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Repair, Sidetrack, Drilling, and Completion of EE-2A for Phase II Reservoir Production Service

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Repair, Sidetrack, Drilling, and Completion of EE-2A for Phase II Reservoir Production Service

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REPAIR, SIDETRACK, DRILLING, AND COMPLETION OF EE-2A FOR PHASE II RESERVOIR PRODUCTION SERVICE

by

D.S. Dreesen, G.G. Cocks, R.W. Nicholson, and J.C. Thomson

ABSTRACT

Hot Dry Rock (HDR) geothermal energy well EE-2 at Fenton Hill, New Mexico, was sidetracked and redrilled into the HDR Phase II reservoir after two unsuccessful attempts to repair damage in the lower wellbore. Before sidetracking was begun, six cement slurries were pumped to plug the abandoned lower wellbore and to support the production casing where drilling wear was predicted and where sidetracking was to occur. This work and the redrill of EE-2A were completed in November 1987. Specifications were prepared for a state-of-the-art tie-back casing, which was procured, manufactured, and delivered to Fenton Hill in May 1988. The well was then completed in June 1988 for hot-water production service by cementing in a liner and the upper section of production casing and installing and cementing a tie-back casing string.

I. INTRODUCTION

The world's first hot dry rock (HDR) geothermal energy system was constructed by the Los Alamos National Laboratory (LANL) at Fenton Hill, New Mexico, in 1977 and is referred to as the Phase I system. It was created by drilling a hole from the surface into the granitic rock to a depth of approximately 3000 m (10,000 ft) at a bottom-hole temperature of 195°C (383°F), producing hydraulic fractures centered at a depth of 2600 m (8500 ft) , and then directionally drilling a second hole to intersect those fractures. Water was injected into and then produced from the man-made reservoir at temperatures and thermal power rates as high as 175°C (347°F) and 5 MWt, respectively. The system was enlarged in 1979 by additional hydraulic fracturing and then operated successfully for almost a year. Complete results of these early reservoir tests are provided by Dash et al.[1]

Construction of a larger, hotter, HDR system was initiated in 1979 to extend the technology to the temperatures and rates of heat production required to support a commercial power plant. It is referred to as the Phase II system. Two new holes about 50 m (150 ft) apart at the surface, EE-2 and EE-3, were drilled directionally; EE-2, the deeper well, to a vertical depth of 4390 m (14,400 ft) and EE-3 to a vertical depth of 3970 m (13,025 ft).

EE-2 was drilled to a measured total depth (TD) of 4660 m (15,289 ft) in 1981 as the intended reservoir stimulation (reservoir creation) and injection well for the Phase II HDR demonstration. Damage to the 339.7-mm (13-3/8-in.) intermediate casing during and following its installation required premature installation of a 244.5-mm (9-5/8-in.) production (injection) casing at a depth of 3529 m (11,578 ft).[2] The production casing was worn thin over several intervals during milling operations that occurred before the well reached TD.

Fracturing deep in the well through a cemented-in liner[3] failed to establish a reservoir connection to well EE-3,[4] and most of the open hole below the production casing was abandoned with the placement of sand plugs up to 3658 m (12,000 ft) and later up to 3550 m (11,646 ft). Fracturing below the casing shoe through casing packers and tubing protected the casing from fracturing pressures that were two to three times higher than had been predicted, based on the Phase I reservoir stimulation.[1] A wellhead failure occurred after the largest injection of 21,000 m^3 (5.6 million gallons) in 1983.[5] Later the tubing-casing annulus was inadvertently blown down during repair of the wellhead.

We believe this blowdown caused the production casing to collapse near the top of the reservoir that had just been created. In any event, damage to the well resulted in leaks that connected (through the uncemented production casing annulus) the well to subhydrostatic aquifers just above the basement rock at 730 m (2400 ft).

The first attempt to repair the well in 1984 isolated the aquifer but left the well connected to a low-pressure reservoir (similar to Phase I) at a depth of 2850-3100 m (9400-10,200 ft). A reservoir connection was achieved during the 1985 redrill of EE-3A into the EE-2 reservoir,[6] but continued deterioration of EE-2 during its first production service prevented wireline logging into the Phase II reservoir. However, production from the reservoir had not been reduced, and a 30-day flow test of the reservoir[7] in 1986 used EE-3A for high-pressure injection and EE-2 for low-pressure production service.

A second repair attempt in 1986 found EE-2 in much worse condition than had been predicted, and the repair was quickly terminated. The condition of the casing was reevaluated following a cement bond log (CBL) and a 64-arm caliper log. The condition of EE-2 above the 3204-m (10,512-ft) collapse was reasonably good. Figure 1 is a schematic of the EE-2 wellbore following the second repair attempt. Costs for several repair and redrilling options were reestimated, and a detailed plan was prepared to sidetrack and redrill EE-2.

EE-2 was plugged with cement to the top of the damaged region in the first stage of the redrilling program. Additional cement was placed in the annulus outside the production casing to

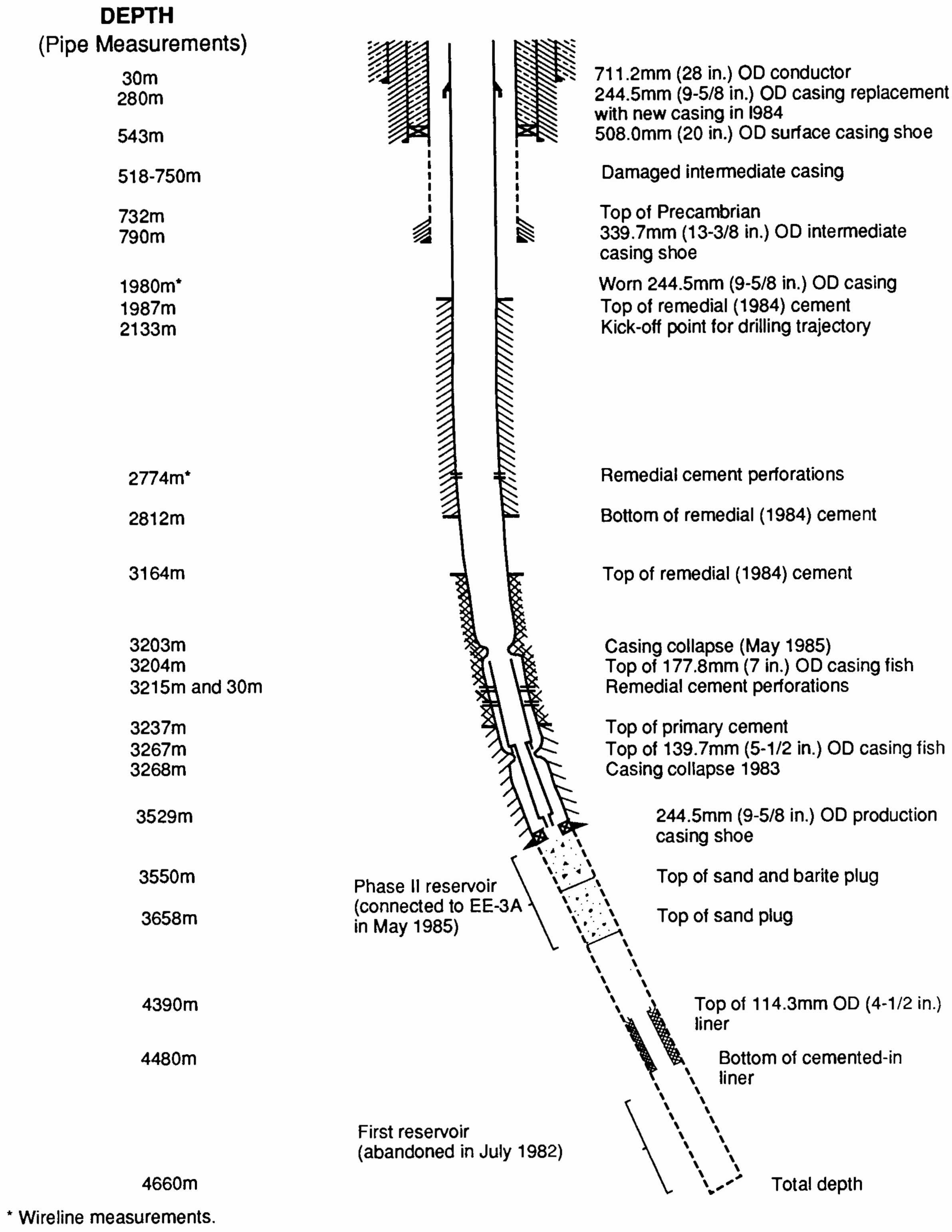

Fig. 1. EE-2A schematic of the well configuration at start of repair and sidetracking.

assure separation of the old and new wellbores and to support the production casing during redrilling. Sidetracking and redrill were completed in November 1987. Operations were suspended after a short reservoir test demonstrated that the redrilled well had successfully penetrated the reservoir and an adequate connection had been achieved.

A specification for surplus casing was prepared and a formal request for quotations (RFQ) was distributed. The procurement of suitable high-strength, sour service 177.8-mm (7-in.) OD casing from surplus stockpiles was not successful, so new casing was purchased at competitive prices using the same specification with a May 1988 delivery at Fenton Hill. Detailed well completion plans were prepared while the casing was manufactured and shipped.

When rig operations resumed in May, a 177.8-mm (7-in.) OD liner was cemented-in, additional cement was placed in the top 275 m (900 ft) of annulus outside the production casing, and 177.8-mm (7-in.) OD tie-back casing was installed and cemented to the surface. In this report the 244.5-mm (9-5/8-in.) OD casing will be referred to as the production casing and the subsequently installed 177.8-mm (7-in.) OD casing will be referred to as the tie-back casing.

II. PLANNING

Los Alamos staff and consultants prepared a detailed plan to plug back, cement the 244.5-mm (9-5/8-in.) casing annulus, sidetrack EE-2, and drill and complete EE-2A. The plan was reviewed by an additional consultant and then presented to a U.S. Department of Energy (DOE) review panel. After revision, the plan had 10 major activities:

(1) Plug the damaged wellbore below the casing collapse at 3200 m (10,500 ft) with cement and with back-up cementing above that point so that the damaged wellbore and the redrilled bore would be isolated from each other.

(2) Cement the annulus behind the production casing to minimize the possibility of a casing failure during the redrilling and to contribute to the success of the planned sidetracking.

(3) Set aside cement for the operations in a reserved silo and formulate and test various slurries using samples from the reserve silos and water from the Fenton Hill domestic supply well.

(4) Sidetrack and redrill using an optimum low dogleg trajectory, a sepiolite drilling fluid, and special low-drag directional drilling assemblies. This procedure was used previously during the successful redrill of EE-3A.[6]

(5) Select drilling targets and a well trajectory that maximized the potential penetration of the reservoir based on earlier seismic (microearthquake) mapping[8-10] and fell within the constraints imposed by the outside review panel.

(6) Build up the pressure in the reservoir through injection into EE-3A during the redrilling in an attempt to prevent the loss of drill cuttings into the reservoir and cause inflow to occur as the reservoir was penetrated by EE-2A. A complete geological and drilling fluid log was specified to assure that the well path was penetrating the reservoir. A postdrilling reservoir flow test was developed to verify successful reservoir penetration.

(7) Perform a complete set of casing stress calculations to assure that casings of suitable strength and wall thickness were installed as liner and tie-back string and to optimize the installation procedure.

(8) Develop a procedure to cement the annulus outside the production casing from 274 m (900 ft) to the surface that would avoid the requirement to cement lost circulation intervals below 520 m (1700 ft). This cemented annulus would reduce the stress in the surface and intermediate casings to acceptable levels and thereby eliminate the need for a wellhead expansion spool.

(9) Install an open-hole, cemented-in liner using technology that was successfully tested in earlier liner installations at Fenton Hill.

(10) Initiate procurement of the tie-back casing as recommended by the outside review panel and plan to cement the tie-back casing to the surface, subject to the existing economic constraints.

A detailed technical specification was prepared for the purchase of approximately 3000 m (10,000 ft) of 177.8-mm (7-in.) OD casing to be used as a tie-back string. This specification was primarily intended to purchase new, previously manufactured (surplus) casing that was believed to be available. The specification was prepared to assure that the casing purchased met the special strength and material requirements that had been identified in earlier well completion work in the Fenton Hill Phase II reservoir.[11]

An 11.5-mm (0.45-in.) thick-wall, moderate-strength casing was needed with controlled hardness of steel for service in a known stress corrosion cracking environment. Surplus casing would be prescreened based on mill certification documentation, general appearance, and evidence of proper handling and storage since the time of manufacture. Tentative award of the procurement would be made based on price if the casing met the technical specification. Final acceptance would be accomplished with a thorough qualification procedure. Destructive testing of a small sample of joints to check mechanical properties and metallography would, if satisfactory, be followed by a complete nondestructive test (NDT) inspection of the casing. The NDT specified exceeded American Petroleum Institute (API) requirements. Final award of the procurement would be negotiated following the NDT.

Premium thread connections were specified, and rethreading was allowed. The specifications and qualification procedure also allowed for the possibility that the surplus casing bid would not be acceptable and that new casing would have to be manufactured, which in fact occurred.

III. CONTRACTS

LANL buyers in the Materials Management Division assisted with the procurement of major services and hardware. The award of these contracts was based on HDR Project staff evaluations of submitted cost and technical proposals. The drilling contract provided for the procurement of reimbursable services and hardware on a third-party basis through the drilling contractor. HDR staff with Materials Management Division oversite used this arrangement to acquire required day-to-day specialty services and equipment.

A. Drill Rig

Big Chief Drilling Company Rig #47 was originally contracted to redrill EE-3A in 1985. The contract was extended and the rig was skidded to EE-2 for the second repair of EE-2. The contract was extended a second time so the rig could be used to redrill and complete EE-2A.

Rig #47 is capable of drilling deep gas wells to 9000 m (30,000 ft). It has a draw works, mast, and substructure rated for 6600-kN (1.5 million-lb) pull (see Table I for detailed description). This capability was larger than specified in the original EE-3A drilling rig specification, but the rig's large capacity had proved valuable several times during the redrill of EE-3A. It was decided to save the cost of demobilizing rig #47 and mobilizing another rig by extending the contract with Big Chief.

TABLE I. DESCRIPTION OF BIG CHIEF RIG #47

	Metric	Customary
Mast (Pyramid type)		
152x30 (ft) rated at	7.1×10^6 N	1.6×10^6 lb_f
Substructure (Pyramid) setback,	3.5×10^6 N	0.8×10^6 lb_f
with hanging load of	6.7×10^6 N	1.5×10^6 lb_f
Draw works (Gardner Denver 3000E)		
Power (electric), 3 each	746 kW	1000 hp
Drilling line	44 mm	1-3/4 in.
Traveling equipment	6.7×10^6 N	750 ton_f
Pumps, 2 each (Gardner Denver PZ-11)		
Power (electric), 2 motors	746 kW	1000 hp
Stroke	279 mm	11 in.
Liners	140 mm	5-1/2 in.
Rotary table (Gardner Denver)	952 mm	37-1/2 in.
Blowout preventers		
Cameron type U	279 mm	11 in.
Working pressure	34.5 MPa	5000 psi
Power supply, type SCR Ross-Hill		
Caterpillar, 3 each, D-399 diesel	970 kW	1300 hp

The drilling contractor provided single-ram, double-ram, and annular blowout preventers. A rotating head was installed to provide maximum safety during drilling and other operations in the Phase II reservoir that is capable of short but prolific production of carbon dioxide gas with up to 150-ppm concentration hydrogen sulfide. A gas buster was installed to salvage drilling fluids when they were in use.

A drilling fluid (mud) cooler was fabricated from DOE surplus liquid-liquid heat exchangers obtained from the East Mesa binary turbine demonstration project. It was connected to the conventional circulating system. The air-contactor type mud cooler, which was used on the EE-3A redrill, was also installed as a supplemental and backup cooler, but it was used as little as possible to minimize the oxygen content of the mud. A mud mixing and storage plant was installed adjacent to the rig's mud tanks to reduce the amount of rig time expended mixing and conditioning mud.

B. Other Contracts

In addition to the drill rig contract, contracts for other major well services were competitively awarded. These included (1) engineering support and rig supervision, Lithos (formerly Well Production Testing); (2) cementing services, Dowell-Schlumberger; (3) high-pressure pumping services, BJ Titan; (4) chemicals and drilling fluid additives, NL Baroid; and (5) geologic and drilling fluid (mud) logging services, Epoch Well Logging.

Two sole source hardware procurements were justified by prior efforts to develop HDR support equipment that was compatible and met technical requirements: (1) a high-temperature/high-pressure open-hole stimulation packer, Baker Service Tools (formerly Lynes, Inc.)[12] and (2) a packstock packer to mate to a LANL-owned whipstock (surplus from the EE-3A redrill), Grant-AZ-Drilex.

C. Third-Party Procurements

Other services and hardware were procured using the third-party agreement with the drilling contractor. The larger third-party procurements were made following evaluation of informal technical and cost proposals. The reviews were made by the LANL drilling team, which included Earth and Space Sciences Division staff and consultants. Some of the larger procurements included (1) directional drilling services, Directional Investment Guidance; (2) drilling motors, Grant-AZ-Drilex; (3) reamers and stabilizers, Spidle; (4) directional wireline services, AMF Scientific Drilling; (5) high-temperature wireline logging and perforating, Oilwell Perforators; (6) low-temperature wireline logging and perforating, Welex; (7) rental equipment, e.g., miscellaneous drill string, handling, and supplemental blowout prevention and safety equipment, Land and Marine; (8) expansion joints to support open-hole packer operations, Baker Service Tools (formerly Brown Oil Tools); (9) wellhead equipment, Food Machinery Corp. (formerly OCT); and (10) wellhead valves, Foster WLG.

IV. WELL OPERATIONS

Most well services, materials, and hardware were furnished from Farmington, New Mexico, 280 km (170 miles) from the Fenton Hill site, from Midland-Odessa, Texas, 1125 km (700 miles), or from Casper, Wyoming, 1290 km (800 miles). Daily planning was required not only to assure that appropriate services and hardware were mobilized to be available as needed but also to keep standby costs at a minimum. Consultants and staff updated a projected schedule of upcoming activities as each major activity was completed. The schedule, drill plan, and detailed procedures that had been prepared for the more complex activities were monitored to identify and alert appropriate service companies and LANL support staff for each activity.

The most significant activities are discussed with a technical perspective in the following sections. Appendix A is a brief summary of daily operations that can be used to place specific activities into sequence.

Rig supervisors, provided by the engineering support contractor, directed well operations. The engineering support contractor also provided a drilling office manager who (1) compiled, edited, and distributed drilling plans and detailed procedures; (2) administered third-party procurements, informal RFQs, rentals, shipping, and receiving; (3) maintained field cost estimates; and (4) performed accounting and budgeting functions.

The rig was operated on an oil field day-work contract, and Big Chief provided an on-site tool pusher on a 24-hour-per-day basis. The drilling staff (LANL and Lithos) received twice-daily reports, made a daily on-site review of operations and plans, and provided on-site supervisory and technical support for the more complex operations.

The Fenton Hill site staff, consisting of LANL technicians and contract staff provided by a site support contractor, supplied support services: (1) fresh water and rig water supply; (2) pit water treatment, flocculation, settling, and clarification; (3) drilling mud storage and disposal; (4) on-site drill pipe and casing movements; (5) auxiliary pumping service; and (6) machine shop and welding support.

A LANL logging team ran high-temperature noncommercial logs in EE-2A in support of cementing and reservoir evaluation that included gamma-ray/temperature, gamma-ray/three-arm caliper, and sonic televiewer. Table II is a complete list of wireline logging and completion services, including commercial and LANL logs.

Routine services supporting rig operations included (1) drill pipe pickup/laydown and casing services; (2) blowout preventer tests; (3) H_2S safety services; (4) drill pipe, drill collar, and casing inspection; (5) welding, machine shop, and fabrication; (6) trucking, hot shot, and motor freight; and (7) premium thread casing makeup services.

TABLE II. SUMMARY OF LOGGING AND WIRELINE OPERATIONS ASSOCIATED WITH THE REDRILL AND COMPLETION OF EE-2A

Date	Description of Log or Activity	Company[a]	Depth Interval Top-Bottom (ft)
11/26/86	Casing profile caliper log	Dia-Log	0-10,500
11/26/86	Casing minimum ID caliper log	Dia-Log	0-10,600
3/19/87	Cement bond/gamma log	OWP	6000-10,495
3/20/87	Casing inspection log	OWP	100-10,495
9/10/87	Kuster slick line temp survey	LANL	10,435
9/12/87	Perforate 9-5/8-in. casing 4 shots/ft	OWP	10,221-10,225
9/12/87	Kuster slick line temp survey	LANL	10,200
9/14/87	Kuster slick line temp survey	LANL	9050-9875
9/15/87	Perforate 9-5/8-in. casing 4 shots/ft	OWP	9546-9550
9/19/87	Spud sinker bars into section mill	Big A	9688
9/27/87	3-arm caliper of milled section	LANL	9600-9820
9/28/87	Temp/casing collar locator	LANL	0-7000
9/28/87	Perforate 9-5/8-in. casing 4 shots/ft	OWP	9470-9476
10/01/87	Kuster slick line temp survey	LANL	800-3500
10/08/87	Orient whipstock	SDI	9685
10/14/87	Temp/casing collar locator	LANL	0-12,025
10/18/87	Gyro (single-shot verification)	SDI	10,150
10/27/87	Fluid sampler	LANL	10,700
10/27/87	Temperature	LANL	0-10,907
11/11/87	Multishot at TD	DIG	9600-12,360
11/14/87	Maximum casing ID	Dia-Log	0-9650
11/15/87	Gamma/temp	LANL	0-12,350
11/15/87	3-arm caliper	LANL	9700-12,350
11/16/87	Gamma/temp	LANL	9700-12,350
5/17/88	Gamma/3-arm caliper	LANL	9600-12,294
5/18/88	Borehole acoustic televiewer	LANL	0-10,000
5/23/88	Gamma/casing collar locator	Welex	0-1200
5/24/88	Kuster slick line temp survey	LANL	500-9350
5/25/88	Gamma/casing collar locator - locate RA frac balls	Welex	0-2502
5/25/88	Perforate 9-5/8-in. casing 2 shots/ft	LANL	885-889
5/27/88	Kuster slick line temp survey	LANL	0-500
5/28/88	Cement bond log	Welex	0-1000
5/28/88	Perforate 9-5/8-in. casing 4 shots/ft	Welex	210-212
6/03/88	Kuster slick line temp survey	LANL	200-8600
6/07/88	Kuster slick line temp survey	LANL	500-9000
6/08/88	Kuster slick line temp survey	LANL	100-5000
6/09/88	Cement bond log/casing collar locator/gamma	OWP	0-10,624
6/16/88	Kuster slick line temp survey	LANL	9000-10,650
6/16/88	Temperature log	LANL	0-12,187
6/17/88	Kuster slick line temp survey	LANL	9000-10,600

[a]Wireline/logging contractors used:
Big A Well Service, Farmington, New Mexico
Dia-Log Company, Odessa, Texas
DIG - Directional Investment Guidance, Inc., Midland, Texas
OWP - Oil Well Perforators, Casper, Wyoming
SDI - Scientific Drilling Int'l (AMF), Midland, Texas
Welex (a division of Halliburton), Farmington, New Mexico.

V. SIDETRACKING AND DRILLING

The production casing section was milled following the first three plug-back cementing operations described in Section VII of this report. The milled section was plugged with sand and cement, and the cementing of the production casing annulus above 1975 m (6480 ft) was completed. The milled section was then drilled out and a packer-anchored whipstock (packstock) was installed. Sidetracking proceeded, and the well was drilled from 2964-3767 m (9725-12,360 ft) with two reservoir production tests; one conducted at a drilled depth of 3356 m (11,009 ft) and another at TD, 3767 m (12,360 ft).

A. Section Milling and Setting a Packer Whipstock

Four A-Z International section mills were used to cut an 18.3-m-long (60-ft) section from 2953-2972 m (9688-9748 ft). The production casing was not centralized at this depth, and we believe this contributed to the intermittent rapid wear of the tungsten carbide(TC)/soft matrix Zitco™ cutting wings. Cut-rite™, Zitco™, and other TC cutting materials wear rapidly during contact with Fenton Hill gneiss or granodiorite.

Mill runs were also complicated by our inability to retract the knives at the end of the mill runs. Reciprocation of the mills, spotting fresh water, high viscosity mud sweeps, and, in one case, a sand line jarring assembly were used during attempts to retract the knives. Deficient drilling fluid properties at the high bottom-hole temperature [the geothermal gradient temperature is 194°C (380°F) at this depth] provided inadequate cuttings removal and resulted in backflow when circulation was stopped.

Both cuttings and backflow may have contributed to the difficulty in retracting the knives. Some drill pipe was bent because of reciprocation with high rotary speeds while attempting to close the cutting wings.

A sand plug was placed in and over the lower production casing (stub) below the milled section; a hard cement plug was placed in the rest of the section and extended up 52 m (170 ft) into the casing. After the cementing procedure at 1975 m (6480 ft) was completed, the cement in and above the milled section was drilled out with a rock bit.

A "dummy" whipstock locator assembly was run but could not be worked through the milled section, presumably because of the presence of a nest of steel cuttings. After a bit and reamer run, the locator was rerun but failed to set properly on the lower casing stub. A final 1-ft cut was made with the fifth section mill to dress off the stub. A final locator run successfully tagged the stub. After the "dummy" was dismantled, the locator was made up between the packer and the whipstock in the packstock assembly (Fig. 2).

The packstock was run on drill pipe, located on the lower casing stub, and oriented with the face of the stock 0.785 rad (45°) left of the high side of the bore. A Scientific Drilling Int'l (SDI) high-temperature-service 204°C (400°F) steering tool was used to orient the stock.

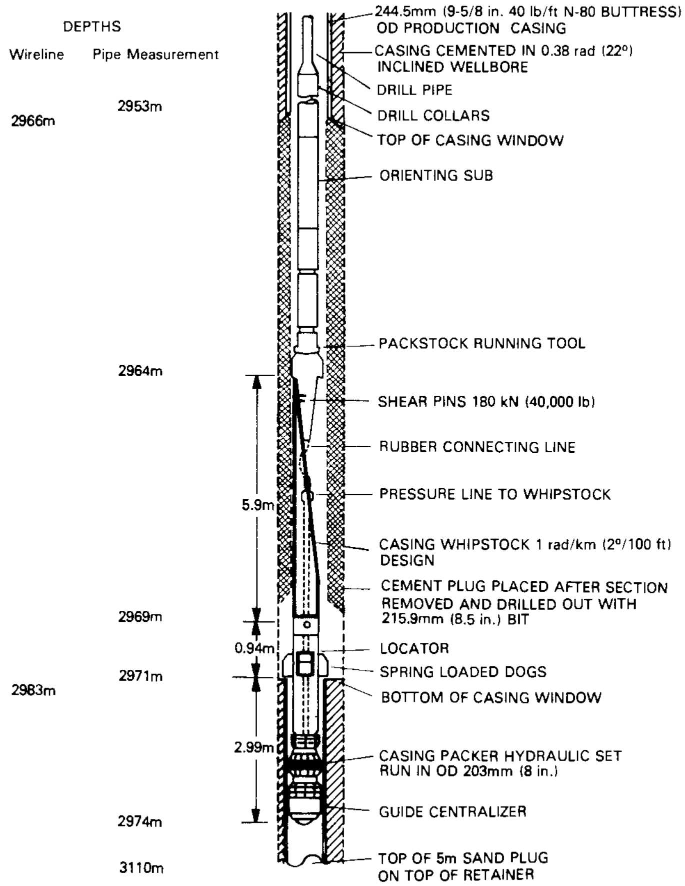

Fig. 2. Production casing window, cement plug, and packstock configuration.

Sidetracking was accomplished with 2 limber drilling assemblies, BHA numbers 1 and 2 of the 22 bottom-hole drilling assemblies used in the drilling of EE-2 (14 rotary, 2 milling, and 6 drilling motor assemblies) listed in Appendix B.

B. Drilling

The drill plan was based on the successful redrilling operation at well EE-3A in 1985. The major features of the plan were (1) elimination of drill pipe twistoffs with large-diameter, moderate-strength drill pipe; (2) accurate directional drilling and longer bit runs with carefully designed BHAs and bit selection; and (3) higher penetration with good hole cleaning using a sepiolite base drilling fluid.

1. Drill String. A 127.0-mm (5-in.) API premium or better drill string, including 2530 m of 29.0-kg/m (8300 ft of 19.5-lb/ft) Grade E, 2500 m of 38.1-kg/m (8200 ft of 25.6-lb/ft) Grade X-95, and 172 m of 74.4-kg/m (565 ft of 50-lb/ft) Grade E heavyweight drill pipe (all with NC 50 tool joints), was available for drill string design. Stronger, lightweight pipe was not used because of its susceptibility to stress corrosion cracking (SCC).[13] The large-diameter pipe was used to

keep bending stresses low and prevent fatigue failures in the high dogleg areas of EE-2 above the kick-off point (KOP).

About 640 m of 29.0-kg/m (2100 ft of 19.5-lb/ft) drill pipe had rough hardbanding for open-hole service and 378 m of 29.0-kg/m (1240 ft of 19.5-lb/ft) and 186 m of 38.1-kg/m (610 ft of 26.5-lb/ft) pipe had smooth hardbanding, which was used in doglegs to minimize wear on the already worn production casing.[14] The drill string weight was kept as low as possible to minimize the wear rate on the casing and yet keep 445-kN (100,000-lb) overpull capacity, based on 80% tensile strength of new pipe. The drill string pipe order was rotated three stands (triples) within each pipe grade on every trip to prevent concentration of wear and fatigue over a short part of the drill string. Pipe-handling procedures and specifications are described in Appendix C.

2. Bottom-Hole Assemblies and Directional Drilling. The trajectory needed to reach the selected drilling targets (Fig. 3) called for a slight left turn and angle-building assemblies to separate the wellbores, followed by angle-holding assemblies in the middle region, followed by dropping assemblies. It was hoped that only one motor run would be required, but the rotary assemblies had a strong left-hand walk in the upper part of the well followed by a shift to right-hand walk once the required right-hand turn had been completed.

The rotary assemblies used three-point and six-point roller reamers to (1) minimize reaming off of bottom (and the resulting casing wear), (2) provide the required directional characteristics in lieu of integral blade stabilizers that wear rapidly in crystalline rock, and (3) reduce the BHA wear and hole drag by providing standoff for the drill collars.

A 171.5-mm (6-3/4-in.) OD, 6-m-long(20-ft) Drilex™ D675 positive displacement motor (PDM) and 0.026 or 0.035 rad (1-1/2° or 2°) bent subs were used on all of the motor runs. The drill plan called for a maximum dogleg severity of 1 rad/km (2°/100 ft),[15] so the five successful motor runs were staggered between rotary runs. Turn rate increased with penetration on the motor runs and great care was needed to pull the assemblies before the maximum allowed dogleg was exceeded. On two occasions the dogleg reached 2 rad/km (4°/100 ft) when motors were run 9-18 m (30-60 ft) too far.

One washout occurred in the drill collars. This was attributed to rotary bending and stress fatigue in the connection in the higher than planned dogleg at 3155 m (10,352 ft). A replacement string of collars was run. The drill collars and heavyweight drill pipe were inspected twice (trip checked with black light). Each inspection found one cracked box.

Nonmagnetic collars were run on all drilling BHAs. Magnetic compass single-shot surveys were run on every connection near the KOP and every second or third connection until the rat hole was drilled below the reservoir. There, surveys were run every fourth connection. A multishot gyro survey was run after drilling to 3093 m (10,149 ft) to assure that the azimuth readings from the single shot were accurate. The multishot location was within 3.5 m (11-1/2 ft) of the single-shot bottom-hole location. A magnetic multishot survey was run at TD and showed a bottom-hole location within 5.5 m (18 ft) of the single-shot projection (Appendix D). EE-2A penetrated the drilling targets selected based on microearthquake locations[8-10] that also met the target criteria of the DOE review panel, which had suggested that the wellbore should be within a 15.2-m (50-ft) radius of the open-hole wellbore of EE-2. Figures 3 and 4 show that all objectives were achieved.

3. Bits. A bit, drilling, and fluid parameters record is shown in Appendix E. The two primary bits used were the Hughes Tool Co. and Smith Tool Co. TC insert bits for hard abrasive formations, IADC class 7-3-2, with roller bearings for air drilling. The air ports through the bearings were plugged and jets were installed to optimize the drilling hydraulics.

Four journal-bearing insert bits were run for comparison purposes. These bits were IADC class 7-3-7 with special gauge protection on one of the bits. They were one and one-half to two times more expensive than the air bits. Although the bearings showed little to no wear, the cone and insert structures were worn out with less total penetration than was obtained with the air bits.

4. Drilling Fluids and Hydraulics. A lightweight, low solids, fresh water sepiolite and bentonite mud treated with lignite, caustic, and Torq-Eze™ was used for section milling and drilling. Normal desired fluid properties were a mud density of 1040 kg/m^3 (8.7 lb/gal), plastic viscosity of 0.0025 Pa·s (25 cp), yield point of 8.6 Pa (18 lb/100 ft^2), and pH of 10+. Appendix E lists typical fluid properties achieved during each bit run.

Experience on EE-3A had shown that the excellent hole cleaning achieved with a fairly high viscosity mud significantly improved total penetration and drill rate with a rotary drilling assembly. Bit jets were sized to maintain an annular velocity in excess of 0.760 m/s (150 ft/min), and bit hydraulic power was usually maintained near the optimum. Hydraulics has been found to play only a minor role in increasing instantaneous penetration rate. An overall drill rate of 29 m/day (95 ft/day) (Fig. 5) was achieved in the crystalline rocks with hole cleaning that extended bit runs and reduced reaming time. As was the case during the EE-3A redrill, the wear on drilling assemblies and the maintenance costs, as compared with previous drilling efforts at Fenton Hill,[2,4] were reduced, and fishing for parted strings was eliminated.

The relatively simple drilling fluid system became more difficult to maintain as the new wellbore penetrated the Phase II reservoir. Flow from the reservoir was encouraged to protect it from becoming plugged with drill cuttings and dehydrated mud. The first fractures penetrated near the top of the reservoir were prolific producers that caused more severe dilution of the mud than had been expected, and the high CO_2 concentration in the reservoir fluids required large caustic treatments to keep the pH in the desired range (10-11). The treatments caused high gel strengths and difficulty in degassing the mud.

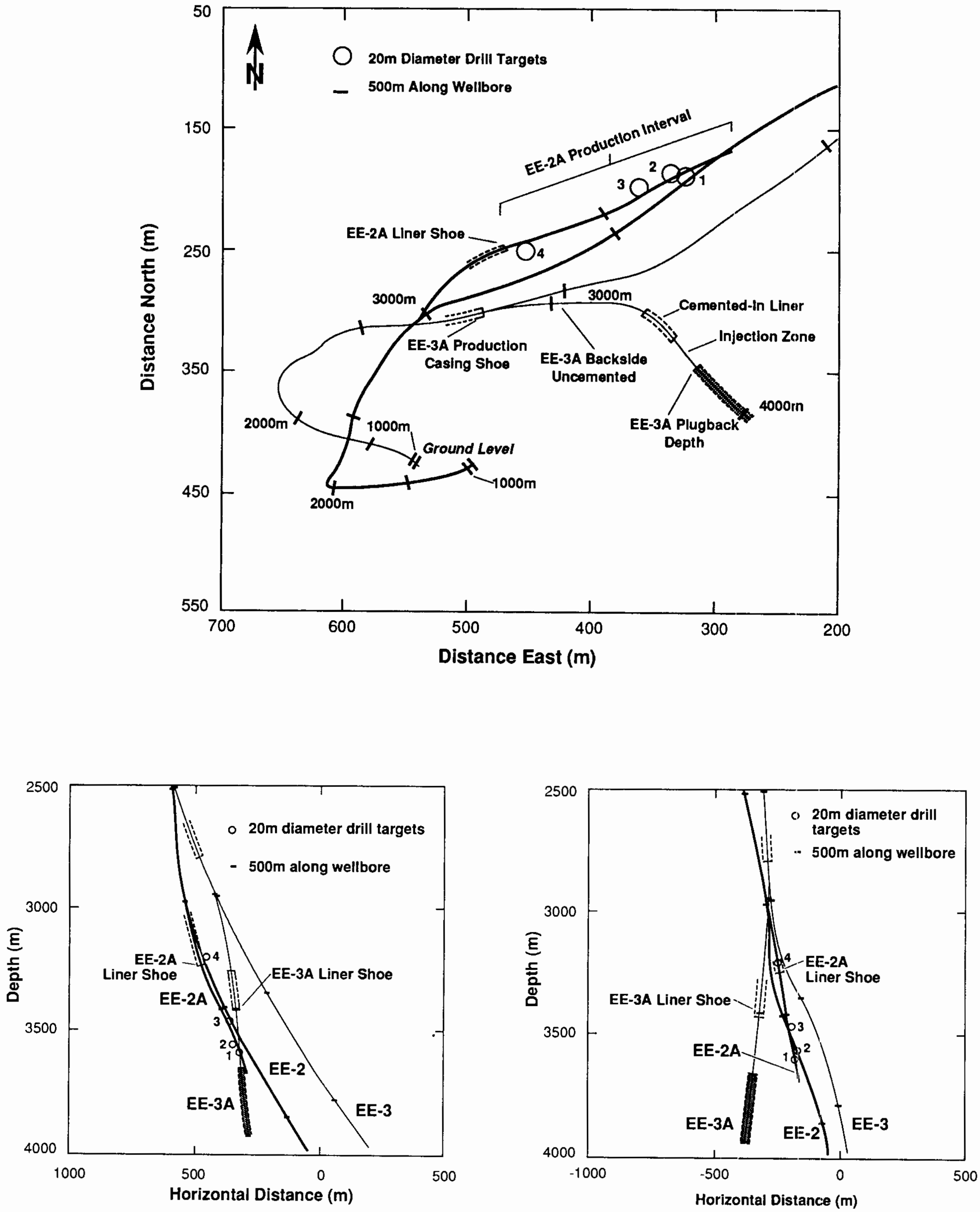

Fig. 3. EE-2A targets and drilled trajectory.

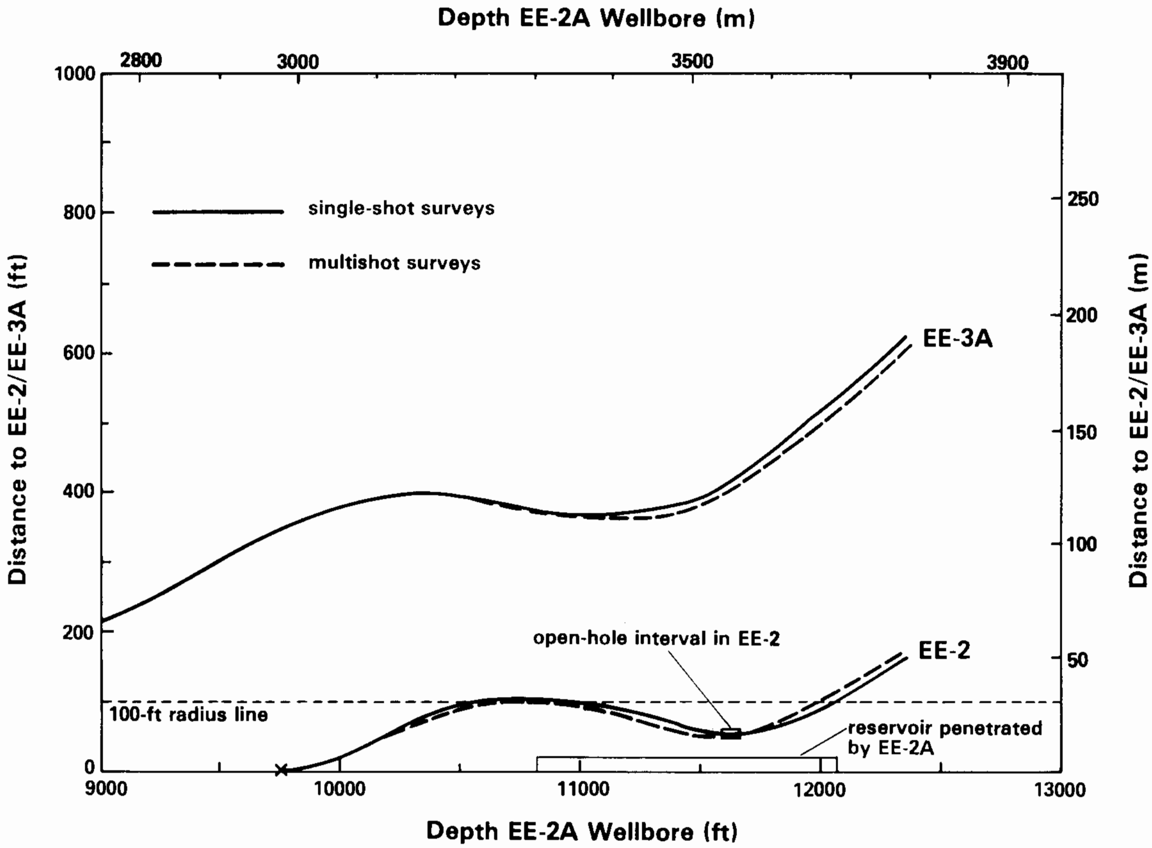

Fig. 4. Wellbore separation distances for the actual EE-2A drilled trajectory.

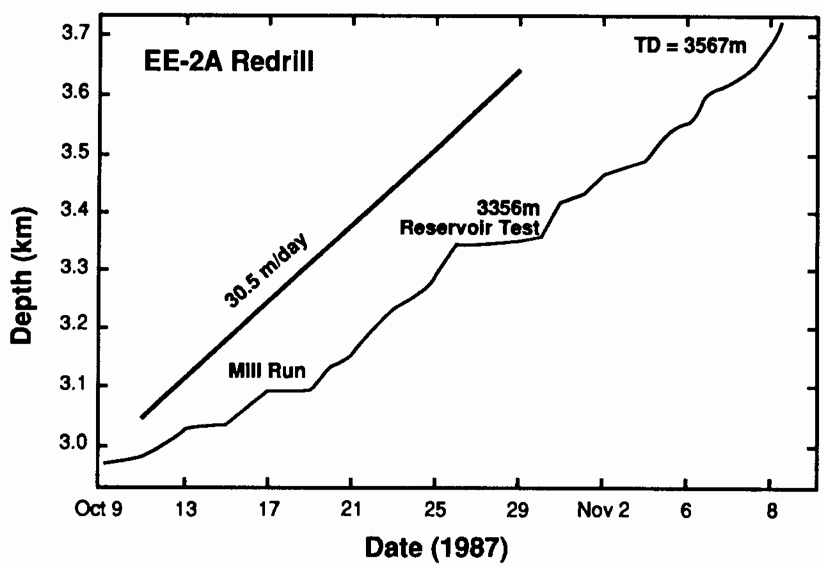

Fig. 5. EE-2A drill depth chronology.

5. Drilling Results. Although minor problems occurred with directional drilling and drilling fluids, the drilling was completed within budget and time estimates. A successful drilling fluids program, described in the previous paragraphs, contributed to an overall average penetration rate of 3.17 meters per hour (10.43 ft/hr) at an average cost of $618 per meter ($188/ft). Table III-B in Section IX contains a comparison of costs and maximum, minimum, and average penetration rates achieved during drilling off the whipstock, rotary drilling, and motor drilling. Figure 6 shows the time spent on various redrilling operations.

VI. WELL COMPLETION

A. Casing Stress Calculations

The well design is based on the successful liner installation deep in EE-2 and the principles of geothermal well design presented by Nicholson,[16] Dench,[17] and Snyder.[18] The 177.8-mm (7-in.) OD casing wall thickness and grade were selected based on stress calculations for an open-hole liner and tie-back casing to surface. A 177.8-mm (7-in.) OD, 52.1-kg/m (35-lb/ft) C-90 VAM (T&C premium connection) casing had been purchased in 1984 for a liner that was not run. It was suitable for the open-hole liner. A 177.8-mm (7-in.) OD, 47.6-kg/m(32-lb/ft) C-95 Nippon NSCC (T&C premium connection) casing string was purchased for the tie-back casing based on a specification that allowed several combinations of weights and grades to satisfy the calculated maximum stress.

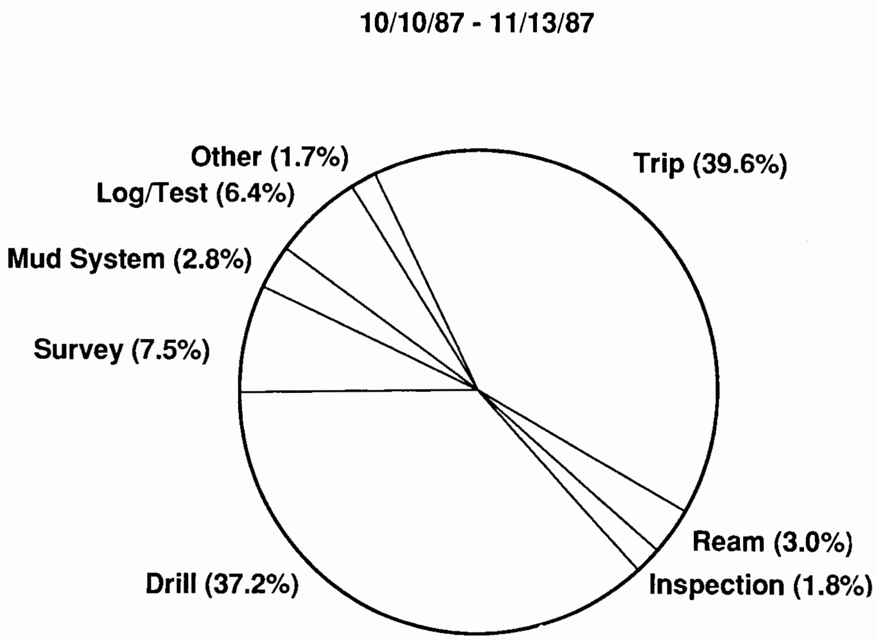

Fig. 6. Time distribution of EE-2A drilling.

Both the liner and tie-back string were designed for high-pressure fracturing and injection and production service.[11] To achieve the flow rates desired between EE-3A and EE-2A, additional stimulation of EE-2A may be needed. Stimulation of the well may require injection at pressures up to 41 MPa (6000 psi) above hydrostatic and a bottom-hole cool-down to 32°C (90°F). During production, a surface temperature of 221°C (430°F) at surface pressures ranging from 3.4 to 39.6 MPa (500 to 5750 psig) is projected. The higher pressure is a shut-in pressure with the well hot and the reservoir acting as a closed system with full injection pressure, 34.5 MPa (5000 psig), on EE-3A.

Additional comprehensive stress calculations were later run for the 177.8-mm (7-in.) OD liner and tie-back casing and the uncemented production casing using a recently developed computer code. The code was developed using the methods presented by Lubinski,[19] Lindsey,[20] and Mitchell.[21] It enabled numerous deviations from the planned procedure to be analyzed to determine the casing stresses that would result. Three major conclusions resulted from the code runs:

(1) A liner hanger on the top of the liner would not increase the calculated stress in the liner as long as the liner was completely cemented. The liner hanger was used.

(2) The liner, if left uncemented or poorly cemented across the milled section in the production casing, would develop high bending stresses under the assumed conditions. To prevent fallback of cement in the event of a float equipment and wiper plug failure, a 1980-kg/m^3 (16.5-lb/gal) drilling mud displacement was used to fill the liner as the cement was displaced into the liner annulus.

(3) Tie-back and production casing stress calculations were made for a well configuration where the cement top outside the 177.8-mm (7-in.) casing was set at 730 m (2400 ft) to match the 244.5-mm (9-5/8-in.) cement top obtained in the predrilling cementing (see Section VII-C). The casing loads calculated for the 177.8-mm (7-in.) and the 244.5-mm (9-5/8-in.) OD casings were acceptable, but the resulting loads that were transferred through the wellhead to the intermediate and surface casings were too high. Unless it was assumed that compression loads imposed by the production and tie-back casings during production were divided evenly between the intermediate and surface casings, the 8-year-old surface casing could be exposed to tension loads exceeding its new rated yield strength. Three ways to reduce the stress on the surface casing were considered:

    (a) The tie-back and production casings could be decoupled from the fully cemented casings with a wellhead expansion spool.

    (b) The production casing could be cemented from some reasonable depth above 520 m (1700 ft) to the surface and the tie-back casing could then be cemented to the surface.

    (c) The production casing could be cut off above 538 m (1766 ft), the upper casing removed, the lower casing hung and packed-off to the intermediate casing with a casing patch-liner hanger-packer assembly, and the tie-back casing could then be cemented to the surface.

A plan to build an annular plug on an existing screw-in sub in the production casing at 274 m (900 ft) was devised, and the production casing was cemented from the plug to the surface. This is described in more detail in Section VII-E.

B. Liner Hardware

The 177.8-mm (7-in.) OD liner was installed and cemented with the hardware shown in Fig. 7. The liner equipment was manufactured from AISI 4140 steel with a 550-MPa (80,000-psi) minimum-yield-strength heat treatment. All pressure connections were VAM™ threads.

(1) Liner float shoe: a taper was cut in the inside of the bottom of a standard float shoe to provide a wireline reentry bevel on the bottom of the liner after drillout. The antirotation blades on a shoe were rounded off so that the shoe would traverse ledges in the hard granite wellbore. Two all-metal dart type floats were specified.

(2) Landing collar: a standard aluminum insert collar was run two joints above the shoe to stop and latch-in the liner-wiper plug following the cement.

(3) Liner: 380 m (1250 ft) of Algoma casing, 52.1 kg/m (35 lb/ft), grade Soo-90, range III, with VAM threads and beveled collars was run with 15 Turbulator™ centralizers spaced out to provide maximum centralization and facilitate rotation of the liner.

(4) Liner hanger: the acme thread and O-ring seal above the roller-bearing assembly in a standard single-cone rotating/reciprocating liner hanger was replaced with a VAM connection (with a metal-to-metal seal).

(5) Cementing polished bore receptacle (PBR): a full ID PBR was specified to mate to a high-pressure and high-temperature seal unit on the liner setting tool.

(6) Liner-setting sleeve: a standard sleeve with a left-hand acme support thread and a 3-m-long (10-ft) tie-back extension was run on top of the liner.

(7) Liner-setting tool: the setting tool with a Molyglass™ seal unit spaced out to seal in the PBR and a high-temperature service, Viton™ liner-wiper plug shear-pinned to a short tubing joint extending into the liner hanger was attached to the liner and pressure tested to 48 MPa (7000 psi).

Geothermal grade Kopr-Kote™ thread lubricant was used to make up the liner casing. The attempt to rotate and cement the liner is described in Section VII-D.

C. Tie-Back Casing Hardware

A 2896-m-long (9500-ft) string of 177.8-mm (7-in.) OD, 47.6-kg/m (32-lb/ft), C-95 NSCC casing was purchased to serve as the main string in the tie-back casing. NSCC, a proprietary Nippon Steel casing connection, is a premium threaded and coupled buttress connection with a metal-to-metal internal flank seal. Six joints of 177.8-mm (7-in.) OD, 52.1-kg/m (35-lb/ft), Algoma Soo-90 VAM casing were run on the bottom; four joints were run on top of the tie-back casing to provide a stiffer, thicker wall casing in the critical, highly stressed regions.

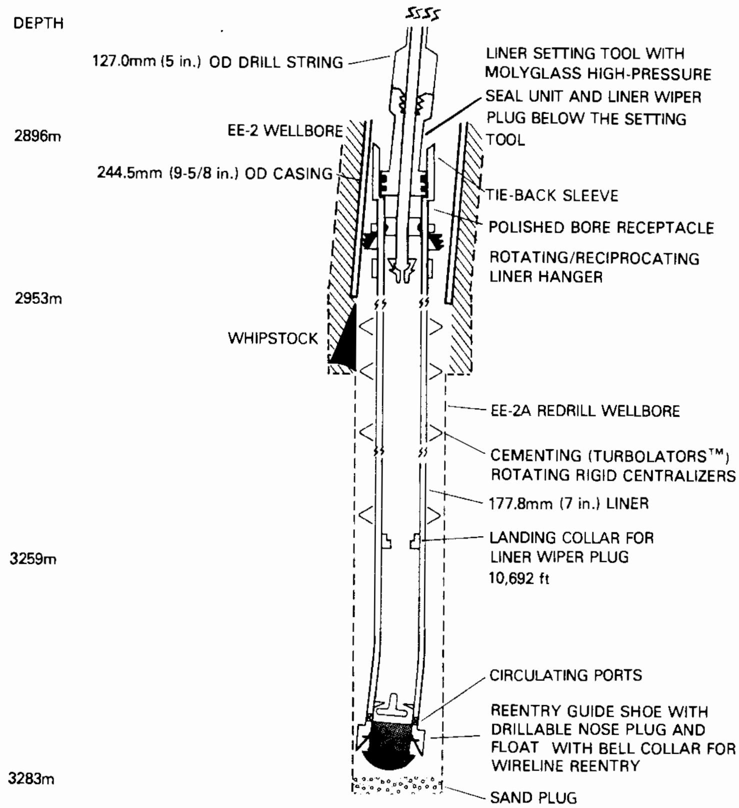

Fig. 7. Liner cementing hardware.

The tie-back casing was installed and cemented-in with a single stage placement, as described in Section VII-F. The following tie-back hardware was manufactured from AISI 4140 steel with a 550-MPa (80,000-psi) minimum-yield-strength heat treatment and proprietary Grade C-95 tube stock with premium threaded connections as listed below.

(1) Tie-back stem: a 3.4-m-long (11-ft) tie-back stem with three Molyglass™ (chevron style) seal units was configured as shown on Fig. 8. The lower seal was intended to be a debris seal to keep cement out of the tie-back sleeve during cementing. The middle seal was a test seal that allowed a pressure test of the tie-back stem before cementing. The top seal was the primary seal that would be activated by shearing the seal protector sleeve and stinging fully into the tie-back sleeve after displacement of the cement.

(2) Landing collar: a standard aluminum insert collar was run two joints (Algoma VAM) above the shoe to stop the liner-wiper plug following the cement to prevent overdisplacement.

(3) Crossover: a VAM pin by NSCC pin crossover pup joint was run four joints (Algoma VAM) above the landing collar.

(4) Casing: 2770 m (9100 ft) of Nippon Steel casing, 47.6 kg/m (32 lb/ft), Grade C-95, range III, with NSCC threads and standard collars was run with 65 rigid centralizers spaced out to provide maximum centralization.

(5) Crossover: a VAM pin by NSCC pin crossover pup joint was run below four joints of Algoma VAM and a cementing crossover joint and cementing head on the rig floor.

The pressure test of the tie-back stem indicated that it was not stung-in. Steel line measurements and casing string weight indications showed that a sting-in had occurred and, in that case, the tie-back stem could be cemented and shut-in to prevent flow-back if the top seals did not function. If a sting-in had not occurred, junk on top of the liner was the most likely explanation. A collar locator log of the tie-back sleeve and stem and removal of the casing, if necessary, to inspect the tie-back stem were ruled out because of predicted risks and limited

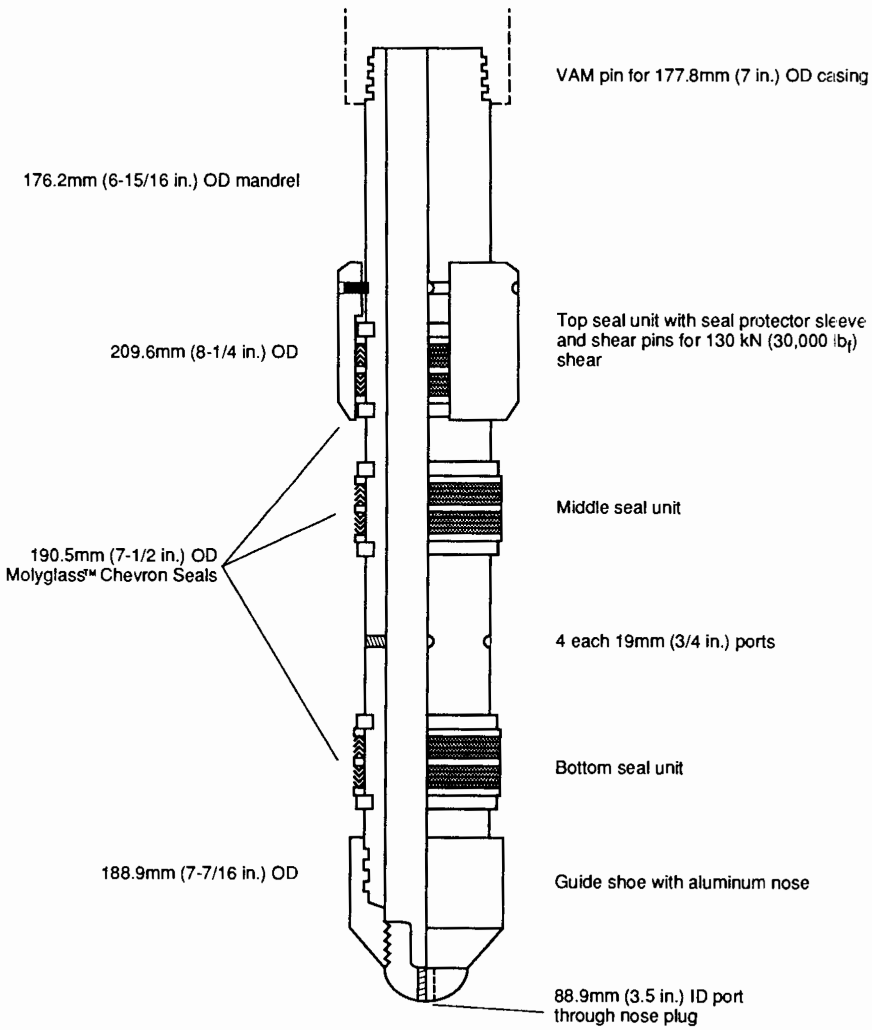

Fig. 8. Tie-back stem.

contingency funds. The tie-back casing was cemented through the tie-back stem. After placement, the ports in the stem could not be isolated with a 667-kN (150,000-lb) reduction in string weight to sting-in and set-down to shear the seal protector sleeve. The collar log on the CBL confirmed that the stem was resting on top of the tie-back sleeve and was not stabbed-in before cementing. Figure 9 shows the final bottom-hole well completion.

After cementing, the tie-back casing was pretensioned to the near optimum axial load to equalize the anticipated thermal stress load during both high-temperature production and low-temperature, high-pressure injection. Stress calculations discussed previously were used to prepare the tensioning procedure. After an attempt to seal off the tie-back stem by shearing the seal-protector sleeve, the string weight was increased to 890 kN (200,000 lb) while the cement at

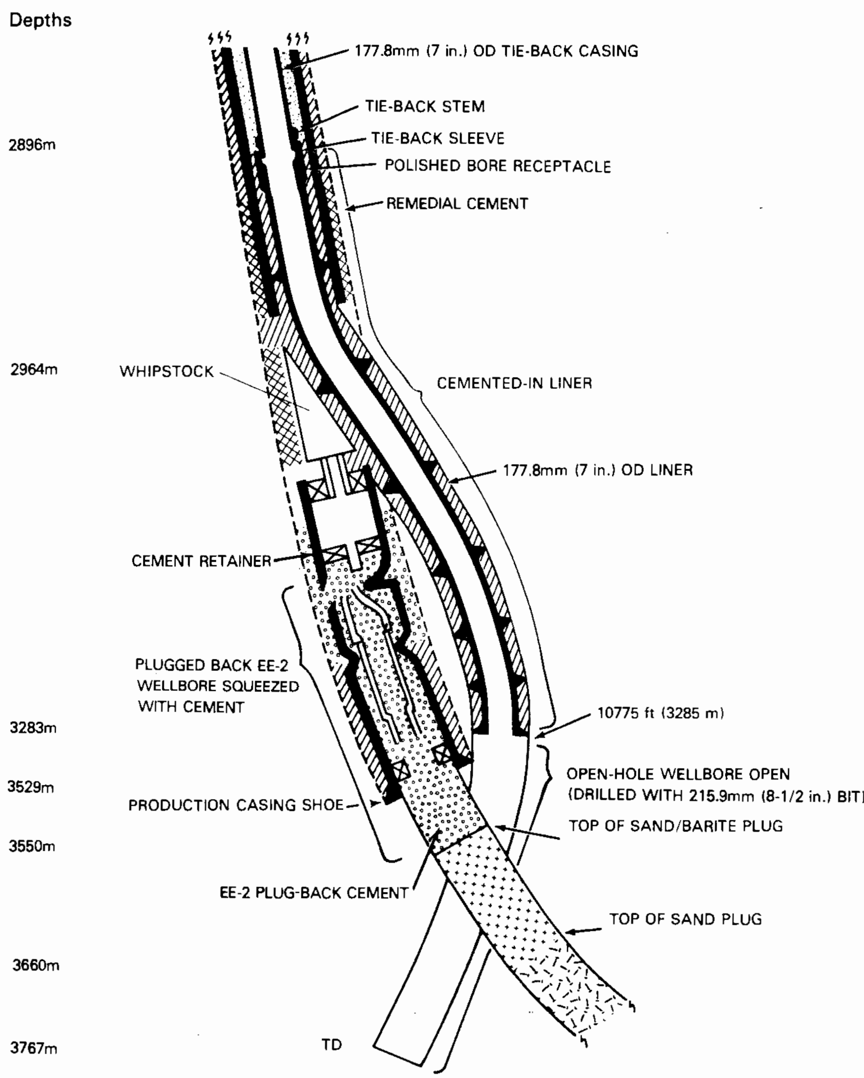

Fig. 9. Final EE-2A schematic of the lower wellbore configuration.

the bottom of the casing was setting up. A slick line temperature survey was run, and final calculations were made to determine the optimum tension for the casing. The casing was landed in a new casing spool with 1450-kN (325,000-lb) tension.

A 179.4-mm (7-1/16-in.), API 10,000-psi (68.9-MPa), working pressure (WP) master valve was installed over the 177.8-mm (7-in.) casing. The casing pack-off consisted of an Aflas elastomer primary seal and an omega style, spring-energized, metallic, secondary seal contained in the bottom of an API 10,000-psi (68.9-MPa), WP tubing spool with 52.4-mm (2-1/16-in.) side outlets and valves. Figure 10 shows the final wellhead configuration.

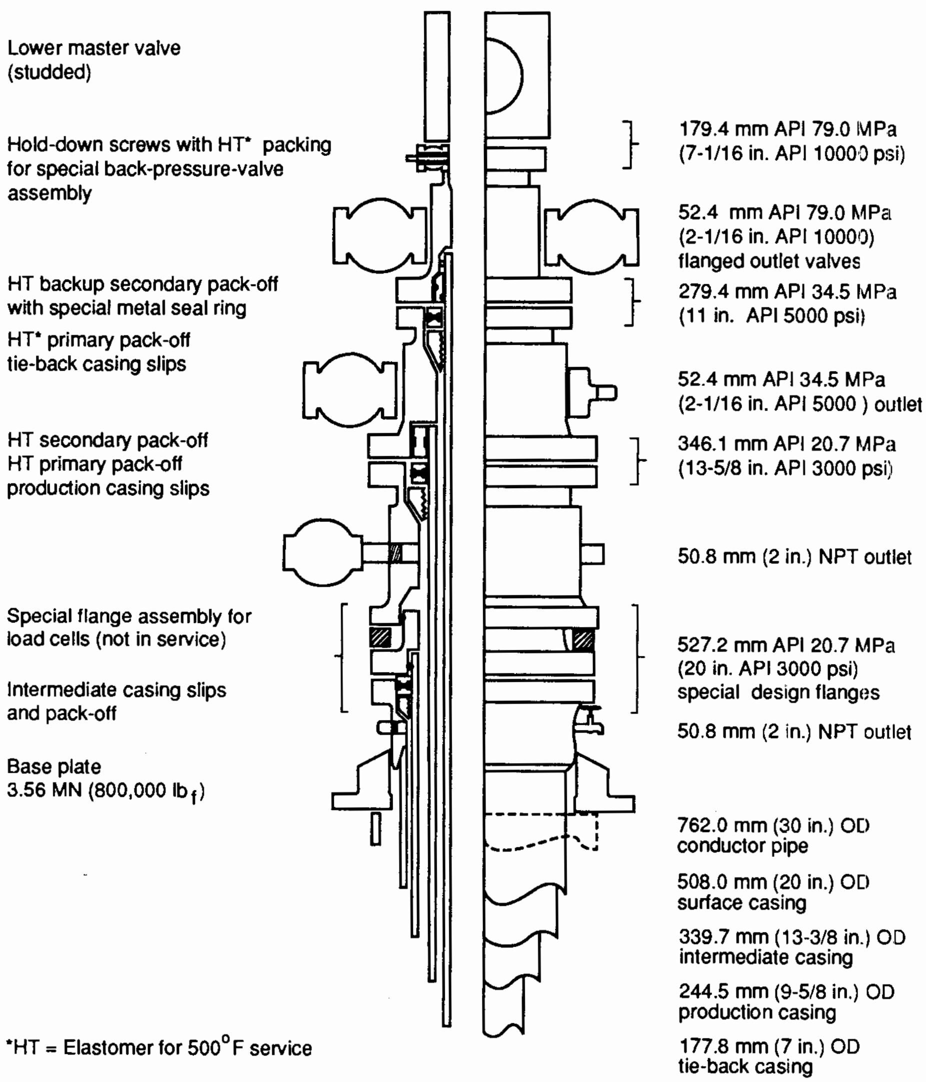

Fig. 10. Final EE-2A wellhead assembly.

VII. CEMENTING

Five cementing operations requiring seven batch-mixed slurries were conducted before EE-2 was sidetracked. After drilling the sidetracked hole, four additional cement placements were conducted during the installation of the open-hole liner and tie-back casing. Appendix F-1 lists the cementing procedures.

The large number of planned procedures required that excellent communication between the cementing service company, Dowell-Schlumberger (DS), and Los Alamos staff and consultants be maintained throughout the planning, cement testing, and operations.[22] Detailed procedures were completed. Cooling and thermal recovery projections were run on the LANL wellbore heat transfer (WBHT) code and the Geotemp2 code, developed by the Sandia National Laboratories. Cement testing was conducted by DS based on the temperature projections and planned cement placement times. Appendix F-2 summarizes the cement formulations; Appendix F-3 lists the cement slurry properties and test results.

API Class H and G cements and 300 mesh silica flour were stored in reserved silos in Farmington, New Mexico. Cement testing was conducted with samples from the reserved silos and water from the Fenton Hill site domestic water well. Typically, a slurry batch mixing time of 2 to 3 hours and a thickening time of 3 to 4 hours were specified. Zero operating free water and no particle segregation or channeling were also specified but not always achieved.

In the formulations that were tested for the predrilling cementing operations, free water was excessive in the lightweight slurries using Class H cement and perlite. A formulation using a California perlite (Perfalite™) and Class G cement was eventually developed with nil free water. In the testing for tie-back casing 6 months later, a suitable Class H cement and Perfalite™ formulation was developed.

To maintain the strength of the cement during 220°C (430°F) production operations, 45% silica flour was specified for high-strength cements and 35% silica flour for lightweight perlite cements. These silica concentrations were intended to provide a CaO/SiO_2 ratio of one, which should result in forming the best phases (xontolite, tobermorite, and calcium silicate hydrate) for high-temperature strength maintenance.[22]

Before cementing, the well was cooled with circulation through or injection into the region to be cemented. The cooling circulation rate and pressure were selected to suit the rig's pumps. This freed the cementing contractor's pumps for batch mixing. The duration of cooling was specified to achieve approximately 95% of maximum cool-down based on WBHT simulations.

Cement, silica flour, and gel (except for prehydrated gel) were weighed and blended in Farmington and then transported to Fenton Hill. All soluble additives were carefully weighed and added to the mix water at Fenton Hill. The slurries were normally mixed "heavy" and then thinned with additional mix water to obtain the proper density.

Cementing procedures were conducted to keep dilution and contamination of the cement to a minimum.[23] Redundant pumping equipment and piping were rigged up to assure that cement placement would be completed in the planned time. Displacement volumes were corrected for thermal expansion[24] and shutdowns were specified to prevent overdisplacement of the cement if wiper plugs failed to latch and seal.

CBLs with an amplitude, transit time, and microseismogram display were run following the cementing procedures. Because the slurries were normally highly retarded, the bond logs were usually run at least 10 days after the cementing. Collar-locator and gamma-ray correlation logs were run simultaneously. Appendix F-4 summarizes the bond log results.

A. Plug Back of Damaged EE-2 Wellbore

Three cementing procedures had been planned to provide certainty, within budget constraints, that the redrilled wellbore would be hydraulically isolated from the reservoir through the damaged wellbore. The drill string, two Baker Service Tools (BST) Model "K-1"™ tubing set cement retainers, and a BST Model "B" Retrievamatic Hurricane Plug™ packer were used for a plug back and two annular cement placements.

Both the retainers and the packer used a proprietary ethylene/propylene/diene/methylene (EPDM) elastomer packer element and O-rings and were set using drill pipe measurements. They were set in cemented casing, where possible, based on a recent CBL. The retainers and packer were tested with a 10-MPa (1500-psi) backside pressure test and operated with a 20-MPa (3000-psi) drill pipe pressure limit with a 7-10-MPa (1000-1500-psi) backside pressure.

Oil Well Perforators made perforations using conventional 34-g 218°C (425°F) Harrison charges in a 127-mm-diameter (5-in.) hollow-steel carrier perforating gun. There were no misruns and all charges fired. Special effort was made to correct wireline depth measurement to drill pipe measurements by tagging drill pipe set retainers with the perforating gun or by running collar locator logs out of open-ended drill pipe near the planned perforating depth. Wireline depths varied from 11 m (36 ft) to 6 m (19 ft) deeper than pipe measurements at 3178 m (10,428 ft) and 1928 m (6326 ft), respectively.

First, the damaged wellbore below 3204 m (10,512 ft) was plugged (procedure 1a in Appendix F-1) with 5.25 m^3 (33 bbl) of cement slurry displaced to a retainer at 21 L/s (8 bbl/min) and injected below the retainer with a decreasing rate (Fig. 11). The final displacement pressure was 14.1 MPa (2040 psi) with an injection rate of 0.6-L/s (0.25-bbl/min).

Second, the cement placement in the production casing annulus through perforations at 3115-3117 m (10,220-10,224 ft) (procedure 1b in Appendix F-1) used two 5.6-m^3 (35-bbl) slurries of cement displaced to a retainer at 14 L/s (5.4 bbl/min) (Fig. 12). The first slurry was overdisplaced when it was certain that a high-pressure squeeze would not be achieved [injecting 2 L/s (0.75 bbl/min) at 13 MPa (1900 psi)]. The second slurry was displaced to the retainer and

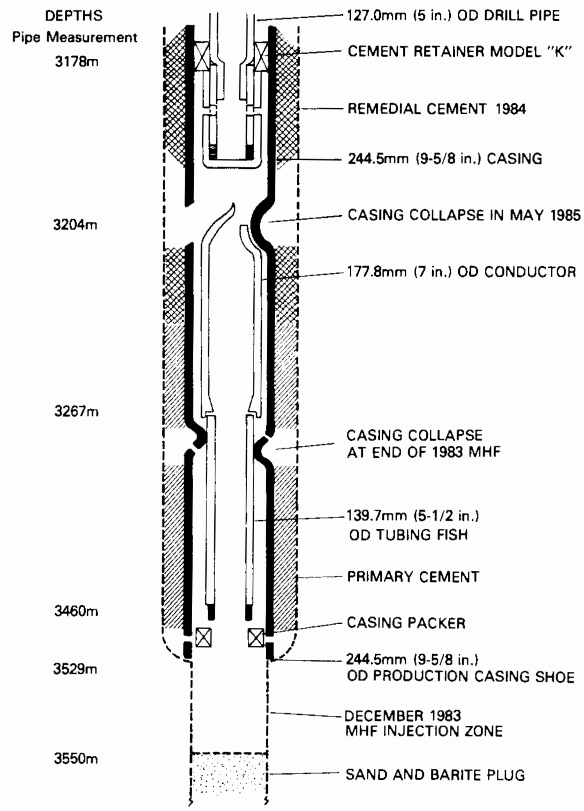

Fig. 11. Plug back of lower EE-2A wellbore.

injected into perforations at 0.6 L/s (0.25 bbl/min) and 15.2 MPa (2200 psi). The 11 m^3 (70 bbl) of cement pumped should have filled the void or unbonded annular volume shown on the most recent CBL.

Following 24 hours of waiting on cement (WOC), a slick line temperature log was run in an unsuccessful attempt to locate the top of the cement based on heat of hydration. A CBL (amplitude display only) was then run and showed a transition from bonded to free casing from 2925-2980 m (9600-9780 ft). A later CBL run at the end of drilling showed a gap in the cement from 2920-2960 m (9580-9710 ft). Apparently the earlier log run in poorly set cement was improperly calibrated because of the assumption that the cement was set and had achieved moderate strength.

Third, a 4-m^3 (25-bbl) slurry of cement was displaced to the packer at 8.5 L/s (3.2 bbl/min) and injected into the perforations at 2910-2911 m (9546-9550 ft) (procedure 1c in Appendix F-1) at 4.5 L/s (1.7 bbl/min) with pressure increasing from 16.9-17.2 MPa (2450-2500 psi) (Fig. 13). Following a 2-hour shut-in, the first attempt to bleed off the pressure and release the packer resulted in flow back of cement. The well was finally bled off after a 7-hour shut-in.

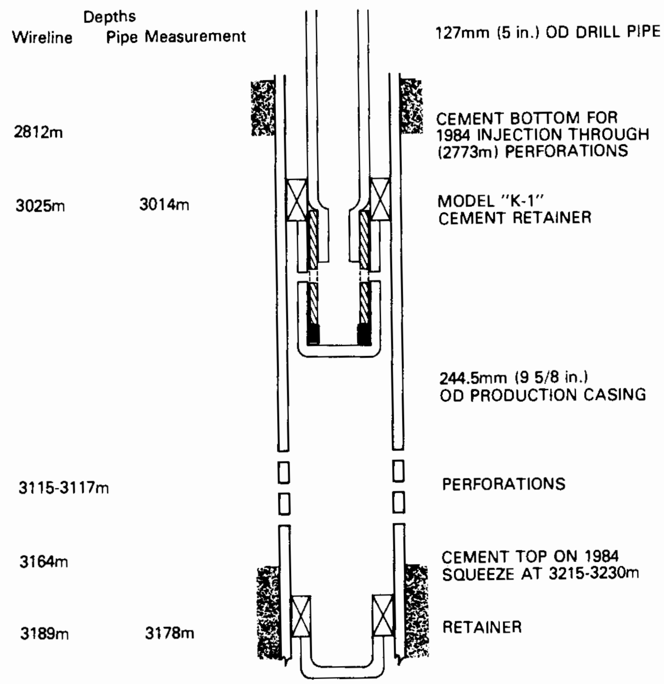

Fig. 12. Cementing the production casing annulus at 3115 m.

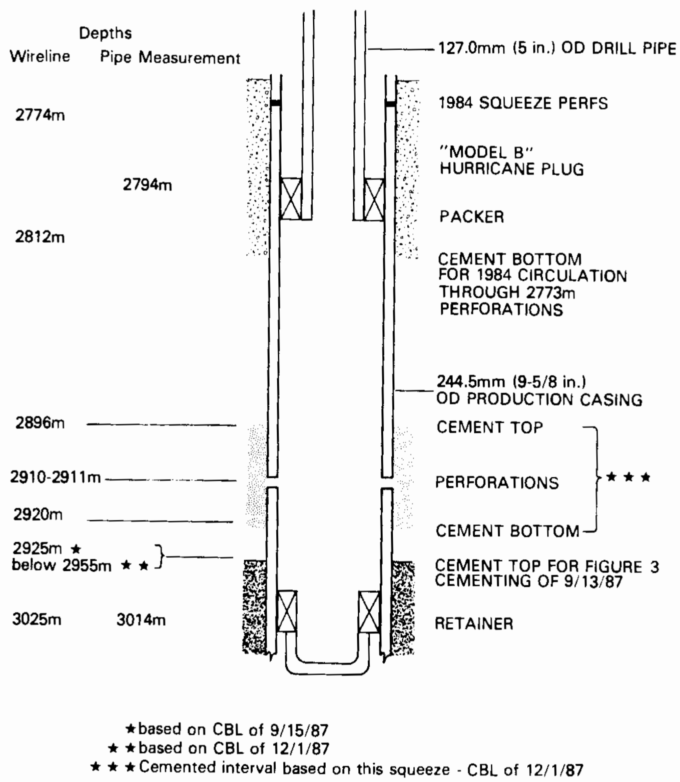

Fig. 13. Cementing the production casing annulus at 2910 m.

The lightweight cement formulation for the next procedure was not ready because of the excess free water in the formulations tested. The section for the whipstock in the production casing was milled and then temporarily plugged with a hard cement plug while the lightweight formulation was modified and tested in the laboratory.

B. Whipstock Plug

After milling an 18-m-long (60-ft) section in the production casing below 2953 m (9688 ft), a 20/40 mesh sand plug was placed in the casing below the milled section, extending 2 m (5 ft) into the bottom of the section. A balanced plug placement through the drill string was used to fill the top 17 m (55 ft) of the milled section, extending 50 m (170 ft) into the casing above the section (procedure 2 in Appendix F-1). The cement plug was intended to prevent potential junk from entering the milled section where the junk would be difficult to remove; i.e., any parts of the drillable cement retainer to be used during cement placement above the milled section.

The plug was to be drilled out with a 215.9-mm-diameter (8-1/2-in.) bit just before the whipstock was to be set, and the remaining plug in the 311-mm (12-1/4-in.) drilled diameter section was intended to provide some support for the whipstock during sidetracking as shown on Fig. 2.

C. Support of Production Casing during Drilling

As recommended by the outside review panel, a cement placement to fill the 244.5-mm (9-5/8-in.) production casing annulus from the existing cement top at 1987 m (6520 ft) to the surface was attempted. Unsuccessful attempts to seal off lost circulation zones from 520-730 m (1700-2400 ft) during the original drilling of EE-2 had placed more than 25,000 sacks of cement in this interval. A successful cementing campaign would probably require at least 6 cement placements extending over 14 full-cost operating days. The estimated cost was $250,000 with no contingency included or 12.5% addition to the total projected redrill and completion cost. This was unacceptable, and the job planned was a best reasonable effort based on economic constraints.

Much of the casing was worn, based on earlier caliper and wall thickness logs run in November 1986 and March 1987 (see Table II), and its calculated collapse resistance was low. A cementing procedure was devised that allowed the cement to be pumped down the casing instead of down the drill pipe and through a packer. The cement was displaced with 1138-kg/m^3 (9.5-lb/gal) fresh water mud to provide an additional safety margin should a loss of well pressure occur when the cement placement was completed (procedure 3 in Appendix F-1).

A modified Model "K-1" retainer with a check valve instead of the standard drill string operated valve was set 40 m (125 ft) above casing perforations at 1972-1974 m (6470-6476 ft). It was used as a string float to place and prevent back flow of the cement (Fig. 14). Equipment to conduct the cement and wiper plugs through the blowout prevention equipment (BOPE) was assembled as shown on Fig. 15. A top liner-wiper plug was shear-pinned to the bottom of two

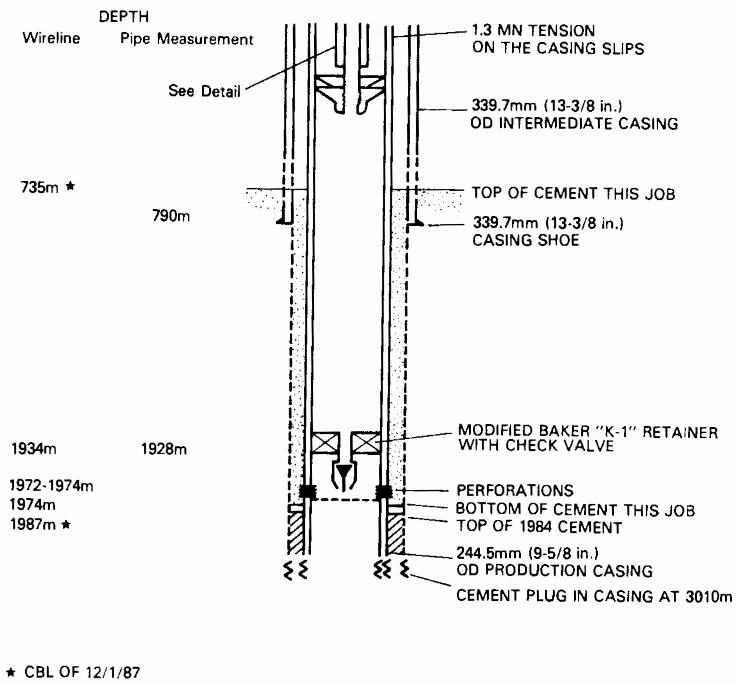

Fig. 14. Cementing the production casing annulus at 790-1975 m.

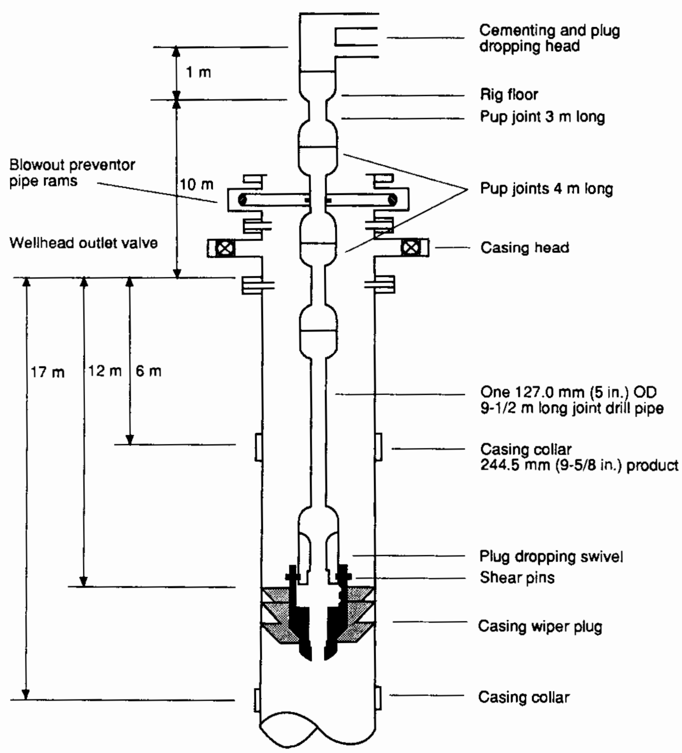

Fig. 15. Surface hardware for cementing through blowout preventers.

joints of drill pipe that were inserted through the BOPE. A plug-dropping (cementing) head was installed on top of the drill pipe, and a drill pipe dart was loaded into the head. The head was manifolded to the rig's mud pump manifold and to the cementing contractor's lines.

The well was cooled for 1 hour by circulating at 19.9 L/s (7.5 bbl/min) without returns. A 6.4 -m^3 (40-bbl) preflush slurry of 1260-kg/m^3 (10.5-lb/gal) pozzolan water was circulated during cooling to clean the annulus and, hopefully, seal off the lost circulation zones. A cement slurry consisting of 76.5 m^3 (481 bbl) of lightweight and 3.82 m^3 (24 bbl) of high-strength cement was pumped and displaced with 75 m^3 (470 bbl) of mud. The slurry volume provided 3% excess based on the calculated annular volume. The final pumping pressure was less than 1.4 MPa (200 psi), and there were no returns during the displacement. The casing was opened to atmosphere, and the well was on a vacuum. A slick line temperature log run 23 hours after shutdown showed a cement top at 730 m (2400 ft), and this was later confirmed on a CBL.

The 15.9 m^3 (100 bbl) of lead slurry was batch mixed; 60.5 m^3 (381 bbl) was mixed on the fly and pumped into a 7.95-m^3 (50-bbl) batch mixer. The mixing rate was approximately 15.9 L/s (6 bbl/min), so an 8-minute residence time in the mixer was provided to even out the mixing variations.

D. Cementing-in the Liner

Operations were suspended after drilling the sidetrack hole, EE-2A, to a TD of 3767 m (12,360 ft) and evaluating the new production path to assure a good connection to the reservoir had been reestablished. Additional funding was needed to purchase 177.8-mm (7-in.) OD casing for the tie-back string recommended by the outside review panel. When operations resumed, the open-hole gamma-ray/temperature, gamma-ray/three-arm caliper, and sonic televiewer logs were run in the interval below the whipstock. The open hole was then filled with sand (see Appendix G) to cover the production interval while an open-hole production liner was cemented-in from 3283-2896 m (10,770-9500 ft).

A 177.8-mm (7-in.) OD, 52.1-kg/m (35-lb/ft), Soo-90 VAM liner was designed as described in Section VI-B (Fig. 7). The liner was run on the 127.0-mm (5-in.) OD drill string and a liner-setting tool that allowed either rotation or reciprocation of the liner during cementing. The liner was successfully rotated at a low torque (approximately the same torque needed to rotate the drill string set at the same depth on an earlier torque measurement) when it was first hung off in the production casing. After circulating through the liner and cooling the well at 22 L/s (8.5 bbl/min) for 1 hour, a slick line temperature log was run to verify well temperature simulation runs. Cooling was resumed for 4 hours based on the verified temperature simulation. A retarder concentration of 0.6% was selected for the slurry, and batch mixing of the slurry was begun.

A second rotation check before cementing showed that the liner could not be turned at the allowed torque limit. It was feared that the cooling had caused spallation of the borehole wall and formation of a bridge on the liner. The bridge, if substantial, could have also prevented reciprocation of the liner and interfered with resetting of the liner hanger. An attempt to reciprocate or rotate the liner during cementing was not made.

A 1.6-m^3 (10-bbl) pad of retarded water (leftover mix water) preceded the 8.7-m^3 (55-bbl) cement slurry (procedure 4 in Appendix F-1). A drill pipe dart was dropped and followed by 0.08 m^3 (1/2 bbl) of cement, which was the volume of cement in surface hard lines, and 0.12 m^3 (3/4 bbl) of retarded water. The slurry was displaced with 6.4 m^3 (40 bbl) of 1990 kg/m^3 (16.6 lb/gal) mud followed by 22.9 m^3 (144 bbl) of water. The mud was almost enough volume to equalize the pressure on the floats and the liner-wiper plug catcher. It thereby provided a backup for them to prevent backflow of the cement when the drill string was released from the liner.

