (see Fig. 2) will be set to assure that a sidetrack operation will be successful on the first attempt and minimize the risk of the whipstock moving after several thermal cycles. A special drill-off assembly using tools without hardfacing will be run to reduce risk of wear on the whipstock face. The starting sidetrack hole will be drilled to a sufficient depth (depends on survey data) to assure satisfactory separation from the original wellbore prior to any orientation for directional drilling to the target.

2.3 Directional Drilling

The directional drilling required to orient the new hole will be performed by contract directional drilling consultants and tools. Mud motors or turbines and steering tools will be run to obtain the desired well path. Rotary drilling assemblies will be utilized to build, drop or maintain this trajectory.

The sidetracked hole should require a minimum of azimuth control after the first azimuth change is made, since the planned trajectory of the side-track hole follows the azimuth of the original drilled hole closely, and a minimum of azimuth control was required in this interval during the original drilling operation. The inclination of the planned sidetracked hole will be decreased from approximately 25° after divergence and turn from the kick-off point, to approximately 2° at total depth.

If major azimuth changes are required during later stages of the side-track drilling, they may be accomplished by using an openhole whipstock (see Fig. 3). Prior to cementing in a whipstock, an azimuth change using (1) a bent sub and motor or (2) a retrievable whipstock may be tried.

2.4 Coring

Oriented cores offer the most positive method to determine the orientation of calcite filled or silica filled fractures and, if we are very fortunate, the orentation of recently opened fractures. Two coring intervals are projected for the sidetracked hole. Two cores will be cut in the interval between the kick-off point and the top of the experiment 2032 seismic cloud. At least one of these cores will hopefully be cut in the transition zone below the thief zone (see section 2.5). These early cores will provide an opportunity to test the oriented coring equipment at a lower temperature and the cores can be compared with four cores to be cut within the seismic cloud. Oriented cores are desired but technical problems remain to be worked out to successfully scribe cores in crystalline rock at high temperatures. The probability of obtaining oriented cores will decrease with depth and increasing temperature.

2.5 Geology and Natural Fractures

The sidetracking operation at 9290 ft will be performed in basement formation, either biotite granodiorite or gneiss (see Fig. 4). This granitic rock is essentially impermeable, except for "thief" zones mentioned below; inert to water; and extremely abrasive. This results in minimal filter cake development and hole gauge approaching the bit diameter. Drilling fluids and equipment will, where possible, be selected to achieve large high quality drill cuttings, and cuttings samples will be collected throughout the drilled interval as specified by the wellsite geologist.

A region of low to moderate loss of drilling fluids was encountered between 9,000 and 10,000 ft in EE-3. Based on fracturing experiments conducted just below the 9-5/8 in. casing shoe it appears that a system of natural fractures extends to a depth of 10,800 ft (the thief or leak off zone). This zone accepts fluid at 1200 psi above hydrostatic and high rate injection can be achieved at pressures around 2000 psi. This contrasts drastically with fracturing experiments in the 11,400 - 11,770 ft interval where breakdown occurred at a pressure of 4500 psi and high rate fracturing occurred at pressures in excess of 5500 psi. It is intended to determine as accurately as possible the extent of the thief zone penetrated by the new wellbore and the location of the transition zone that seperates the thief zone and the high fracture pressure region.

2.6 Drilling Fluids

The hole will be drilled with a mud system, stable at high temperatures, using viscous sweeps, periodically, to assist hole cleaning. The primary functions of the mud system will be to reduce drag, improve hole cleaning and reduce corrosion. Triglycerides (torque trim) or mechanical friction reducers will be used, as needed, to overcome torque and drag problems. Scale, corrosion and pH control will be employed. Mechanical separation equipment will be required on the mud pits for drill solids control.

2.7 Fracture Detection

Mud logging, temperature logs, radioactive tracer logs, caliper logs, a high temperature sonic televiewer, if available, and injection or flow tests using openhole packers will be used to locate fractures created during experiment 2032 and determine the structure of the experiment 2032 reservoir penetrated by the wellbore. If the repair of EE-2 is successful, the experiment 2032 reservoir will be maintained at a pressure of about 1000 psi during drilling operation in EE-3.

2.8 Well Completion

It may be possible to openhole complete the well using a 4-1/2 in. tubing string stung into a 9-5/8 in., casing packer set 100 ft above the whipstock. Based on previous completion work in EE-3 it is very likely that a 7 in. liner will have to be cemented-in for zone isolation and flow distribution equipment. A 7 in. liner extending up into the 9-5/8 in. casing above the whipstock would also eliminate the possibility of serious re-entry problems that could result from damage to the 9-5/8 in. casing at the top of the section or loosening of the whipstock after several thermal cycles.

If the original drilling trajectory fails to intersect sufficient fractures in the experiment 2032 reservoir, and stimulation using openhole packers does not achieve a useful flow connection to EE-2, the openhole will be plugged back to an undetermined depth, an openhole whipstock will be cemented-in and the well kicked of on a new trajectory.

3.0 GENERAL PLUGBACK AND REDRILLING PROGRAM

3.1 EE-3 - Present Wellbore Configuration

A detailed drawing of the present wellbore configuration of EE-3 is shown in Figure 1. After setting 2550 ft of 13-3/8 in. casing through volcanics and sediments a 12-1/4 in. hole was drilled in the Precambrian to 10,528 ft when a twist off during reaming occurred. After an unsuccessful fishing attempt the 12-1/4 in. hole was sidetracked off of a 10-1/2 in. OD whipstock at 9444 ft. The hole size was reduced to 8-3/4 in. at 10811 ft.

After the 8-3/4 in. hole was drilled to a total depth of 13,933 ft a 9-5/8 in., 47 lb/ft, P-110 production casing was set and cemented in at 10,374 ft. Early injection tests down the production casing showed the existence of a low pressure injection zone, the "leak off or thief zone", which was later determined to extend down to a depth of 11,800 ft.