A calculated displacement volume of 30.7 m^3 (193 bbl) and a density correction for the projected temperature and pressure resulted in a theoretical displacement volume of 29.4 m^3 (185 bbl). A rapid pressure increase occurred after 28.5 m^3 (179 bbl) of displacement. When the displacement rate was reduced from 10.6-1.4 L/s (4-0.50 bbl/min), the pressure broke back and then increased a second time. The displacement was shut down at 29.3 m^3 (184 bbl) as the pressure increased rapidly toward the pressure limit set by the procedure, 20.7 MPa (3000 psi).

When the drill pipe was vented back to check the floats, it was on a vacuum. It is assumed that the pressure increases were the result of the previously mentioned spallation bridge being circulated up into the milled section by the high-density cement. Pressure increases would have occurred when the bridge hit the top of the milled section and the liner hanger. Displacement volumes at the time of the increases support this explanation.

E. Surface Cementing in the Production Casing Annulus

It was necessary to cement the 244.5-mm (9-5/8-in.) OD casing to the surface to reduce the potential loading on the 508-mm (20-in.) casing (see Section VI-A). Cost constraints precluded another series of attempts to plug and fill the zones from 520-730 m (1700-2400 ft) using conventional cementing. Review of unconventional cementing and applicable lost circulation materials did not offer any nonexperimental method to seal this zone.

A method was devised to set an annular plug at 274 m (900 ft) in which a 298.5-mm (11-3/4-in.) OD screw-in sub was located at 280 m (920 ft) (see Fig. 16). It had been installed when the top 275 m (900 ft) of casing had been replaced during the 1984 workover. By dropping 19-mm (3/4-in.) OD rubber ball perforation sealers down the 244.5-mm (9-5/8-in.) OD casing annulus, a bridge was built up on the sub that was 28.6-mm (1-1/8-in.) larger diameter than the casing collars. Balls tagged with an Ir-192 radioactive (RA) tracer were dropped and logged with a gamma-ray detector to assure that most of the balls were falling all the way to the screw-in sub and that none were getting past the sub. Over 600 ball sealers and 0.2 m^3 (5 gallons) of pea gravel [enough to form a 0.45-m-long (18-in.) annular plug] were dropped over a 12-hour interval. Then

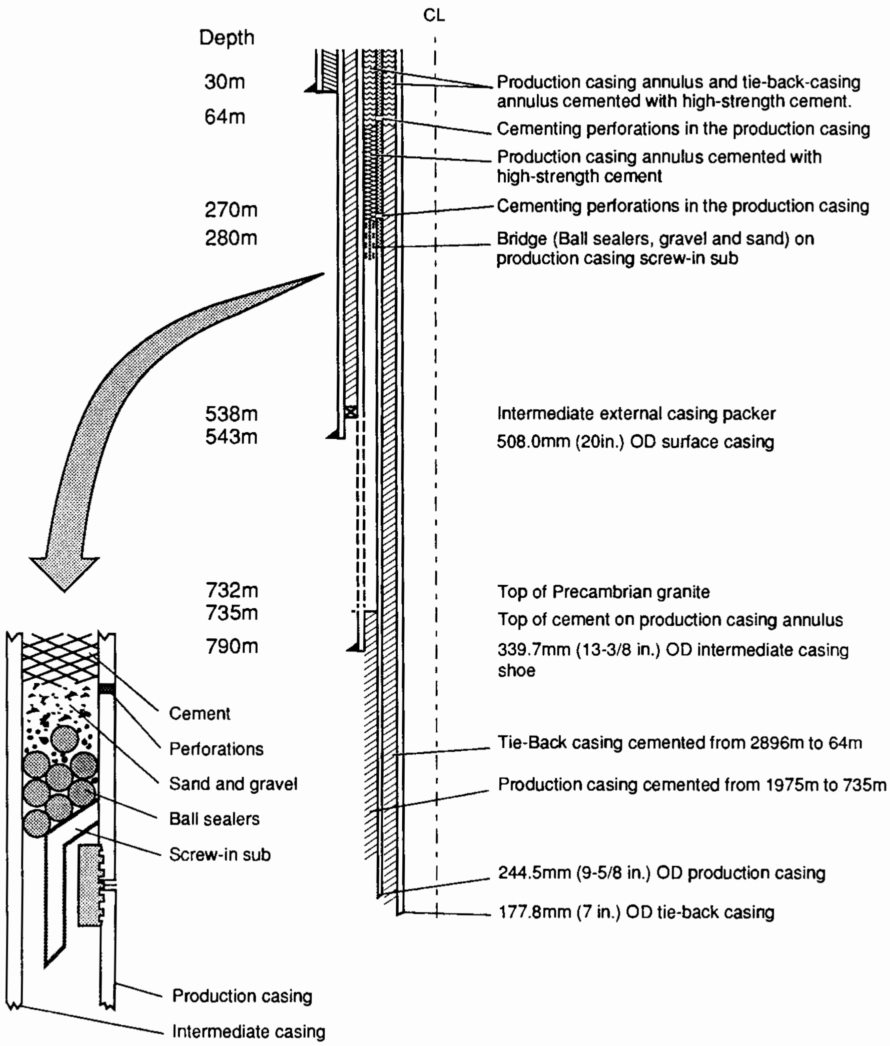

Fig. 16. Final EE-2A schematic of the upper wellbore configuration.

0.6 m^3 (160 gallons) of pea gravel and 20/40 mesh "frac" sand were mixed into a 0.01-0.03-L/s (3-10-bbl/min) stream of water, which was run into the annulus. At one point, gravel was added too rapidly and appeared to bridge off high in the annulus. After pumping on the bridge, it appeared to break when the pressure above the bridge was released. Additional RA ball sealers were dropped and logged. Many of the frac balls were located at a depth of approximately 49 m (160 ft). After perforating 10 m (30 ft) above the screw-in sub, an attempt to break circulation above the perforations was successful, proving that a bridge had been formed on the screw-in sub. Some of the bridges that formed above 280 m (920 ft) were broken up and circulated out.

A solid rubber wiper plug was pushed and located below the perforations with the drill string. A liner wiper plug was installed using the same hardware and procedure that was used during the previous cementing at 1975 m (6480 ft) (see Fig. 15).

An 11.4-m^3 (71.5-bbl) slurry of high-strength cement was mixed and pumped down the 244.5-mm (9-5/8-in.) OD casing (procedure 5 in Appendix F-1). Just as the displacement started, the cement slurry hit the perforations and the pressure increased to 7.6 MPa (1100 psi). The pressure broke back, and the displacement was pumped at 6.6 L/s (2.5 bbl/min) until the slurry reached a calculated depth of 40 m (130 ft) and the pressure rapidly increased to 8.6 MPa (1250 psi), the maximum allowable pumping pressure. Several attempts to resume pumping and complete the displacement were not successful. Consequently, the job was terminated with no circulation of cement.

A CBL was run that showed a clean cement top at 65 m (215 ft). It was decided to perforate the production casing at 64-65 m (210-212 ft) and cement the 244.5-mm (9-5/8-in.) annulus during the same operation that the 177.8-mm (7-in.) OD casing annulus was cemented.

Both the perforations at 282 m (926 ft) and 65 m (212 ft) were made by Welex using special shallow penetration 10-g Big Hole™ charges in a 79.4-mm-diameter (3-1/8-in.), hollow steel carrier perforating gun. There were no misruns; all charges fired and there was no indication that the charges penetrated the 339.7-mm (13-3/8-in.) OD or 508-mm (20-in.) OD casing.

F. Cementing-in the Tie-Back Casing

The drillout of the production casing, the cleanout of the top 335 m (1100 ft) of the liner, and a fluted mill run to dress off the tie-back sleeve on top of the liner were completed before running the tie-back casing.

A tie-back stem (Figs. 8 and 9) was run on bottom, and a cementing head was installed on top of the tie-back casing. The tie-back stem did not sting in properly and the casing was cemented with the tie-back stem tagging the top of the tie-back sleeve, which is described in more detail in Section VI-C.

Breaking circulation through the tie-back casing at 40 L/s at 8.3 MPa (15 bbl/min at 1200 psi) revealed a leak in the cementing head. Two attempts to repair the leak were unsuccessful, and the head was replaced. The second head also leaked but was successfully repaired. When cement mixing preparations were completed, the tie-back string was circulated for 3 hours at 40 L/s (15 bbl/min) while batch mixing of the lead and tail slurries was completed.

A 1.4-m^3 (9-bbl) pad of retarded water preceded the bottom plug. A shutdown was required to insert the bottom plug into the casing and load the top plug into the cementing head. A 33.9-m^3 (213-bbl) lightweight lead slurry and the 15.9-m^3 (100-bbl) high-strength tail slurry were pumped (procedure 6 in Appendix F-1).

Flow line returns were lost several times during the pumping of cement. To assure that the tie-back stem was not closing and sealing off, the 177.8-mm (7-in.) OD casing was raised several feet with the rig's casing elevators. Flow line returns did not resume, but flow resumed later and was lost again. It is assumed that the cement outran the pumped slurry so far that it back-flowed on the two occasions that flow ceased.

The cement slurry was injected into the tie-back casing. During a short shutdown, the top plug was dropped and followed by 0.08 m^3(1/2 bbl) of cement, which was the volume of cement in surface hard lines, and 0.12 m^3 (3/4 bbl) of retarded water. The slurry was displaced with 1.6 m^3 (10 bbl) of retarded water followed by 36.7 m^3 (231 bbl) of water.

Cement was circulated out of the 177.8-mm (7-in.) OD by 244.5-mm (9-5/8-in.) OD (first) casing annulus; shortly thereafter, cement was circulated out of the 244.5-mm (9-5/8-in.) OD by 339.7-mm (13-3/8-in.) OD (second) casing annulus through perforations in the production casing at 64 m (210 ft) just as the planned displacement volume was reached (Fig. 16). The tie-back casing was lowered and set down on the liner in an attempt to close and seal the tie-back stem to the liner. Approximately 1.6 m^3 (10 bbl) of water was then bled back, confirming that the tie-back stem had not sealed off. The rig pumps were used to clear the perforations at 64 m (210 ft) and circulate the first and second annuli through the perforations to clean out the lightweight, low-strength cement.

G. High-Strength Cement for Top Annuli

The tie-back casing was tensioned as described in Section VI-C. As soon as this was complete, a 4-m^3 (25-bbl) unretarded slurry was mixed and circulated through the perforations in the production casing by pumping down the second annulus (Fig. 16). The cement became too thick to pump just as the first cement returns were circulated. The cementing lines were removed and cleaned with diluted cement recovered in the flow lines (procedure 7 in Appendix F-1).

H. Results of Cementing Operations

Cementing operations were very successful. The placement procedures provided sufficient contingencies and flexibility to allow all jobs to be completed without any major problems. Injection and production tests conducted in EE-2A have shown no evidence that the plug back and isolation of the old wellbore were not accomplished. Bond logs showed that the remedial cementing of the production casing and cementing of the liner and tie-back casing achieved better placement and higher cement strength than had been predicted. These results are summarized in Appendix F-4.

The attempted squeeze cementing of the production casing annulus below 2812 m (9225 ft) left large voids between the well bonded annular plugs. The bond log showed some uncemented casing below 2920 m (9580 ft) and between the upper squeeze at 2910 m (9546 ft) and the cement placed in November 1984 at 2774 m (9100 ft) (Fig. 13). The voids are attributed to the difficulty of squeezing low-permeability fractured rock. Natural joints or fractures have been opened between 2865-3109 m (9400-10,200 ft), based on injection temperature logs following the massive hydraulic fracture in 1983. It was assumed that even with three or four more squeeze injections into the voids, the size of the voids would be significantly reduced but the voids would not be eliminated. The financial constraints on the project precluded this undertaking.

The good bond obtained over most of both lightweight cement slurries is indicative of high compressive strengths and little or no channeling. Poor centralization of the production casing and the highly retarded, lightweight cement used on both the production and tie-back casing may have contributed to the intermittent poor cement bond on the CBLs.

The bond log of the production casing showed a small void between the 1987-m (6520-ft) top of the 1984 cement and the cement circulated in at 1974 m (6476 ft) (Fig.14). It also showed two 6-m-long (20-ft) intervals of poor bond at 1608 m (5275 ft) and 1647 m (5405 ft) and a cement top at 735 m (2410 ft). A 6-m^3 slurry of 1260-kg/m^3 (40 bbl of 10.5-lb/gal) pozzolan water and over 31.8 m^3 (200 bbl) of cement was placed in the subhydrostatic aquifer at 735 m (2410 ft), just above the top of the Precambrian rock.

The bond log of the tie-back casing showed minimal bond between 899-902 m (2950-2960 ft) and several regions between 381-1579 m (1250-5180 ft) where intermittent poor bond occurs (Appendix F-4). It also showed two poorly defined cement tops from 389-259 m (1250-850 ft) and from 49 m (160 ft) to the surface. Because cement was circulated on both of the cement jobs (procedures 6a and 7 in Appendix F-1), the lower top is believed to be the top of the well set and cured cement and the upper top is thought to lie under channeled and diluted cement, both having insufficient strength to indicate any bond at the time the log was run.

The safety factors for retardation of the cement were based on several premature sets that occurred in earlier cementing in wells EE-2 and EE-3A. The long set times that resulted probably contributed to some separations and segregation of the cement. Staged cementing might have significantly reduced separation problems, but the higher risks, costs, and additional requirement for cement formulation testing exceeded our resources. Cement strength and bond strength will probably increase with time. The cement voids, if they exist, should not cause future problems based on stress calculations of the thick-wall, high-strength 177.8-mm (7-in.) casing.

VIII. RESERVOIR AND CASING EVALUATION

The reservoir evaluation and protection plan called for EE-3A to be pressurized and the reservoir to be inflated to 15.2 MPa (2200 psi) above the hydrostatic pressure as EE-2 penetrated the reservoir. As flow and CO_2 were detected by the mud loggers' flow monitoring equipment, the top of the reservoir was located. When additional major flowing fractures were penetrated, the mud log and geochemistry log located many of them by detecting changes in flow, pH, CO_2, and other ion concentration changes.

A 2-day logging and flow testing operation was conducted after the top 60 m (200 ft) of the reservoir had been penetrated, so the upper reservoir, 3290-3550 m (10,800-11,000 ft), and the total reservoir, 3290-3675 m (10,800-12,050 ft), could be compared without high-cost and higher-risk open-hole packer operations.[12] After drilling to 3356 m (11,009 ft), the drilling mud was displaced with water and the drill pipe was removed. Temperature logs, a bottom-hole fluid sampler, and flow tests were run over a 2-day interval. Drilling was resumed after displacing the well with drilling mud.

EE-3A injection pressure was reduced several times as more fractures were intercepted to achieve a balance between protection of the reservoir and dilution of drilling fluid and increased drilling costs. By the end of the redrill, the EE-3A pressure had been reduced to less than 2.8 MPa (400 psi) above hydrostatic.

More than 90 m (300 ft) of rat hole drilled below the lowest indication of reservoir flow provided a large volume for rock spalls and sand fill below the producing interval.

After reaching TD at 3767 m (12,360 ft), the well was again displaced with water. A final 2-day logging and flow testing operation was conducted, including (1) a CBL of the production casing, (2) a 64-arm maximum ID (wear measurement log of the production casing), (3) the multishot magnetic directional survey, and (4) a short flow test of the entire producing interval.

The casing ID caliper log showed moderate wear of the casing over the entire length, but the effort to protect the previous high wear areas with reduced string weights and smooth hardbanded pipe was apparently successful. The lack of decomposed drill pipe rubbers and their reinforcing straps contributed to an excellent wireline logging environment and to high quality caliper logs on the first attempt. The steel straps and rubber had jammed the caliper tools and hung up other logs during the EE-3A redrill.

A longer, more comprehensive production and tracer test was conducted in December that included (1) temperature/gamma-ray logs, both background and RA tracer gamma ray; (2) a three-arm caliper/ gamma-ray log, and (3) a 7-day flow test of the entire penetrated reservoir with a 6.6-L/s, 20.7-MPa (2.5-bbl/min, 3000-psi) injection into EE-3A. Two RA bromine tracer injections into EE-3A were conducted with surface monitoring of EE-2A for both tests and downhole RA logging for the second test. Temperature and RA logs showed the same production interval that the mud logs predicted. A well completion was subsequently designed based on a producing interval from 3284-3673 m (10,775-12,050 ft) (Fig. 17).

After the completion of EE-2A with the installation of the 177.8-m (7-in.) OD liner and tie-back string, a final production, injection, shut-in, and flow back testing sequence was run. This assured before the drilling rig was released that the productivity of the open-hole wellbore below the liner had not been damaged by the sand back or the cleanout of the sand placed to protect the open hole during the cementing of the liner.

Two days before beginning the sand cleanout below the liner, injection into EE-3A was initiated to increase the reservoir pressure to 6.9-13.8 MPa (1000-2000 psi) above hydrostatic

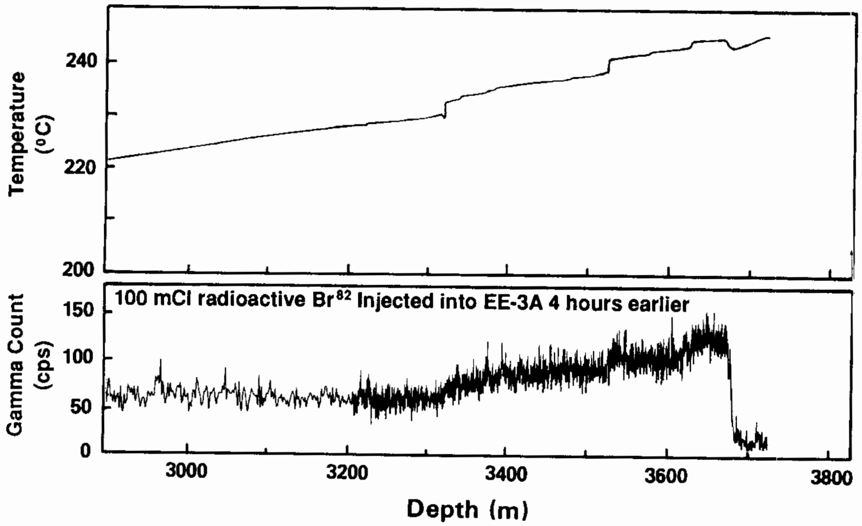

Fig. 17. Production temperature and gamma-ray (tracer) logs of EE-2A open hole below the production casing window at 2953 m.

pressure. This caused flow into EE-2A as the sand in the open hole was penetrated and helped keep sand out of the fractures. The production heated EE-2A during the cleanout and accelerated the set of cement in the first annulus. Once cleanout was complete, EE-2A was vented, a slick line temperature log was run, and the drill pipe was removed. A 10.3-MPa (1500-psi) pressurized CBL was run while injecting approximately 1.3-2.6 L/s (0.50-1 bbl/min) into the EE-2A open-hole bore. After flowing the well back, a cleanout run was made with the drill pipe in before the well was shut-in for 2 days.

After tripping into the hole and laying down drill pipe, a flowing temperature log showed that all production intervals detected before well completion (Fig. 17) were still productive. A 185-m^3 (1150-bbl) cool-water stimulation was conducted at a maximum rate of 40 L/s at 29.3 MPa (15 bbl/min at 4250 psi) injection pressure. Following a 9-hour shut-in, the pressure had declined to 3.3 MPa (480 psi). There was some concern that flow was leaving the wellbore between the tie-back casing and liner. Consequently a short injection was conducted with the rig's pumps, and slick line temperature logs were run with no conclusive evidence of a leak.

IX. OPERATING COSTS

A. Sidetracking and Redrilling

Itemized costs for all cementing, section milling, sidetracking, drilling, and reservoir evaluation from September 8 to November 16, 1987, are summarized in Table III-A. The per-unit costs shown in Table III-B reflect all expenses associated with drilling (drilling fluids, tubular

TABLE III-A. SUMMARY OF OPERATIONAL COSTS FOR CEMENTING, SIDETRACKING, AND DRILLING OF EE-2A
September 8, 1987, to November 16, 1987

Item	Cost($)
Contract rig day rate (69-1/8 days)	436,300
Fuel	42,200
Drilling fluids	63,100
Cementing materials and service	120,500
Retainers and plugs	20,300
Section milling	21,400
Mud logging	58,000
Supervision	122,000
Drill bits	53,000
Reamers and stabilizers	27,200
Rentals:	
Mud system	18,400
BOPE	14,000
H_2S alarm system	4800
Downhole tools (scrapers, mills, etc.)	4500
Other	4200
Directional drilling:	
Supervision	22,100
Tools (motors, non-mag DCs, etc.)	20,500
Wireline	43,700
Logging and perforating	41,600
Transportation	25,100
Drill pipe pickup/laydown	6500
Inspection service	9000
Miscellaneous services	12,200
Miscellaneous purchases	21,100
TOTAL	1,211,700

TABLE III-B. EE-2A DRILLING STATISTICS

	Penetration Rate					
	Maximum		Minimum		Average	
	m/hr	(ft/hr)	m/hr	(ft/hr)	m/hr	(ft/hr)
Overall						
803 m (2635 ft) with 20 bits						
Penetration rate	9.8	(32)	0.6	(2)	3.17	(10.43)
Penetration per bit	97.5	(320)	0.3	(1)	40.16	(131.75)
Cost - $618/m ($188/ft)						
Drill off Whipstock						
12 m (40 ft) with 2 bits						
Penetration rate	1.2	(4)	0.6	(2)	0.87	(2.86)
Penetration per bit	7.0	(23)	5.2	(17)	6.10	(20.00)
Cost - $2527/m ($770/ft)						
Directional (Motor) Drilling						
189 m (620 ft) with 6 bits						
Penetration rate	9.8	(32)	1.8	(6)	3.81	(12.50)
Penetration per bit	64.3	(211)	0.3	(1)	31.51	(103.37)
Cost - $639/m ($195/ft)						
Rotary Drilling						
602 m (1975 ft) with 12 bits						
Penetration rate	8.8	(29)	1.8	(6)	3.19	(10.45)
Penetration per bit	97.5	(320)	1.5	(5)	50.25	(164.85)
Cost - $531/m ($162/ft)						

TABLE IV. COST SUMMARY OF OPERATIONS AND HARDWARE FOR EE-2A COMPLETION
May 16, 1988, to June 17, 1988

Item	Cost($)
Contract rig day rate (31-1/2 days)	187,100
Fuel	15,100
Cementing materials and service	97,900
Retainers and plugs	9400
Supervision[a]	41,500
Drilling fluids	4300
Drill bits and mills	2500
Liner and tie-back casing[b]	285,500
Premium thread service	3800
Liner and tie-back hardware[b]	31,100
Wellhead equipment and service	56,900
Rentals:	
Drill string/handling tools	12,700
BOPE	8400
H_2S alarm system	2800
Other	4200
Commercial logging and perforating[c]	26,100
Transportation	10,800
Pickup/laydown service	20,500
Miscellaneous services	10,700
Miscellaneous purchases	4600
TOTAL	835,900

[a]Contract supervision only; no LANL costs are included.

[b]Actual cost was lower than what is shown. Surplus 177.8-m (7-in.) casing, liner hardware, and centralizers from a previous campaign were used in the string. Costs shown include an estimated value of surplus materials.

[c]No LANL logging costs are included.

inspections, mud logging, and the rig operation base rate, which includes all supervision, rentals, fuel, etc.). Not included in the rotary and directional drilling costs are two runs associated with suspected junk in the hole where no actual penetration was made. This "trouble" cost is, however, reflected in the overall cost per meter (ft).

B. Completion Costs

An itemized breakdown of completion costs in Table IV indicates what actual costs could realistically be expected for a deep hot dry rock completion. Actual costs were slightly lower in the completion of EE-2A because of surplus equipment that was used.

X. CONCLUSIONS

The EE-2 plug back and repair of EE-2 and the drilling and completion of EE-2A were completed on schedule and within the optimum cost estimates using primarily standard oil field services and high-temperature-rated equipment. This demonstration and previous EE-3A drilling results show that HDR drilling should no longer be viewed as high risk and overly difficult. With good planning, sufficient lead time to order the proper equipment, and most importantly, excellent rig supervision to assure careful judgments and adjustments to changed conditions, a drilling project in a difficult drilling environment similar to Fenton Hill can be undertaken with moderate risk. However, further research, development, and tests of HDR well technology are suggested. Accomplishments and needs are listed below.

1. Eleven cement slurries were placed without any serious disruptions. Bonding was better than expected, but remedial cementing in the fractured reservoir was just as difficult as cementing in naturally fractured oil field rocks. Cementing procedures were necessarily complicated and involved a great deal of planning. WBHT code runs, numerous laboratory tests, and several field planning meetings were required. This effort would not be practical in many commercial ventures. Sufficient retarding of the cement for safe placement resulted in long WOC times and a misleading CBL for perforating, and it precluded completion of the cementing work as planned. Improved retarders with more time dependence and less temperature dependence are needed to simplify high-temperature cementing.

2. Packer, retainer, and perforating operations were nearly perfect, but problems can be expected in the future if temperatures exceed 260°C (500°F).

3. Section milling to cut the 12.3-m (60-ft) segment of the production casing was difficult and risky. A redesigned mill modified specifically for crystalline rock and high-temperature drilling fluids might reduce the risk.

4. The drilling itself was the least risky operation. Available drilling fluids, BHA equipment, and bits are suitable for the Fenton Hill environment. Development of a journal-bearing bit with a cutting structure similar to that of a mining bit would extend bit life. Temperatures above 260°C (500°F) would probably cause problems with the drilling motors, drilling fluids, and directional survey and steering tools. Much of the difficulty with the well trajectory, such as higher than planned dogleg severity and unexpected azimuth drift, should be overcome with additional experience in this drilling environment.

5. Reservoir evaluation was less expensive and the results more meaningful than in any previous drilling campaign, partially because of developments in microseismic studies. Improvement of the caliper log and completion of the high-temperature, high-resolution televiewer are needed for future HDR evaluation.

6. The well completion in EE-2A represented a consensus of both hydrothermal and HDR technology. A reasonable attempt, given the economic constraints, was made to prevent additional failures in the underdesigned 244.5-mm (9-5/8-in.) casing. Perhaps this effort will prove successful, but it is premature to make that claim at this time.

7. Hydrothermal completion technology offers no solution to the two major HDR well completion problems: a) how to provide for multiple-completion, high-pressure zone isolation for reservoir stimulation and for long-term injection in a high-temperature crystalline rock at an acceptable cost and risk and b) how to prevent unacceptable loss of reservoir fluids around cemented-in casings and liners? Should the role of the two Phase II wells, EE-2A and EE-3A, be reversed, the present completion will not allow multiple-zone isolation nor backside monitoring that might be desired in an injection well. It is yet to be verified that the problem of flow bypass around cemented-in liners has been solved by total cementing of casings and liners. Possibly the problem is only removed from view.

ACKNOWLEDGMENTS AND DISCLAIMER

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APPENDIX A

SUMMARY OF DAILY OPERATIONS
REMEDIAL CEMENTING, SIDETRACK, REDRILL, AND COMPLETION OF EE-2A

Abbreviations:

bbl - barrel (42 gallons)	OWP - Oil Well Perforators
BHA - bottom-hole assembly	perf - perforate
BOPE - blowout prevention equipment	perfs - perforations
bbl/min- barrels per minute	POH - pull (drill pipe) out of hole
BPV - back pressure valve	RA - radioactive
CBL - cement bond log	TD - total depth
CCL - casing collar log	TIH - trip (drill pipe) in hole
circ - circulate	WOC - wait on cement (to set)

Date	Operations
09/08/87	Change out rams and test BOPE.
09/09/87	Pick up 5-in. drill string, 8-1/2-in. bit, and (9-5/8-in.) casing scraper.
09/11/87	Set Baker 9-5/8-in. K-1 cement retainer at 10,428 ft, inject into formation to cool well.
09/12/87	Pump 33 bbl cement and displace thru retainer to plug off lower wellbore, pull out of retainer and circ, test casing to 1500 psi - leaked off to 1000 psi in 45 seconds, perf 10,221-10,225 ft, pump thru perfs and run temp tools.
09/13/87	Set Baker K-1 retainer at 9889 ft, inject into formation w/rig pumps to cool well and establish rate, pump 36 bbl cement and displace thru perfs to plug off lower casing annulus, no squeeze, pump into formation, attempt second squeeze w/38 bbl cement, pull out of retainer and circ.
09/14/87	Build volume and condition mud, run Kuster temp survey to predict cement setup time.
09/15/87	Build mud system, run CBL, perf 9546-9550 ft, set Baker Retrievamatic cementer at 9166 ft, inject into formation to cool well and establish rate.
09/16/87	Pump 25 bbl cement and displace to fill void behind 9-5/8 in. casing, hold pressure to allow cement to set, POH w/packer.
09/17/87	Drill out cement to 9889 ft, displace drilling mud into hole.
09/18/87	Begin section milling, mill #1 - 9688-9697 ft, circ hole clean, attempt to POH - cutter arms not retracted, circ high vis sweep and attempt to close cutter arms.

Date	Operations
09/19/87	Continue circ and work mill cutter arms, mill 9697-9699 ft, work cutter arms, set slips on drill pipe in spider on annular preventer, break off kelly, run sinker bars on wireline - ram into piston in section mill to retract cutter arms, POH.
09/20/87	Run section mill #2, attempt to break circ - pipe plugged, found mill plugged w/iron, make 8-1/2-in. bit run to retainer at 9889 ft.
09/21/87	Complete bit run, run section mill run #2, mill 9700-9706 ft.
09/22/87	Mill #2 - 9706-9735 ft, attempt to close cutter arms, circ.
09/23/87	Circ and work cutter arms closed, POH.
09/24/87	Mill #3 - 9735-9746 ft, work cutter arms closed.
09/25/87	Run mill #4, re-mill 9739-9746 ft, mill to 9747 ft, make 8-1/2-in. bit run.
09/26/87	Could not work bit past 9755 ft, make junk mill and basket run, drill and wash out 9755-9885 ft.
09/27/87	Displace mud from hole w/water and store, run LANL 3-arm caliper log through window, TIH open ended, rig up cementers and circ to cool well.
09/28/87	Circ, sand back to 9717 ft, wash out sand to 9742 ft, pump 17.4 bbl cement top plug and displace, POH 6 stands, drop wiper plug and circ, POH to 6300 ft, run LANL CCL, TIH to 7100 ft, place high vis pill below 6475 ft, POH, perf 6470-6476 ft, attempt to circ thru perfs - no flow from annulus, TIH w/9-5/8-in. casing scraper.
09/29/87	Make bit and casing scraper run to 6420 ft, set K-1 retainer at 6326 ft, POH w/setting tool, rig up cementers, pump 900 bbl water thru perfs to cool well, pump 481 bbl lightweight cement and 24 bbl tail slurry and displace volume of cement pumped to fill 9-5/8-in. x 13-3/8-in. annulus to surface.
09/30/87	Rig down cementers and WOC, test BOPE.
10/01/87	Run Kuster temp survey and WOC, make 8-1/2-in. bit run to top of cement at 6326 ft, pressure test casing to 1500 psi - no leak off, drill out cement and retainer to 6351 ft.
10/02/87	Drill out retainer, TIH to cement top at 9520 ft, displace water w/mud, circ, pressure test casing to 1500 psi - leaked to 1450 psi in 10 min, drill out cement to 9718 ft.
10/03/87	Drill out cement to 9748 ft, wash out sand to 9875 ft, circ and condition mud, make bit and casing scraper run to 9660 ft.

Date	Operations
10/04/87	Run locator sub and dummy packstock - could not work past 9688 ft, TIH w/bit and roller reamers.
10/05/87	Ream 9631-9768 ft, run locator sub and dummy packstock, could not locate casing stub.
10/06/87	Modify dogs on locator sub, run locator sub and dummy packstock - could not locate casing stub, run section mill #5, ream 9737-9747 ft, mill 9747-9748 ft, circ and work cutter arms in.
10/07/87	Run locator sub and dummy packstock, locate on top of casing stub, run whipstock/packstock assembly.
10/08/87	Orient and set whipstock, make bit run w/BHA #1.

Date	Depth (ft)	Footage Drilled	Redrilling Operations
10/09/87	9725-9727	2	Start to drill off whipstock.
10/10/87	9727-9754	27	Drill off whipstock, survey, run BHA #2.
10/11/87	9754-9779	25	Drill to 9765 ft, survey, repair rig, drill ahead.
10/12/87	9779-9835	56	Drill to 9804 ft, survey, drill to 9735 ft, survey, run BHA #3.
10/13/87	9835-9924	89	Ream 9690-9835 ft, drill to 9892 ft, survey, drill to 9924 ft, survey twice, run drilling motor #1.
10/14/87	9924-9946	22	Orient motor w/steering tool, drill to 9946 ft, bit stuck, work free, POH, inspect drilling tools and found cracked box on drill collar.
10/15/87	9946-9960	14	Run BHA #4, ream 9727-9951 ft, make 5-ft-depth correction, survey twice.
10/16/87	9960-10,051	91	Run drilling motor #2, orient w/steering tool, and drill ahead.
10/17/87	10,051-10,149	98	Run BHA #5, ream 9954-10,051 ft, drill to 10,055 ft, survey, drill to 10,118 ft, survey, drill ahead.
10/18/87	10,149-10,151	2	Survey, POH to 9014 ft, pump-in test held 1650 psi, TIH, circ and condition mud, run drilling motor #3, drill ahead.
10/19/87	10,151-10,151	0	Motor stalling, bit markings showed junk in hole, run gyro survey, make junk mill run.

APPENDIX A (cont)

Date	Depth (ft)	Footage Drilled	Redrilling Operations
10/20/87	10,151-10,281	130	Run drilling motor #4, orient and drill ahead.
10/21/87	10,281-10,358	77	Drill to 10,358 ft w/motor, run BHA #6, ream 10,151-10,164 ft.
10/22/87	10,358-10,478	120	Ream to bottom, survey twice, drill to 10,415 ft, survey, drill to 10,478 ft, survey, POH to 9268 ft, pump-in test held 1420 psi.
10/23/87	10,478-10,620	142	Run drilling motor #5, orient and drill ahead.
10/24/87	10,620-10,689	69	Drill w/motor to 10,689 ft, run BHA #7.
10/25/87	10,689-10,821	132	Ream 10,450-10,689 ft, drill to 10,716 ft, survey twice, drill to 10,811 ft, survey, drill ahead.
10/26/87	10,821-11,009	188	Drill to 10,904 ft, survey, drill to 11,009 ft, survey, clean mud system.
10/27/87	11,009-11,009	0	Displace hole w/water, POH, repair rig, shut in and monitor pressure buildup, inject and flow well, run fluid sampler and LANL temp log.
10/28/87	11,009-11,009	0	Inject 1.5 bbl/min @ 1700 psi while logging, vent down well, run BHA #8, displace hole with mud.
10/29/87	11,009-11,014	5	Circ and condition mud, ream 10,841-11,009 ft, apparent junk in hole, pump high vis pill and fiber sweep, bit showed no iron marks.
10/30/87	11,014-11,039	25	Run BHA #9, drill to 11,021 ft, circ and condition mud, drill to 11,029 ft, pump pressure drop (bit washout), ran BHA #10, drill ahead.
10/31/87	11,039-11,257	218	Drill to 11,103 ft, survey, drill to 11,198 ft, survey, drill to 11,257 ft.
11/01/87	11,257-11,296	39	Drill to 11,292 ft, survey, run BHA #11, ream 11,147-11,292 ft, drill ahead.
11/02/87	11,296-11,409	113	Drill to 11,342 ft, survey, drill to 11,405 ft, survey, drill ahead.
11/03/87	11,409-11,455	46	Run drilling motor #6, drill ahead.
11/04/87	11,455-11,497	42	Drill ahead, run BHA #12.

APPENDIX A (cont)

Date	Depth (ft)	Footage Drilled	Redrilling Operations
11/05/87	11,497-11,661	164	Ream 11,460-11,495 ft, survey, drill to 11,557 ft, survey, drill to 11,652 ft, survey, drill ahead.
11/06/87	11,661-11,715	54	Repair swivel, run BHA #13, drill ahead.
11/07/87	11,715-11,886	171	Drill to 11,728 ft, survey, drill to 11,790 ft, survey, drill to 11,886 ft, survey.
11/08/87	11,886-11,936	50	Drill ahead, inspect drilling tools, run BHA #14.
11/09/87	11,936-12,014	78	Ream 11,919-11,936 ft, drill to 11,996 ft, survey, drill ahead.
11/10/87	12,014-12,161	147	Drill to 12,129 ft, survey, drill ahead.
11/11/87	12,161-12,360	199	Run BHA #15, drill to 12,259 ft, survey, drill to TD, drop multishot survey.
11/12/87	12,360	0	Run bit, pipe plugged, POH and unplug, displace mud from hole and circ.

Date	Completion Operations
11/13/87	Run bit and casing scraper to 9660 ft, install corrosion inhibitor, lay down drill pipe.
11/14/87	Finish laying down drill pipe, store mud and clean pits, run max casing ID log to 9650 ft, set bridge plug and remove BOPE.
11/15/87	Install master valve, remove bridge plug and install lubricator, run LANL gamma/temp and 3-arm caliper logs.
11/16/87	Complete logs, furlough rig till 5/16/88.
05/16/88	Activate rig, run LANL gamma/temp log.
05/17/88	Run LANL gamma/caliper log.
05/18/88	Run LANL acoustic televiewer, set bridge plug, install new 9-5/8-in. casing spool, install BOPE.
05/19/88	Retrieve bridge plug, test BOPE, pick up 3-1/2-in. drill pipe and stand back.
05/20/88	Pick up 8-1/2-in. bit and 5-in. drill pipe.

APPENDIX A (cont)

Date	Completion Operations
05/21/88	Circ and wash to 12,356 ft. TIH w/1500 ft open-ended 3-1/2-in. drill pipe on 5-in drill pipe, tag bottom and circ.
05/22/88	Sand back to 10,740 ft, wash out sand to 10,775 ft.
05/23/88	Pick up and run 1250 ft 7-in. 35 #/ft VAM C-90 casing and liner assy, drop RA frac balls in 9-5/8 x 13-3/8-in. casing annulus and locate with Welex gamma log.
05/24/88	Run Kuster temp survey, circ and record cooldown, hang liner w/bottom at 10,770 ft, circ to cool well, pump 50 bbl cement and displace behind liner, POH w/setting tool, plug 9-5/8 x 13-3/8-in. annulus w/frac balls and gravel, make 8-1/2-in. bit run.
05/25/88	Drill cement 9269-9299 ft, build bridge in casing annulus w/gravel and sepiolite, drop RA frac balls and locate with Welex gamma log, perf 9-5/8-in. casing 885-889 ft, circ thru perfs, pressure test annular bridge to 500 psi.
05/26/88	Make 8-1/2-in. bit run, wash and drill 9269-9499 ft, push 9-5/8-in. wiper plug to 900 ft, pump 70 bbl cement and displace into 9-5/8 x 13-3/8-in. annulus thru perfs - pressure up before complete displacement, shut in, WOC.
05/27/88	Make 8-1/2-in. bit run, drill cement 522-523 ft, run Kuster temp survey to locate cement top, run 8-1/2-in. bit and drill thru cement 523-920 ft.
05/28/88	Tag liner top at 9499 ft and circ, run Welex CBL, perf 9-5/8-in. casing 210-212 ft, circ thru perfs, make 5-3/4-in. bit run and drill out liner.
05/29/88	Clean out liner to 10,608 ft, run 9-5/8-in. casing scraper to liner top, lay down 5-in. drill pipe.
05/30/88	Pick up fluted mill and 3-1/2-in. drill pipe.
05/31/88	Mill out tie-back receptacle, remove 11-in. BOPE.
06/01/88	Pick up tie-back stem and run 7-in. 32 #/ft NSCC C-95 casing tie back, attempt to sting into tie-back receptacle.
06/02/88	Circ to cool well, pump 223 bbl lightweight cement and 100 bbl tail slurry, displace to cement in tie back, pump water down 9-5/8 x 13-3/8-in. annulus thru perfs at 212 ft and up 7-in. annulus, WOC.
06/03/88	Pump thru perfs, run Kuster temp survey to measure buildup, cement 9-5/8 x 13-3/8-in. and 7 x 9-5/8-in. annuli w/17 bbl slurry, install and test 7-in. BOPE.
06/04/88	Make 5-3/4-in. bit run, drill out cement to 9407 ft.
06/05/88	Pick up new bit and drill out to 9530 ft, pressure test tie-back seal to 4000 psi, drill out cement to 10,749 ft.

APPENDIX A (cont)

Date	Completion Operations
06/06/88	Drill out shoe w/5-3/4-in. flat bottom mill, pressure test liner to 2500 psi, drill out cement to 10,812 ft, wash out sand to 11,592 ft.
06/07/88	Wash out sand to 12,360 ft, circ hole clean, run Kuster temp survey.
06/08/88	Pump into EE-3A with rig pumps to develop flow in EE-2A to increase temp and set cement, run Kuster temp survey, make 5-3/4-in. bit run, tag ledge at 12,186 ft, circ reservoir to heat well.
06/09/88	Run OWP CBL/gamma log, run 5-3/4-in. mill - plugged, POH.
06/10/88	Run 5-3/4-in. mill to TD and circ hole clean.
06/11/88	Clean pits, release rig to standby secured status.
06/13/88	Reactivate rig, run 5-3/4-in. bit to TD and circ.
06/14/88	Lay down 3-1/2-in. drill pipe, run LANL temp log, set bridge plug, remove BOPE.
06/15/88	Replace 7-in. casing spool, install BOPE, retrieve bridge plug, set BPV, remove BOPE, install frac valves, retrieve BPV, pump 1160 bbl water at up to 4120 psi at 12 bbl/min with BJ Titan.
06/16/88	Run Kuster temp survey, set BPV, install 7-in. BOPE, retrieve BPV, run LANL temp log.
06/17/88	Pump 373 bbl water into formation w/rig pumps, run Kuster temp survey, remove BOPE, release rig for demobilization.

APPENDIX B
BOTTOM-HOLE DRILLING ASSEMBLIES USED IN EE-2A DRILLING

BHA No.	Depth Out(ft)	Footage Drilled	Bottom-Hole Assembly	Vertical Deviation (end of run)	Remarks
1	9742	17	Bit #1 (0.8), bit sub w/float (3.0), XO (1.8), 2 jts 5-in. 25.60 #/ft DP (63.4), XO (2.6), 6 ea 6-1/4-in. DCs (174), XO (2.7), 12 jts 5-in. HWDP (377).	12.0	Slick assembly to drill off whipstock.
2	9765	23	Bit #2 (0.8), bit sub w/float (4.0), IBS (3.9), XO (1.8), 2 jts 5-in. 25.60 #/ft X-95 DP (63.4), XO (2.6), 6 ea 6-1/4-in., DCs (174), XO (2.7), 12 jts 5-in. HWDP (377).	13.5	Slick build assembly to drill by whipstock.
3	9835	70	Bit #3 (0.8), bit sub w/float (1.2), 3 pt RR (5.7), 6-1/4-in. NMDC (30.9), 6-1/4-in. DC (28.3), 6 pt RR (8.6), 13 ea 6-1/4-in. DCs (366), XO (2.7), 15 jts 5-in. HWDP (470).	13.5	Slight build assembly.
4	9924	89	Bit #4 (0.8), bit sub w/float (1.2), 3 pt RR (4.3), baffle plate, 6-1/4-in. NMDC (30.9), 6-1/4-in. DC (28.3), 6 pt RR (8.6), 13 ea 6-1/4-in. DCs (366), XO (2.7), 15 jts 5-in. HWDP (470).	14.8	Slight build assembly.
5	9946	22	Bit #5 (0.8), Drilex motor (20.8), float sub (1.2), 1-1/2° bent sub (1.3), orientation sub (2.0), XO (2.7), 1 ea 6-1/2-in. NMDC (30.9), 12 ea 6-1/4-in. DCs (341), XO (2.7), 15 jts 5-in. HWDP (470).	15.0	Stuck on bottom - worked free.
6	9960	14	Bit #rr5 (0.8), bit sub w/float (1.2), 3 pt RR (5.8), baffle plate, 6-1/4-in. NMDC (30.9), 6 pt RR (8.6), 6-1/8-in. DC (28.1), 3 pt RR (5.7), 14 ea 6-1/8-in. DCs (397), XO (2.7), 15 jts 5-in. HWDP (470).	15.0	Hold assembly.
7	10,051	91	Bit #6 (0.8), Drilex motor (20.8), float sub (1.2), 1-1/2° bent sub (1.2), orientation sub (2.0), XO (2.7), 1 ea 6-1/2-in. NMDC (30.9), 15 ea 6-1/4-in. DCs (425), XO (2.7), 15 jts 5-in. HWDP (470).	15.0	Azimuth correction and slight build.
8	10,150	99	Bit #7 (0.8), bit sub w/float (1.2), 3 pt RR (5.3), 6-1/4-in. NMDC (30.9), 6-1/4-in. DC (28.1), 6 pt RR (8.6), 6-1/4-in. DC (28.8), 3 pt RR (5.7), 13 ea 6-1/4-in. DCs (368), XO (2.7), 15 jts 5-in. HWDP (470).	16.5	Slight build assembly.

APPENDIX B (cont)

BHA No.	Depth Out(ft)	Footage Drilled	Bottom-Hole Assembly	Vertical Deviation (end of run)	Remarks
9	10,151	1	Bit #8 (0.8), Drilex motor (23.8), float sub (1.2), 1-1/2° bent sub (0.9), orientation sub (2.0), XO (2.7), 1 ea 6-1/2-in. NMDC (30.9), 15 ea 6-1/4-in. DCs (425), XO (2.7), 15 jts 5-in. HWDP (470).	16.5	Motor stalled-junk in hole. Pulled for mill run.
10	10,358	207	Bit #9 (0.8), Drilex motor (23.8), float sub (1.2), 1-1/2° bent sub (0.9), orientation sub (2.0), XO (2.7), 1 ea 6-1/2-in. NMDC (30.9), 15 ea 6-1/4-in. DCs (425), XO (2.7), 15 jts 5-in. HWDP (470).	18.8	Azimuth correction and build.
11	10,478	120	Bit #10 (0.8), bit sub w/float (1.2), 3 pt RR (5.7), 6-1/2-in. NMDC (31.0), 6-1/4-in. NMDC (30.9), 6 pt RR (8.6), 6-1/4-in. DC (28.1), 3 pt RR (5.7), 10 ea 6-1/4-in. DCs (287), XO (2.7), 15 jts 5-in. HWDP (470).	20.5	Washed out DC -removed from string.
12	10,689	211	Bit #11 (0.8), Drilex motor (23.42), float sub (1.2), 2° bent sub (1.0), orientation sub (2.0), XO (2.7), 2 ea 6-1/2-in. NMDCs (61.8), 11 ea 6-1/4-in. DCs (315), XO (2.7), 15 jts 5-in. HWDP (470).		Lay down DCs. Pick up replacement collars.
13	11,009	320	Bit #12 (0.8), 6 pt RR (9.1), 6-5/8-in. NMDC (27.1), 6 pt RR (8.6), 6-1/2-in. NMDC (31.0), 6-9/16-in. DC (30.6), 3 pt RR (5.7), 8 ea 6-1/2-in. DCs (241), XO (2.7), 18 jts 5-in. HWDP (565).	25.8	Hold assembly.
14	11,014	5	Bit #13 (0.8), 6 pt RR (9.6), 6-1/4-in. DC (8.7), 6 pt RR (9.6), 6-5/8-in. NMDC (27.1), 3 pt RR (4.7), 6-1/2-in. NMDC (31.0), 3 pt RR (5.6), 9 ea 6-1/2-in. DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	25.8	Apparent junk in hole.
15	11,029	15	Bit #rr13 - SAME AS ABOVE.	25.8	No iron marks on bit - reran.
16	11,292	263	Bit #14 (0.8), 6 pt RR (9.6), 6-1/4-in. DC (8.7), 6 pt RR (9.6), baffle plate, 6-5/8-in. NMDC (27.1), 3 pt RR (4.7), 6-1/2-in. NMDC (31.0), 9 ea 6-1/2-in. DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	26.3	Hold assembly.
17	11,409	117	Bit #15 (0.8), bit sub w/float (3.0), baffle plate, 6-5/8-in. NMDC (27.1), 6 pt RR (8.6), 6-1/2-in. NMDC (31.0), 6 pt RR (9.6), 9 ea DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	25.3	Drop assembly.

APPENDIX B (cont)

BHA No.	Depth Out(ft)	Footage Drilled	Bottom-Hole Assembly	Vertical Deviation (end of run)	Remarks
18	11,497	88	Bit #16 (0.8), Drilex motor (23.8), float sub (1.2), 1-1/2° bent sub (1.0), orientation sub (2.0), XO (2.7), 2 ea 6-1/2-in. NMDCs (58.0), 9 ea 6-1/2-in. DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	23.8	Azimuth correction.
19	11,660	163	Bit #17 (0.8), 3 pt RR (5.4), 6-5/8-in. NMDC (27.1), 6 pt RR (8.6), 6-1/2-in. NMDC (31.0), 3 pt RR (4.6), 9 ea DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	24.0	Hold assembly.
20	11,936	276	Bit #18 (0.8), 3 pt RR (5.4), 6-1/4-in. short DC (8.7), 6 pt RR (8.8),6-5/8-in. NMDC (27.1), 6 pt RR (9.6), 6-1/2-in. NMDC (31.0), 9 ea 6-1/2-in. DCs (272), XO (2.7), 18 jts 5-in. HWDP (565).	23.3	Hold assembly.
21	12,161	225	Bit #19 (0.8), bit sub (2.9), 6-5/8-in. NMDC (27.1), 6-1/4-in. short DC (8.7), 6 pt RR (8.6), 6-1/2-in. NMDC (31.0), 6-1/2-in. DC (30.6), 3 pt RR (4.6), 8 ea 6-1/2-in. DCs (242), XO (1.7), 18 jts 5-in. HWDP (565).	21.5	Drop assembly.
22	12,360	199	Bit #20 (0.8), 6 pt RR (9.1), baffle plate, 2 ea 6-1/2-in. NMDC (58.0), 3 pt RR (5.7), 3 ea DCs (91.7), 3 pt RR (4.6), 3 ea 6-1/2-in. DCs (91.1), XO (1.7), 18 jts 5-in. HWDP (565).	23.0	Slight drop assembly.

Numbers in (xx) are lengths in feet.

Abbreviations: XO = crossover sub; DP = drill pipe; DC = drill collar; HWDP = heavyweight drill pipe; IBS = integral blade stabilizer; pt = point; RR = roller reamer; NMDC = nonmagnetic drill collar; #rr = bit number rerun

APPENDIX C

DRILL PIPE HANDLING PROCEDURES FOR EE-2A DRILLING

The following procedures minimize additional wear damage on the 9-5/8-in. casing, fatigue damage, and downhole drill string failures:

1. All drill pipe rotated inside the 9-5/8-in. casing must have "smooth" hardbanding or no hardbanding.

2. Drill pipe protectors (rubbers) will not be used. They decompose at projected circulation temperatures leaving rubber and reinforcing steel straps that foul logging and other wireline operations.

3. A wear bushing will be installed in the 9-5/8-in. casing head during all drilling.

4. Drill pipe specifications are as follows:

	19.50 # - GRD E	25.60 # - X-95
Actual weight	21.34 #/ft	28.62 #/ft
Makeup torque	20,000 ft/lb	32,300 ft/lb
Tool joint (TJ) dimensions	6-3/8-in.x 3-3/4-in.	6-1/2-in.x 3-in.
Tube ID	4.276-in.	4.00-in.
Torsional yield TJ	44,600 ft/lb	62,400 ft/lb
Torsional yield tube	32,230 ft/lb	66,070 ft/lb
Tensile yield TJ	1,128,460 lb	1,619,520 lb
Tensile yield tube (new)	311,400 (395,600)	535,000 (671,520)
Collapse	7070 psi	14,510 psi
Burst	8690 psi	15,200 psi
Slip max load	304,000 lb	450,000 lb

   a. Drill pipe and heavyweight pipe have 4-1/2-in. IF connections.

   b. Drill collars and reamers have 4-1/2-in. XH connections.

5. Generally the drill string will have about 5300-5700 ft of 19.50 #/ft Grade E on the bottom of the string.

   a. The remaining drill pipe will be 25.60 #/ft X-95.

   b. Maximum pull at surface will be limited to 280,000 lb at the top of the 19.50 #/ft Grade E.

   c. Max surface pull = (25 #/ft) x (length of 25.60 #/ft X-95) + 280,000 lbs + wt of blocks + wt of kelly.

   d. Toolpusher and LANL supervisor are to be consulted before exceeding these limits.

6. The minimum BHA weight for drilling will be 45,000 lb.

7. Four (4) stands of heavyweight will be run above the drill collars.

8. Special hardbanded 25.60 #/ft X-95 drill pipe will be run through the dogleg section from 500-700 ft while drilling.

9. Coarse hardbanded 19.50 #/ft Grade E will be run only in the granite open-hole section.

10. Drill pipe and heavyweight are to be rotated on each trip as follows:

    a. Bottom three (3) stands of 25.60 #/ft are to be rotated on top of string and change "break" on tool joints.

    b. Bottom three (3) stands of 19.50 #/ft Grade E are to be rotated to top of Grade E section and change "break" on tool joint. (Avoid running coarse hardbanding in casing.)

11. Maintain record of total rotating hours on drill pipe and drill collars. (Note daily cumulative in log book.)

12. All BHA components are to be inspected after 150 rotating hours. All drill pipe is to be inspected after 200 rotating hours.

13. Pump pressures are to be monitored for washouts.

14. Corrosion rings will be run in the bottom and top stands of drill pipe.

APPENDIX D
EE-2A SINGLE-SHOT SURVEY DATA

No.	MEAS. DEPTH	CRSE LEN.	DRIFT	VERT. CRSE	TOTAL DEPTH	VERT. SECTION	DRIFT DIR.	DOG SEV.	COURSE COORDS. NORTH	COURSE COORDS. EAST	TOTAL COORDS. NORTH	TOTAL COORDS. EAST	OLD TOTAL COORDS NORTH	OLD TOTAL COORDS EAST
0	9745		12.00		9653.02	250.88	45.5				412.8	-170.8	-1014.67	-1774.26
1	9830	85.0	13.50	82.90	9735.92	269.40	37.0	2.82	14.12	12.28	426.9	-158.5	-1000.55	-1761.98
2	9886	56.0	14.25	54.36	9790.29	282.81	32.0	2.52	11.07	7.59	438.0	-150.9	-989.49	-1754.39
3	9918	32.0	14.75	30.98	9821.27	290.82	29.0	2.81	6.90	4.06	444.9	-146.9	-982.58	-1750.33
4	9954	36.0	15.00	34.79	9856.07	300.04	31.0	1.58	8.00	4.62	452.9	-142.3	-974.58	-1745.71
5	10049	95.0	15.00	91.76	9947.83	324.62	31.0	0.00	21.08	12.66	474.0	-129.6	-953.50	-1733.05
6	10112	63.0	16.00	60.71	10008.54	341.42	38.0	3.36	13.83	9.55	487.8	-120.1	-939.67	-1723.50
7	10144	32.0	16.50	30.72	10039.26	350.34	37.0	1.79	7.10	5.45	494.9	-114.6	-932.57	-1718.05
8	10245	101.0	17.25	96.65	10135.91	379.57	38.0	0.79	23.26	17.85	518.2	-96.8	-909.31	-1700.20
9	10352	107.0	18.75	101.81	10237.73	411.86	52.0	4.27	23.10	23.33	541.3	-73.5	-886.21	-1676.87
10	10409	57.0	19.75	53.81	10291.54	429.36	53.0	1.84	11.44	14.91	552.7	-58.6	-874.77	-1661.96
11	10471	62.0	20.50	58.21	10349.75	449.47	52.0	1.33	12.99	16.92	565.7	-41.6	-861.79	-1645.04
12	10609	138.0	22.25	128.55	10478.30	494.97	63.0	3.16	26.75	42.34	592.5	0.7	-835.03	-1602.69
13	10706	97.0	24.50	89.06	10567.37	526.52	72.0	4.34	14.56	35.51	607.0	36.2	-820.48	-1567.19
14	10800	94.0	25.00	85.36	10652.73	556.88	73.0	0.69	11.83	37.53	618.9	73.7	-808.65	-1529.66
15	10894	94.0	25.50	85.02	10737.75	588.26	70.0	1.46	12.73	38.01	631.6	111.8	-795.92	-1491.64
16	10999	105.0	25.75	94.67	10832.43	624.76	69.0	0.47	15.90	42.53	647.5	154.3	-780.01	-1449.11
17	11075	76.0	26.00	68.38	10900.81	651.59	69.0	0.32	11.89	30.96	659.4	185.2	-768.13	-1418.15
18	11171	96.0	26.25	86.19	10987.00	685.79	69.0	0.26	15.15	39.46	674.5	224.7	-752.98	-1378.68
19	11262	91.0	26.25	81.61	11068.62	718.14	70.0	0.48	14.09	37.70	688.6	262.4	-738.88	-1340.99
20	11338	76.0	26.00	68.23	11136.85	744.51	72.0	1.20	10.90	31.64	699.5	294.0	-727.99	-1309.35
21	11400	62.0	25.25	55.90	11192.75	765.50	71.0	1.39	8.50	25.43	708.0	319.5	-719.48	-1283.92
22	11489	89.0	23.75	81.01	11273.77	796.14	62.0	4.51	14.60	33.79	722.6	353.3	-704.88	-1250.13
23	11551	62.0	23.50	56.80	11330.57	818.03	60.5	1.05	11.95	21.78	734.6	375.0	-692.93	-1228.35
24	11646	95.0	24.00	86.95	11417.53	852.19	59.0	0.82	19.28	33.05	753.8	408.1	-673.66	-1195.31
25	11705	59.0	24.00	53.89	11471.43	873.76	59.0	0.00	12.36	20.57	766.2	428.7	-661.30	-1174.74
26	11767	62.0	23.75	56.69	11528.12	896.41	58.0	0.76	13.11	21.40	779.3	450.1	-648.19	-1153.34
27	11863	96.0	23.75	87.87	11615.99	931.30	59.0	0.41	20.20	32.97	799.5	483.0	-627.99	-1120.37
28	11999	136.0	23.00	124.83	11740.83	979.59	60.0	0.62	27.39	46.49	826.9	529.5	-600.59	-1073.89
29	12126	127.0	21.75	117.43	11858.27	1022.28	62.0	1.15	23.45	42.27	850.4	571.8	-577.14	-1031.62
30	12249	123.0	22.25	114.04	11972.31	1062.97	60.0	0.73	22.34	40.29	872.7	612.1	-554.80	-991.34
TD	12360	111.0	22.25	102.73	12075.04				21.01	36.40	893.7	648.5	-533.79	-954.94

(Projection based on prior survey.)

APPENDIX D (cont)
EE-2A MAGNETIC MULTISHOT DATA

No.	MEAS. DEPTH	CRSE LEN.	DRIFT	VERT. CRSE	TOTAL DEPTH	VERT. SECTION	DRIFT DIR.	DOG SEV.	COURSE COORDS. NORTH	COURSE COORDS. EAST	TOTAL COORDS. NORTH	TOTAL COORDS. EAST	OLD TOTAL COORDS NORTH	OLD TOTAL COORDS EAST
0	9745		12.00		9653.02	250.88	45.5				412.8	-170.8	-1014.67	-1774.26
1	9777	32.0	13.25	31.23	9684.25	257.79	30.0	11.24	5.51	4.21	418.3	-166.6	-1009.16	-1770.05
2	9871	94.0	14.00	91.35	9775.60	279.92	33.0	1.09	18.87	11.58	437.2	-155.0	-990.30	-1758.47
3	9966	95.0	14.25	92.12	9867.73	303.10	32.0	0.36	19.55	12.45	456.8	-142.6	-970.74	-1746.01
4	10060	94.0	14.75	91.01	9958.75	326.54	40.0	2.19	18.98	13.82	475.7	-128.7	-951.76	-1732.19
5	10154	94.0	15.50	90.74	10049.49	350.93	38.0	0.97	19.06	15.42	494.8	-113.3	-932.70	-1716.76
6	10248	94.0	17.00	90.25	10139.74	376.89	45.0	2.62	19.62	17.45	514.4	-95.9	-913.08	-1699.31
7	10343	95.0	18.00	90.60	10230.35	404.44	51.0	2.16	19.06	21.23	533.5	-74.7	-894.02	-1678.08
8	10437	94.0	21.00	88.59	10318.95	434.28	51.0	3.19	19.74	24.38	553.2	-50.3	-874.28	-1653.70
9	10531	94.0	22.00	87.47	10406.42	466.26	58.0	2.92	19.93	28.03	573.2	-22.3	-854.34	-1625.67
10	10626	95.0	22.00	88.11	10494.53	496.97	68.0	3.93	16.10	31.60	589.3	9.3	-838.24	-1594.08
11	10720	94.0	25.00	86.19	10580.73	527.06	71.0	3.43	13.07	35.11	602.3	44.4	-825.18	-1558.96
12	10814	94.0	24.50	85.36	10666.10	558.27	70.0	0.69	13.13	37.10	615.5	81.5	-812.04	-1521.86
13	10909	95.0	25.00	86.27	10752.37	589.82	71.0	0.68	13.27	37.49	628.7	119.0	-798.77	-1484.37
14	11003	94.0	25.25	85.10	10837.48	621.28	71.0	0.26	12.99	37.74	641.7	156.8	-785.78	-1446.64
15	11097	94.0	26.00	84.75	10922.23	653.31	71.0	0.79	13.24	38.44	655.0	195.2	-772.54	-1408.20
16	11191	94.0	26.00	84.48	11006.72	685.56	72.0	0.46	13.07	39.08	668.0	234.3	-759.47	-1369.12
17	11286	95.0	25.75	85.47	11092.19	718.00	71.0	0.52	13.15	39.32	681.2	273.6	-746.31	-1329.81
18	11380	94.0	25.50	84.75	11176.95	749.82	72.0	0.53	12.90	38.55	694.1	312.1	-733.41	-1291.26
19	11474	94.0	23.75	85.47	11262.42	781.78	64.0	4.00	14.56	36.27	708.6	348.4	-718.86	-1254.99
20	11569	95.0	23.25	87.12	11349.55	815.03	59.0	2.16	18.05	33.27	726.7	381.7	-700.81	-1221.72
21	11663	94.0	23.50	86.28	11435.84	848.41	60.0	0.49	18.93	32.13	745.6	413.8	-681.89	-1189.58
22	11757	94.0	24.00	86.03	11521.87	881.99	61.0	0.68	18.64	32.95	764.3	446.8	-663.25	-1156.63
23	11852	95.0	23.75	86.87	11608.75	916.09	60.0	0.50	18.93	33.47	783.2	480.2	-644.31	-1123.17
24	11946	94.0	23.75	86.03	11694.79	949.67	61.0	0.42	18.64	32.95	801.8	513.2	-625.67	-1090.22
25	12040	94.0	21.25	86.83	11781.62	981.57	60.0	2.69	17.70	31.31	819.5	544.5	-607.98	-1058.90
26	12229	189.0	22.25	175.54	11957.17	1043.68	61.0	0.56	34.47	60.96	854.0	605.5	-573.50	-997.95
27	12323	94.0	23.00	86.77	12043.94	1074.80	66.0	2.19	16.10	32.35	870.1	637.8	-557.40	-965.60
28	12346	23.0	23.00	21.17	12065.11	1082.33	66.0	0.00	3.66	8.21	873.8	646.0	-553.75	-957.39
TD	12360	14.0	23.00		12078.01	1086.94	66.0	0.00	2.22	5.00	876.0	651.0		

(Projection based on prior survey.)

APPENDIX E

BIT RECORD, DRILLING PARAMETERS, AND TYPICAL MUD PROPERTIES FOR EE-2A DRILLING

BIT#	MFG	TYPE	JET SIZES 1	JET SIZES 2	JET SIZES 3	DEPTH OUT	FTGE	HOURS RUN	FT/HR	WEIGHT 1000#	RPM	VERT DEV.	PUMP PRES	PMP SPM	DULL CODE T-B-G
1	SEC	H8J	13	15	15	9742	17	5.25	3.24	6-8	40	13.50	1300	123	5-6-I
2	HTC	HH77	14	15	15	9765	23	9.00	2.56	15	44	13.75	1300	122	4-5-I
3	STC	7GA	12	12	16	9835	70	9.00	7.78	35-40	40	13.50	1500	120	1-4-I
4	STC	7GA	12	12	13	9924	89	8.00	11.13	40-45	45	14.75	1800	120	2-4-1/16
5	STC	7GA	13	13	13	9946	22	0.75	29.33	20-40	MM		1475	96	
RR5	"	"	13	13	13	9960	14	1.00	14.00	40	50	15.00	1700	110	2-4-I
6	HTC	HH77	13	13	13	10051	91	9.50	9.58	20-25	MM		1600	98	4-5-I
7	HTC	HH77	13	13	13	10150	99	8.00	12.38	45	60	16.50	1750	120	5-5-I
8	STC	7GA	13	13	13	10151	1	0.25	4.00	3-4	MM		1750	120	5-2-I
9	STC	7GA	13	13	13	10358	207	16.00	12.94	20-25	MM		1700	98	6-6-I
10	STC	F7	14	14	0	10478	120	8.75	13.71	45	60	20.50	2150	115	2-2-1/16
11	STC	7GA	13	13	13	10689	211	13.00	16.23	20-22	MM		1600	98	2-5-I
12	HTC	HH77	14	14	0	11009	320	26.00	12.31	40	60	25.50	2125	115	8-8-3/8
13	HTC	HH77	14	14	0	11014	5	1.00	5.00						RERAN
RR13	"	"	14	14	0	11029	15	3.00	5.00		60	25.50			WASHOUT
14	STC	F7	14	14	0	11292	263	23.25	11.31	30-40	60	26.25	1950	115	4-2-1/8
15	HTC	HH77	13	13	12	11409	117	14.25	8.21	30-40	60	25.25	1400	115	4-5-I
16	HTC	HH77	13	13	12	11497	88	9.50	9.26	45	MM	23.00	1500	97	4-5-I
17	STC	F7L	13	13	13	11660	170	16.00	10.63	30-40	65	24.00	1600	120	6-4-1/8
18	HTC	ATJ77	11	11	14	11936	276	27.00	10.22	40	60	23.25	1600	120	8-8-3"
19	STC	7GA	12	12	13	12161	225	22.00	10.23	40-45	60	21.50	1550	110	6-7-1/8
20	STC	7GA	12	12	13	12360	199	17.75	11.21	44	60	23.00	1600	110	7-7-1/16
RR9	STC	7GA		OUT		12360	0								

HTC = HUGHES TOOL CO.
SEC = SECURITY TOOL CO.
STC = SMITH TOOL CO.

JET SIZES ARE MEASURED IN 1/32-in. DIAMETER

DULL CODE MEASURES TOOTH AND BEARING WEAR ON A SCALE OF 1-8. GAUGE WEAR IS IN INCHES.

MM = MUD MOTOR

APPENDIX E (cont)

TEMP		MUD WEIGHT		PLAS. VISC.		YIELD POINT		GEL STRENGTH		FUNNEL VISC.		SOLIDS %		LUBRICITY		pH		HOURS CIRC.	BIT#
OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN		
112	80	8.7	8.7	14	14	6	3	1/12	1/7	47	37	3	3	N/A	N/A	10.5	10.5	1:30	1
120	100	8.8	8.8	16	13	7	4	1/18	1/13	42	39	3	3	.24	.26	10.0	9.8	2:40	2
156	149	8.9	8.8	15	14	5	7	2/28	2/24	45	43	3	3	.37	.36	9.8	10.0	3:30	3
142	115	8.8	8.7	12	13	4	6	1/19	1/21	43	42	4	3	.32	.32	10.5	10.5	3:30	4
155	141	8.8	8.8	13	14	8	7	1/13	1/16	47	46	3	3	.32	.32	10.0	10.0	6:00	5
154	130	8.8	8.8	20	20	19	13	1/31	1/26	67	52	3	3	.31	.32	10.0	10.0	3:00	RR5
146	133	8.8	8.8	18	15	12	9	1/25	1/18	74	52	3	3	.31	.32	10.0	10.0	8:00	6
157	128	8.8	8.8	22	22	14	12	1/30	1/23	62	50	3	3	.31	.31	9.5	9.5	8:30	7
149	118	8.9	8.9	22	20	13	11	2/32	2/20	83	47	4	4	.32	.32	9.5	10.0	19:00	9
149	121	8.9	8.9	22	20	7	5	1/23	1/16	76	42	4	4	.36	.34	10.0	10.0	9:30	10
135	120	8.9	9.0	21	20	16	13	2/28	1/21	56	49	5	5	.39	.37	10.0	9.5	16:00	11
151	121	9.0	9.1	28	26	27	18	4/37	3/28	72	52	5	6	.34	.32	9.5	9.5	23:00	12
155	134	8.6	8.6	13	15	7	11	4/28	4/34	47	55	3	3	.36	.36	7.9	9.1	5:30	14
153	128	8.7	8.6	10	11	6	6	4/58	4/42	52	47	3	2	.36	.36	8.8	9.2	4:30	15
170	143	8.8	8.8	7	7	13	11	7/72	4/48	75	52	3	3	.34	.34	9.8	10.0	4:00	16
156	126	8.7	8.6	9	13	4	11	1/23	3/48	38	62	3	2	.36	.35	9.3	9.5	5:30	17
172	126	8.6	8.6	8	10	4	6	3/16	3/33	39	44	2	2	.40	.38	8.0	9.2	34:00	18
152	120	8.6	8.6	8	11	4	11	3/22	4/34	40	50	2	2	.38	.37	9.4	9.8	16:00	19
164	138	8.8	8.7	13	11	13	12	4/51	4/49	52	48	3	3	.36	.38	10.2	10.0	11:30	20

NOTE: THE TIMES LISTED FOR HOURS CIRCULATING ARE FROM THE TIME OF FIRST BREAKING CIRCULATION TO TIME OF MUD REPORT.

APPENDIX F-1
CEMENTING PROCEDURES

SLURRY PROCEDURE No.	DESCRIPTION	REFERENCED FIGURE	PROJECTED TEMPERATURE BHST(a) °C	(°F)	BHCT(b) °C	(°F)	CEMENT VOLUME CALCULATED m^3	(bbl)	PUMPED m^3	(bbl)
Predrilling - September 1987										
1a(c)	Plug 244.5-mm (9-5/8-in.) casing below 3180 m (10,420 ft).	2	210	(410)	149	(300)	8.44	(53.1)	5.25	(33.0)
1b	Plug 244.5-mm (9-5/8-in.) casing annulus from 3165-2810 m (10,380-9225 ft).	3	206	(403)	149	(300)	10.24	(64.4)	11.13	(70.0)
1c	Plug 244.5 mm (9-5/8-in.) casing annulus from 2924-2810 m (9590-9225 ft).	4	198	(388)	149	(300)	3.24	(20.4)	3.97	(25.0)
2	Temporary plug in window cut in 244.5-mm (9-5/8-in.) casing from 2954-2972 m (9688-9748 ft).	6	197	(287)	149	(300)	3.56	(22.4)	2.77	(17.4)
3a	Fill 244.5-mm (9-5/8-in.) casing annulus above 1860 m (6100 ft).	5	127	(260)	113	(235)	77.9 (3a + 3b)	(490)	76.5	(481) (d)
3b	Fill 244.5-mm (9-5/8-in.) casing annulus above 1980 m (6500 ft) with high-strength tail slurry.	5	127	(260)	113	(235)			3.82	(24.0)
Postdrilling - May and June 1988										
4	Cement-in 177.8-mm (7-in.) open-hole liner from 3920-2900 m (10,770-9500 ft).	11	216	(420)	(e)		43.4	(273)	8.11	(51.0)
5	Fill 244.5-mm (9-5/8-in.) casing annulus above 282 m (926 ft).	12	40	(104)	38	(100)	8.76	(55.1)	11.4	(71.5)
6a	Cement-in 177.8-cm (7-in.) tie-back casing from 2900 m (9500 ft) to surface.	13	182	(360)	(f)		44.8 (6a + 6b)	(282)	33.9	(213) (d)
6b	Cement-in 177.8-mm (7-in.) tie-back casing from 2900 m (9500 ft) to surface with high-strength tail slurry.	13	182	(360)	(g)				15.9	(100)
7	Circulate high-strength slurry into 177.8-mm (7-in.) by 244.5-mm (9-5/8-in.) casing annulus and 244.5-mm (9-5/8-in.) by 339.7-cm (13-3/8-in.) casing annulus.	12	25	(77)	25	(77)	2.66	(16.7)	2.7	(17.0)

(a) Bottom-hole static temperature.
(b) Bottom-hole circulating temperature.
(c) Two batch-mixed slurries of 5.5 m^3 were placed.
(d) Downhole volume corrected for projected crushing of Perfalite.
(e) Formulations for 149°C (300°F), 177°C (350°F), and 207°C (405°F) were tested.
(f) Formulations for 149°C (300°F) and 177°C (350°F) were tested.
(g) Formulations for 93°C (200°F), 149°C (300°F), and 177°C (350°F) were tested.

APPENDIX F-2

CEMENT FORMULATIONS

SLURRY PROCEDURE (No.)	CEMENT API CLASS	SILICA FLOUR D66 (%BWOC)(a)	BENTONITE D20 (%BWOC)	DISPERSANT D65 (%BWOC)	RETARDER D28 (%BWOC)	EXTENDER (VARIOUS) (%BWOC)	PERFALITE (PERLITE) By Vol.	MIX WATER (%BWOC)
1a,b,c	H	45	0.75	0.25	0.7	--	--	55.3
2	H	45	0	0.7	0.6	--	--	43.0
3a	G	35	2.0(b)	0.5	0.3	0.44 D75	1:1	101.2
3b	H	45	0.75	0.3	0.2	--	--	55.3
4	H	45	0.75	0.75	1.6	0.80 L10	--	49.0
	Various retarder concentrations tested				0.6 0.5 0.3			
5	G	45	0	0.25	0	(c)	--	58.1
6a	H	35	1.75	0.75	0.5	--	1:1	82.3
	Various retarder concentrations tested				0.4 0.35 0.3			
6b	H	45	0.75	0.75	0.5	--	--	49.0
	Various retarder concentrations tested				0.3			
7	H	45	0	0.25	0	--	--	57.6

(a) BWOC = by weight of cement.

(b) Prehydrated for 48+ hours.

(c) Last 2.7 m^3 (17 bbls) slurry accelerated with 1% calcium chloride.

APPENDIX F-3
CEMENT SLURRY PROPERTIES AND TEST RESULTS

SLURRY	DENSITY		YIELD		MIX	THICKENING TIME					FREE	COMPRESSIVE TESTING						
					TIME	RETARDER	TIME(a)	TEMP			WATER	TIME	TEMP		PRESSURE		STRENGTH	
No.	kg/m^3	(lb/sk)	l/sk	(ft^3/sk)	hours	%BWOC	h:mm	°C	(°F)		ml	hours	°C	(°F)	MPa	(psi)	MPa	(psi)
1a,b,c	1920	(16.0)	44.5	(1.57)	2	0.7	4:13	149	(300)		0(b)	12	177	(350)	34.5	(5000)	22.4	(3250)
					heat-up rate °/min -			3.06	(5.5)			24	''	''	''	''	25.9	(3750)
												48	''	''	''	''	29.3	(4250)
												72	''	''	''	''	29.6	(4300)
												96	''	''	''	''	29.6	(4300)
2	2040	(17.0)	39.6	(1.40)	2	0.6	2:56	149	(300)		N/A	12	177	(350)	34.5	(5000)	32.4	(4700)
					heat-up rate °/min -			3.06	(5.5)			24	''	''	''	''	36.2	(5250)
												48	''	''	''	''	42.7	(6200)
												72	''	''	''	''	43.4	(6300)
												96	''	''	''	''	43.4	(6300)
3a (c)	1530	(12.8)	68.8	(2.43)	1	0.3	4:53				0(b)	12	127	(260)	34.5	(5000)	7.3	(1060)
(d)	1590	(13.3)	66.0	(2.33)	heat-up rate °/min -			2.7	(4.8)			24	''	''	''	''	8.6	(1250)
												48	''	''	''	''	9.1	(1325)
												72	''	''	''	''	9.5	(1375)
												96	''	''	''	''	9.7	(1400)
3b	1920	(16.0)	45.0	(1.59)	2	0.2	2:57				0(b)	12	127	(260)	34.5	(5000)	22.1	(3200)
					2	0.2(e)	2:39					24	''	''	''	''	26.2	(3800)
					heat-up rate °/min -			2.7	(4.8)			48	''	''	''	''	32.1	(4650)
												72	''	''	''	''	35.8	(5200)
												96	''	''	''	''	37.6	(5450)

(a) Time to reach 100 Bc (Bearden unit of consistency), not including designated mixing time, with heat-up rate indicated.
(b) No particle gelling or channeling.
(c) As mixed properties.
(d) Properties after exposure to 31 MPa (4500 psi).
(e) Duplicate test.

APPENDIX F-3 (cont)

SLURRY No.	DENSITY kg/m^3	(lb/sk)	YIELD l/sk	(ft^3/sk)	MIX TIME hours	THICKENING TIME RETARDER %BWOC	TIME(a) h:mm	TEMP °C	(°F)	FREE WATER ml	COMPRESSIVE TESTING TIME hours	TEMP °C	(°F)	PRESSURE MPa	(psi)	STRENGTH MPa	(psi)
4	1980	(16.5)	42.8	(1.51)	2.5	1.6(b)	4:10	207	(405)	0(c)	24	216	(420)	20.7	(3000)	83.0	(12035)
											48	''	''	''	''	73.4	(10650)
											72	''	''	''	''	53.4	(7750)
						0.5	2:43	179	(350)	0(c)	24	177	(350)	20.7	(3000)	0	(0)
											36	''	''	''	''	13.1	(1900)
											48	''	''	''	''	30.9	(4475)
						0.3	2:04	149	(300)		(c)						
5	1890	(15.8)	45.9	(1.62)	N/A	N/A	N/A	N/A		N/A	N/A	N/A		N/A		N/A	
6a (d)	1610	(13.4)	60.9	(2.15)	2.5	0.5	4:45	177	(350)	0.2(c)	24	182	(360)	20.7	(3000)	17.6	(2550)
(e)	1680	(14.0)	58.0	(2.05)		0.4	2:28	177	(350)	(f)	48	''	''	''	''	18.6	(2700)
						0.4	7:00	149	(300)	(f)	72	''	''	''	''	20.5	(2975)
						0.35	6:15	149	(300)	(f)	72	129	(265)	20.7	(3000)	No set	
						0.3	2:45	149	(300)	(f)	96	''	''	''	''	10.3	(1500)
					heat-up	rate	°/min -	4.4	(8.0)		120	''	''	''	''	13.4	(1959)
					2.5	0.5	2:02	177	(300)	(f)	288	93	(200)	20.7	(3000)	No set	
					heat-up	rate	°/min -	4.4	(8.0)								
6b	1890	(16.5)	42.2	(1.49)	1.5	0.6	3:20	177	(350)	0.8(g)	24	177	(350)	20.7	(3000)	30.3	(4400)
											48	''	''	''	''	31.9	(4625)
											72	''	''	''	''	31.9	(4625)
						0.35	3:33	149	(300)	0.7(g)	24	149	(300)	20.7	(3000)	33.1	(4800)
											48	''	''	''	''	35.2	(5100)
											72	''	''	''	''	35.2	(5100)
7	1970	(16.4)	42.2	(1.49)	N/A	N/A	N/A	N/A		N/A	N/A	N/A		N/A		N/A	

(a) Time to reach 100 Bc (Bearden unit of consistency), not including designated mixing time, with a 3.06°C/min (5.5°F/min) heat-up rate.
(b) With 0.08% L-10.
(c) No particle gelling or channeling.
(d) As mixed properties.
(e) Properties after exposure to 31 MPa (4500 psi).
(f) No compressive testing performed.
(g) No sedimentation or gellation observed.

APPENDIX F-4
CEMENTING RESULTS

SLURRY PROCEDURE No.	DATE	RESULT OF PLACEMENT	CEMENT BOND LOG DATE	DEPTH m	DEPTH (ft)	AMPLITUDE	COMMENTS
1a	9/12/87	Cement placed as planned below retainer at 3178 m (10,428 ft). Cement injection pressure 10-14 MPa (1450-2040 psi).	N/A	N/A	N/A	No opportunity for CBL	Cement plug and retainer leaked during pressure test of 244.5-mm (9-5/8-in.) casing. Subsequent injection and production testing indicate that EE-2 was successfully plugged. Bond log run 12/1/87 showed that the 9/15/87 log was misleading or inaccurate.
1b	9/13/87	Two 5.5 m^3 (35 bbl) slurries pumped thru perforations at 3115-3117m (10,221-10,225 ft). First injected at 8-13 MPa (1200-1900 psi) and over-displaced. Second injected at 10-15 MPa (1500-2200 psi).	N/A	3045-3165	(9990-10,380)	Same as above	
			9/15/88	2975-3020	(9760-9900)	80±10%	
			9/15/88	2940-2975	(9640-9760)	0-80%	
			9/15/88	2810-2940	(9225-9640)	No bond	
1c	9/16/87	Cement injected thru perforations at 2910-2911m (9546-9550 ft). Slurry injected at 14-17 MPa (2050-2450 psi).	12/1/87	2960-3165	(9710-10,380)	No CBL	
			12/1/87	2920-2960	(9580-9710)	No bond	
			12/1/87	2895-2920	(9500-9580)	80-99%	
			12/1/87	2810-2895	(9225-9500)	No bond	
2	9/28/87	Cement spotted thru drill string using balanced plug technique.	N/A	N/A	N/A	N/A	Good hard cement was drilled out leaving a hard in-gauge cement sheath to set the whipstock in.
3a,b	9/29/87	Cement circulated thru perforations at 1972-1974 m (6740-6776 ft). Displaced w/1140 kg/m^3 (9.5 lb/gal) mud. Final pump pressure 1.3 MPa (190 psi). No circulation of water or cement during cooling and cement placement.	12/1/87	1975-1985	(6480-6520)	50%	Gap between 1984 and 1987 cement.
			12/1/87	1650-1975	(5420-6480)	90-100%	Top of high-strength cement at 1860 m (6100 ft).
			12/1/87	1585-1650	(5200-5420)	30-99%	
			12/1/87	1160-1585	(3800-5200)	70-99%	
			12/1/87	760-1160	(2500-3800)	90-100%	
			12/1/87	735- 760	(2410-2500)	0-100%	Top of cement.

APPENDIX F-4 (cont)

SLURRY PROCEDURE No.	DATE	RESULT OF PLACEMENT	CEMENT BOND LOG DATE	m DEPTH	(ft)	AMPLITUDE	COMMENTS
4	5/23/88	Displaced with 6.4 m^3 (40 bbl) of 1940 kg/m^3 (16.2 lb/gal) mud followed by water. Pressured up to 18.6 MPa (2700 psi) and broke back as lead slurry hit top of window in 244.5-mm (9-5/8-in.) casing and again at top of liner.	6/9/88	3245-3285	(10,640-10,770)	N/A	Logging tool set down and hung up at 3243 m (10,640 ft).
			6/9/88	2895-3245	(9500-10,640)	95-100%	
5	5/26/88	Circulate with full returns thru perforations at 270-271 m (885-889 ft). Pressure increased to 8.6 MPa (1250 psi) 2.2 m^3 (14 bbl) before placement was completed.	5/22/88	270-285	(890-928)	30-50%	Ball sealers and gravel.
				240-270	(790-890)	90-100%	
				200-240	(660-790)	60-100%	
				135-200	(445-660)	30-100%	
				80-135	(255-445)	70-100%	
				65-80	(215-255)	45-90%	Collar at 62.8 m (206 ft).
				0-65	(0-215)	No bond	
6	6/2/88	Full circulation with excess returns followed by two short periods of no returns. Cement circulated on both inner and outer annuli.	6/9/88	2835-2895	(9300-9500)	98-100%	
				2815-2835	(9230-9300)	70-95%	
				2370-2815	(7770-9230)	90-100%	
				2235-2370	(7325-7770)	80-100%	
				2205-2235	(7240-7325)	60-100%	
				1950-2205	(6400-7240)	90-100%	
				1390-1950	(4560-6400)	40-100%	Calculate top of high-
				1040-1390	(3420-4560)	90-100%	strength cement at
				365-1040	(1200-3420)	30-100%	1845-1965 m (6050-6450 ft).
				900-905	(2945-2965)	0-30%	Cement may not have been
				360-900	(1175-2945)	20-100%	hot enough to set up.
7	6/3/88	Reverse circulation with diluted cement returns on inner annulus. Cement became too thick to pump.	6/9/88	50-65	(160-215)		
				0-50	(0-160)		

APPENDIX G

PROCEDURE TO SAND BACK EE-2A
FROM 12,360-10,775 ft

1. Run in hole to total depth w/1500 ft of 3-1/2-in. drill pipe on bottom of string. Put red-band joint on bottom of drill pipe

Drill Pipe Size and Grade	Weight (lb/ft)	Length (ft)	Capacity bbl/ft	Volume (bbl)
3-1/2-in. G-105	15.50	1500	0.00658	9.87
5-in. Grade E	19.50	4500	0.01776	79.72
5-in. X-95	25.60	6360	0.01555	98.90
				188.49

2. Circulate at 375 gpm for 1-1/2 hours or until gas is cleared up. Rig up Dowell while circulating. Dowell should have 20 lb/1000 gallon guar gel mixed in storage tanks. Rig up Dowell to Big Chief's 3-in. stand pipe (service line) with drill pipe and from rig pumps to drill pipe. Rig up fresh water supply line to Dowell from rig.

3. Sand plugs are to be pumped in 100-bbl stages. Set back kelly and rig up Dowell pump-in sub. Pump 10 bbl water. Mix and pump 100 bbl sand and gel water with 3 lb/gal sand.

   Volumes:

   4200 gal x 3 lb/gal =

   Weight of sand = $\dfrac{12{,}600 \text{ lb sand}}{107 \text{ lb/ft}^3} = 117.75 \text{ ft}^3$ fill.

   Capacity of hole = $\dfrac{117.75 \text{ ft}^3}{0.3941 \text{ ft}^3\text{/ft}} =$ 298 ft of fill.

4. After pumping sand and gel, switch to rig pump and displace with 169 bbl water.

   3.4 gal/stroke = 0.081 bbl/stroke.

   169 bbl/0.081 bbl/stroke = 2086 strokes.

   Displace at 100 spm.

   Knock off Dowell lines on pump-in sub - pull 15 stands - pick up kelly and circulate for 45 min.

5. Set back kelly and run in hole and tag sand. Pick up 15-20 ft and run another plug. Adjust diplacement depending on where sand is tagged.

6. Continue sanding until above 10,775 ft. Wash out sand until top of sand plug is at 10,775 ft.

LA-11498-HDR

ICFT: An Initial Closed-Loop Flow Test of the Fenton Hill Phase II HDR Reservoir

Los Alamos

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ICFT: AN INITIAL CLOSED-LOOP FLOW TEST OF THE FENTON HILL PHASE II HDR RESERVOIR

by

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ABSTRACT

A 30-day closed-loop circulation test of the Phase II Hot Dry Rock reservoir at Fenton Hill, New Mexico, was conducted to determine the thermal, hydraulic, chemical, and seismic characteristics of the reservoir in preparation for a long-term energy-extraction test. The Phase II heat-extraction loop was successfully tested with the injection of 37 000 m^3 of cold water and production of 23 300 m^3 of hot water. Up to 10 MW_t was extracted when the production flow rate reached 0.0139 m^3/s at 192°C. By the end of the test, the water-loss rate had decreased to 26% and a significant portion of the injected water was recovered; 66% during the test and an additional 20% during subsequent venting. Analysis of thermal, hydraulic, geochemical, tracer, and seismic data suggests the fractured volume of the reservoir was growing throughout the test.

SUMMARY

The Initial Closed-Loop Flow Test (ICFT), Experiment 2067, was designed as a precursor to a long-term energy-extraction experiment in the Phase II Hot Dry Rock (HDR) reservoir at Fenton Hill. The ICFT successfully evaluated the Phase II heat-extraction loop from May 19 through June 18, 1986. Cold water was injected under high pressures at EE-3A and hot water was produced at EE-2, cooled, and reinjected (Hendron, 1987).

Well EE-2 was completed with a packer and tubing set at 3170 m and well EE-3A with a cemented-in liner and tubing set at 3485 m. A temporary experimental surface system was constructed to meet the needs of the ICFT and was operated 24 hours per day using rotating shifts. Temperatures, pressures, and flow rates were recorded in the Data Acquisition Trailer (DAT) throughout the experiment and subsequent shut-in, as were seismic data collected by the MASSCOMP data acquisition system. A series of borehole temperature surveys were also made to monitor the condition of the wellbores during injection and production. A chronology of operations and various performance parameters (i.e., pressure, flow rate, temperature, etc.) are plotted versus time on Plates I and II.

A total of 37 000 m^3 (9.76 million gal.) of water was injected while 23 300 m^3 (6.15 million gal.) of hot water was produced. The injection rates at the surface ranged up to 0.0265 m^3/s (420 gpm), although most of the pumping was done at rates of 0.0106 m^3/s (168 gpm) and 0.0185 m^3/s (294 gpm), with surface pressures around 26.9 MPa (3900 psi) and 30.3 MPa (4400 psi), respectively. The production well surface pressure was controlled at around 3.5 MPa (500 psi), resulting in surface production flow rates from 0.0063 m^3/s (100 gpm) to 0.0139 m^3/s (220 gpm).

The EE-2 production temperature increased throughout the test, reaching a maximum of 192°C at the surface and 232°C at the bottom of the well near the end of the test. The production flow rate also increased throughout the test. This increase was related to the significant amount of time required to inflate the reservoir to a pseudo steady-state volume. A slight reduction in the production wellbore impedance was also observed. As a result of the temperature and production increases, there was a corresponding increase in power production, which reached a maximum of 10 MW_t after 28 days.

The bottom-hole pressure in EE-3A did not change much with injection rate or time, indicating fracture inflation and stimulation were occurring near the injection wellbore. The near-wellbore impedance at EE-3A decreased from 0.72 $GPa{\cdot}s/m^3$ (6.6 psi/gpm) to 0.002 $GPa{\cdot}s/m^3$ (0.02 psi/gpm) during the early part of the test because of cooling and pressurization near the well. The decline in the production well impedance during the test was not as significant. The decrease in overall reservoir impedance, from 7 GPa·s/m^3 (64 psi/gpm) to 2 GPa·s/m^3 (18 psi/gpm), resulted primarily from stimulation of the reservoir, especially near the injection well. However, the injection well impedance was only a minor portion of the overall impedance, indicating that strategies for reducing the impedance of the reservoir should concentrate on the region surrounding the production well.

The rate of water loss decreased throughout the test, starting at 70% after 4 days of pumping and reducing to 26% after 30 days. The apparently high water-loss rate during the early portion of the test was due primarily to the water requirement of inflating or filling the fractures that make up the reservoir. Of the total injected water, 66% was recovered during the test and an additional 20% was recovered during a subsequent vent-down.

The geochemical behavior of the fluid produced at EE-2 was monitored continuously to determine the concentration of dissolved anions, cations, and gases. The concentration of most species was two to three times higher than encountered in the shallower Phase I reservoir, probably because of higher reservoir temperatures and a larger contribution from the in situ pore fluid. The Na-K-Ca and SiO_2 geothermometers yielded temperatures that agree well with the downhole temperature measured during fully equilibrated temperature surveys. Several periods of high dissolved CO_2 concentration in the production stream created a temporary two-phase flow condition at a shallow depth in the production wellbore and in the surface loop, indicating future operations will require gas separation.

Studies of corrosion coupons placed in the flow loop during the test indicated generalized, uniform corrosion at rates of 0.25 to 0.38 mm/yr (10 to 15 mpy). One case of pitting, attributed to increased concentration of dissolved O_2, was observed. To minimize pitting in future operations, an oxygen scavenger will be used. Scale deposition was minimal and did not affect operations.

Results of the two radioactive tracer experiments suggest flow was occurring through a large, highly fractured region of rock. Modal volumes were about twice as large as that of the previous shallower reservoir at Fenton Hill and tracer recoveries were lower, indicating fluid was flowing through a large number of fractures. Calculations indicate this fractured rock volume is equivalent to a sphere with diameter approximately equal to the separation distance between the injection and production points in the two wells.

The new MASSCOMP seismic data acquisition system operated successfully during the 30-day ICFT experiment. Data from almost 700 microseismic events were collected. A number of the smallest events collected could not be located because of low signal-to-noise ratio, which indicates that the data set is complete in terms of locatable events.

The resulting seismicity fell into the now familiar, nearly vertical, northerly striking tabular region, yet occupied only half of the volume defined by the seismicity of Expt. 2032, the massive hydraulic fracture (MHF) in 1983. The active region was located entirely in the southern or injection end of the Expt. 2032 active volume. This pattern may have been caused by a pressure asymmetry set up by the source-sink "dipole" at the injection and production points. This implies that seismicity, reservoir extension, and possibly water loss could be controlled by introducing additional production wells surrounding the injection point.

The northern portion of the reservoir was only active following shut-in. The large size of many of these events was curious since shut-in pressures should not have been enough to exceed the fracture extension threshold. It is possible these events occurred in the lower-pressure, Phase I reservoir region.

The reservoir was continually enlarging during the ICFT. Microseismic locations generally fell to the east of previous seismic clouds (Expt. 2032). A significant breakthrough to previously inactive shallow depths in the southern portion of the active region occurred midway through the experiment. This activity was not associated with any major change in injection pressures.

I. INTRODUCTION

The primary objective of the U.S. Hot Dry Rock (HDR) Program is to develop an economical, commercially usable technology for recovering thermal energy from hot rock at accessible depths in the earth's crust. The Program so far has concentrated on hot crystalline rock of low initial permeability, on the use of fluid pressure (hydraulic fracturing) to create flow passages and heat-transfer surface in that rock, and on the operation of a closed, recirculating, pressurized-water loop to extract heat from the rock and transport it to the earth's surface. Large-scale field experiments are conducted at Fenton Hill in the Jemez Mountains of northern New Mexico, and supporting activities are conducted primarily at Los Alamos National Laboratory, about 35 km east of the Fenton Hill site. The latter include development of new or improved downhole equipment and instruments, field and laboratory experimental techniques, and analytical and numerical data analyses and modeling procedures. Many of these developments have been found useful in other experimental programs and in a variety of industrial applications. Other HDR programs are underway in the Federal Republic of Germany, France, Japan, Sweden, the United Kindom, and the USSR.

The technical issues faced in HDR development are challenging. Wells must be drilled to depths where temperatures (200-300°C) are suitable for electricity generation. Even in regions with favorable geothermal gradients, such temperatures are found at great depths, 3 to 5 km, where the minimum component of the <u>in situ</u> earth stress is likely to be 35 to 100 MPa. One must then fracture the rock formation at this great stress and hold open the fractures so that the permeability remains high and the flow resistance is low. Large areas of hot rock must be adequately bathed by the injected water to result in high heat production. At the same time, since all water must be provided from an external source, one must avoid excessive water losses to the country rock surrounding the fractured reservoir. Furthermore, the potential for damaging earthquakes caused by downhole accumulation of this water loss must be considered. One must also avoid or counter potential geochemical problems, such as scaling of surface equipment with precipitated products of aqueous rock dissolution and corrosion of surface and downhole piping.

The incentive for meeting these challenges is the enormous resource base that HDR energy provides. Unlike hydrothermal reservoirs, which are rarely found, potential HDR reservoirs underlie much of the world.

Even if one considers just the high-grade resources, i.e., regions with geothermal gradients greater than 40°C/km, where high temperatures can be attained at relatively shallow depths, the HDR resource base in the U.S. alone represents a thermal energy equivalent to nearly 100 million megawatt centuries, about 10 times that of coal deposits.

A. Background

The world's first hot dry rock geothermal energy system was completed at Fenton Hill in 1977 and is referred to as the Phase I system. It was created by drilling a hole from the surface into granitic rock to a depth of approximately 3000 m, at about 195°C, producing hydraulic fractures centered at about 2600-m depth, and then directionally drilling a second hole to intersect those fractures. Water was produced from the man-made reservoir at temperatures and thermal power rates as high as 140°C and 5 MW_t. The system was enlarged in 1979 by additional hydraulic fracturing and then operated successfully for almost a year. Additional results of these early reservoir tests are provided by Dash et al. (1983).

To extend the technology to the temperatures and rates of heat production required to support a commercial power plant, construction of a larger, hotter, hot dry rock system was initiated at Fenton Hill in 1979. This is referred to as the Phase II system. Two new holes, about 50 m apart at the surface, were drilled directionally, the deeper one to a vertical depth of 4.39 km where the rock temperature was 327°C. Based upon experience in the shallower system described above, it was expected that hydraulic fractures produced from the new wells would be substantially vertical, with an approximately north-northwest strike. To provide the horizontal separation required to isolate a series of such fractures, the bottom 1000 m of each hole were drilled toward the east-northeast and inclined at 35° to the vertical. Figure I-1 shows a perspective view. The upper well, EE-3, lies 300 m above the lower well, EE-2, in the slanted interval. Also shown in Fig. I-1 is a Phase I reservoir well, which contains a geophone sonde. This sonde and similar seismic sensors emplaced in other boreholes detect microearthquakes triggered during hydraulic fracturing (House et al., 1985).

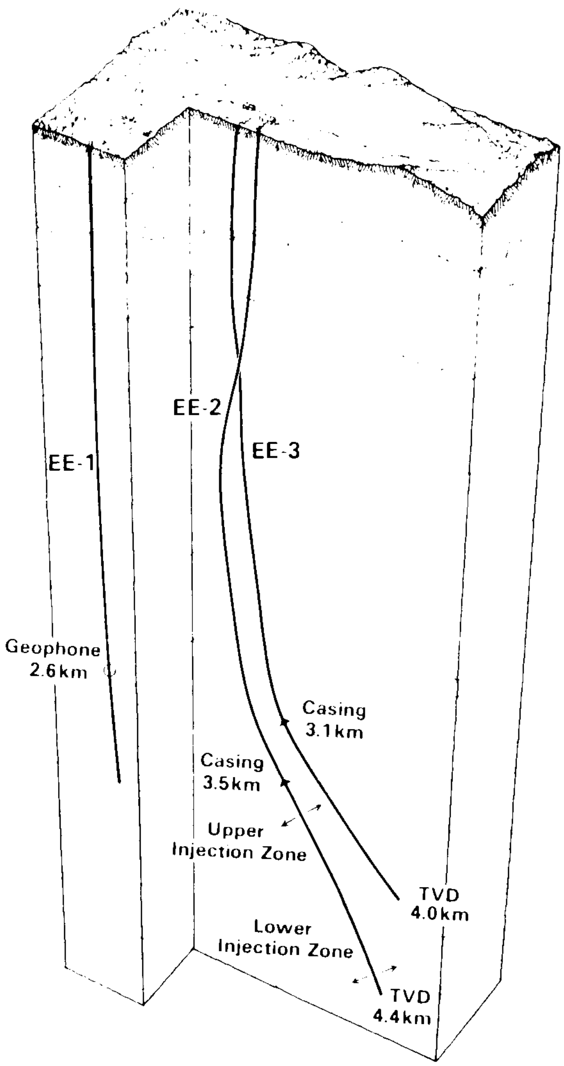

Figure I-1. Perspective view of Phase II boreholes and typical geophone tool emplaced for microearthquake monitoring during fracturing.

In 1982, hydraulic fracturing experiments were conducted at the greatest depths in the two new wells. Unexpectedly, the fracture zones produced were three-dimensional distributed networks of stimulated natural joints rather than single planar fractures. Furthermore, the fracture zones were inclined rather than vertical and did not connect the two wells hydraulically. The unexpected nonvertical inclination may be related to the presence of a cooling magma body beneath a volcanic caldera a few kilometers east of Fenton Hill, which altered the earth stresses.

In December 1983 a massive hydraulic fracturing operation was conducted in which 21 200 m^3 of water was injected at 3.5 km in the lower well at a downhole pressure of 83 MPa with an average flow rate of 100 l/s. Details are provided by Dreesen and Nicholson (1985) and House et al. (1985). Figure I-2 shows the locations of the induced microearthquakes. Because of the extremely low background noise, the downhole seismic sensors detect events with extrapolated Richter body wave magnitudes as low as -5, however Fig. I-2 shows only the 850 high-quality events with magnitudes from -3 to 0. Note that seismicity is induced over an ellipsoidal rock volume that is about 0.8 km high, 0.8 km wide in the north-south direction, and about 0.15 km thick, or about 0.05 km^3 of fractured rock volume. This rock volume is about 2500 times greater than the water volume injected.

Despite the huge volume of water injected into the lower well during the massive hydraulic fracturing in 1983, the hydraulically fractured zone did not propagate into the vicinity of the upper well, as shown in Fig. I-2, and hydraulic communication between the two wells was

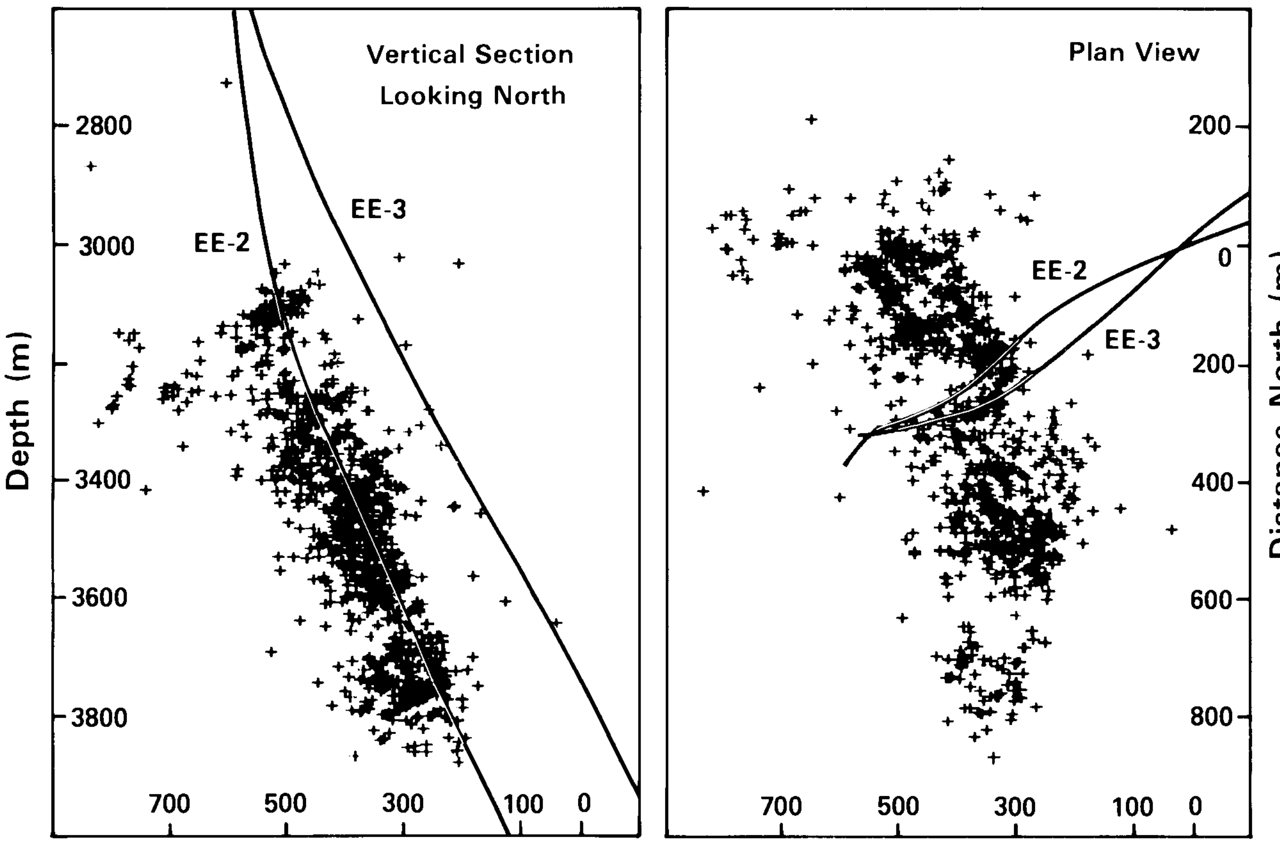

Figure I-2. Hypocentral locations of microearthquakes induced by massive hydraulic fracturing in injection well EE-2. Left-hand side presents elevation view, looking north, while right-hand side is plan view, looking down.

not observed. Another large fracturing operation was conducted, this time in the upper well (Dash et al., 1985), but the two stimulated zones did not overlap sufficiently and again no communication was observed. Consequently, in March of 1985 the upper well was sidetracked at a depth of 2.9 km and directionally drilled as shown in Fig. I-3 through the fracture zone created from the lower well. This redrilled well is referred to as EE-3A.

Low flow connections were observed at joints where water flowed into EE-3A during drilling while EE-2 was pressurized to 14.5 MPa. Hydraulic stimulation of the joints near 3.6 km was accomplished by setting a specially developed, high-temperature packer (Dreesen et al., 1986) in EE-3A at a depth of 3.52 km, where the drill hole was reasonably smooth, and then pumping water into the open-hole interval between the packer and the bottom of the hole, which at that time was

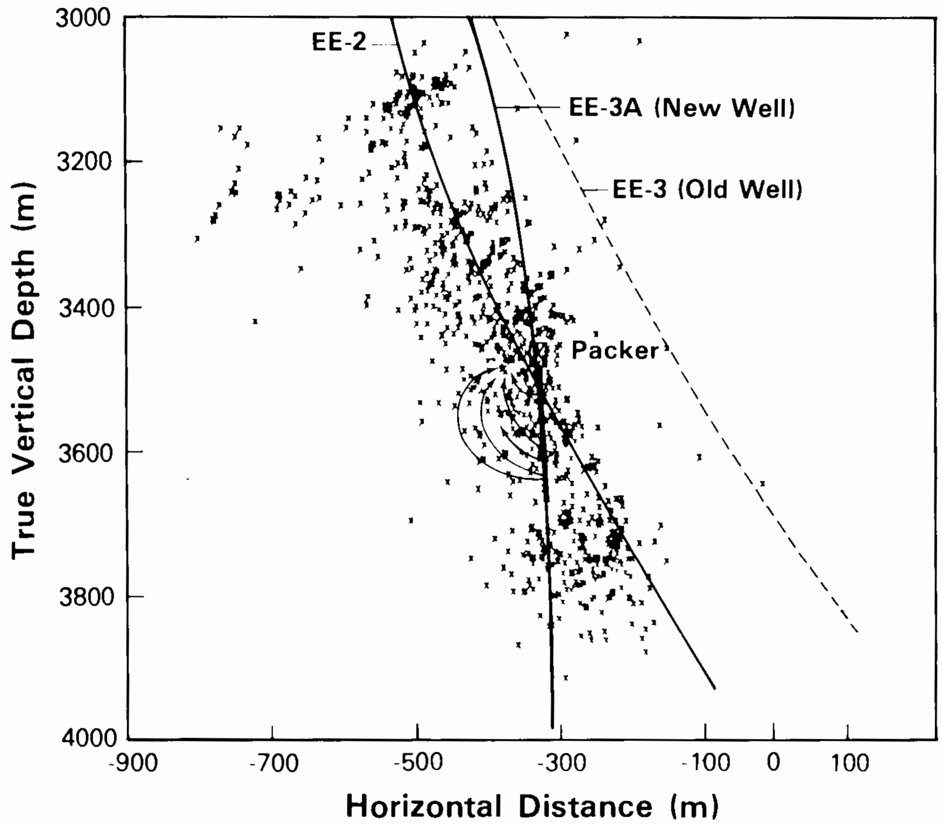

Figure I-3. Elevation view of reservoir, looking north. Packer shown allowed supplementary stimulation of EE-3A, which resulted in low flow resistance connection between EE-2 and EE-3A. The flow paths indicated are inferred from joint locations determined from a temperature survey in EE-3A.

located at 3.72 km. A postconnection temperature survey taken in EE-3A showed that several joints had been stimulated and served as flow entries from EE-3A to the reservoir.

Following this successful connection, the redrilled well was extended to 4 km and additional stimulations were conducted using the open-hole packers. The second stimulation was conducted very deep, at 3.83 km, and failed to result in additional hydraulic communication. The third stimulation, at 3.65 km, a depth about midway between the successful and unsuccessful ones, achieved another hydraulic connection, but the final stimulation, which occurred at 3.76 km, failed to result in additional hydraulic communication.

In March and April of 1986 the new reservoir was readied for preliminary testing by 1) cementing in a liner in well EE-3A, 2) installing a temporary surface piping system, 3) readying the water-to-air heat exchanger used previously for the Phase I reservoir, and 4) hiring a service company to pump water. The Initial Closed-Loop Flow Test was begun May 19, 1986, and completed on June 18, 1986. Cold water was injected into EE-3A, and hot water (as hot as 192°C) was produced from EE-2. The hot water was cooled to 20°C in the heat exchanger before being reinjected, and up to 10 MW_t was produced. Further details are provided in the remainder of this report.

B. Objectives

Experiment 2067, the Initial Closed-Loop Flow Test (ICFT), was designed as a precursor to a long-term energy-extraction experiment in the Phase II reservoir at Fenton Hill. Previous testing in this reservoir consisted of three stimulation experiments conducted in EE-2, Expts. 2018, 2020, and 2032 (the 1983 MHF), that initially created the system and two stimulation experiments during EE-3A redrilling operations, Expts. 2059 and 2062, that resulted in successful fracture connections. Injection parameters of interest from these experiments and the ICFT are summarized in Table I-I. The ICFT sought to prove the feasibility of the Phase II reservoir as an energy producer, determine important reservoir parameters necessary to the design of the final flow loop for the Long-Term Flow Test (LTFT), and evaluate various completion schemes for wellbore EE-3A and repair work on EE-2 (Dreesen and Nicholson, 1985). We envisioned that, at the end of the ICFT, the final

TABLE I-I

SUMMARY OF PERTINENT PHASE II RESERVOIR INJECTIONS

Expt. Number	Date	Injection Wellbore	Open-Hole Interval (m)	Volume Injected (m^3)	Nominal Rate (m^3/s)	Nominal Pressure (MPa)[a]	Connection to Other Well
2018	82/07/19- 82/07/20	EE-2	3528-3656	910	0.0315	48.3 7,000psi	no
2020	82/10/06- 82/10/07	EE-2	3528-3656	3090	0.0928	46.9	no
2032 (MHF)	83/12/06- 83/12/09	EE-2	3528-3550	21 200	0.1140	48.0	no
2059	85/05/27- 85/05/28	EE-3A	3516-3719	1590	0.0106	5 31.7 4597psi	yes
2062	85/07/18- 85/07/20	EE-3A	3651-3825	5770	0.0106	5 35.9 5206psi	yes
2067 (ICFT)	86/05/19- 86/06/18	EE-3A	3487-3750	37 000	0.0106 0.0185	26.9 3901 30.3 4394	yes

[a] Surface injection pressure.

completion of EE-3A would be accomplished and surface loop design, procurement, and construction could begin. In this section the goals and objectives of the experiment are discussed in more detail, along with a short rationale for each item and a justification of various decisions made in preparation for this flow test.

1. Reservoir Characteristics. All Phase II (wells EE-2 and EE-3A) flow tests to date had been either single-well hydraulic stimulation experiments or very short interwell flow tests after a connection was achieved. Thus, important long-term reservoir information necessary for the design of a permanent flow loop had not been obtained.

2. Flow Splits. Experiment 2059 stimulated a shallower depth of the wellbore by setting the packer at 3.52 km (11 537 ft). A deeper set of fracture connections was created during Expt. 2062 with the packer at 3.65 km (11 976 ft). Information about the relative flow rates and

volumes of the 2059 and 2062 reservoirs would help determine whether to keep the 2059 fractures in the system for the final completion. A chemical tracer experiment would provide a rough estimate of the heat-transfer capacity of this reservoir by comparing the modal volume to previous reservoirs. If the modal volume was less than 150 m^3, then the 2059 reservoir probably had an insufficient heat-transfer capacity and should be isolated from the remainder of the fracture connections in the final completion.

3. Impedance. Since the 2059 and 2062 reservoirs had never been operated in together, we needed to know what the overall impedance would be. Furthermore, impedance was likely to drop during the test, so a longer ICFT would provide a better estimate of long-term flow behavior. These data were of primary importance for pump selection and determination of power requirements for the long-term loop.

4. Water Loss. Pumping at pressures and flow rates sufficient to achieve hydraulic fracturing is obviously of little use in determining water-loss characteristics at closed-loop, recirculating conditions. The ICFT would provide these essential water-loss data. Again, the longer the test, the more relevant the data would be to the permanent system design.

5. Geochemistry. Our estimates of dissolved gases and the possibility of corrosion and scaling in the surface and downhole piping were based entirely on the hydraulic stimulation experiments and the Phase I operations. A circulating loop operated for 30 days should allow the dissolved components (gases and ions) to reach their ultimate values. During the ICFT we planned no major water treatment program. The objective was to monitor the buildup of dissolved species and evaluate the severity of chemical problems both during the ICFT and in future operations. The dissolved CO_2 content at the end of the test would indicate whether a separator was necessary in the final surface system design. Corrosion coupons would be examined periodically since protection of the heat exchanger and rented pumps was imperative for this experiment. Surface piping would be checked for corrosion and solids deposition after the ICFT.

6. Tracer Experiments. Fracture volume and dispersive characteristics can be measured most effectively using tracers. The primary goal

of the tracer tests would be to measure the system residence time, which would indirectly tell us whether the 2059 reservoir had sufficient heat-transfer capacity to be incorporated into the long-term loop. Since more detailed information about fracture geometry is possible with a radioactive tracer, we prepared to run $NH_4{}^{82}Br$. We had also planned, but decided not to run, the first reactive tracer experiment in the Fenton Hill reservoir. Ultimately, this technique could provide a method for rapidly determining the rate of reservoir cooldown, and in the ICFT this test would have been considered to be a baseline experiment to develop the best operational procedures for performing these new tracer tests.

II. SYSTEM DESCRIPTION, OPERATIONS, AND PERFORMANCE

A. Wellbore Configurations

1. Production Well EE-2. The 244.5-mm (9-5/8-in.) production casing in EE-2 was severely damaged in December 1983 during the uncontrolled blowdown that occurred after pumping 21 200 m^3 (5.6 million gal.) of water (Expt. 2032 MHF) into the 3530- to 3550-m (11 580- to 11 648-ft) deep interval extending from the 244.5-mm (9-5/8-in.) casing shoe to a sand and barite plug in the open hole as shown in Fig. II-1. The tubing, the tubing-production casing annulus (backside), and the production casing-intermediate casing annulus were all in direct communication with the subhydrostatic aquifers between 520 and 760 m (1700 and 2500 ft) deep several months after the blowdown.

The damaged 139.7-mm (5-1/2-in.) tubing was removed to a depth of 3268 m (10 722 ft) and the well repaired during the fall of 1984. Two cementing (squeeze) placements behind the production casing at 3170 to 3230 m and 1980 to 2774 m (10 400 to 10 600 ft and 6500 to 9100 ft), using 3.8 m^3 (24 bbl) and 27.8 m^3 (175 bbl) of cement respectively, eliminated the direct communication. The high risk of additional repairs and a limited budget prevented the removal of the remaining tubing and packer below 3268 m. A small drill pipe string was used to clean out through the fish into the open hole below the production casing to a depth of 3548 m (11 640 ft). A second packer and a repaired tubing were installed as shown in Fig. II-1. Slim-hole logging tools

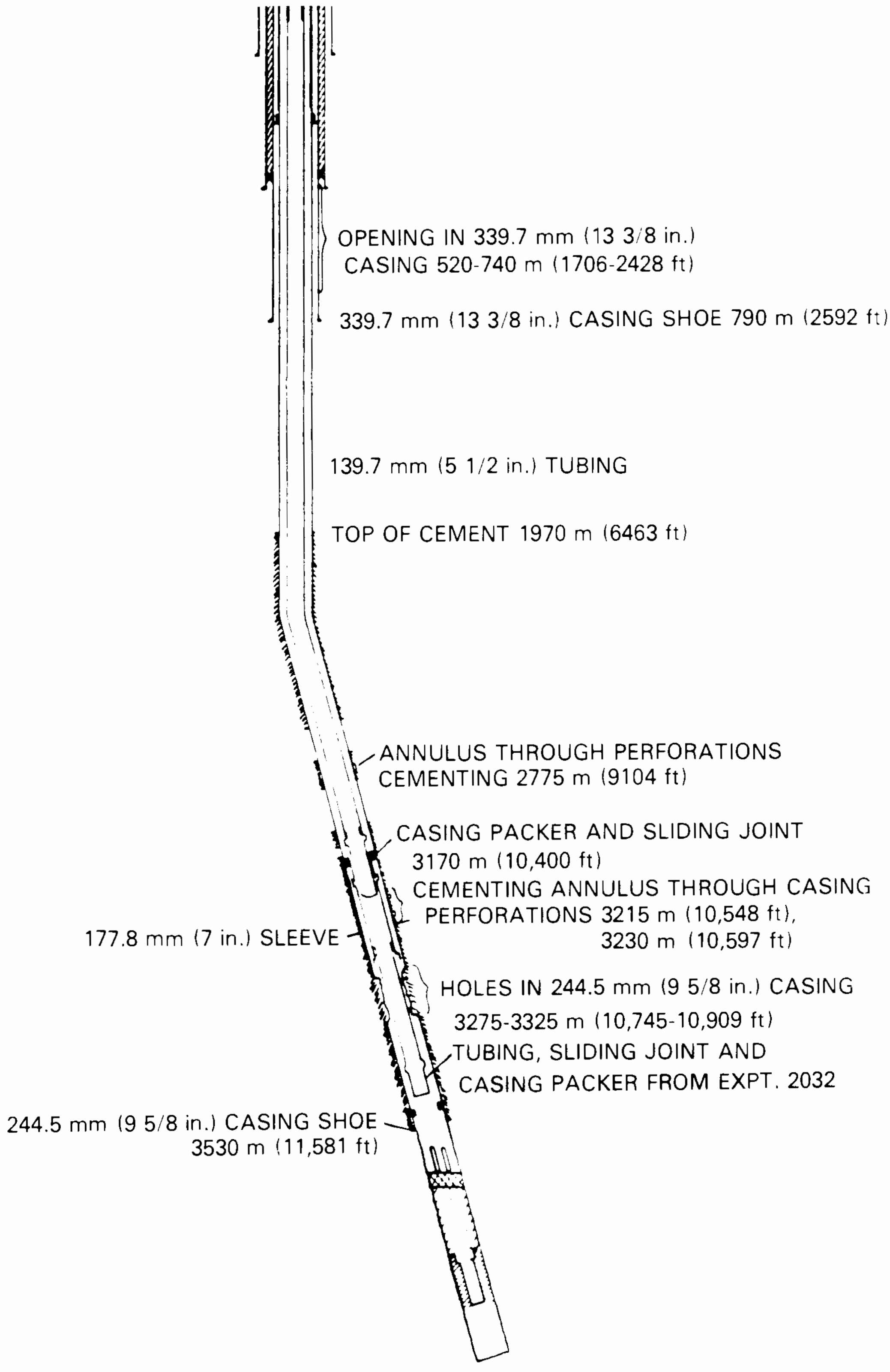

Figure II-1. EE-2 well configuration during the ICFT.

were successfully run into the open hole. An injection test showed that the well remained in pressure communication with an 11.7-MPa (1700-psi) injection zone (possibly Phase I) above the production casing shoe.

EE-2 was first produced during the two connection experiments (Expts. 2059 and 2062). Several weeks before Expt. 2059, EE-2 was cleaned out with a 25.4-mm (1-in.) coil tubing unit to 3473 m (11 394 ft) using 0.35 m^3/s (750 SCF/min) of nitrogen. A large amount of mud was removed. The coil tubing was friction stuck after the mud was unloaded. After cooling the well by circulating soap and cold water, the tubing was removed. Subsequent attempts to log the well with 54.0-mm (2-1/8-in.) o.d. tools encountered an obstruction at 3215 m (10 550 ft), and no further logging below this depth was attempted.

During the second connection stimulation (Expt. 2062), the EE-2 backside began to flow. A small leak between the tubing and the production casing-tubing annulus has been observed intermittently since that flow was first noticed.

2. Injection Well EE-3A. EE-3A was completed in April and May of 1986. The completion followed 10 open-hole packer runs resulting in 6 injection tests in isolated regions of the wellbore. In two of these injection tests, connections to EE-2 were demonstrated: 1) Expt. 2059 injection resulted in injection into four intervals between 3515 and 3712 m (11 532 and 12 180 ft); and 2) Expt. 2062 resulted in injection into four intervals between 3650 and 3749 m (11 975 and 12 300 ft). The packer was stuck in the hole on the final packer run and left at 3750 m (12 300 ft). The configuration of the wellbore at the beginning of the completion operations is shown in Fig. II-2.

Initial completion plans called for a permanent packer, developed in conjunction with Baker Production Technology (formerly Lynes Inc., presently Baker Service Tools), to be set. The packer failed 3 days after it was successfully set and tested at 3560 m (11 685 ft). The packer completion is shown in Fig. II-3.

After fishing out the packer from 3560 m, the wellbore was prepared for a cemented-in liner completion. The bottom of the liner was to be located in an in-gauge wellbore section at 3600 m (11 810 ft), and the well was temporarily plugged back to that depth with sand. A 139.7-mm (5-1/2-in.) liner was run and cemented in using the puddling technique.

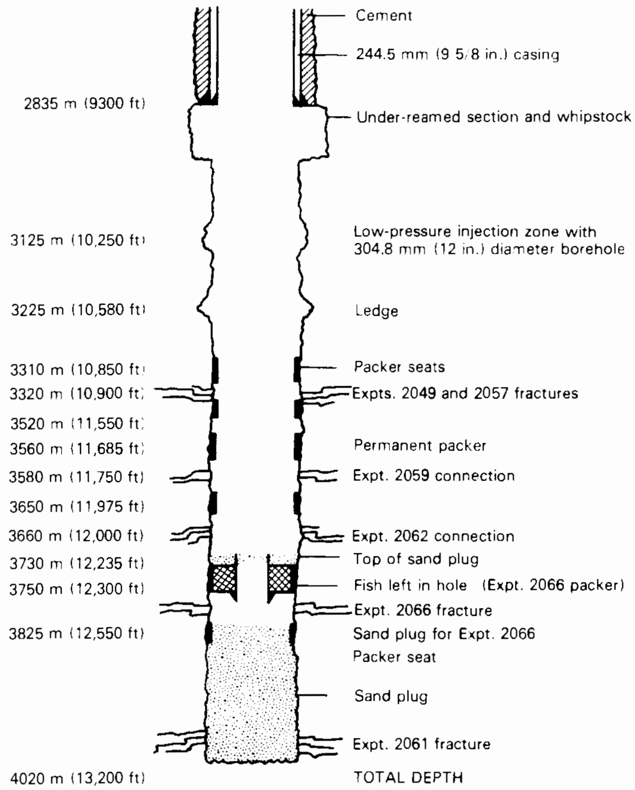

Figure II-2. EE-3A well configuration before the ICFT well completion.

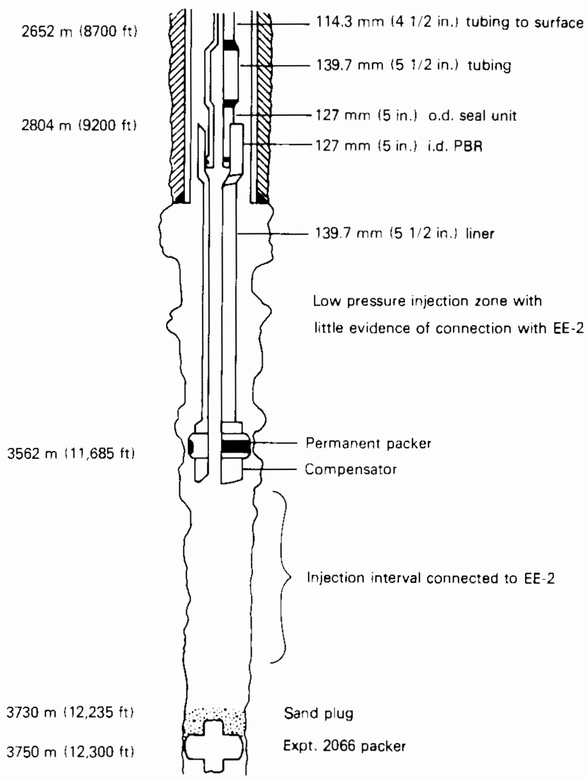

Figure II-3. EE-3A well configuration after installation of a permanent packer at 3560 m (11 685 ft). The packer failed after 3 days and was removed.

The liner was to have been installed over the main fracture entry point observed after Expt. 2059 at 3580 m (11 750 ft), but an early set of the cement prevented completion of the procedure and the liner bottom was located at 3485 m (11 435 ft). A cement sheath from 3485 to 3600 m remained in the hole after cleanout. A subsequent cement bond log showed that there was good cement behind the liner from 3485 to 3340 m (11 435 to 10 950 ft), and the liner was judged to be satisfactory for the ICFT experiment.

A pressure test of the liner showed that a leak had developed in a threaded connection above the cement top. The liner was backed off in a VAM^{TM} connection at 3530 m (11 590 ft) and the liner was replaced with new VAM^{TM} casing. A screw-in was successful on the first attempt using a machine shop fabricated VAM^{TM} screw-in sub. The liner and open hole were cleaned out to 3729-m (12 235-ft) depth and the well completed with a 127-mm (5-in.) seal assembly, 150-m (500-ft) long 139.7-mm (5-1/2-in.) cushion tubing, and 114.3-mm (4-1/2-in.) tubing as shown in Fig. II-4.

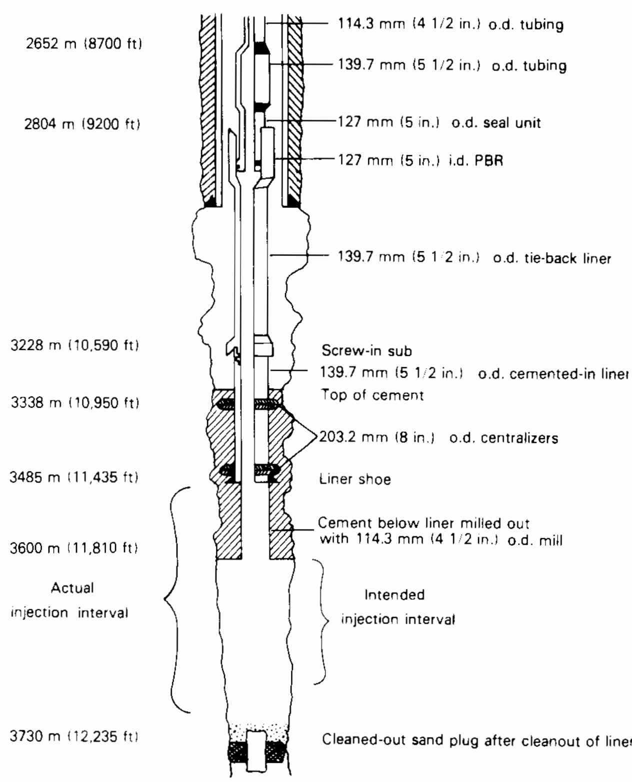

Figure II-4. EE-3A well configuration after installation of the cemented-in liner. This was the configuration of the well for the ICFT.

B. Surface System

A schematic of the surface system is shown in Fig. II-5. This system was constructed as a temporary experimental surface system to meet the needs of the ICFT. The major subsystems were the EE-2 and EE-3A wellheads, the heat-extraction system, the feed-water system, the main circulating pumps, the chemical-sampling system, data acquisition and control, and the seismic system.

The surface piping system may be divided into six segments, according to the pressure rating of each segment. The first segment was the EE-2 wellhead up to the high-low safety valve. This segment consisted of 69-MPa (10 000-psi) API-rated wellhead, master valve, wing valves, 103-MPa (15 000-psi) rated hammer union pipe and pipe fittings, and the 34.5-MPa (5000-psi) rated high-low safety valve. The high-low valve was the key element to protect lower pressure-rated items downstream. This valve automatically shut in the well if the pressure exceeded 4.8 MPa (700 psi) or dropped below 1.7 MPa (250 psi). This segment also contained vent lines to the surface pond through choke manifolds and the low-pressure gas separator.

The second segment of the system was between the high-low valve and control valve CV-1. This was rated at 10.3 MPa (ANSI 1500 psi), which has a 22.6-MPa (3280-psi) working pressure at 204°C (400°F) and a 38.4-MPa (5575-psi) hydrostatic proof pressure. This valve was installed to drop the pressure, if necessary, down to a safe operating value for the third segment of piping. It was used during high-back-pressure experiments and as an isolation valve during the cleaning of the strainer.

The third segment lay between the control valve CV-1 and the back-pressure control valve CV-6. Control valve CV-6 has a 4.1-MPa (ANSI 600-psi) rating, or a cold working pressure of 10 MPa (1450 psi) and a hydrostatic test pressure of 15.3 MPa (2225 psi). The piping in the heat exchanger area, which is part of this third segment, was constructed by the Zia Co. in 1982. The finned-tube, forced-draft, water-to-air heat exchangers have a working pressure rating of 17.2 MPa (2500 psi) at 260°C (500°F) and were hydrostatically tested several times to 19.3 MPa (2800 psi). This third segment of piping was protected by a 38.1-mm by 63.5-mm (1-1/2-in. by 2-1/2-in.) Kunkle pressure relief valve with a

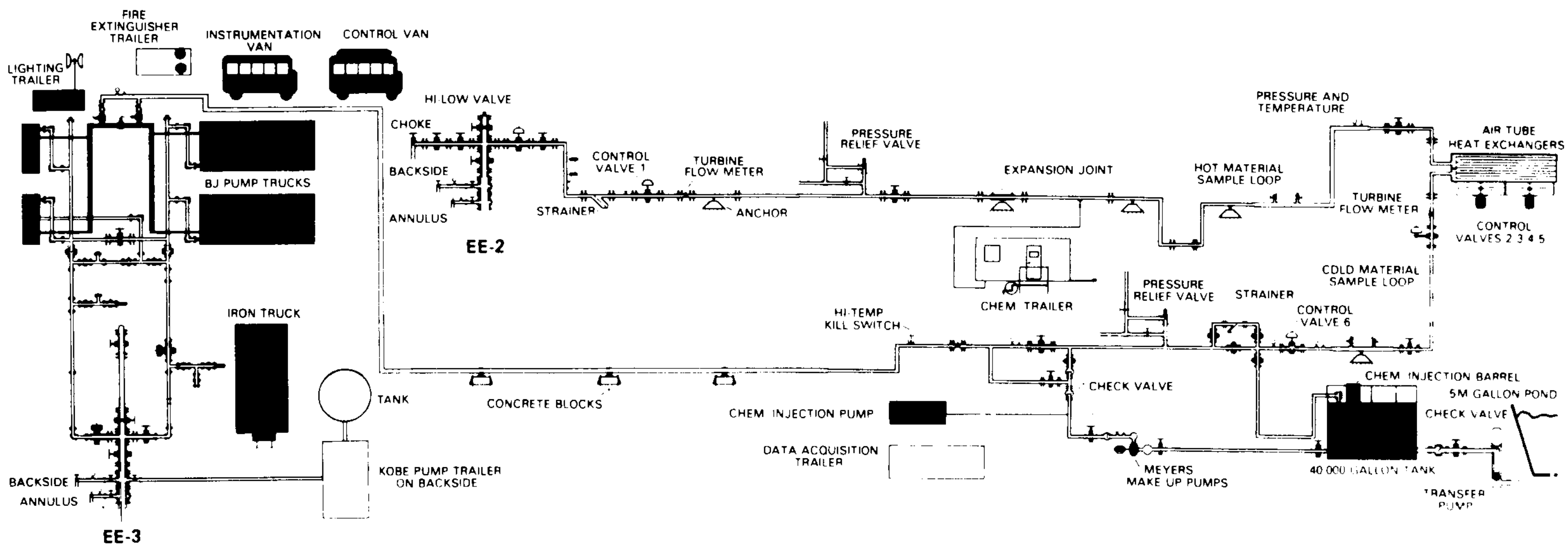

Figure II-5. Schematic of the ICFT surface system.

0.0003245-m^2 (0.503-in.^2) nozzle. This valve handled all anticipated flow rates from the EE-2 well, provided that the water was cool. As the water became hotter, there was a tendency for the nozzle to convert to two-phase flow and choke the flow at about 0.00265 to 0.0053 m^3/s (1.0 to 2.0 bpm). This pressure relief valve was set at 4.1 MPa (600 psi) for all of the experiment except for some high-back-pressure experiments where control valve CV-1 was not used.

The fourth segment of piping was downstream of CV-6. It incorporated all of the system downstream of the Meyers makeup pumps and terminated at the suction inlet manifold to the B.J. Titan contract pumps. This section was low pressure, 1.2-MPa (175-psi) normal working pressure, and was protected with a 50.8-mm by 76.2-mm (2-in. by 3-in.) safety relief valve set at 1.7 MPa (250 psi). This relief valve flows 0.0186 to 0.0212 m^3/s (7 to 8 bpm) at its maximum open pressure of 2 MPa (290 psi). This section was plumbed with 101.6-mm (4-in.) schedule 40 and 160 pipe, 76.2-mm (3-in.) schedule 80 and 160 pipe, and 152.4-mm (6-in.) schedule 40 and 80 pipe. The weakest parts of this segment were the two class-150, 101.6-mm (4-in.) check valves downstream of the Meyers pumps, which have a rating of 2 MPa (285 psi) at 38°C (100°F). The rest of the segment was grossly overdesigned with schedule 80 and 160 pipe, which was on hand.

The fifth segment was the 18 900-m^3 (5 million-gal.) pond to the 150-m^3 (40 000-gal.) holding tank. This system was contractor installed, was low pressure [less than 0.3 MPa (50 psi)], and went from open pond to open tank. The suction for the Meyers makeup water pumps came from the 150-m^3 (40 000-gal.) tank.

The sixth and possibly most critical segment of pipe was the high-pressure contract piping that injected the water into the reservoir via EE-3A. This was supplied by the B.J. Titan Co., the oil field pumping contractor that had been selected to provide the high-pressure pumping services on a competitive bid. The specifications for this work had required both pumping services and equipment. The piping was rated at 103-MPa (15 000-psi) working pressure. It consisted of 76.2-mm (3-in.) pipe with hammer unions, valves, etc., feeding our 69-MPa (10 000-psi) API-rated wellhead. The equipment specified for this section was inspected before being accepted.

The B.J. Titan system was assembled around a suction and discharge manifold trailer and four truck-mounted frac pumps, using 12V149 Detroit diesel engines, 8961 Allison five-speed transmissions, and 1300 OPI plunger pumps. Pumps were remotely controlled from a treating van. Pressure, flow, and temperature were monitored and recorded in a second van.

B.J. Titan also provided double 101.6-mm (4-in.) suction and 76.2-mm (3-in.) discharge lines, which were used with remote-operated wing valves on the wellhead. A 50.8-mm (2-in.) vent line was laid to the pond.

Critical parts of the entire surface system piping were anchored with about 40 concrete safety blocks. These blocks were precast by a firm in Albuquerque using 27.6-MPa (4000-psi) concrete. All blocks weighed between 1140 and 1820 kg (2500 and 4000 lb) and were additionally staked to the ground using 25.4-mm (1-in.) diameter stakes. These blocks either sat over the pipe with the pipe running through tunnels precast into the blocks, or the pipes sat on top of the blocks and were anchored with straps that were fastened to anchor bolts cast into the blocks. Further details on the surface system components, fabrication, safety, etc., are contained in Appendix A.

C. Data Acquisition

1. Flow Loop Instrumentation and Recording. Signals from all active transducers, measuring temperatures, pressures, and flow rates, were conditioned and recorded in the Data Acquisition Trailer (DAT). The data from the active transducers were digitized and processed on a Hewlett Packard 9835 computer. These data were recorded on disk, displayed on a large CRT screen, and printed. The computer was programmed to provide a number of options that allowed visual and audible alarm of selected data channels should the measurement exceed either a high or low limit. Data from each channel were averaged over a specified time interval selected by the operator and easily changed through a function key. The data rate for printout was also selectable over a range of once per minute to once per hour. However, if an alarm should occur, the computer would automatically revert to maximum output rate. The program also allowed the operator to select a data channel interrupt to facilitate maintenance such as changing out transducers,

balancing pressure gauges, etc. Some data channels were used primarily for process control and alarm but were not printed out or stored (i.e., air compressor pressure). Data channels for the flow loop were set up as shown in Appendix B (Table B-I).

A remote control panel was designed and installed in the DAT that would allow remote operation of the six control valves used in the system. This control system also provided on-off control for the makeup pumps and heat exchanger fans. Makeup pumps could be cycled from time to time to reduce downtime and increase flow on demand. The system also allowed for manual override at the pump or fan location. The data acquisition and control system remained on-line for the entire flow experiment (May 19 through June 18) and the following extended shut-in to monitor all wellhead pressures and temperatures. The HP9835 computer and associated data acquisition equipment were run off an uninterruptable power supply system (UPS), and the only downtime recorded throughout the experiment was during monitoring of the shut-in when the system was running unmanned.

2. Seismic Coverage Instrumentation. The three separate seismic detection networks were used throughout the interim flow test. Nine surface stations, using the S-13 seismometers, are located on a radius of approximately 3.2 km (2 miles) from the EE-2/EE-3A wellheads. These stations are powered by batteries with solar panels used to maintain sufficient charge during the long-term operations. Data from each station are transmitted to the DAT via FM/FM telemetry. The seismic signal is converted to a VCO frequency that is used to modulate a radio frequency carrier for "line-of-sight" transmission to the receiving system located in the DAT. The frequency response for each seismometer data channel is 100 Hz. The output data are conditioned for interfacing to a MASSCOMP computer system for continuous recording and data storage.

Secondly, three "Precambrian" geophone stations are located on an approximate 1.6-km (1-mile) radius from the EE-2/EE-3A wellheads. The geophones are emplaced in boreholes drilled into the volcanic-Precambrian rock interface at about 610 m (2000 ft). The output signals from each station (PC-1, PC-2, and GT-1) are transmitted to the surface via wireline where the signals are processed in systems identical to the surface network except the data channel frequency response is 300 Hz.

The third seismic detection system was designed to use a triaxial geophone array to be emplaced in deep boreholes adjacent to the EE-2/EE-3A system. The triaxial geophone package was deployed on a seven-conductor armored wireline in EE-1 to a depth of 2865 m (9400 ft). The output microseismic (acoustic) signal detected by each geophone was amplified and transmitted to the surface over the seven-conductor wireline. These data were then conditioned for interfacing to the MASSCOMP. A parallel data link was wired to a digital storage scope (Biomation) for on-line "quick look" analysis to determine the proper operation of the downhole system occasionally.

Figure II-6 shows a block diagram of the recording and data acquisition system for the entire seismic network. Data were also recorded on analog tape recorders used as backups when the MASSCOMP was inoperative. Tape recorder channel assignments are shown in Appendix B (Tables B-II and B-III). The surface seismic stations are coded FNHR, BRLY, etc. The Precambrian stations are coded PC-1, PC-2, and GT-1, and the deep triaxial geophone package nomenclature refers to the EE-1

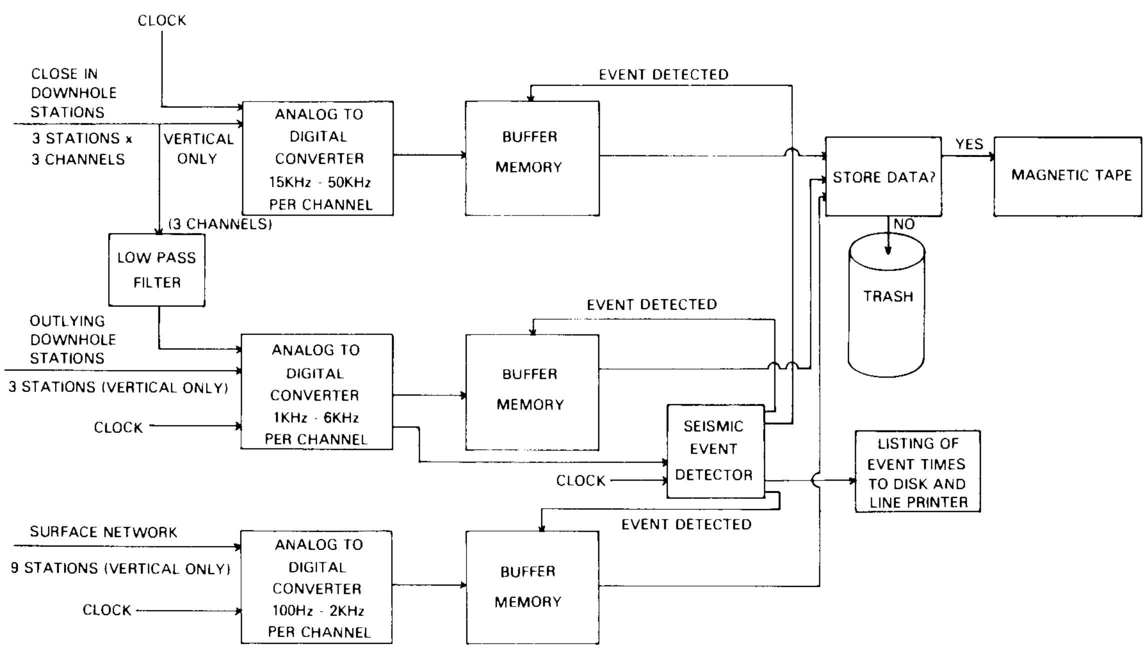

Figure II-6. Schematic of the Hot Dry Rock seismic digital event detecting and recording system.

borehole vertical geophones, upper horizontal geophones, and lower horizontal geophones. Upper horizontal and lower horizontal describes the location of the respective transducers in the geophone cradle forming an orthogonal set.

The overall system performance of the entire seismic/microseismic network performed very well, providing maximum coverage and data collection. The surface seismometer network and the Precambrian geophone array were monitored continuously throughout the experiment except for occasional downtime for maintenance and repair. The triaxial geophone sonde was deployed in the EE-1 wellbore during high-injection pressure tests. During the ICFT the triaxial geophone was deployed at four different intervals of time, the shortest interval being 12 hours and the longest interval being 51 hours. Total time on station in EE-1 was 96.5 hours.

3. Borehole Temperature Measurements. A series of borehole temperature surveys were made in EE-2, EE-3A, EE-1, and GT-2B as an integral part of the ICFT. Background and postexperiment temperature surveys were made using Los Alamos logging equipment. Since the EE-3A wellbore was pressurized above 28 MPa (4000 psi) throughout the pumping experiment, it was not possible to use the Los Alamos logging equipment to run temperature surveys during this time. The high-temperature service cable used by Los Alamos is not well suited for high-pressure service above 17 MPa (2500 psi) and the Bowen packoff for the 11.1-mm (7/16-in.) diameter cable is only rated for a wellhead pressure of about 21 MPa (3000 psi). Therefore, three temperature surveys were made in the EE-3A borehole during the flow test by a commercial oil field service company (Oil Well Perforators) using a high-pressure grease-injector control head and lubricator on the wellhead and a small-diameter cable.

Temperature measurements in the EE-2 production well were made using a slickline (a wireline with no electrical conductors) and a high-temperature Kuster sonde that recorded temperature using a stylus on a metal film driven by a mechanical clock. Four temperature surveys, three obtained during the ICFT and the one made when the flow test was terminated, were run by Tefteller, Inc. The tools were lowered in the wellbore at a rate of 0.25 m/s (50 ft/min) and stopped periodically to allow complete stabilization of temperature and to verify time-depth correlation. Upon retrieval of the tool from the well, data points were chosen to give definition to any temperature anomalies. Because of the damaged EE-2 wellbore, temperature surveys could not be run below 3185 m (10 450 ft). Results of the wellbore temperature logging are discussed in Section III.

D. Loop Operations

The system was operated 24 hours per day using rotating shifts. Each shift consisted of an experiment manager who was in overall charge of the shift, two electronic technicians who controlled the system from the Data Acquisition Trailer (DAT) and were also responsible for all instrumentation and control, two mechanical technicians who operated out of the operations building and made hourly checks of the surface system, three contract pumping people working out of the B.J. Titan control vans, a chemical technician located in one of the two chemistry trailers, an emergency medical technician located in the operations building, and a security guard. On-site communications were provided by an intercom system, which was backed up by portable radio communication.

The various modes of system operation are listed below:

1. Start-up mode. 100% makeup water into EE-3A; EE-2 in vent mode.
2. Vent mode. All production fluid vented directly to EE-1 pond.
3. Closed-loop mode. Normal operating condition with all production fluid cooled and returned to the injection pumps. Makeup water added as needed.
4. Gas-purge mode. All production fluid cooled and diverted through makeup water-holding tank.
5. Fresh-water-flush mode. 100% makeup water with all production fluid cooled and vented to the EE-1 pond.
6. Shut-in. Both wells shut in but instrumentation left on.

The system operated as follows. Water was transferred from a 18 900-m^3 (5 million-gal.) pond to a 150-m^3 (40 000-gal.) holding tank. Water was drawn from this tank as needed and fed to the high-pressure injection pumps by the makeup/feed-water pumps. Water leaving these pumps was injected into the reservoir via the injection well, EE-3A. After passing through the reservoir, the water returned to the surface through the production well, EE-2. The hot production stream was piped to the heat exchangers where it was cooled before being combined with the makeup water and returned to the injection pumps.

System operations were started by filling the holding tank with water from the 18 900-m^3 pond and then starting the makeup pumps. After the lines were filled with water, the high-pressure (B.J. Titan) injection pumps were brought on-line and the inflation of the reservoir began. The system was operated by setting the injection flow rate and temperature into EE-3A. The surface pressure of the production well (i.e., the back pressure) was controlled, and the reservoir determined the flow rate and the temperature. When the reservoir was inflated sufficiently, as indicated by a rise in pressure at EE-2, the system was put into vent mode. Once the system was purged of start-up gas, the vent to the pond was valved off, flow was directed to the heat exchangers, and closed-loop operation started.

Throughout the 30-day test the system was operated in various modes as needed. When the dissolved gas content of the water became too high for the chemists to obtain a total gas measurement, the system was run in gas-purge mode (open system operation). For system maintenance, the loop was usually put into vent mode where all of the returns were dumped into the EE-1 pond; on a few occasions the well was shut in. Sufficient excess pumping equipment had been specified to allow for routine maintenance to be accomplished without interruption of the loop. During power failures, all pumping was stopped and the production well was vented to the EE-1 pond. High-back-pressure mode was used during closed-loop operations. EE-2 pressure was increased by simply closing down a control valve. For fresh-water-flush mode, an open system operation, the returns from the production well were first cooled in the heat exchangers and vented to the EE-1 pond. All injection fluid was then supplied by the makeup water system.

The system was shut down by turning off the injection pumps and shutting in EE-3A and EE-2. Pressure instrumentation on both EE-2 and EE-3A was left in place with the data acquisition computer running and recording. Appendix C gives a chronological summary of operations.

E. Borehole Performance

On June 8, the 20th day of the test, a 5100-kg (155 000-SCF) slug of nitrogen was injected during a 30-min interval. The main purpose of the gas injection was to attempt to clean out the EE-2 production interval. Some sand and mud had previously been removed from EE-2 by surging the well. By gas lifting the production well to increase flow velocity, it was felt debris that was thought to be filling and covering near wellbore fractures could be removed. Although a significant surge of flow occured, little debris was seen. Review of production data showed that the flow rate measurements were inflated because of continuing nitrogen production.

Two radioactive (^{123}I) velocity logs were run in EE-3A, and their results are summarized in Table II-I. The fact that the observed cross flow during shut-in was flowing from the upper zone to the lower zone was surprising based on the original injection pressures measured during Expts. 2059 and 2062. This cross flow may be evidence of a large convection system that was driven by thermal buoyancy and possibly increased by nitrogen left in the reservoir, or by the cooled injection zone. The velocity logs are in good agreement with the temperature logs discussed in Section III.

When temperature logs were run in EE-3A, a collar locator log was run through the lower tubing, seal assembly, polished bore receptacle, and liner. Table II-II shows the results of calculations that check the operation of the PBR/seal assembly expansion joint. From this analysis it appears that the seals were never locked up by scale or debris during the test. The temperature logs and velocity surveys all showed that the liner, the PBR seals, and the screw-in-sub connection were not leaking during or after the ICFT.

EE-3A backside performance is examined in Fig. II-7 where EE-3A backside flow during the ICFT is compared to both EE-3A and EE-2 pressures. A comparison of backside performance to EE-3A frontside pressure (Fig. II-7a, b, and c) indicates a flow response on the backside that lags frontside pressure by approximately 2 days. There are also common pressure inflections between the frontside and backside during the shut-in. However, it seems clear that the leak path between the frontside (tubing) and backside is long and tortuous. A tubing or liner leak would not act this way. A microannulus in the cement or small fractures or porosity in the cement or near-wellbore rock would better explain the pressure flow performance. The shut-in temperature

TABLE II-I

RESULTS OF RA VELOCITY LOGS IN EE-3A

Depth m	(ft)	Description	Injection Log 6/16/86 m^3/s	(gpm)	Shut-in Log 6/23/86 m^3/s	(gpm)
			Flow Rate Observed[a]			
3456	(11340)	Inside liner	0.01735	(275)	0	(0)
3485	(11435)	Bottom of liner	0.01735	(275)	0	(0)
3500	(11484)	Cemented open hole	0.01735	(275)		
3515	(11532)		0.01640	(260)		
3538	(11608)				Fluid entry	
3545	(11632)		0.01640	(260)	0.000158	(2.5)
3553	(11658)		0.01356	(215)		
3561	(11682)		0.01136	(180)		
3572	(11718)		0.01136	(180)	0.000189	(3.0)
3584	(11758)		0.00852	(135)	0.000170	(2.7)
3597	(11800)				0.000126	(2.0)
3608	(11838)		0.00852	(135)	0.000095	(1.5)
3620	(11878)		0.00536	(85)		
3625	(11892)		0.00473	(75)		
3630	(11908)		0.00442	(70)		
3634	(11922)		0.00252	(40)		
3639	(11938)		0.00126	(20)	0.000076	(1.2)
3658	(12000)		0.00126	(20)		
3675	(12056)		0	(0)	0	(0)
3729	(12235)	Cleanout TD				

[a] All flows observed were down flows.

log (Fig. III-2, discussed later) would also suggest a long flow path with many small pressure drops between 3320 and 3535 m. The gradually increasing backside flow during the experiment may reflect a slowly expanding pressure field around the main reservoir.

EE-2 pressures (Figs. II-7d and e) at times seem to be related to backside flow at EE-3A. On several occasions the EE-3A backside flow

TABLE II-II

EE-3A EXPANSION JOINT PERFORMANCE

127-mm (5-in.) i.d. Polished Bore Receptacle
127-mm (5-in.) o.d. Molyglass Seal Mandrel

Activity	Date	Average Tubing Temp[a] °C (°F)	Differential Pressure MPa (psi)	Seal Mandrel Position Measured[b] m (ft)	Seal Mandrel Position Calculated m (ft)
Static temp log	5/15/86	116 (240)	0	4.3 (14) initial condition	4.3 (14)
Injection temp log $0.0106\ m^3/s$ (4 bpm)	5/28/86	41 (105)	25.9 (3750)	8.2 (27)	8.9 (29)
Injection temp log $0.0172\ m^3/s$ (6.5 bpm)	6/16/86	33 (91)	31.0 (4500)	8.5 (28)	9.5 (31)
Shut-in temp log 5-day shut-in	6/23/86	91 (196)	12.8 (1850)	5.2 (17)	6.0 (20)

[a] Average temperature calculated using $T_{ave} = \frac{15.5°C + T_{bh}}{2}$ where T_{bh} is the temperature in °C at 3322 m (10 900 ft).

[b] Measurements based on casing collar locator logs with assumed accuracy of ± 0.3 m (± 1 ft). A position of 0 represents a fully closed expansion joint.

appeared to increase a short time after the EE-2 frontside was shut in, though there does not seem to be a consistent pattern. There also appears to be some response in EE-3A to changes in EE-2 backside pressure, but still a clear pattern is not observed.

Figure II-8a shows the EE-2 backside pressure during the ICFT and the first 30 days of the shut-in. For comparison, the EE-2 annulus pressure is shown on Fig. II-8b, the EE-2 frontside (production) pressure is shown on Fig. II-8c, the EE-2 production temperature on Fig. II-8d, and the EE-3A frontside (injection) pressure on Fig. II-8e. From these plots it is concluded that the EE-2 backside is in intermittent pressure communication with the EE-2 tubing (frontside) with no observable time delay. Failure of the EE-2 casing packer was later

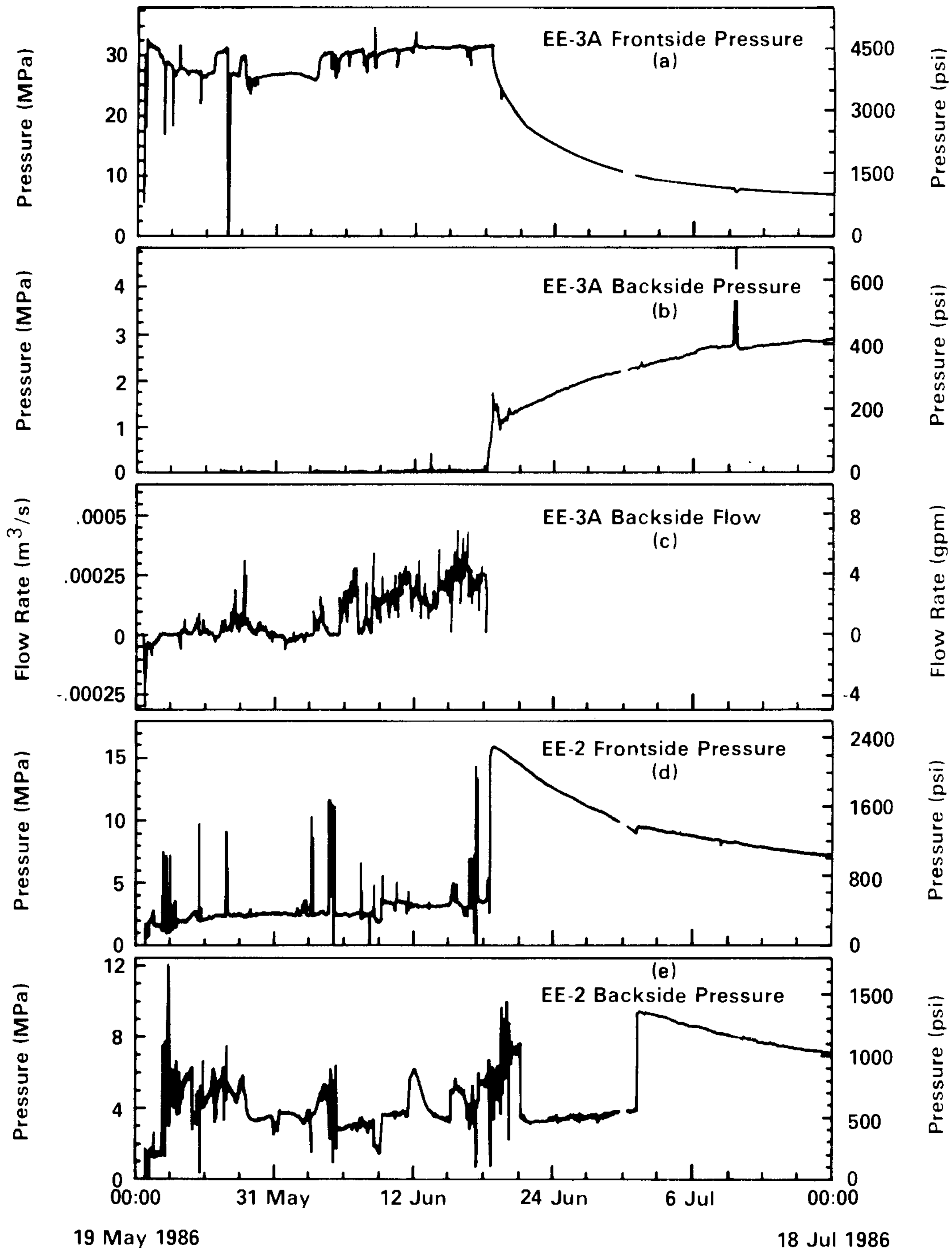

Figure II-7. EE-3A backside flow compared to EE-3A and EE-2 pressures: a) EE-3A frontside pressure, b) EE-3A backside pressure (there is some evidence of a 2-day response on the backside to pressure changes on the frontside), c) EE-3A backside flow data (negative flow occurred as the well was cooled and liquid was added to the backside to make up for fluid contraction), d) EE-2 frontside pressure, and e) EE-2 backside pressure.

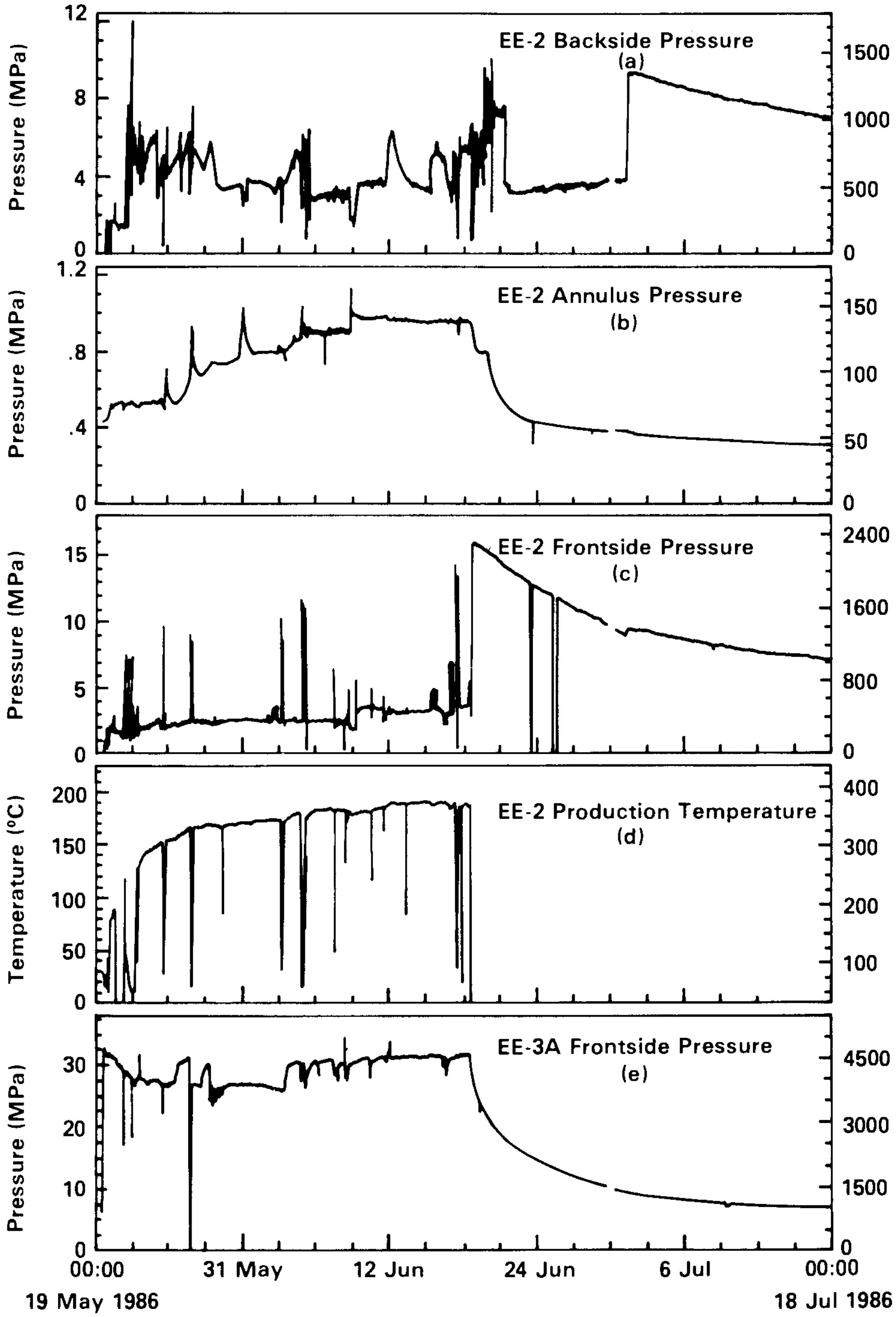

Figure II-8. EE-2 backside pressure (a) compared to b) EE-2 annulus pressure, c) EE-2 frontside pressure (an intermittent connection from the frontside to the backside is indicated), d) EE-2 surface production temperature (backside pressure intermittently responded to temperature changes in the tubing, indicating the leak on the backside was occasionally sealing off), and e) EE-3A frontside pressure (the reservoir connection is evident but subtle).

shown to be the cause. Communication commences with a sudden increase in frontside pressure (Fig. II-8c). EE-2 backside is in communication with the EE-3A frontside (Fig. II-8e) with a 3-hour delay. The communication path observed with the EE-3A frontside is most likely the main reservoir connection through the EE-2 frontside.

The EE-2 backside at times appears to become isolated from the EE-2 frontside and acts like a closed pressure vessel. During these periods, the backside pressure indicated good thermal communication between the tubing and annulus (Figs. II-8d and b).

III. THERMAL BEHAVIOR

A. Temperature Measurements

Temperature measurements were an integral part of Expt. 2067. Injection and production temperatures were measured at the EE-3A and EE-2 wellheads, respectively. Inlet and outlet temperatures were also measured across the heat exchangers. In addition, a series of borehole temperature surveys were made in both the Phase II and Phase I Fenton Hill wells.

1. EE-3A Borehole Temperature Measurements. A background temperature survey was conducted in injection well EE-3A on May 15, 1986, before pumping into the Phase II system (Fig. III-1). Since the EE-3A wellbore was pressurized above 25 MPa (4000 psi) throughout the pumping experiment, temperature surveys of the EE-3A borehole were run by a commercial service company, Oil Well Perforators (OWP). Three high-pressure logs were run by OWP (Fig. III-2), two during ICFT injection, May 28 and June 16, and one 5 days after shut-in, June 23. Two additional post-ICFT temperature surveys were run in EE-3A on August 5 and August 28, 1986 (Fig. III-1).

The OWP temperature logs (Fig. III-2) show that a well-distributed injection interval was established between 3535 and 3660 m (11 600 and 12 000 ft) with two major entry zones, one above and one below the 3600- to 3630-m (11 800- to 11 900-ft) zone, which was the intended bottom of the liner and actually the bottom of a cement sheath remaining after cleanout. Possible discrete fractures noted at 3540 m (11 620 ft), 3580 m (11 750 ft), and 3640 m (11 950 ft) correspond to fractures first

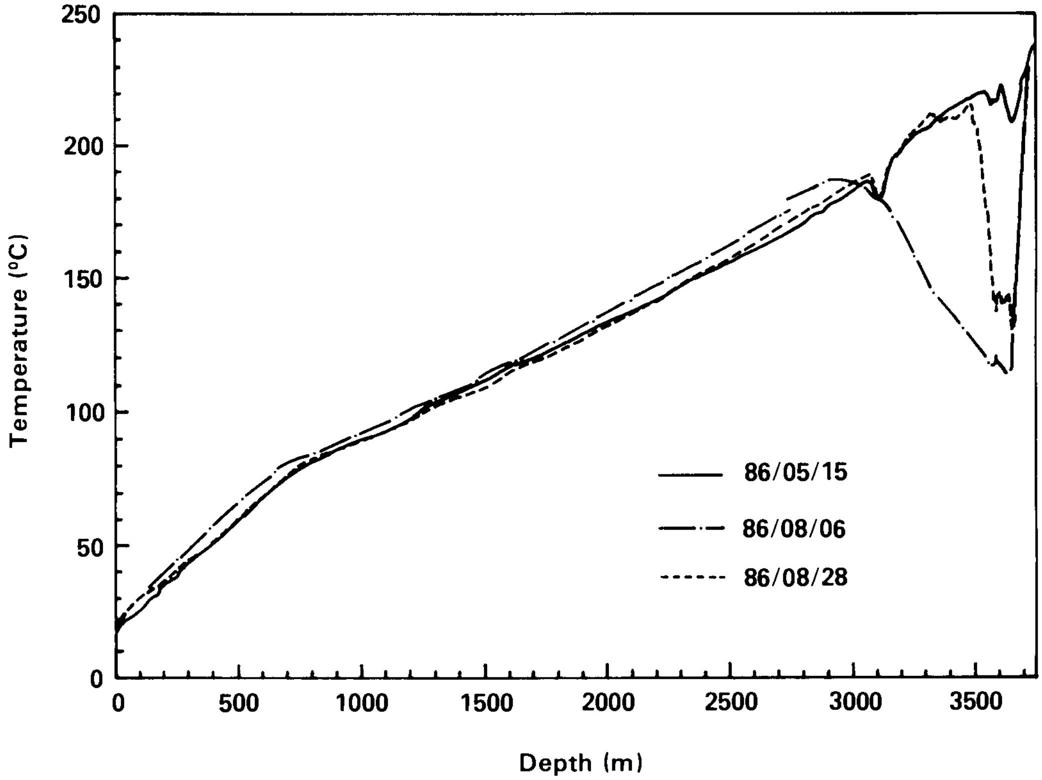

Figure III-1. Pre- and post-ICFT temperature surveys of EE-3A run by Los Alamos.

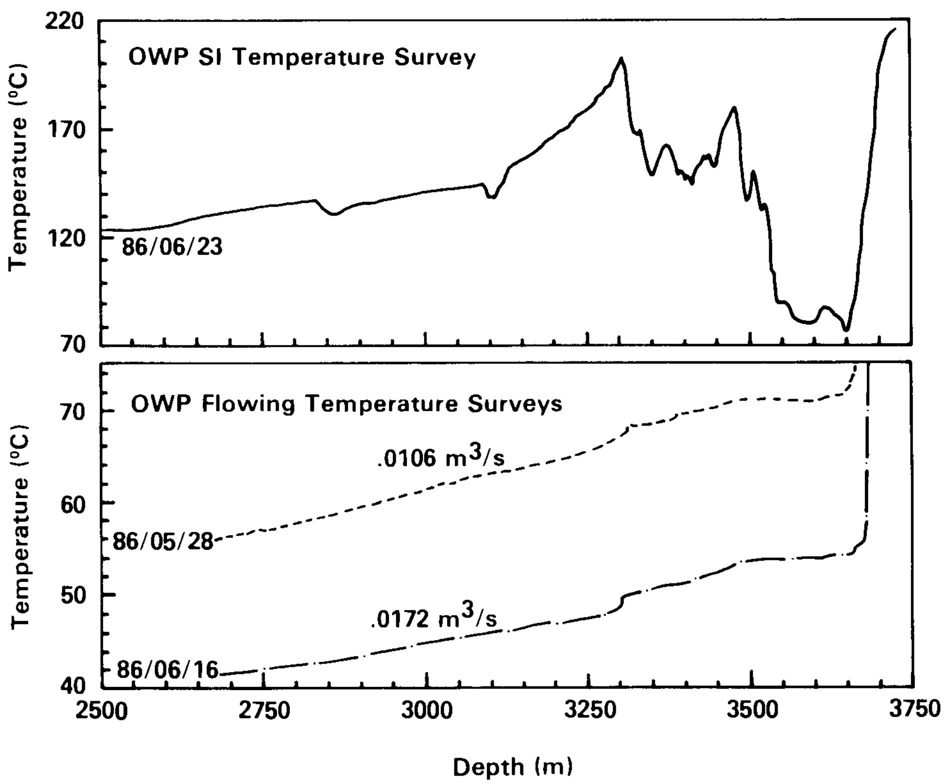

Figure III-2. High-pressure temperature surveys of EE-3A run by OWP.

stimulated in Expt. 2059 and later during Expt. 2062. The thermal anomalies between 3300 to 3510 m (10 825 to 11 520 ft) on the shut-in log are consistent with the flow observed on the EE-3A backside. The appearance of these anomalies suggests a near-wellbore leakage path that is long and tortuous. It is estimated that about 0.0004 m^3/s (6 gpm) is entering behind the liner and flowing up the well, with about 0.0001 m^3/s (2 gpm) leaving the wellbore region at 3125 m (10 250-ft, low-pressure zone) and 0,0003 m^3/s (4 gpm) at the surface. The postexperiment temperature surveys are compared to the background run made on May 15 (Fig. III-3) and show the thermal recovery of the wellbore with time.

2. <u>EE-2 Temperature Measurements</u>. During the ICFT, 3 temperature surveys of the EE-2 production well were obtained and a fourth survey was made 10 days after the flow test was terminated (Fig. III-4). These measurements were with the Kuster recorders (a downhole mechanical recording system). The first three surveys made on May 28, June 4, and

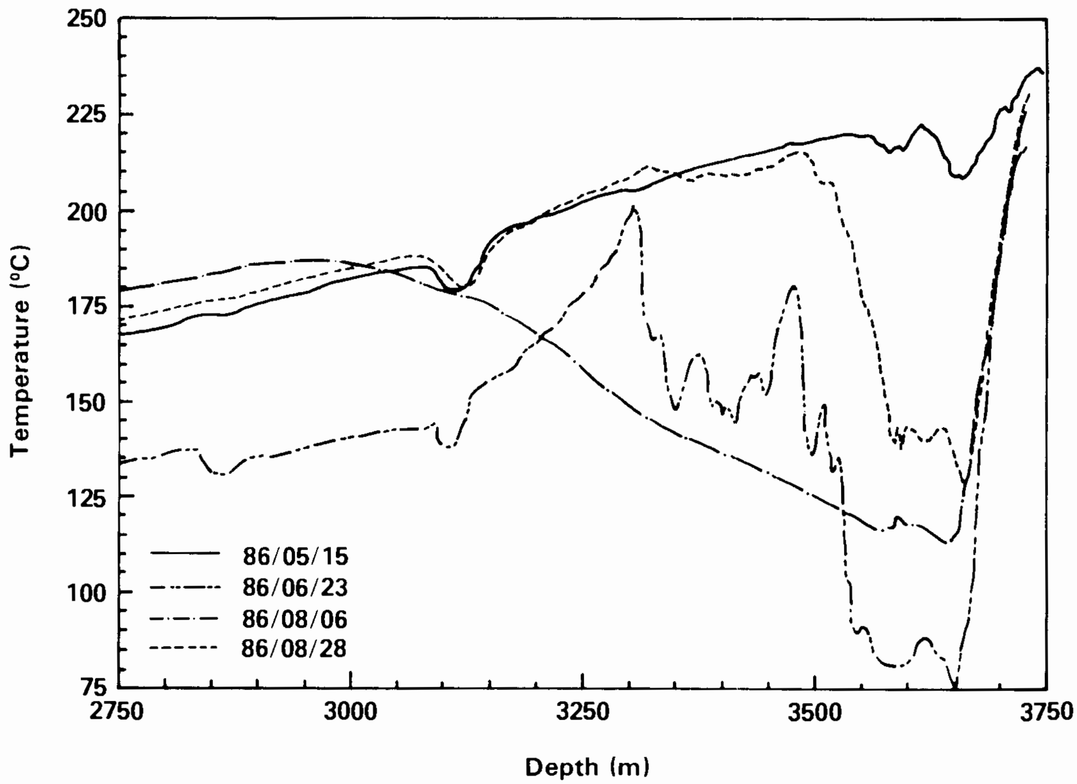

Figure III-3. Comparison of the pre-ICFT survey with post-ICFT surveys showing thermal recovery of EE-3A with time.