The leak off zone accepts water at high rates at pressures below 2000 psi (all pressures in this plan refer to wellhead injection pressures) and its pore pressure is at least 260 psi subhydrostatic. An attempt to fracture below 11,400 ft using an openhole inflatable packers resulted in a packer failure. A 4-1/2 in. liner was cemented in from 11,390 ft to 10,890 ft in order to isolate the leak off zone and allow high pressure fracturing below the liner and above a sand plug at 11,770 ft. This lower interval was treated at a pressure exceeding 5500 psi and the 4-1/2 in. liner failed, near the cement top at 10,890 ft, five hours into the treatment. Several attempts to reconnect the liner, after removing a collapsed joint using overshot packoffs and screw-in subs, also resulted in failures. The internal patch assembly shown in the inset on Fig. 1 was installed, and the lower zone was fractured with two million gallons at 10 BPM at 6000 psi injection pressure.

The pressure flow rate behavior observed during fracturing showed evidence that the high pressure lower zone is in communication with the leak off zone. At rates below 1-1/2 BPM the injection pressure dropped far below the expected 4500 psi injection pressure to below 2000 psi. Channeling behind the 4-1/2 in. cemented in liner was suspected, but subsequent temperature logs give some evidence that flow is through a near wellbore fracture system.

3.2 Plugback of Openhole

After the tower is removed and the rotary rig is installed, the well will be bled off from both the tubing and annulus. Extreme precaution will be observed during bleed off since the presence of CO_2 and H_2S is possible. Once bled down, both the tubing and annulus should be loaded with water. Then the 4-1/2" tubing will be raised to unsting the 5-1/4 in. seal assembly, and CO_2 and H_2S gas will be circulated out using the wrap around hanger for control. After bottoms are circulated up, blowout prevention equipment will be installed. After stinging back into the PBR a pump-in test of the lower openhole section will be run.

If a pump-in test indicates a rate of 2 BPM, at 3000 psi or less, a barite slurry or cement will be pumped in stages to seal off the lower openhole zone between the top of the present sand plug at 11,770 ft and shoe of the openhole liner at 11,390 ft. When a pump-in rate of less than 1/2 BPM is achieved, the 2-7/8 in. seal liner and 5-1/2 in. tie-back liner will be removed. A retrievable packer will be run on 4-1/2 in. drill pipe and set near the shoe of the 9-5/8 in. casing. A pump-in test will be performed on the upper openhole zone between the top of the scab liner at 10,898 ft and shoe of the 9-5/8 in. casing at 10,374 ft. Previous pump-in rates of 5 BPM at 1600 psi to 10 BPM at 2000 psi have been established. A barite slurry or cement will then be pumped to seal off the upper zone. The retrievable packer will be pulled.

A 500 ft cement plug will be spotted through drill pipe bottomed at 10,374 ft, or the top of the sand and barite plug, whichever is higher. The drill pipe will be pulled and preparations for sidetracking made.

Detailed procedures of this and other operations will be prepared and available. Autoclave tests are being conducted on mud gel or frac gel and barite slurries to determine if a mixture can be made which will set up sufficiently to provide an adequate plug material. If the tests are successful cement will not be used and thereby prevent the risk of a flash set during plugging.

3.3 Sidetrack and Directional Program

A cast iron bridge plug will be set in the 9-5/8 in. casing a minimum of 50 ft below the bottom depth of the planned sidetracking window.

A section mill will be used to mill a section out of the 9-5/8 in. casing

9450

9285 9370

from ~~9250~~ ft to ~~9290~~ ft. A sand plug will then be spotted from the top of the bridge plug at 9340 ft up 4 ft into the milled section~~.~~ and A 200 ft cement plug ~~will then be~~ spotted on top of the sand. The drill pipe will be pulled and after waiting for the cement to set, the cement will be drilled out through the window, and the sand plug will be washed out.

A locator sub will be run, located on the lower stub, and removed prior to the actual installation of the packstock. This will assure proper packstock location on the lower 9-5/8 in. stub. Then the packstock whipstock (see Fig. 2) will be oriented and set in the 9-5/8 in. casing stub below the milled out section. A special drill-off assembly, without hardfacing, will be used to drill off the whipstock to reduce wear on the whipstock face. Rotary drilling will be continued off the whipstock until divergence from the original wellbore is assured based on surveys. Drill cuttings shall be closely checked for cement and new formation during drill-off, and while drilling, to establish separation of wellbores. (first inclination) established

After separation is achieved, the rotary drilling hook-up will be pulled, and a motor run will be made to achieve the ~~azimuth~~ change required for ~~in~~ the new wellbore. Once the initial downward curvature azimuth ~~change~~ has been achieved, rotary drilling assemblies will be used to drop, or hold ~~or build~~ angle while drilling ahead. ~~If~~ Additional azimuth changes ~~must be made~~ during drilling~~,~~ will utilize a mud motor ~~run or open-hole whipstock may be utilized to affect the desired azimuth change~~. Dogleg severity will be restricted to 2°/100 ft or less to reduce potential fatigue problems which could occur in the drill string and hold bending stresses to moderate levels in liners or other completion equipment.

The trajectory of the new wellbore will be turned to the right and down from the existing wellbore. ~~to minimize curvature at the whipstock point.~~ The length of the new hole will be approximately ~~3350~~ 3700 ft, with ~~a low but constant~~ the last 2100 ft being straight-drilled with a packed-hole rotary assembly ~~dogleg severity of approximately 0.5°/100 ft.~~

The development of the selected ~~points used to calculate the~~ trajectory is presented in Section 6 ~~(see Fig. 5 for downview and two side views) are listed in Attachment I~~

3.4 Drill Bits

Since the sidetrack hole in well EE-3 will be restricted to 8-1/2 in. diameter, a review of all comparable size bits utilized in drilling the deeper sections of both wells EE-2 and EE-3 was made. This review indicated that the most efficient 8-3/4 in. hard formation bits used in both wells was the Smith

Tool, 8-3/4 in. 7GA for regular rotary drilling, and the Hughes Tool, 8-3/4 in. HH-77 for motor drilling. It is therefore planned to utilize these bits in an 8-1/2 in. size for the sidetrack drilling of EE-3.