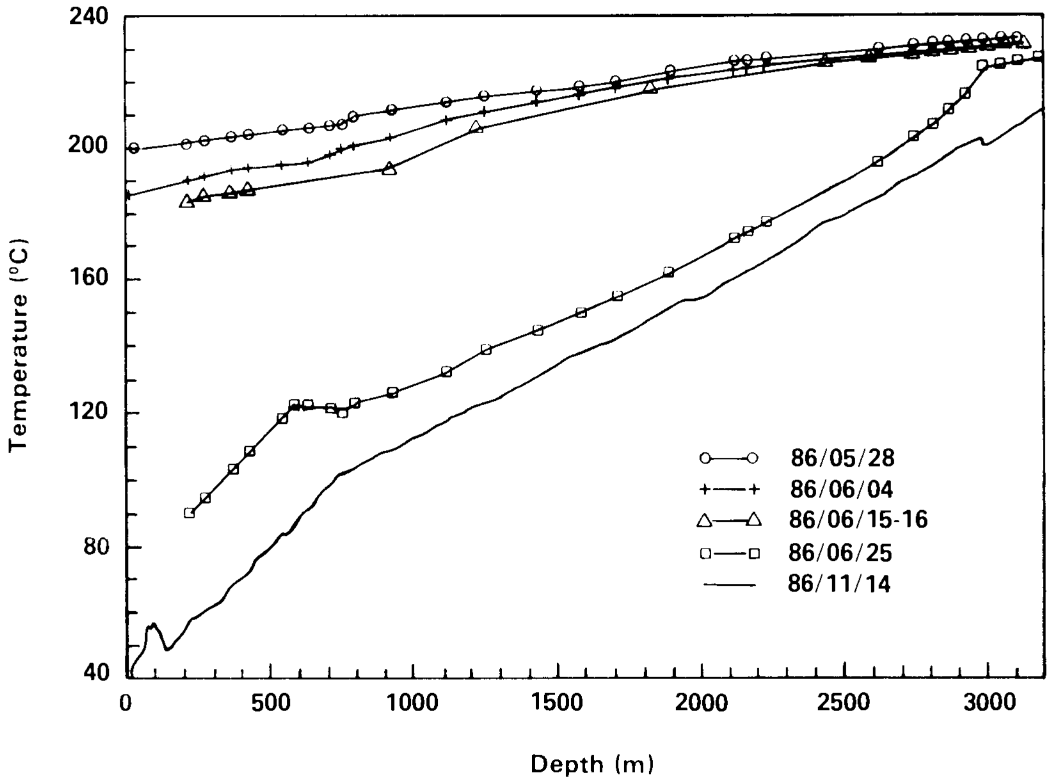

Figure III-4. Kuster temperature surveys of EE-2 during the ICFT compared to a post-ICFT temperature survey.

June 15 show the progressive heating of the entire wellbore throughout the experiment. A temperature survey run on Los Alamos equipment on November 14, 1986, (also shown on Fig. III-4) when compared to the fourth Kuster survey (June 28, 1986) shows the temperature recovery of the wellbore. Because of the damaged EE-2 wellbore, temperature surveys could not be run below 3185 m (10 450 ft).

Figure III-5 shows a calculated boiling pressure curve, based on EE-2 production temperature, compared to the pressure measured in the EE-2 244.5- to 339.7-mm (9-5/8- to 13-3/8-in.) casing annulus. At the beginning of the test the annulus pressure was 0.4 to 0.5 MPa (62 to 75 psig), well above the boiling point. Once the increase in EE-2 production temperature caused the calculated boiling pressure to exceed 0.5 MPa (75 psig), the annulus pressure followed the boiling curve until a pressure of 1 MPa (140 psig) was reached and then declined slowly until cooling occurred at shut-in. It is assumed that the fluid level

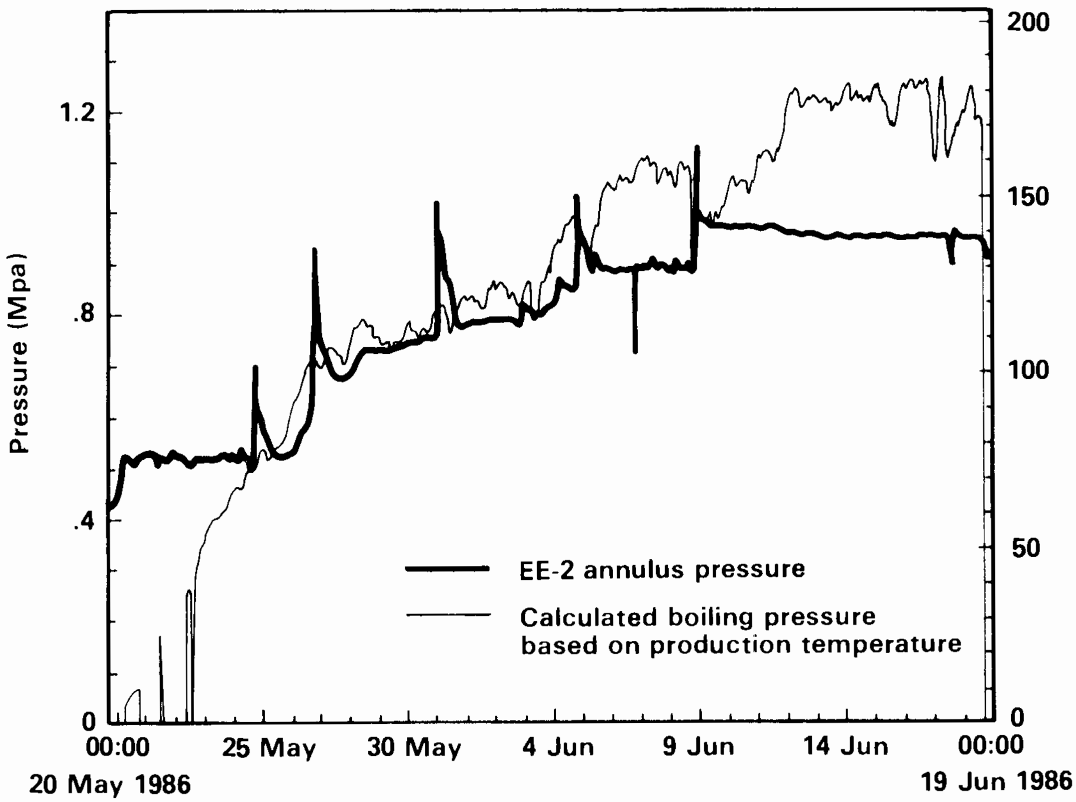

Figure III-5. A calculated boiling pressure curve (based on the EE-2 surface production temperatures) compared to the EE-2 annulus pressure data.

in the annulus was lowered as the pressure followed the boiling pressure curve. The fluid, displaced by steam, was pushed out into the aquifers through the damaged 339.7-mm (13-3/8-in.) o.d. casing (damaged during drilling) below 536 m (1760 ft). The pressure leveled out at 1 MPa (140 psi) when the fluid level reached the first aquifer that would accept all of the steam being produced in the annulus. The temperature anomalies on the Kuster production surveys (Fig. III-4) between 245 and 915 m (800 and 3000 ft) were quite pronounced, while the annulus pressure followed the boiling pressure curve but had almost disappeared once the annulus pressure deviated from the boiling curve.

An active cross-flow region between 640 and 790 m (2100 and 2600 ft) was observed on the Kuster log following shut-in (June 28, 1986). This corresponds to an aquifer near the transition of the sediments and Precambrian basement rock. This thermal anomaly might also be attributed to changes in thermal conductivity in the different geologic formations. The possibility of a small leak in this area should not be ignored. Another, deeper anomaly was noted in the temperature gradient on the shut-in temperature log. The gradient is quite flat from 2990 to 3185 m (9800 to 10 450 ft) indicating some flow behind the casing believed to be the top of a cross flow between the main HDR reservoir and the Phase I low-pressure system. It is estimated a small amount of fluid, about 0.0019 m^3/s (30 gpm), was still entering the wellbore below 3185 m after EE-2 was shut in and flowed up the well and out into the rock at 2990 m. On Fig. III-6 an interpretation of cement bond log amplitude shows cemented regions behind the 244.5-mm (9-5/8-in.) casing that resulted from the squeeze work done to "repair" EE-2 in 1984. The existence of this cross flow would indicate a deterioration of the squeeze cement between 3215 to 3230 m (10 550 to 10 600 ft). The cement placed above the 2775-m (9100-ft) squeeze perforations appears to be in good condition based on the temperature logs.

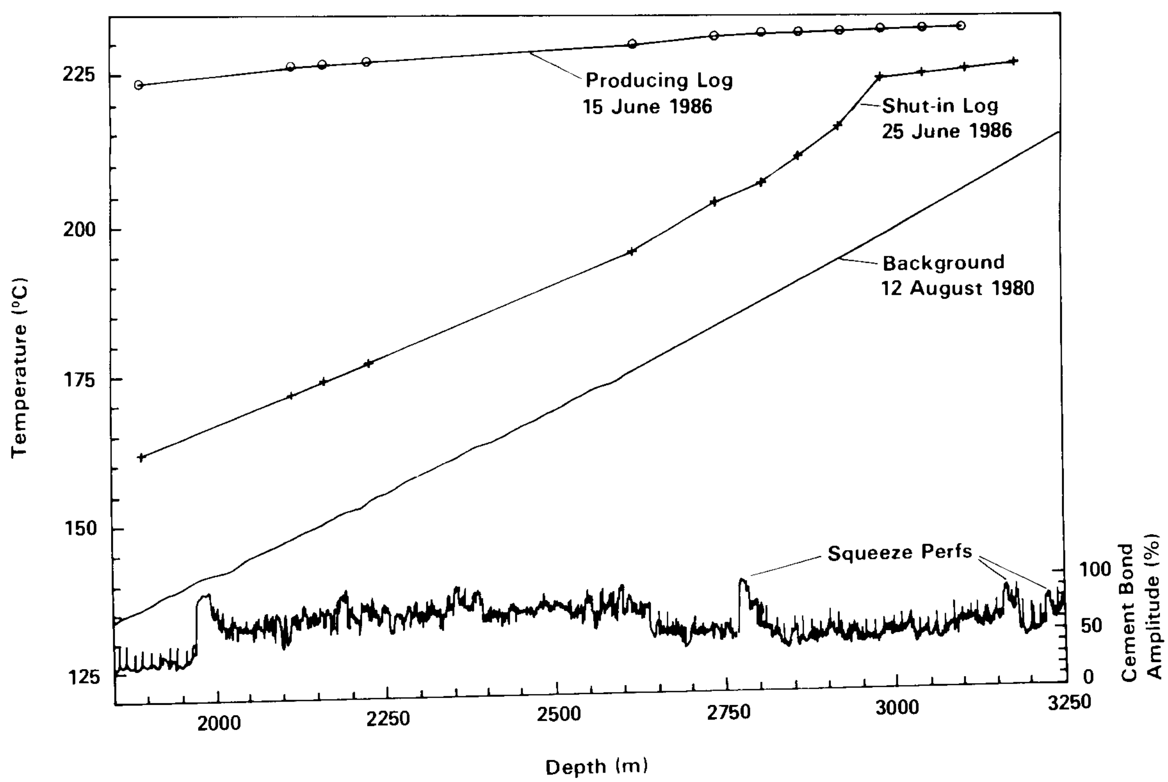

Figure III-6. EE-2 temperature logs with interpretation of the 1984 cement bond log amplitude shown. The bond log was run following the squeeze cement jobs conducted during the 1984 EE-2 repair.

3. Phase I Wells. Background temperature surveys were made in EE-1 and GT-2B on May 13 and May 14, 1986, respectively, before the start-up of the ICFT. Throughout the experiment, the EE-1 and GT-2B wellheads were monitored. A small amount of fluid was noted flowing from GT-2B on June 12, 1986. When this wellbore was shut in, a pressure increase at the wellhead was noted and recording of both EE-1 and GT-2B pressures commenced. On July 31, 1986 (about 43 days after the pumping into EE-3A was terminated), a second survey was run in EE-1. The data from the three temperature surveys are shown in Fig. III-7. The effects of the warming of the EE-1 borehole via the leakage into the old Phase I system are clearly defined.

B. Modeling Thermal Performance

Following completion of the ICFT, simulations of both EE-3A and EE-2 performance were made to match the data collected during the experiment using a wellbore heat transfer (WBHT) code (Dash and Zyvoloski, 1982). The WBHT model solves the basic 2-D radial equations

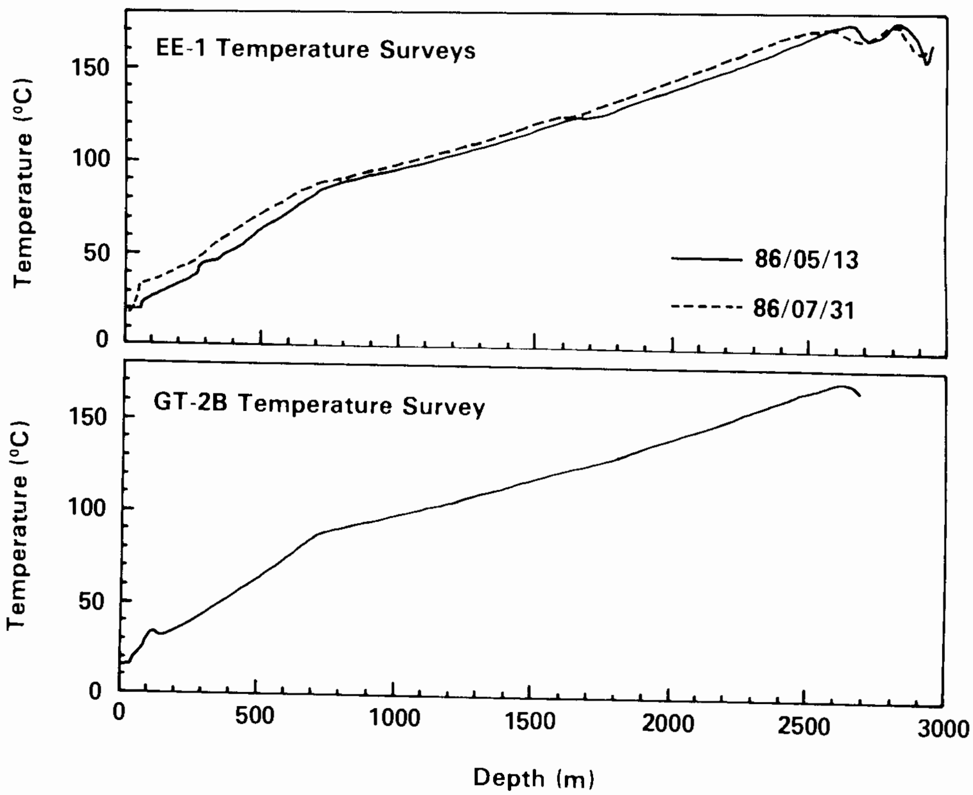

Figure III-7. EE-1 and GT-2B temperature surveys.

for heat transfer and accounts for forced convection in the wellbore and annulus and for conduction to the surrounding rock mass.

1. EE-3A WBHT Simulation. EE-3A injection was modeled using an approximation to the measured flow rates (Fig. III-8) and a constant inlet temperature of 20°C, which corresponds to the average injection temperature over the course of the experiment. The resulting bottom-hole temperature versus time is given in Fig. III-9. WBHT-calculated wellbore temperature profiles are compared to corresponding OWP temperature surveys in Fig. III-10. The EE-3A simulation profiles are in good agreement with wellbore cooldown during injection and postinjection thermal recovery. The model used, however, is not sufficiently complex to model flow into the reservoir. The simulation also provided information that allowed estimation of bottom-hole injection pressures.

2. EE-2 WBHT Simulation. EE-2 production was modeled using a reservoir outlet temperature of 232°C, which corresponds to the original rock temperature at 3535 m (11 600 ft) and flow rate as measured at EE-2

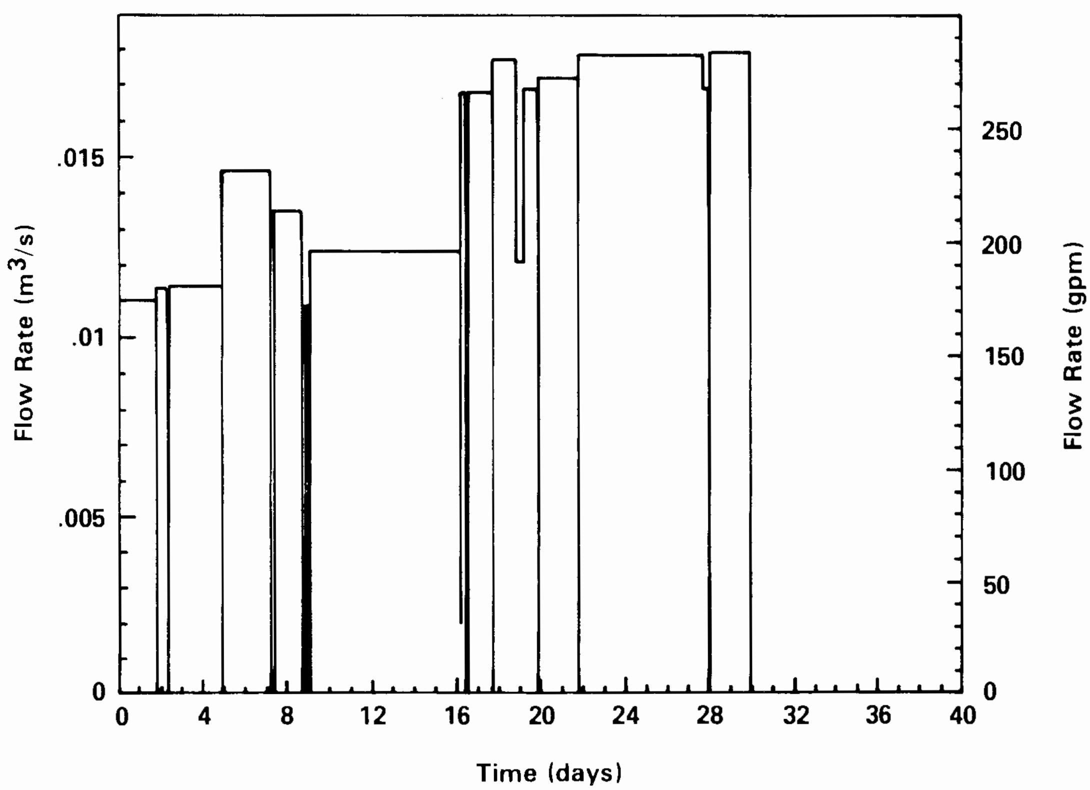

Figure III-8. EE-3A injection flow rate versus time.

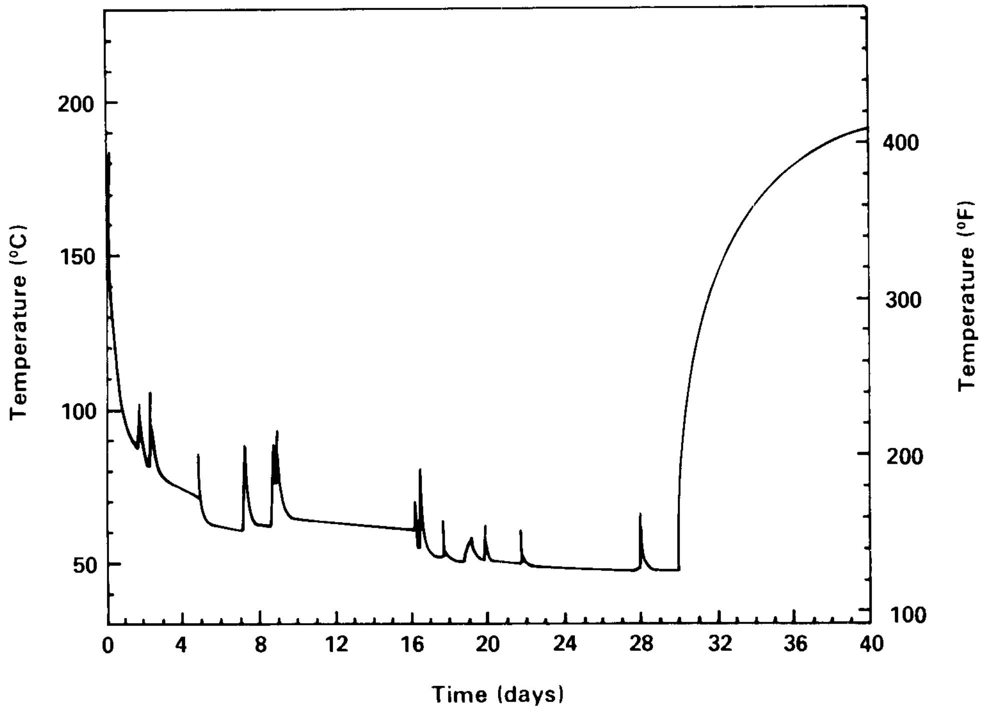

Figure III-9. WBHT projection of EE-3A bottom-hole temperature.

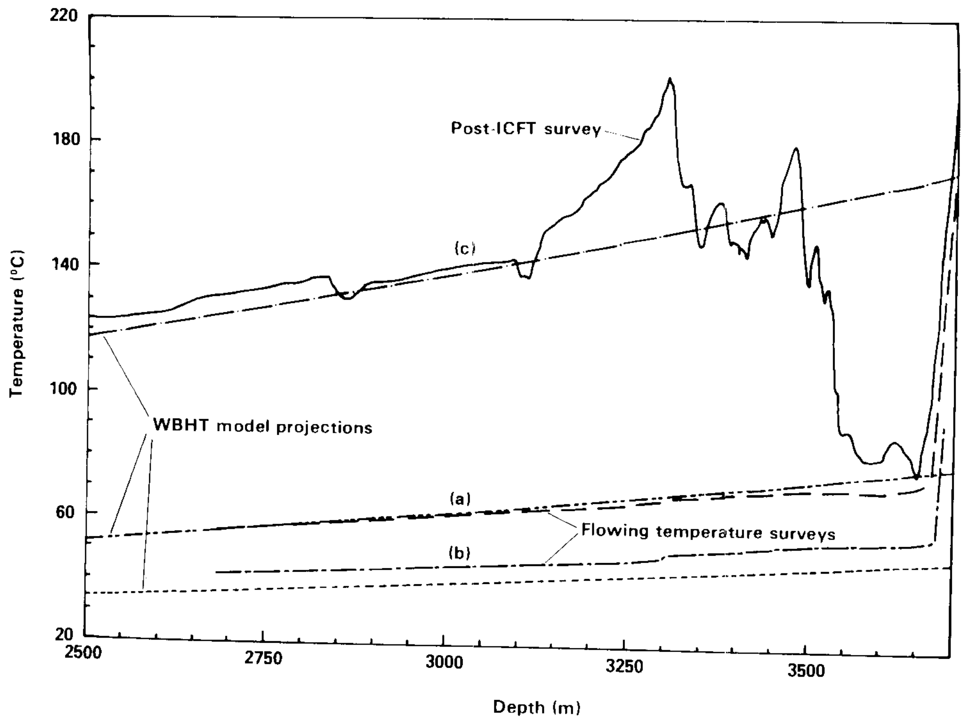

Figure III-10. WBHT projection of EE-3A temperature surveys compared to OWP surveys: a) OWP survey 86/05/28; b) OWP survey 86/06/16; and OWP survey 86/06/23.

wellhead (Fig. III-11). The production temperature projected by the model as a function of time is given in Fig. III-12 and compared with measured production temperatures. These temperatures are in good agreement during the first 9 days of the ICFT. At that time the temperature predicted by the model exceeds that measured by about 5 to 10°C. Around the 20th day of the simulation, this difference has increased to 20°C. In general, the discrepancies correspond with the appearance of more gas in the production fluid; in particular, the largest discrepancies correspond to an experiment in which nitrogen was introduced into the system on June 8. The same discrepancies can be noted between the downhole Kuster measurements and WBHT wellbore temperature profiles (Fig. III-13).

Because of the increasing error in predicted production temperature, the model was rerun using a production rate derived from summing the flow rates through the heat exchangers (Fig. III-11). During the early part of the test, EE-2 wellhead and heat exchanger flow rate measurements were consistent, but a difference in the measurements of

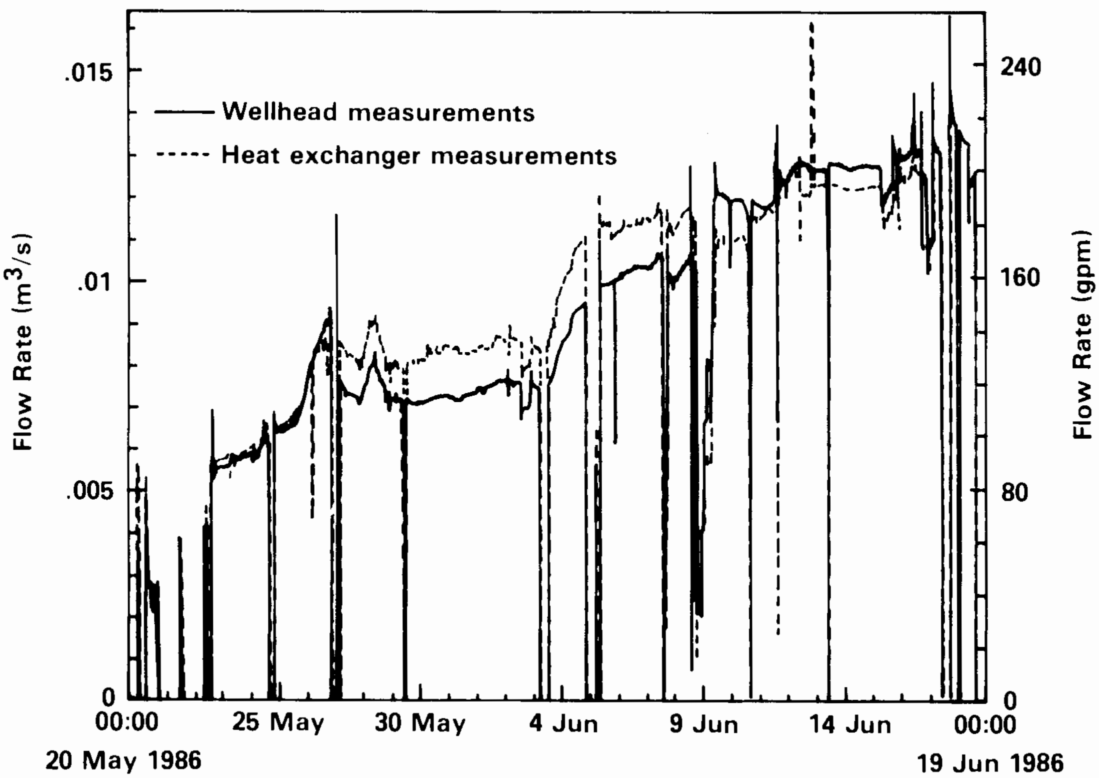

Figure III-11. EE-2 production flow rate.

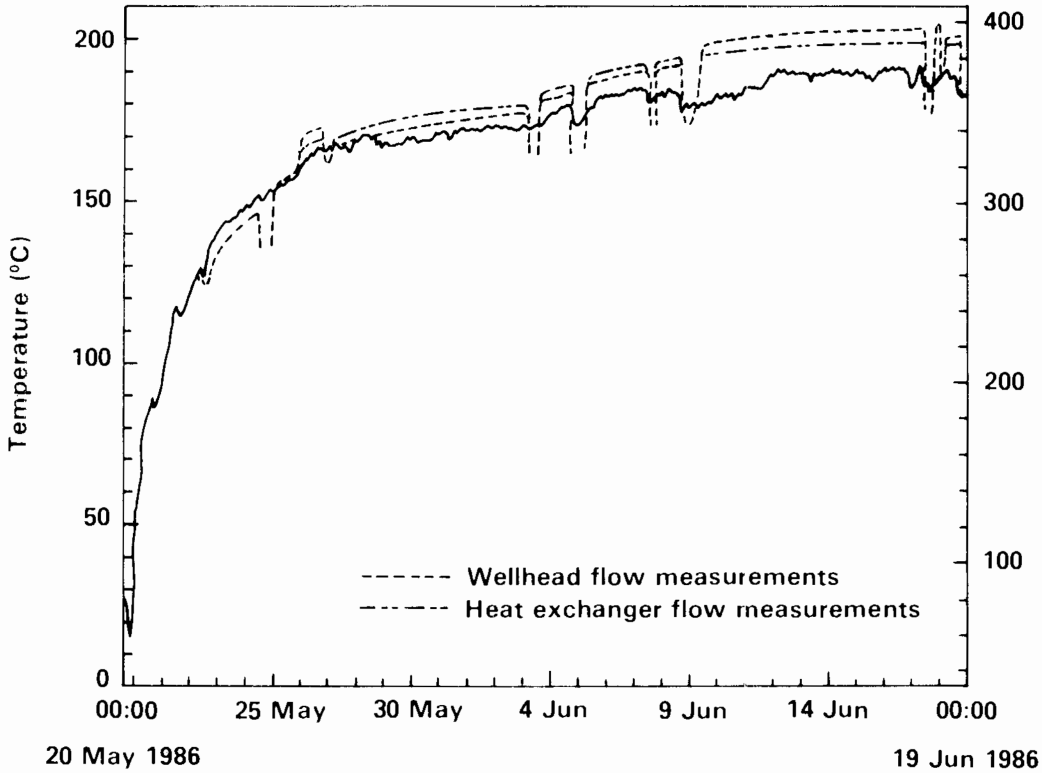

Figure III-12. EE-2 wellhead production temperature compared to WBHT projection of production temperature using wellhead measured flow rates and using heat exchanger rates.

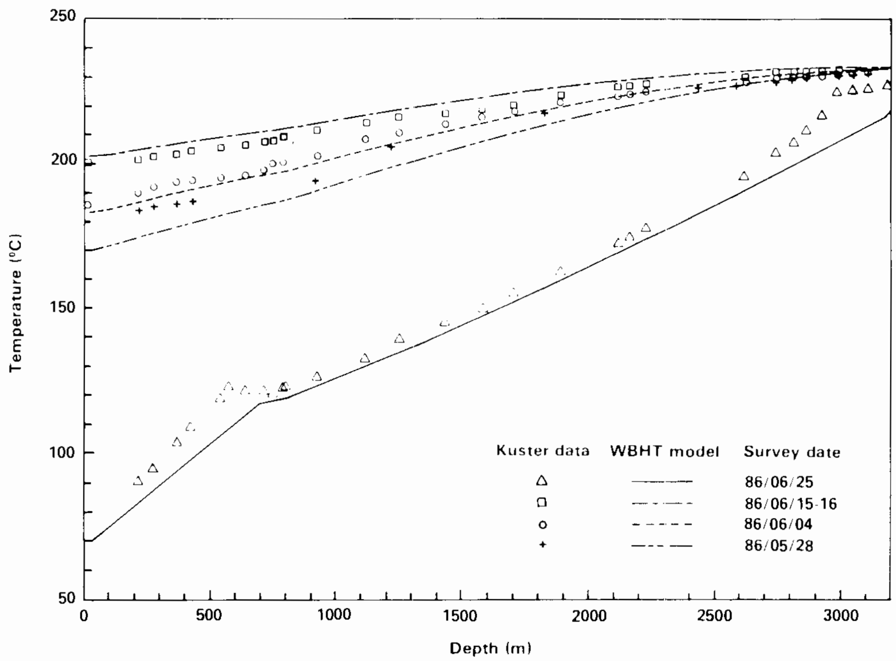

Figure III-13. EE-2 Kuster temperature surveys compared to WBHT projections using wellhead flow rates.

flow rate was noted after about 8 days. This deviation between wellhead and heat exchanger flow rates occurred at about the same time the strainer in front of the wellhead flow meter required cleaning owing to severe clogging, suggesting some debris may have affected the wellhead flow meter. To determine which flow rate measurements were more reliable, a cross check was made by estimating flow using the difference between injection and makeup flow meters (Fig. III-14). The values obtained consistently match the heat exchanger flow rates when the system was not being run in gas-purge mode. Therefore, it is believed that the heat exchanger flow rates provide the most reliable values. Projections of production temperature using the heat exchanger flow rates, although still high (about 5 to 10°C), are in much better agreement with experimental results (Fig. III-12). Downhole Kuster measurements and WBHT wellbore temperature profiles compared in Fig. III-15 are also in much better agreement.

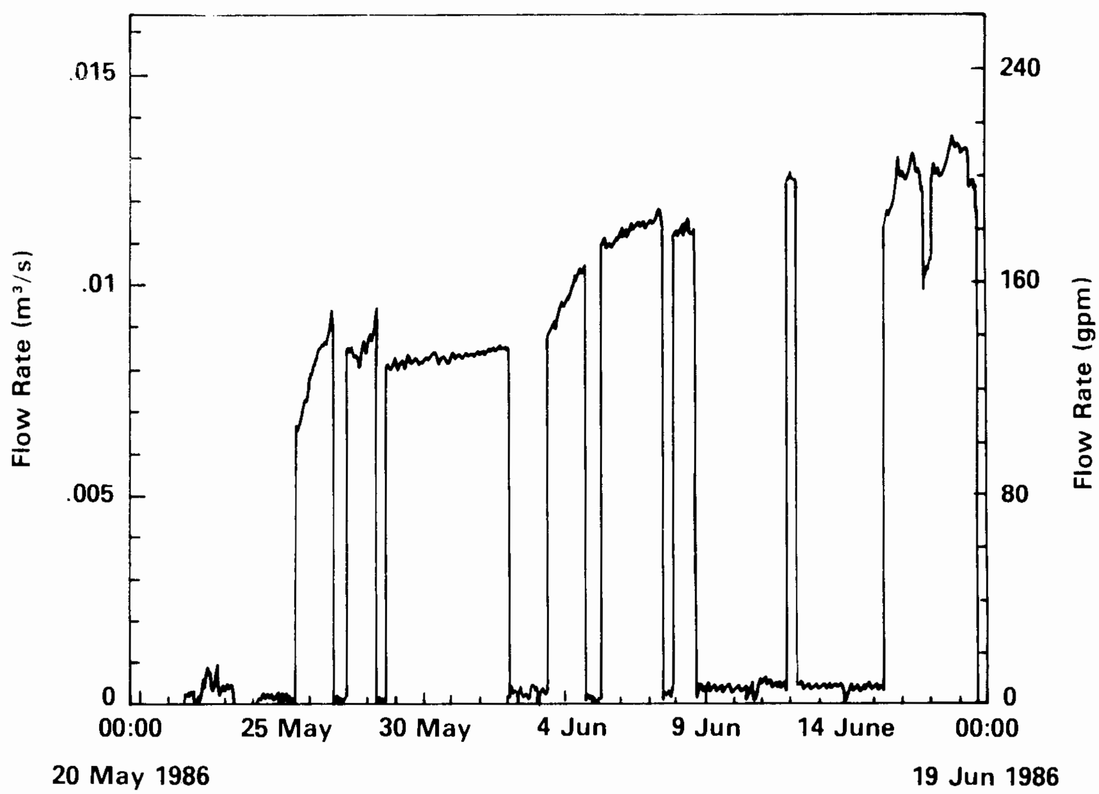

Figure III-14. EE-2 production flow rate estimated from difference between makeup flow and injection flow measurements.

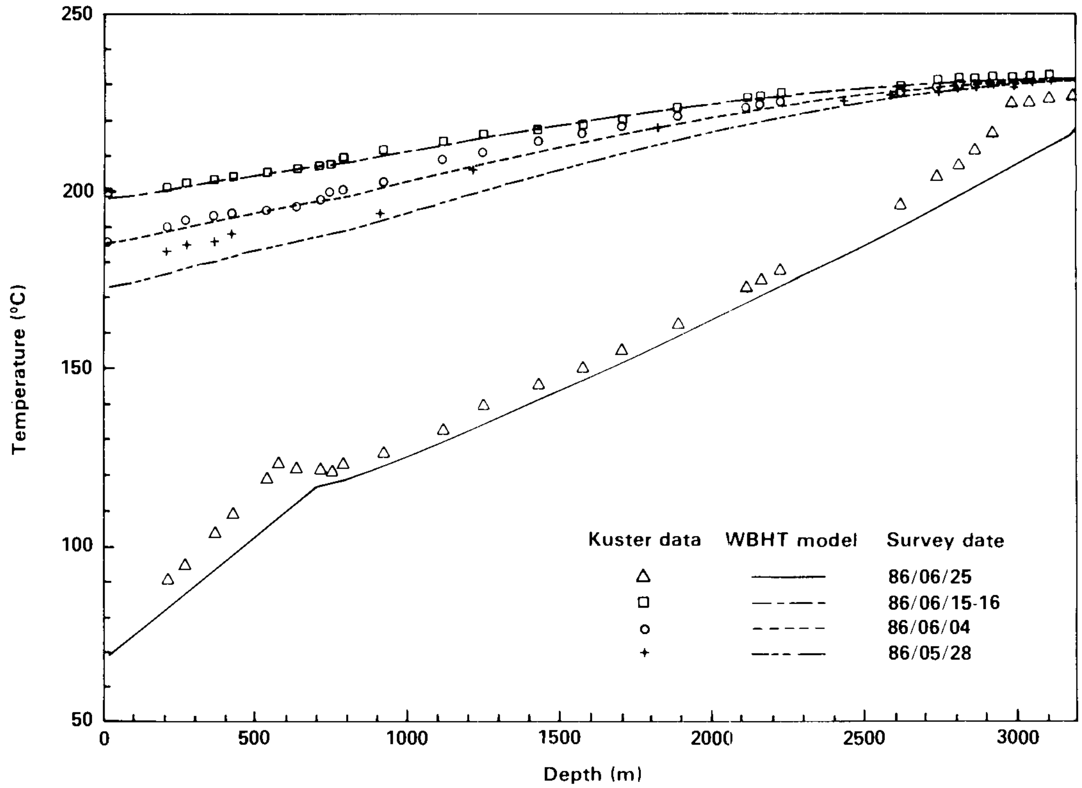

Figure III-15. Kuster measurements with WBHT projections of downhole temperature using heat exchanger flow rates.

C. Estimation of Thermal Power Production

Thermal power production was estimated for the ICFT using the measured production temperature at the EE-2 wellhead, the injection temperature at EE-3A, and production flow rate. First calculations used the production flow rate measured at the EE-2 wellhead; later calculations used the flow rates measured at the heat exchangers (Fig. III-16). Using the wellhead measurement of flow, a peak power of 10.5 MW_t was estimated; however, with the lower flow rates measured at the heat exchangers, this peak was slightly under 10 MW_t. A model projection using a sustained flow rate of 0.0126 m^3/s (200 gpm), which is close to the rate maintained over the last 7 days of the test, results in a power production of 10 MW_t.

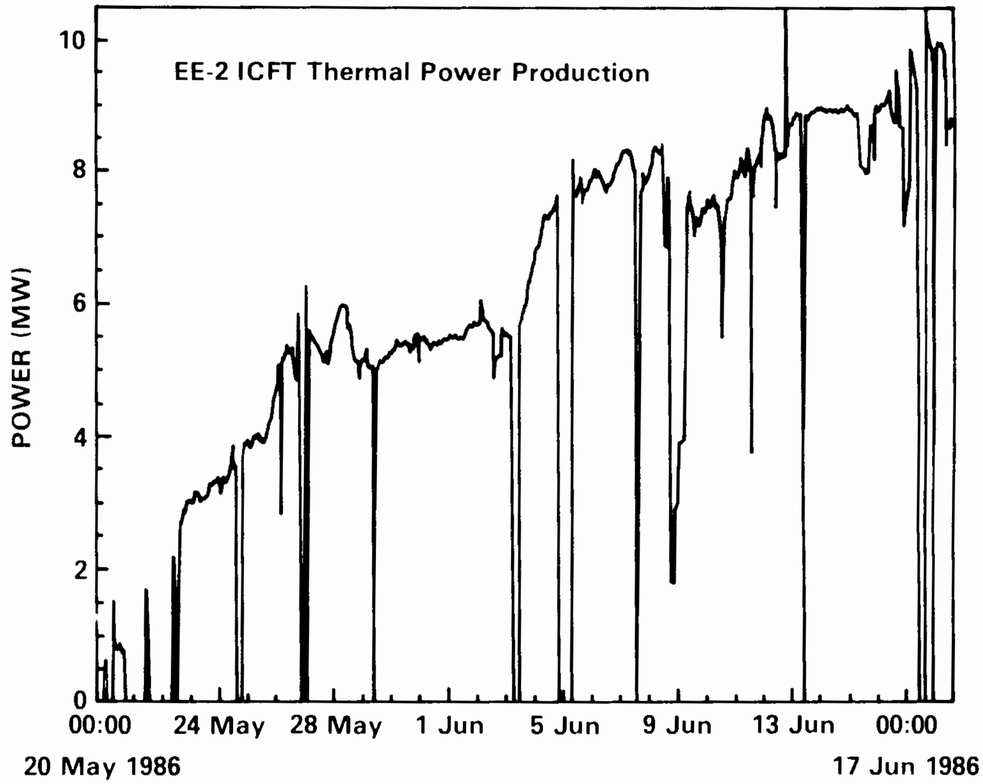

Figure III-16. Thermal power production during the ICFT estimated using heat exchanger flow rates.

IV. RESERVOIR HYDRAULICS

A. Pressure Rate Response

Many hydraulic reservoir tests were conducted within the ICFT that included shut-ins, vents, and pressure and flow rate variations. These experiments provided information about reservoir and well characteristics and the changes caused by water circulation during the ICFT.

1. Analysis of EE-3A Data.

a. Introduction. Figure IV-1 shows the EE-3A pressure and flow rate (averaged every 15 min) on a condensed time scale; Table IV-I lists the many shut-ins of the injection well during the ICFT along with the estimated instantaneous shut-in pressure for each shut-in. A short step-rate test was conducted at the start of the ICFT, followed by a nominally steady injection at 0.0114 m^3/s (180 gpm) for 6 days. The injection pressure decreased from 32.1 MPa (4650 psi) to 27.6 MPa (4000

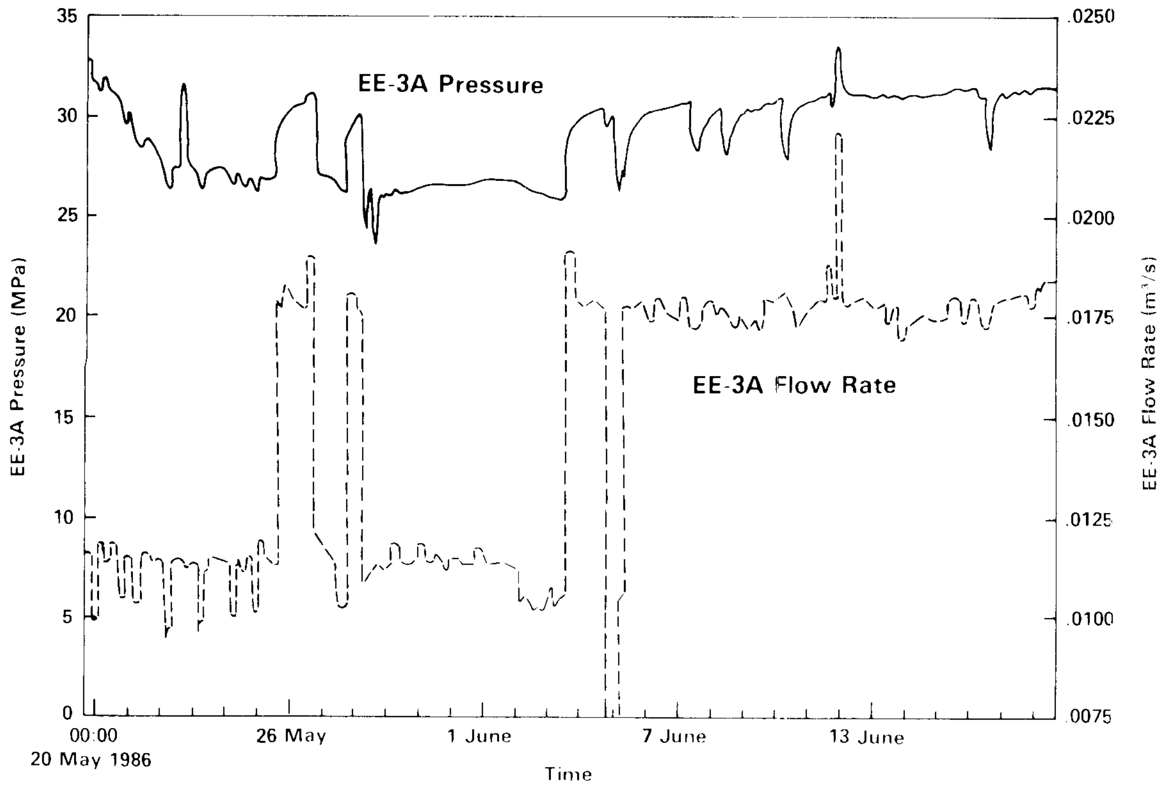

Figure IV-1. EE-3A pressure and flow rate.

psi) during the first 3 days of injection, leveling off to 26.9 MPa (3900 psi) later in the test. Following the 6 days of steady injection, there were two short intervals with elevated rates: one at 0.0180 m^3/s (286 gpm) for 28.2 hours beginning at 1620 hours on May 25, and one at 0.0174 m^3/s (276 gpm) for 12.9 hours beginning at 2008 hours on May 27. Both caused the surface injection pressure to increase quickly to approximately 31.0 MPa (4500 psi), reflecting a very small increase in the bottom-hole pressure. The 4.1-MPa (600-psi) rise in surface pressure was due mainly to increased pipe friction. The injection rate was then dropped back to 0.0113 m^3/s (180 gpm) for 5 days and further down to 0.0107 m^3/s (170 gpm) for 2 days. After this, the injection rate was increased to 0.0180 m^3/s (285 gpm) and held to the end of the ICFT except for a short pump of 0.0265 m^3/s (420 gpm) at 2325 on June 11 and several shut-ins. There are two especially noteworthy facts from these data:

TABLE IV-I

EE-3A SHUT-INS

Date	Time	P_o (MPa)	P_{ISIP} (MPa)	Q (l/s)
5/19/86	1651	0.0	27.9	4.4
5/19/86	1811	0.0	29.8	8.5
5/19/86	1922	0.0	30.2	10.7
5/19/86	2042	0.0	32.6	19.1
5/21/86	0941	17.8	26.9	11.4
5/22/86	0027	19.4	26.1	11.5
5/24/86	1209	22.7	26.2	11.4
5/28/86	0810	24.1	25.3	11.9
5/28/86	1513	23.6	25.1	11.1
6/04/86	1953	27.5	28.5	17.8
6/05/86	0328	26.8	28.0	10.4
6/06/86	0820	27.7	28.6	18.0
6/07/86	1244	27.9	28.9	17.7
6/08/86	1255	27.6	28.4	11.0
6/08/86	1737	27.2	28.1	17.5
6/10/86	0937	28.1	29.5	18.0
6/16/86	1053	27.7	29.5	17.9
6/18/86	1601	28.6	29.6	10.1

1) The bottom-hole injection pressure changed only slightly in response to large changes in injection rates.

2) The pumping pressure at a given pumping rate stayed fairly constant.

It is concluded from this behavior that the fractured region began to "inflate" with fluid soon after injection began.

b. Early Time Data. Figures IV-2 and IV-3 show the injection pressure versus time plot for the initial step flows of 0.0044 m^3/s (70 gpm) and 0.0085 m^3/s (134 gpm), respectively. During the initial pressure rise in both buildups, water was being stored in the wellbore and the rapid pressure increase is due to fluid and wellbore compressibility. Figures IV-2 and IV-3 indicate that the wellhead

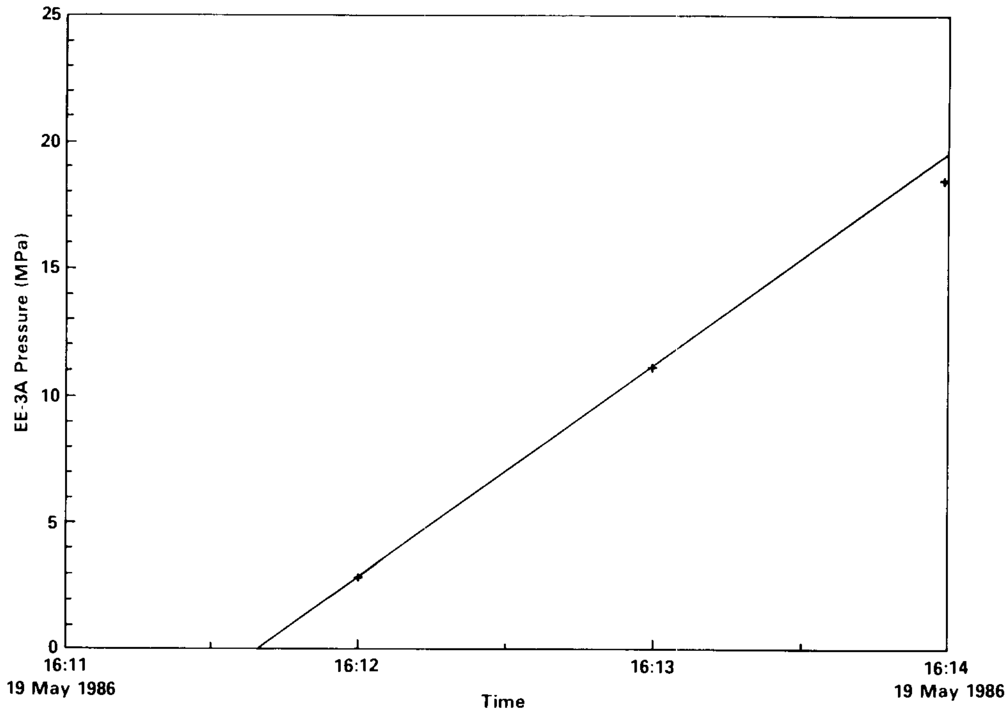

Figure IV-2. EE-3A pressure buildup during first step-rate test.

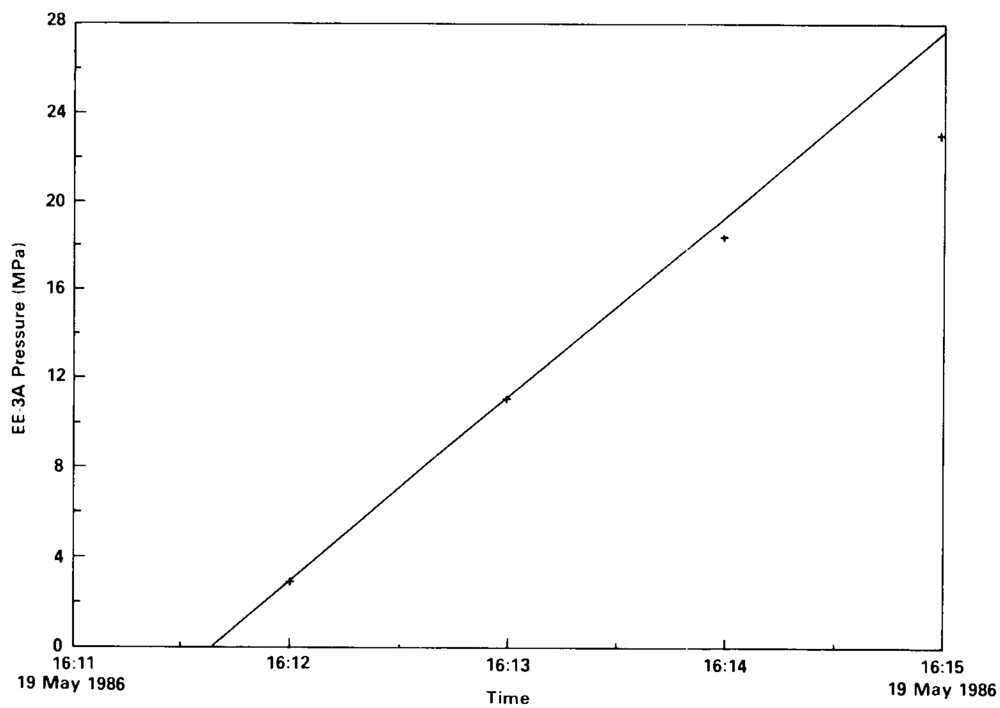

Figure IV-3. EE-3A pressure buildup during second step-rate test.

pressure starts deviating from straight-line behavior at about 17.2 MPa (2500 psi), indicating the threshold pressure at which fluid began to flow into the formation. This value agrees with the previous findings listed in Table IV-II. From the initial slope of these curves, the wellbore compressibility is estimated to be between 6.5×10^{-4} MPa^{-1} and 7.0×10^{-4} MPa^{-1} (4.5×10^{-6} psi^{-1} and 4.8×10^{-6} psi^{-1}).

c. Fracture Closure Stresses. The EE-3A wellhead pressure, injection flow rate, surface temperature, and estimated bottom-hole temperature and pressure are given for several different times in Table IV-III. The bottom-hole values were calculated using the WBHT code, which accounts for heat transfer with the formation as well as for variations in fluid density, viscosity, pipe friction, and hydrostatic head.

Bottom-hole pressures are plotted versus the square root of their flow rates in Fig. IV-4 for several previous experiments and the ICFT. A linear relationship in these coordinates is expected based on the assumption of turbulent flow through a fracture parallel with an opening, or aperture, which varies linearly with pressure excess over the fracture closure stress. Extrapolated back to zero flow rate, these curves yield the theoretical bottom-hole fracture closure pressures for each experiment. In the case of this experiment (2067, or ICFT), two sets of data were used, one grouping the initial pumps of 0.0044,

TABLE IV-II

COMPARISON OF EXPERIMENT 2067 RESULTS WITH PREVIOUS TESTS

	Initial Pump Data		Shut-In Data	
Experiment Number	Compressibility (MPa^{-1})	Deviation from Straight Line (MPa)	ISIP (MPa)	Slope ($MPa/min^{1/2}$)
2049	3.9E-4	22.8	29.6	1.4
2057	10.2E-4	13.8	29.9-31.7	1.7-2.2
2059	6.4E-4	8.3	34.5	2.0
2061	5.1E-4	<6.9	38.4	0.43
2062	7.4E-4	8.3	29.5	0.97
2067	(6.5-7.0)E-4	13.8-17.2	29.8	0.12

TABLE IV-III

ESTIMATED EE-3A BOTTOM-HOLE PRESSURES AND TEMPERATURES

Time (hours)	Flow Rate (l/s)	$P_{surface}$ (MPa)	$T_{surface}$ (°C)	T_{bottom} (°C)	P_{bottom} (MPa)
0.33	4.4	25.9	9.5	235	61.7
2.0	8.5	30.2	10.0	222	65.0
3.0	10.7	29.6	11.5	227	64.9
96.0	11.4	27.6	12.5	74.2	62.8
120.0	14.6	27.6	12.0	69.8	62.3
290.4	12.3	26.2	16.0	62.4	61.3
559.2	27.3	33.1	20.0	45.0	65.5
590.4	17.6	31.0	17.5	47.9	65.3

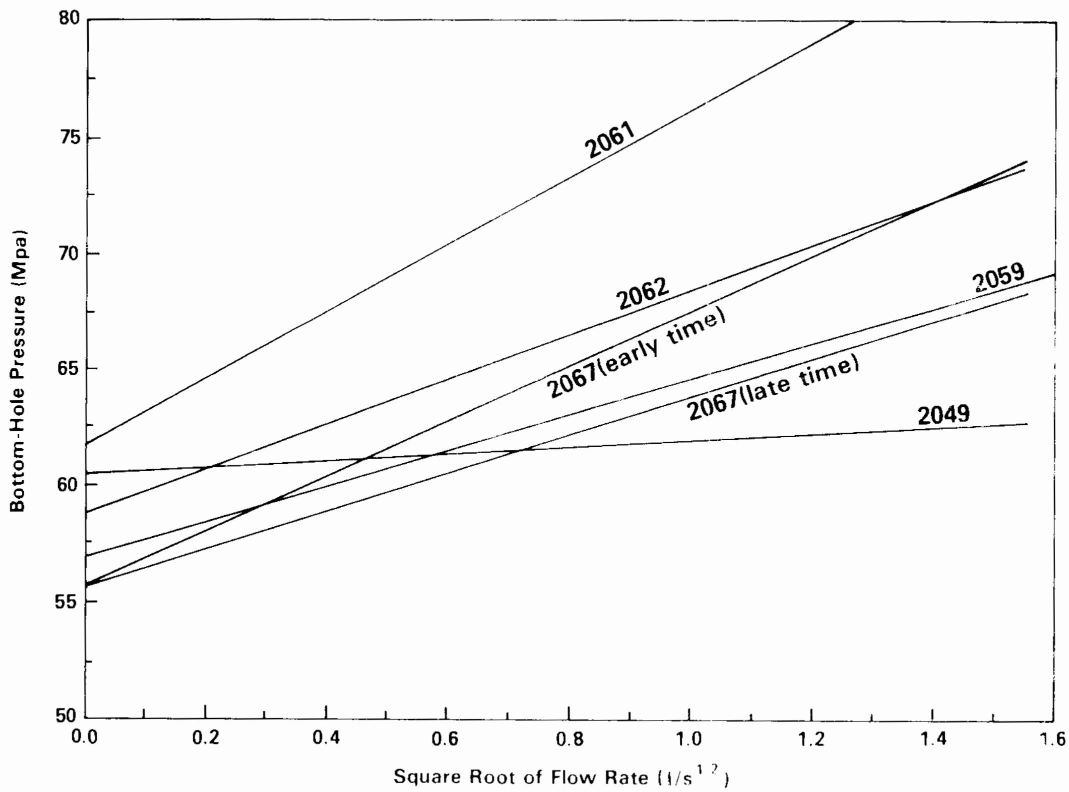

Figure IV-4. Bottom-hole fracture closure pressure for five experiments.

0.0085, and 0.0107 m^3/s (70, 134, and 170 gpm), and another consisting of data obtained during later steady flows. Although the slopes for these two data sets are different, they indicate approximately the same bottom-hole fracture closure stress of 55.6 MPa (8070 psi), or 19.7 MPa (2850 psi) at the surface. This value is about 3 MPa (435 psi) lower than that obtained in Expt. 2062 and is quite close to that obtained from Expt. 2059. This indicates that significant volumes of water went into the connections created previously by these two experiments.

d. Shut-Ins. The final shut-in occurred after 30 days of pumping at various rates. At the injection well (EE-3A), the surface pressure transient exhibited the expected sudden drop of 2 MPa (290 psi) because of wellbore friction followed by a more gradual decay. Assuming that the pressure drop is caused by a discharge of wellbore fluid into the formation through fracture faces, with no tensile fracture extension (i.e., the fluid pressure is below the closure stress), the estimated initial shut-in pressure (ISIP) using the square-root-of-time method is 29.8 MPa (4318 psi), as shown in Fig. IV-5. The slope of this curve is 0.1 $MPa/min^{1/2}$ (18 $psi/min^{1/2}$). This is about an order of magnitude less than values obtained during past tests (Table IV-II).

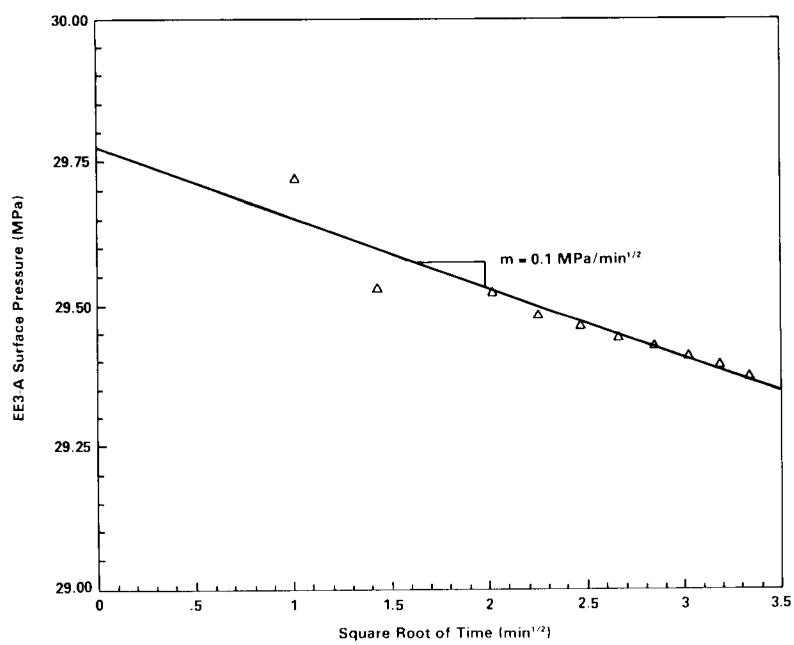

Figure IV-5. Shut-in curve for the final shut-in.

With the hope of spotting some orderly trend to explain this discrepancy, the slopes of the linear regions of all the shut-in curves were plotted versus the total volume of injected water to the time they occurred (Fig. IV-6). A sharply decreasing trend is noted in this figure, with the curve leveling off around 0.1 - 0.2 MPa/min$^{1/2}$ after the injection of about 8000 m^3 (2.1 million gal.). As shown in Fig. IV-7, the qualitative character of the shut-in pressure response also changes during injection. This suggests that perhaps the standard method (Hickman and Zoback, 1983) of determining ISIP is not valid after a large amount of fluid (i.e., approximately 3800 m^3, or 1 million gal.) is pumped into a reservoir. The reason for the decreasing slopes is thought to be due to the inflation of the reservoir. As more and more fluid is pumped into the formation and the reservoir approaches a pseudo steady state, local pressure gradients decrease, leading to reduced flow.

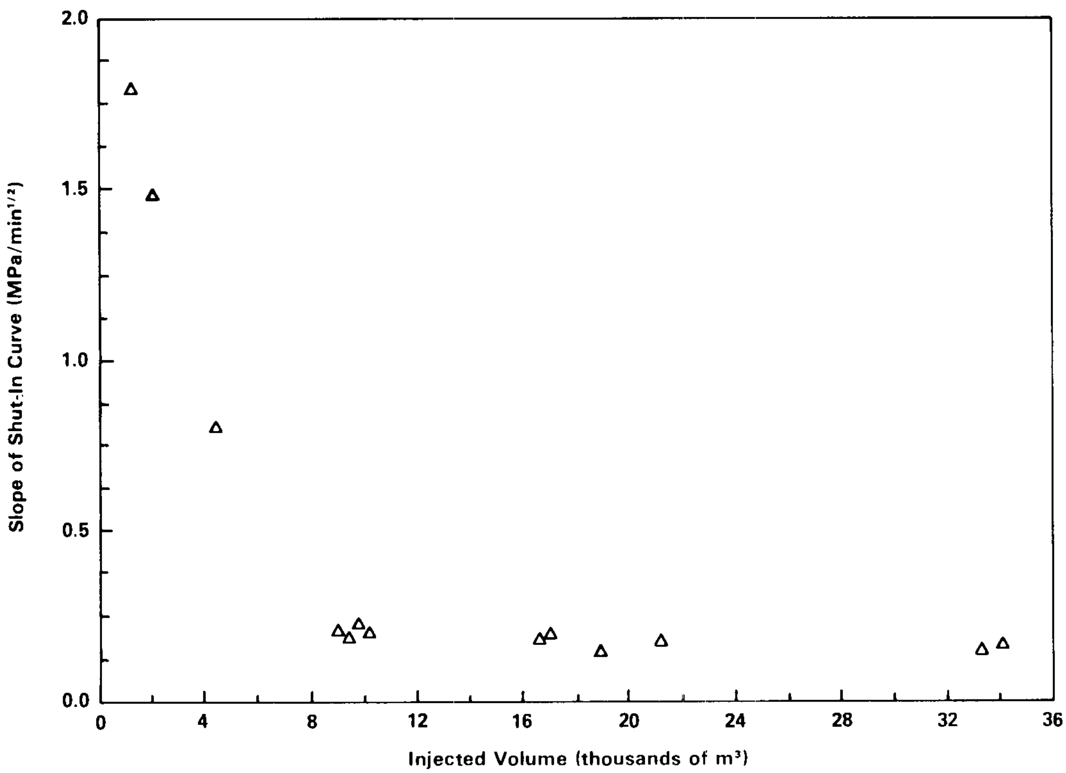

Figure IV-6. Slope of shut-in curves versus volume injected for EE-3A falloffs.

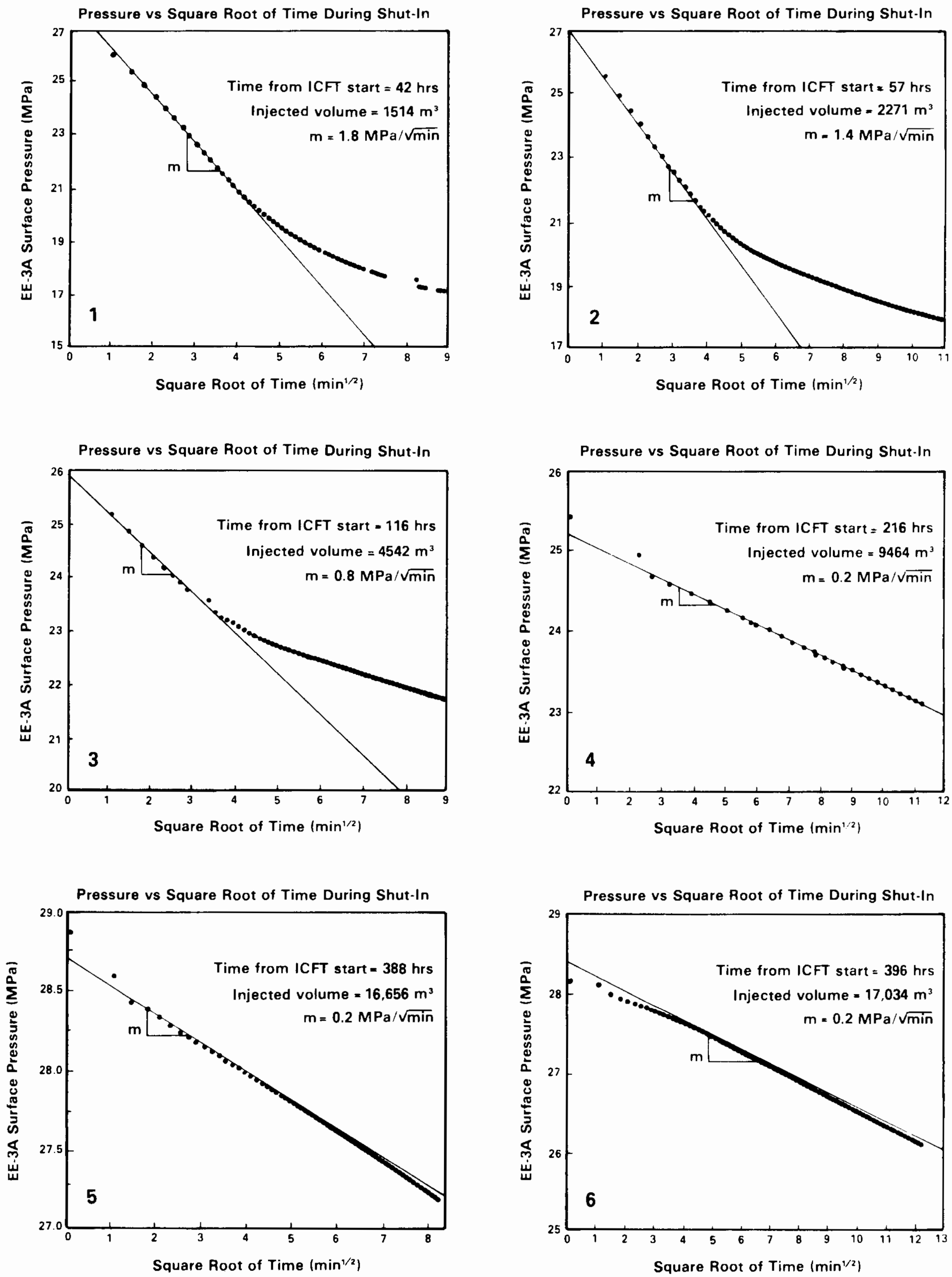

Figure IV-7. Six different shut-in curves during the ICFT.

Figures IV-8 and IV-9 are Horner curves for the wellhead pressures at EE-3A and EE-2, respectively. Assuming an injection zone of 150 m (492 ft) in height, the average permeability near EE-3A is 30×10^{-15} m^2 (30 md) and the skin factor is about -1. Around EE-2, the data were more ambiguous. Again assuming a 150-m production zone, the average permeability varied between 2×10^{-15} to 3×10^{-15} m^2 (2 to 3 md) and the skin factor varied between -3 to -2. The variability of results is due to little or no wellbore storage effect, making the location of a linear region rather arbitrary. The negative skin factors denote the expected presence of fractures, and the range of permeabilities is of the expected order of magnitude.

Another use for the fall-off curve is to identify the equilibrium pressure of the reservoir after a long shut-in (often denoted as p^*). Figure IV-8 shows that, on the surface, p^* of the Phase II reservoir is 29.0 MPa (4200 psi), or about 64.8 MPa (9400 psi) bottom hole. Using an overall compressibility of 3×10^{-5} MPa^{-1} (2×10^{-7} psi^{-1}) and a water-loss volume of 13 680 m^3 (3.61 million gal.), a total reservoir volume of 16.3×10^6 m^3 (4300 million gal.) can be derived. This volume compares well with that of a sphere of radius 150 m (492 ft). Looked at another way, a p^* of 29 MPa (4206 psi) leads to a fracture volume porosity of 0.08%.

Fracturing pressures are summarized in Table IV-IV, comparing the values obtained during the ICFT with those of the 1985 redrilling campaign. Figure IV-10 shows that the new values follow the same general trend with depth, falling around a pressure gradient of about 19 MPa/km (0.8 psi/ft). Also, the fracture closure stress obtained from the shut-in data is lower than that extrapolated from the ISIP method, again remaining consistent with previous results.

2. Analysis of EE-2 Data. EE-2 production pressures and rates were controlled by maintaining a fairly constant back pressure on the well. The wellhead pressure was generally maintained between 1.4 and 3.4 MPa (200 and 500 psi) so as to have single-phase flow from the well and through the heat exchangers. Notable exceptions to this occurred during various shut-ins, vents, gas kicks, and the nitrogen experiment. The pressure and flow rate data are summarized in Fig. IV-11 and compared with EE-3A in Figs. IV-12 and IV-13. The percentage of injection

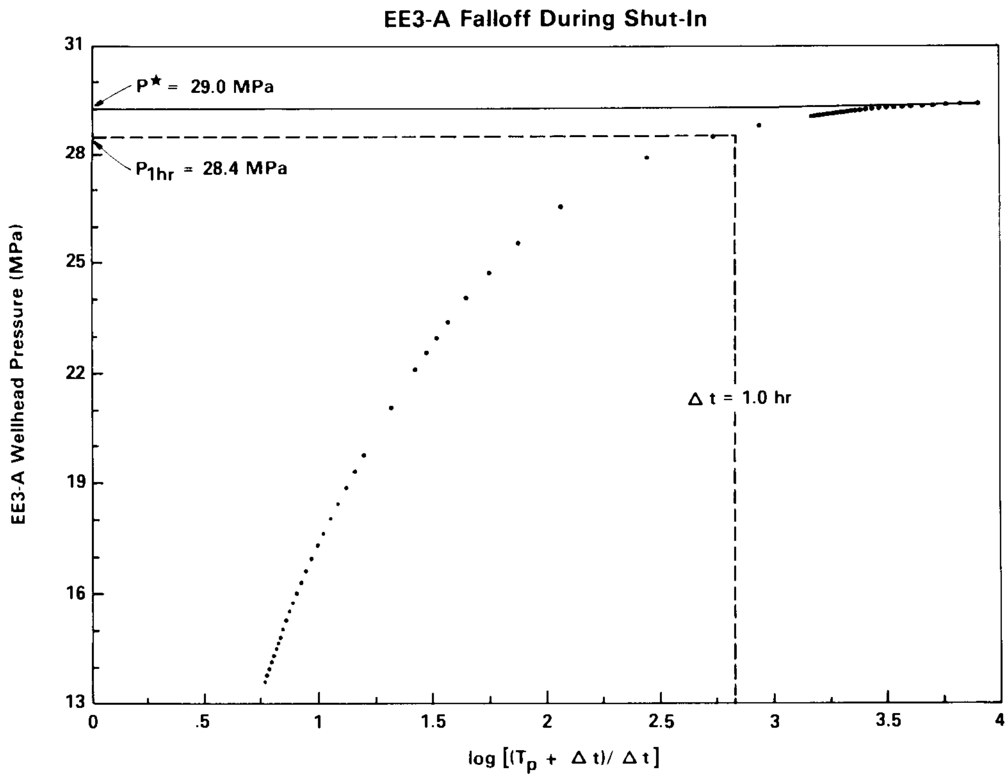

Figure IV-8. Horner curve for EE-3A wellhead pressure.

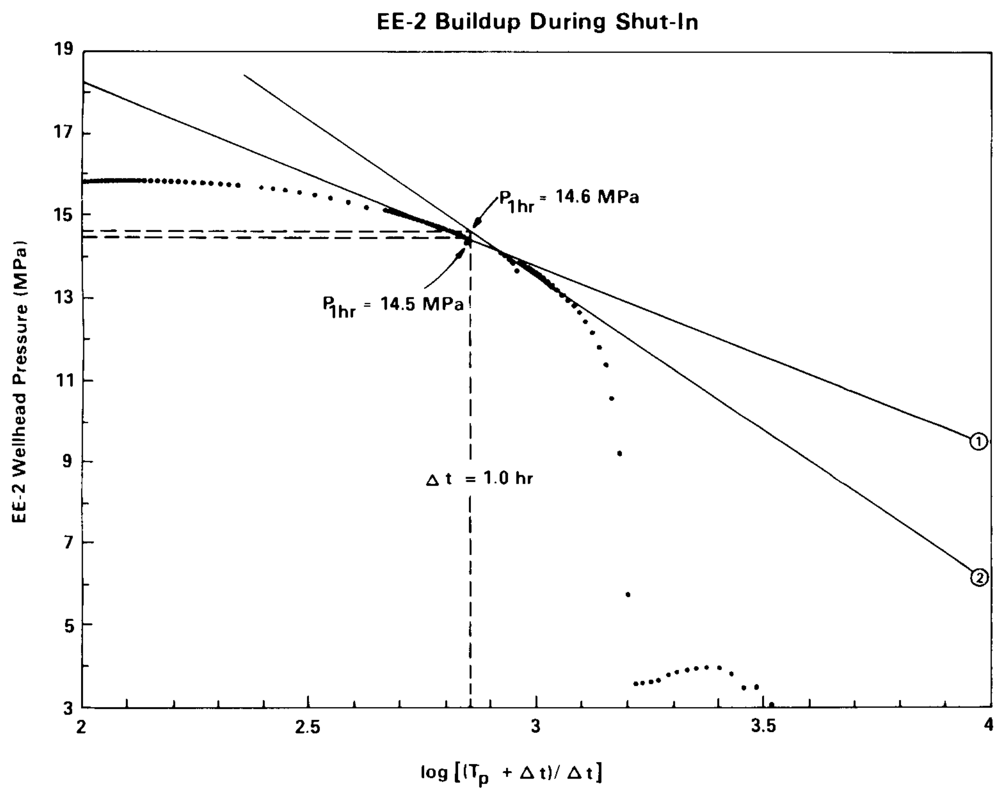

Figure IV-9. Horner curve for EE-2 wellhead pressure.

TABLE IV-IV

EE-3A FRACTURING PRESSURE COMPARISON WITH 1985 DRILLING CAMPAIGN

Expt. Number	Injection Interval (m along wellbore)	Fracturing Pressures (MPa) ISIP ($t^{1/2}$ method)	Extension Press. ($Q^{1/2}$ method)	Comments
2049	3301-3316		61.0	5.3 l/s
		60.2		10.6 l/s
		60.3		15.9 l/s
			61.8	5.3,10.6,15.9 l/s
2057	3301-3316	60.6		5.3 l/s
		62.7		15.9 l/s
2059	3516-3719 (most taken @ 3600)	69.6	56.7	connection
2061	about 4020	77.8	61.4	
2062	about 3660	64.9	59.0	connection
2067	about 3660	65.8	55.6	

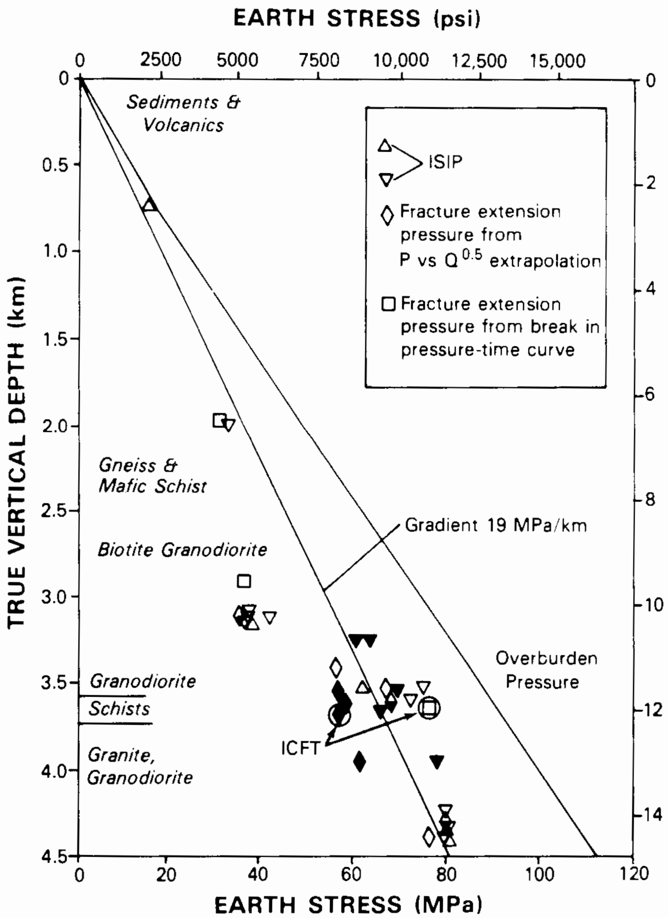

Figure IV-10. Fracture closure pressure versus depth for several experiments.

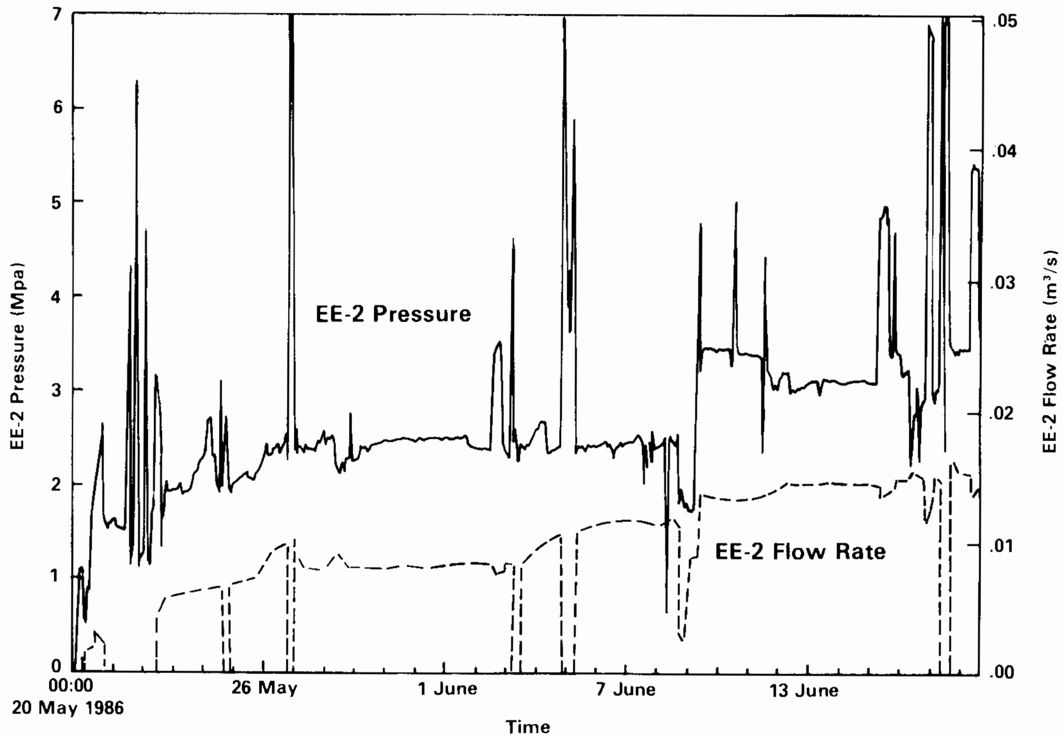

Figure IV-11. EE-2 pressure and flow rate.

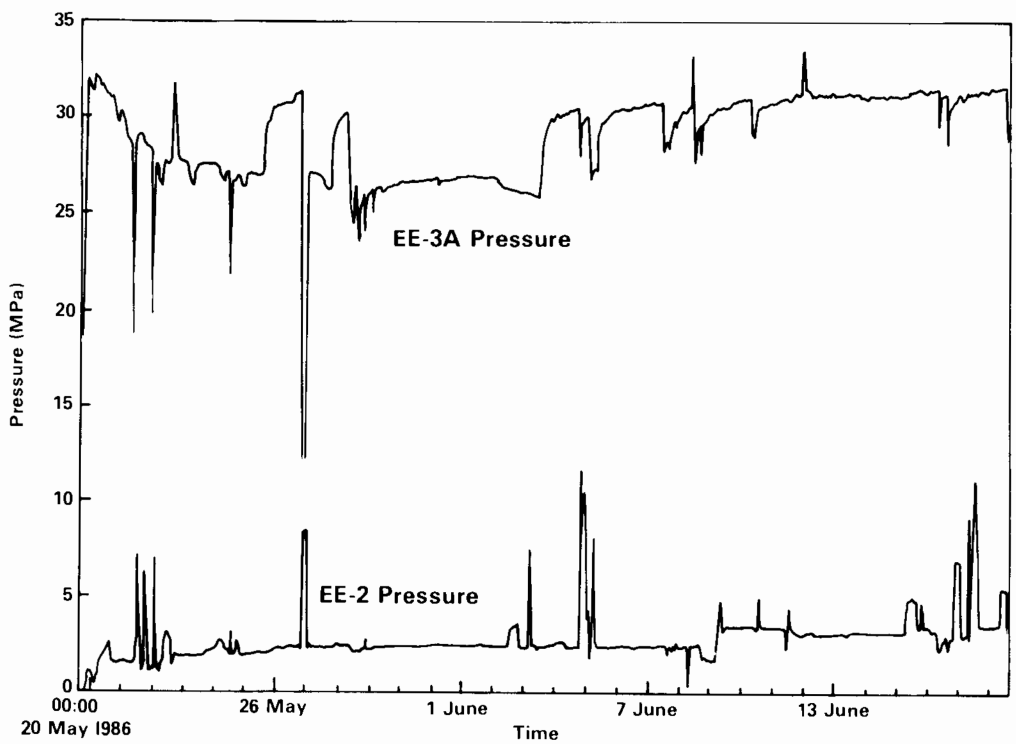

Figure IV-12. EE-2 and EE-3A pressure.

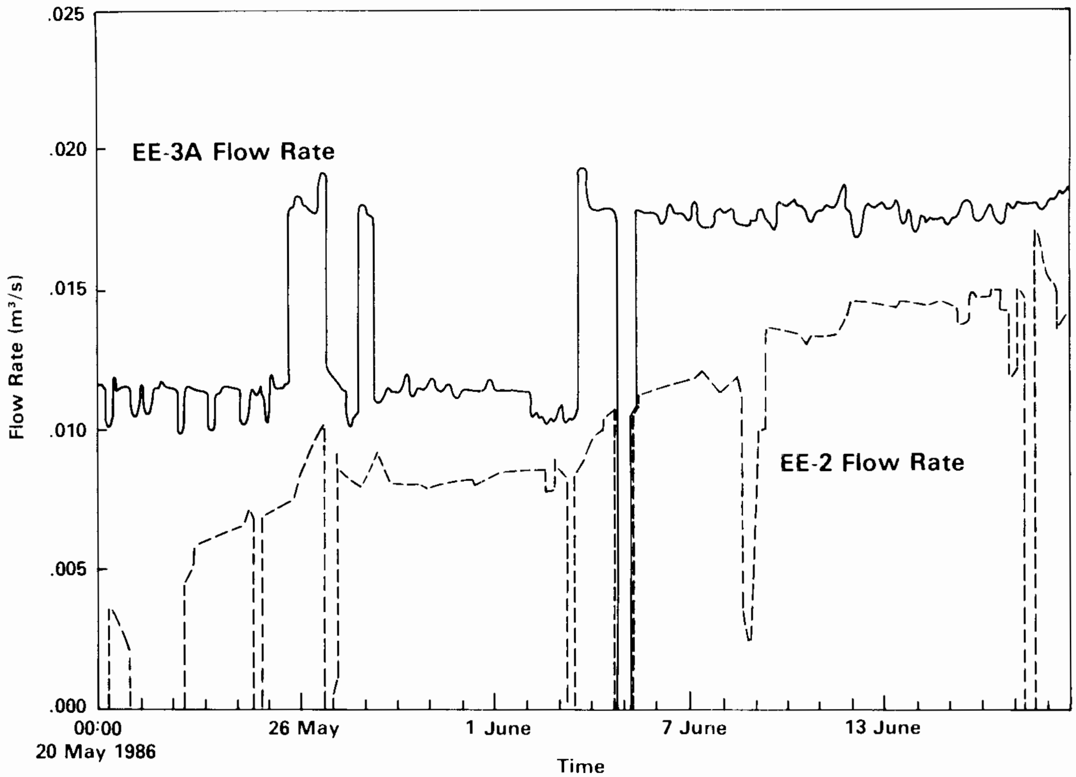

Figure IV-13. EE-2 and EE-3A flow rate.

flow that returned through the production wellbore increased throughout the flow test as the reservoir inflated to a quasi steady-state size.

Figure IV-14 shows the response of EE-2 pressure during the first 8 hours of pumping while EE-2 was shut-in. It took approximately 4.25 hours after the start of injection into EE-3A to observe a significant pressure response in EE-2. After this, the pressure increased at a rate of $1.6\text{x}10^{-4}$ MPa/s (1.4 psi/min).

3. Pressure Response at Phase I Wells. A flow connection from the Phase II reservoir to the Phase I reservoir, a pre-existing fractured region, was noted during the ICFT. Figure IV-15 shows that after 28 days of pumping into EE-3A while flowing EE-2, the two Phase I wells, EE-1 and GT-2B, experienced a pressure rise from atmospheric to 0.15 MPa (22 psi). The pressure increased steadily to 0.83 MPa (120 psi) 12 days after the final shut-in, a total increase of 0.68 MPa (98 psi).

The pressure rise in the Phase I wells was modeled by representing the fractured rock in the region previously mapped by microseismic events as a spherical region of constant pressure embedded in an

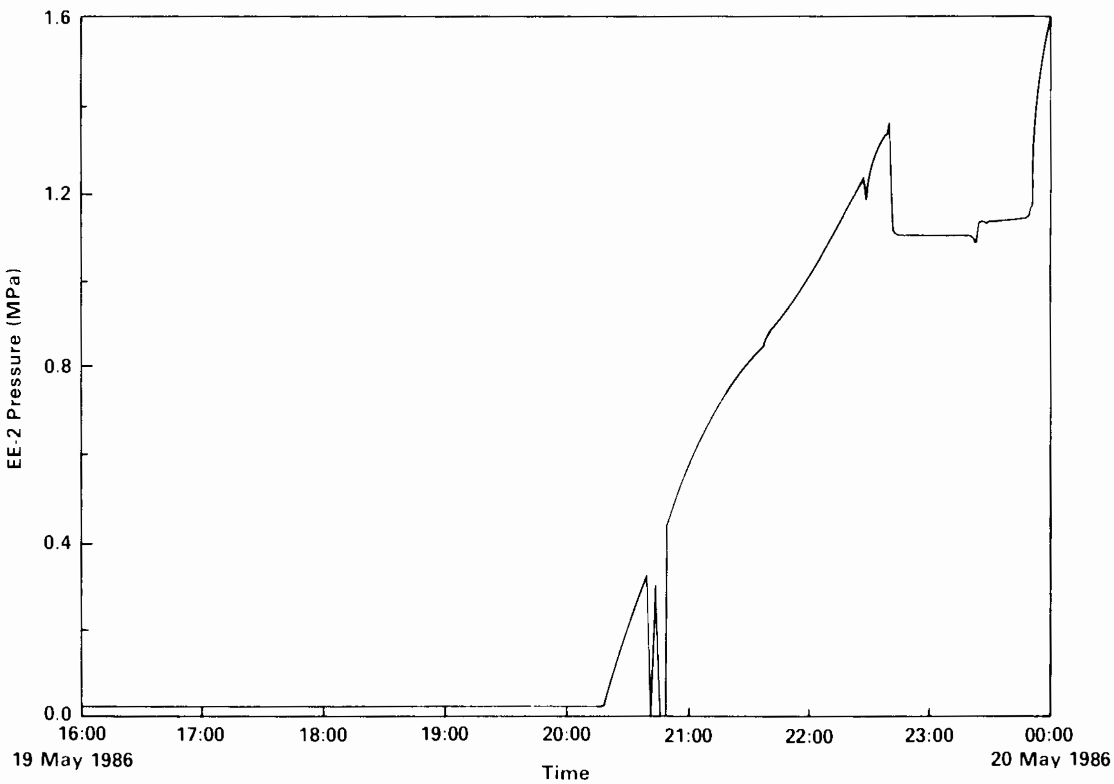

Figure IV-14. EE-2 pressure during the first 8 hours of the ICFT.

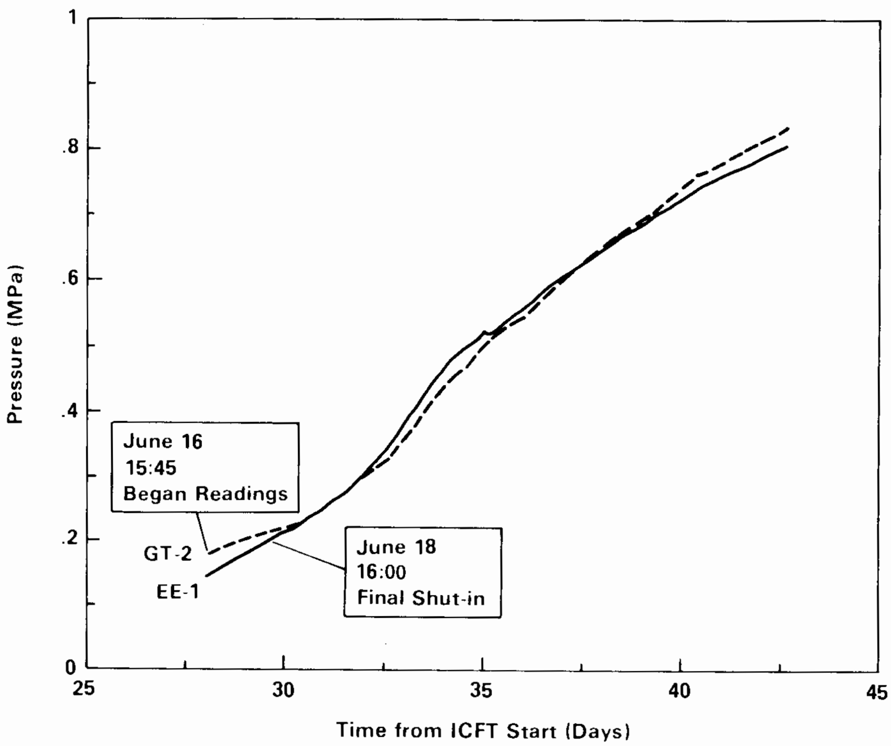

Figure IV-15. EE-1 and GT-2B response to the ICFT pressurization.

infinite homogeneous medium (Malzahn, 1986). Using an overall compressibility of 3×10^{-5} MPa^{-1} (2×10^{-7} psi^{-1}) given by Murphy et al. (1977), preliminary results indicate a regional permeability of 18×10^{-18} m^2 (18 μd). This compares well with Fisher's (1980) estimations of 5×10^{-18} to 10×10^{-18} m^2 (5 to 10 μd).

B. Impedance

Impedance is a measure of the ability of a formation to transmit fluid and is analogous to electrical resistance. It is determined by simply dividing the pressure drop across a segment by the flow rate exiting the segment.

Reservoir impedance, calculated by removing the wellbore effects from the data, differs from overall impedance because of correction of the pressure drop for buoyancy and pipe friction, thereby eliminating the effects of depth and the pumping system. Figure IV-16 shows that the reservoir impedance decreased throughout the ICFT, going from 7 GPa·s/m^3 (64 psi/gpm) to 2 GPa·s/m^3 (18 psi/gpm) over the 30-day test with the most rapid decrease occurring during the first week of injection. This is due to hydrothermal stimulation along the fracture surface, especially near the injection wellbore.

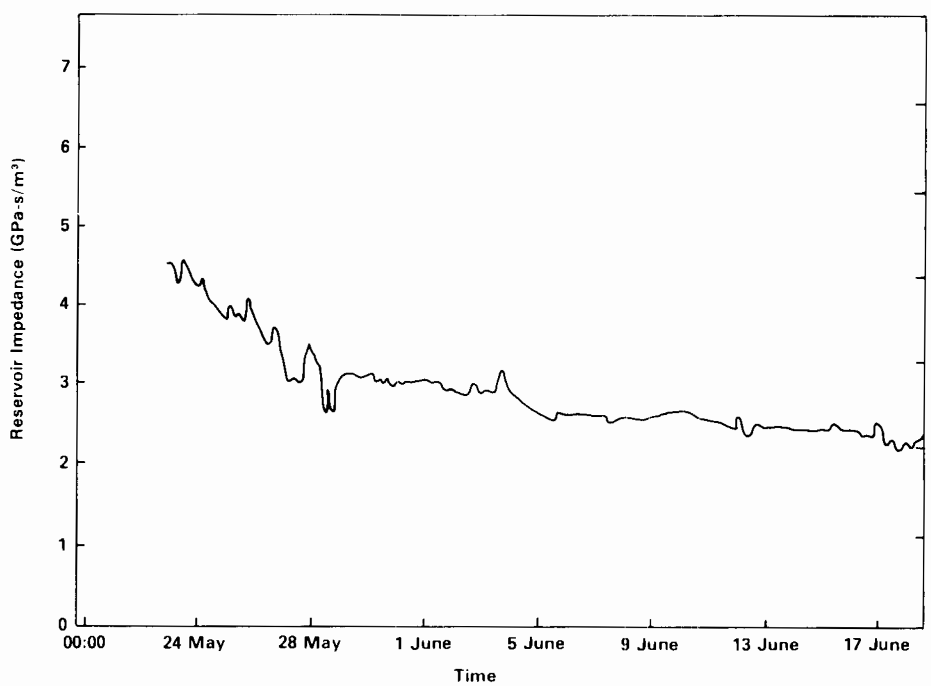

Figure IV-16. Overall reservoir impedance.

Near-wellbore impedance describes the part of the reservoir impedance immediately surrounding the wellbore and is found by subtracting the surface pressure from the instantaneous shut-in pressure, correcting this amount for buoyancy and friction, and then dividing by the surface flow rate immediately before the shut-in. Figure IV-17 shows that the EE-3A injection well impedance dropped rapidly during the first half of the test from 0.7 GPa·s/m^3 (6.6 psi/gpm) to 0.002 GPa·s/m^3 (0.02 psi/gpm), while the decrease at the production well, EE-2, was much more gradual. This may indicate that the EE-2 wellbore is damaged or otherwise restricted, e.g., by the short open-hole reach below the casing shoe and/or the casing restriction at 3200 m (10 500 ft).

C. Water Loss

There were four mechanisms of water loss operating during the ICFT: 1) reservoir extension indicated by microseismic activity; 2) reservoir inflation of the active reservoir and the static regions of several previous fracture experiments; 3) flow into the Phase I system; and 4)

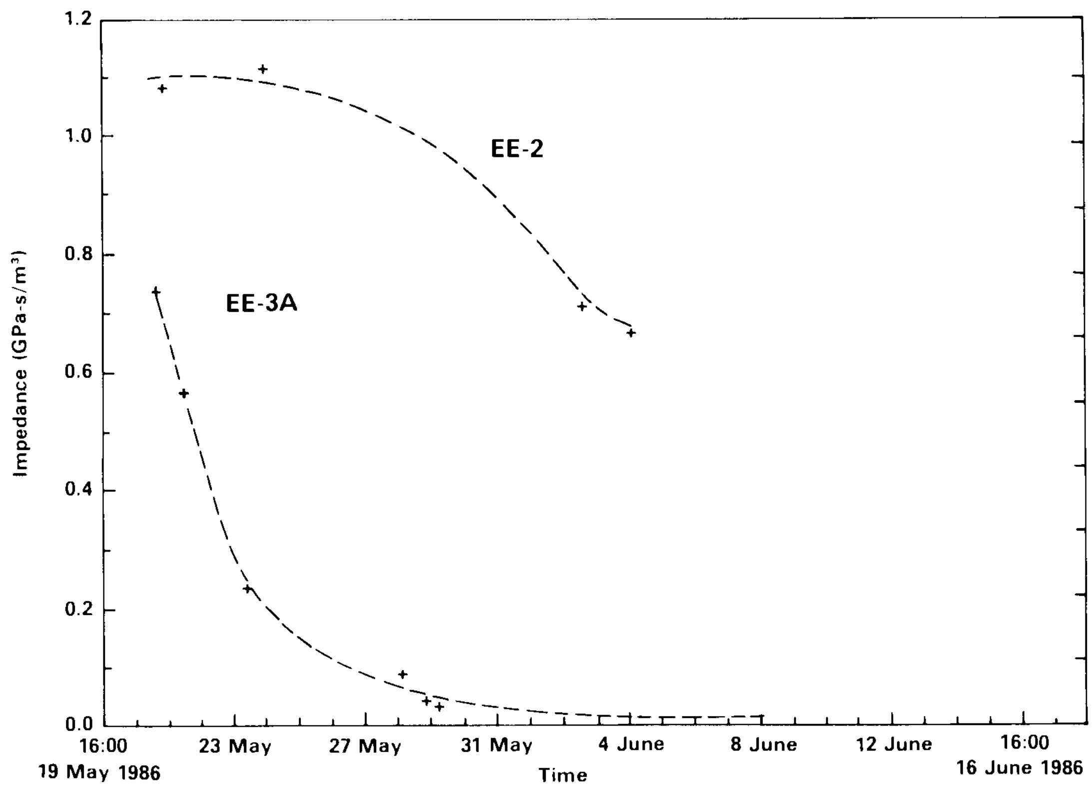

Figure IV-17. Wellbore impedance for EE-3A and EE-2.

leakoff into secondary porosity (i.e., into the country rock surrounding the fracture).

To calculate the cumulative water loss, the difference between the cumulative injection, 36 950 m^3 (9.76 million gal.), and the cumulative production, 23 270 m^3 (6.15 million gal.), was used as a first estimate giving 13 680 m^3 (3.61 million gal.). This does not account for the times that the production well, EE-2, was being vented to the EE-1 pond. An estimated 950 m^3 (0.25 million gal.) of water was vented based on log book records and data observations of the length of the vent and the previous flow rate from EE-2. This leaves approximately 12 730 m^3 (3.36 million gal.) of water lost during the experiment.

As shown in Fig. IV-18, the largest water loss occurred near the beginning of the ICFT, as the formation inflated. As the reservoir approached a quasi equilibrium, water loss averaged 30% of the injected volume, with a low of 26%. At this point, loss was due to reservoir extension, loss to the Phase I system, and leakoff into the surrounding rock.

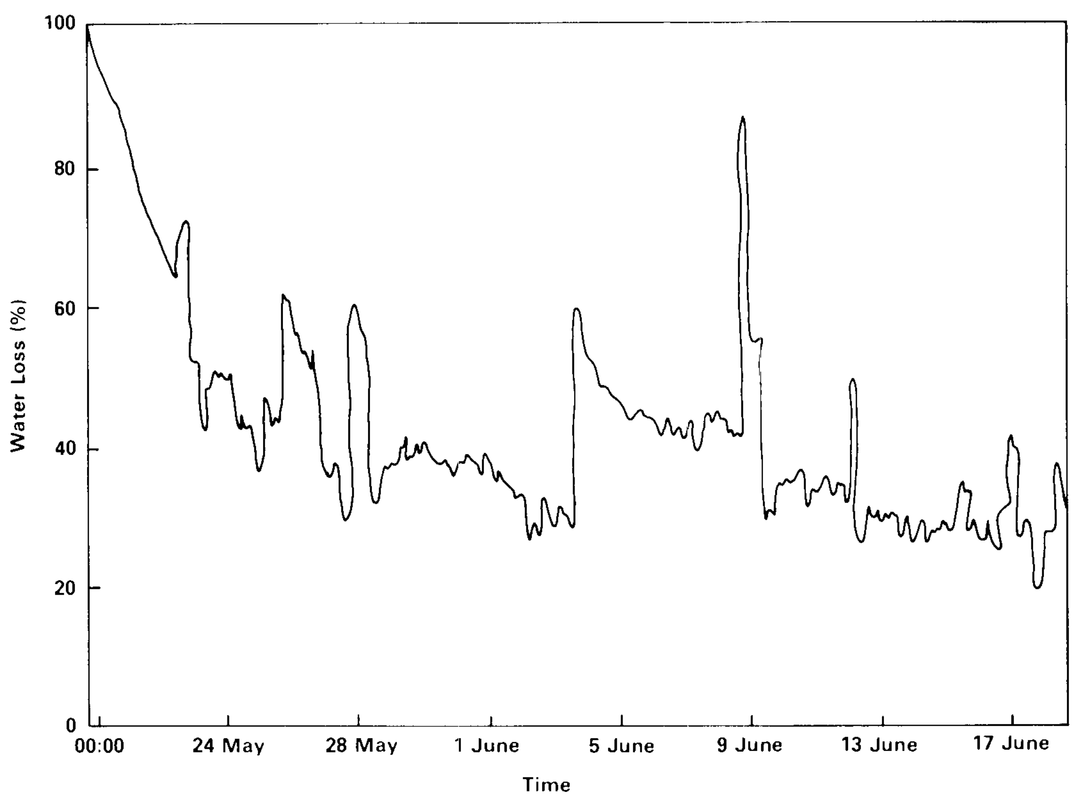

Figure IV-18. Percent water loss.

V. GEOCHEMISTRY AND TRACERS

A. Geochemistry Data

1. Sampling Apparatus and Procedures. The apparatus used to collect produced fluid gas and liquid samples is shown in Fig. V-1. Hot, pressurized fluid from a side stream off the production wellhead flowed to a small chemistry laboratory containing this equipment. The fluid was cooled under pressure in a heat exchanger and directed to the various apparatus in the figure either manually or automatically, depending on the sample being collected. Filtered and unfiltered liquid samples were collected manually through the ports labeled 1 and 2. Alternatively, fluid passed through an instrumented manifold kept at a pressure sufficient to prevent degassing. The eH, pH, and electrical conductivities of the fluid were recorded automatically in this manifold. The gas separation equipment on the right side of the figure supplied gas samples for the gas chromatographic and radon analyses. This separator was operated continuously, with gas samples directed

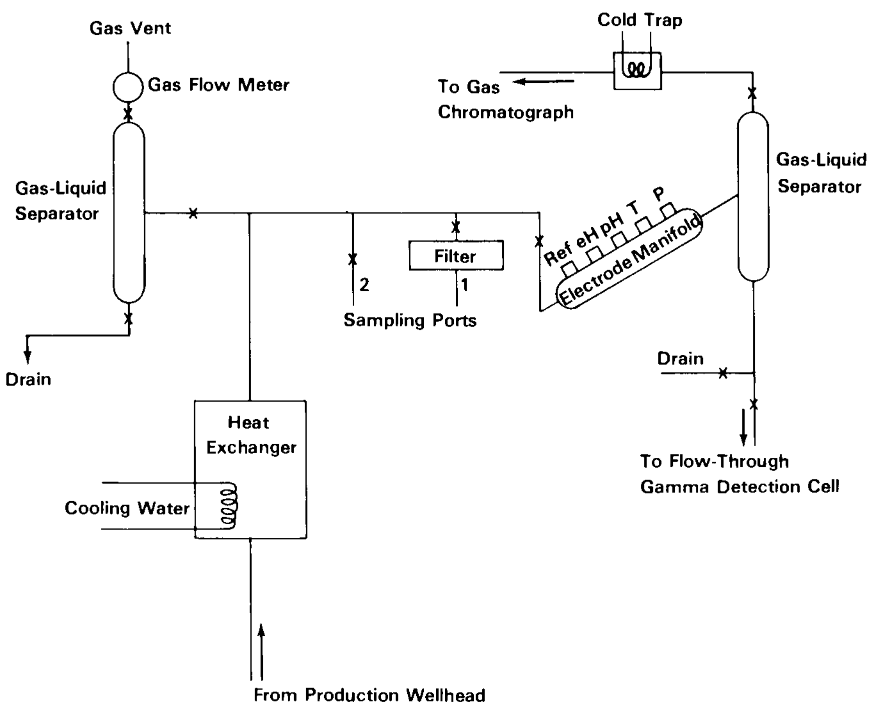

Figure V-1. Schematic of the sampling apparatus for production fluid liquids and gases.

periodically to the gas chromatograph after passing through a cold trap to remove any remaining moisture. In addition, the liquid effluent from this separator was directed to the gamma counter during the radioactive tracer experiments.

The other gas separation unit was used to measure gas and liquid flow rates simultaneously to obtain the gas mass fraction in the produced fluid. The separator was manually adjusted to achieve a constant liquid level and gas flow rate, and the gas and liquid flow rates were measured simultaneously. Since the gas was predominantly CO_2, the concentration of CO_2 (in weight percent) in the produced fluid was determined directly.

The procedures employed at Fenton Hill for analyzing gas and liquid samples for dissolved anions, cations, gas concentrations, suspended solids, and other species are described in detail by Trujillo et al. (1987).

2. Major Dissolved Species. Figure V-2 shows the concentration-time behavior of the major dissolved anions and cations in the produced fluid. Table V-I shows the concentrations in a sample collected 6 days

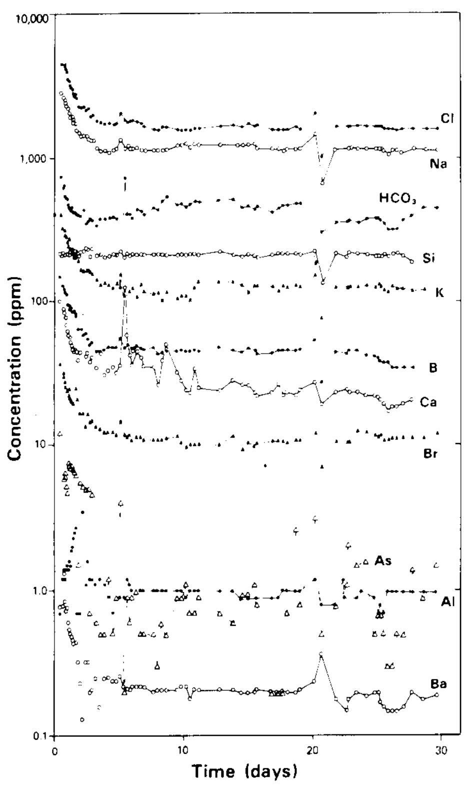

Figure V-2. Concentration-time behavior of the major dissolved species in the production fluid.

TABLE V-I

TYPICAL ION CONCENTRATIONS
(Sample Collected on Day 6)

Component	Concentration (ppm)
As	0.6
B	48
Br	11.5
Ca	42
Cl	1814
F	10.4
Fe	2.1
HCO_3	408
K	114
Li	23.4
Na	1180
pH	5.79
SiO_2	452
SO_4	183
TDS	4300 (I = 0.05 m)

into the flow test, after the geochemical behavior had reached a quasi steady state. The concentrations of most species are two to three times higher than in previous reservoirs, probably because of higher reservoir temperatures and a larger contribution from the in situ pore fluid. The total dissolved solids value of 4300 ppm, equivalent to ionic strength I = 0.05 m, is low enough that major brine-handling problems are not expected.

3. Noncondensable Gas Analyses. Gas analysis consisted of total gas flow rate (Fig. V-3) and gas chromatograph analysis of the dry gas composition. After the initial transient in the first few days of the flow test, the average gas flow rate was about 0.2% CO_2 by weight. Dismissing the high gas flow rates during a nitrogen injection experiment on day 20, the highest values were observed during the experiment

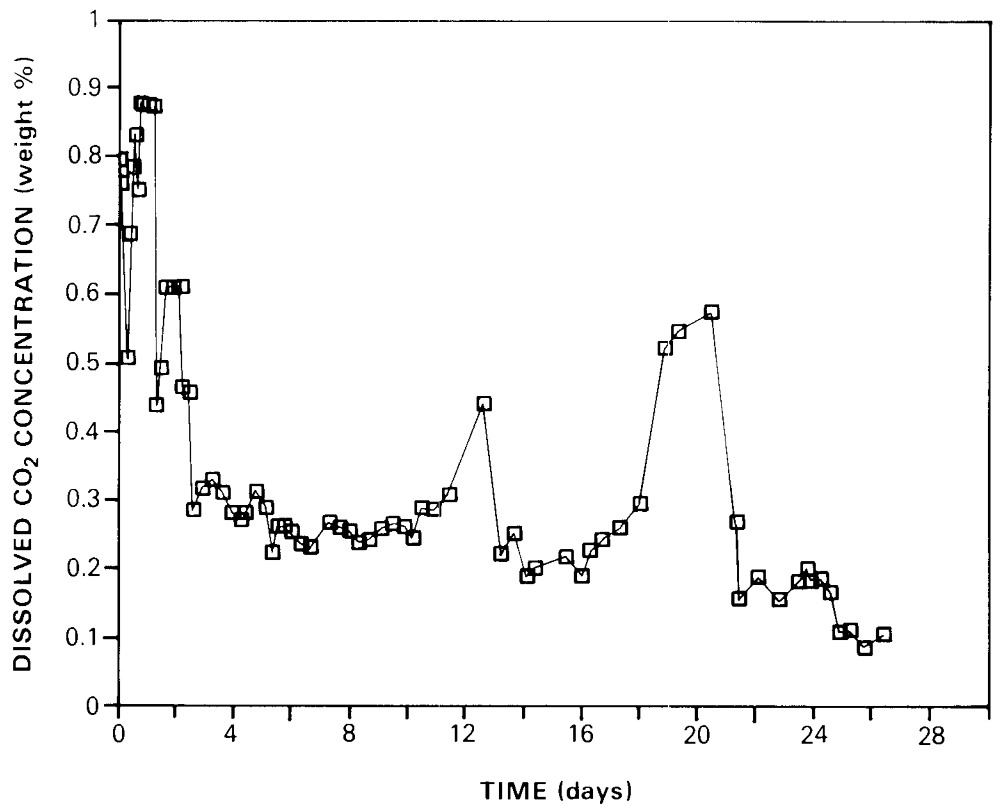

Figure V-3. Dissolved CO_2 concentration in the production fluid.

start-up. The high value of 0.9% is the best estimate of the CO_2 concentration in the pore fluid. Higher gas concentrations may have been present during periods of two-phase flow, but our sampling apparatus did not enable us to obtain a representative sample of the fluid during two-phase flow.

Gas chromatograph analyses determined the dry gas to be predominantly CO_2 (typically 90-95%), with lesser quantities of N_2, minute amounts of H_2S, O_2, and occasionally CH_4 and C_2H_6.

B. Interpretation of Geochemistry

1. Time-Dependent Behavior. When fluid of different concentration than the underground pore fluid is injected into a circulating HDR reservoir, the resulting produced fluid geochemistry behavior will be governed by three mechanisms: 1) displacement of the downhole fluid by the injected water; 2) rock-water dissolution, precipitation, or alteration reactions; and 3) adsorption of chemical species on the reservoir rock. Throughout most of the flow test, the downhole, injection, and

makeup fluids were all at similar concentrations (approximately those listed in Table V-I). However, early in the test the inlet and outlet concentrations were different and can be interpreted most effectively by defining a nondimensional concentration C* (Grigsby, 1983):

$$C^* = \frac{C - C_{in}}{C_o - C_{in}} \quad ; \tag{V-1}$$

where C_{in} is the injection concentration and C_o is the initial produced fluid concentration, which is the true downhole concentration of the component if the sample is collected immediately after the wellbore fluid is displaced. (A summary of geochemistry nomenclature is provided in Appendix D.) The most common behavior is that of an inert, nonadsorbing species, which behaves like a tracer for a negative step change in injection concentration. Injected fluid gradually sweeps the concentrated underground pore fluid from the reservoir until the produced fluid concentrations approach the injection values (Fig. V-4).

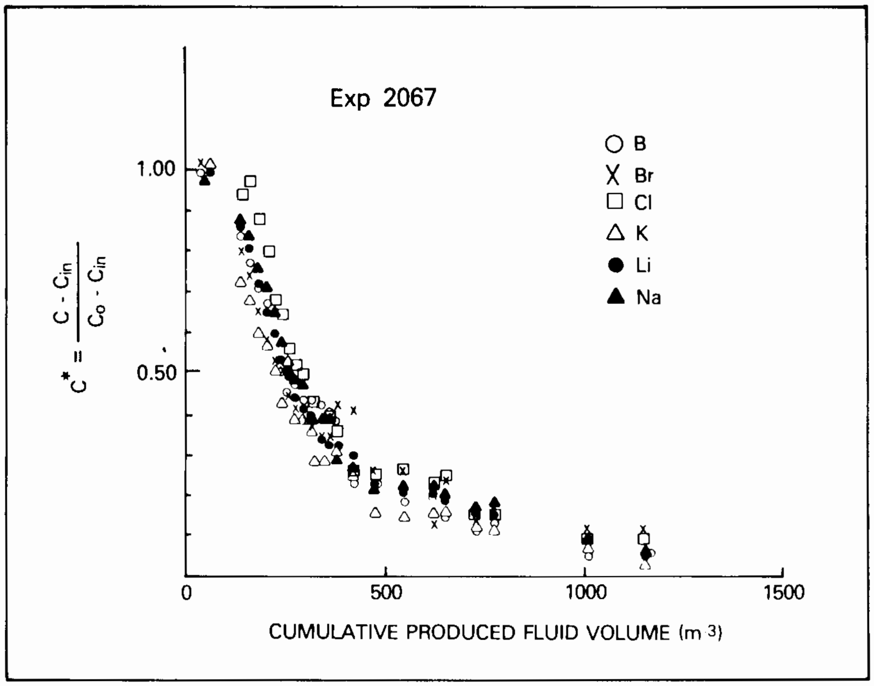

Figure V-4. Dimensionless concentration versus produced fluid volume for inert species during initial reservoir operation. Concentrations start at high downhole values and decline to injection fluid concentration.

Chloride ion, Cl, as well as B, Br, K, Li, Na, electrical conductivity, and total dissolved solids all fall in this category.

Two other characteristic concentration-time responses are exhibited in Fig. V-5. The dissolved silica concentration remained constant during the initial sweep of pore fluid from the reservoir and throughout the entire 30-day test. Quartz dissolution supplies a constant source of silica to the undersaturated injection fluid, allowing the solution to reach equilibrium in one pass through the reservoir. The third type of time-dependent behavior is for species whose concentration decreases to a value below the injection value. This result implies consumption of the component, either by adsorption on the rock surface or precipitation reactions. Divalent cations such as magnesium clearly show a propensity to adsorb on granite, and, as shown in the figure, fall into this third category. Calcium, bicarbonate, and iron also exhibit this behavior, although the mechanisms for these three components are as yet unclear. Finally, a few species such as Ba, Mn, and SO_4 exhibit anomalous time dependences, which have not been explained.

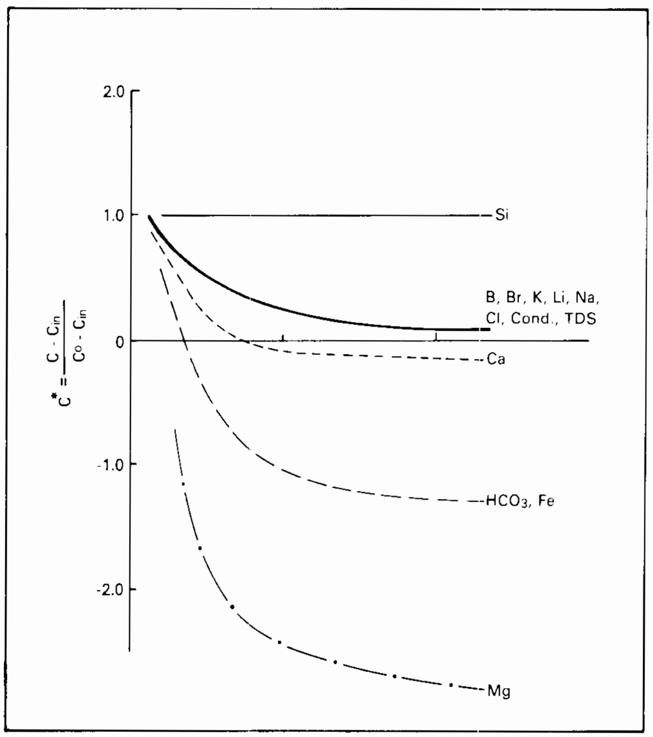

Figure V-5. Different types of concentration-volume behavior observed during initial reservoir operation.

2. <u>Sources of Dissolved Species</u>. The origin of dissolved species in hot dry rock geothermal fluids has been treated by Grigsby et al. (1983). The two primary sources of dissolved species are displacement of downhole pore fluid and dissolution of minerals. Current models postulate a continuous extraction of the original pore fluid from the fractured rock mass over long periods of time. The most compelling argument supporting this theory is the presence and continued supply of chemically inert species such as boron and chloride, which are not found in the reservoir granite and hence are not supplied by a dissolution reaction.

Since most reservoir fluid samples are composed of the original downhole fluid after dilution with injected fluid, true values of the pore fluid concentrations are difficult to obtain. Grigsby (1983) has demonstrated that even when the pore fluid is diluted, the ratios of ions in solution should remain constant for conservative species supplied only by pore fluid rather than by mineral dissolution or alteration. When the concentration of one component is plotted directly against another, the data should fall on a single straight line if the source of the pore fluid is the same. Figure V-6 is a plot of boron

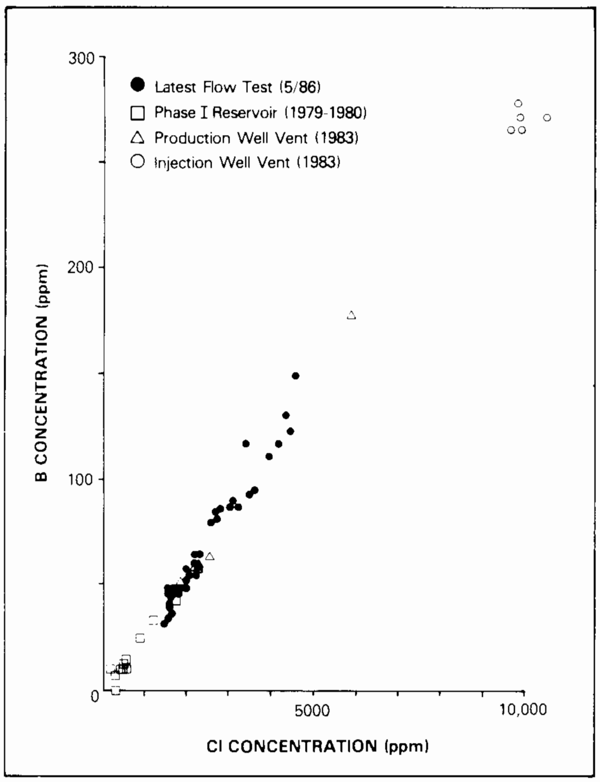

Figure V-6. Boron versus chloride for fluid samples collected in the Fenton Hill HDR reservoir over the past 6 years.

versus chloride for the ICFT and previous Fenton Hill circulation experiments and vents of the past 6 years. The new data all fall on the same straight lines as those for other fluid samples collected at Fenton Hill. The evidence now even more strongly supports the pore fluid hypothesis and suggests that a single underground fluid supplies the conservative species found in fluid samples at the Fenton Hill site.

Rock-water reactions are also important in the production or consumption of some species. For example, quartz dissolution controls the concentration of dissolved silica in the production fluid. The constant concentration measured during the flow test implies that the kinetics of quartz dissolution were rapid enough for the fluid to reach saturation in one pass through the system. Robinson (1982) measured the rate of quartz dissolution as a function of temperature and rock surface area and determined the following relation:

$$\ln \Phi = \ln \left[\frac{C^{\infty} - C}{C^{\infty} - C_{in}}\right] = -ka^{*}t \quad ; \qquad \text{(V-2)}$$

where a* is the quartz surface area to fluid volume ratio ($2f_q/b$ for a flat fracture, where b is the fracture aperture and f_q is the fraction of quartz present in the granite), C^{∞} is the saturation concentration, and k is the rate constant for dissolution. To obtain a minimum value for a*, or a maximum value for the average fracture aperture, the following values were used:

Φ = 0.1 (equivalent to the dissolution reaction reaching 90% of its equilibrium value),

t = 10 hours (the residence time at the peak tracer response),

k = 4.13×10^{-8} m/s at 250°C (Robinson, 1982), and

f_q = 0.3.

These assumptions yield a* = 1550 m^{-1}, or b = 0.4 mm. In other words, the average aperture encountered by fluid should be no greater than about 0.4 mm and quite possibly less in order for the system to reach saturation with respect to quartz in one pass through the reservoir. Future models for the permeability and tracer behavior of the reservoir must be consistent with this information.

Another set of reactions affecting the produced fluid chemistry is the dissolved carbon dioxide-bicarbonate equilibrium reactions, which are coupled to the calcite dissolution reaction. Carbon dioxide is present in the underground pore fluid and is produced along with other pore fluid elements. If calcite (calcium carbonate, $CaCO_3$) is present, its solubility is also affected by the presence of dissolved CO_2. For a CO_2-rich fluid in equilibrium with calcite, the following chemical reaction applies:

$$CaCO_3 + H_2O + CO_{2(g)} \leftrightarrow Ca^{2+} + 2HCO_3^- \quad , \tag{V-3}$$

with equilibrium constant K_{eq} equal to

$$K_{eq} = \frac{\gamma_{Ca}\, \gamma^2_{HCO_3}\, [Ca][HCO_3]^2}{P_{CO_2}} \quad . \tag{V-4}$$

The concentrations are in mol/l and the activity coefficients, γ, are related to ionic strength and temperature using a modified Debye-Huckel model (Henley et al., 1984). The partial pressure of CO_2, P_{CO_2}, is given by

$$P_{CO_2} = K_H\, x_{CO_2} \quad ; \tag{V-5}$$

where K_H, the Henry's law constant for CO_2, is a function of temperature, and x_{CO_2} is the fraction of CO_2 in the liquid. Using the measured values of all concentrations, and expressions supplied by Henley et al. (1984) for K_H and the γ's, we may iteratively calculate the equilibrium temperature at which these dissolved species were produced. For the 75 samples analyzed, the average calculated temperature was 211°C, with a standard deviation of 16°C. These temperatures are in reasonable agreement with the measured downhole production temperature of about 232°C, suggesting that for a given downhole P_{CO_2}, calcite dissolution is governing the equilibrium between dissolved CO_2, bicarbonate ion, and Ca. As significant changes in downhole temperatures occur due to thermal drawdown or exposure of hotter fluid flow paths, corresponding changes in these concentrations should also occur. However, to use these equilibrium reactions to evaluate reservoir temperature patterns, further refinements of the calculations will be required to explain the 20°C discrepancy between the actual and average calculated temperatures.

3. Geothermometer Readings. Since rock-mineral dissolution or alteration reactions are temperature dependent, the concentrations of certain dissolved species will depend on temperature. The calculations just presented are one example. Two more commonly used chemical geothermometers that exploit this temperature sensitivity are the quartz and Na-K-Ca geothermometers. These two measurements are shown for samples collected throughout the flow test in Fig. V-7. The recorded geothermometer temperature for quartz dissolution of about 250°C agrees fairly closely with the actual downhole temperature. The reactions governing the Na-K-Ca geothermometer do not reach equilibrium in short times, however. Thus, since the produced fluid is a mixture of the

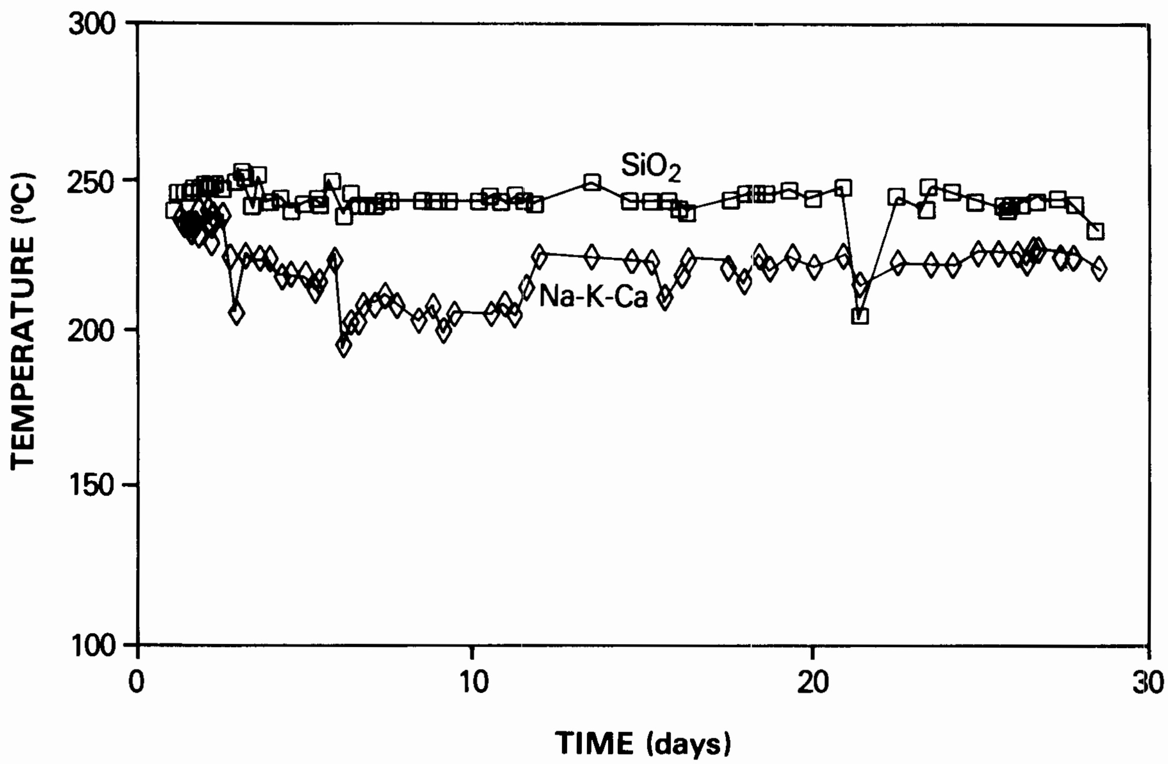

Figure V-7. Silica and Na-K-Ca geothermometer temperatures.

injection fluid and underground pore fluid, these geothermometer readings are not as precise. The Na-K-Ca temperatures decrease from essentially the known rock temperature to a somewhat lower value. In future work we will model this behavior, as well as the carbon dioxide-bicarbonate equilibrium reactions, as the mixing of fluids of different concentrations and temperatures to attempt to determine what concentrations and flow fractions are required to match the results.

C. Chemical Effects on Operations

1. Corrosion Studies. Because of the large number of metal hardware failures attributed to metallic corrosion during the drilling of the injection and production wellbores, corrosion monitoring was performed during this flow test. Of greatest concern are the high temperatures, gas concentrations, and concentrations of corrosive ions such as Cl^-. This 30-day flow test provided data for future surface loop design.

Corrosion coupons were placed on side streams off the main-stream flow on both the hot and cold sides of the heat exchanger. Each station contained two coupons attached to a coupon holder of sufficient length that the coupons were exposed to a representative sample of the fluid. The coupons were oriented parallel to the fluid flow to minimize erosion. Shutoff valves placed at both stations allowed the coupons to be removed periodically. Pressure taps were placed at the entrance and exit points of the side-stream piping to direct the fluid flow to the coupons. The coupons were analyzed periodically for corrosion rate (by measuring coupon weight loss over a specified time, typically 150 hours), type of corrosion, and scale formation.

The corrosion rates at various times during the flow test are presented in Fig. V-8. The more rapid corrosion rates occurring on the hot side of the heat exchanger are due to the higher temperature, which increases the attack of metal hardware by elemental species present in the production fluid. The highest corrosion rate of 15 mils per year (mpy), occurring with the second set of coupons, will be used as the design criterion for the surface equipment for future tests. In the final set of coupons, the dramatic decrease in hot-side corrosion rate is attributed to equipment malfunctions that prevented liquid flow from reaching the coupons.

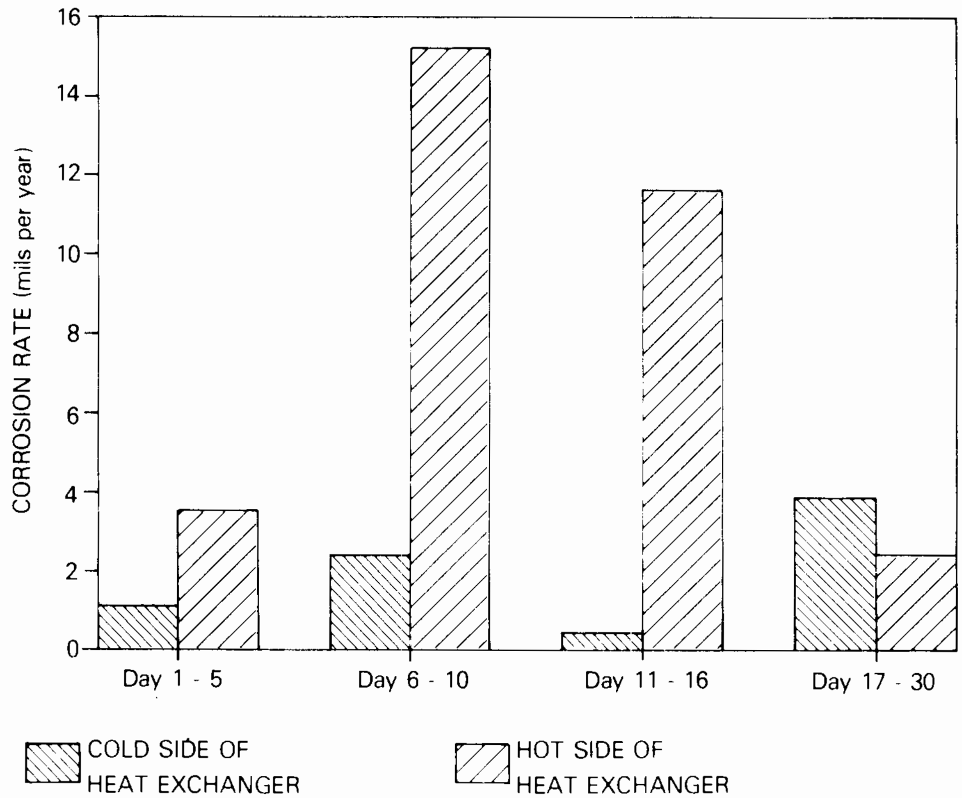

Figure V-8. Corrosion rates measured on the hot and cold sides of the heat exchanger. Each value is obtained from a determination of weight-loss for a coupon exposed to fluid during the times labeled.

The type of corrosion observed on both sample stations was generalized and uniform. This behavior is typical of metal exposed to acidic fluid under flowing conditions. The only deviation from this pattern was in the final set of coupons on the cold side, where the corrosion rate increased and extensive pitting was observed. This anomalous behavior is probably due to the increase in dissolved oxygen observed at this time in the experiment.

When assessing the potential for corrosion damage in geothermal systems, the type of corrosion may be more important than the rate of metal dissolution. A high concentration of Cl^- or dissolved O_2 induces pitting, which increases potential equipment failures dramatically. The lack of heavy pitting on our corrosion coupons suggests that materials will not be subjected to severe corrosive attack. Nonetheless, surface hardware durability and performance in future flow tests can be enhanced with appropriate corrosion treatment. Alternatively, corrosion-resistant materials or heavy-walled pipe could be used, but in our case the cost advantages of light carbon steel equipment outweigh the possible benefits of these approaches, particularly if dissolved gases are handled properly. To minimize pitting corrosion during longer periods of operation, dissolved oxygen in the injection fluid will be kept low (in the parts per billion range) by injecting an oxygen scavenger such as ammonium bisulfite or hydrazine.

2. Gas Handling. To keep a geothermal fluid containing dissolved CO_2 a single phase, the total system pressure must be greater than the sum of the partial pressures of CO_2 and water:

$$P > P_{CO_2} + P_w \quad . \tag{V-6}$$

This expression is valid for a closed system not open to the atmosphere. The partial pressure of water, P_w, is approximately equal to its vapor pressure. The term P_{CO_2} is a function of the concentration of CO_2 in the liquid phase and its Henry's law constant K_H, as given by Eq. (V-5). The constant K_H and P_w are both functions of temperature. Figure V-9 shows the minimum pressure required to keep the solution a single-phase liquid for different temperatures and concentrations of dissolved CO_2.

During most of the flow test, dissolved CO_2 remained in the liquid phase and was reinjected after energy extraction. A simple calculation or use of Fig. V-9 shows why this was possible. The dotted line in Fig. V-9, representing the pressure-temperature behavior of fluid in the surface loop, shows that only fluids with dissolved CO_2 concentrations greater than 0.7% will cause flashing. For the typical value of 0.2 - 0.3%, the mixture will remain a single phase. Occasionally, new regions of the reservoir were accessed and a transient period of high CO_2 concentration occurred. Phase separation in the production wellbore prevented us from collecting a representative sample, but Fig. V-9 shows that the CO_2 concentration must have been about 1% or greater. For future operations we will install a high-pressure, high-temperature gas separator to handle these occasional gas surges.

3. Scale Deposition. The two types of scale deposition that were of greatest concern before the flow test were silica and calcite

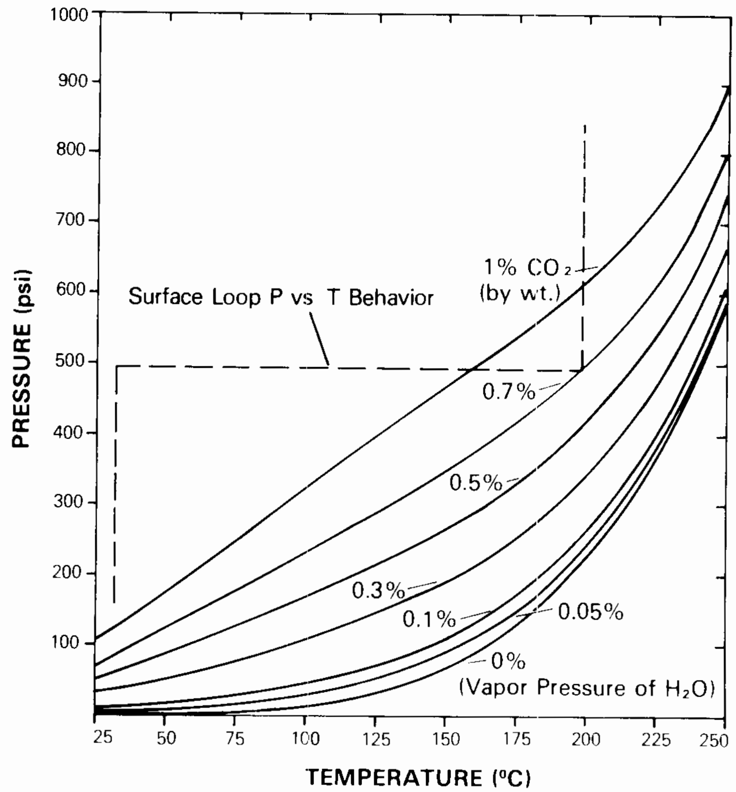

Figure V-9. Pressure required to keep CO_2 - H_2O solution single phase for different CO_2 concentrations and temperatures. Dotted line is a typical (P,T) curve for an element of fluid passing through the surface loop equipment.

precipitation. When water saturated with respect to quartz at reservoir temperatures is cooled, it becomes supersaturated with respect to all forms of silica. Hence a driving force for silica scaling is present. Calcite precipitation occurs for a different reason. Flashing of CO_2 from solution creates disequilibrium which, according to elementary chemical thermodynamics, will cause the reaction of Eq. (V-3) to proceed to the left to reachieve equilibrium. Thus, calcite ($CaCO_3$) is deposited.

Despite these potential mechanisms, very little scale deposition was uncovered in a postexperiment examination of the surface loop, and this scale did not adversely affect the performance of the equipment. Only a small amount of calcium carbonate scale was found on a pipe leading to the heat exchanger, while no silica deposits were found. However, some magnetite scale was detected in the inlet manifolds of the heat exchangers, although we cannot determine whether it was deposited during this or a previous flow test. In addition, a yellowish precipitate containing about 4% arsenic was detected on the corrosion coupons on the cold station of the heat exchanger and in the heat exchanger itself.

D. Tracer Experiments

1. Procedures. Two radioactive tracer experiments, the first on day 10 and the second on day 25, were carried out using an irradiated form of the water soluble salt, ammonium bromide, NH_4Br. The tracer, ^{82}Br, a gamma-emitting radionuclide with a half-life of 35.3 hours, has been used as a conservative (nonreacting, nonadsorbing) tracer at Fenton Hill for several years (Robinson and Tester, 1984). In each tracer experiment a sample was irradiated in the Los Alamos Omega West nuclear reactor, assayed, and transported to the Fenton Hill site. Accounting for radioactive decay during the transportation, the injected pulse strengths were 61.9 mCi and 70.2 mCi. Measurements of gamma activity as a function of time were obtained in the mobile chemistry laboratory by flowing a liquid side stream through a continuous flow cell equipped with a NaI scintillation counter.

2. Results. To obtain a residence time distribution (RTD) curve from a pulse injection tracer experiment, the background radioactivity must be subtracted and the resulting value corrected for radioactive decay. Then, the RTD f(V) is given by

$$f(V) = \frac{C(V)}{m_p} \quad ; \qquad \text{(V-7)}$$

where C(V) is the corrected concentration at produced fluid volume V, and m_p is the mass of the tracer pulse.

When the produced fluid is recirculated, as in the first test, the concentration-time response must also be corrected for the reinjection of radioactive fluid using a mathematical deconvolution technique (Robinson and Tester, 1984). This calculation was performed for the first experiment, while the second test was conducted in the open-loop injection mode with production fluid returns temporarily vented to a holding pond. Thus in the second test the true RTD was obtained directly from Eq. (V-7).

The RTD curves for the two experiments are shown in Fig. V-10. The most striking difference from tracer tests in past Fenton Hill reservoirs is the low recovery of tracer. The ^{82}Br tracer experiment is limited to 2-3 days owing to its half-life, so the low tracer recoveries actually imply that a larger percentage of the fluid has residence times longer than 3 days. According to current models of tracer flow through fractured reservoirs, the present system must contain flow paths of large volume that conduct at least half the fluid. In addition, the modal volume (produced fluid volume at the peak of the response curve), a standard correlating parameter for estimating the heat-transfer capacity of a fractured HDR reservoir (Robinson and Tester, 1984) is larger by roughly a factor of 2 than previous Fenton Hill reservoirs at a similar stage of operation. Hence we expect a longer-lasting reservoir with more gradual production fluid temperature drawdown than in the past.

Comparing the two tracer curves, the response is shifted to larger volumes, and less tracer was recovered in the second test. This result

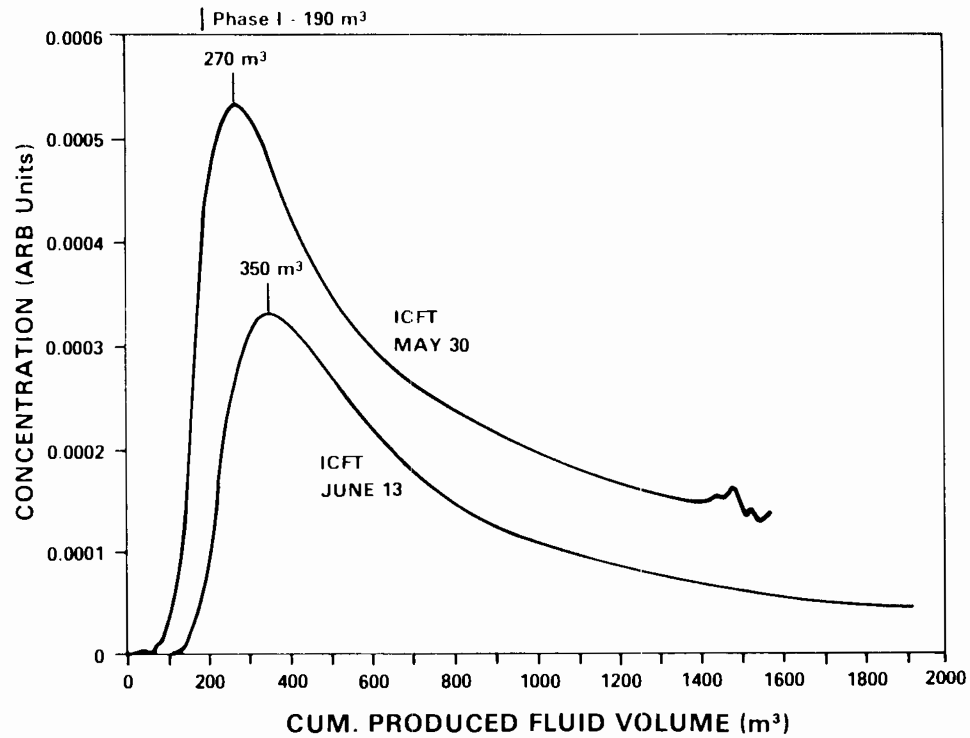

Figure V-10. Residence time distribution curves obtained from the two radioactive tracer experiments.

is due to the transient state of the reservoir during the flow test; throughout the test, the difference of the inlet and outlet flow rates, commonly thought of as water loss, was in large part going into charging the reservoir. Thus a dramatic increase in the integral mean volume (the volume of all fractures connecting the two wellbores, regardless of residence time) from 2180 to 8440 m^3 was observed. The postexperiment vent of the reservoir supports the idea that the observed water loss was caused by the need to fill the fracture system. Of the total of 12 000 m^3 net water lost to the fracture system, 6400 m^3 returned during the vent. Both of these values are in rough agreement with the fracture volume of 8440 m^3 measured in the second tracer test.

The fracture volume estimates aid in the development of conceptual models of the flow system. Assuming a homogeneous fracture network of known porosity, fracture volumes may be used to calculate the swept rock volume. The value of fracture porosity may be bounded between 0.0004 - 0.004, based on measurements of seismicity and reservoir compressibility calculations. For a fracture porosity of 0.003, the rock volumes calculated from the second tracer experiment correspond to a sphere of diameter 150 m. Although the value of porosity is inexact, the resulting sphere diameter is of the same order of magnitude as the wellbore separation distance of 110 m. Thus the conceptual model of flow through a large network of fractures with a point source and sink is a reasonable first approximation.

VI. SEISMOLOGY

A. Data Collection and Processing

Seismic sensors were deployed at 17 sites during the ICFT (Fig. VI-1, Table VI-I). Nine of these were the Fenton Hill surface network stations. These were augmented by four three-component MIT remote digital recorders. These four temporary stations were located very close to the site in order to study anisotropy that should cause shear wave "splitting" because of vertically oriented structures such as cracks. Unfortunately, little data were obtained from the remote digital recorders. Precambrian stations PC-1, PC-2, and GT-1 ran continuously throughout the experiment, while the three-component EE-1

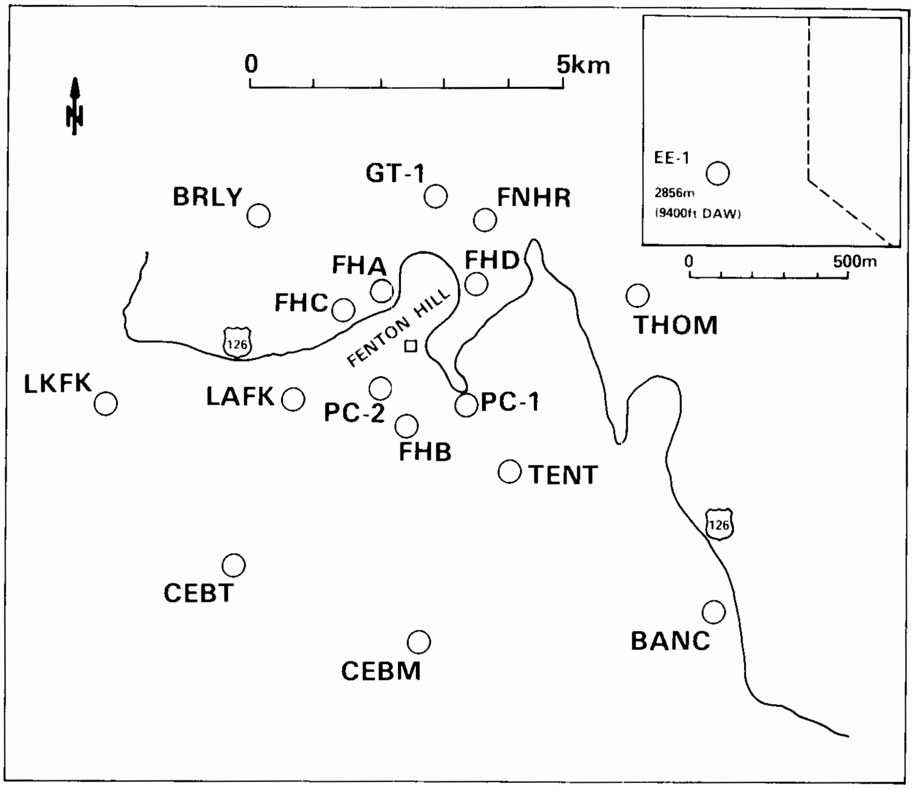

Figure VI-1. Seismic stations used during the ICFT.

tool was deployed intermittently (Table VI-II). The PC-2 station proved to be quite noisy, so a 100-Hz low-pass filter was applied. This remedied the situation but also produced a lower frequency pulse that degraded the quality of the arrival time determination.

The new MASSCOMP digital seismic data acquisition system was employed to perform real-time, on-line event detection and digitizing. The system employed three digitizers that were operated at software selectable digitizing rates. One of the digitizers was run at a relatively slow rate, 500 samples per second per channel, and digitized data from the 9-station surface seismic network. A second digitizer operated at 5000 samples per second and digitized data from the 4-station Precambrian network. The third digitizer was only used when the triaxial geophone was downhole in EE-1. This digitizer was set at a rate of 50 000 samples per second per channel. In addition to the channels of seismic data, a time signal was sent to each digitizer.

TABLE VI-I

FENTON HILL SEISMIC STATION LOCATIONS AND CORRECTIONS

	Location[a]			Correction[b]	
	North	East	Depth	P-wave	S-wave
EE-1	-480.82	-562.26	2854.60	0.6	2.3
GT-1	1976.63	-229.82	804.98	-0.5	10.9
PC-1	-954.44	613.53	741.88	4.6	10.2
PC-2	-925.93	-1358.80	577.94	30.0	0.0
FNHR	1483.0	774.0	-21.0		
BRLY	1393.0	-2967.0	24.0		
CEBM	-4312.0	-464.0	54.0		
CEBT	-3630.0	-3290.0	77.0		
BANC	-4456.0	4204.0	172.0		
LAFK	-1113.0	-2178.0	55.0		
THOM	218.0	3047.0	139.0		
TENT	-2411.0	1035.0	11.0		
LKFK	-1302.0	-5273.0	81.0		

[a] Locations in meters, relative to reference at latitude 35.855°, longitude -106.6687°, elevation 2651.76 m.

[b] Station corrections in milliseconds.

TABLE VI-II

EE-1 TRIAXIAL GEOPHONE DOWNHOLE (MDT)

On		Off	
Date	Time	Date	Time
5/19/86	2220	5/20/86	1450
5/27/86	1850	5/28/86	1000
6/03/86	1036	6/05/86	1305
6/11/86	2141	6/12/86	1000

All data were written temporarily to disk so that data before event declaration (described below) were always stored; data from time periods that did not correspond to events were discarded and the disk space reused. Because of this scheme, total system throughput was limited by the speed of the disk. The maximum achievable aggregate digitizing rate (from all digitizers and channels) was about 400 000 samples per second.

While the data were being digitized, a real-time event detector operated in the CPU of the system. The event detector analyzed data from the medium-speed (5000 samples per second) digitizer to determine the occurrence of a seismic event. The procedure used was to perform long- and short-term averages of each channel of the seismic data. If an event occurred, the short-term average would rise faster than the long-term average because of the increase in signal level. When the ratio of the short- and long-term averages exceeded a specified value, a flag was set at the station. If enough other stations also triggered on the ratio test, an event was declared and all digital data from the event were stored.

Tables VI-III and VI-IV list setup and trigger parameters used during times that EE-1 was in operation. Parameters are described in detail in the Raven user's manual (written by NEWT, Inc.). The only problem that occurred with this setup was that an occasional P-wave was lost at station EE-1. This is most likely the result of a late event declaration; perhaps P-waves were missed and an S-wave provided the decisive trigger. This can be rectified in the future by extending the pre-event memory (if possible), at most by the S-P time at the most distant Precambrian station.

During the ICFT the MASSCOMP data collection system ran from May 19 to June 20 with occasional downtime, primarily because of power outages. Downtime was not logged completely as problems often occurred when seismologists were not present. A list of times that the analog tapes were run as backup appears in Table VI-V; these times represent a liberal estimate of downtime. Perhaps an automatic system of logging downtime can be devised for the LTFT; this would involve the addition of an internal clock that will not be affected by a crash.

TABLE VI-III

SETUP PARAMETERS

Parameter	Digitizer 1	Digitizer 2	Digitizer 3	Description
nch	4	5	10	number channels
bufalloc	580	96	16	total buffer size (kB)
nbufs	6	8	8	number buffers
trate	50000	5000	500	digitizing rate
tpem	450	900	2000	pre-event memory (ms)
max-evlength	2	10	20	max-event length (buffers)

TABLE VI-IV

TRIGGER PARAMETERS

Parameter	Value	Description
ntrig	5	number of stations to compute trigger
nstatrig	3	number of station flags to declare event
nppsta	300	data points per short-term average
ltadiv	8	long-term average constant
enumer	12	sensitivity constant: numerator
edenom	8	sensitivity constant: denominator
equiet	6	quiet station constant
trigmin	58	min duration of trig; multiples of STA
trigmax	20	max duration of trig; multiples of buffers
decimate	5	decimation for trigger algorithm
trig-reset	1	max-event length reset of STA to LTA

TABLE VI-V

ICFT MAGNETIC TAPE BACKUP TO MASSCOMP (MDT)

On		Off	
Date	Time	Date	Time
5/22/86	1253	5/22/86	1324
5/25/86	1037	5/26/86	1220
5/27/86	1535	5/27/86	1614
5/27/86	1814	5/27/86	2206
5/29/86	1626	5/29/86	1841
6/03/86	1627	6/03/86	1856
6/03/86	2341	6/04/86	0717
6/06/86	0907	6/06/86	1450
6/06/86	1611	6/08/86	1255
6/13/86	1205	6/13/86	1408

Microearthquake locations were determined using arrival-time data from the Precambrian stations and EE-1. The station corrections used are listed in Table VI-I. When EE-1 was downhole, microearthquake locations were normally based on P- and S-wave arrival times at EE-1 and GT-1 and P-wave arrival times only at PC-1 and PC-2. When EE-1 data were not available, S-wave times at PC-1 had to be added in order to obtain high-quality locations. PC-1 S-wave arrival times were often difficult to determine. Hence, we investigated the possibility of systematic biases between locations obtained with and without EE-1 data. To do this, a number of ICFT events were re-located by adding PC-1 S-wave data while ignoring the EE-1 P- and S-wave data. Nine events were assigned "A" quality locations in both cases; results are shown in Fig. VI-2. RMS differences in the locations are only 10 m in the horizontal directions and 20 m in depth. No systematic differences were noted. These small differences give us confidence that those "A" quality events that occurred while EE-1 was not operating were reliably located. Of course, the total number of located events increased when the EE-1 tool was operating as a result of the addition of high-quality data.

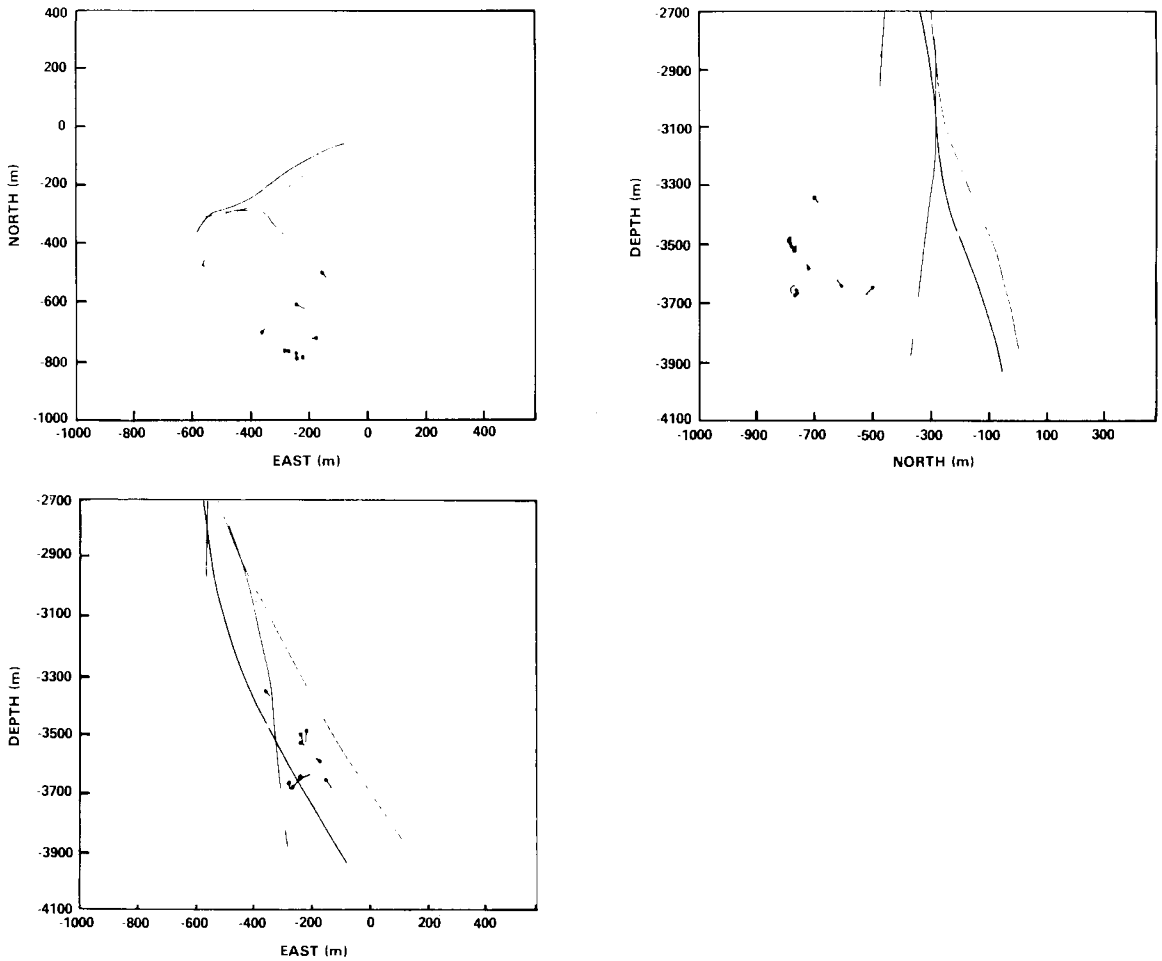

Figure VI-2. Event location changes with addition of EE-1 data. Filled circles represent locations based on P- and S-wave data from PC-1 and GT-1 and P-wave data from PC-2. Line segments represent the location change when P- and S-wave data from EE-1 are added and S-wave data from PC-1 are removed. A cluster of locations on the map view were not given line segment extensions since their horizontal changes were small.

B. ICFT Seismicity

The ICFT produced a considerable amount of seismicity; 684 events were located. Qualities of "A" or "B" were assigned to 611 events. Location quality can range from "A" to "D" depending on the number of arrivals, the data RMS, and the computed solution error (Table VI-VI). A time histogram of all locatable events is shown in Fig. VI-3. The first locatable event occurred the night of May 27, roughly corresponding to two intervals of high flow rates ($\geq 0.02\ m^3/s$). The

TABLE VI-VI

LOCATION QUALITIES

Quality	Arrivals	Solution Error	Data RMS
A	>5	≤25 m	<0.3 ms
B	>5	≤50 m	<0.3 ms
C	>4	≤75 m	
D	>4		

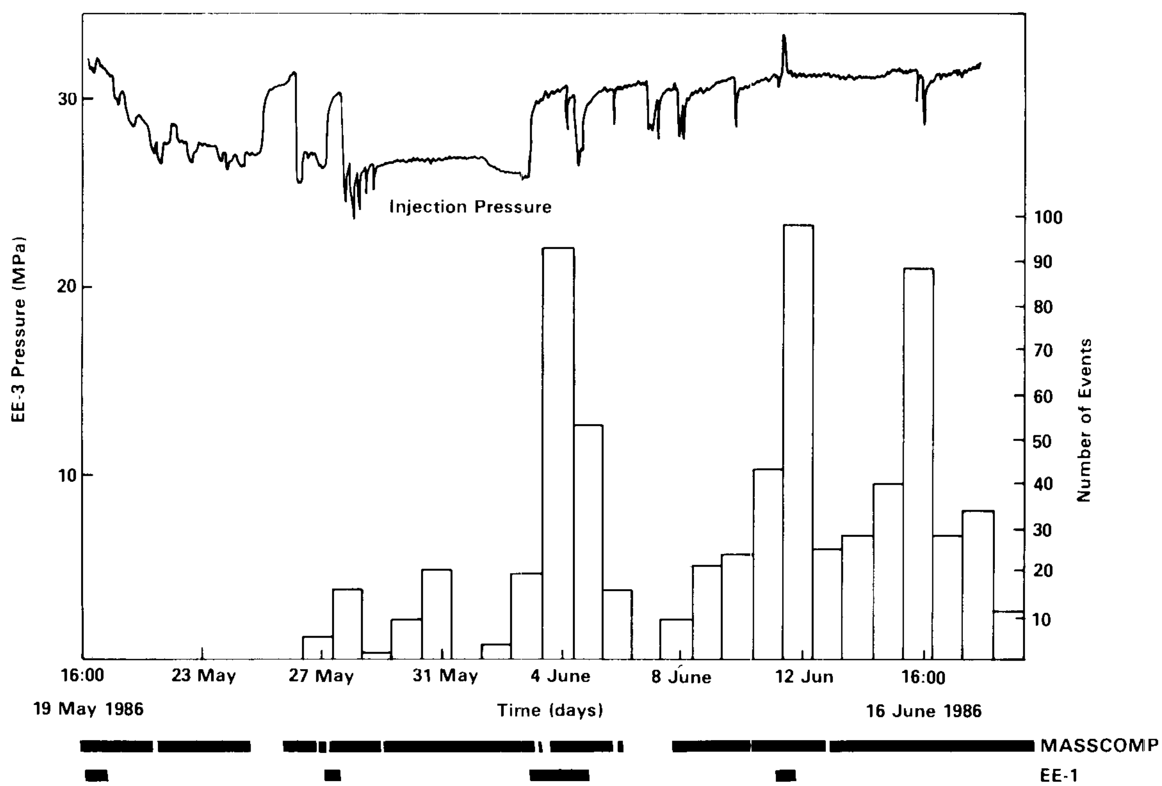

Figure VI-3. ICFT seismicity histogram. Time is measured in days from May 19 00:00 MDT. The top bar under the histogram indicates the times that the MASSCOMP was operating. The lower bar indicates the times that the EE-1 geophone was downhole. Injection pressure curve for the ICFT is also included for comparison.

majority of the seismicity followed the flow rate increase to 0.02 m^3/s on June 4. An average rate of 30-40 events per day was seen between this date and the final shut-in on June 18. Over 90 events were seen on June 12 alone, corresponding to a short, high flow rate injection (0.027 m^3/s) the previous night and early morning. A third peak in seismicity occurred on June 16. This may have been the most active day of the test as 90 events were located without the benefit of the EE-1 tool. No corresponding increases in flow or pressure were noted for this period. The majority of the activity was in seismic subvolume 4 (Fig. VI-4) and may represent a sudden breakthrough to shallow depths. A few events were seen after shut-in, including a number of anomalous

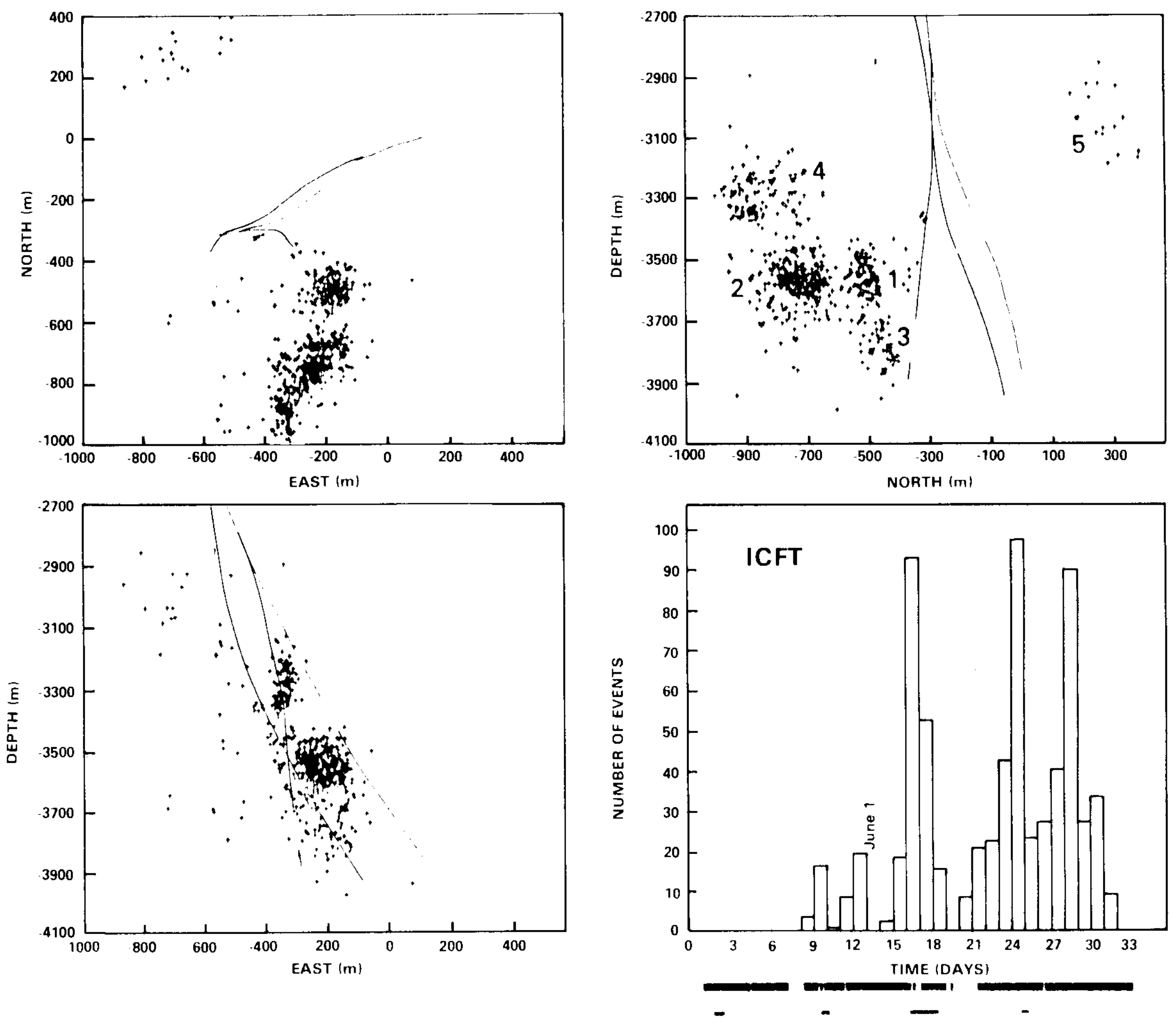

Figure VI-4. Event locations for the ICFT. Only results that have been assigned qualities "A" or "B" are shown.

shallow northerly ones. The event rate slowly decayed away from 20 events/day at shut-in to 1-2 events/day in mid-July as observed from the Precambrian network strip charts.

Events tended to group spatially during the ICFT. The temporal behavior of each of five event clusters is shown in histogram form in Fig. VI-5 (note that vertical scales are different on different plots). Activity in the first two (main) seismic regions occurred during similar times. Region 3, the deepest, was active at the same times as regions 1 and 2, but the event rate increased as the experiment progressed, including 14 events on June 18 after the initial shut-in. Region 4, the shallowest on the south side, was not active until June 5, following the midexperiment step to 0.02 m^3/s flow rates. Fourteen events occurred here June 12-13 after the short 0.027 m^3/s injection. Over 55 events were located in this region on June 16, just before initial shut-in. In region 5, located shallow and well to the north, activity was completely confined to initial and final shut-in periods (Fig. VI-6). This behavior may be due to increased pressures in the production side of the reservoir after shut-in, although shut-in pressures of 16 MPa should be too low for fracturing to occur in the Phase II reservoir. Alternatively, these events may represent fracturing in the low-pressure, Phase I region. However, a number were large enough to be seen by the surface stations. No event was seen on the surface during Phase I operation; however, coverage was relatively sparse at that time.

A plan and two elevation views of the ICFT seismicity are shown in Fig. VI-4. The events occur in a region similar to that observed during the massive hydraulic fracture experiment (MHF or 2032), Fig. VI-7. However, the ICFT seismicity only occupies the southern portion of the MHF seismic region except for the small number of events that occurred after shut-in. This could be due to the following reasons: 1) the injection and production intervals create a pressure dipole effect that results in pressures below the fracture threshold on the production (northern) side of the reservoir; or 2) if the fracture system emanating from the production interval (EE-2) is of dendritic or tree root form, then flow would naturally be channeled toward EE-2, effectively sealing off the northern portion of the fractured volume.

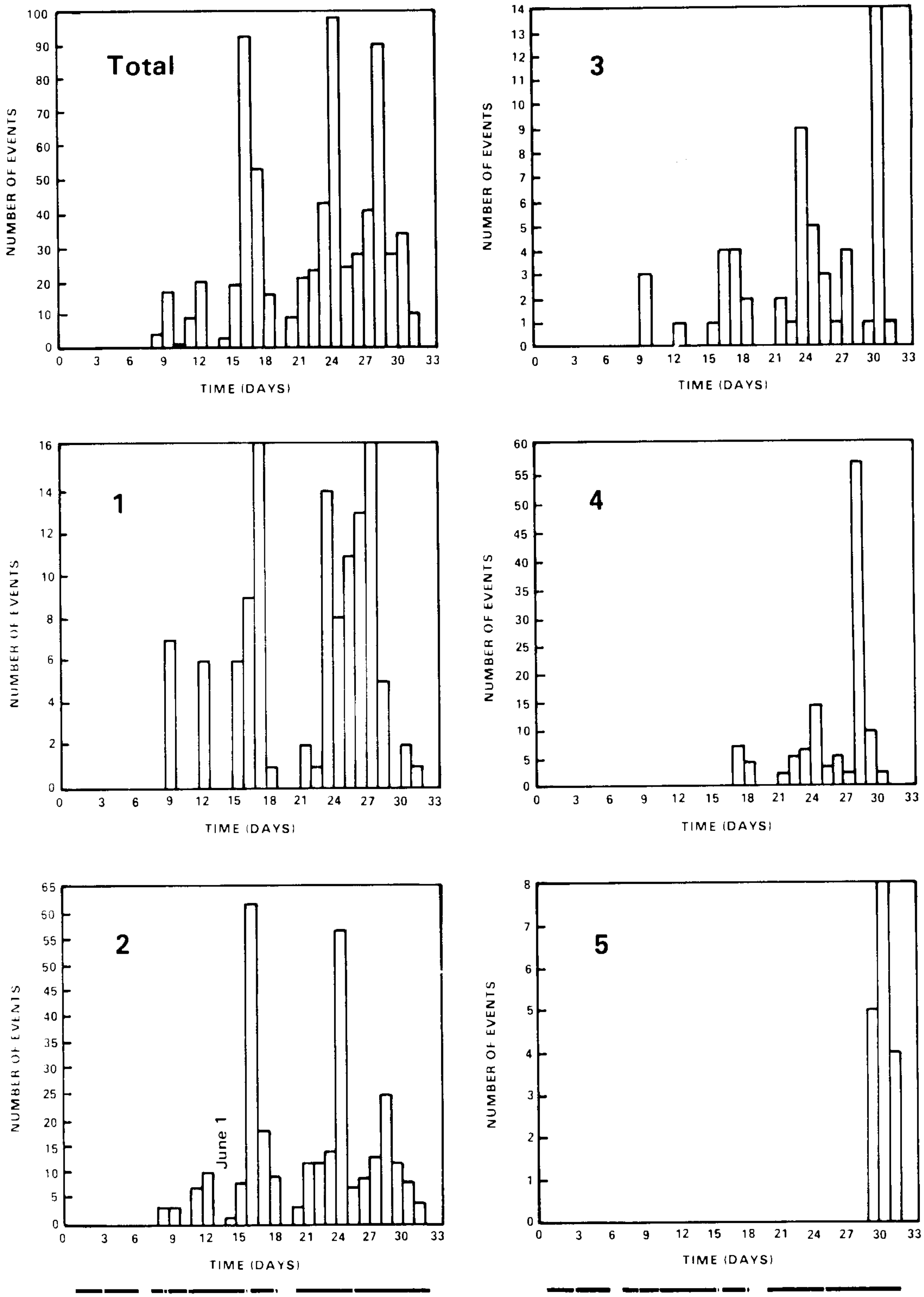

Figure VI-5. Histograms of various seismic clusters that appear in the ICFT results (see Fig. VI-4). MASSCOMP and EE-1 operation times are as in Fig. VI-3; note the different scales on the "number of events" axes.

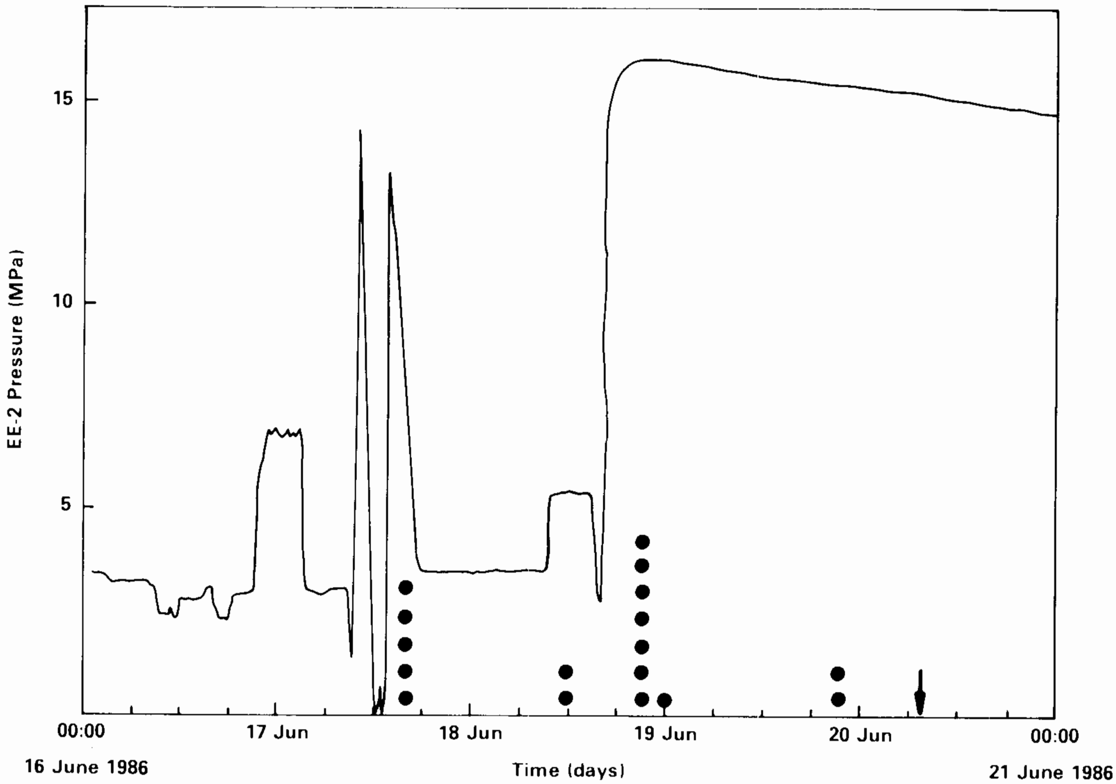

Figure VI-6. Times of anomalous northerly events (solid circles) and production well pressures indicating initial and final shut-ins. All events in group 5 (see Fig. VI-4) fall within the time interval depicted.

The ICFT seismicity also tends to lie on the eastern side of the planar fracture system defined by the MHF locations. This had been evident since the onset of seismicity and seems to indicate reservoir extension. In addition, toward the middle and end of the experiment, both shallow and deep activity intensified, the shallow region extending upward well beyond the MHF volume.

The bunching of events into distinct "patches" can be most easily seen in the westward-looking elevation view (Fig. VI-4). The reasons for such bunching are unknown but may be structurally caused, as similarly located seismic and aseismic regions can be seen in the MHF results. The aseismic regions are intriguing since water must be transmitted through them in order to reach outlying regions of high activity.