Since these bits are not used extensively in the drilling industry, their availability is severely limited. A check with Hughes Tool and Smith Tool in August, 1984 revealed only five 8-1/2 in., HH-77 and three 8-1/2 in., 4GA bits available (no 7GA's are available in the U.S). These bits have been shipped to Farmington, New Mexico for use on the Fenton Hill project. Hughes Tool Co. has indicated the next planned run of HH-77 bits will be in January, 1985. Smith Tool Co. has indicated their next run of 7GA bits will also be in January, 1985. Smith will set aside 20 bits out of that run for EE-3 drilling.

From the review of drill bit records for wells EE-2 and EE-3 mentioned above, it is estimated a minimum of eight HH-77 bits will be required for motor runs, and a minimum of twenty 7GA bits will be required for rotary drilling in the sidetracked hole of EE-3.

Once the sidetracked hole is drilled off the whipstock, the divergence may be established between wellbores, and partial azimuth orientation may be accomplished with the three 4GA and five HH77 bits presently available. Once these bits are exhausted, further drilling would have to be accomplished with whatever bits are available. It is anticipated that drilling could be significantly more expensive as a result of reduced penetration and increased trip and reaming time.

3.5 Coring Heads

From past coring experience in basement rock at Fenton Hill, the Smith Tool hybrid roller cone stratapax bit has been selected as most efficient. This bit designation is 7-7/8 in. x 3 in. TC7. Six of these bits have been ordered from Smith Tool. They will be manufactured when Smith makes their next run in early Spring 1985, and should be available for coring in the two intervals currently projected.

LANL has 2-20 foot core barrels remaining from previous drilling operations. These are re-conditioned and available. Presently, modifications are being considered to allow directional cores to be taken.

3.6 Drillstring and Drilling Assemblies

Sidetracking and early drilling will be done using Brinkerhoff 78, the completion rig which is currently repairing EE-2. This rig has a rental string of pipe which includes: 11,000 ft of 4-1/2 in., 16.60 lb/ft, GRADE E premium and 2000 ft of 4-1/2 in., 20.0 lb/ft, GRADE X premium. In order to maintain 100,000 lbs overpull in air with an 80,000 lb bottomhole assembly this string will be limited to a depth of 10,300 ft. Since the completion rig is limited to a depth of 10,700 there is not much justification for upgrading the string. The rig will be released after sidetracking and a larger drilling rig will be mobilized.

The specifications for the drilling rig require a 5 in. drillstring as follows: A minimum of 16,000 ft of 5 in. drillpipe API premium, or better, with suitable grades to provide a minimum of 100,000 lbs overpull in air while drilling at 14,500 ft w/80,000 lbs bottomhole assembly. This drill string must consist of at least 4000 ft of pipe with fresh hard banding and a minimum of 8,000 ft of pipe with smooth metal hard banding or no hard banding. After drilling the 8-1/2 in. hole, it is anticipated that a 7 in. liner will be set from about 7,800 ft to some depth (maximum drill depth anticipated is 14,500 ft). At this time the required drill pipe will be 8000 ft of 5 in. and 7,000 ft of 3-1/2 in. 13.30 S-135. All drill pipe is to have full tube and end area inspections since its past use. Depths shown in this specification provide for contingencies not covered in this drilling plan.

All tripping of the drillpipe will be done using the air-driven pipe spinner instead of the rotary or the spinning chain. This practice should significantly reduce the abrasive wear on the 9-5/8 in. casing and drillpipe handling damage. Similarly, caution should be exercised when setting the rotary slips on the drillstring to avoid creating external, circumferential indentations of a magnitude commensurate to fatigue crack development. Geothermal grade Jet Lube Kopr-Kote will be used for thread lubricant on all drillpipe, tubing and casing run in EE-3. Drillpipe protectors (rubbers) will be run one per joint on the top 4000 ft of pipe at all times.

The igneous basement rock below 2,400 ft at Fenton Hill is a very effective abrasive. Continuous monitoring of tool joint outside diameters and remaining hardfacing life will be required to keep drillstring replacement cost at an acceptable level.

Drilling fluid additives will be utilized as specified in the "Drilling Fluids Program" to control the corrosion rate (especially oxidation), and prevent scale formation. Additionally, corrosion rings will be run continuously in the string at the top of the drill collars and in the saver sub. These rings will be removed periodically to evaluate the performance of the corrosion prevention treatments. Magnetic induction, ultrasonic or gamma ray tube inspections will be performed to measure minimum wall thickness, cross sectional area and to detect cracks. A magnetic particle inspection of the tool joints and additional visual inspection of the internal bore at each end of the joint for deep, sharp pitting should be performed at the same time. Inspection frequency should be determined by the wellsite supervisor as actual operating conditions dictate, but at no time should the pipe be used in excess of 30° rotating hours without being subjected to a full length inspection. Blacklight or magnetic particle inspection of all tool joints in the bottomhole assembly should be performed at an interval not to exceed 100 rotating hours.

Bottomhole assemblies to build, hold or drop inclination will be run as required to follow the proposed drilling trajectory. The following equipment will be available on site for the make up of drilling assemblies as needed.