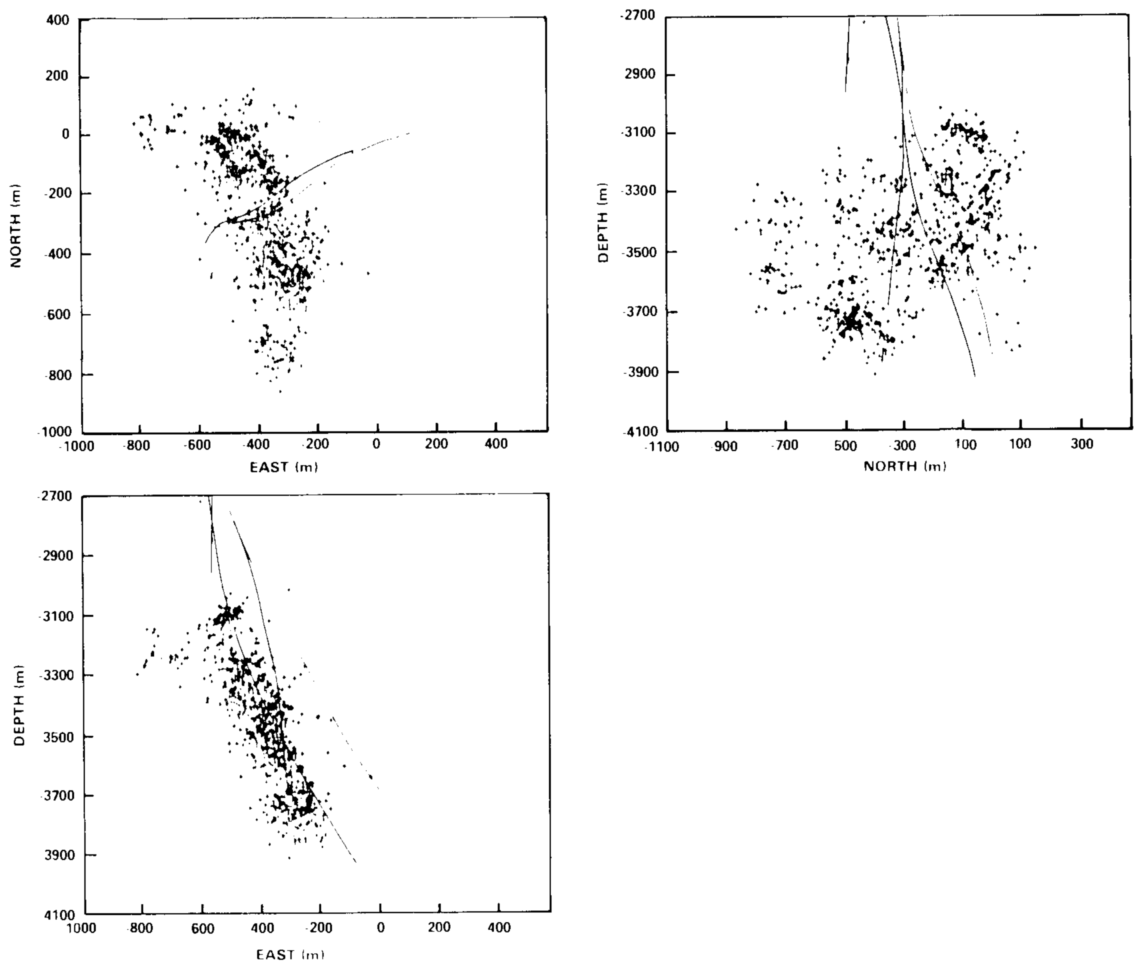

Figure VI-7. Event locations for the massive hydraulic fracture experiment; "A" and "B" qualities only.

Magnitude measurements have not been determined for the ICFT events; however, events can be grouped by size in a crude manner depending on whether or not waveforms were seen by the surface network. The network found 75 large microseismic events (10% of the total number); only 2 of these tripped the event detectors at stations FHA, FHB, FHC, and FHD (Fig. VI-8). All of these events occur after the June 4 flow rate increase. The first (time) histogram peak lags the ICFT total seismicity by 1 day, but the two match fairly well for the remainder of the experiment. Locations are spread fairly uniformly throughout the ICFT seismic volume, except for a concentration in the northern, post shut-in subvolume for which 50% of the events are observed on the surface.

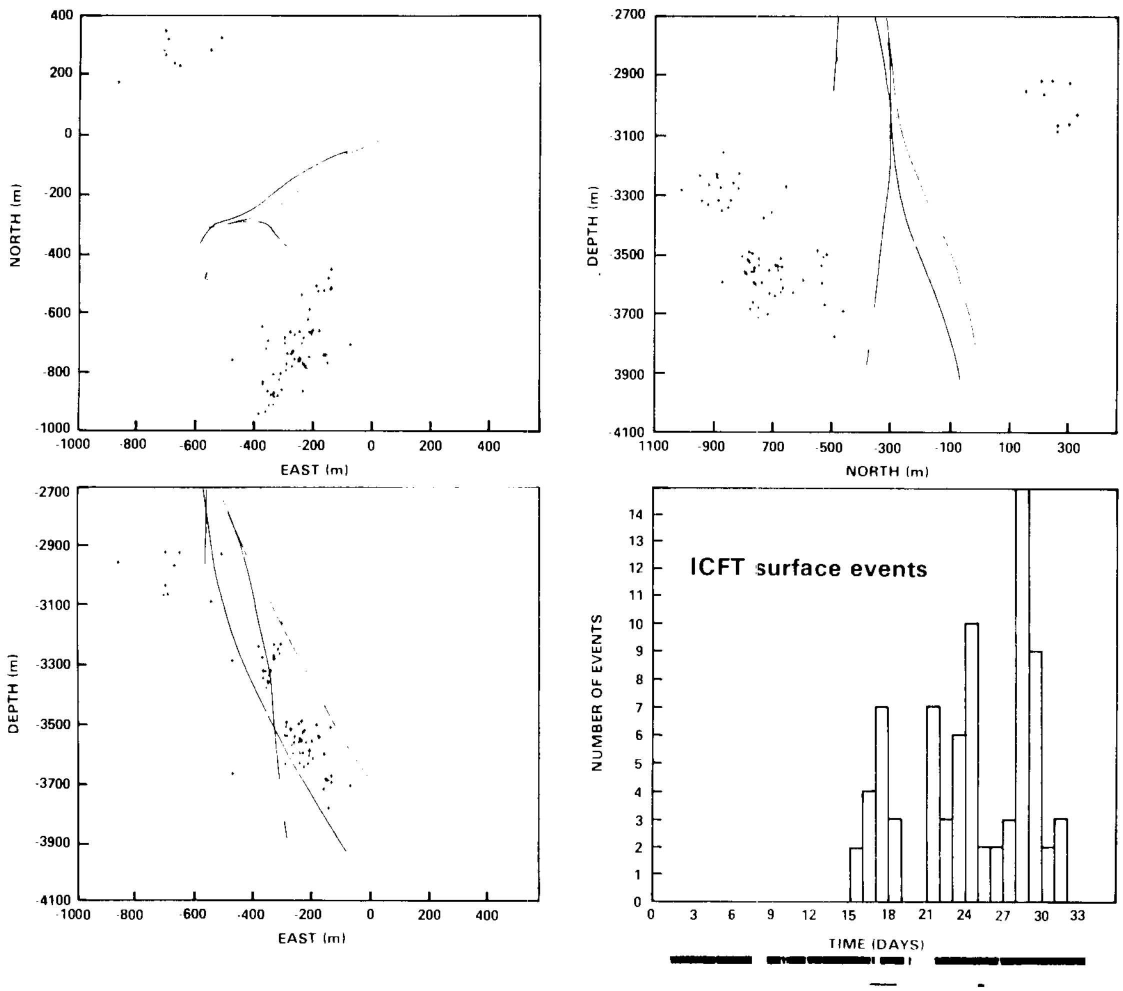

Figure VI-8. ICFT events that were strong enough to be recorded by surface network stations. A histogram is included, with MASSCOMP and EE-1 operation indicated as in Fig. VI-3.

C. Seismic Attenuation

The quality factor (Q) of seismic waves was bounded using the single-scattering, coda-wave method (Aki and Chouet, 1975) with data from temporary stations FHA, FHB, FHC, and FHD. For frequencies (f) between 12 and 48 Hz, $Q = 24f^{0.7}$. This coda Q is thought to represent an upper bound on the average Q of the medium within a volume of radius less than 8 km about the Fenton Hill site. These measurements will be important to any spectral studies that must employ an attenuation correction in order to estimate source parameters of the microearthquakes.

D. Environmental Monitoring

An important aspect of the seismic surveillance at Fenton Hill was to monitor the incoming data for the possible occurrence of a large earthquake resulting from the perturbation of the environment during the experiment. A memo that was distributed before the ICFT concerning environmental monitoring is included in Appendix E. This memo addresses the following: 1) criteria for discriminating between near-site and distant earthquakes based on strip chart records, and 2) procedures to follow in the event of a large near-site earthquake. This memo is sufficient for use in future experiments with one modification. The 5-km radius cutoff is not practical; instead we should say "within the limits of the surface array." A program to discriminate between events occuring within and outside our array has been implemented on the MASSCOMP and can be run by entering

```
/usr/raven/RAVEN4.1/ICFT/progs/massloc -p  .
```

After determining arrival times, this routine simply fits a plane wave to the data in order to find the direction and apparent velocity of the incoming wavefront. For events located outside the array, the apparent velocities will be reasonable (<10 km/s). For events within the array, apparent velocities will be unreasonably large. Results of running this routine on data from various types of events are listed in Table VI-VII.

TABLE VI-VII

RESULTS OF PLANE-WAVE PROGRAM

Event	Apparent Velocity (km/s)
Redondo Creek "blast"	5.5
Local	6.8
Fenton Hill microearthquake	40.5

VII. CONCLUSIONS

A. Comparison of HDR Reservoirs

Only three deep HDR reservoirs have ever been field tested by circulating water down the injection well, through the reservoir, and up a production well for periods of several weeks. The first of these reservoirs, called Phase I, was also created at the Fenton Hill, New Mexico, site and was tested over the period 1978 to 1980 (Dash et al., 1983). This first reservoir, the results of which proved the scientific feasibility of the HDR concept, was created in two stages. In the first stage, a very small fracture system was hydraulically induced and then tested by circulating water through it in three run segments, which lasted 4, 75, and 28 days. In the second stage, the reservoir was enlarged by further hydraulic fracturing and then tested in two run segments lasting 23 and 280 days. For the purpose of making comparison with the present Phase II reservoir, we selected the enlarged Phase I reservoir, and we chose Phase I results at the end of 30 days of the final run segment lasting 280 days because the ICFT lasted 30 days.

The second comparison reservoir is the British one, located at Rosemanowes Quarry in Cornwall (Bachelor, 1984). Although not as deep nor as hot as either the Phase I or Phase II reservoirs at Fenton Hill, the British reservoir was also created in granite, and like the Phase II reservoir, it required redrilling and supplemental hydraulic stimulation before a satisfactory hydraulic connection was obtained. A circulating flow experiment has been ongoing at Rosemanowes since August 1985.

Table VII-I compares the three reservoirs at the end of 30 days of flow circulation. Because the ICFT was limited to this test duration, a 30-day basis is the obvious choice for comparison, but it can be misleading as a guide to reservoir behavior during longer-term testing. For example, after 280 days of operations the impedance of the Phase I Fenton Hill reservoir was reduced to 1.1 GPa·s/m^3; and the water-loss rate was estimated, after correcting for flow out through a poorly cemented wellbore-to-casing annulus, at 7% of the injection rate. Likewise, after 14 months of flow, the impedance of the British reservoir was 0.6 GPa·s/m^3, the production flow rate was 0.016 m^3/s, the water-loss rate was 11%, the modal volume was 495 m^3 (see Section V -

TABLE VII-I

COMPARISON OF THREE HDR RESERVOIRS AFTER 30 DAYS OF OPERATION

	Fenton Hill		
	Enlarged Phase I Reservoir	Current Phase II Reservoir	Rosemanowes Cornwall, UK
Depth of reservoir, m	2800	3550	2400
Temperature of reservoir, °C	195	240	85
Modal volume, m^3	160	350	270
Surface temperature, °C	135	192	76
Thermal power, MW_t	3	9	1
Production flow rate, m^3/s	0.007	0.013	0.004
Injection well pressure, MPa	10	30	4
Reservoir impedance, $Gpa \cdot s/m^3$	1.7	2.2	1.0
Water-loss rate, m^3/s	0.00011 (16%)	0.006 (33%)	0.0004 (10%)

Tracer Experiments - for a discussion of modal volume), and the produced power was 5 MW_t.

Although no assurance can be given that equally significant improvements will occur during long-term testing of the new Phase II reservoir, such improvements are quite likely. Even without improvement, the Phase II reservoir properties already exceed its predecessor's. The produced water temperature is considerably hotter (192°C), already high enough for electricity generation, and, based upon modal volume, the Phase II reservoir is already twice the size of the enlarged Phase I reservoir. The impedance is 30% higher, but improvement can be expected in the future, particularly when the EE-2 production well is repaired so that it can be subjected to high-pressure injections, which should reduce the localized reservoir impedance in the production well vicinity. Present water losses are expected to decline during longer future experiments because more and more of the country rock surrounding the fracture system will become water saturated. Based on microseismic interpretation (see Section VI), future system operation should result in less fracture extension.

B. Conclusions from Thermal and Hydraulic Analysis

1) During the 30 days of operation, a total of 37 000 m^3 (9.76 million gal.) of water was injected, while a total of 23 300 m^3 (6.15 million gal.) of hot water was produced, cooled, and reinjected. Nearly 14 000 m^3 of fresh water was added to make up the difference. An additional 950 m^3 (0.25 million gal.) was vented directly to the EE-1 pond. A maximum injection rate of 0.0265 m^3/s (420 gpm) was obtained, although most of the pumping was done at 0.0106 m^3/s (168 gpm) and 0.0185 m^3/s (294 gpm) with surface pressures around 26.9 MPa (3900 psi) and 30.3 MPa (4400 psi), respectively. The injection well pressure was fairly constant with rate. Hence, LTFT planning should include high-pressure injection capabilities.

2) The production surface pressure was maintained between 1.4 MPa (200 psi) and 3.5 MPa (500 psi), resulting in surface production flow rates from 0.0063 m^3/s (100 gpm) to 0.0139 m^3/s (220 gpm). The production rate from EE-2 showed an overall increasing trend as a result of reservoir inflation and a decrease in overall impedance. Production flow measurements tended to be high when gas (i.e., CO_2 or N_2) content of the fluid was significant, confirming the need for gas separation in future operations.

3) The production well temperature increased throughout the test, reaching a maximum surface temperature of 192°C (232°C bottom hole). The production power showed a corresponding increase, reaching a maximum of about 10 MW_t after 28 days. The power increase resulted from the rise in production temperature combined with the rise in production rate. A projection of performance trends during the test, assuming no thermal drawdown in the reservoir, indicates that up to 12 MW_t could be produced after 1 year if the flow rate is maintained between 0.0126 m^3/s (200 gpm) to 0.0158 m^3/s (250 gpm) and production temperature is around 200 to 210°C.

4) The bottom-hole injection pressure did not change significantly with injection rate or time, indicating fracture inflation and stimulation were occurring near the injection wellbore. The overall reservoir impedance decreased throughout the test, mainly as a result of

the stimulation, especially near the injection well. The injection well impedance decreased from 0.72 GPa·s/m^3 (6.6 psi/gpm) to 0.002 GPa·s/m^3 (0.02 psi/gpm) during the early part of the test as a result of near-wellbore cooling and pressurization. However, the injection well impedance was only a minor portion of the overall impedance, and the decrease in the production well impedance was not as significant. Further plans for reduction in impedance should concentrate on improvement and repair strategies for the production well.

5) Although initially high, the rate of water loss decreased from around 70% after 4 days of pumping to 26% after 30 days of pumping. The high water-loss values during the early portion of the test were caused primarily by reservoir inflation. Almost 66% of the total injected water was recovered during this test with an additional 20% being recovered during a subsequent vent-down.

C. Conclusions from Geochemistry and Tracer Analysis

1) The geochemistry of individual dissolved chemicals in the production fluid over the first 5 days of the experiment fell into three categories: a) the decline of inert species from their initial concentrations to the injection fluid concentration; b) no change in concentration, indicating a supply of the dissolved species via dissolution reaction (SiO_2); and c) decline of concentration to below the injection concentration, caused by adsorption, precipitation, or ion exchange reactions.

2) The Na-K-Ca and SiO_2 geothermometers yielded temperatures that agree well with the known downhole background temperature. Also in agreement with these temperatures are the equilibrium reactions of calcite dissolution and bicarbonate-dissolved CO_2.

3) Corrosion coupon studies found generalized and uniform corrosion at rates of 0.25 - 0.38 mm/yr (10 - 15 mpy). One case of pitting was observed, which we attribute to increased dissolved O_2. An oxygen scavenger will be injected in future operations to minimize pitting corrosion. Scale deposition was minimal and did not affect operations.

4) Several periods of high dissolved CO_2 concentration, estimated at 1% by weight, created a temporary two-phase flow condition at a shallow depth in the production wellbore and in the surface loop.

Future operations will require gas separation to handle these transients.

5) Two radioactive tracer experiments indicated modal volumes about twice as large as previous reservoirs at Fenton Hill. Furthermore, tracer recoveries are lower, indicating flow through a large number of fractures. The total swept fracture volume increased during this flow test as injected fluid continued to fill the reservoir. The total swept rock volume, calculated from tracer-determined fracture volumes and reasonable estimates of fracture porosity, is equivalent to a sphere of diameter approximately equal to the wellbore separation distance. This agreement lends credence to a point-source, point-sink model of flow through a network of fractures.

D. Conclusions from Microseismic Analysis

1) Nearly all events that occurred during the operation of the MASSCOMP system were recorded. The success of our new data aquisition system was marred only by downtime that was due to power outages. Effort must be made to protect the MASSCOMP as well as to implement automatic recording of downtime for future experiments.

2) Because of the duration of the test, events were located both with and without data from the EE-1 triaxial tool. Tests indicated the "A" quality locations were reliable in the latter case.

3) The seismicity of the reservoir was sporadic during the experiment. Peaks in seismic activity generally followed abrupt increases in flow rate. A peak occuring on June 16 did not correspond to pumping changes and was part of an apparent breakthrough to shallow depths.

4) The asymmetry in event locations relative to those of Expt. 2032 may be due to a pressure dipole set up by the adjacent injection and production intervals.

5) Eastward extension from previous seismic zones was noted throughout, while downward and upward extension became apparent midway through the experiment.

6) Seismicity fell into well-defined clusters corresponding to patterns seen in previous experiments; perhaps an east-west-trending geologic structure controls these patterns.

7) The northern portion of the reservoir became seismically active only after shut-in. This may be the first time during the experiment that high pressures were felt in the production end of the reservoir; however, shut-in pressures should not have been high enough to fracture rock. These events may have been located in the lower-pressure Phase I reservoir, but the path between the two reservoirs is a matter of controversy.

8) The seismic quality factor (Q) was estimated using the coda-wave method: $Q = 24f^{0.7}$ for frequencies (f) between 12 and 48 Hz.

E. Conclusions About Loop Operations and Equipment

1) OPI Triplex pumps were used by B.J. Titan. These had 146.1-mm (5-3/4-in.) plungers with 203.2-mm (8-in.) strokes. At 0.0188 m^3/s (7.1 bpm), this equates to 110 rpm or a total of 330 pulses per minute, 19 895 pulses per hour, or about 0.5 million pulses per day.

2) The continuous noise from the diesel engines on the B.J. Titan pump trucks was heard inside homes in La Cueva even with windows closed. It was heard in Sierra Los Pinos, about 13 miles away, anytime one stepped outside and listened. The sound even reached an area that is several miles below La Cueva. This should be resolved before the LTFT.

F. Conclusions About Instrumentation and Control

1. Surface Instrumentation. Some problems with the surface instrumentation were unavoidable because of electrical power failures and/or fluctuations on the incoming power lines. On several occasions stormy weather caused damage from lightning. The use of transorbs as surge arrestors did minimize lightning damage to most of the data acquisition equipment.

Flow measurements in the turbine flow meters were erratic and questionable when there was a high concentration of gas in the circulating fluids.

A number of thermocouple failures were attributed to low-battery voltage in the electronic reference junctions. One pressure transducer located on the EE-3A wellhead was damaged during installation owing to excessive force used on a nearby hammer joint. One instrumentation cable was burned when inadvertently moved into contact with the EE-2 production wellhead.

The water level in the 150-m^3 (40 000-gal.) supply tanks to the Meyers pumps was initially measured using a pressure transducer near the bottom of the tank. The pressure port was eventually plugged with debris, which affected the output of this transducer. Level float switches were subsequently used to control the filling of the supply tank from the 18 930-m^3 (5 million-gal.) pond.

A dc power supply in the control valve and heat exchanger fan panel failed. There was no backup supply in this control panel. Before the problem could be determined, hot water was delivered to the B.J. Titan pumps that damaged the seals.

Some of the data acquisition equipment was affected by dust and insufficient cooling. The major concern was with the computer peripherals (primarily disk drives) and with the tape recorders. This equipment is very susceptible to dusty environments.

2. Seismic/Microseimic Networks. The major concern with monitoring all of the seismic data during this flow test was downtime on the MASSCOMP computer caused primarily by power fluctuations in the line power. The MASSCOMP was powered directly off the main line power and was not regulated through the Uninterruptable Power System (UPS). This computer was not located near the main data acquisition equipment and it was not always apparent to the operators when it was not operational. There was also a problem with adjacent air conditioning and dust accumulations in the DAT.

There were three occasions when one of the surface seismometer stations required maintenance. This was not a critical problem since the other eight stations were recording data with adjacent seismic coverage. The station with the malfunction was generally repaired within a 12-hour period.

VIII. RECOMMENDATIONS FOR THE LONG-TERM FLOW TEST

A. Loop Operations and Equipment

1. Pulsation Dampening. All B.J. Titan pumps were equipped with suction and discharge pulsation dampeners. When the dampeners were serviced and working, they were effective. Pulsation measured upstream, at the Meyers makeup pumps, was as low as a few psi when the equipment

was serviced and working. But it was as high as 0.6 to 0.7 MPa (90 to 100 psi) when the equipment was not performing well. The largest pulsations occurred when a suction valve or seat was washed out. One suction pulsation dampener and two discharge dampeners were replaced during the test.

Pulsation dampeners will be required for the LTFT. Dampeners without a rubber bladder should be specified to eliminate the blistering and failure that occurred as a result of the CO_2 in the water.

2. Plunger Pumps. Design for fatigue will be important for LTFT planning. Based on the performance of the OPI pumps, we can come to several conclusions.

First, two fluid ends were lost because of cracks in the highly stressed area of valve seats. Special order materials and analytical proof of a low-stress design will be necessary in the pump ends to prevent this during the LTFT. Second, several valve seats and insert snap rings indicate possible stress corrosion cracks because of the influx of sulfide and/or hydrogen. Special materials will be required for these. Third, three steel-reinforced suction hoses were lost from a combination of embrittlement, high pulsation loads, an occasional high suction pressure when pumps were off-line but still subjected to system pressures, and vibration abrasion of the hoses with the ground. Elimination of the hoses or replacement with hoses of a higher working pressure will be necessary as well as supporting them in an abrasion-free manner.

We conclude that for the LTFT to run with a minimum of downtime and materials-related failures, special fluid ends on the plunger pumps will be necessary, or water chemistry must be such that this is not a concern. Variable-speed, dc or ac drive pumps should be ordered to provide more flexibility in matching the performance curves of the various components that must work together as a system. The pump motors should be powered with electricity from Jemez Electric or with large, slow-running, stationary diesel generators. Finally, pulsation dampening is a necessity and will be an ongoing maintenance item.

3. Control Valves. CV-6 failed early in the test. Upon inspection after the test, it was found that the multiple small holes in the cage simply plugged, as did the strainers elsewhere in the system.

This valve needs to be replaced or have strainers upstream of it. A bypass line around the valve with a manually operated globe valve is suggested for the LTFT

CV-2 thru CV-5, the V-Ball type of control valves on the heat exchangers, were used during the ICFT to control flow and hold a back pressure on EE-2 because of the failure of CV-6. They were never intended for this and as a result they are in need of repair or replacement. In their study of a LTFT surface system, Kaiser Engineers suggested that the 38.1-mm (1-1/2-in.) pipes in the area of the heat exchangers be replaced because the velocity in these small pipes gets high enough to cause water hammer should the system flow rate be changed abruptly with these valves.

In general, all critical control valves should have a bypass line so that any necessary repairs can be made while maintaining loop operations.

For the LTFT we will need five 103.2-mm, 69-MPa (4-1/16-in., 10 000-psi) valves for both EE-2 and EE-3 (double master, a swab valve, and two wing valves). It would be best if these were geothermal grade so that any backflow could be handled safely. Five additional 101.6-mm, 34.5-MPa (4-in., 5000-psi) API-rated geothermal valves are needed for a double-strainer complex downstream of EE-2. A sixth 101.6-mm, 34.5-MPa (4-in., 5000-psi) valve is needed to replace valve V-3. V-3 is a Grove valve that is about 30 years old and is no longer manufactured.

Four 73.5-mm (3-in.) geothermal-grade valves are needed on the entrance to the heat exchangers. Three new valves are needed for a strainer/bypass upstream of CV-6 and a totalizer flow meter. There are many 50.8-mm (2-in.) valves that also need to be replaced.

4. Strainers. EE-2 is an open-hole completion, thus rocks and sand came to the surface. This required cleaning the strainer just downstream of the EE-2 wellhead several times during the ICFT. Each time this happened, it was necessary to shut in the well and vent to the EE-1 pond to allow the strainer to cool. A five-valve, double-strainer complex is needed to eliminate the perturbations which occurred to the experiments that were interrupted by the unplanned shut-ins. The strainer downstream of CV-6 should have a higher pressure rating and should be moved upstream of CV-6.

5. Expansion Joints. That part of the line between EE-1 and the heat exchangers which is located in the underground tunnel had thermally expanded. It caused no problems during the ICFT but left the pipe permanently deformed. This will be corrected by changing the anchor points or flexibility of the piping run. Additionally, all bolted flanges will be removed and the pipe will be welded.

The cold leg of the loop between the heat exchangers and EE-3 experienced one temperature excursion during the ICFT when the power went out during a storm and B.J. Titan continued to pump. The resulting temperature rise in this pipe moved concrete blocks, bent pipe, etc. This needs to be corrected for the LTFT, using either a simple interlock or an expansion joint. A single 0.3-m (12-in.) stroke expansion joint is currently available, as is one bellows type of expansion joint.

6. Makeup Water System. It is essential that the 18 930-m^3 (5 million-gal.) pond stay clean. There is only one transfer pump from the pond to the holding tank at the heat exchangers. Kaiser Engineers' report suggested that a backup pump be installed.

The 150-m^3 (40 000-gal.) tank used as the holding tank needs to be replaced. It is suggested that two 64-m^3 (400-bbl) frac tanks be purchased to replace it.

A system for control of O_2 and H_2S needs to be designed and installed. A filter has also been suggested in the event that the 5 million-gal. pond remains dirty or river water is used for the LTFT.

7. Makeup Pumps. The Meyers pumps are inflexible, old, and in need of rebuilding. New pumps with a capacity of about 0.013 m^3 (5 bpm) at 1.1- to 1.2-MPa (160- to 170-psi) operating pressure should be purchased.

8. Gas Separators. Gas-purge mode was used several times during the ICFT. It has been suggested that a high-pressure separator be installed downstream of EE-2 to eliminate the open system resulting from the gas-purge mode of operation. It has also been suggested that the separator be configured to allow settling of the sand and the rocks that are brought up with the production fluid. It is possible that this could replace the strainer complex mentioned above.

9. Pressure Relief Valves. The 4.1-MPa (600-psi) pressure relief valve worked well; however, it would have choked because of two-phase

flow if we had unloaded the well through it. To provide full production flow capability through the pressure relief valve, it is suggested that this valve and its line be upgraded.

10. Chicksans and Hammer Unions. All chicksans and hammer unions on the hot leg of the system should be replaced with special 1.2-m (4-ft) radius bend pipe and flanges or welds. We had numerous leaks in these components and had to shut the system down several times to replace them.

11. Geochemistry. The only serious problem during the ICFT was trying to obtain total gas samples. One possible solution is a gas separator. Other items that need to be considered are the domestic water and sewer system, a location where all three streams (i.e., production, makeup, and injection) of system loop water can be monitored, and an UPS for the computer in the chemistry trailer.

12. Corrosion. A corrosion sampling/coupon system for the LTFT needs to be integrated into the piping design. A means of injecting corrosion inhibitors down the backsides of EE-2 and EE-3 is also needed.

13. Safety. Hot exposed sections of pipe should be insulated, or a controlled access fence should be installed. Loop operations should be simplified and experiment managers should be better trained in the operation of the loop.

B. Instrumentation and Control

1. Surface Instrumentation. Little can be done to avoid the electrical storms that frequent Fenton Hill. The Uninterruptable Power Supply (UPS) system, however, can protect much of the data acquisition system from electrical power failures and/or fluctuations on the incoming power lines. Installation of additional air conditioners will provide needed cooling and may also result in a positive air pressure in the DAT that could reduce dust accumulations.

Although the flow meters cannot measure two-phase flow or read fluids with high gas concentrations, it would be beneficial if a bypass line was included in the main flow piping to allow removal of a damaged flow meter, especially in the heat exchanger area.

It is presently planned to replace all thermocouple temperature transducers with resistance thermometers (RTD) for more reliable operation.

It is also recommended that an automatic temperature shut-off valve be installed upstream of the main injection pumps to avoid the occurrence of hot water being cycled through these pumps. A backup power supply should also be installed in the remote control system.

The on-line analog strip chart recorders used to determine periods of high seismicity were operated continuously throughout the experiment. This equipment is more than 10 years old and is difficult to maintain since spare parts are no longer available. New strip chart recorders are needed for the LTFT.

The HP9835 is obsolete and cannot be repaired. It is recommended that it be replaced with an HP9845, which will also increase the capabilities of the data acquisition and control functions. Some reprogramming will be required.

The pressure transducer is a very reliable measurement of fluid level in the supply tank and can be alarmed in the DAT when predetermined fluid levels are exceeded. It will be necessary, however, to build a suitable screen around the pressure port in the tank to prevent clogging with sediments. The float switches should be installed as backup devices.

The current instrumentation and control setup worked for the ICFT; however, for a longer operating time a totally automatic system with manual override for nonstandard operations is needed. Transfer to emergency power should also be automatic, or simplified.

The resolution of the visual display screen was poor, and too much data were displayed for emergency operations. A remote monitor has been suggested both for the MASSCOMP and the system data display screen. A viewing screen at TA-33 would eliminate many questions, phone calls, and trips to Fenton Hill.

2. Seismic Network. Expanded accommodations for the MASSCOMP computer are under consideration. An existing office trailer could be moved to Fenton Hill that would only require electricity for lights and heat and a phone. The office equipment now housed in the DAT would be moved into this temporary office trailer. The MASSCOMP computer would then be installed in an area more accessible to adequate air conditioning and personnel attendance.

A separate UPS system should be procured to eliminate line-power fluctuations. A knowledgeable seismologist and/or on-site personnel trained in the operation of this equipment should be in attendance during the flow tests. Perhaps an alarm could be programmed into this system to alert operators when the computer malfunctions.

The surface seismic stations usually worked well. A new solar charging circuit is being designed to improve continuous battery operation. This charger will be installed in all nine surface stations and the three Precambrian stations. It is also recommended that the three Precambrian downhole packages be retrieved for redressing and maintenance and be redeployed before any long-term flow tests.

3. Borehole Surveys. Equipment could be purchased to allow logging of both the EE-3A and EE-2 boreholes under high-pressure conditions. The equipment essential to the logging operations would include a small-diameter, 4.8-mm (3/16-in.), seven-conductor, TFE-Teflon, insulated cable and a suitable lubricator/packoff system. New sheaves with proper cable grooves would also be required. The high-pressure borehole logging equipment would allow consistent and accurate surveys throughout the entire LTFT. There are a number of slimline tools that could be run in either the injection well (EE-3A) or the production well (EE-2) that would greatly enhance the evaluation of the HDR reservoir.

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APPENDIX A
SURFACE SYSTEM

I. SURFACE SYSTEM FABRICATION

The system consisted of valves, control valves, pipe, flanges, flow meters, expansion joints, etc., purchased for an "interim surface system" and stored since 1982. The system also contained pipe and structures left over from the Phase I loop operations (i.e., heat exchangers, Meyers pumps, 4-in. schedule 160 flanged pipe, tunnel, etc). The system included API-rated wellhead equipment purchased since 1982 and contract pumping supplied by the B.J. Titan service company.

The system was fabricated by many sources: Smith and Smith Construction (the 5 million-gal. pond); Zia Co. (the line from the pond to the holding tank and the heat exchanger piping); and Albuquerque Heating and Ventilating, Zia, and CJC (the Phase I system). Fenton Hill technicians and CJC personnel fabricated remaining parts of the system. All of the Zia welds were done in Zia welding shops; the remainder of the welds were done in the field.

All critical welds in the ICFT system were performed by Jim Moore of CJC. Welds were done with E-7018-1 Lincoln Arc Welding Co. low-hydrogen rod. Fittings and flanges were tacked to the pipe; then the joint was preheated, using a gas torch to drive off moisture. Welding consisted of a stringer pass, hot pass, fill pass, and cap pass. All passes were hand chipped and then finished with a power wire brush. Weld preparation consisted of gas cutting and hand grinding.

Pipe anchors were cast into excavated holes using concrete. To compensate for poor control on cement strength, anchor blocks were oversized and had ample, even excess, reinforcing. Underground bends in pipes were supported with reinforced thrust blocks cast in place between the pipe bend and undisturbed earth, usually tuff.

II. CALCULATIONS

The thrusts applied to the line between EE-2 and the EE-1 tunnel by the expansion joint were calculated. This force is due to the piston effect of the expansion joint. The calculation was done according to Bulletin SCS 6651 published by the manufacturer of the expansion joint.

Pipe anchors were designed keeping in mind the manufacturer's recommendations.

Stresses in the pipe anchors at each end of the expansion joint run were calculated, sketches were made, and the anchors were field fabricated accordingly. Piston force on the line was calculated at 3000 psi since this is in a 4-in. schedule 160 line, which is rated at that pressure. Some components of this segment are rated at only 1450 psi.

Thermal expansion stresses in the segment of pipe between the pipe anchor at the heat exchanger end of the EE-1 tunnel and the heat exchanger were not calculated this time. However, the interim design was calculated in 1982 and accepted at that time. The ICFT piping is nearly identical, or more limber when not identical.

All other thermal expansions occur downstream of the heat exchangers and are of a small value because of the lower temperature extremes. Common practice, which eliminates trapped stresses, was employed.

Flows from the Kunkle safety relief valves were calculated. The size of the production line relief valve, set at 600 psi, is too small to flow 100% of the anticipated production flow from EE-2 (this was an experimental loop and this number was not known before the test). However, it would handle a large percentage of the anticipated flow, and if the pressure should continue to rise, the valve at the production wellhead (with high and low pressure controls) would close at 700 psi. The well would be put on a controlled manual vent through the choke manifold as quickly as possible should this occur.

III. SAFETY AND EXPERIENCE FACTORS

The system was constructed with the best material available from Los Alamos stock. The system was designed along the guidelines laid out in the ANSI B16.5 specifications and the ASME Unfired Pressure Vessel Code.

Supporting the pipe with safety blocks, as mentioned above, far exceeds any real need for them. This was done mainly out of a desire for safety.

The system was remotely controlled from two locations: the DAT trailer, which controls all the loop up to the contract pumps, and the operating van, which controls the contract pumps. This remote control was backed up by manual control, and both control systems were an important safety, as well as convenient, design feature of this system.

Fire protection was provided by B.J. Titan's fire extinguisher trailer with foam and CO_2 equipment, the site fire trailer with water and foam, the La Cueva fire department (5 miles away), and the Jemez Springs Fire Department (15 miles away).

Other safety items included steps over the high-temperature flow line so that operating and maintenance personnel could safely move from one side of the hot line to the other. Danger signs, roped-off exclusion areas for nonessential personnel, controlled access by site guards, and personnel training also enhanced site safety. Finally, H_2S alarms were rented and set up around the site.

IV. TRAINING

Between 20 and 30 hours of training classes were conducted for operating technicians over a 2-month period. Two sessions of 2 to 3 hours each were given to experiment managers who were 24-hour supervisors during the ICFT. Schematics of the system as well as a book of operating procedures were made available to all people involved.

APPENDIX B

DATA CHANNELS AND TAPE SETUPS

TABLE B-I

ICFT DATA CHANNELS

Channel No.	Location	Range	Type
P1	EE-2 Wellhead Pressure	0-2500 psi	CEC
P2	EE-2 Wellhead Pressure-Strainer	0-2500 psi	CEC
P3	Heat Exchanger Inlet	0-2500 psi	B&H
P4	Heat Exchanger Discharge	0-2500 psi	B&H
P5	Heat Exchanger Strainer Inlet	0-500 psi	CEC
P6	Heat Exchanger Strainer Output	0-500 psi	CEC
P7	Meyers Pump Discharge	0-250 psi	CEC
P8	High-Pressure Pump Inlet	0-500 psi	Statham
P9	EE-3A Wellhead	0-10 000 psi	CEC
P10	EE-3A Annulus	0-1000 psi	CEC
P11	EE-3A Backside	0-2500 psi	B&H
P12	Kobe Pump Discharge	0-3000 psi	Dynisco
P13	EE-2 Annulus	0-250 psi	CEC
P14	EE-2 Backside	0-2500 psi	B&H
P15	Separator Inlet Pressure	0-1000 psi	Precise
P16	Separator Inlet Gas Pressure	0-200 psi	Gould
P17	Separator Discharge Gas Pressure	0-200 psi	Gould
P18	Air Compressor	0-500 psi	Celesco
T1	EE-2 Wellhead	0-300°C	Thermocouple
T2	Heat Exchanger Inlet	0-300°C	Thermocouple
T3	Heat Exchanger Discharge	0-100°C	Thermocouple
T4	Meyers Pump Outlet	0-100°C	Thermocouple
T5	High-Pressure Pump Inlet	0-100°C	Thermocouple
T6	Separator Inlet	0-300°C	Thermocouple
T7	Separator Discharge	0-300°C	Thermocouple
F1	EE-2 Wellhead Flow	0-420 gpm	3-in. Halliburton
F2	Heat Exchanger Bundle 1	0-150 gpm	1-1/2-in. Halliburton
F3	Heat Exchanger Bundle 2	0-150 gpm	1-1/2-in. Halliburton
F4	Heat Exchanger Bundle 3	0-150 gpm	1-1/2-in. Halliburton
F5	Heat Exchanger Bundle 4	0-150 gpm	1-1/2-in. Halliburton
F6	Meyers Pump Discharge	0-1000 gpm	Clampitron
F7	High-Pressure Pump Inlet	0-420 gpm	4-in. Halliburton
F8	Separator Liquid Flow Discharge	0-200 gpm	2-in. Halliburton
F9	Separator Liquid Flow Discharge	0-600 gpm	4-in. Halliburton

TABLE B-II

EXPERIMENT 2067 (ICFT) TAPE SETUP

Tape No. 1 (3020)/1-7/8 IPS

Track	Range	Channel
1	q 1.4 FM	EE-1 "VERT"
2	q14 FM	EE-1 "VERT"
3	q 1.4 FM	EE-1 "UPPER"
4	q14 FM	EE-1 "UPPER"
5	q 1.4 FM	EE-1 "LOWER"
6	q14 FM	EE-1 "LOWER"
7	q 1.4 DIR	Time Code "B" (1 kHz)
8	q14 FM	PC-1
9	q 1.4 FM	PC-1
10	q14 FM	PC-2
11	q 1.4 FM	PC-2
12	q14 FM	GT-1
13	q 1.4 FM	GT-1
14	q 1.4 DIR	Time Code "A" (10 kHz)

TABLE B-III

EXPERIMENT 2067 (ICFT) TAPE SETUP

Tape No. 3 (2230)/1-7/8 IPS

Track	Range	Channel
1	q14 FM	FNHR
2	q14 FM	BRLY
3	q 1.4 FM	PC-1
4	q14 FM	CEBM
5	q14 FM	CEBT
6	q14 FM	BANC
7	q 1.4 FM	GT-1
8	q14 FM	LAFK
9	q14 FM	THDM
10	q14 FM	TENT
11	q 1.4 FM	PC-2
12	q14 FM	LKFK
13	q 1.4 FM	EE-1 "VERT"
14	q 1.4 DIR	Time Code (100 Hz)

APPENDIX C

CHRONOLOGICAL SUMMARY OF ICFT PUMPING AND OPERATIONS

May 19:

Lines were pressure tested from the heat exchangers up to the EE-3 wellhead. By 1600 pressure testing was finished. BJ's strip chart showed a test pressure of 7550 psi, which dropped to 7200 psi in 30 min. The EE-3 frontside pressure transducer, P-9 SN-18771, was not working. It was replaced later with SN-15370.

A safety meeting was conducted. At 1608 EE-3 wellbore filling was started. At 1612 step-rate flow testing was started.

STEP-RATE FLOW TESTING EE-3

Start Time	Flow Rate (gpm)	Pressure at End (psi)
1612	72.0	4056.0
1736	140.0	4380.0
1849	172.0	4519.0
2000	310.0	4990.0

The pressure in EE-2 backside started rising above background at 1952. The frontside showed pressure at 2018. After this time the pressures followed each other and were reading 102 psi at 2115 when continuous rate pumping was started at 190 gpm or a nominal 4.5 bpm.

May 20:

At 0021 EE-2 pressure was up to 277 psi. It was decided to put EE-2 on production through the heat exchangers and then vent to the pond. Initial flow was at about 60 gpm and 170 psi. Control valve CV-6, the main system control valve, showed no ability to control the flow. Control of the system was switched to the backup for this valve (i.e., the individual control valves on each of the four heat exchanger bundles). When this valve was inspected at the end of the test, it was plugged with mud and scale. CV-6 is a slide-in cage type of control valve with small-diameter holes (about 3/32 in.). We had thought the holes to be much larger based on manufacturer's pictures. The strainers downstream of this control valve should be moved upstream for the LTFT and/or this control valve should be replaced.

At 0127 a gas bubble was suspected, and vent through the heat exchangers was changed to vent through the choke. At this time flow measurements were lost, which brings up the second limitation of the ICFT surface system. All vents of any nature that were directed straight to the pond had no flow measurements. Meyers pump #2 heated up and had to be repaired later in the experiment.

At 0310 an attempt to put EE-2 back on production through the heat exchangers was made. Still too much gas. EE-2 backside was opened to the tank. At 0700 the loop was successfully placed in the gas-purge mode with flow directed through the heat exchangers and then dumped into the makeup water tank. The flow settled down at about 50 gpm at 266 psi. At 1708 EE-2 was placed in vent mode through the chokes to work on CV-6 and to balance pressure transducers. This mode of operation continued until the next day.

<u>May 21</u>:

At 0915 a check on the EE-2 flow was made by directing the flow through the separator. Flow was 53.5 gpm at 267 psi. At 0942 BJ was shut down to obtain a shut-in pressure. Pressure dropped from 4064 to 3870 psi and then slowly decayed to 2497 psi at 1102.

At 1314 the first of four shut-ins and vents to surge the system were conducted. At 2230 the flow rate was 64 gpm. Surging EE-2 continued till around midnight. During the first shut-in, EE-2 frontside pressure built up to 1118 psi at 1419 while the backside reached 1098 psi. During the vent, the frontside dropped to 127 psi at 1426 when it was shut in again. The corresponding backside pressure was 1043 psi and continued to drop down to 943 psi at 1433, when it increased. EE-2 reached 1110 psi at 1451 during the second shut-in; then the second vent started. The backside showed a momentary drop in pressure and then continued to rise in pressure till 1510 when it peaked at 1134 psi. At 1847 the third shut-in was started. EE-2 frontside pressure was 200 psi, while the backside was 184 psi. During the third shut-in, the backside pressure lagged the frontside pressure by about 200 psi or 17 min. The third vent was started at 1943; the backside pressure continued to rise for another 12 min before following the vent. At the end of the fourth shut-in, at 2026, the frontside was vented down to 105 psi before it was leveled out at about 180 psi. This time the backside continued to climb, and by midnight it reached 1830 psi. Pumping by BJ was shut down and the backside watched. The pressure continued to climb.

May 22:

At 0203 the EE-2 frontside was shut in and the backside vented through the choke. Note that during this time the frontside and the backside shared the same choke and vent line. This was changed later in the experiment. At 0229 pumping was resumed. The backside was shut in and started to climb again by 0240. At 0442 the frontside was shut in and reopened at 0500. A bucket measurement at 0530 gave 68 gpm at 164 psi. At 0600 the vent rate was 62 gpm at 165 psi, and by 0715 the flow rate was 61 gpm at 160 psi.

The production was changed from vent mode to gas-purge mode between 0910 and 0930. At 1152 a leak was found in the tunnel under the road. Went back to vent mode to find and fix leak. Leak turned out to be the back pressure valve on the Meyers pump venting through a pipe and then leaking underground into the tunnel.

The MASSCOMP went off during the night. The system was returned to gas-purge mode with four heat exchanger bundles at 1510. An increased flow rate experiment was started at 1625. BJ increased their pump rate to 7.5 bpm, 315 gpm. Injection pressure rose to 4400 psi and then climbed slowly to 4600 psi during the next 80 min. During this time CV-6 was bypassed using two 1-in., high-pressure hoses. At 1820 Meyers pump #6 went off-line. It was later reset with the thermal relay and put back in service. Injection flow rate was cut back to 6 bpm (250 gpm) at 1851 and then to 4.3 bpm (180 gpm) at 1947. At 1920 the loop was taken out of gas-purge mode and placed in closed-loop operation. A few minutes later it was returned to gas-purge mode as BJ's pumps ran rough with the high gas content. The EE-2 backside was vented from 884 to 504 psi between 2257 and 2305.

May 23:

A flow meter on bundle 1 stopped working early in the morning. The meter started later in the day when flow was switched back to this bundle. There was some indication of a damaged vane on the impeller. The first dye tracer experiment was started at 1000. The rest of the day was simply pumping in the gas-purge mode with gas readings still about 0.23%.

May 24:

Since the last vent the EE-3 backside pressure steadily increased to 930 psi. At 0230 the pressure was vented down to 500 psi and then shut in again. A midday gas reading was given at 0.21%. At 1203 pumping was stopped to obtain a shut-in pressure reading. Pressure dropped from 3955 to 3667 psi and then decayed to 3231 psi at 1254. Pumping at 4.2 bpm (176 gpm) was resumed at 1334.

Tracer data were very scattered. The tracer injection line was changed to allow a more concentrated slug of dye to be injected for the next tracer experiment.

At 1433 EE-2 production was shut in to obtain buildup data. The well was shut in until 1531 and a pressure of 1473 psi and then vented. The system was left in the vent mode, to obtain bottoms up, until 1948 when it was put back into gas-purge mode. The first set of corrosion coupons was removed/replaced at 1700.

May 25:

A morning summary reported boiling water in the cellar of EE-2. BJ was reported to have all four trucks ready to pump except that two discharge pulsation dampeners were out of commission. The MASSCOMP was down again. A safety meeting was conducted to go over placing the system in closed-loop mode. The CO_2 at this time was 0.169%. At 1245 the loop was placed on closed-loop flow. BJ's pumps were able to handle this amount of CO_2. At 1620 the injection rate was increased from 180 to 280 gpm. The first report of a yellow stain was reported on filter paper in the chemistry trailer. This was later identified as arsenic sulfide. The first signs of strainer plugging were noticed during the evening of this day.

May 26:

The MASSCOMP was repaired and put back on-line by noon. EE-2 strainer still indicated signs of plugging. At 1403 the injection rate was increased from 6.7 to 7.5 bpm. Injection pressure before the increase was 4463 psi. Because of the venting to the EE-1 pond during the first days of the test, it was necessary to pump water from the EE-1 pond to the 5 million-gal. pond.

During the evening, the EE-2 annulus pressure started to climb and the backside pressure started to drop. The backside was vented and the annulus pressure leveled out.

The pressure difference across the strainer continued to rise during the day. At 1945 the injection rate was decreased to 4.5 bpm. Shortly thereafter, injection was stopped and EE-2 was shut in. By 2034 EE-2 had built up to 1500 psi and a vent to the pond was started. By 2316 the backside pressure had climbed to 1169 psi, and it was put on a vent till 500 psi was reached. The leak from the conductor pipe into the EE-2 cellar was reported to have increased.

May 27:

The strainer and flow meter at EE-2 were checked and ready to go back on-line shortly after midnight. There were no problems found with either except for some metal in the strainer. An attempt to place the system back into production was short lived as the pressure drop across the strainer required the system to be shut in again. At 0134 EE-2 was shut in; BJ continued to pump at 4.5 bpm. The strainer was removed from the system and the system put back on-line at 0310. The injection pressure into EE-3 during this period remained constant at 3930 psi. At 0830 a CO_2 reading of 0.164% was given. At 0910 the loop was switched from gas-purge mode to closed-loop operation. The loop ran smoothly except for Meyers pump #5, which had a leak and a defective pressure gauge. The MASSCOMP went down in the evening. At 2008 the injection flow rate was increased to 7.1 bpm. MASSCOMP was back on at 2205.

May 28:

The loop ran smoothly during the night and morning. At 0815 the injection flow was decreased to 4 bpm to allow for a temperature log in

EE-3 by Oil Well Perforators (OWP). At the same time Tefteller of Farmington was getting ready for a Kuster temperature log in EE-2. BJ was shut down from 0901 till 1219 while OWP was lubricating their tool into the well. A flowing temperature log was run with BJ pumping at 4.2 bpm and 3800 psi. The log was completed and BJ shut down to remove the temperature tool at 1514. Pumping resumed at 1729 at 4.2 bpm.

At 1750 the system was placed in closed-loop flow, and all went well until 2120 when the power supply to the DAT control panel failed. Remote control of the system was lost at this time. Meyers makeup pumps went off, the heat exchanger fans stopped, etc. Before BJ was shut down they received 140°C water, which caused considerable problems. One suction hose was lost, both flow meters had to be rebuilt, the rubber seals on the suction manifold valves failed, and BJ later dismantled the fluid end of the pump for inspection. It is probable that the pulsation dampeners were also damaged. The line running from the heat exchangers to the BJ pump trucks was bent because of the thermal growth. Concrete safety blocks were moved. The damage to equipment turned out to be small, and there were no injuries. A thermal switch was installed to shut down the system if this should occur again. It never did.

May 29:

At 0410 the 250-psi safety relief valve was leaking and had to be replaced. BJ shut down at 0936 to replace their flow meters. During the change out of the meters, it was assumed that some air was trapped in the heat exchangers, the highest elevation in the system. BJ was placed on-line with all water coming from the makeup water system. EE-2 was vented to the pond through the choke manifolds. All four of the heat exchangers were purged of gas, and the loop was put back into normal operation by 1130.

At 1620 MASSCOMP down again; at 1841 MASSCOMP back on-line. All ran smoothly for the rest of the day.

May 30:

The system ran quietly all night. This was the day of the first radioactive tracer experiment. The tracer experiment was to inject approximately 70 to 75 mCi of ^{82}Br. At 1015 RA material arrived at

Fenton Hill. A safety meeting was held at 1150. The pressure locks on each well were valved off and filled with water so that any leaks could be detected by the sight of water. The high/low valve on EE-2 was set to trip at 250 and 500 psi. The 500-psi set pressure was selected to shut in the well before the pressure relief valve, which was set at 600 psi, could open in the event of a high-pressure excursion in the wellbore. This would keep any RA material confined within the surface system. The backside of EE-3 was shut in to seal up that potential leak path. Then the planned step-by-step procedure was followed, and the RA tracer was injected by 1430.

The RA material was injected into EE-3 by first injecting the RA tracer into one of the two injection lines between BJ's pumps and the wellhead. Second, that line was valved off from the RA tracer pig and brought up to the injection pressure of 3875 psi by one of the pumps on that line. Next, the wing valve was opened and, while continuing to pump on the second line, a pump was started on the first line and the RA tracer injected into the well. As soon as the tracer was well below the surface, the pump on the second line was shut down and pumping continued on the RA tracer line. First arrival of the tracer from the production well occurred at 1924 and was reported at 2998 cpm with a background reading of 2815 cpm. The second set of corrosion coupons was removed/replaced at 1530.

<u>May 31</u>:

The RA tracer peaked in the sample analyzed at 0206 in the morning. Maximum counts were 32 554 cpm. An unknown problem with the remote start-up of Meyers pump #6 was encountered. Switching to local control and then later back to remote control corrected the problem. A power glitch knocked out the MASSCOMP. This happened several times during the experiment both to the MASSCOMP and the chemistry trailer computer. Neither were protected by an uninterrupted power supply system.

<u>June 1</u>:

All ran smoothly until near midnight when the chemistry trailer sampling line flowed only gas and no water. After a safety check the line was removed and cleaned. This did not cure the problem.

June 2:

The back pressure on EE-2 was increased for a short period around 0300 in an attempt to drive the gas back into solution. This had no effect on the gas. At 0313 the back pressure was lowered back down to 350 psi and we went on gas-purge mode. Meyers makeup pump #7 stopped working and was removed for inspection. A piece of rubber was found to be wedged between the impellers and the housing. It was removed and after reassembly the pump was put back into service. Meyers pump #5 was then taken down to repair the seals. From about 1340 to 2100 the back pressure on EE-2 was increased to 500 psi to drive the gas back into solution. This time the higher pressure seemed to work; however, it was decided to stay in gas-purge mode. A shut-in of EE-2 was scheduled for 0400.

June 3:

At 0512 EE-2 was shut in; it climbed to 1500 psi by 0534. The backside pressure in EE-2 during this time slowly decreased from 540 to 252 psi and continued to go down to as low as 145 psi. The 1500-psi pressure was vented through the choke manifold down to 350 to 400 psi. At 0808 a second shut-in occurred while the site crew changed out the strainer. At 1132 we changed from vent mode to gas-purge mode. For a short time, from 1343 to 1417, the system was placed on closed-loop. All went well, so at this time the injection rate was increased to 7.5 bpm. The rest of the experiment was basically run at 6.9 to 7.5 bpm.

A loss of electrical power caused the MASSCOMP to go down for several hours.

June 4:

Barley seismic station stopped sending signals at 0245. It was determined the problem was low batteries. It was repaired and back on-line at 1011. A Kuster temperature log was run in EE-2 between 0900 and 1600. The third set of corrosion coupons was removed/replaced at 1745. A sequence of EE-2 shut-ins and vents started at 1953. Pressure built up to 1799 psi, then was vented to 350 psi before being shut in again.

June 5:

Shut-in/vent of EE-2 continued for 12 total cycles. A leak on EE-2 frontside had to be repaired before restarting closed-loop operations. Closed-loop operation commenced at 0910 at 7 bpm and ran smoothly. The EE-1 geophone tool was off-line and removed from the well at 1300. The EE-2 flow meter was briefly off-line at 2107. The problem was corrected, and the meter was working by 2120.

June 6:

A brief shut-in occured at 0823 to replace check valves on Meyers pumps #5 and #6. They were back on-line and everything was running smoothly by 0842. The MASSCOMP was down for servicing between 0915 to 1430. It went down again at 1610; seismicity was being recorded on analog tapes. It was determined that the tape drive was bad and needed to be replaced with the one from the TA-33 system.

June 7:

The system had to be shut down at 1245 to clean the EE-2 strainer. Closed-loop operations were restored by 1800. The system was run in gas-purge mode due to high CO_2 content of the production fluid.

June 8:

A 1500-kg (155 000-SCF) slug of nitrogen was injected into EE-3A from 1121 to 1200. The main purpose of the gas injection was to attempt to clean out the EE-2 production interval where it was assumed debris was filling and possibly covering near-wellbore fractures. Because of a storm one phase of power was lost at 1255; the site and DAT switched to emergency backup power. Jemez power was back on-line at 1436, so normal loop operations were reinitiated. The loop was back to normal by 1500. The DAT switched back to normal power at 1630 and all was running normally by 1636, including the MASSCOMP which was back on-line.

First sign of N_2 at EE-2 was seen at 1212 and was back to background by 1240. This was probably not a result of N_2 injection. The major pulse arrived at EE-2 at 1715 with an increase to 45% nitrogen fraction in the gas stream. Too much gas was present in the production stream to make reliable measurements of total gas. The system was switched to gas-purge mode operation. The vent line on EE-2 was opened at 1737 to prevent fouling the heat exchangers with sand or other debris if the nitrogen was successful in cleaning EE-2. It was determined by 1800 that the debris being produced was minimal, and a side stream was run through the surface system and heat exchangers to allow good gas measurements. At 2136 production pressure was reduced to 250 psi to surge fractures as much as possible during projected peak nitrogen production. BANC and CEBT seismic stations were not working at 2305.

June 9:

At 0630 the EE-2 production pressure was increased to 550 psi, and at 0715 the vent was shut in and all production was through the loop. The N_2 content of the gas stream peaked at 1044 with 79%. Surface loop was still being operated in gas-purge mode. High/low valves on EE-2 were reset so the back pressure on EE-2 could be raised to 800 psi and N_2 could be kept in solution. The EE-2 flow meter was reading 40 gpm higher than the sum of the flow through the heat exchanger flow meters, probably as a result of gas in the system. BANC seismic station was checked out and back on line at 0937. The MASSCOMP was down from 1930 to 2332.

June 10:

Rough calculations indicated more N_2 was being produced than was injected. Not getting good gas measurements from the way system was set up. Saw second peak in N_2 content of gas stream (79%) at 1315. A water sample taken of fluid being sent to injection pumps indicated not much N_2 was recycling through the system. Seismic station CEBT was still down; water in the electronics enclosure caused the problem and the electronics had to be brought to the site for repairs.

June 11:

The N_2 content was going down in the gas stream. EE-2 back pressure was dropped from 456 to 350 psi in preparation of going to closed-loop operation. Gas concentration went up, so EE-2 pressure was raised to the previous level. The system was operating in closed-loop mode with 500 psi on EE-2 at 2225. EE-3A injection rate was increased to 10 bpm at 2323. The CEBT electronics were repaired and the station put back on-line.

June 12:

Operations running smoothly. Significant seismicity occurred as a result of high-rate pumping but with a considerable time lag. Changed operation to gas-purge mode, flowing nominal 7 bpm. Seismic activity from high-rate pumping down; therefore pulling EE-1 geophone at 1000. It was noticed that water, about 1 gpm, was flowing from GT-2 at 1240. Wellhead will be shut in, and pressures from GT-2 and EE-1 will be recorded.

June 13:

MASSCOMP was down and put back on-line by 0613. EE-2 strainer was cleaned out from 0830 to 0930. Preparations were made for the second radioactive tracer test. System is being run in vent mode. The RA tracer was injected at 1207 to 1224. At 1228 "fresh" water flush mode was initiated. RA tracer was first seen at EE-2 at 1656; peak of 23 580 counts/min was seen at 2151. MASSCOMP was down from 1205 to 1408.

June 14:

System was running smoothly. At 2354 system was switched to gas-purge mode and water was being recycled.

June 15:

System was switched to closed-loop mode at 0745. The RA count was down to 3340 at 0630. Tefteller started Kuster survey of EE-2 at 2115.

June 16:

Kuster tool was out of EE-2 at 0305. At 1100 OWP was starting temperature log of EE-3A while injecting 6.5 bpm. Log was completed at 1606. At 2045 back pressure on EE-2 was increased to 1000 psi and was maintained between 950 and 1068 psi.

June 17:

EE-2 back pressure was reduced to 435 psi at 0320. EE-2 was shut in from 0933 to 1032; then system was put in vent mode. EE-2 wellhead was shut in at 1138 for repairs. Vent mode was reinitiated at 1336. EE-2 strainer was cleaned out starting at 2352.

June 18:

EE-2 strainer cleaned out and back on-line at 0036. System back in closed-loop operation by 0051, pumping at 7 bpm. BJ is down to one pump that will operate. Fourth set of corrosion coupons were changed out. The pumping was terminated at 1600, and EE-3A and EE-2 were shut in. BJ trucks and missile were moved out by 1730. The DAT will be kept on-line to monitor the shut-in.

June 19:

EE-2 backside had to be vented intermittently to maintain pressure below 1000 to 1500 psi.

June 20:

EE-2 backside was plumbed so it will vent to pond automatically. MASSCOMP was shut down at 1130. At 1406 DAT was set up for unmanned operations.

June 23:

OWP ran temperature and tracer logs in EE-3A.

June 25:

Tefteller ran a Kuster survey of EE-2.

APPENDIX D
GEOCHEMISTRY NOMENCLATURE

a^*	quartz surface area to fluid volume ratio (m^2/m^3)
b	fracture aperture (m)
C	concentration (kg/m^3)
C^*	dimensionless concentration in Eq. (V-1)
C_{in}	injection fluid concentration (kg/m^3)
C_o	initial production fluid concentration (kg/m^3)
C^∞	silica saturation concentration (kg/m^3)
f_q	fraction of quartz present in granite
$f(V)$	residence time distribution curve (m^{-3})
k	quartz dissolution rate constant (m/s)
K_{eq}	equilibrium constant
K_H	Henry's law constant (bar/mole fr.)
m_p	mass of tracer injected (kg)
P	pressure (bar)
P_{CO_2}	partial pressure of CO_2 (bar)
P_w	vapor pressure of water (bar)
t	time (s)
V	cumulative produced fluid volume (m^3)
x_{CO_2}	mole fraction of CO_2
γ_i	activity coefficient for component i
Φ	dimensionless concentration in Eq. (V-2)

APPENDIX E

ENVIRONMENTAL MONITORING: DISCRIMINATION CRITERIA

Strip charts containing surface and Precambrian station recordings will be run during the ICFT for the purpose of environmental monitoring. In the event that a large earthquake is suspected to have occurred, the following simple criteria should be applied before contacting the on-call seismologist if he is not on-site. A calendar containing names and phone numbers will be posted on the MASSCOMP.

If a large earthquake has occurred under Fenton Hill, the following must have been observed at all working stations:

1. The strip chart recordings must show coherent arrivals at all stations (within a few seconds).
2. The <u>initial</u> portions of the recordings will be saturated (truncated).
3. The <u>initial</u> portions will contain high frequencies; if individual "wiggles" are seen, then the event is fairly distant.
4. The signal (coda) duration will be large: 100 sec = magnitude 2.5; 160 sec = 3.0; 360 sec = 4.0 (be sure to check strip chart speed before measuring duration). See following procedures for appropriate action based on the coda duration.

The following may also be observed:

1. The event should be felt.
2. Rapid changes in pumping parameters may occur.

If a large-magnitude, nearby earthquake is suspected, the on-call seismologist should be contacted in order that on-site personnel may be "talked through" the location procedure on the MASSCOMP. See following section (Procedures) for subsequent action.

Environmental Monitoring: Procedures

ALERT - $M_L > 2$ (Duration > 100 sec)

Event must be located. Contact on-call seismologist for a "talk through" location on the MASSCOMP if he is not on-site. If location is within 5 km of injecton point, proceed to:

1. Notify needed personnel in case further seismic activity requires shut-in or immediate vent under the criteria below.
2. Notify project management.
3. Pay close attention to pressure/flow data.

SHUT-IN - $M_L > 2.5$ (Duration > 150 sec)

Event must be located as above. If within 5 km of injection, proceed to:

1. Inform experiment manager of need to shut in. Pumping should resume only after consultation with project management.
2. Inform project management.
3. Pay close attention to pressure/flow data.

IMMEDIATE VENT - $M_L > 3.5$ (Duration > 360 sec)

Event will be located as above. If within 5 km of injection, inform experiment manager of need to begin venting reservoir fluids. Further action will be determined by project management.

Plate I. Event Chronology with ICFT Performance Data.

LA-11498-HDR

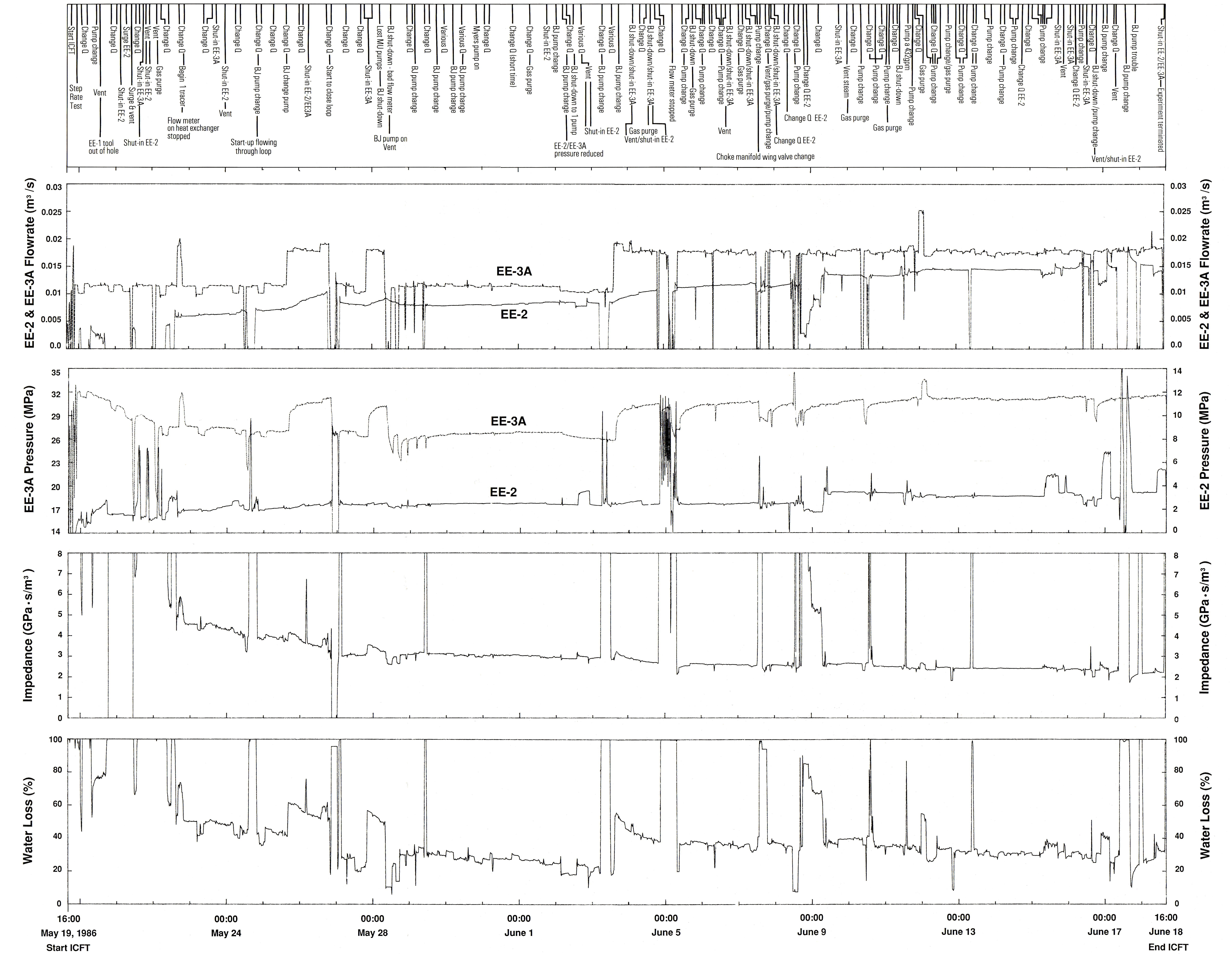
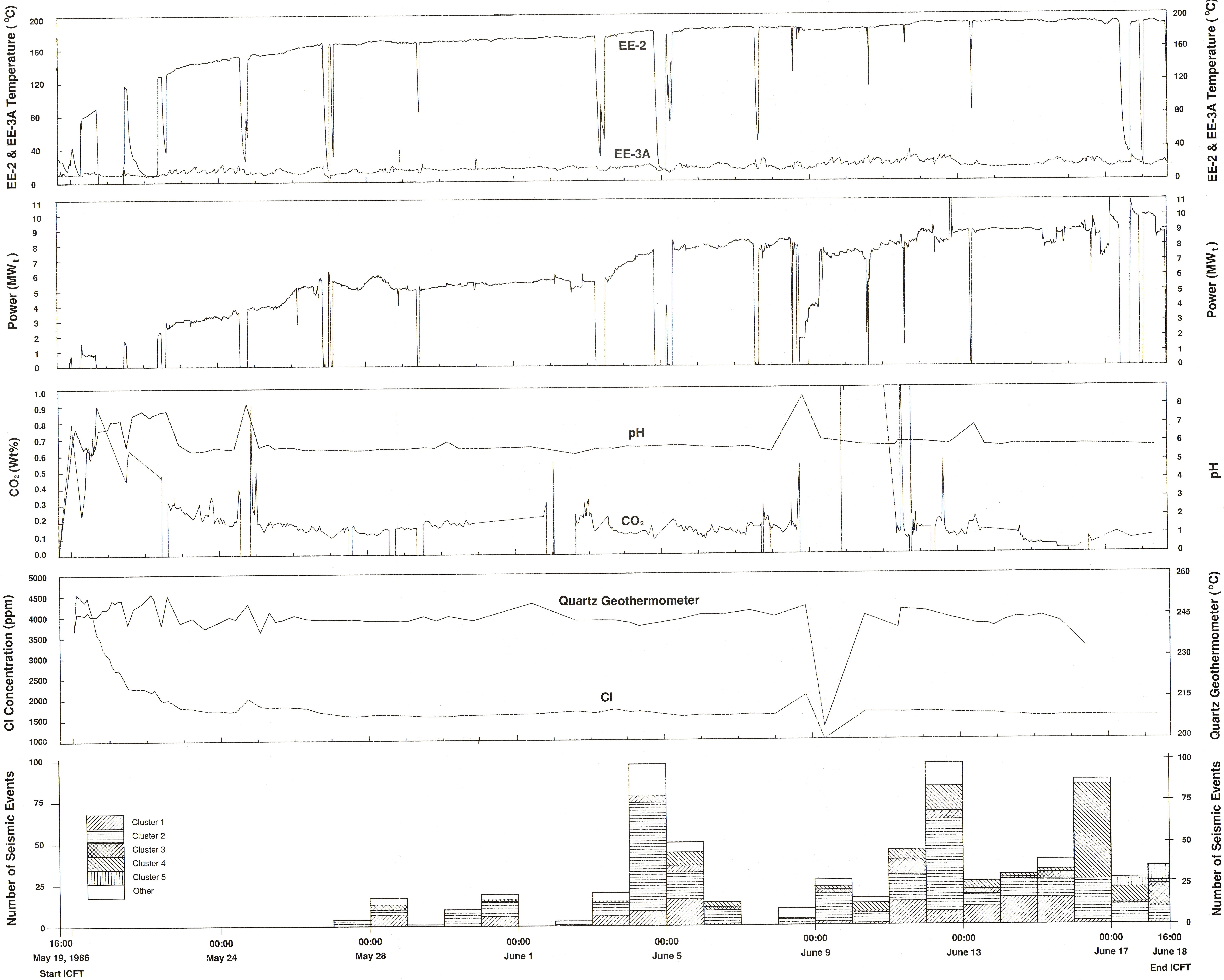


Plate II. ICFT Performance Data.



LA-UR-02-5009
August 2002

LOS ALAMOS NATIONAL LABORATORY

CLOSURE PLAN FOR FENTON HILL GEOTHERMAL 1-MG SERVICE POND AND EE-2A PRODUCTION WELL

Prepared by:

Los Alamos National Laboratory
Los Alamos, New Mexico 87545

RECEIVED

AUG 15 2002

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August 14, 2002

Mr. Robert Beers
University Technical Representative
RRES-WQH
Los Alamos National Laboratory
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Project No. 819592

Task Order No.7
Contract No. 003CT0008-8L

Transmittal
Los Alamos National Laboratory Closure Plan for Fenton Hill
Geothermal 1-Million Gallon Service Pond and EE-2A Production Well

Dear Mr. Beers:

Shaw Environmental & Infrastructure (Shaw E&I) is pleased to provide a final copy of the "Los Alamos National Laboratory Closure Plan for Fenton Hill Geothermal 1-Million Gallon Service Pond and EE-2A Production Well" for signature. Upon receipt of the signature page, a total of 20 copies will then be provided for distribution.

If you have any questions or require additional information on this submittal, please contact me at 661-5710.

Respectfully submitted,
Shaw E&I

Jennifer Griffin
Project Manager

Enclosures
cc: Central Files

Document: Fenton Hill Closure Plan
Revision No.: 0.0
Date: August 2002

LOS ALAMOS NATIONAL LABORATORY

CLOSURE PLAN FOR FENTON HILL GEOTHERMAL 1-MG SERVICE POND AND EE-2A PRODUCTION WELL

LA-UR-02-5009

August 2002

Prepared by:

Los Alamos National Laboratory
Los Alamos, New Mexico 87545

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F	NM OCD Approval of July 1998 Minor Modification Request, May 1999
F	LANL Draft Seeding Specification

LIST OF ABBREVIATIONS/ACRONYMS

1-MG	1-million gallon
ft	feet/foot
HDR	Hot Dry Rock Geothermal Project
HSR-1	Health Physics Operations Group
in.	inch(es)
LANL	Los Alamos National Laboratory
NM	New Mexico
NORM	naturally occurring radioactive material
OCD	Oil Conservation Division
P&A	plugging & abandonment
PPE	personal protective equipment
PVC	poly vinyl chloride
SSHSP	Site-Specific Health and Safety Plan
TA	technical area
yd^3	cubic yard(s)

FENTON HILL
GEOTHERMAL 1-MILLION GALLON SERVICE POND AND EE-2A PRODUCTION WELL CLOSURE PLAN

1.0 INTRODUCTION

Los Alamos National Laboratory (LANL) intends to close the 1-million gallon (1-MG) service pond and the EE-2A geothermal production well associated with the Hot Dry Rock (HDR) Geothermal Project at the Technical Area (TA) 57 Fenton Hill site. The TA-57 Fenton Hill site is located approximately 30 miles west of Los Alamos on State Road 126 in Sandoval County, New Mexico, at an elevation of 8,700 feet (ft). Fenton Hill is the site of the first HDR geothermal research experiment in the world and is located at the western margin of the Valles Caldera in Northern New Mexico. The purpose of the experiment was to utilize the natural heat present beneath the surface of the Valles Caldera as geothermal energy for commercial production.

The HDR experiment involved the drilling of two wells into an impermeable rock formation and fracturing the space between the wells. Cold water from the surface was then injected into the first well and heated by geothermal energy from the rock formation. The heated water was returned to the surface through the second well, passed through a turbine or heat exchanger and was re-circulated through the system. The site originally consisted of four wells: two for experimental confirmation of the technology and two for verification of commercial applicability. The HDR experiment has since been concluded and the U.S. Department of Energy has determined that geothermal energy production at the site is cost prohibitive.

This closure plan describes the methods by which the 1-MG service pond and EE-2A production wellhead will be decommissioned. The plugging and abandonment (P&A) of the EE-2A production well is not covered by this closure plan. The closure plan describes existing site conditions, decommissioning procedures for the pond and wellhead, waste management, site characterization, and restoration of the site.

2.0 SITE DESCRIPTION

The 1-MG service pond and EE-2A production well are located in the southwest section of TA-57 as indicated on Figure 1. Detailed photographs of the site are provided in

Appendix A. The following sections provide detailed descriptions of the service pond and production well to be closed at the site.

2.1 1-MG Service Pond

The 1-MG service pond was installed in 1990 by the HDR project to store geothermal fluids vented from the EE-2A production well. The pond is 90-ft wide, 270-ft long and 12-ft deep and has a capacity of approximately 600,000 gallons. It is constructed of a dual membrane liner system that consists of 30 mil XR5 and 30 mil oil-resistant polyvinyl chloride (PVC) liners, with intermediate geo-fiber and bottom pads. The estimated area covered by each liner is 25,000 square feet. The pond includes:

- Drainpipe - 4-inch (in.) diameter, approximately 30-ft long
- Overflow Pipe - 21-in. by 15-in. diameter, approximately 50-ft long
- PVC feed line, 12-in. diameter, approximately 60-ft
- PVC feed line, 12-in. diameter, approximately 70-ft
- Leak collection system underlying the primary liner – Schedule 40 PVC perforated pipe with an oil-resistant secondary liner embedded in a gravel trench.
- PVC leak detection well - 16-in. diameter, approximately 20-ft deep,
- A steel sump – 8-ft diameter, 18-ft deep
- Piping associated with the sump and leak detection well.

Figures 2, 3, and 4 provide site grading plans and details for the equipment and structures associated with the 1-MG service pond.

2.1.1 Geothermal Fluids

The 1-MG service pond was drained in 1997 and cleaned to remove accumulated sludge. From 1997 to present, the pond has been used to hold vented geothermal fluid from EE-2A production well and ion exchange back flush water from the Milagro Project. Currently, the volume of the 1-MG service pond varies from 30,000 – 80,000 gallons depending on the amount of precipitation and evaporation in the area. Table 1 provides analytical results for the liquids accumulated in the 1-MG service pond as of July 2002.

Table 1
Summary of Analytical Results of Geothermal Fluid Sample from the 1-Million Gallon Service Pond at TA-57 Fenton Hill

Analyte	Result (mg/L) [a]	Maximum Concentration of Contaminants (40CFR 261.24) (mg/L)
Silver	<0.01	5.0
Aluminum	<0.01	NA
Arsenic	3.56	5.0
Boron	22.2	NA
Barium	1.3	100.0
Beryllium	<0.002	NA
Cadmium	<0.01	1.0
Chlorine	7612	NA
Cobalt	<0.01	NA
Chromium	<0.01	5.0
Copper	<0.01	NA
Fluorine	1.26	NA
Iron	0.03	NA
Mercury	0.0003	0.2
Lithium	10.7	NA
Magnesium	134	NA
Manganese	0.039	NA
Molybdenum	0.02	NA
Sodium	3220	NA
Nickel	<0.01	NA
Lead	<0.01	5.0
PH	7.91	NA
Selenium	<0.0002	1.0
Antimony	<0.1	NA
Sulfate	179	NA
Strontium	5.08	NA
Titanium	<0.002	NA
TDS	36,728 [b]	NA
TSS	32.9 [b]	NA
Vanadium	<0.002	NA
Zinc	<0.01	NA

a Sample collected on April 18, 2002.
b Sample collected on July 30, 2002.

NA = not applicable
mg/L = milligrams per liter

2.1.2 Sludge

Fenton Hill project personnel estimate the volume of sludge located in the 1-MG service pond to be approximately 35 cubic yards (yd^3). The exact composition of this material is currently unknown. One representative sample of the sludge will be collected prior to the commencement of closure activities to determine characteristics for waste disposal. This sample will be analyzed for total metals plus boron, toxicity characteristic leaching procedure metals, volatile organic compounds, and semi-volatile organic compounds.

2.2 EE-2A, Production Well

The EE-2A production well was originally completed as a production well with a 7-in. casing from the surface to just above the injection interval. The production well will be P&A in accordance with the LANL Groundwater Discharge Permit GW-031. Approval for the P&A was obtained from the New Mexico (NM) Oil Conservation Division (OCD) on July 19, 2002. The approval documentation and P&A plan are provided in Appendix B.

2.3 EE-2A, Production Wellhead

The EE-2A production wellhead is located at the northeast end of the service pond as shown on Figure 1. It is surrounded by an approximately 12 ft long by 10 ft wide by 6-in. thick concrete pad and prefabricated metal tower. The metal tower will be removed prior to the commencement of final decommissioning activities at the service pond and wellhead. Removal of the finished wellhead, associated valves and piping, the concrete sump, grating, and the casing are included in the scope of this closure plan. Figure 5 provides a schematic of the wellhead. Photographs of the tower and wellhead are provided on pages 1 and 10 of Appendix A. A schematic, which details the production well completion is provided in Appendix C.

3.0 CLOSURE REQUIREMENTS

Closure of the 1-MG service pond and EE-2A production wellhead will be conducted in accordance with NM OCD and U.S. Forest Service, Jemez Ranger District, requirements. This will include, at a minimum:

- Removal and treatment/disposal of the pond contents.
- Removal and disposal of all equipment, concrete, piping, and liners at a solid waste facility in compliance with 19 NMAC 15.9.712 (Appendix D).
- Restoration of the site to current site contours and grading.
- Completion of a site inspection by the NM OCD.

The closure of the 1-MG service pond and EE-2A production wellhead is not subject to the requirements of the Resource Conservation and Recovery Act because wastes generated due to geothermal exploration are exempt in accordance with 40 CFR 261.4(b)(5). This includes

> *Drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy.*

The 1-MG service pond contents (i.e., geothermal fluids, and sludge) currently consist of both exempt geothermal fluids and non-exempt Milagro Project wastewater as described in Section 2.1.1. However, the Milagro Project wastewater has been limited to less then 5% of the total volume of the pond, in accordance with the mixing policy of the NM OCD. This maintains the applicability of the exemption for the overall contents of the pond. The mixing of Milagro Project wastewater with the pond contents was approved by the NM OCD on May 10, 1999 in accordance with a LANL request for modification of the Ground Water Discharge Plan GW-031. The request for modification is provided in Appendix E. The NM OCD approval letter is provided in Appendix F.

The LANL Groundwater Discharge Permit GW-031 regulates the P&A of the EE-2A production well. The P&A of the EE-2A production well is outside of the scope of this closure plan.

4.0 HEALTH AND SAFETY REQUIREMENTS

Job hazards associated with closure activities will be identified, controls developed, and workers briefed before closure activities are conducted, in accordance with LANL safety procedures. Personnel involved in closure activities will wear appropriate personal protective equipment (PPE), specified by Health Physics Operations Group (HSR-1) and Industrial Hygiene and Safety Group, and will follow good hygiene practices to protect themselves from exposure to hazardous waste. Minimum PPE requirements will consist of coveralls, steel-toed shoes, and safety glasses. All workers involved in closure activities will be required to have appropriate training including HAZWOPER for general site workers (40 hours and refresher) and TA-57 site specific, as appropriate.

Prior to initiating fieldwork a staging area will be established at the site. This area will provide space for staging scrap, wastes (roll-off bins, drums) equipment and material storage, and sanitation facilities. All personnel will be required to review and acknowledge the Site-Specific Health and Safety Plan (SSHSP) and adhere to the procedures and requirements set forth in the SSHSP. All activities will also be coordinated with the appropriate LANL organizations, state and federal regulatory agencies.

5.0 DECOMMISSIONING ACTIVITIES

5.1 Removal of Fluids

Following P&A of the EE-2A production well, fluids contained in the 1-MG service pond will be pumped and stored temporarily in frac tanks at the Fenton Hill site. A representative sample of the liquid will be collected and submitted to the LANL Hydrology, Geochemistry, and Geology Group laboratory for water quality parameter analysis prior to disposal. Disposal options include:

- On-site evaporation with disposal of the evaporator bottoms at a NM OCD approved facility.
- Off-site disposal at a NM OCD approved facility.

Other options for disposal of the 1-MG service pond liquid will be evaluated as they become available. Final disposal will be determined by LANL personnel in coordination with NM OCD and U.S. Forest Service personnel, prior to the termination of closure activities at the site.

5.2 Removal of Sludge

The sludge contained in the 1-MG service pond will be pumped and staged on-site prior to disposal as described in Section 9.0.

5.3 1-MG Service Pond

Decommissioning of the 1-MG service pond will commence after the fluids and sludge have been removed for storage pending disposal. Figures 2, 3 and 4 provide schematics and details of the 1-MG service pond, sump, drain bulkheads, and leak detection system. Decommissioning activities will include:

- Removal of approximately 5,800-ft of 4-ft high chain link fence from the perimeter of the pond.
- Removal of the primary and secondary pond liners.
- Excavation and removal of the three concrete reinforced drain bulkheads and piping.
- Excavation and removal of the leak detection piping and fill.
- Excavation and removal of the sump located at the east-end of the pond including the piping connecting it to the pond.
- Excavation and removal of the leak detection well
- Removal of approximately 5 hydrants from the perimeter of the site. These hydrants will be cut and capped below the hydrant assembly. The piping will be abandoned in place.

The fencing, hydrants, concrete, liners, piping, and fill will be staged on-site pending recycling and/or disposal as described in Section 9.0.

5.3.1 1-MG Service Pond Liners

The 1-MG service pond consists of a primary and secondary liner system with leak detection and pads. After the geothermal fluids and sludge have been removed from the 1-MG service pond, the primary liner will be pressure washed to remove any excess sludge. The water will be collected and staged with the sludge on-site for disposal as described in Section 9.0. After the liner is cleaned it will be cut into manageable pieces and removed from the service pond for staging on-site prior to waste disposal. The primary liner will be managed to ensure that it meets solid waste landfill criteria as described in 19 NMAC 15.9.712, prior to disposal.

The secondary liner is located beneath the leak detection system (i.e., gravel, sand, perforated piping). The fill material will be removed from the service pond as described in Section 5.3.2. If any evidence of a breach in the primary liner is present in the fill material, the secondary liner will also be pressure washed to ensure that it meets solid waste landfill criteria for disposal. It will then be cut into manageable pieces and removed from the containment for staging on-site prior to waste disposal. The secondary liner will be managed to ensure that it meets solid waste landfill criteria as described in 19 NMAC 15.9.712, prior to disposal.

5.3.2 Leak Detection Fill

The fill material (sand and gravel mix) associated with the leak detection system is located between the primary and secondary liners of the pond. This material will be examined for evidence of a containment breach in the primary liner (i.e., moisture, stains). If it is determined that this fill material was not exposed and is clean, it will be excavated and set aside for use as fill material during the site restoration phase of the closure. If it is determined that the fill material was exposed and mixed with pond liquids and/or sludge, it will be excavated, sampled and analyzed for contamination. The fill material will be staged on-site for waste disposal in accordance with the level of contamination as described in Section 9.0.

5.4 EE-2A Production Wellhead

Decommissioning of the EE-2A Production Wellhead will commence after the production well has undergone P&A and the tower structure is removed for recycle and/or disposal. Figure 5 provides a schematic of the wellhead. A photograph of the wellhead is also provided on page 10 of Appendix A. Decommissioning activities at the EE-2A production well head will include:

- Excavation and removal of approximately 125 cubic feet of concrete surrounding the EE-2A production wellhead.
- Removal of the piping, grating.
- Removal of the wellhead to the flanged fitting.
- Excavation and removal of the concrete sump.
- Excavation of the soil around the wellhead to a depth of 3-ft to allow for the well casing to be cut.
- Installation of a NM OCD approved underground marker in accordance with 19 NMAC 15.4.202.
- Backfill and restoration of the area to the current contours and grade of the site.

The well casing, pipe, and concrete removed during the cutting will be staged on-site to be recycled or disposed at a solid waste landfill. Prior to disposal, the waste from cutting will be surveyed for naturally occurring radioactive material (NORM) by LANL HSR-1 personnel. Results of the survey and written authorization from the NM OCD will be required prior to recycling or disposal of the material in accordance with 19 NMAC 15.9.712.

6.0 SITE CHARACTERIZATION

The 1-MG service pond is identified as PRS 57-004(b) in LA-UR-96-1062, "RFI Report for Potential Release Sites at TA-57" (LANL, 1996). Section 1.2.1.3 of the RFI report indicates that there is no evidence of contaminate release from the 1-MG service pond and that the sediments will be investigated upon decommissioning of the site. Characterization and/or confirmation soil samples may be collected from the soils underneath the liner and around the drain and feed line excavations by the Environmental Restoration Group prior to the commencement of restoration activities at the site.

6.1 Inspection of Surface beneath the Secondary Liner

The ground beneath the secondary liner of the 1-MG service pond will be inspected for moisture accumulation and/or soil discoloration. If any evidence of leakage is detected, the affected soil will be excavated, sampled, and analyzed for contamination. The affected soil will be staged on-site for waste disposal in accordance with the level of contamination as described in Section 9.0.

6.2 Geodetic Survey

A geodetic survey will be conducted of the excavated pond area and all associated structures (i.e., sumps, drains, and the EE-2A production well) following complete removal of all equipment and materials associated with the 1-MG service pond.

7.0 SAMPLING ACTIVITIES

The following sections describe procedures and methods for sampling, analysis, and documentation applicable to closure activities. Sampling will be conducted in accordance with procedures given in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, " *SW-846* (EPA, 1986).

7.1 Soil Sampling

Soil samples will be in accordance with ESH-18-HCP-012.2, "Sediment Sampling," (LANL, 2001a).

7.2 Liquid Sampling

Liquid samples will be collected in accordance with ESH-18-HCP-005.3, "Special Sampling of Waste Streams" (LANL, 2001b).

7.3 NORM Surveys

The NM OCD requires that waste materials generated at the site be surveyed for NORM prior to disposal. These surveys will be conducted by LANL HSR-1 personnel to determine if the site is above background levels due to the drilling and venting operations associated with the 1-MG service pond and/or EE-2A production well. To be considered above the background, the survey measurements will have to be at least 50 counts per micro Rankin per hour above the background as provided by 20.3.1.14 NMAC. Personnel conducting measurements shall use ER-SOP-10.14 "Performing and Documenting Gross Gamma Radiation Scoping Surveys" as a guideline (LANL, 2001c).

8.0 SITE RESTORATION

LANL intends to utilize the earthen berm located on the southern boundary of the 1-MG service pond as backfill material pending the results of the site characterization activities, if any, described in Section 6.0. This berm will provide approximately 1000 yd^3 of backfill material. If necessary, the remaining excavation will be backfilled with ASTM D2487 certified clean crushed tuff. The fill will be placed in 8-in. lefts then compacted. IThe pond and other areas of extensive soil removal will be backfilled to current site contours and grade, not to exceed a 3:1 slope. Subsequent to the emplacement and compaction of the final lift, approximately 3 to 5 in. of loose topsoil will be applied to disturbed areas in preparation for permanent seeding.

During backfilling and restoration activities, temporary silt fencing and straw bale check dams will be installed, maintained, and routinely inspected. All disturbed areas will be re-seeded according to the LANL seeding specifications provided in Appendix G and in accordance with U.S. Forest Service requirements. A geodetic survey will be conducted at the site following restoration activities.

Upon completion of the restoration activities, LANL will schedule a site inspection for NM OCD officials to finalize approval of the closure.

9.0 WASTE MANAGEMENT

All closure activities will be conducted with waste minimization goals in mind. All waste materials generated will be controlled, handled, and disposed of in accordance with LANL waste management procedures. Several waste streams will be generated during the decommissioning activities associated with this closure plan. Table 2 provides a summary of the anticipated waste streams, the waste type, anticipated volume, and appropriate disposal options.

Table 2
Potential Waste Streams, Types, Volumes, and Disposal Options

Waste Stream	Waste Type	Estimated Volume [a]	Disposal Options
1-MG service pond fluids	Liquid	30,000 –100,000 gallons	• On-site treatment • NM OCD Permitted Facility
Sludge	Solid	35 yd^3	• NM OCD Permitted Facility
Concrete	Solid	10 – 20 yd^3	• LANL Recycle Program • Solid Waste Facility
Piping (metal)	Solid	100-150 ft	• LANL Recycle Program • Solid Waste Facility [b]
Piping (PVC)	Solid	150 – 200 ft	• LANL Recycle Program • Solid Waste Facility
Gravel (Leak Detection System)	Solid	20 – 60 yd^3	• Backfill • NM OCD Permitted Facility
Hydrants/Scrap metal	Solid	<1 yd^3	• LANL Recycle Program
Pumps	Solid	<1 yd^3	• LANL Recycle Program
Liner	Solid	150 –200 yd^3	• Solid Waste Facility

a Estimated from as-built drawings of the 1-MG service pond and EE-2A well casing.
b Must be accompanied by analytical data for NORM and written authorization for disposal from OCD.

ft = feet/foot
LANL = Los Alamos National Laboratory
NM OCD = New Mexico Oil Conservation Division
PVC = polyvinyl chloride
yd^3 = cubic yard(s)

10.0 POST CLOSURE REPORTING

A post-decommissioning/closure report will be prepared for the NM OCD that details all of the closure activities. It will, at a minimum, include:

- Disposal records
- Photographs of the site and the closure activities.
- Data from sludge and geothermal water analysis.
- Copies of permits (as applicable)
- As-built site drawings from the geodetic surveys of the containment before and after restoration.

11.0 REFERENCES

EPA, 1986 and all approved updates, "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," *(SW-846)* Office of Solid Waste and Emergency Response, U.S. Government Printing Office, Washington, D.C..

LANL, 2001a, "Sediment Sampling," ESH-18-HCP-12.2, Los Alamos National Laboratory, Los Alamos, New Mexico.

LANL, 2001b, "Special Sampling of Waste Streams," ESH-18-HCP-005.3, Los Alamos National Laboratory, Los Alamos, New Mexico.

LANL, 2001c, "Performing and Documenting Gross Gamma Radiation Scoping Surveys," ER-SOP-10.14, Los Alamos National Laboratory, Los Alamos, New Mexico.

LANL, 1996, "RFI Report for Potential Release Sites at TA-57," LA-UR-96-1062, Los Alamos National Laboratory, Los Alamos, New Mexico.

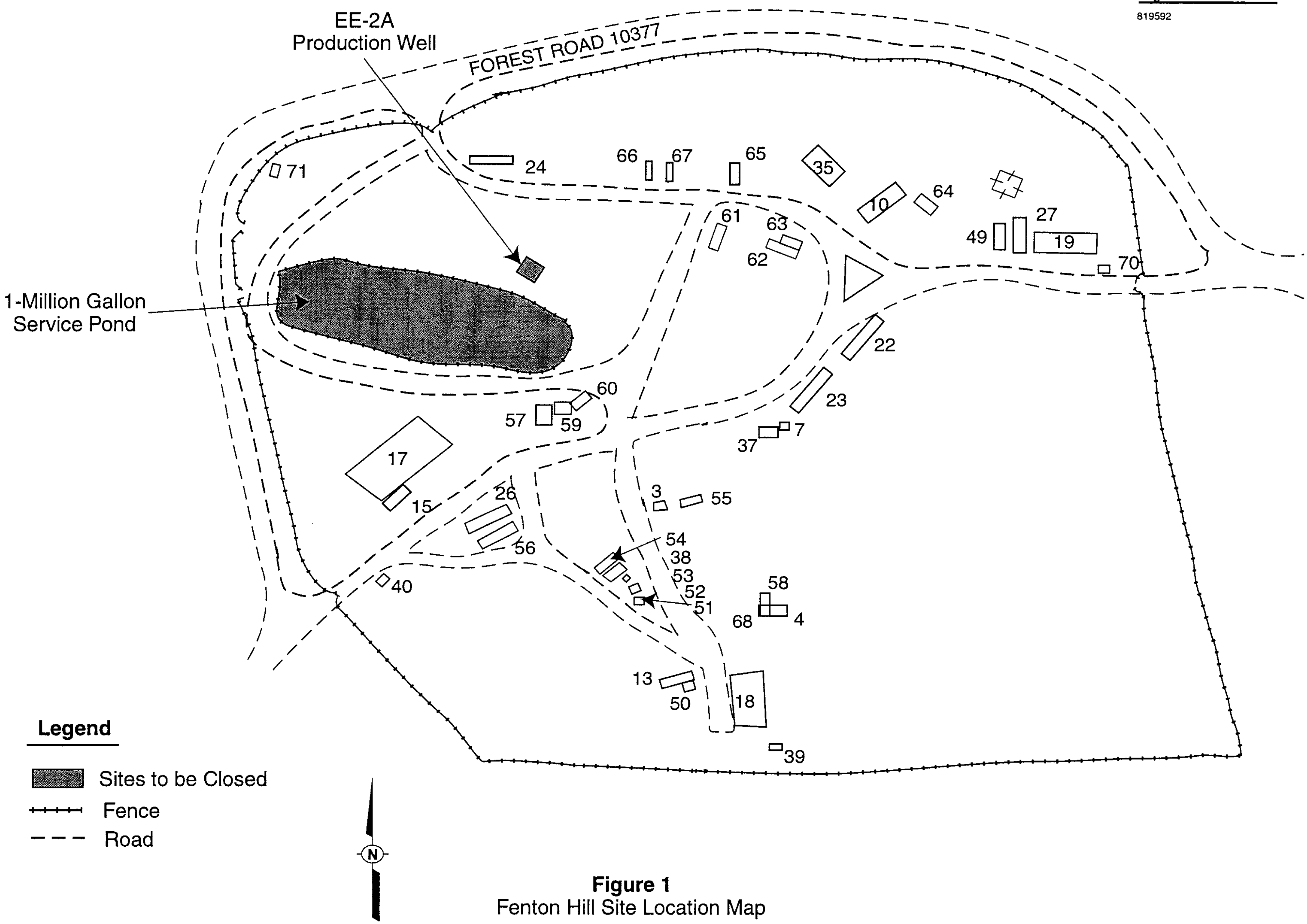


Figure 1
Fenton Hill Site Location Map

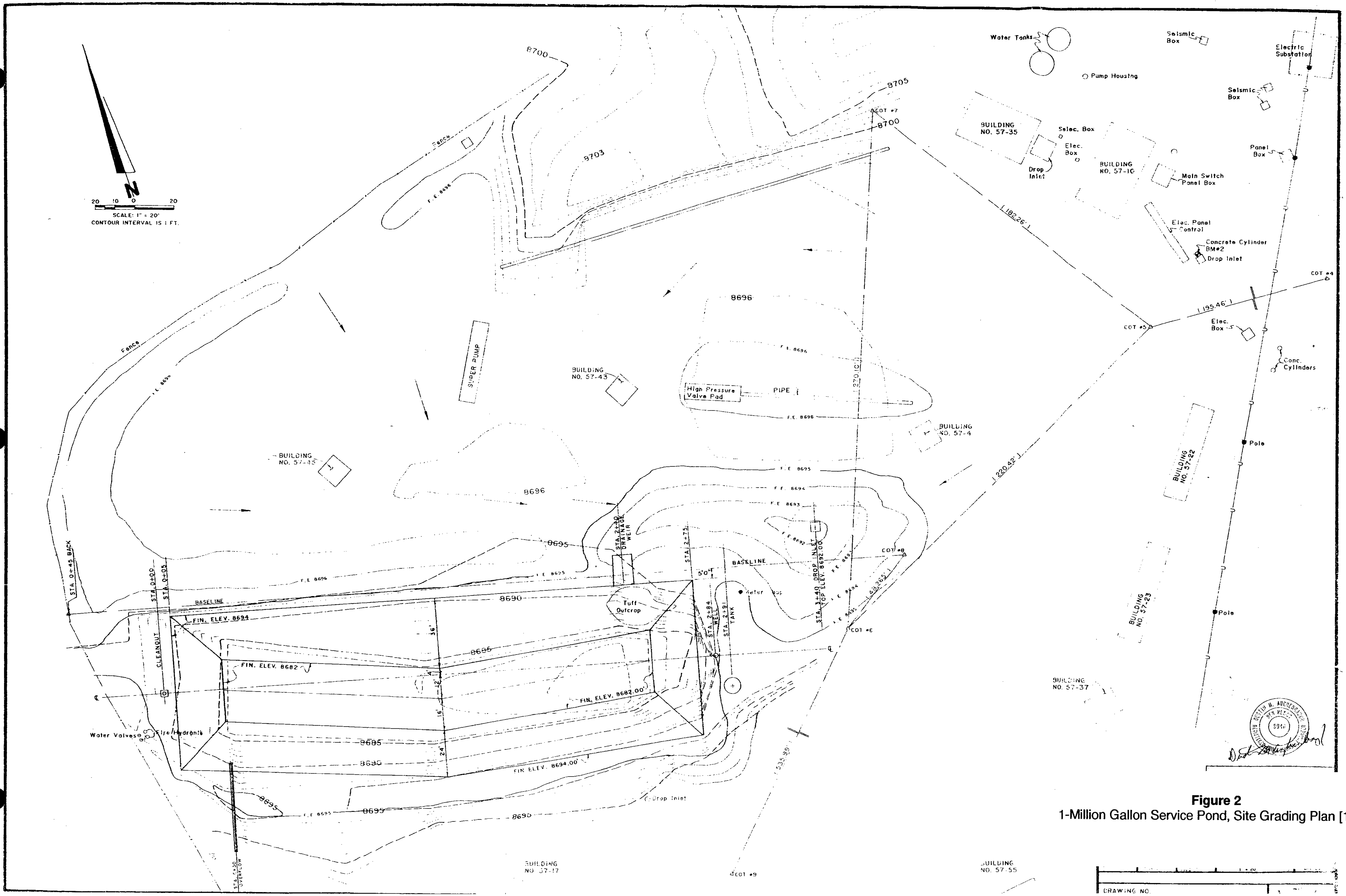


Figure 2
1-Million Gallon Service Pond, Site Grading Plan [1989]

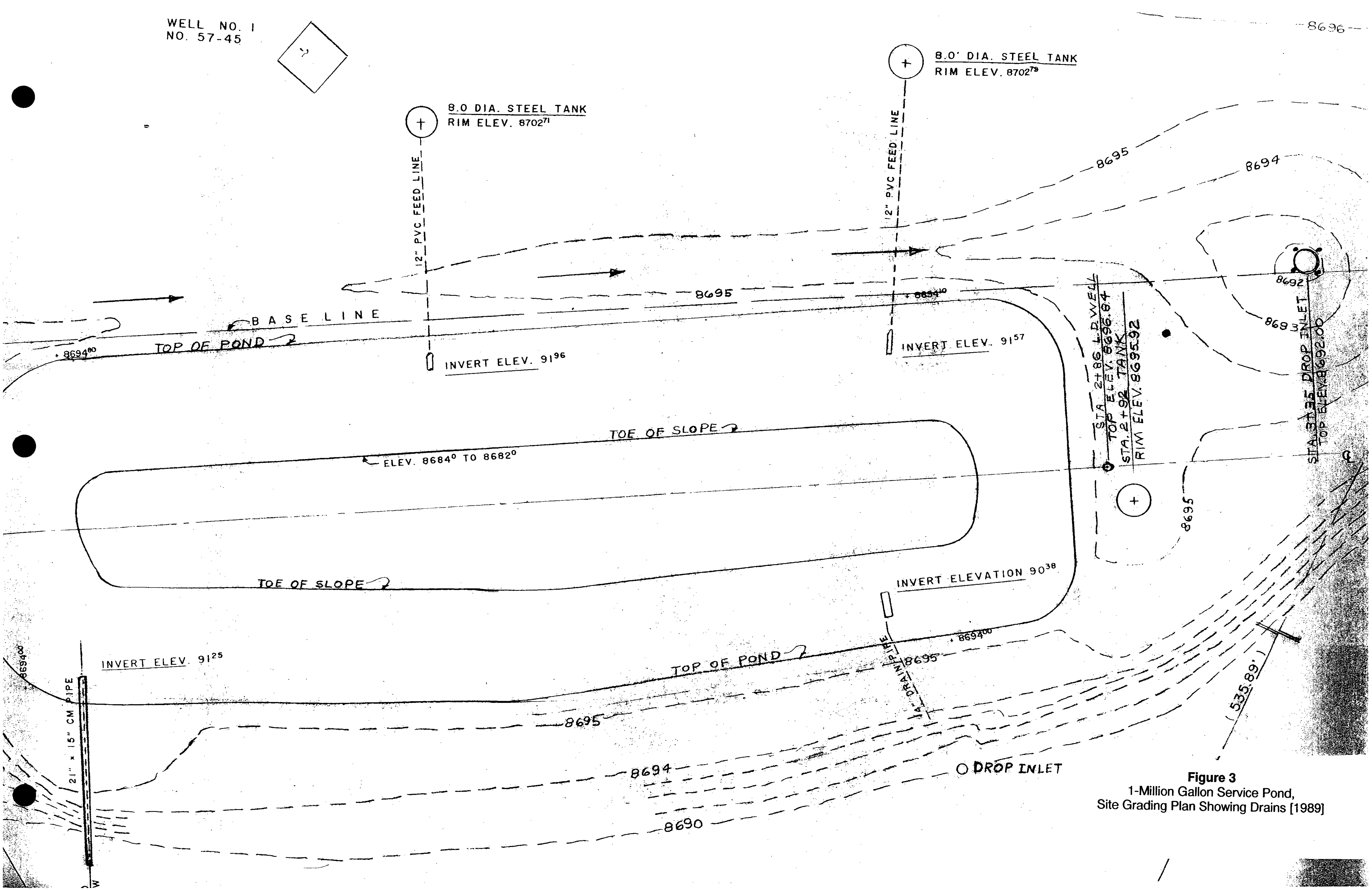


Figure 3
1-Million Gallon Service Pond,
Site Grading Plan Showing Drains [1989]

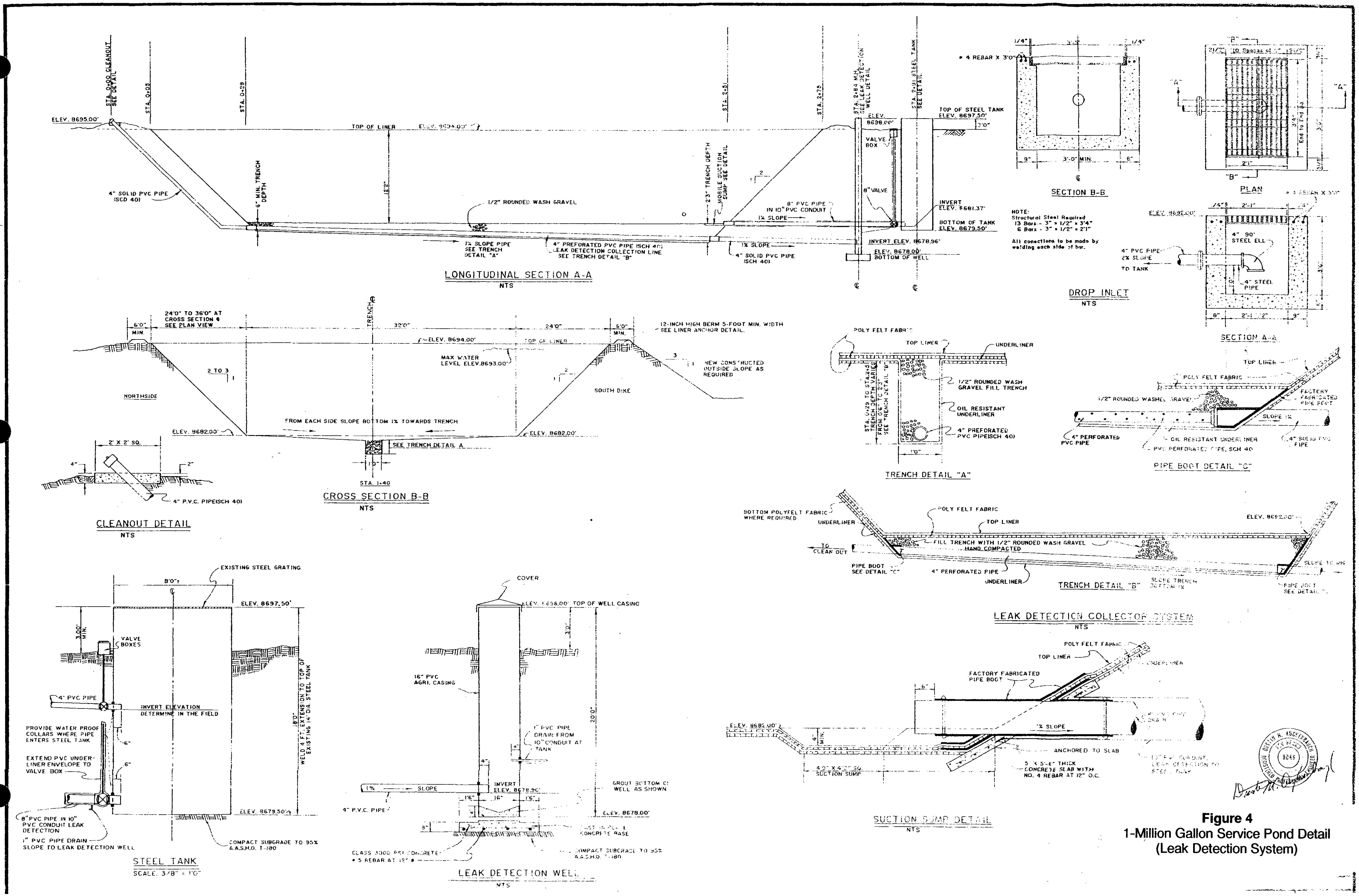


Figure 4
1-Million Gallon Service Pond Detail
(Leak Detection System)

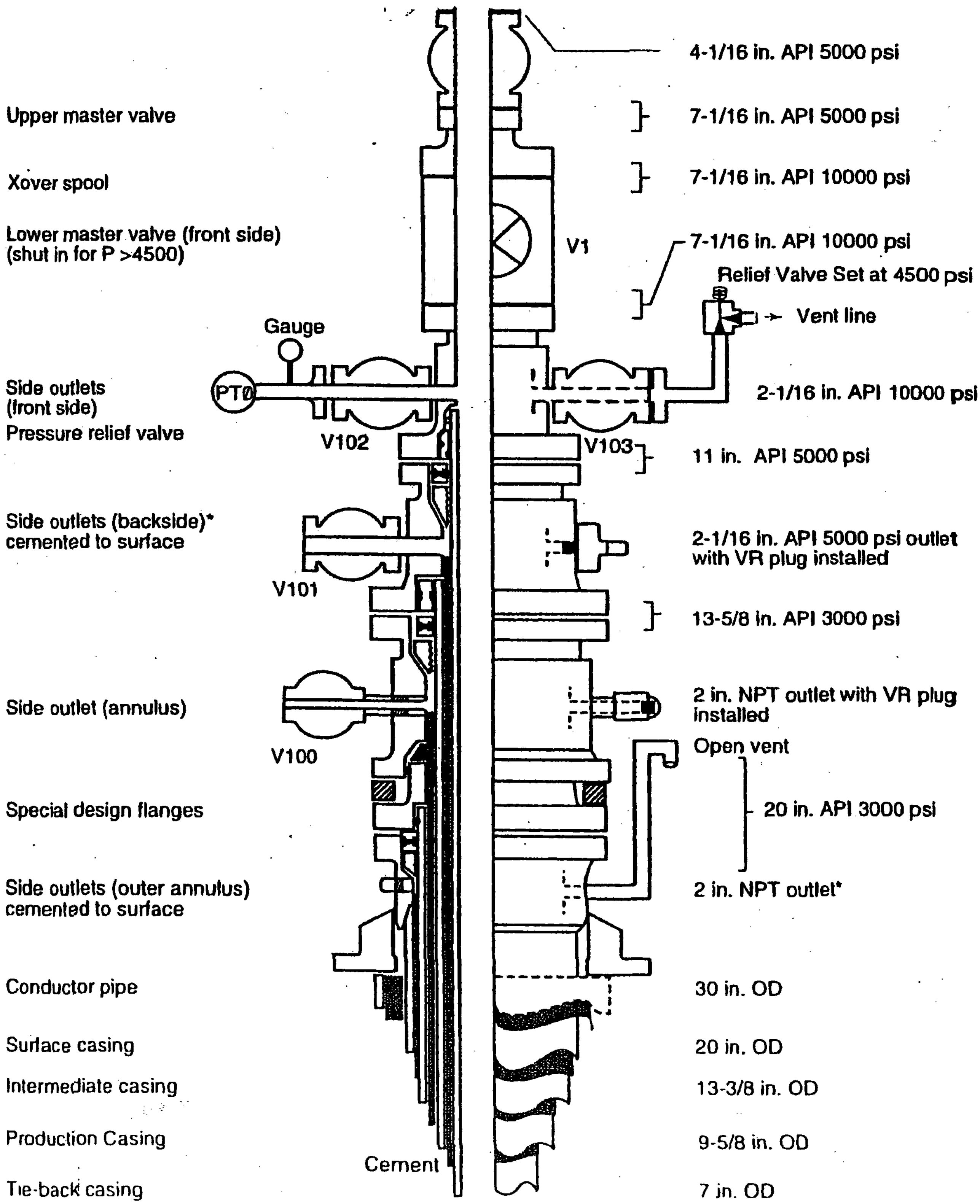


Figure 5
EE-2A Production Wellhead Schematic

CERTIFICATION

I certify under penalty of law that this document and all appendices were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Paul Weber

14 Aug '02

Paul Weber
EES Division Director
Los Alamos National Laboratory
Operator

Date Signed

APPENDIX A

Fenton Hill Site Photographs

TA-57, Fenton Hill, Site Photograph Looking Southeast
EE-2A Production Well and Tower
(June 25, 2002)

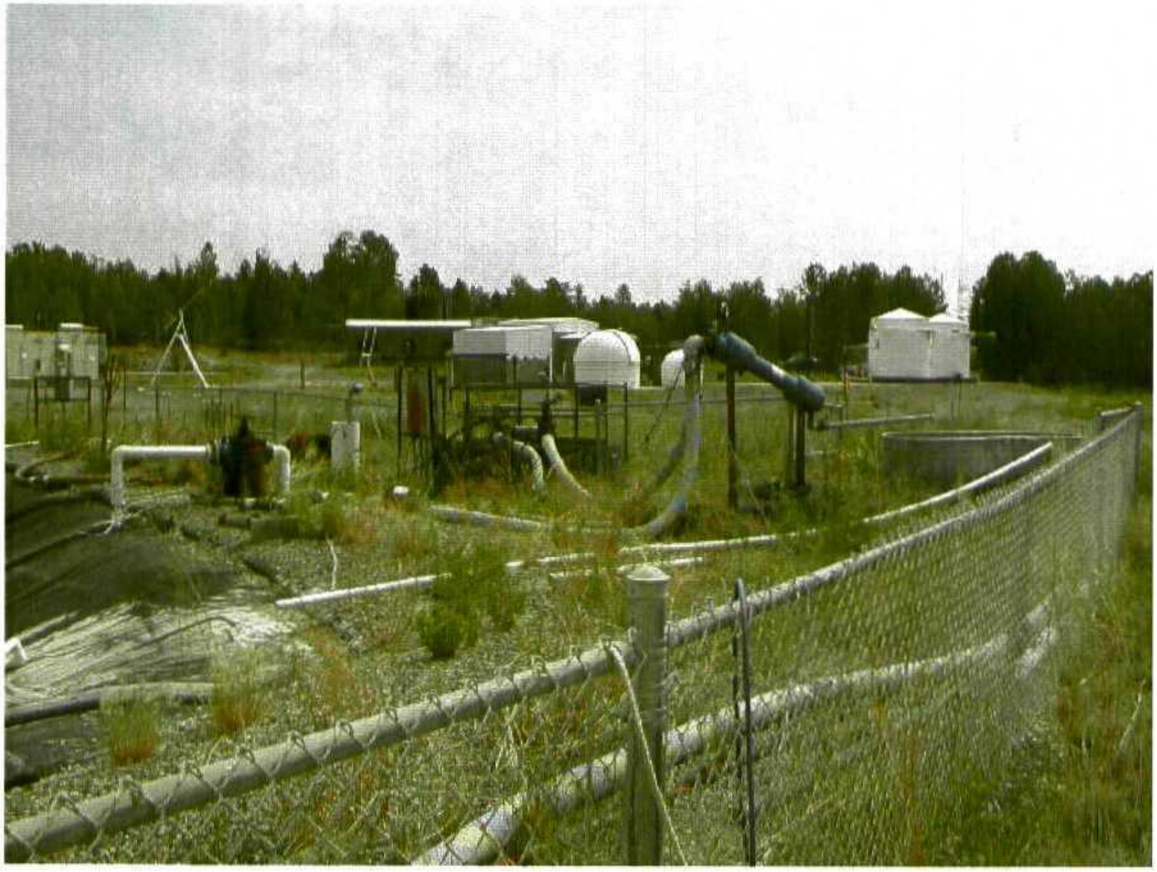
TA-57, Fenton Hill, Site Photograph Looking Southwest
1-Million Gallon Service Pond
(June 25, 2002)

TA-57, Fenton Hill, Site Photograph Looking Northwest
1-Million Gallon Service Pond
(June 25, 2002)

TA-57, Fenton Hill, 1-Million Gallon Service Pond
(June 25, 2002)

TA-57, Fenton Hill, 1-Million Gallon Service Pond Looking Northeast
(June 25, 2002)

TA-57, Fenton Hill, 1-Million Gallon Service Pond Bunker and Drain
(June 25, 2002)



TA-57, Fenton Hill, 1-Million Gallon Service Pond Sump and Leak Detection Well
(June 25, 2002)

TA-57, Fenton Hill, Sump Exterior
(June 25, 2002)

TA-57, Fenton Hill, Sump Interior
(June 25, 2002)

TA-57, Fenton Hill, EE-2A Well Head
(June 25, 2002)

TA-57, Fenton Hill, Hydrant
(June 25, 2002)

APPENDIX B

NM OCD Form C-103 and LANL Plugging and Abandonment Procedures for Geothermal Well EE-2A

Submit 3 Copies To Appropriate District Office
District I
1625 N. French Dr., Hobbs, NM 88240
District II
301 W. Grand Ave., Artesia, NM 88210
District III
1000 Rio Brazos Rd., Aztec, NM 87410
District IV
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised March 25, 1999

	WELL API NO. EE-2A (non-API)
	5. Indicate Type of Lease STATE ☐ FEE ☐
	6. State Oil & Gas Lease No. N/A
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.) 1. Type of Well: Oil Well ☐ Gas Well ☐ Other – Experimental geothermal production well	7. Lease Name or Unit Agreement Name: Fenton Hill Hot Dry Rock Geothermal Project
2. Name of Operator Los Alamos National Laboratory	8. Well No. – EE-2A
3. Address of Operator P.O.Box 1663, Los Alamos, NM 87545	9. Pool name or Wildcat N/A

10. Well Location

Unit Letter______: well is located 1609 feet from the East line and 1405 feet from the North line

Section 13 Township 19N Range 2E NMPM Sandoval County

10. Elevation *(Show whether DR, RKB, RT, GR, etc.)*
KB

11. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☒	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	PLUG AND ABANDONMENT ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPLETION ☐	CASING TEST AND CEMENT JOB ☐	
OTHER: ☐		OTHER: ☐	

12. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 1103. For Multiple Completions: Attach wellbore diagram of proposed completion or recompilation.

Please find detailed procedure and well diagrams attached. It is currently estimated that the abandonment will occur in September, 2002. NMOCD will be notified by LANL of the exact time that the abandonment work will commence at least 48 hours in advance.

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Paul G Weber TITLE Division Leader DATE 9 July '02

Type or print name PAUL G. WEBER Telephone No. 505-667-5777

(This space for State use)

APPPROVED BY [signature] TITLE DISTRICT SUPERVISOR DATE 7-19-02

Conditions of approval, if any:

PLUGGING AND ABANDONMENT PROCEDURES FOR GEOTHERMAL WELL EE-2A

Fenton Hill Hot Dry Rock Geothermal Project
Los Alamos National Laboratory

July 1, 2002

Geophysics Group – EES-11
Earth and Environmental Sciences Division

Water Quality and Hydrology Group – RRES-WQH
Risk Reduction and Environmental Stewardship Division

REGULATORY APPROVAL:

____

Mr. Roy Johnson, N.M. Oil Conservation Division — Date

EXTERNAL REVIEWERS:

Mr. Fred Oneyear, U.S. Bureau of Land Management
Mr. John Peterson, U.S. Forest Service, Jemez Ranger District
Ms. Linda Gordan, N.M. Office of the State Engineer

Procedures for abandonment of HDR Well EE-2A
July 1, 2002

Current well configuration: EE-2 was drilled and completed in 1979-80. The original well was damaged following a wellhead failure that ended a massive hydraulic fracturing treatment. Following an extensive well reentry, repair, and plug back procedure, the well was sidetracked and redrilled in 1987-88. The well was completed as a geothermal production well with 7" casing and the annulus cemented to surface. 7-inch OD, 35 lb./ft, S-90, NSCC premium (internal flush) joint threaded and coupled casing was installed from just above the production interval at 10,770 ft to 9,500 ft. A 7-inch OD, 32 lb./ft, C-95, NSCC T&C tie-back string was then installed from 9,500 ft to the surface and cemented-in. The production interval, 10,770' to 12,360' total depth (TD) is uncased open hole. Casing schematics can be found in Attachments 1 and 2. Attachment 3 contains a wellhead diagram. Attachment 4 is a well trajectory survey for well EE-2A.

Although the well was used for geothermal production intermittently for several years, no steam flashing has ever occurred in the wellbore and it is unlikely that any significant scale deposits are present on the inner casing wall.

P&A procedures:

The minimum acceptable coiled tubing diameter for the required operations is 1-1/2" OD.

1) A bridge plug will be set in the 7" casing at 10,700 ft
   a) A casing scraper shall be run to the bridge plug setting depth on wireline or coiled tubing prior to running the bridge plug.
   b) The plug will be capable of maintaining a positive seal against a differential pressure of at least 5,000 psi at a temperature of 430° F
   c) The bridge plug may be deployed on wireline or coiled tubing.
   d) The bridge plug shall be tagged with 1000 lb. set down force using the end of the (cementing shoe on the) coiled tubing prior to pumping the first cement plug to assure proper set and depth.
   e) The initial cement plug shall be tagged to confirm proper location prior to proceeding with mud displacement. This is the only cement plug that will be tagged.
2) A plugging mud shall be displaced into the well from the bottom plug to the surface. The plugging mud shall:
   a) Have sufficient viscosity and density to prevent movement of the cement plugs
   b) Be compatible with the cement slurries proposed.
   c) Remain in the hole between the cement plugs
   d) Contain a sufficient quantity of corrosion inhibitor to provide long-term protection from casing degradation.
3) There is a remote possibility that Hydrogen Sulfide gas may be present in the fluid displaced from the well. Standard industry precautions, ie. H2S monitoring equipment, shall be present and operational during fluid displacement.

4) Every effort shall be made by the vendor to minimize the amount of waste water, mud and materials produced by the operations.
5) Cement plugs may be placed sequentially up the hole. It will not be necessary to tag any cement plugs other than the bottom plug.
6) Required cement plug placement depths, as specified by NMOCD, shall be located in the intervals shown on Table 1. The temperature at the bottom of each interval is included. Cement formulations shall be designed accordingly.
7) After Plug #6 is placed, wash the top of the plug out to 5-ft below the bottom of the wellhead and rig down BOPE and the CTU.
8) Demobilize equipment.

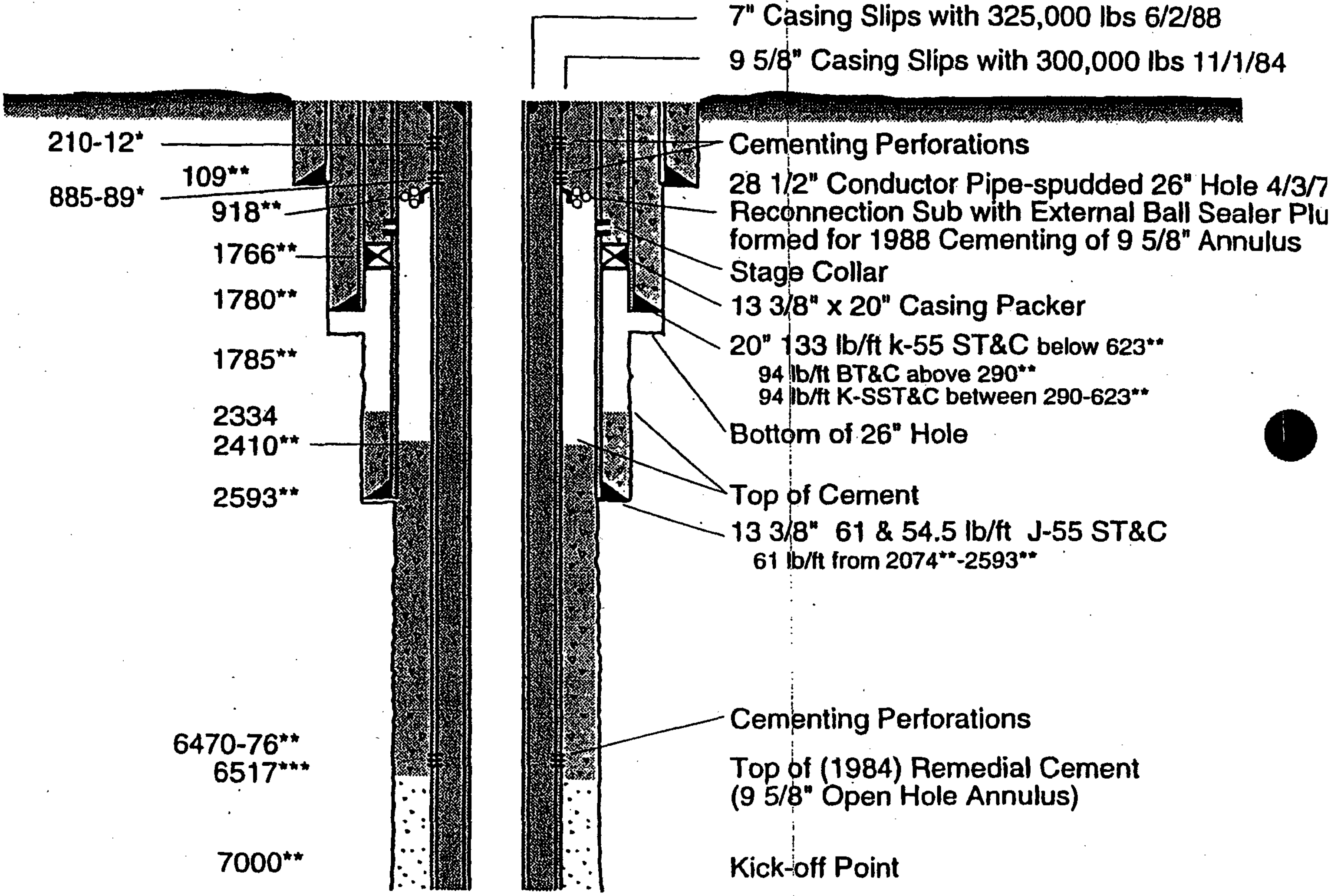
TABLE 1 – NMOCD Plugging Intervals and Estimated Temperature

Plug #	Interval (ft)	Length (linear feet)	Temp.°F *
1	10,700 – 10,500	200	423
2	9,600 – 9,400	200	386
3	6,550 – 6,450	100	285
4	3,550 – 3,450	100	212
5	2,693 – 2,493	200	169
6	75 – surface*	75	53
*	Estimated temperature of the hole prior to circulation.		
**	Circulate out cement to 5-ft below the well head after placing cement.		

ATTACHMENT 1

Present Configuration of EE 2-A

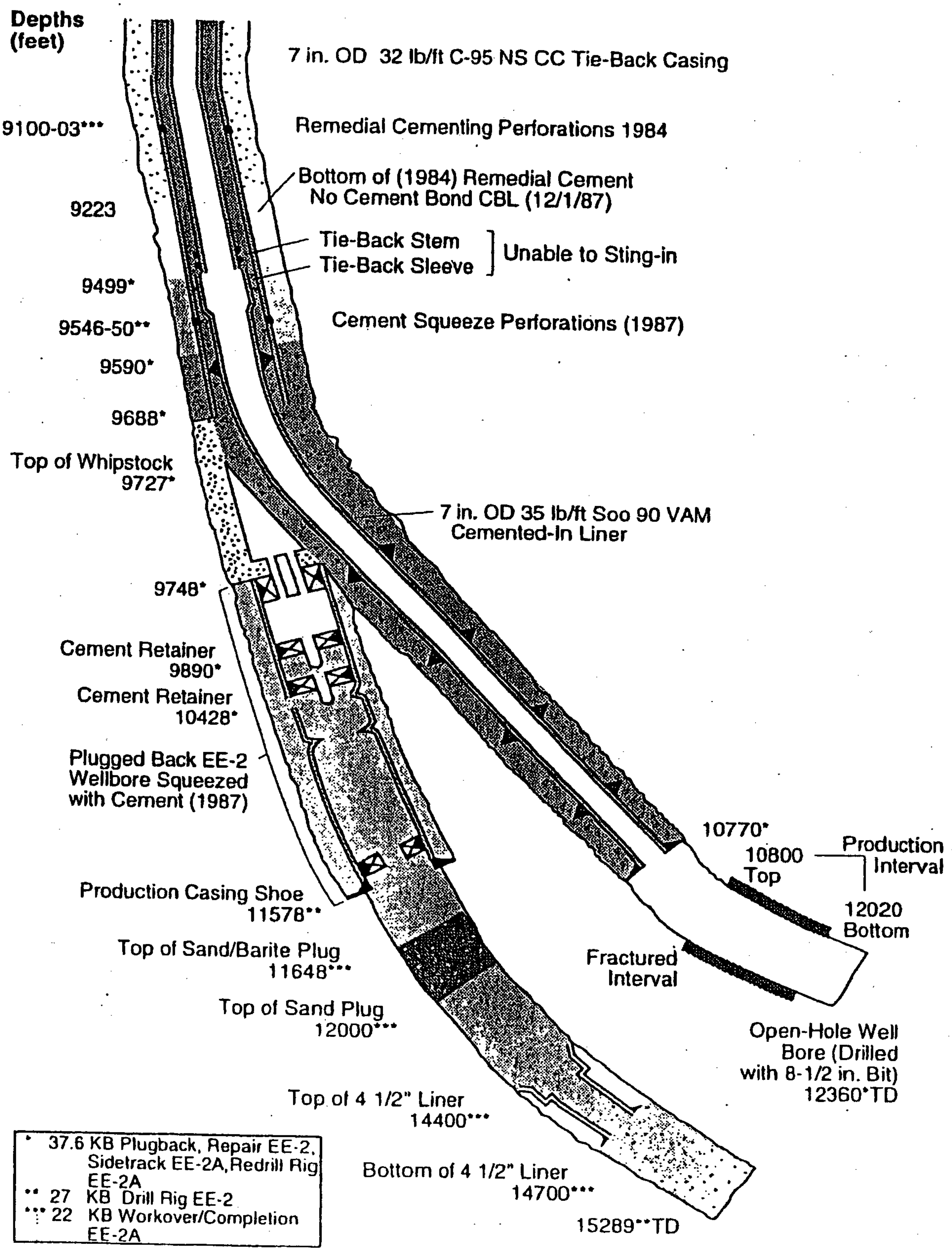
As completed June 17, 1988
(Drawing revised 7/15/91, all depths in ft)



*	37.6	KB Plugback, Repair EE-2, Sidetrack EE-2A, Redrill Rig EE-2A
**	27	KB Drill Rig EE-2
***	22	KB Workover/Completion EE-2A

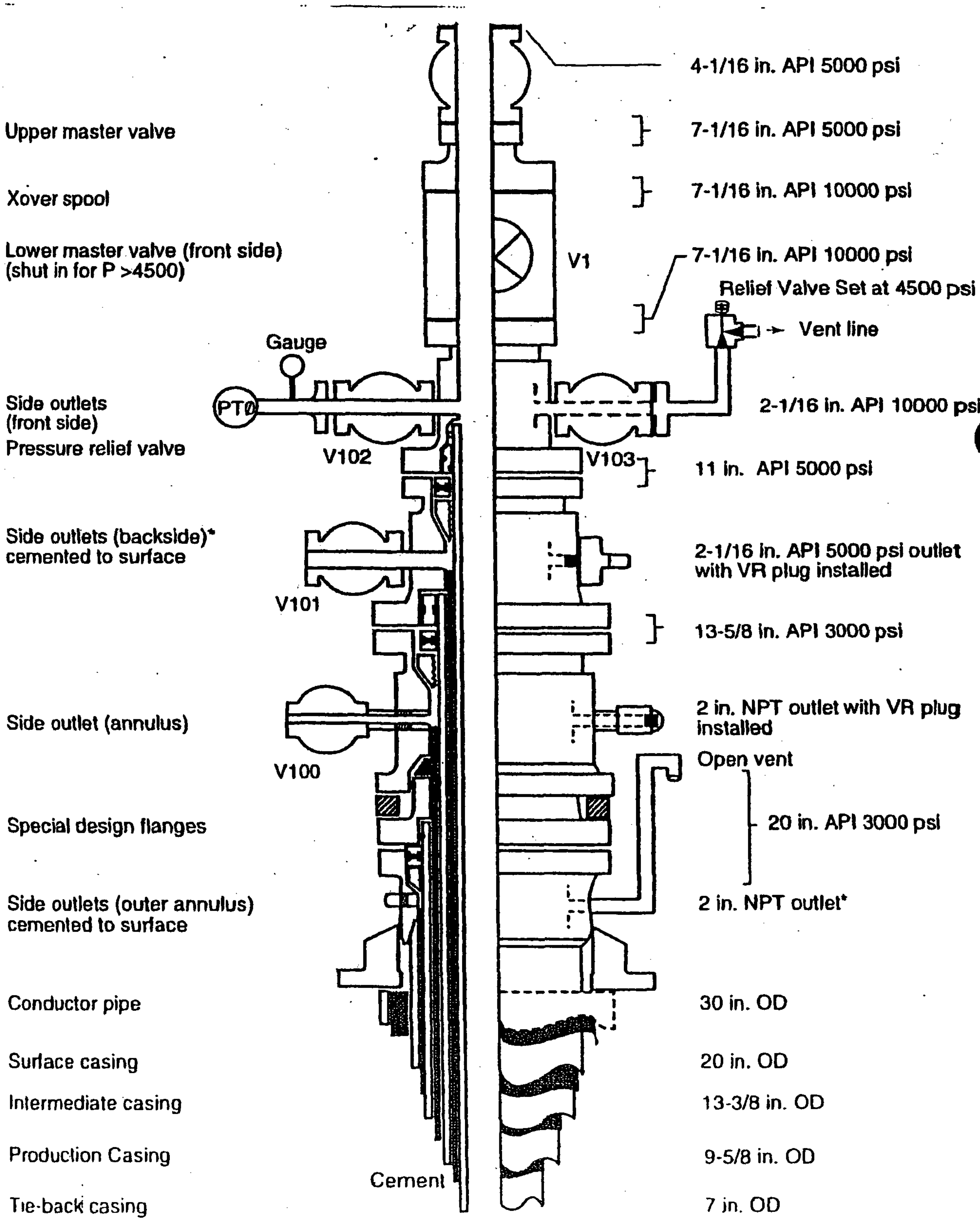
ATTACHMENT 2

Present Configuration of EE-2A. Completed June 17, 1988
(Drawing revised 7/15/91, all depths in ft)

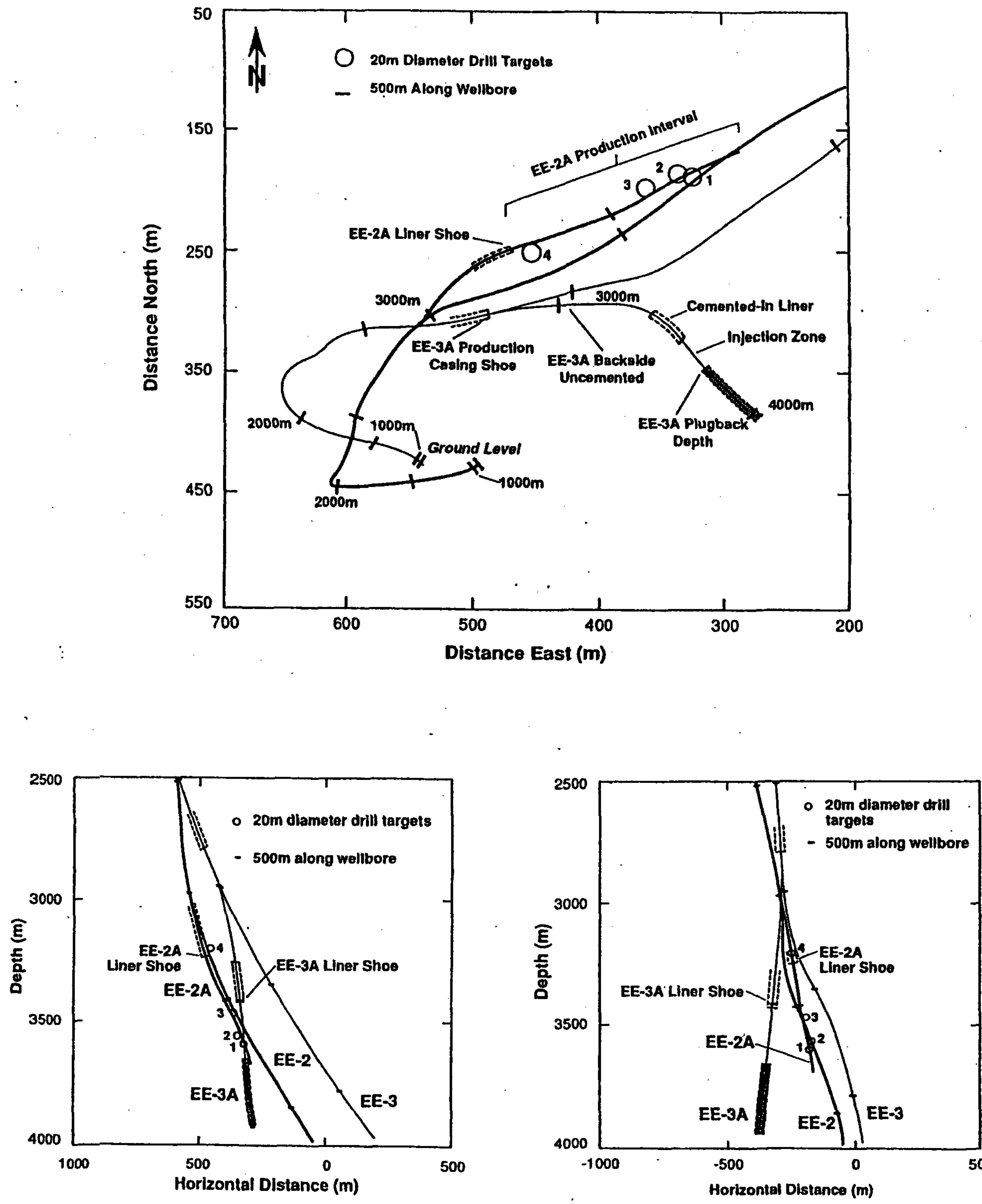


ATTACHMENT 3

EE-2A Production Wellhead



ATTACHMENT 4

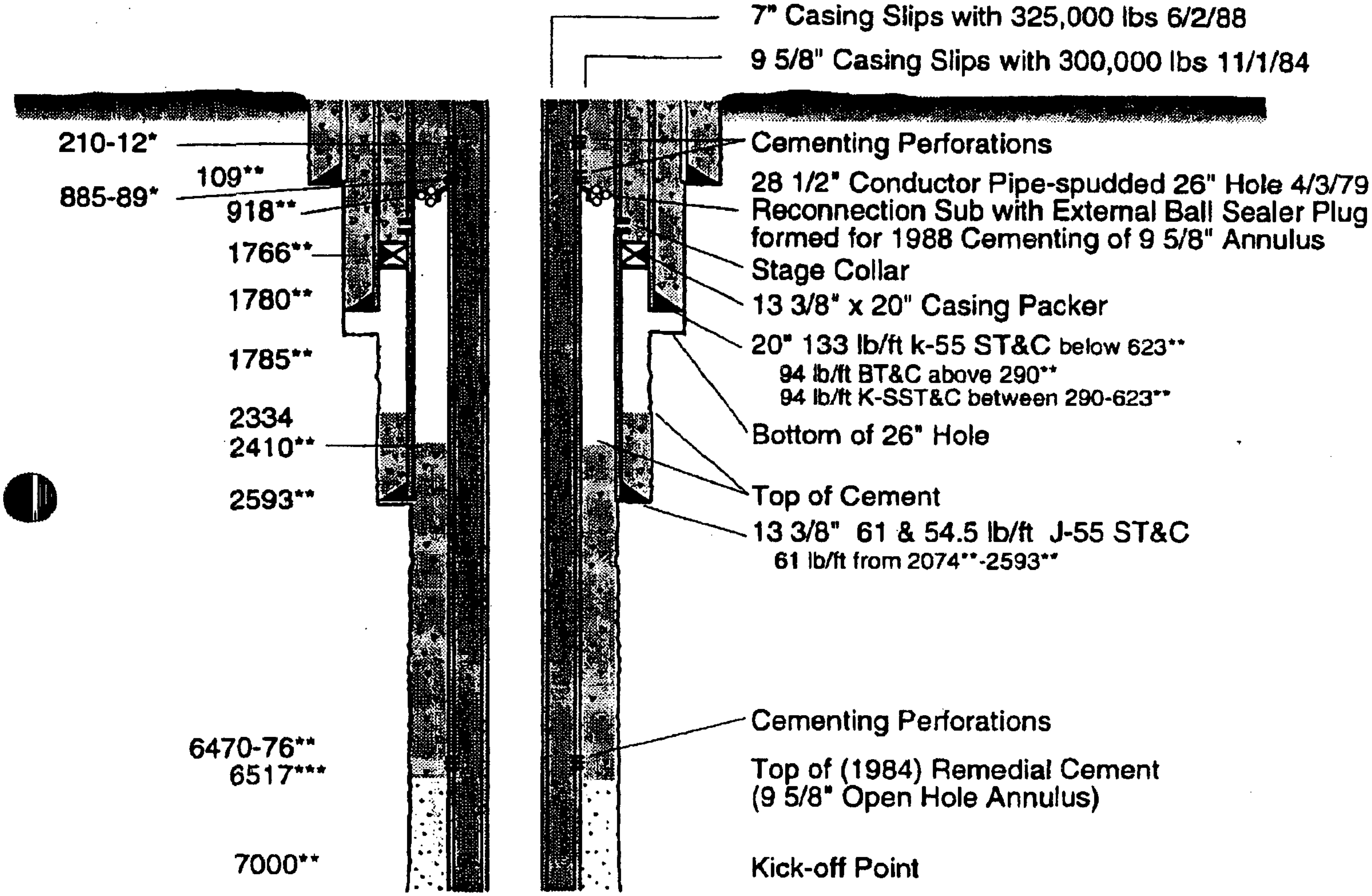


EE-2A targets and drilled trajectory.

APPENDIX C

EE-2A Well Casing Schematic

Present Configuration of EE 2-A
As completed June 17, 1988
(Drawing revised 7/15/91, all depths in ft)



*	37.6	KB Plugback, Repair EE-2, Sidetrack EE-2A, Redrill Rig EE-2A
**	27	KB Drill Rig EE-2
***	22	KB Workover/Completion EE-2A

Effective 4/30/92

APPENDIX D

19 NMAC 15.9.712

(1) within one (1) year after the effective date permitted facilities submit the information required in Subsection B, Paragraph (1), Subparagraphs (a, h, i and l) of 19.15.9.711 NMAC not already on file with the Division;

(2) within one (1) year after the effective date unpermitted facilities submit the information required in Subsection B, Paragraph (1), Subparagraphs (a) through (j) and Subsection B, Paragraph (1), Subparagraph (l) of 19.15.9.711 NMAC;

(3) comply with Subsections C and D of 19.15.9.711 NMAC unless the Director grants an exemption from a requirement in these sections based upon a demonstration by the operator that such requirement is not necessary to protect public health and the environment.

[6-6-88...2-1-96; 19.15.9.711 NMAC - Rn, 19 NMAC 15.I.711, 11-30-00]

19.15.9.712. DISPOSAL OF CERTAIN NON-DOMESTIC WASTE AT SOLID WASTE FACILITIES.

A. General - Certain non-domestic waste arising from the exploration, development, production or storage of crude oil or natural gas, certain nondomestic waste arising from the oil field service industry, and certain non-domestic waste arising from the transportation, treatment or refinement of crude oil or natural gas, may be disposed of at a solid waste facility.

B. Definitions - The following words and phrases have particular meanings for purposes of this section:

(1) "BTEX." The acronym "BTEX" in this section refers to benzene, toluene, ethelbenzene and xylene.

(2) "Discharge Plan." A "discharge plan" is a plan submitted and approved by the Division pursuant to NMSA 1978, Section 70-2-12(B)(22) (2000 Cum.Supp.) and rules and regulations of the Water Quality Control Commission.

(3) "EPA." The acronym "EPA" refers to the United States Environmental Protection Agency.

(4) "EPA Clean." The phrase "EPA Clean" refers to cleanliness standards established by the EPA in 40 C.F.R. Part 261, Section 261.7(b).

(5) "NESHAP." The acronym "NESHAP" refers to the National Emission Standards for Hazardous Air Pollutants of the EPA, 40 C.F.R. Part 61.

(6) "NORM." The acronym "NORM" refers to naturally occurring radioactive materials regulated by 20 NMAC 3.1, Subpart 14.

(7) "Section." "Section" or "this section" refers to Section 19.15.9.712.

(8) "Solid Waste Facility." A "solid waste facility" is a facility permitted or authorized as a solid waste facility by the New Mexico Environment Department pursuant to the Solid Waste Act, NMSA 1978, Sections 74-9-1 et seq. and rules and regulations of the Environmental Improvement Board, to accept industrial solid waste or other special waste.

(9) "TCLP" The acronym "TCLP" in this section refers to the testing protocol established by the EPA in 40 C.F.R. Part 261, entitled "Toxicity Characteristic Leaching Procedure" or an alternative hazardous constituent analysis approved by the Division.

(10) "TPH." The acronym "TPH" in this section refers to the phrase "total petroleum hydrocarbons."

(11) "Waste." The word "waste" refers to nondomestic waste resulting from the exploration, development, production or storage of crude oil or natural gas pursuant to NMSA 1978, Section 70-2-12(B)(21) and nondomestic waste arising from the oil field service industry, and certain non-domestic waste arising from the transportation, treatment or refinement of crude oil or natural gas pursuant to NMSA 1978, Section 70-2-12(B)(22).

C. Procedure

(1) Waste Listed in Subsection D, Paragraph (1) of Section 19.15.9.712. Waste listed in Subsection D, Paragraph (1) of Section 19.15.9.712 may be disposed of at a solid waste facility without prior written authorization of the Division.

(2) Waste Listed in Subsection D, Paragraph (2) of Section 19.15.9.712. Waste listed in Subsection D, Paragraph (2) of Section 19.15.9.712 may be disposed of at a solid waste facility after testing and prior written authorization of the Division. Before authorization is granted, copies of test results must be provided to the Division and to the solid waste facility where the waste is to be disposed. Disposal may commence only after written authorization of the Division. In appropriate cases and so long as a representative sample is tested, the Division may authorize disposal of a waste stream listed in Subsection D, Paragraph (2) of Section 19.15.9.712 without individual testing of each delivery.

(3) Waste Listed in Subsection D, Paragraph (3) of Section 19.15.9.712. Waste listed in Subsection D, Paragraph (3) of Section 19.15.9.712 may be disposed of at a solid waste facility on a case-by-case basis after testing required at the discretion of the Division and after prior written authorization of the Division. Before authorization is granted, copies of test results must be provided to the Division and to the solid waste facility where the waste is to be disposed. Disposal may commence only after written authorization of the Division.

(4) Simplified Procedure for Holders of Discharge Plans. Holders of an approved discharge plan may amend the discharge plan to provide for disposal of waste listed in Waste Listed in Subsection D, Paragraph (2) of Section 19.15.9.712 and, as applicable, Subsection D, Paragraph (3) of Section 19.15.9.712. If the amendment to the Discharge Plan is approved, wastes listed in Subsection D, Paragraph (2) of Section 19.15.9.712 and Subsection D, Paragraph (3) of Section 19.15.9.712 may be disposed of at a solid waste facility without the necessity of prior written authorization of the Division.

D. Waste Governed By This Section

(1) Waste That Does Not Require Testing Before Disposal:

(a) Barrels, drums, 5-gallon buckets, 1-gallon containers so long as empty and EPA-clean.

(b) Uncontaminated brush and vegetation arising from clearing operations.

(c) Uncontaminated concrete.

(d) Uncontaminated construction debris.

(e) Non-friable asbestos and asbestos contaminated waste material, so long as the disposal complies with all applicable federal and state regulations for nonfriable asbestos materials and so long as asbestos is removed from steel pipes and boilers and, if applicable, the steel recycled.

(f) Detergent buckets, so long as completely empty.

(g) Fiberglass tanks so long as the tank is empty, cut up or shredded, and EPA clean.

(h) Grease buckets, so long as empty and EPA clean.

(i) Uncontaminated ferrous sulfate or elemental sulfur so long as recovery and sale as a raw material is not possible.

(j) Metal plate and metal cable.

(k) Office trash.

(l) Paper and paper bags, so long as empty (paper bags).

(m) Plastic pit liners, so long as cleaned well.

(n) Soiled rags or gloves. If wet, must pass Paint Filter Test prior to disposal.

~~(o) Uncontaminated wood pallets.~~

(2) Waste That Must Be Tested:

(a) Activated alumina must be tested for TPH and BTEX.

(b) Activated carbon must be tested for TPH and BTEX.

(c) Amine filters must be tested for BTEX (and air-dried for at least 48 hours before testing).

(d) Friable asbestos and asbestos-contaminated waste material must be tested pursuant to NESHAP (and so long as the disposal otherwise complies with all applicable federal and state regulations for friable asbestos materials, and so long as asbestos is removed from steel pipes and boilers and, if applicable, the steel should be recycled before disposal).

(e) Cooling tower filters must be tested for TCLP/chromium (and drained and then air-dried for at least 48 hours before testing).

(f) Dehydration filter media must be tested for TPH and BTEX (and drained and then air-dried for at least 48 hours before testing).

(g) Gas condensate filters must be tested for BTEX (and drained and then air-dried for at least 48 hours before testing).

(h) Glycol filters must be tested for BTEX (and drained and then air-dried for at least 48 hours before testing).

(i) Iron sponge must be oxidized completely and then undergo Ignitability Testing.

(j) Junked pipes, valves, and metal pipe must be tested for NORM.

(k) Molecular sieve must be tested for TPH and BTEX (and must be cooled in a non-hydrocarbon inert atmosphere and hydrated in ambient air for at least 24 hours before testing).

(l) Pipe scale and other deposits removed from pipeline and equipment must be tested for TPH, TCLP/metals and NORM.

(m) Produced water filters must be tested for Corrosivity (and drained and then air-dried for at least 48 hours before testing).

(n) Sandblasting sand must be tested for TCLP/metals or, at the discretion of the Division, TCLP/total metals.

(o) Waste oil filters must be tested for TCLP/metals (and must be drained thoroughly of oil for at least 24 hours before testing and oil and metal parts must be recycled).

(3) Waste That May Be Disposed Of On A Case-By-Case Basis:

(a) Sulfur contaminated soil.

(b) Catalysts.

(c) Contaminated soil other than petroleum contaminated soil.

(d) Petroleum contaminated soil in the event of an emergency declared by the director.

(e) Contaminated concrete.

(f) Demolition debris not otherwise specified herein.

(g) Unused dry chemicals (in addition to any testing required by the Division, a copy of the Material Safety Data Sheet shall be forwarded to the Division and the solid waste facility on each chemical proposed for disposal).

(h) Contaminated ferrous sulfate or elemental sulfur.

(i) Unused pipe dope.

(j) Support balls.

(k) Tower packing materials.

(l) Contaminated wood pallets.

(m) Partial sacks of unused drilling mud (in addition to any testing required by the Division, a copy of the Material Safety Data Sheet shall be forwarded to Division and the solid waste facility at which the partial sacks will be disposed).

(n) Other wastes as applicable.

E. Testing

(1) General - Testing required herein shall be conducted according to the Test Methods for Evaluating Solid Waste, EPA No. SW-846. Any questions concerning the standards or a particular testing facility should be directed to the Division.

(2) Methodology - Testing must be conducted according to the test method listed:

(a) TPH: EPA method 418.1 or 8015 (D-R-O and G-R-O only) or an alternative hydrocarbon analysis approved by the Division.

(b) TCLP: EPA Method 1311 or an alternative hazardous constituent analysis approved by the Division.

(c) Paint Filter Testing: EPA Method 9095A.

(d) Ignitability Test: EPA Method 1030.

(e) Corrosivity: EPA Method 1110.

(f) Reactivity: Test procedures and standards established on a case-by-case basis by the Division.

(g) NORM. 20 NMAC 3.1, Subpart 14.

(3) Limits - To be eligible for disposal pursuant to this section, substances found during testing shall not exceed the following limits:

(a) Benzene: Less than 10 mg/Kg.

(b) BTEX: Less than 500 mg/Kg (sum of all).

(c) TPH: Shall not exceed 1000 mg/Kg.

(d) Hazardous Air Pollutants: Shall not exceed the standards set forth in NESHAP.

(e) TCLP: Shall not exceed the following:

(i) Arsenic: 5.0 mg/l
(ii) Barium: 100.0 mg/l
(iii) Cadmium: 1.0 mg/l
(iv) Chromium: 5.0 mg/l
(v) Lead: 5.0 mg/l
(vi) Mercury: 0.2 mg/l

(vii) Selenium: 1.0 mg/l
(viii) Silver: 5.0 mg/l

19.15.9.713 This entire section moved and renumbered to 19 NMAC 15.A.32.
[12-30-95, 2-1-96; A, 6-15-99; 19.15.9.713 NMAC - Rn, 19 NMAC 15.I.713; 11-30-00]

19.15.9.714 DISPOSAL OF REGULATED NATURALLY OCCURRING RADIOACTIVE MATERIAL (REGULATED NORM)

A. Purpose - This rule establishes procedures for the disposal of regulated naturally occurring radioactive material (Regulated NORM) associated with the oil and gas industry. Any person disposing of Regulated NORM, as defined at 19 NMAC 15.A.7, is subject to this rule and to the New Mexico Environmental Improvement Board regulations at 20 NMAC 3.1, Subpart 14.

B. Nonretrieved Flowlines and Pipelines

(1) The Division will consider a proposal for leaving flowlines and pipelines (hereinafter "pipeline") that contain Regulated NORM in the ground provided such abandonment procedures are performed in a manner to protect the environment, public health, and fresh waters. Division approval is contingent on the applicant meeting the following requirements as a minimum:

(2) An application submitted to the Division must contain the following as a minimum:

(a) The pipeline layout over its entire length on an OCD Form C-102 (Well Location and Acreage Dedication Plat) including the legal description of the location of both ends and all surface ownership along the pipeline.

(b) Results of a radiation survey conducted at all accessible points and a surface radiation survey along the complete pipeline route in a form approved by the Division. All surveys are to be conducted consistent with procedures approved by the Division.

(c) The type of material for which the pipeline had been used.

(d) The procedure to be used for flushing hydrocarbons and/or produced water from the pipeline.

(e) An explanation as to why it is more beneficial to leave the pipeline in the ground than to retrieve it.

(f) Proof of notice of the proposed abandonment to all surface owners where the pipeline is located. Additional notification may be required as described in Subsection F of 19.15.9.714 NMAC.

(3) Procedure

(a) Upon approval of the application by the Division, the operator must notify the OCD District office at least 24 hours prior to beginning any work on the pipeline abandonment.

(b) As a condition of completion of the pipeline abandonment, all accessible points must be permanently capped.

APPENDIX E

LANL Request for Minor Modification to the Ground Water Discharge Plan GW-031, July 1998

Los Alamos
NATIONAL LABORATORY

Los Alamos National Laboratory
Los Alamos, New Mexico 87545

Date: July 20, 1998
In Reply Refer To: ESH-18/WQ&H:98-0232
Mail Stop: K497
Telephone: (505) 667-7969

Mr. Roger C. Anderson
Environmental Bureau Chief
Oil Conservation Division
New Mexico Energy, Minerals, and Natural Resources Department
2040 South Pacheco St.
Santa Fe, New Mexico 87505

SUBJECT: MINOR MODIFICATION OF GROUND WATER DISCHARGE PLAN GW-031

Dear Mr. Anderson:

Enclosed please find Los Alamos National Laboratory's Minor Modification of Ground Water Discharge Plan GW-031 for the Fenton Hill Geothermal Facility, Sandoval County, New Mexico. Also enclosed is the required $50.00 filing fee. This minor modification is being submitted to your agency in accordance with Section 3107.C of the Water Quality Control Commission Regulations due to the following operational changes which have been implemented, or are being proposed, at the facility:

1) Discontinuation of the Fenton Hill NPDES Permit No. NM0028576,
2) Installation of an enhanced evaporation system on the 1 MG pond, and
3) The proposed mixing of exempt and nonexempt wastes in the 1 MG pond in accordance with N.M. Oil Conservation Division's mixture policy.

If you have any questions concerning this submittal, please feel free to call Bob Beers of my staff at (505) 667-7969.

Sincerely,

Steven R. Rae

Steven R. Rae
Group Leader
Water Quality and Hydrology Group

RB/rj

Enclosures: a/s

Cy: J. Peterson, Jemez Ranger District, U.S. Forest Service, Jemez Springs, New Mexico, w/enc.
W. Whatley, Jemez Pueblo, New Mexico, w/enc.
G. Suazo, CIO, w/enc., MS A117
P. Bustamante, NMED/GWQB, Santa Fe, New Mexico, w/enc.
G. Saums, NMED/SWQB, Santa Fe, New Mexico, w/enc.
B. Koch, DOE/LAAO, w/enc., MS A316
J. Albright, EES-4, w/enc., MS D443
G. Sinnis, P-23, w/enc., MS H803
D. Thomas, P-FM, w/enc., MS D459
J. Thomson, EES-4, w/enc. MS D443
S. Rae, ESH-18, w/enc., MS K497
N. Williams, ESH-18, w/enc., MS K497
WQ&H File, w/enc., MS K497
CIC-10, w/enc., MS A150

ENCLOSURES

1) Minor Modification of Ground Water Discharge Plan (GW-031)

2) Letter from EPA Approving the Discontinuation of NPDES Permit No. NM0028576

3) Figure 1.0. Schematic of 1 MG Pond Enhanced Evaporation System

4) Table 1.0. Water Quality Data: GAC Filter Backwash Water

5) Table 2.0. Water Quality Data: Softener Regeneration Water

6) Assaigai Analytical Laboratories, Inc. Report: Sample ID Nos. MGRO 5A-11C

7) Figure 2.0. Schematic of Proposed Mixing of Exempt and Nonexempt Wastes

8) Figure 3.0. Schematic of 5 MG Pond to 1 MG Pond Piping

9) Table 3.0. Final Mixture Summary and Estimated Volumes of Exempt and Nonexempt Wastes

Discontinuation of NPDES Permit No. NM0028576

On December 29, 1997, the EPA approved a request by the U.S. Department of Energy and Los Alamos National Laboratory to discontinue the Fenton Hill Geothermal Site NPDES Permit No. NM0028576. Please find the enclosed copy of the EPA approval letter. The Fenton Hill Geothermal Facility had not discharged through the NPDES outfall since June 1988.

Enhanced Evaporation System

The Fenton Hill Geothermal Facility's 1 million gallon (MG) pond has been outfitted with an enhanced evaporation system. Figure 1.0 illustrates the system's basic configuration. The evaporation system consists of two segments of 2" PVC pipe, each running the length of the pond, one on the north side and the other on the south. Adjustable hose nozzles are installed at 10 ft. intervals on the 2" lines; a total of 25 nozzles on each side, 50 in all. The spray from each nozzle is directed towards the center of the pond at a 45 degree angle. The nozzles are adjusted to produce a fine mist, maximizing evaporation. All piping and nozzles are contained within the perimeter of the pond's liner. A pressure switch has been installed in the pump control circuitry to shut off the system in the event of a line break or plug. A large duplex basket strainer is installed near the pump to remove solids. The estimated volume being spayed is approximately 2 gallons per minute (gpm) per nozzle or approximately 100 gpm for the entire system.

The enhanced evaporation system is managed to ensure that wind blown drift does not travel beyond the perimeter of the pond's liner. The system is monitored twice daily and as wind conditions change the nozzles are adjusted to confine any drift to within the pond's liner. Under severe wind conditions, the evaporation system will be shut off.

Mixing of Exempt and Nonexempt Wastes

Exempt Wastes. Since 1989, the Fenton Hill Geothermal Facility has retained exclusive use of the 1 MG pond for the containment of geothermal production fluids. These fluids are exempt from Resource Conservation and Recovery Act (RCRA) regulation due to a specific exclusion for geothermal exploration, development, or the production of produced waters and other associated wastes [40 CFR 261.4(b)(5)]. In September 1997, approximately 675,000 gallons of geothermal fluids and sludge were removed from the pond and transported off-site for disposal. The pond had not been cleaned since its construction in 1989.

Currently, geothermal well EE-2 is the only remaining source of geothermal fluids discharging to the 1 MG pond. All of the facility's other geothermal wells were plugged and abandoned in 1996. Fluids vented from EE-2 originate from the Phase II geothermal reservoir. Annual venting volumes from EE-2 have been estimated at approximately 100,000 gallons per year.

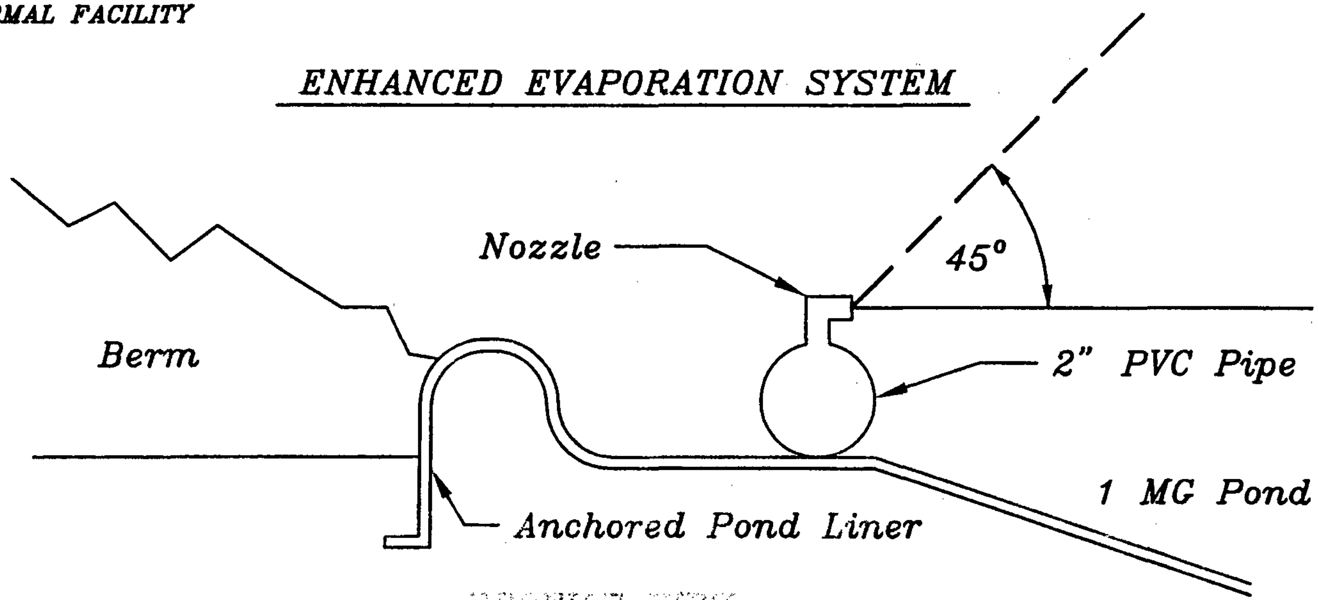
Mixing of Exempt and Nonexempt Wastes (con't)

The Laboratory's proposal to mix nonexempt and exempt waste meets the following two requirements of the New Mexico Oil Conservation Division's mixture policy (rev. 9/97):

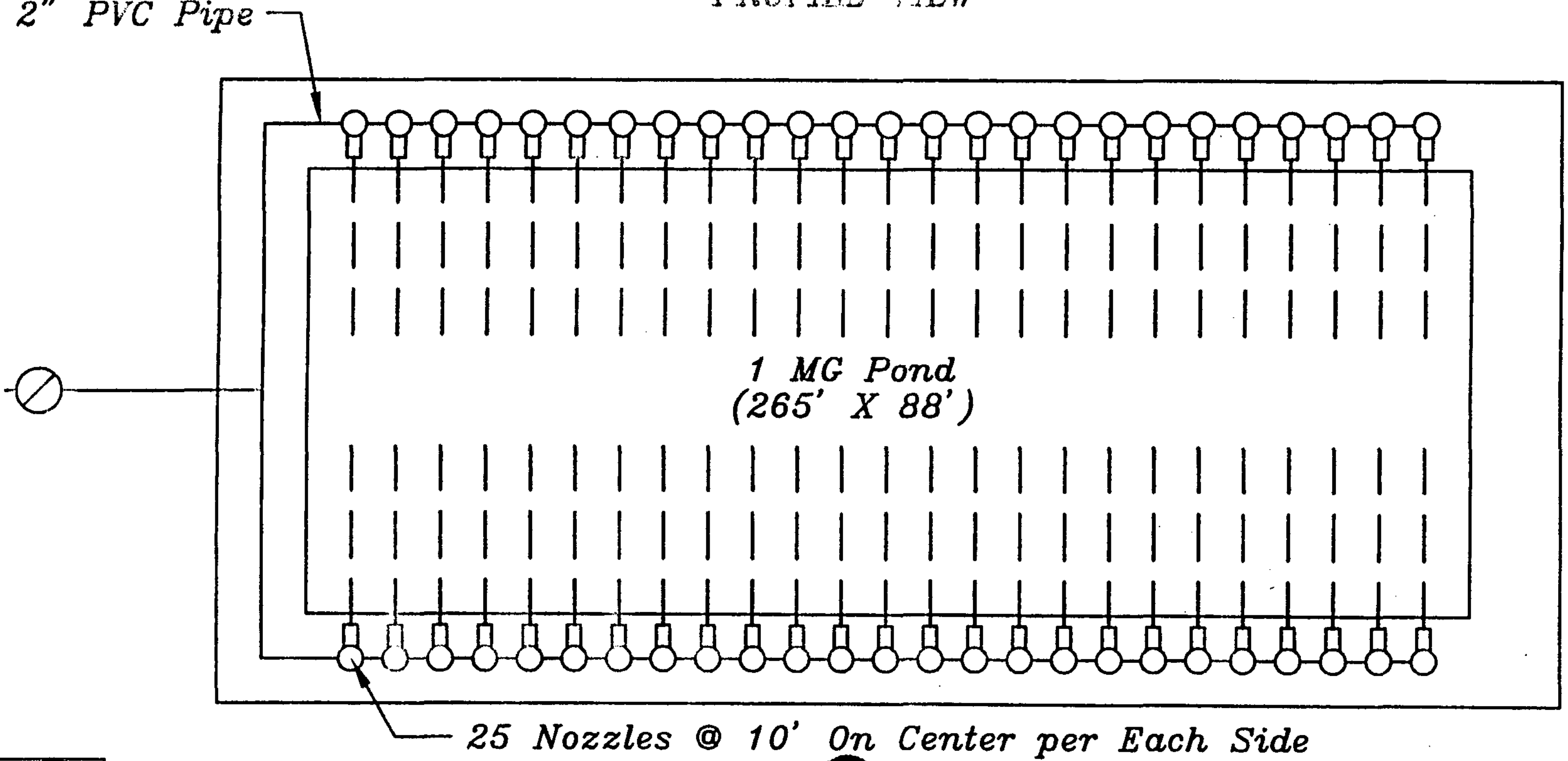
> First, sampling and analysis of the nonexempt portion of the waste, the softener regeneration wastewater and the GAC filter backwash wastewater, shows that the waste is nonhazardous (See Table 1.0 and 2.0); and
>
> Second, the total nonexempt portion of the waste constitutes no more than five (5) percent by volume of the final mixture. Table 3.0 presents an estimate of the volume of exempt and nonexempt solids that would accumulate in the 1 MG pond if mixing were to occur for nine years of operation. Using the best information available, the Laboratory estimates that the final mixture will be 3 percent nonexempt wastes.
>
> (Note: A final mixture based upon the volume of solids in the 1 MG pond, rather than the combined volume of solids and liquid, is being proposed due to the facility's capability to evaporate off the liquid fraction.)

MINOR MODIFICATION
GROUND WATER DISCHARGE PLAN CW-031
FENTON HILL GEOTHERMAL FACILITY

ENHANCED EVAPORATION SYSTEM



PROFILE VIEW



PLA VIEW

07/06

gure 1.0

Milagro Project at Fenton Hill

Water Quality Data: GAC Filter Backwash Water

Sample Date: 12/12/97

Sample Type: total, unfiltered

Sample ID No.: MGRO-5A, 7A, 8A, 9A, 9B, 10A, and 10B

Analyte	**Results (mg/L)**	**40 CFR 261 TCLP Concentration Limits (mg/L)**	**NM WQCC 3103. Ground Water Standards (mg/L)**
Al	<0.5		5.0
As	<0.06	5.0	0.1
Ba	0.06	100.0	1.0
Be	<0.004		
B	1.2		0.75
Cd	<0.008	1.0	0.01
CN	<0.02		0.2
Cr	<0.04	5.0	0.05
Co	<0.01		0.05
Cu	<0.04		1.0
Fe	0.6		1.0
Hg	<0.0002	0.2	0.002
Pb	<0.06	0.4	0.05
Mn	<0.01		0.2
Mo	<0.02		1.0
Ni	<0.04		0.2
Se	<0.005	1.0	0.05
Ag	<0.02	5.0	0.05
Tl	<0.3		
U	0.0049		5.0
Zn.	0.3		10.0
Nitrate-N	<0.2		10.0
pH (standard units)	7.4		between 6 and 9
TDS	422		1000.0
TSS	9		
Chloride	67.7		250.0
Fluoride	<0.5		1.6
Sulfate	12.7		600.0
<u>Semi-volatiles</u>			
SW846-8270	Non-detect		
<u>Volatiles</u>			
SW846-8240	Non-detect		

Milagro Project at Fenton Hill

Water Quality Data: Softener Regeneration Water

Sample Date: 12/12/97

Sample Type: total, unfiltered

Sample ID Nos.: MGRO-11A, 11B, and 11C

Analyte (Sample ID No.)	**Results (mg/L)**	**40 CFR 261 TCLP Concentration Limits (mg/L)**	**NM WQCC 3103 Ground Water Standards (mg/L)**
TDS (11A)	422	NA	1,000
TDS (11B)	9,930	NA	1,000
TDS (11C)	12,550	NA	1,000

NOTES:

Softner backwash cycle took 85 minutes to complete. Sample 11A was collected 3 minutes into the cycle, 11B was collected 25 minutes in the cycle, and 11C was collected 55 minutes into the cycle.