30 jts of 5 in. hevi-wate drill pipe
18 ea 6-1/2 in. OD drill collars
2 ea 6 point roller reamers with knobby cutters
2 ea 3 point rollar reamers with knobby cutters
3 ea 3 blade 8-1/2 in. OD spiral stabilizers
2 ea 6-1/2 in. OD short drill collars 10 ft to 14 ft long
1 ea 6-1/2 in. OD 30 ft Monel drill collar
2 ea shock absorber 6-3/4 in. rated for 500°F service

The following addition equipment will be available for motor runs as they are needed.

1 EA 1/2° BENT SUB, 1° BENT SUB, 1-1/2° BENT SUB α 2° BENT SUB
2 EA HIGH TEMPERATURE DRILL PIPE FLOATS WITH EXTRA EPDM INSERTS

Four 5-3/8 in. OD Maurer Engineering Turbodrills are being prepared for service in EE-3. These turbodrills were operated at depths up to 12,960 ft in the original drilling of EE-3. Directional runs with penetration exceeding 60 ft were obtained on the last three runs using Hughes Tool HH-77 bits.

Inquires have also been made into the possible use of several positive displacement motors in high temperature service but no specific plans to use motors have been prepared at this time.

3.7 Drilling Fluids and Hydralics

3.7.1 Interval ~~9290~~ 9300 ft - 12,730 ft

A lightweight, low solids, fresh water sepiolite and bentonite mud treated with ligite and caustic will be used in the 8-1/2 in. borehole. The mud weight will be kept below 9.2 ppg using double deck shakers, desanders, desilters and water dilution. High viscosity mud sweeps will be used to aid in hole cleaning. Torque trim or glass beads will be used if lubricity needs to be increased to reduce drag and torque. Bicarbonate of soda will be used to treat for cement contamination. A high pH, coating amines or oxygen scavenger and sulfide scavenger should be maintained at a concentration sufficient to protect the drillpipe and casing from oxygen during normal drilling and from CO_2 and H_2S should a substantial gas flow occur.

Mud properties should be adjusted to meet the specific requirements of operations planned. Typical properties should be:

1.	Mud Weight	8.7 to 9.2 ppg
2.	Plastic Viscosity	25 cp
3.	Yield Point	18 lb/100 ft^2
4.	Water loss	25 - 30 cc/30 mins.
5.	pH	10.0 - 11.0

Funnel viscosity and mud weight will be recorded on the driller's daily log four times each tour while drilling or circulating. A complete mud check will be run by the mud engineer at least every 24 hours, or as needed to maintain required mud properties.

3.7.2 Hydraulics for 8-1/2 in. Hole

Depth Interval	Drillpipe	Circulation Rate (gpm)	Annular Velocity (ft/min)	Nozzle Total Area (in^2)	Standpipe Pressure
9350-10,000	4-1/2"	305	144	.220	2500
9350-10,000	5"	295	153	.220	2500
10,000-11,000	4-1/2"	290	137	.205	2500
10,000-11,000	5"	285	148	.205	2500
11,000-12,000	4-1/2"	280	132	.20	2500
11,000-12,000	5"	275	143	.20	2500
12,000-12,730	4-1/2"	265	125	.190	2500
12,000-12,730	5"	265	137	.190	2500

(Variable pump speed based on maximum bit horse power)

The Smith Tool Company 7GA geothermal air bits were modified to use Jets for previous drilling at Fenton Hill. The hydraulics program for rotary drilling using 7GA bits is based on the rig having two pumps capable of delivering 210 gpm at 2500 psi on a continuous basis. The program assumes 540 ft of 6-1/2 in. x 2-1/4 in. drill collars, 900 ft of 5 in. Hevi-wate drillpipe and 4-1/2 in. 16.60 lb/ft and 20.00 lb/ft (2000 ft) or 5 in. 19.50 lb/ft drillpipe as indicated. The actual implementation will depend upon the pumps on the rig selected, the actual drill pipe received and the bottom-hole assemblies used. The hydraulics will be maximized using impact force and bit hydraulic horsepower. The flow regime in the annulus will be kept in laminar flow. Typical bit hydraulics will be:

1. Nozzle velocity 457 FPS
2. Impact force 607 lbs
3. Bit HP 280 HP/in^2
4. Pressure drop at bit 1683 PSI

3.8 Blowout Prevention Equipment

The blowout preventer stack will consist of (1) a 10 in. - 5000 psi working pressure double ram preventer with one set of pipe rams and one set of blind rams; (2) a 10 in. - 5000 psi working pressure x 18 in. spacer spool with two 3 in. outlets with a manual valve on one outlet and a HRC flow line valve on the other outlet; (3) a 10 in. - 5000 psi working pressure single ram preventer with a set of pipe rams; and (4) a 10" - 2000 psi working pressure annular preventer.

A closing unit of the appropriate size and configuration will operate the preventers and HRC valve. A 3 in. 10,000 psi working pressure choke manifold with two choke lines and a bypass line will be tied into the HRC valve flow line.

The ram rubbers shall be of high temperature resistant material. Pipe rams for 5 in. drill pipe, 4-1/2 in. drill pipe, 3-1/2 in. drill pipe, 5-1/2 in. casing (tubing) and 4-1/2 in. tubing will be used as appropriate for drilling and completion operations.

The blowout prevention equipment will be tested at 5000 psi when installed (2000 psi on the annular preventer) and at least once every 30 days thereafter, and following repairs that require disconnecting a pressure seal in the assembly including changing rams. The operation of the pipe rams will be checked daily and the operation of the blind rams will be checked once each trip. All BOP checks and pressure tests will be recorded daily on the drillers daily log.

The rig will supply an inside BOP and a full opening valve with the appropriate crossovers to install in any section of the drill string. The kelly will have a lower kelly cock and saver sub.

3.9 H_2S and CO_2 Safety

Large quantities of CO_2 gas have been produced with the flow back water after every large volume fracturing treatment performed below 11,000 ft in EE-2 or EE-3. H_2S concentrations in the CO_2 gas ranging from less than 10 ppm to as high as 300 ppm have been measured, but with concentrations above 60 ppm fairly rare. As these hydraulically created fractures are penetrated during drilling there is some possibility that large flows of CO_2 gas may occur.

CO_2 gas presents a safety hazard any time its presence significantly reduces the oxygen concentration in the air. At the Fenton Hill site the effect of a given CO_2 concentration may be more pronounced due to the rarified air at 8700 ft elevation. H_2S gas can cause hydrogen sulfide poisoning and should be considered dangerous when measured at concentrations above 10 ppm particularly since 10 ppm H_2S would be expected to occur only when very high concentrations of CO_2 have made a significant reduction in the oxygen content of the air. H_2S gas in air is potentially very dangerous at concentrations above 100 ppm. No data on H_2S in a predominately CO_2 atmosphere have been presented at any of our previous H_2S safety courses.

H_2S detectors will be installed on the rig floor, the cellar, the mud pits near the flow line and near the choke manifold. The detectors will set off an H_2S alarm whenever H_2S concentration exceeds 10 ppm. An audio alarm, loud enough to be heard over rig noise, will sound and a light alarm at eye level on the rig floor will shine when the detectors activate the system. A monitor in the dog house will provide a read out of H_2S levels at the 4 detectors. The alarm will be checked with a test switch and the detector will be tested weekly with H_2S gas bottles. All checks and tests should be recorded in the Driller's Daily Report.

The rig's choke mainfold will be connected into a geothermal separator with a 20 ft high gas venting stack. Any time significant volumes of CO_2 gas are circulated out of EE-3, the separator and vent stack should be used to disipate the gas if wind direction allows. Wind socks and surveyer's tape should be hung at appropriate places on the rig, pits and separator to serve as wind direction indicators.

H_2S safety training courses should be provided for each rig crew before operations on EE-3 begin. Reviews will be conducted once a week with each crew. Five Scott Air Packs should be properly stored within 100 ft of the rig floor, and two portable H_2S pocket monitors should be available to the rig crews (one for use at the mud pits and one for use at the cellar, choke manifold or separator).

The rig shall provide two portable 4 ft fans and these will normally be used at the cellar and flow line to assure dissipation of CO_2 and H_2S.

run through any cemented-in liner installed as part of the "final" completion of the well.

4.3 Coring

An important method for gaining information about the rock mass containing the Phase II reservoir system is oriented coring. The specific goals for the coring operation in wellbore EE-3A are:

1) Determination of the general petrographic structure and foliation of the rock mass.
2) Gaining information about the pre-existing (natural) fracture systems (number, orientation, spacing, toughness, extension) and their change with depth.
3) Determination of the orientation of the in situ stress field.

To reach the above given goals, long oriented cores have to be drilled. Because coring attempts in hard igneous rock have, in past coring attempts, failed due to rotating core barrels, new coring equipment is under investigation. A new coring device from Norton Christensen has promising features. It has a mudmotor with an internal stator connected to a nonrotating core barrel and external rotor rotating the bit.

Because of temperature limitations of the mudmotor (Navi-Drill) the cores in the deeper part of the new well EE-3A may have to be drilled with a standard coring barrel.

4.4 Openhole Packers

Openhole packers may be needed during the drilling, reservoir evaluation and well completion segments. Packers may be run during drilling to (1) determine the extent of the transition zone and the "leakoff zone", if encountered; (2) conduct openhole mini-frac breakdown tests for in-situ stress measurements; and (3) to develop confidence in an openhole packer system prior to drilling into the "seismic cloud" created during Experiment 2032.

Packer runs may be made during the drilling in the "seismic cloud" to (1) determine the extent of the sidetracked EE-3, EE-3A, that is communicating with EE-2; and (2) provide zone isolation for injection testing and communication tests to locate and evaluate fractures and suspected structures within the seismic cloud.

5.0 TENTATIVE WELL COMPLETION PLAN

5.1 Assumptions

At this time, planning for a "final" completion of EE-3 must remain very flexible. This final completion could follow a temporary open-hole completion as described in the summary (paragraph 2.8). Two 4-1/2 in. liners have been successfully cemented into 8-3/4" openhole sections of EE-2 and EE-3. Therefore permanent completions being considered use a 7 in. cemented liner. Cementing a liner across a section of the hydraulicly fractured region may present a much higher potential for loss of cement into fractures than has been seen before. Extensive use of openhole packers may be required to identify regions in the wellbore which are suitable for cement placement. Cement surries containing high temperature lost circulation materials (ie. ground battery casings) may be needed in the fractured region. Basic assumptions made for the planning are:

(1) EE-3 may be required to serve as both a production well (550°F production) and as an injection well (40°F injection) during reservoir testing and heat extraction experiments.

(2) High pressure fracturing treatments (7000 psi surface pressure) with or without proppant may be required to reduce the near wellbore flow resistance into or out of the reservoir fractures.

(3) Production fluids and injection fluids may be corrosive and a tubing string will be required to protect the 9-5/8" production casing.

(4) At some point in the reservoir evaluation process completion equipment to distribute flow into or out of several fracture systems may be needed (flow control) to maximize heat extraction from the existing 2032 reservoir.

(5) Flow rates as high as 10 BPM may be required for the heat extraction experiments.

(6) The reservoirs fracture systems are expected to grow substantially as heat extraction occurs.

5.2 Basic Completion Design

A 7 in. liner will be cemented-in above a liner shoe located at the top of the bottom designated openhole completion interval in the experiment 2032 reservoir. Several liner designs are being considered and liner hardware that is compatible with all of the designs will be selected whenever possible over equipment that is specifically intended for only one of the designs. The final liner design may be completed only days before installation. Designs being considered include:

(1) Short Openhole Liner - A short 200 to 300 ft long liner would be cemented-in deep in the openhole interval using a puddling technique. The liner would have a short near full bore PBR and tie-back sleeve on top (see Fig. 8). The openhole interval above the scab liner could be produced out of or injected into, but it would be in communication with the "leak-off zone" if it is penetrated. A very well centralized 4-1/2" OD liner of the same basic design can be cemented-in and, at a later date, removed using washover operations.

(2) Tie-back Liner System - This design would build upon the short liner by cementing-in one or two additional tie-back liners (See Fig. 9). In theory one openhole completion interval can be isolated with cement at the bottom or top of each liner. By using an external casing packer, gravity segregation or a sand fill outside of the liner each tie-back liner would have a competent cement behind part of the liner and the rest would remain uncemented. The final tie-back liner would extend 200 ft up into 9-5/8 in. casing and be cemented-in to prevent future problems re-entering the 9-5/8 in. casing at the whipstock. Each tie-back liner would have a short near full bore PBR to provide for internal seal assemblies for a cementing pack-off and flow control distribution equipment. Tie-back liners can be cemented using puddling or conventional cementing techniques.

(3) Fuller Liner - This design would provide a 7 in. liner from the top of the primary openhole interval to 200 ft up into the 9-5/8" casing. Several liner configurations would be possible:

1. Fully cemented liner. This will require perforations and breakdown treatments to reconnect to cemented fractures covered by the liner (an unproven technique). It would also provide the most assurance of a seal between the growing heat extraction reservoir and the thief zone,
2. Partially cemented liner with a 7 in. x 9-5/8 in. liner hanger and liner packer,

3. Stage cemented liner with external casing packers, or
4. Fully cemented liner into the top of the experiment 2032 reservoir with much of the reservoir drilled and completed subsequent to the initial testing using through liner straight hole drilling and completion with a 4 1/2 in. liner (See Fig. 10)

5.3 Tubulars

Tubulars used for liners and protective tubing strings will meet the following minimum requirements:

(1) L-80 or C-90 material for service in a stress corrosion environment.
(2) Premium connections with metal to metal seals - threaded and coupled (VAM) for cemented-in liners and integral joint with multiple seals (Hydril) for critical service tubing where high compressive loads may occur.

Tubulars in our present inventory will be used where they meet design requirements. These include (approximate footages):

(1) 2000 ft of 7 in. 35 lb/ft C-90 VAM (new);
(2) 1500 ft of 5-1/2 in., 20 lb/ft, C-90, hydril TAC I (1000 ft new and 500 ft used) and
(3) 11,000 ft of 4-1/2 in., 15.1 lb/ft, L-80, VAM (used-some will need new collars and to be rethreaded).

5.4 Liner and Completion Hardware

All completion hardware will be constructed from heat treatable low-alloy steels (AISI 4130 or 4140) heat treated to a maximum Rockwell hardness of RC-22. Premium threads will be used where possible and all eight round threads used will be pressure tested to the of 125% full maximum rated working pressure after make up. All seals will use molyglass chevron seals or Y-267 EPDM with mild steel backup rings to provide as close to a zero clearance extrusion path as possible.

Liner equipment will use cast iron or cast bronze for drillable insert floats. Thick wall aluminum can be used for guide shoes, baffles and landing collars. Centralizers will be a rigid design. Wiper plugs will be constructed of Viton or Y267 EPDM. Liner cementing equipment that may be needed for the various liner designs being considered include:

1) non-ported drillable guide shoe to set on temporarily sand plugs in the openhole;
2) ,circulating collar;
3) double float collar;
4) landing collar with latch in wiper plug;
5) external casing packer;
6) near full bore PBR;
7) jay type liner setting sleeve;
8) tie-back sleeve;
9) tie-back stem;
10) slip type mechanical set liner hangers;
11) liner packers;
12) rigid centralizers; and
13) Jay-type liner setting tools with "molyglass" seal unit pack offs.

5.5 Liner Design Calculations

Triaxial (maximum distortion energy theory) stress will be calculated which includes bending, thermal, mechanical and hydraulic loads on the liner. A 20% safety factor and a 20% yield strength reduction for high temperature service will be applied to the rated yield strength of the pipe for a 36% total reduction. Measured doglegs will be doubled for the calculations and additional bending will be imposed where axial compression or buckling is occurring. Potential hydraulic pressure traps will be eliminated from all liner designs or appropriate pressure relief systems will be designed.

5.6 Cementing Procedures

Prior to cementing, the wellbore will be cooled to mid range (300°F) in the maximum potential thermal cycle (50°F to 550°F) by circulating water or drilling mud through the liner. Circuling rates and times to achieve cool down will be calculated using the Wellbore Heat Transfer Code to simulte cool down. Cement placement will attempt to achieve a uniform uncontaminated slurry. Batch mixing will be used for all slurries. Bottom and top wiper plugs will be used where possible. Where appropriate the puddling technique will be used and the contaminated lead and tail slurry will be reversed out off of the cement column prior to lowering the liner into the cement for final placement.

Critical cement plugs will be spotted with a cement placement tool using two wiper plugs. Cement plugs may be spotted on top of high viscosity and/or high density pills to minimize inversion.

5.7 Cementing Materials

All cement for high temperature cementing will be sampled and set aside in reserved silos while laboratory cement slurry design and testing is done. Fenton Hill site water will be sent to the laboratory for the tests. LANL staff will duplicate cement testing with the same batches of cement and water. The basic system to be used will consist of:

(1) Class "H" cement;

(2) 40% silica flour;

(3) high temp retarder for 3-1/2 to 4 hour thickening time at bottomhole circulating temperature; and

(4) de-foamer;

Typical slurry properties will be:

(1) 16.5 lbs/gal;

(2) 1.4 ft^3/sack;

(3) 5.2 gal of mix water per sack; and

(4) 8000 psi compressive strength in 48 hours.

Variation of this mixture will be made to achieve lower density, lower fluid loss, loss circulation materials or change the cement setting temperature. A cement slurry will be designed with a setting time which occurs 1/4 to 1/3 of the way into temperature recovery after placement is complete. This will immobilize the liner at a point somewhat above midpoint in the maximum thermal cycle and cause the liner to have a tensile stress at full cool down which is somewhat higher than the compressive stress of full heat up. This may be fairly critical where uncemented sections of liner are designed to provide openhole completion intervals. In these cases buckling calculations at the maximum compressive stress will be made to assure integrity of the liner.

5.8 Tubing String

A 4-1/2 in., 15.1 lb/ft, L-80, VAM tubing will be used to protect the 9-5/8 in. casing from corrosive produced fluids or high injection pressure. Thermal expansion and contraction of the tubing will be provided for with an expansion joint, PBR seal assembly or slick OD joint stung into a casing packer with internal seals. Depending on the liner completion finally selected, some 5-1/2 in. 20 lb/ft C-90 TAC I may be needed at the top or bottom of the tubing to minimize buckling or tensile loads (engineered string). A clear water packer fluid with a high temperature corrosion inhibitor, a biocide, and a pH of 10.0 will be pumped into the tubing-casing annulus just for the final landing of the tubing.

5.9 Wellhead and Tubing Landing System

A 10 in. - 5000 psi x 4" 10,000 psi tubing head bonnet with a 5 in. VAM tubing hanger bushing will support a 38 ft long 5 in. OD, 20.8 lb/ft, C-90, VAM slick OD landing joint. A 5 in. wrap around tubing hanger will seal on the slick OD joint and land in a 10 in. - 5000 psi x 12 in. - 5000 psi tubing spool with 2 in. - 5000 psi flanged outlets below the wrap around. A 4 in. - 10,000 psi master gate valve will be used on top of the bonnet. Various valves and choke configurations will be installed for stimulation, injection and production service.

A wear bushing will be installed in the tubing spool prior to beginning drilling operations and removed prior to tripping in the tubing for final landing on the wrap around.

DSD/jwc

Enc. a/s

Figures

Omit

ATTACHMENT I

NORTH	EAST	DEPTH	DRILL DEPTH	AZIMUTH	INCLINATION	CURVATURE
-297.45	-476.86				2816.81	2863.81 70
.21 22.57	KOP					
-293.47	-465.67				2843.52	2892.98 70
.33 25.18	.78					
-288.56	-452.45				2873.41	2926.03 68
.71 24.90	.57					
-283.42	-439.88				2903.30	2958.86 66
.78 23.97	.56					
-278.09	-428.02				2933.19	2991.46 64
.85 23.06	.55					
-272.61	-416.84				2963.08	3023.83 62
.91 22.16	.55					
-267.02	-406.34				2992.97	3056.01 60
.98 21.27	.54					
-261.34	-396.49				3022.86	3087.99 59
.06 20.39	.53					
-225.60	-387.28				3052.75	3119.79 57
.15 19.51	.52					
-249.86	-378.69				3082.64	3151.41 55
.26 18.64	.51					
-244.12	-370.70				3112.53	3182.88 53
.39 17.77	.50					
-238.44	-363.31				3142.42	3214.19 51
.55 16.90	.50					
-232.84	-356.48				3172.31	3245.36 49
.74 16.02	.50					
-227.36	-350.20				3202.20	3276.39 47
.97 15.13	.49					
-222.03	-344.47				3232.09	3307.29
46.24	14.23				.49	
-216.89	-339.25				3261.98	3338.06 44

Omit

.55	13.31	.50			
-221.96		-334.53	3291.87	3368.72	42
.92	12.38	.50			
-207.29		-330.31	3321.76	3399.27	41
.34	11.43	.51			
-202.90		-326.55	3351.65	3429.71	39
.82	10.45	.52			
-198.83		-323.24	3381.54	3460.06	38
.36	9.44	.53			
-195.12		-320.37	3411.43	3490.31	36
.99	8.40	.54			
-191.79		-317.93	3441.32	3520.49	35
.73	7.33	.56			
-188.89		-315.88	3471.21	3550.59	34
.60	6.23	.57			
-186.44		-314.22	3501.10	3580.63	33
.67	5.08	.59			
-184.47		-312.92	3530.99	3610.61	33
.11	3.90	.61			
-183.03		-311.98	3560.88	3640.55	33
.07	2.72	.57			
-182.07		-311.36	3590.77	3670.46	33
.07	1.67	.50			
-181.54		-311.02	3602.66	3700.66	33
.07	.76	.43			
-181.38		-310.91	3650.55	3730.25	33
.07	.01	.36			
-181.53		-311.01	3680.44	3760.14	33
.07	.64	.29			
-181.92		-311.26	3710.33	3790.03	33
.07	1.13	.21			
-182.50		-311.64	3740.22	3819.93	33
.07	1.48	.14			
-183.20		-312.09	3770.11	3849.83	33
.07	1.69	.07			
-183.96		-312.59	3800.00	3879.74	33
.07	1.76	0.00			

Omit

SIDETRACKING PROCEDURE FOR EE-3

1. AFTER PLUG BACK OF OPEN HOLE SECTION AND REMOVAL OF 4½" TUBING RUN A CEMENT BOND LOG AND COLLAR LOCATOR LOG TO 9500'.

2. RUN AND SET A PERMENANT BRIDGE PLUG AT 9410'.

3. MILL A SECTION OF 9⅝" CASING FROM 9293'± TO 9360'± (AT SELECTED SIDETRACK POINT BASED ON ABOVE CBL AND COLLAR LOCATOR LOG — ORIGINAL 12¼" HOLE WAS OPENED TO 16" FROM 9293' TO 9330' FOR UNSUCCESSFUL SIDETRACK ATTEMPT).

4. RUN DRESSING MILL AND JUNK BASKET THROUGH WINDOW TO BRIDGE PLUG BELOW WINDOW, CIRCULATE WORKING DRESSING MILL THROUGH 9⅝" STUB BELOW WINDOW.

5. RUN OPEN-ENDED DRILL PIPE AND SPOT SAND PLUG ON TOP OF BRIDGE PLUG AND UP INTO MILLED SECTION 4' ABOVE TOP OF BOTTOM STUB OF 9⅝" CASING. AFTER ALLOWING TO SETTLE, CHECK TOP OF SAND PLUG (USE BRIDGE PLUG FOR REFERENCE POINT PRIOR TO SPOTTING SAND).

6. AFTER CIRCULATING FOR COOL DOWN, SPOT A CEMENT PLUG FROM TOP OF SAND ACROSS WINDOW AND MINIMUM OF 200' ABOVE WINDOW. USE DOWELL SYSTEM #1 PLUG TYPE CEMENT.

7. AFTER WOC 12 HOURS RUN IN HOLE WITH STIFF HOOK UP (BIT OR MILL, SHORT SQUARE COLLAR, SPIRAL STABILIZER, SHORT SQUARE COLLAR, SPIRAL STABILIZER AND SUFFICIENT DRILL COLLARS FOR WEIGHT — SQUARE COLLARS AND STABILIZERS TO HAVE NO HARD FACING). CHECK TOP OF PLUG AND PLUG HARDNESS.

8. AFTER WOC 24 HOURS, DRILL OUT CEMENT TO JUST BELOW TOP OF WINDOW TO 9298', CIRCULATE BOTTOMS UP AND PULL OUT OF HOLE.

9. PICK UP DIAMOND BIT, MUD MOTOR, KICK SUB AND ORIENTING TOOLS ON HEVI-WATE DRILL PIPE AND RUN IN TO 9295'. ORIENT TOOLS AND START SIDE-TRACK ATTEMPT USING EXTREME CAUTION ON WEIGHT CONTROL (SIDE TRACK ATTEMPT WILL BE MADE OUT OF LOW SIDE OF HOLE WHICH HAS APPROXIMATE 22° OF INCLINATION AT SIDETRACK POINT).

10. IF SIDETRACK IS SUCCESSFUL, DRILL SUFFICIENT DISTANCE WITH MOTOR TO ASSURE DIVERGENCE FROM OLD BOREHOLE (APPROXIMATELY .00').

11. AFTER APPROXIMATELY 200 OF NEW HOLE IS DRILLED, THE TURN AND DROP OF THE NEW HOLE WILL BE INITIATED TO FOLLOW THE PROJECTED NEW DIRECTIONALLY ORIENTED WELL PATH.

12. IF THE SIDETRACK ATTEMPT IS UNSUCCESSFUL, AND THE CEMENT THROUGH THE WINDOW IS DRILLED OUT TO THE BOTTOM OF THE ENLARGED (16") HOLE, RUN OPEN-ENDED DRILL PIPE AND RESPOT CEMENT PLUG THROUGH WINDOW AND 200' ABOVE WINDOW USING CEMENT MIX AS ABOVE IN STEP 6.

13. AFTER WOC 12 HOURS RUN IN HOLE WITH STIFF HOOK- AS ABOVE IN STEP 7. CHECK TOP OF PLUG AND PLUG HARDNESS.

14. AFTER WOC 24 HOURS, DRILL OUT CEMENT THROUGH WINDOW AND WASH OUT SAND TO TOP OF BRIDGE PLUG. PULL OUT OF HOLE.

15. PICK UP WHIPSTOCK LOCATOR SUB ON DRILL COLLARS WITH STABILIZER IMMEDIATELY ABOVE LOCATOR SUB AND ABOVE FIRST DRILL COLLAR, RUN IN HOLE AND LOCATE BOTTOM STUB OF 9 5/8" CASING. WHEN LOCATED, BE SURE VERY ACCURATE MEASUREMENT OF PIPE AND TOOLS IS MADE TO FACILITATE LOCATION OF WHIPSTOCK ON SUBSEQUENT RUN. PULL OUT OF HOLE.

16. PICK UP, RUN, ORIENT AND SET PACK-STOCK

whipstock in bottom sub of 9 5/8" casing

17. RUN SIDETRACK STARTING HOOK-UP (BUTTON BIT

WITH NO PROTECTION ON SHANK OR SHIRT TAIL, SPIRAL STABILIZER, SHORT SQUARE COLLAR, SPIRAL STABILIZER AND DRILL COLLARS FOR WEIGHT. THE SPIRAL STABILIZERS AND SHORT SQUARE COLLARS ABOVE SHALL HAVE NO HARDFACING).

18. DRILL OFF 10' (APPROXIMATELY [illegible] THE WHIPSTOCK FACE). PULL OUT OF HOLE AND INSPECT STARTING HOOK-UP FOR WEAR AND CONDITION. IF OKAY, RUN BACK IN HOLE AND CONTINUE ON OFF OF WHIPSTOCK. CHECK FOR INCREASE IN FORMATION CUTTINGS. DRILL AHEAD 15' TO 20' AND PULL STARTING HOOK-UP OUT OF HOLE.

19. RUN IN WITH DRILL AHEAD HOOK-UP (EXACT HOOK-UP TO BE DETERMINED BY DIRECTIONAL SUPERVISOR).

20. ROTARY DRILLING WILL BE CONTINUED OFF THE WHIPSTOCK UNTIL SEPARATION FROM THE ORIGINAL WELLBORE IS ASSURED. DRILL CUTTINGS SHALL BE CLOSELY CHECKED FOR CEMENT AND NEW FORMATION, AND DEVIATION SURVEYS SHALL BE TAKEN PERIODICALLY WHILE DRILLING AHEAD TO ESTABLISH SEPARATION OF WELLBORES.