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Client: LOS ALAMOS NATIONAL LABS

Project: 9712126 FENTON HILL

Client Sample ID: MGRO-2A,2B — Sample Matrix: WATER_COMP

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			EPA-335 / SM-4500						
12/12/97	9712126-02A	W97547	Cyanide	< 0.02	mg / L	0.02		MW.1997.1027 - 10	12/17/97

Client Sample ID: MGRO-3A,3B — Sample Matrix: WATER_COMP

N/A

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			EPA 300 series						
12/12/97	9712126-03A	W97543	Nitrate, Nitrogen	< 0.2	mg N/ L	0.2		MW.1997.1025 - 16	12/16/97

Client Sample ID: MGRO-4A,4B — Sample Matrix: WATER_COMP

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			EPA 150.1						
12/12/97	9712126-04A	WPH-573	pH	7.4	units	0.1		MT.1997.446 - 4	12/13/97
			EPA 160 series						
12/12/97	9712126-04A	WTDS-435	Total Dissolved Solids	406	mg / L	10		MT.1997.476 - 6	12/16/97
		WTSS-404	Total Suspended Solids	< 4.0	mg / L	4		MT.1997.469 - 7	12/17/97
			EPA 300 series						
12/12/97	9712126-04A	W97543	Chloride	71.4	mg / L	0.5		MW.1997.1025 - 22	12/16/97
		W97543	Fluoride	< 0.5	mg / L	0.5		MW.1997.1025 - 13	
		W97543	Sulfate	13.0	mg / L	0.5		MW.1997.1025 - 13	

Client Sample ID: MGRO 5A GAC Filter Backwash — Sample Matrix: WATER

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			ASTM V 11.01/02						
12/12/97	9712126-05A	MT.1998.91	Uranium, total	0.0049	mg/L	0.0001		MT.1998.91 - 2	01/09/98
			EPA 200 series AA/GF						
12/12/97	9712126-05A	M97914	Molybdenum	< 0.02	mg / L	0.02		MW.1997.1044 - 12	12/23/97
		M97914	Selenium	< 0.005	mg / L	0.005		MW.1998.6 - 15	01/05/98
			EPA 200.7 ICP						
12/12/97	9712126-05A	M97927	Aluminum	< 0.5	mg / L	0.5		MW.1998.1 - 23	12/31/97
		M97927	Arsenic	< 0.06	mg / L	0.06		MW.1998.1 - 23	
		M97927	Barium	0.06	mg / L	0.01		MW.1998.1 - 23	
		M97927	Beryllium	< 0.004	mg / L	0.004		MW.1998.1 - 23	
		M97927	Boron	1.2	mg / L	0.1		MW.1998.21 - 23	01/06/98
		M97927	Cadmium	< 0.008	mg / L	0.008		MW.1998.1 - 23	12/31/97
		M97927	Chromium	< 0.04	mg / L	0.04		MW.1998.1 - 23	
		M97927	Cobalt	< 0.01	mg / L	0.01		MW.1998.1 - 23	
		M97927	Copper	< 0.04	mg / L	0.04		MW.1998.1 - 23	
		M97927	Iron	0.6	mg / L	0.2		MW.1998.21 - 23	01/06/98
		M97927	Lead	< 0.06	mg / L	0.06		MW.1998.1 - 23	12/31/97
		M97927	Manganese	< 0.010	mg / L	0.01		MW.1998.1 - 23	
		M97927	Nickel	< 0.04	mg / L	0.04		MW.1998.1 - 23	
		M97927	Silver	< 0.02	mg / L	0.02		MW.1998.1 - 23	
		M97927	Thallium	< 0.3	mg / L	0.3		MW.1998.1 - 23	
		M97927	Zinc	0.3	mg / L	0.1	3	MW.1998.21 - 23	01/06/98

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Project: **9712126 FENTON HILL**

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			EPA 300 series						
12/12/97	9712126-05A	W97543	Nitrate, Nitrogen	< 0.2	mg N/ L	0.2		MW 1997.1025 - 8	12.16/97
			SW846-7470 / EPA 245.1						
12/12/97	9712126-05A	M97925	Mercury	< 0.0002	mg / L	0.0002		MW 1997 1051 - 14	12/24/97

Client Sample ID: **MGRO 7A** GAC FILTER BACKWASH — Sample Matrix: **WATER**

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			EPA 335 / SM4500						
12/12/97	9712126-07A	W97547	Cyanide	< 0.02	mg / L	0.02		MW.1997 1027 - 11	12/17/97

Client Sample ID: **MGRO 8A** GAC FILTER BACKWASH — Sample Matrix: **WATER**

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			EPA 150.1						
12/12/97	9712126-08A	WPH-573	pH	7.4	units	0.1		MT.1997.446 - 1	12/13/97
			EPA 160 series						
12/12/97	9712126-08A	WTDS-435	Total Dissolved Solids	422	mg / L	10		MT 1997 476 - 7	12/16/97
		WTSS-494	Total Suspended Solids	9.0	mg / L	4		MT.1997.469 - 8	12/17/97
			EPA 300 Series						
12/12/97	9712126-08A	W97543	Chloride	67.7	mg / L	0.5		MW.1997 1025 - 33	12/16/97
		W97543	Fluoride	< 0.5	mg / L	0.5		MW.1997 1025 - 7	
		W97543	Sulfate	12.7	mg / L	0.5		MW.1997 1025 - 7	

Client Sample ID: **MGRO 9A** GAC FILTER BACKWASH — Sample Matrix: **WATER**

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			SW846-8270 / EPA 625 Semi-Volatiles						
12/12/97	9712126-09A	X97468	1,2,4-Trichlorobenzene	< 2.2	ug / L	1		XG.1997 373 - 10	12/19/97
		X97468	1,2-Dichlorobenzene	< 2.2	ug / L	1		XG.1997.373 - 10	
		X97468	1,3-Dichlorobenzene	< 2.2	ug / L	1		XG.1997 373 - 10	
		X97468	1,4-Dichlorobenzene	< 2.2	ug / L	1		XG.1997 373 - 10	
		X97468	1-Methylnaphthalene	< 2.2	ug / L	1		XG.1997 373 - 10	
		X97468	2,3,4,6-Tetrachlorophenol	< 110	ug / L	50		XG.1997 373 - 10	
		X97468	2,4,5-Trichlorophenol	< 22	ug / L	10		XG.1997 373 - 10	
		X97468	2,4,6-Trichlorophenol	< 22	ug / L	10		XG.1997.373 - 10	
		X97468	2,4-Dichlorophenol	< 22	ug / L	10		XG.1997 373 - 10	
		X97468	2,4-Dimethylphenol	< 2.2	ug / L	1		XG 1997 373 - 10	
		X97468	2,4-Dinitrophenol	< 110	ug / L	50		XG.1997 373 - 10	
		X97468	2,4-Dinitrotoluene	< 22	ug / L	10		XG.1997.373 - 10	
		X97468	2,6-Dinitrotoluene	< 22	ug / L	10		XG.1997 373 - 10	
		X97468	2-Chloronaphthalene	< 2.2	ug / L	1		XG.1997.373 - 10	
		X97468	2-Chlorophenol	< 2.2	ug / L	1		XG.1997 373 - 10	
		X97468	2-Methylnaphthalene	< 2.2	ug / L	1		XG 1997 373 - 10	
		X97468	2-Methylphenol	< 2.2	ug / L	1		XG 1997 373 - 10	
		X97468	2-Nitroaniline	< 22	ug / L	10		XG.1997 373 - 10	
		X97468	2-Nitrophenol ccc	< 22	ug / L	10		XG.1997 373 - 10	
		X97468	3+4 Methylphenol	< 2.2	ug / L	1		XG 1997 373 - 10	
		X97468	3,3'-Dichlorobenzidine	< 22	ug / L	10		XG.1997 373 - 10	
		X97468	3-Nitroaniline	< 22	ug / L	10		XG.1997 373 - 10	

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12/12/97	9712126-09A	X97468	4,6-Dinitro-2-methylphenol	< 22	ug / L	10	XG.1997 373 - 10	12.19.97
		X97468	4-Bromophenyl-phenylether	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	4-Chloro-3-methylphenol	< 22	ug / L	10	XG.1997 373 - 10	
		X97468	4-Chloroaniline	< 22	ug / L	10	XG.1997 373 - 10	
		X97468	4-Chlorophenyl-phenylether	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	4-Nitroaniline	< 22	ug / L	10	XG.1997 373 - 10	
		X97468	4-Nitrophenol	< 44	ug / L	20	XG.1997 373 - 10	
		X97468	Acenaphthene	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Acenaphthylene	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Aniline	< 22	ug / L	10	XG.1997 373 - 10	
		X97468	Anthracene	< 2.2	ug / L	1	XG.1997.373 - 10	
		X97468	Azobenzene&1,2-Diphenylhydrazine	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Benzo (a) anthracene	< 2.2	ug / L	1	XG.1997.373 - 10	
		X97468	Benzo(a)pyrene	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Benzo(b & k)fluoranthene	< 2.2	ug / L	1	XG.1997.373 - 10	
		X97468	Benzo(g,h,i)perylene	< 22	ug / L	10	XG.1997 373 - 10	
		X97468	Benzoic acid	< 220	ug / L	100	XG.1997.373 - 10	
		X97468	Benzyl alcohol	< 110	ug / L	50	XG.1997.373 - 10	
		X97468	bis (2-Chloroethyl) ether	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	bis(2-Chloroethoxy)methane	< 2.2	ug / L	1	XG.1997.373 - 10	
		X97468	bis(2-Chloroisopropyl)ether	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	bis(2-Ethylhexyl)phthalate	< 22	ug / L	10	XG.1997 373 - 10	
		X97468	Butylbenzylphthalate	< 2.2	ug / L	1	XG.1997.373 - 10	
		X97468	Chrysene	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	di-n-Butylphthalate	< 22	ug / L	10	XG.1997 373 - 10	
		X97468	di-n-Octylpthalate	< 22	ug / L	10	XG.1997.373 - 10	
		X97468	Dibenz(a,h)anthracene	< 22	ug / L	10	XG 1997 373 - 10	
		X97468	Dibenzofuran	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Diethylphthalate	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Dimethylphthalate	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Fluoranthene	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Fluorene	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Hexachlorobenzene	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Hexachlorobutadiene	< 2.2	ug / L	1	XG.1997.373 - 10	
		X97468	Hexachlorocyclopentadiene	< 110	ug / L	50	XG.1997.373 - 10	
		X97468	Hexachloroethane	< 2.2	ug / L	1	XG 1997 373 - 10	
		X97468	Indeno(1,2,3-cd)pyrene	< 22	ug / L	10	XG.1997 373 - 10	
		X97468	Isophorone	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	n-Nitroso-di-n-propylamine	< 2.2	ug / L	1	XG 1997 373 - 10	
		X97468	n-Nitroso-dimethyl-amine	< 22	ug / L	10	XG.1997 373 - 10	
		X97468	n-Nitrosodiphenylamine	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Naphthalene	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Nitrobenzene	< 2.2	ug / L	1	XG.1997.373 - 10	
		X97468	Pentachlorophenol	< 22	ug / L	10	XG.1997.373 - 10	
		X97468	Phenanthrene	< 2.2	ug / L	1	XG.1997 373 - 10	
		X97468	Phenol	< 22	ug / L	10	XG 1997 373 - 10	
		X97468	Pyrene	< 2.2	ug / L	1	XG 1997 373 - 10	
		X97468	Pyridine	< 22	ug / L	10	XG 1997 373 - 10	

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Client: **LOS ALAMOS NATIONAL LABS**

Project: **9712126 FENTON HILL**

Client Sample ID: **MGRO 9B** GAC FILTER BACKWASH   Sample Matrix: **WATER**

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			SW846-8270 / EPA 625 Semi-Volatiles						
12/12/97	9712126-10A	X97468	1,2,4-Trichlorobenzene	< 2.0	ug / L	1		XG.1997 373 - 11	12/19/97
		X97468	1,2-Dichlorobenzene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	1,3-Dichlorobenzene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	1,4-Dichlorobenzene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	1-Methylnaphthalene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	2,3,4,6-Tetrachlorophenol	< 100	ug / L	50		XG.1997 373 - 11	
		X97468	2,4,5-Trichlorophenol	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	2,4,6-Trichlorophenol	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	2,4-Dichlorophenol	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	2,4-Dimethylphenol	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	2,4-Dinitrophenol	< 100	ug / L	50		XG.1997 373 - 11	
		X97468	2,4-Dinitrotoluene	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	2,6-Dinitrotoluene	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	2-Chloronaphthalene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	2-Chlorophenol	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	2-Methylnaphthalene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	2-Methylphenol	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	2-Nitroaniline	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	2-Nitrophenol ccc	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	3+4 Methylphenol	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	3,3'-Dichlorobenzidine	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	3-Nitroaniline	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	4,6-Dinitro-2-methylphenol	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	4-Bromophenyl-phenylether	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	4-Chloro-3-methylphenol	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	4-Chloroaniline	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	4-Chlorophenyl-phenylether	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	4-Nitroaniline	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	4-Nitrophenol	< 41	ug / L	20		XG.1997 373 - 11	
		X97468	Acenaphthene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Acenaphthylene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Aniline	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	Anthracene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Azobenzene&1,2-Diphenylhydrazine	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Benzo (a) anthracene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Benzo(a)pyrene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Benzo(b & k)fluoranthene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Benzo(g,h,i)perylene	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	Benzoic acid	< 200	ug / L	100		XG.1997 373 - 11	
		X97468	Benzyl alcohol	< 100	ug / L	50		XG.1997 373 - 11	
		X97468	bis (2-Chloroethyl) ether	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	bis(2-Chloroethoxy)methane	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	bis(2-Chloroisopropyl)ether	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	bis(2-Ethylhexyl)phthalate	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	Butylbenzylphthalate	< 2.0	ug / L	1		XG.1997 373 - 11	

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Project: **9712126 FENTON HILL**

12/12/97	9712126-10A	X97468	Chrysene	< 2.0	ug / L	1		XG.1997 373 - 11	12/19/97
		X97468	di-n-Butylphthalate	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	di-n-Octylpthalate	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	Dibenz(a,h)anthracene	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	Dibenzofuran	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Diethylphthalate	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Dimethylphthalate	< 2.0	ug / L	1		XG.1997.373 - 11	
		X97468	Fluoranthene	< 2.0	ug / L	1		XG.1997.373 - 11	
		X97468	Fluorene	< 2.0	ug / L	1		XG.1997.373 - 11	
		X97468	Hexachlorobenzene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Hexachlorobutadiene	< 2.0	ug / L	1		XG.1997.373 - 11	
		X97468	Hexachlorocyclopentadiene	< 100	ug / L	50		XG.1997.373 - 11	
		X97468	Hexachloroethane	< 2.0	ug / L	1		XG.1997.373 - 11	
		X97468	Indeno(1,2,3-cd)pyrene	< 20	ug / L	10		XG.1997.373 - 11	
		X97468	Isophorone	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	n-Nitroso-di-n-propylamine	< 2.0	ug / L	1		XG.1997.373 - 11	
		X97468	n-Nitroso-dimethyl-amine	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	n-Nitrosodiphenylamine	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Naphthalene	< 2.0	ug / L	1		XG.1997.373 - 11	
		X97468	Nitrobenzene	< 2.0	ug / L	1		XG.1997.373 - 11	
		X97468	Pentachlorophenol	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	Phenanthrene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Phenol	< 20	ug / L	10		XG.1997 373 - 11	
		X97468	Pyrene	< 2.0	ug / L	1		XG.1997 373 - 11	
		X97468	Pyridine	< 20	ug / L	10		XG.1997 373 - 11	

Client Sample ID: **MGRO 10A** GAC Filter Backwash Sample Matrix: **WATER**

Collect	*Fraction*	*QC Group*	*Analyte*	*Result*	*Units*	*Limit*	*	*Run Group - #*	*Run Date*
			SW846-8240 Volatiles						
12/12/97	9712126-11A	X97483	1,1 Dichloroethane	< 1.0	ug / L	1		XG 1997.380 - 7	12/24/97
		X97483	1,1 Dichloroethene	< 1.0	ug / L	1		XG.1997.380 - 7	
		X97483	1,1,1 Trichloroethane	< 1.0	ug / L	1		XG.1997.380 - 7	
		X97483	1,1,1,2 Tetrachloroethane	< 1.0	ug / L	1		XG.1997.380 - 7	
		X97483	1,1,2 Trichloroethane	< 1.0	ug / L	1		XG.1997 380 - 7	
		X97483	1,1,2,2 Tetrachloroethane	< 1.0	ug / L	1		XG.1997 380 - 7	
		X97483	1,2 Dibromoethane (EDB)	< 1.0	ug / L	1		XG.1997 380 - 7	
		X97483	1,2 Dichlorobenzene	< 1.0	ug / L	1		XG.1997 380 - 7	
		X97483	1,2 Dichloroethane	< 1.0	ug / L	1		XG.1997 380 - 7	
		X97483	1,2 Dichloropropane	< 1.0	ug / L	1		XG.1997 380 - 7	
		X97483	1,2,3 Trichloropropane	< 1.0	ug / L	1		XG.1997 380 - 7	
		X97483	1,3 Dichlorobenzene	< 1.0	ug / L	1		XG.1997 380 - 7	
		X97483	1,4 Dichloro-2-butene	< 10	ug / L	10		XG.1997 380 - 7	
		X97483	1,4 Dichlorobenzene	< 1.0	ug / L	1		XG.1997 380 - 7	
		X97483	2-Butanone (MEK)	< 5.0	ug / L	5		XG.1997 380 - 7	
		X97483	2-Chloroethylvinylether	< 5.0	ug / L	5		XG.1997 380 - 7	
		X97483	2-Hexanone (MBK)	< 5.0	ug / L	5		XG.1997 380 - 7	
		X97483	4-Methyl-2-pentanone (MIBK)	< 5.0	ug / L	5		XG.1997 380 - 7	
		X97483	Acetone	< 5.0	ug / L	5		XG.1997 380 - 7	

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Project: **9712126** **FENTON HILL**

12/12/97	9712126-11A	X97483	Acrolein	< 20	ug / L	20	XG.1997.380 - 7	12/24/97
		X97483	Acrylonitrile	< 20	ug / L	20	XG.1997.380 - 7	
		X97483	Benzene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Bromodichloromethane	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Bromoform	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Bromomethane	< 5.0	ug / L	5	XG.1997.380 - 7	
		X97483	Carbon disulfide	< 5.0	ug / L	5	XG.1997.380 - 7	
		X97483	Carbon tetrachloride	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Chlorobenzene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Chlorodibromomethane	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Chloroethane	< 5.0	ug / L	5	XG.1997.380 - 7	
		X97483	Chloroform	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Chloromethane	< 5.0	ug / L	5	XG.1997.380 - 7	
		X97483	cis-1,2 dichloroethene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	cis-1,3 dichloropropene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Dibromomethane	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Ethyl methacrylate	< 5.0	ug / L	5	XG.1997.380 - 7	
		X97483	Ethylbenzene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Freon 113	< 5.0	ug / L	5	XG.1997.380 - 7	
		X97483	Freon 12	< 10	ug / L	10	XG.1997.380 - 7	
		X97483	Iodomethane	< 5.0	ug / L	5	XG.1997.380 - 7	
		X97483	Methyl t-butyl ether (MTBE)	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Methylene chloride	< 10	ug / L	10	XG.1997.380 - 7	
		X97483	o-Xylene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	p/m Xylenes	< 2.0	ug / L	2	XG.1997.380 - 7	
		X97483	Styrene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	t-1,2 Dichloroethene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	t-1,3 Dichloropropene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Tetrachloroethene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Toluene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Trichloroethene	< 1.0	ug / L	1	XG.1997.380 - 7	
		X97483	Trichlorofluoromethane	< 5.0	ug / L	5	XG.1997.380 - 7	
		X97483	Vinyl acetate	< 5.0	ug / L	5	XG.1997.380 - 7	
		X97483	Vinyl chloride	< 5.0	ug / L	5	XG.1997.380 - 7	

Client Sample ID: **MGRO-10B** Backwash Sample Matrix: **WATER**

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	Run Group - #	Run Date
			SW846-8240 Volatiles					
12/12/97	9712126-12A	X97483	1,1 Dichloroethane	< 1.0	ug / L	1	XG.1997.380 - 8	12/24/97
		X97483	1,1 Dichloroethene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	1,1,1 Trichloroethane	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	1,1,1,2 Tetrachloroethane	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	1,1,2 Trichloroethane	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	1,1,2,2 Tetrachloroethane	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	1,2 Dibromoethane (EDB)	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	1,2 Dichlorobenzene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	1,2 Dichloroethane	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	1,2 Dichloropropane	< 1.0	ug / L	1	XG.1997.380 - 8	

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Project: **9712126 FENTON HILL**

12/12/97	9712126-12A	X97483	1,2,3 Trichloropropane	< 1.0	ug / L	1	XG.1997.380 - 8	12/24/97
		X97483	1,3 Dichlorobenzene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	1,4 Dichloro-2-butene	< 10	ug / L	10	XG.1997.380 - 8	
		X97483	1,4 Dichlorobenzene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	2-Butanone (MEK)	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	2-Chloroethylvinylether	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	2-Hexanone (MBK)	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	4-Methyl-2-pentanone (MIBK)	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	Acetone	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	Acrolein	< 20	ug / L	20	XG.1997.380 - 8	
		X97483	Acrylonitrile	< 20	ug / L	20	XG.1997.380 - 8	
		X97483	Benzene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Bromodichloromethane	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Bromoform	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Bromomethane	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	Carbon disulfide	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	Carbon tetrachloride	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Chlorobenzene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Chlorodibromomethane	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Chloroethane	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	Chloroform	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Chloromethane	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	cis-1,2 dichloroethene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	cis-1,3 dichloropropene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Dibromomethane	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Ethyl methacrylate	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	Ethylbenzene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Freon 113	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	Freon 12	< 10	ug / L	10	XG.1997.380 - 8	
		X97483	Iodomethane	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	Methyl t-butyl ether (MTBE)	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Methylene chloride	< 10	ug / L	10	XG.1997.380 - 8	
		X97483	o-Xylene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	p/m Xylenes	< 2.0	ug / L	2	XG.1997.380 - 8	
		X97483	Styrene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	t-1,2 Dichloroethene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	t-1,3 Dichloropropene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Tetrachloroethene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Toluene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Trichloroethene	< 1.0	ug / L	1	XG.1997.380 - 8	
		X97483	Trichlorofluoromethane	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	Vinyl acetate	< 5.0	ug / L	5	XG.1997.380 - 8	
		X97483	Vinyl chloride	< 5.0	ug / L	5	XG.1997.380 - 8	

Client Sample ID: **MGRO-11A** [illegible] WATER Sample Matrix: **WATER**

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			EPA 160 series						
12/12/97	9712126-13A	WTDS-435	Total Dissolved Solids	426	mg / L	10		MT 1997 476 - 8	12/16/97

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Project: 9712126 FENTON HILL

Client Sample ID: MGRO 11B SOFTENER REGEN. WATER — Sample Matrix: WATER

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			EPA 160 series						
12/12/97	9712126-14A	WTDS-435	Total Dissolved Solids	9930	mg / L	10		MT.1997.476 - 9	12/16/97

Client Sample ID: MGRO 11C SOFTENER REGEN. WATER — Sample Matrix: WATER

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			EPA 160 series						
12/12/97	9712126-15A	WTDS-435	Total Dissolved Solids	12550	mg / L	10		MT.1997.476 - 10	12/16/97

Client Sample ID: MGRO 12 — Sample Matrix: WATER

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			ASTM [illegible]						
12/12/97	9712126-16A	MT.1998.91	Uranium, total	0.0029	mg/L	0.0001		MT.1998.91 - 3	01/09/98
			EPA 200 series AA/GF						
12/12/97	9712126-16A	M97914	Molybdenum	< 0.02	mg / L	0.02		MW.1997.1044 - 13	12/23/97
		M97914	Selenium	< 0.005	mg / L	0.005		MW.1998.6 - 16	01/05/98
			EPA 200.7 ICP						
12/12/97	9712126-16A	M97927	Aluminum	< 0.5	mg / L	0.5		MW.1998.1 - 26	12/31/97
		M97927	Arsenic	< 0.06	mg / L	0.06		MW.1998.1 - 26	
		M97927	Barium	< 0.01	mg / L	0.01		MW.1998.1 - 26	
		M97927	Beryllium	< 0.004	mg / L	0.004		MW.1998.1 - 26	
		M97927	Boron	1.4	mg / L	0.1		MW.1998.21 - 26	01/06/98
		M97927	Cadmium	< 0.008	mg / L	0.008		MW.1998.1 - 26	12/31/97
		M97927	Chromium	< 0.04	mg / L	0.04		MW.1998.1 - 26	
		M97927	Cobalt	< 0.01	mg / L	0.01		MW.1998.1 - 26	
		M97927	Copper	< 0.04	mg / L	0.04		MW.1998.1 - 26	
		M97927	Iron	< 0.2	mg / L	0.2		MW.1998.21 - 26	01/06/98
		M97927	Lead	< 0.06	mg / L	0.06		MW.1998.21 - 26	
		M97927	Manganese	< 0.010	mg / L	0.01		MW.1998.1 - 26	12/31/97
		M97927	Nickel	< 0.04	mg / L	0.04		MW.1998.1 - 26	
		M97927	Silver	< 0.02	mg / L	0.02		MW.1998.1 - 26	
		M97927	Thallium	< 0.3	mg / L	0.3		MW.1998.1 - 26	
		M97927	Zinc	0.7	mg / L	0.1	B	MW.1998.21 - 26	01/06/98
			SW846 7470 / EPA 245.1						
12/12/97	9712126-16A	M97925	Mercury	< 0.0002	mg / L	0.0002		MW.1997.1051 - 17	12/24/97

Client Sample ID: MGRO 13 — Sample Matrix: WATER

Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			EPA 335 / SM 4500						
12/12/97	9712126-17A	W97547	Cyanide	< 0.02	mg / L	0.02		MW.1997.1027 - 13	12/17/97

NA

Client Sample ID: MGRO 14 — Sample Matrix: WATER

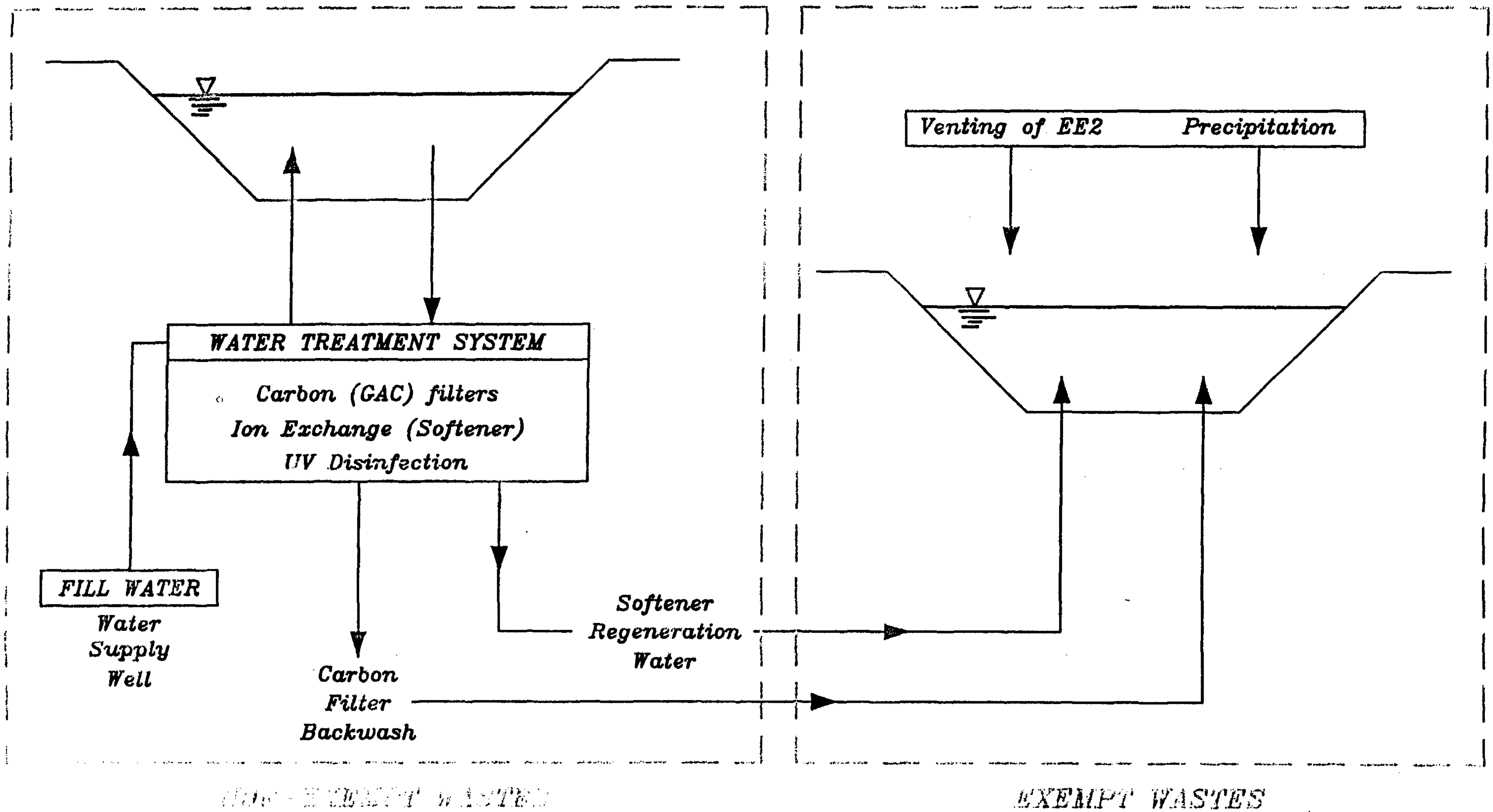
Collect	Fraction	QC Group	Analyte	Result	Units	Limit	*	Run Group - #	Run Date
			EPA 300 series						
12/12/97	9712126-18A	W97543	Nitrate, Nitrogen	< 0.2	mg N/ L	0.2		MW.1997.1025 - 18	12/[illegible]

MINOR [illegible]DIFICATION
GROUND WATER DISCHARGE PLAN GW-031
FENTON HILL GEOTHERMAL FACILITY

MIXING OF EXEMPT AND NON-EXEMPT WASTES

MILAGRO PROJECT - 5 MG POND

GEOTHERMAL PROJECT - 1 MG POND
(100% CONTAINMENT - NO DISCHARGE)

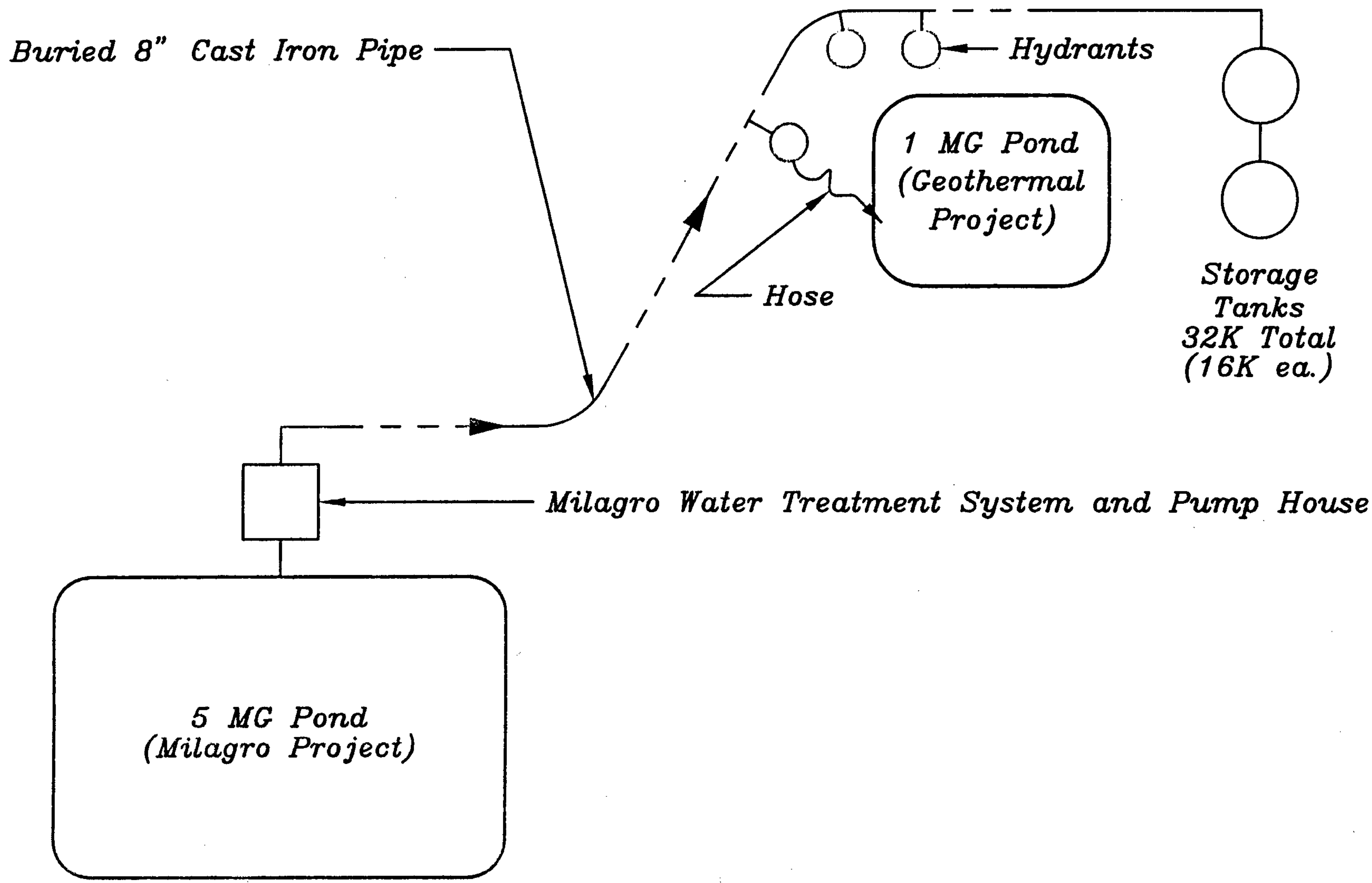


07/01/98

Figure 2.0

MINOR MODIFICATION
GROUND WATER DISCHARGE PLAN GW-031
FENTON HILL GEOTHERMAL FACILITY

5 MG POND to 1 MG POND PIPING SCHEMATIC



07/01

Figure 3.0

FINAL MIXTURE SUMMARY: 1 MG Pond: 1998-2006[1]	
Total Estimated Nonexempt Solids (ft^3)	106
Total Estimated Exempt Solids (ft^3)	4,184
Percent of Final Mixture that is Nonexempt	3%

Milagro Project Nonexempt Wastes: Softener Regeneration & GAC Filter Backwash Wastewater

Years	Source	Wastewater Volume (gal)	Wastewater Volume (liters)	TDS (mg/L)	TDS (kg)	TSS (mg/L)	TSS (kg)	Total Solids TSS+TDS (kg)	Total Solids Volume (ft^3)[2]
1998	GAC Filter	78,500	297,123	422	125	9	3	134	3
1998	Softener	75,000	283,875	12,550	3,563	9	3	3,572	88
1999	GAC Filter	48,000	181,680	422	77	9	2	78	2
2000	GAC Filter	48,000	181,680	422	77	9	2	78	2
2001	GAC Filter	48,000	181,680	422	77	9	2	78	2
2002	GAC Filter	48,000	181,680	422	77	9	2	78	2
2003	GAC Filter	48,000	181,680	422	77	9	2	78	2
2004	GAC Filter	48,000	181,680	422	77	9	2	78	2
2005	GAC Filter	48,000	181,680	422	77	9	2	78	2
2006	GAC Filter	48,000	181,680	422	77	9	2	78	2
					Estimated volume of nonexempt solids after 9 years of operation (ft^3)				106

Geothermal Project Exempt Wastes: 1 MG Pond[4]

Year	Source	Wastewater Volume (gal)	Wastewater Volume (liters)	% Solids	Solids Volume (gal)	Solids Volume (ft^3)
2006	Geothermal	25,000	94,625	20	18,925	2,536
	Geothermal	650,000	2,460,250	0.5[3]	12,301	1,648
		Estimated volume of exempt solids after 9 years of operation (ft^3)				4,184

NOTES:

[1] Final mixture is based upon nine years of operation.

[2] Weight-to-volume conversions are based upon an estimated solids weight of 90 lbs/ft^3.

[3] A percent solids of 0.5% is equivalent to a TDS/TSS concentration of 5,000 ppm. Analysis of the 1 MG pond water on 5/5/97 showed a TDS concentration of 5,034 ppm.

[4] The estimated volume of solids in the 1 MG pond in the year 2006 are based upon the volume of solids removed during pond cleaning in Sept., 1997, after 9 years of operation.

APPENDIX F

NM OCD Approval of July 1998 Minor Modification Request, May 1999

NEW MEXICO ENERGY, MINERALS
& NATURAL RESOURCES DEPARTMENT

OIL CO .SERVATION DIVISION
2040 South Pacheco Street
Santa 'e, New Mexico 87505
(505) 27-7131

May 10, 1999

CERTIFIED MAIL
RETURN RECEIPT NO. Z 559 573 595

Mr. Steven Rae
Los Alamos National Laboratory
MS K497
Los Alamos, NM 87545

Subject: Minor Modification of Ground Water Discharge Plan GW-031

Dear Mr. Rae:

The New Mexico Oil Conservation Division (NMOCD) is receipt of Los Alamos National Laboratory's (LANL) letter dated July 20, 1999 requesting a minor modification to the existing discharge plan GW-031. The NMOCD hereby approves of the minor modification subject to the following conditions:

1. All waste will be disposed of at an OCD approved facility.

2. The 8" (inch) buried cast iron pipe using to convey the wastewater from the 5 (mmgal) pond to the 1 (mmgal) pond shall be tested to demonstrate mechanical integrity at present and then every 5 years thereafter, or prior to discharge plan renewal. Permittees may propose various methods for testing such as pressure testing to 3 pounds per square inch above normal operating pressure or other means acceptable to the OCD. The OCD will be notified at least 72 hours prior to all testing. **LANL shall perform this mechanical integrity test and submit the results by June 15, 1999.**

Please be advised that NMOCD approval of this minor modification does not relieve LANL of liability should their operations fail to adequately investigate and remediate contamination that pose a threat to ground water, surface water, human health or the environment. In addition, NMOCD approval does not relieve LANL of responsibility for compliance with any other federal, state, or local laws and/or regulations.

If you have any questions, please contact Wayne Price of my staff at (505-827-7155). On behalf of the staff of the OCD, I wish to thank you and your staff for your cooperation during this discharge plan review.

Sincerely,

Roger Anderson

Roger Anderson
Environmental Bureau Chief

xc: Roy Johnson

APPENDIX G

LANL Draft Seeding Specification

SECTION 02936

SEEDING

****

LANL MASTER CONSTRUCTION SPECIFICATION

When editing to suit project, author shall add job-specific requirements and delete only those portions that in no way apply to the activity (e.g., a component that does not apply). To seek a variance from applicable requirements, contact the LEM Civil POC.

When assembling a specification package, include applicable specifications from all Divisions, especially Division 1, General Requirements.

Delete information within "stars" during editing.

Specification developed for ML-3 projects. For ML-1 / ML-2, additional requirements and QA reviews are required.

****

PART 1 GENERAL

1.1 SECTION INCLUDES

A. Preparation of seedbed.

B. Seeding.

C. Mulching and erosion control blankets.

D. Watering and maintenance.

1.2 RELATED SECTIONS

A. Section 02270, Slope Protection and Erosion/Sediment Control

1.3 SUBMITTALS

A. Submit the following in accordance with Section 01330, Submittal Procedures:

1. Catalog data, including sources of supply for amendments, mulch, tackifier, fertilizer and erosion control blankets.

2. Certification substantiating that material complies with specified requirements. Submit certified seed bag tags and copies of seed invoices identified by project name.

3. Installation instructions, including proposed seeding schedule. Coordinate with specified maintenance periods to provide maintenance from date of final acceptance. Once schedule is accepted, revise dates only with LANL approval after documentation of delays.

1.4 QUALITY ASSURANCE

A. Contractor Qualifications:

1. Perform work by a single firm experienced with the type and scale of work required and having equipment and personnel adequate to perform the work satisfactorily.

B. Material Quality Control:

1. Provide seed mixture in containers showing species percentages in seed mix; test information including, purity, germination and noxious/restricted weeds; net weight; date of packaging; and location of packaging.

2. Furnish seed labeled in accordance with the requirements of federal and New Mexico statutes and regulations governing seed labeling. Such resulting requirements include but are not necessarily limited to: Federal Seed Act and Amendments, rules and regulations established by the United States Department of Agriculture; the New Mexico Seed Law; and all resulting regulations or restrictions established by New Mexico State University or other authorized entity.

3. In addition, ensure seed mix and its application complies with the requirements of all other federal and New Mexico statutes and regulations governing seeds, plants, and weeds. These requirements include but are not necessarily limited to: the Noxious Weed Control Act and all rules, regulations, or control measures by a noxious weed control district embracing Los Alamos County, New Mexico; and the Harmful Plant Act.

1.5 DELIVERY, STORAGE AND HANDLING

A. Deliver packaged materials in sealed containers showing weight, analysis and name of manufacturer. Protect materials from deterioration during delivery and while stored at site. Opened or wet seed shall be rejected and returned to the responsible party.

PART 2 PRODUCTS

2.1 PRODUCT OPTIONS AND SUBSTITUTIONS

A. Comply with 01630, Product Options and Substitutions.

2.2 SEED

A. Obtain native grass seed from sources whose origin would ensure site adaptability at LANL. Plant sources from New Mexico or surrounding states are preferred.

B. Obtain shrub and wildflower seed from sources whose origin would ensure site adaptability at LANL. Plant sources from New Mexico or surrounding states are preferred.

C. Cover crops (e.g., annual barley, oats, winter rye, etc.) may be used only as a temporary stabilization measure and shall not be used in conjunction with a perennial seed mix.

D. Furnish certification, showing origin of seed and pure live seed (PLS) content as determined by a certified authority. Provide bags of seed that are tagged and sealed in accordance with the State Department of Agriculture or other local certification authority within the state of origin. The tag or label shall indicate analysis of seed and date of analysis, which shall not be more than 9 months prior to delivery date. Seed may be premixed by the seed dealer and appropriate data indicated on the bag label for each variety.

E. Seed mixture shall be:

****

Develop seed mixture from the following guidelines. Choose a minimum of 5 grass species from the list. Should wildflowers be included in the mix, use a ratio of 80 – 90 percent grasses and 10-20 percent wildflowers. Choose 3 –5 species from the forb and wildflowers list.

****

NATIVE PERENNIAL MIX

Common Name	Scientific Name	% of Mix
Grasses		
Blue grama*	*Bouteloua gracilis*	5 – 10%
Galleta grass*	*Hilaria jamesii*	5- 10%
Mutton grass	*Poa fendleriana*	10-15%
Sideoats grama*	*Bouteloua curtipendula*	10-15%
Arizona fescue†	*Festuca arizonica*	10 – 15%
Prairie junegrass†	*Koeleria macrantha*	5 – 10%
Bottlebrush squirreltail*	*Elymus elymoides*	15 – 20%
Little bluestem†	*Schizachyrium scoparium*	10 – 15%
Indian ricegrass*	*Oryzopsis hymenoides*	10 – 15%
Mountain brome†	*Bormus marginatus*	10 – 15%
Sand dropseed*	*Sporobolus cryptandrus*	1 - 8%
Thickspike wheatgrass	*Agropyron dasystachyum*	20 – 25%
Needle and Thread grass*	*Stipa comata*	5 – 10%
New Mexico needlegrass*	*Stipa neomexicana*	10 - 15%
Sheep fescue	*Festuca ovina*	10 – 15%
Forbs/ Wildflowers		1%
Firewheel	*Gaillardia pulchella*	2%
Evening primrose	*Oenothera caespitosa*	1%
Gooseberry leaf Globemallow	*Sphaeralcea grossulariafolia*	1.5%

Common Name	Scientific Name	% of Mix
Scarlet gilia	*Ipomopsis aggregata*	1%
Plains aster	*Aster biglovii*	1%
Western yarrow	*Achillea millifolium*	½%
Fringed sage	*Artemisia frigida*	1%
Blue flax	*Linum perenne lewisii*	4%
Scarlet bulgler	*Penstemon barbatus*	2%
Palmer penstemon	*Penstemon palmerii*	2%
Prairie coneflower	*Ratibida columnifera*	1%
Showy golden-eye	*Heliomerus multiflora*	1%
Purple geranium	*Geranium caespitosum*	5%

***Species particularly suited for especially dry sites**
†Species particularly suited for higher elevations (above 7000 ft.)

2.3 STRAW MULCH

A. Straw shall be stalks from oats, wheat, rye, barley, or rice that are free from noxious weeds, mold, or other objectionable material. At least 65 percent of the herbage by weight of each bale of straw shall be 10 inches in length or longer. Rotted, brittle or molded straw is not acceptable. Straw from introduced grasses is acceptable if cut prior to seed formation. If possible, provide marsh grass composed of mid to tall native grasses (usually tough and wiry grass and grass-like plants found in the lowland areas within the Rocky Mountain Region).

2.4 HYDRAULIC MULCH/TACKIFIER

A. Provide mulch material consisting of 100 percent virgin wood fibers manufactured expressly from whole wood chips, such as Eco-Fibre, Conwed, etc. Process chips in such a manner as to contain no growth or germination inhibiting factors. Do not produce fiber from recycled material such as sawdust, paper, cardboard, or residue from pulp and paper plants. Provide materials free from contaminants such as lead paint, varnish or other metal contaminants. Hydraulic mulch shall contain non-toxic dye to assist in visually determing even distribution. Mulch material shall meet the following specifications:

Parameter	Value
pH at 3% consistency	4.5 +/- 0.5
Ash content	0.8% +/- 0.2%
Moisture holding capacity	1250 (grams water/100 grams oven dry fiber)
Moisture content	12% +/- 3% (Wet weight basis)

B. Combine mulch with an organic plantago based tackifier, such as M-binder, etc., that has no growth or germination inhibiting factors and is nontoxic. Apply the uniform mixture to the seeded area.

C. Bagged mulch/tackifier mix that is homogenous within the unit package may also be used. Tackifier shall adhere to the fibers during manufacturing to prevent separation during shipment and to avoid chemical agglomeration during mixing in the hydraulic mulching equipment.

2.5 EROSION CONTROL BLANKET

A. Provide erosion control blankets of a uniform web of interlocking excelsior wood fibers, weed-free straw, or a combination of straw and coir fibers.

****
Use an appropriate blanket chosen for the site conditions and functionality for the desired growing seasons.
****

1. 3:1 slopes or gentler

Single netted blankets	A machine produced erosion control blanket using 100 percent straw or excelsior fibers sewn into a medium weight photo degradable bottom net. Minimum weight of blanket 0.5 lbs/ square yard, such as Greenfix America WS05, etc.

2. 3:1 – 2:1 slopes

Double netted blankets	A machine produced erosion control blanket using 100 percent straw or excelsior fibers sewn into a medium weight photo degradable top net and a light weight photo degradable bottom net. Minimum weight of blanket 0.7 lbs/ square yard, such as Greenfix America WS072, etc.

3. 2:1 slopes and steeper and/or 2 growing seasons of protection

Straw/ coir blend blankets	A machine produced straw /coir fiber erosion control blanket using 70 percent straw /30 percent coir fibers sewn into a heavy weight photo degradable top net and a medium weight photo degradable bottom net. Minimum weight of blanket 0.7 lbs/square yard, such as Greenfix America CFS072R, etc.

B. Staples: U-shaped, 11 gauge or heavier steel wire, minimum leg length of 8 inches after bending, with a throat approximately 2 inches wide.

C. Wood Stakes: Use 2 x 2 x 12 inch pine or fir stakes, beveled at one end, in place of wire staples in tuff locations.

2.6 BONDED FIBER MATRIX

A. Provide Bonded Fiber Matrix (BFM) composed of natural color, long strand wood fiber, produced by therm-mechanical defribration of wood chips and joined together by a high strength non-toxic adhesive, such as Eco-Ageis, etc. The product shall be composed of 90 percent wood fiber, 9 percent blended hydrocolloid-based binder, and 1 mineral activators, all by total weight. The BFM shall be 100 percent biodegradable and non-toxic to fish and wildlife, and it shall not contain any synthetic fibers.

2.7 AMENDMENTS / SOIL ADDITIONS

A. Fertilizer: Apply slow-release organic fertilizers such as Biosol Mix, Biosol, Osmocote, composted manure or approved equal to minimize deficiencies of the topsoil. If composted manure is to be applied, test the nutrient content and interpret before it is used.

B. Water: Clean, fresh, and free of substances or matter that could inhibit vigorous growth.

C. Sand: Clean, washed, and free of toxic materials.

D. Wood chips: Wood chips shall have a relatively large surface area to volume ratio to be more easily broken down in the soil. Incorporate wood chips at low rates (0.5 ton/ acre) in order to assure the Carbon to Nitrogen ratio in soil is at favorable conditions for plant germination and growth. If higher rates are used, add nitrogen fertilizer to assure nutrient availability to plants.

PART 3 EXECUTION

3.1 PREPARATION

A. Preparation of the Seedbed:

1. Prepare seedbed to a maximum depth of 4 inches by tilling with a disc harrow or chiseling tool. Uproot all competitive vegetation during seedbed preparation and work soil uniformly, leaving surface rough to reduce surface erosion. Remove large clods and stones, or other foreign material that would interfere with seeding equipment.

2. Do not till on ground that is already loose to a depth of 2 inches or more that has undergone regrading and fill. Till newly cut slopes.

3. Perform tillage across slope when practical and perform in 2 directions whenever one pass is insufficient to adequately break up soil. Do not till up and down slopes, as this will create excessive surface erosion problems.

4. Do not do work when moisture content of soil is unfavorable or ground is otherwise in a non-tillable condition. To minimize dust problems for adjoining areas, do not till when wind speeds are over 10 mph.

5. The extent of seedbed preparation shall not exceed the area on which the entire seeding operation can be accomplished within a 24-hour period.

B. Soil Amendments/Additions: Uniformly apply slow release organic fertilizer to prepared seedbed in accordance with manufacturer recommended rates.

C. Prepare seedbed again if prior to seeding LANL Construction Inspector determines that rain or some other factor has affected prepared surfaces and that it may prevent seeding to proper depth.

D. On excessively steep slopes (steeper than 2:1), hydraulic/broadcast seeding may be appropriate. If seeding in this fashion, multiply application rate of seed by a factor of 2.

E. If cover crop has been established in area to be seeded, mow cover crop early in growing season before cover crop is ready to drop seeds.

3.2 APPLICATION OF SEED

A. General:

1. Avoid seeding between August 1 and September 30. Do not seed during windy weather, or when topsoil is dry, saturated or frozen.

2. Equip seed boxes used for drill and broadcast seeding with an agitator.

3. To prevent stratification of seed mix, do not run seed box agitators while seeding is not being performed.

4. If seed mix is transported to site in a seed box or other equipment that subjects mix to shaking or similar movement that has the potential to cause stratification, remix seed prior to application.

5. Calibrate seeding equipment in presence of LANL Construction Inspector to determine that equipment setting is appropriate to distribute seed at the specified rates.

6. Unless otherwise shown on Drawings, seed areas disturbed by or denuded by construction operations or erosion.

7. Use markers to ensure that no gaps will exist between passes of seeding equipment.

8. If cover crop has been established, mow the crop and drill seed perennial seed mix into the crop stubble.

B. Drill Seeding:

When drill seeding, plant seed mix at a rate of 20 - 25 PLS lbs/acre. Uniformly apply prescribed mix over area to be seeded as follows:

1. Accomplish seeding operations, where practical, by drilling in a direction across slope.

2. Plant seeds approximately 1/4 inch deep.

3. Do not exceed 4 inches distance between drilled furrows. If furrow openers on drill exceed 4 inches, drill area twice to obtain a 4-inch distance between furrows.

4. Seed with grass wheels, rate control attachments, seed boxes with agitators, and separate boxes for small seed.

C. Broadcast Seeding:

When broadcast seeding, plant seed mix at a rate of 32 - 37 PLS lbs/acre.

1. Where it is not practical to accomplish seeding by drilling, mechanically broadcast seed by use of a hydraulic mulch slurry blower, rotary spreader, or a seeder box with a gear feed mechanism. If seeding is done with a slurry blower, use highest pressure and smallest nozzle opening that will accommodate the seed.

2. Immediately following seeding operation, lightly rake seedbed or loosen with a chain harrow to provide approximately 1/4 inch of soil cover over most of the seed.

3. If hydraulically applying mulch as part of the broadcast seeding process, use a 2 step process. Apply seed with a tracer (200 – 300 lbs/ acre) amount of mulch across entire seeded area. Once seed is applied, apply full complement of mulch (to equal 2000 lbs/ acre). This shall allow seed to be in good contact with soil surface and not suspended in mulch matrix.

4. Prohibit vehicles and other equipment from traveling over the seeded areas.

3.3 STRAW MULCH: Slopes Flatter than 2:1, Non-Irrigated Projects

A. For locations that have not been hydraulically mulched, immediately following raking/chaining operation, add straw mulch to seeded areas.

1. Apply straw mulch at a minimum rate of 1.5 tons per acre of air-dry material. Spread straw mulch uniformly over area either by hand or with a mechanical mulch spreader to achieve 80 percent ground cover. When spread by hand, tear bales of straw apart and fluff before spreading. Depth of applied straw mulch shall not exceed 3 inches. Do not mulch when wind velocity exceeds 10 mph.

2. Wherever use of crimping equipment is practical, place mulch in manner noted above and anchor it into the soil to a minimum depth of 2 inches. Use a crimper or heavy disc such as a mulch tiller, with flat serrated discs at least 1/4 inch in thickness, having dull edges, and spaced no more than 9 inches apart. Provide discs of sufficient diameter to prevent frame of equipment from dragging the mulch. Where practical, perform crimping in 2 (opposite) directions. Do not use Sheep's Foot Rollers, heavy equipment tracks, and standard disc cultivators for crimping.

3. If straw mulched areas cannot be anchored by crimping, use hydraulic mulch wood fibers with tackifier. Mix slurry in a tank with an agitation system and spray under pressure uniformly over the soil surface. Keep all materials in uniform suspension throughout the mixing and suspension cycle when using hydraulic mulching equipment. Mix 100 lb. of wood fiber with 150 lbs. of tackifier to anchor straw mulch. Apply mixture at a rate of 250 lbs/acre.

4. Use both horizontal and vertical movements in the applicator to achieve an even application of the slurry material.

3.6 BONDED FIBER MATRIX (BFM): Slopes 2:1 and Steeper, Irrigated and Non-Irrigated Projects

A. Hydraulically apply BFM over seeded area (or apply seed with a tracer amount, 200-300 lbs/ acre) immediately following raking/chaining operations and in accordance with manufacturer's specified procedures. Hydraulically apply BFM as a viscous mixture. Upon drying, it shall form a continuous, porous and erosion resistant mat. Upon drying, matrix shall not inhibit germination and growth of plants in and beneath the layer. Matrix shall retain its form despite re-wetting.

B. Apply matrix uniformly across area and apply in multiple directions to ensure a 100 percent soil surface coverage.

C. Apply at a rate of approximately 3,500-lbs/ acre in a manner that achieves uniform coverage of all exposed soils.

D. Prohibit vehicle traffic on hydraulic BFM applications.

3.7 WATERING

A. Where temporary watering is required for seeded areas, provide temporary water system which may be a sprinkler system, or a water truck with a spray boom or any other method satisfactory to distribute a uniform coverage of clean water (free or oil, acid, salt or other substances harmful to plants) to previously seeded and mulched areas.

B. If a temporary sprinkler system is used, keep all pipe connections tight to avoid leakage and loss of water, and to prevent washing or erosion of growing areas. Maintain sprinklers in proper working order during watering.

C. Do not drive trucks with spray systems on seeded areas and ensure water force does not cause movement of mulch or seed on the ground.

D. Water revegetated areas only if areas were planted between April 15 and July 31.

E. Apply water at a maximum of 1/2 inch/hour for 2 hours. Additional applications of water may be made as designated by LANL Construction Inspector. Water source will be approved by LANL, prior to use.

3.8 MAINTENANCE

A. Begin maintenance immediately after planting.

B. Maintain seeded areas for not less than 60 days after final acceptance of work and longer as required to achieve final stabilization as described in Section 3.10 ACCEPTANCE.

C. Reseed void areas greater than 6 square feet or repetitive voids greater than 2 square feet amounting to more than 10 percent of any area that appears the growing season following installation.

D. Keep revegetated areas free of noxious weeds until acceptance by LANL. Contact LANL Construction Inspector prior to application of any control measure.

3.9 CLEANUP AND PROTECTION

A. After completion of work, clear site of excess soil, waste material, debris and objects that may hinder maintenance and detract from neat appearance of site.

B. Protect work and materials from damage due to seeding operations, operations by other contractors and trades, and trespassers. Maintain protection during installation and maintenance periods. Treat, repair or replace damaged work as directed.

3.10 ACCEPTANCE

A. Seeded areas will be reviewed for acceptance by LANL when final stabilization has been achieved. Final stabilization is defined as "All soil disturbing activities at the site have been completed and a uniform (e.g., evenly distributed, without large bare areas) perennial vegetative cover with a density of 70 percent of the native background vegetative cover for the area has been established on all unpaved areas and areas not covered by permanent structures, or equivalent permanent stabilization measures (such as the use of riprap, gabions, or geotextiles) have been employed."

B. In the event that all other work required by the Contract is completed before final stabilization is achieved or because seasonal limitations prevent seeding, partial acceptance of the work shall be made with final acceptance delayed until satisfactory vegetative growth has been established.

END OF SECTION

STORM WATER MANAGEMENT PLAN

Prepared for

TECHNICAL AREA 57
FENTON HILL PROJECT SITE

Los Alamos National Laboratory
Los Alamos, NM

a requirement of the

APPLICATION FOR RENEWAL – DISCHARGE PLAN (GW-031)

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STORM WATER MANAGEMENT PLAN

for
TECHNICAL AREA 57
FENTON HILL PROJECT SITE

LOS ALAMOS NATIONAL LABORATORY

PREFACE

This Storm Water Management Plan was developed to comply with a condition for approval for renewal of Discharge Plan GW-031, as set forth by the State of New Mexico Energy, Minerals, and Natural Resources Department, Oil Conservation Division. The plan addresses facility and site characteristics, storm water characteristics, potential pollutants, and current storm water management.

1.0 SITE DESCRIPTION

The Fenton Hill Project Site is located in the Jemez Mountains of North Central New Mexico, approximately 35 miles west of Los Alamos and 10 miles north of Jemez Springs. This site is associated with the Department of Energy's Los Alamos National Laboratory (LANL), and has been given the LANL designation of Technical Area (TA) 57. TA-57 has an approximate size of 16 acres. The following sections provide brief descriptions of the history of the site and current operations.

1.1 Site History

The Fenton Hill Project Site was established in 1972 to support the Los Alamos Hot Dry Rock (HDR) Geothermal Energy Development Project. HDR is a research program to develop the technology necessary to economically extract the energy contained at accessible depths within the earth's crust. The project called for injecting water via a borehole to a depth where it would be naturally heated by the hot rocks at that depth, and then pump the water back to the surface for recovery of the energy contained in the heated water. Experimental operations were conducted from 1972 to approximately 1996.

During the period from 1995 to 2000, the HDR project experienced substantial funding reductions, which resulted in the termination of project activities and partial decommissioning of the facility. In 1995, a new astrophysical observatory was constructed in and around the existing 5.7 million gallon reservoir at the Site. Discharges from the venting of the remaining geothermal well is now directed to the existing one million gallon service pond. In 1998, an enhanced evaporation system for this service pond was installed and the discontinuation of the NPDES permitted outfall NM0028576 was approved by the U.S. Environmental Protection Agency.

1.2 Current Status

In 1996, all HDR Project geothermal wells, with the exception of well EE-2A, were plugged and abandoned. With this action the HDR Project no longer has the capability to perform geothermal research and experimentation. Current Site activities are primarily limited to site maintenance, further decommissioning and salvage of equipment and materials, and work associated with the astrophysical observatory. Future HDR activities will be limited to the testing of down-hole logging tools in well EE-2A and experimental drilling using micro-borehole equipment. Micro-borehole depths will be limited to 350 feet to ensure that the aquifer is not penetrated and all drilling fluids will be contained on-site in the one million gallon service pond.

There is no use of geothermal water at the Site by either the HDR Project or the astrophysical observatory. Vented geothermal water from well EE-2A is impounded until evaporation in the one million gallon service pond (see Photo 1, Appendix B). Water used at the site is provided by the facility's domestic water supply well. No commingling of geothermal and potable water occurs and no chemical additives are used.

2.0 STORM WATER CHARACTERISTICS

The following sections address environmental and physical elements that effect the accumulation and transport of storm water at the Fenton Hill Project Site. These include general climatology, runoff patterns, receiving waters, and non-storm water discharges.

2.1 General Climatology

The Site is located in a semiarid, temperate, mountain climate. Summers are generally sunny with moderate, warm days and cool nights. Winter conditions can be experienced from October through March and large snowfall accumulations are not uncommon. Summer temperatures range from 50°F at night to 90°F during the day. Winter temperatures range from 0°F at night to above 32°F during the day. The average annual precipitation is approximately 17 inches. Of this amount, approximately 40% (6.8 inches) is received through brief, intense thunderstorms occurring during the summer monsoon season (July – September).

2.2 Runoff Patterns

The Fenton Hill Project Site slopes gently to the south. This topography produces sheet flow runoff across the majority of the Site with minor concentrated flow at three Site discharge locations. (See Site Map, Appendix A for discharge locations.)

Runoff patterns within the Site can be primarily be categorized with relation to the one million gallon service pond. The area to the north and east of the pond drains to the south where it discharges to a wide, well vegetated, natural conveyance located on the south side of the main Site roadway (see Photo 2, Appendix B). This natural conveyance is lower in elevation than the roadway and runoff is conveyed to the area through a 12 inch corrugated metal pipe. Runoff on the north side of the pond flows either east to the natural conveyance or west and south along the west side of the pond to a low area located on the south side of the pond. A corrugated metal pipe is located in this low area to transfer significant accumulations of runoff off-site to the west (see Photo 3, Appendix B). The areas south and directly east of the service pond drain south to a well vegetated, natural conveyance known as Burns Swale (see Photo 4, Appendix B). Runoff from these areas sheetflow to the top of a gentle slope just south of the fuel storage shed, TA-57-56, and then is concentrated as it is conveyed down the slope in an earthen channel. At the toe of the slope the channel discharges the flow onto a flat, well vegetated area where the runoff resumes sheetflow characteristics as it moves through Burns Swale.

Receiving waters for the Site are tributaries of the Jemez River, which is the major surface water drainage for the area. Surface runoff from the Site discharges into Lake Fork Creek located to the south. Lake Fork Creek is a tributary of the Rio Cebolla, which in turn is a tributary of the Rio Guadalupe. The Rio Guadalupe flows into the Jemez River below the town of Jemez Springs.

2.3 Non-Storm Water Discharges

With the termination of geothermal activities and partial decommissioning of the facility, there are very few non-storm water discharges at the site. Those that do occur are of such minor magnitude that they do not significantly impact runoff accumulations or patterns. Non-storm water is typically discharged through a standard "garden" hose. Potential non-storm water discharges may include vehicle/equipment washing, dust suppression or soil moistening associated with maintenance activities, and watering of vegetation.

3.0 POTENTIAL POLLUTANTS

Potential Pollutants that have been identified at the Fenton Hill Project Site include equipment, materials, and exposed soil. These items area are discussed in the following section. Controls associated with these potential pollutants are addressed in Section 4. Potential Release Sites (PRSs), which resulted from previous site activity and were identified by the LANL Environmental Restoration (ER) Project, are also discussed for informational purposes.

3.1 Equipment, Materials & Soil

Equipment that includes a forklift, a bulldozer, transport vehicles, piping systems, pumps, and generators are stored in multiple locations throughout the Site. The vehicles and heavy equipment are used primarily for site maintenance activities while the majority of the remaining items are awaiting salvage. Potential pollutants associated with the equipment include fuel and fluid leaks from operational equipment, and potential leaching of materials from salvage items subjected to long-term exposure.

Materials at the Site include metal and plastic storage tanks; assorted piping; 55-gallon drums of salt; metal cuttings and slag from cutting, grinding, and welding; fuel and fluids from equipment and vehicles; fuel stored in two metal tanks; and residual waste oil stored in one fiberglass tank. Storage tanks and piping materials are awaiting salvage while the remaining items are used in associated with maintenance operations.

The majority of the interior area of the Site, which includes the roadways, is exposed soil. However, this area is relatively flat, and with sheetflow runoff patterns, there is no evidence of erosion or significant sediment transport. The perimeter of the Site is well vegetated. There are no identified erosional problems within the Fenton Hill Project Site or locations with significant offsite sediment transport.

3.2 Potential Release Sites

Geothermal experiments at the Fenton Hill Project Site facilitated the creation of circulation ponds, an outfall, a sludge disposal pit, and discharge areas for an on-site analytical trailer and other materials associated with the experiments. Ten such locations were identified and labeled PRSs by the LANL ER Project in 1994.

The drilling fluids, produced waters, and other wastes associated with exploration, development, or production of geothermal energy are not hazardous wastes as defined in the Resource Conservation and Recovery Act (RCRA), and are exempt from RCRA hazardous waste consideration. For this reason the PRSs at the Fenton Hill Project Site are not listed in LANL's Hazardous and Solid Waste Amendments (HSWA) permit. However, LANL agreed to follow the requirements of HSWA (Module VII of the RCRA permit) to ensure that all environmental problems are investigated in a consistent manner.

3.2.1 PRS Descriptions

Of the ten identified PRSs, two were recommended for no further action (NFA) and two for deferred action. The remaining six were evaluated in a Phase I investigation conducted in 1996. Following is a brief description of these six PRSs.

- 57-001(b): This PRS comprises two settling ponds designated GTP-3E (east) and GTP-3W (west) that were used during the drilling and operation of well GT-2. Pond GTP-3W was created by building a 10 foot high berm across the head of Burns Swale and excavating into the tuff. The ponds contained a homogeneous mix of cuttings, drilling mud, additives, and dissolved materials that were returned to the surface in the heated waters. Following decommissioning of the site, the pond was backfilled with boulders and clean soil and leveled with the surrounding terrain.

- 57-001(c): This PRS is a settling pond used during geothermal energy recovery experiments. It contained a homogeneous mix of cuttings, drilling mud, additives, and dissolved materials that were returned to the surface in the heated waters. The pond was decommissioned, cleaned, and filled with clean soil to the level of the surrounding terrain.
- 57-002: This PRS was a sludge pit used between 1974 and 1990. The pit received solids removed from the bottom of the settling ponds and mud removed from the drilling mud pits. Solids included cuttings, drilling muds, and the precipitate from recovered circulation water.
- 57-004(a): This PRS is settling pond GTP-1E. The pond was originally excavated for use as the disposal pit for the drilling of well EE-1 and was later enlarged to serve as a settling pond for discharged drilling materials and for recycling of fluids from the circulation loop. The pond was decommissioned, cleaned of sludge, and backfilled with clean soil to the level of the surrounding terrain.
- 57-006: This PRS was a 55-gallon drum buried beneath a trailer that was used as an analytical chemistry laboratory. The drum contained chemicals that were considered too dangerous to be disposed of via the sink drain. A special drain in the trailer connected to the drum. The drum and its residual contents were removed as a voluntary corrective action on September 15, 1994.
- 57-007: This PRS was a chemical waste leach field associated with the analytical chemistry laboratory. Wastewater from the trailer was poured into a sink that drained to the subsurface leach field.

3.2.2 ER RECOMMENDATIONS

Following are the remediation recommendations provided by the LANL ER Project at the conclusion of the Phase I investigation.

- 57-001(b) – Pond GTP-3W: Elevated concentrations of arsenic and barium were detected in pond GTP-3W at a level 11-12 feet below the ground surface. At this depth the potential for human contact with the contaminants is negligible. For this reason, this portion of the PRS was recommended for NFA.
- 57-001(b) – Burns Swale: Samples in this portion of the PRS revealed arsenic and manganese concentrations that exceeded upper tolerance levels (UTL). For this reason Burns Swale is scheduled for Phase II (accelerated, focused) field investigation to determine the extent of the contamination.
- 57-001(c): Multiple analytes were detected but their concentrations were below their respective background UTLs. On this basis this PRS was recommended for NFA.
- 57-002: Arsenic was detected at concentrations greater than its UTL and barium in concentrations exceeding its screening action level (SAL). For this reason, voluntary corrective action is recommended.
- 57-004(a): Analysis of samples from this pond showed that there were no chemicals found in concentrations exceeding the SALs. On this basis, NFA was recommended.
- 57-006: Sampling of the soil beneath the drum showed that there were no chemicals found in concentrations exceeding the SALs. On this basis, NFA was recommended.
- 57-007: Analytical results and the screening assessment indicated negligible risk. For this reason the PRS was recommended for NFA.

4.0 STORM WATER MANAGEMENT

In general, no attempt is made to eliminate or minimize the natural flow of storm water from the Site. Instead, emphasis is placed on preventing contamination of the runoff by retaining sediment on-site; minimizing contact with potential pollutants, and by diverting it from the locations in which erosion or pollutant contamination may take place. This control is achieved through the use of both applicable structural controls and administrative work procedures.

4.1 Structural Controls

Structural controls associated with storm water management include culverts, a drainage channel, rock check dams, covering, and secondary containment units. Three culverts are in place at the Site to facilitate the management of runoff. Corrugated metal pipes on the west and southeast sides of the Site have been installed at locations where storm water runoff accumulates and leaves the Site. A third culvert located under a concrete walkway adjacent to the CMP on the southeast side of the Site conveys runoff to the discharge location. By conveying concentrated flows through culverts, erosion and sediment transport is minimized.

At the head of Burns Swale is a small gentle south-facing slope. Sheetflow runoff that reaches the top of the slope is collected and conveyed down the west side of the slope in a constructed earthen drainage channel. At the toe of the slope the channel directs the flow east to the middle of the area where the terrain is flat and well vegetated. Use of the channel minimizes the potential for erosion down the face of the slope and conveys runoff to a location where it is most likely to resume sheetflow characteristics. Within the drainage channel are three rock check dams (see Photo 5, Appendix B). The check dams dissipate energy and velocity in the flow, allowing transported sediment to settle out within the channel.

Two fuel storage areas are located within the Site. One area, located on the north side of the facility, contains a fiberglass waste oil tank that is currently empty. The second area, located south of building 57-17, houses two small metal tanks containing gasoline and diesel fuel (see Photo 6, Appendix B). Both areas are covered and all the tanks reside in concrete secondary containment.

4.2 Administrative Controls

Administrative controls associated with storm water management include appropriate work procedures, Site inspections, and spill response and reporting. Appropriate work procedures minimize the risk of contact between storm water and potential pollutants. To achieve this, equipment and materials are properly stored and maintained, and fueling operations and the loading/unloading of identified potential pollutants are not conducted during precipitation events.

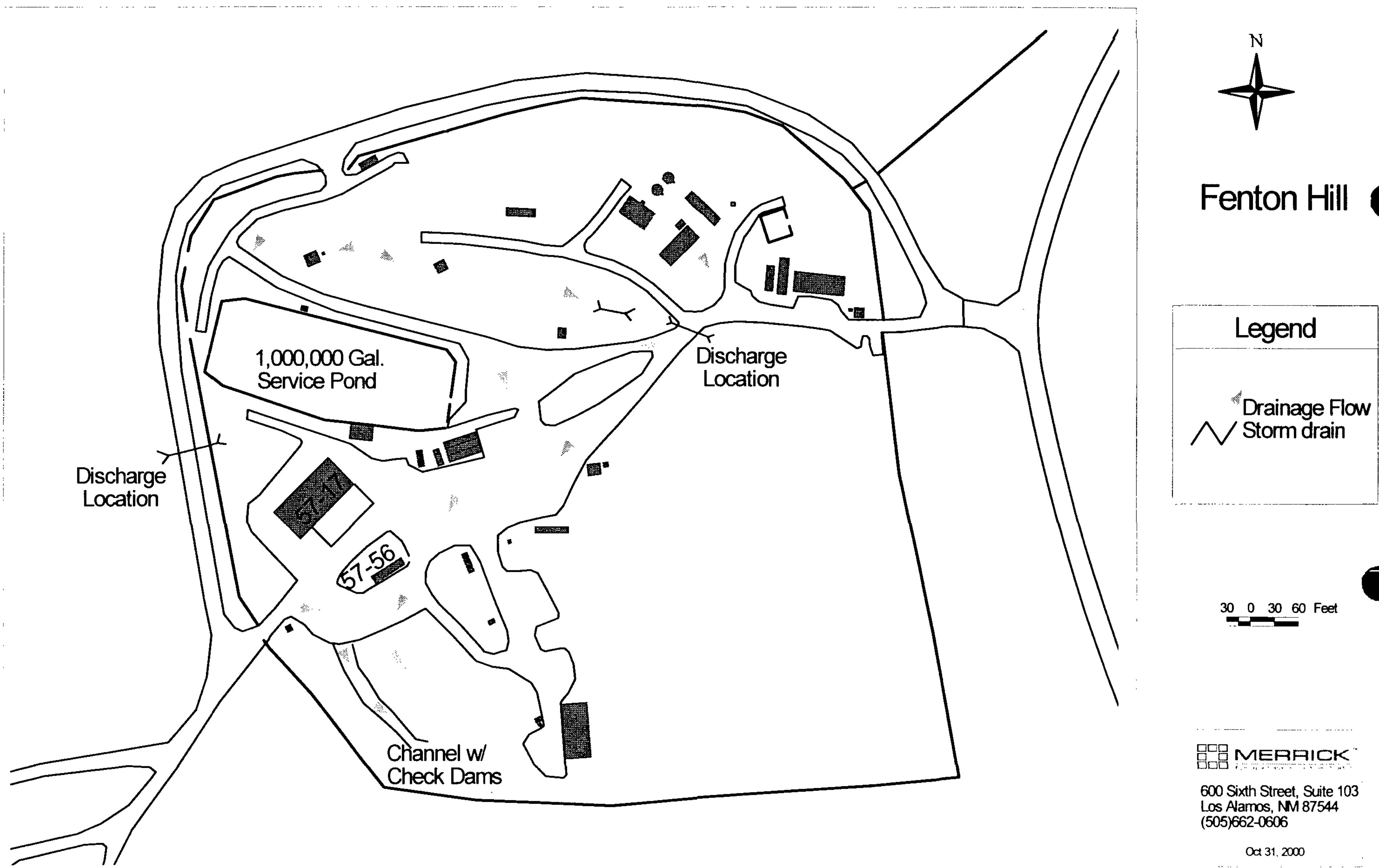
Site inspections are conducted monthly. Items that are evaluated include general site conditions, equipment and material storage areas, fuel storage area secondary containment units, storm water structural controls, new areas of erosion or significant sediment transport, and the general condition of the one million gallon service pond with its associated secondary containment unit and sump pump. If deficient items are identified, appropriate maintenance activities are initiated.

Spill control equipment is available on site to address minor spills and leaks. In addition, spills or releases of oil or hazardous substances will be reported to the Emergency Management & Response (EM&R) Office at **667-6211** or, after hours, at **667-7080**. In accordance with LANL requirements, internal spill reporting will be completed in the event of any release and copies of the reports will be maintained by both the responsible organization and ESH-18. ESH-18 and the EM&R Office, in accordance with Laboratory and DOE policies, and federal and state regulatory reporting requirements, will make the determination for federal notification.

APPENDIX A:

Site Map

Fenton Hill



MERRICK
600 Sixth Street, Suite 103
Los Alamos, NM 87544
(505)662-0606

Oct 31, 2000

APPENDIX B:

Site Photographs

Photo 1 – One Million Gallon Service Pond

Photo 2 – Southeast Discharge Location

Photo 3 – West Side Discharge Location

Photo 4 – Burns Swale

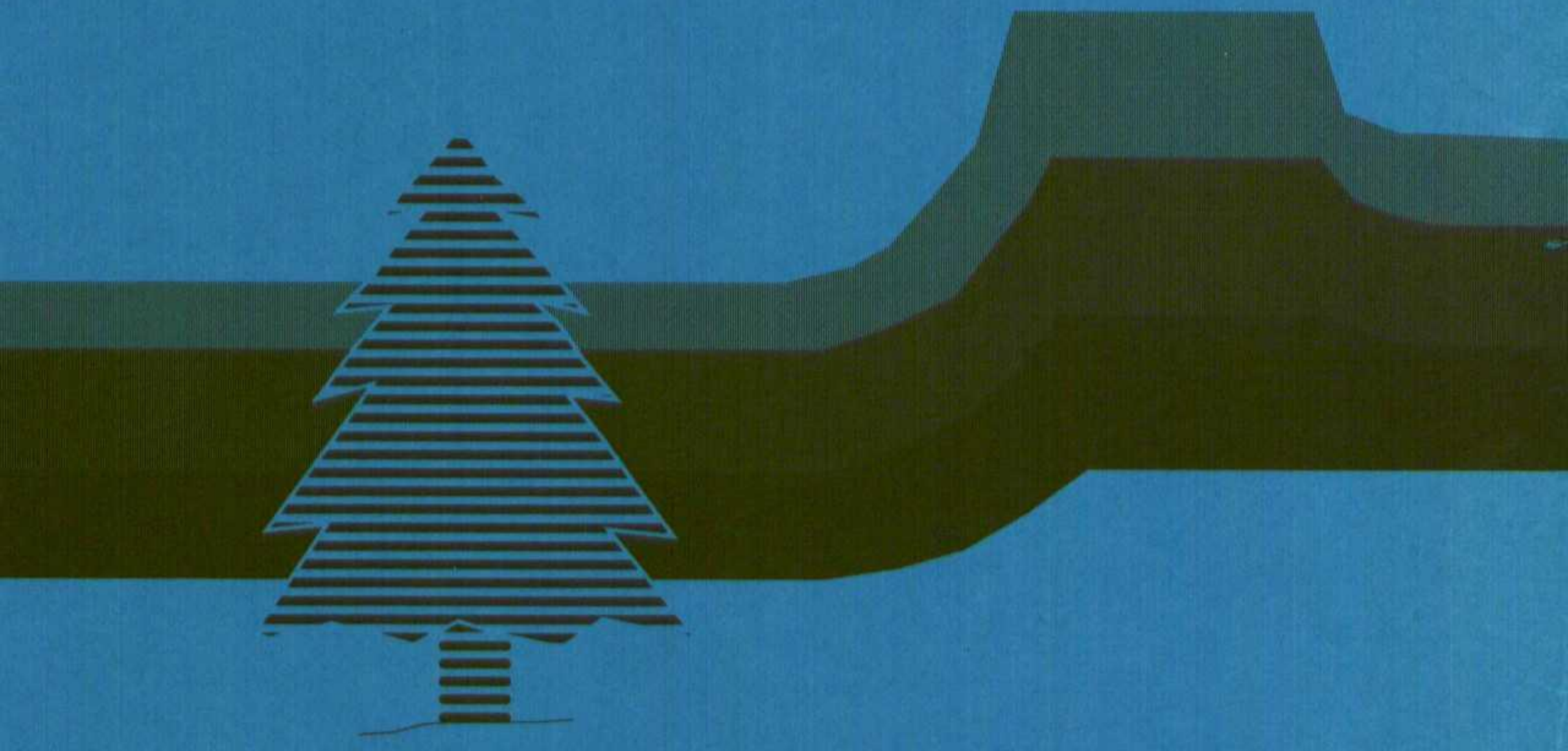
Photo 5 – Drainage Channel & Rock Check Dam

Photo 6 – Fuel Storage Area (TA-57-56)

AS PART OF THE
SPILL PREVENTION CONTROL
AND
COUNTERMEASURE PLAN

Group SPCC Implementation Plan

FOR TA-57 FENTON HILL



Los Alamos

Environment, Safety & Health Division
Los Alamos National Laboratory
Los Alamos, New Mexico 87545

GROUP/FACILITY (SPCC) IMPLEMENTATION PLAN (GSIP) FOR TA-57, FENTON HILL

Under the Oil Pollution Prevention regulation, 40 CFR 112 , the SPCC Plan shall be a carefully thought-out plan, prepared in accordance with good engineering practices, and which has the full approval of management at a level with authority to commit the necessary resources. Because of the diverse and changing operations at the Laboratory, the development of an SPCC Plan detailing the requirements and operating conditions for each location and operation would be impractical and would require frequent updates and revisions. By using the GSIP approach, the operating conditions for each location are addressed, and as these conditions change only the individual GSIP will require revision. Accordingly, the SPCC Master Plan provides background and guidance for development of GSIPs, with the GSIPs providing the site-specific requirements under 40 CFR 112. Owners or operators of a facility shall amend the plan (GSIP) whenever this is a change in facility design, construction, operation or maintenance which materially affects the facility's potential for a release. Any amendment shall be fully implemented as soon as possible, but not later than 6 months.

The responsibility for the development and implementation of the GSIP is the owner/operator of a facility.

Owner/Operator: James N. Albright Date: 8/30/95

James N. Albright, Group Leader, EES-4

Reviewed By: Mike R. Alexander Date: 7/25/95

Michael R. Alexander, SPCC and Storm Team Leader, ESH-18

Prepared By: Steven J. Veenis Date: 7/21/95

Steven J. Veenis, Santa Fe Engineering Ltd.,

GROUP SPCC IMPLEMENTATION PLAN

GSIP

FOR TA-57
FENTON HILL

PART OF THE

SPILL PREVENTION CONTROL

& COUNTERMEASURE PLAN

Prepared by: Santa Fe Engineering, Ltd.
1429 2nd Street
Santa Fe, New Mexico 87501
(505) 988-7438

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1. INTRODUCTION

The Los Alamos National Laboratory's Spill Prevention Control and Countermeasure (SPCC) Plan is a comprehensive plan developed to meet the regulatory requirements of the United States Environmental Protection Agency (EPA) that regulate water pollution from oil and toxic chemical spills.

The purpose of the SPCC Plan is to ensure that adequate prevention and response measures are provided to prevent oil spills from reaching navigable waters. Prevention measures include maintenance and inspections of facilities to ensure the integrity of the oil handling equipment, and proper operator training.

According to Title 40 of the Code of Federal Regulations (CFR) 112.7, "The SPCC Plan shall be a carefully thought-out plan, prepared in accordance with good engineering practices, and which has the full approval of management at a level with authority to commit the necessary resources. If the plan calls for additional facilities or procedures, methods or equipment not yet fully operational, these items should be discussed in separate paragraphs..."

Because of the diverse and changing operations at the Laboratory, the development of an SPCC Plan detailing the requirements and operating conditions for each location and operation would be impractical and would require frequent updates and revisions. By using the Group SPCC Implementation Plan (GSIP) approach, the operating conditions for each location are addressed, and as the conditions change, only the individual GSIP will be revised.

In addition, the National Pollutant Discharge Elimination System (NPDES), requires that those facilities that must obtain an NPDES permit and who use, produce or discharge any of the listed toxic or hazardous pollutants must develop and implement a Best Management Practice (BMP) program as required under 40 CFR 125, Subpart K. BMPs are developed for controlling discharges of toxic or hazardous substances into receiving streams from associated or ancillary activities. A comprehensive description of appropriate BMPs for GSIP Locations is provided in Chapter 4 of the SPCC Plan Revision 3.

1.1. SPILL CONTROL COMMITTEE

The Spill Coordinator (SC) has identified a committee of individuals responsible for development, implementation, maintenance and revision of the GSIP. These individual members understand that part of their responsibility is to be knowledgeable about spill control and prevention matters. The committee includes the following members:

1. Jay Thorne - EES-4 Staff
2. Dan Thomas, EES Facility Manager and Division Spill Coordinator

Effective organization of the Spill Control Committee is important in order for the team to be able to accomplish the task of developing and implementing this plan. To ensure that this plan remains effective, the SC must be aware of any changes that are made in plant operations to determine if any changes must be made.

1.2. SPILL COORDINATOR AUTHORITY

The SC is assigned a documented level of authority, by the group leader, in order to properly conduct the required responsibilities. At a minimum, the level of authority assigned needs to address the following:

- Approve or request Work Orders (WO) for the Support Services Subcontractor (SSS) to conduct a cleanup or to correct known deficiencies,
- Decision making ability on SPCC related items, and
- Assure group personnel abide by these decisions.

1.3. GSIP PLAN AMENDMENTS

Owners or operators of facilities subject to these requirements shall amend the GSIP Plan in accordance with 40 CFR 112.7 whenever there is a change in facility design, construction, operation or maintenance that materially affects the facility's potential for the discharge of oil or chemicals into or upon the navigable waters of the United States or adjoining shorelines. Such amendments shall be fully implemented as soon as possible, but not later than six months after such change occurs.

If the GSIP calls for additional facilities or procedures, methods, or equipment not yet fully operational, these items will be discussed in separate paragraphs, and the details of installation and operational start-up will be explained separately. At a minimum, the GSIP will be reviewed and updated annually.

1.4. EMPLOYEE TRAINING

Owners or operators are responsible for properly instructing their personnel in the operation and maintenance of equipment to prevent the discharges of oil and applicable pollution control laws, rules and regulations.

The Spill Coordinator is responsible for oil pollution training and reporting status to line management. Training should be scheduled at intervals frequent enough to assure adequate understanding of the GSIP for their facility. The meetings should highlight and describe known spill events or failures, malfunctioning components, precautionary measures and spill kit usage.

2. FACILITY DESCRIPTION

Fenton Hill is located in the Jemez mountains approximately thirty-five miles west of Los Alamos. The site is designated Technical Area 57 (TA-57) and is the site chosen for the Laboratory's Hot Dry Rock Pilot Plant. The plant was built to attempt to demonstrate the potential of the hot dry rock technology as an alternate energy source.

The process concept of the plant can be summarized as follows. Circulation of fluid through the reservoir is created and maintained by an injection pump which delivers water under high pressure to the reservoir through the injection well. After passing through the rock fractures and extracting the heat energy, the water is returned to the surface via the production well. At the surface, the hot geothermal water passes to a separator where any gas and solids are removed from the process stream. Production temperatures are expected to be in the range of 400° to 425°F. The hot fluid then flows to a heat exchanger where the temperature is reduced and the extracted heat energy is measured. After cooling, the fluid is returned to the injection pumps to complete the cycle. Previous tests have shown that some water loss will occur during the circulation process. For this reason, a makeup water facility is included as part of the plant to replace the lost water.[1]

2.1. GSIP LOCATIONS

This plan includes a brief but concise description of each GSIP location function. A major component of this description is a listing of characteristics that qualify areas as GSIP locations. Designating GSIP locations serves the purpose of dividing the Spill Coordinator's total region of responsibility into manageable pieces. This facilitates the preparation of facility site maps. Each of these locations may include several structures and numerous GSIP location types. There are five (5) GSIP locations identified at TA-57, Fenton Hill Site.

They are categorized as:

- Two aboveground storage tanks containing diesel fuel and waste fuel oil (57-56),
- One aboveground storage tank containing gasoline (57-56),
- One covered drum storage area (57-56),
- One covered drum storage area (57-59) , and
- One aboveground storage tank containing diesel fuel and the associated transfer area (57-26).

Chapter 4 provides a description of each GSIP location in detail. A map following this section shows TA-57, Fenton Hill Site, direction of storm water flow, GSIP locations, and other areas of concern.

2.2. OTHER AREAS OF CONCERN

This plan also identifies relevant areas at TA-57, Fenton Hill Site that may have spill potential but are not considered priority #1 or #2 GSIP locations. These are areas that may require future action, but due to their nature and/or size do not require as detailed information as is provided for GSIP locations.

There are two other locations of concern at TA-57, Fenton Hill Site.

They are categorized as:

- One portable aboveground storage tank used to collect waste fuel oil, and
- One polyethylene aboveground storage tank used for ethylene glycol storage.

[1] Ponden, Raymond F., *The Design and Construction of a Hot Dry Rock Pilot Plant,* Los Alamos National Laboratory.

Following is a brief description of each area and any deficiencies which may exist.

2.2.1. Portable Waste Fuel Collection Tank

Description

This tank is mounted on a trailer and is pulled by a vehicle to collect waste oil from permanent site equipment. The capacity of the tank is approximately 500 gallons. Site personnel have indicated that this tank is used only for temporary oil storage.

Deficiencies

Some type of secondary containment should be installed on the trailer to prevent any accidental discharge of oil into the environment.

2.2.2. Ethylene Glycol Storage Tank

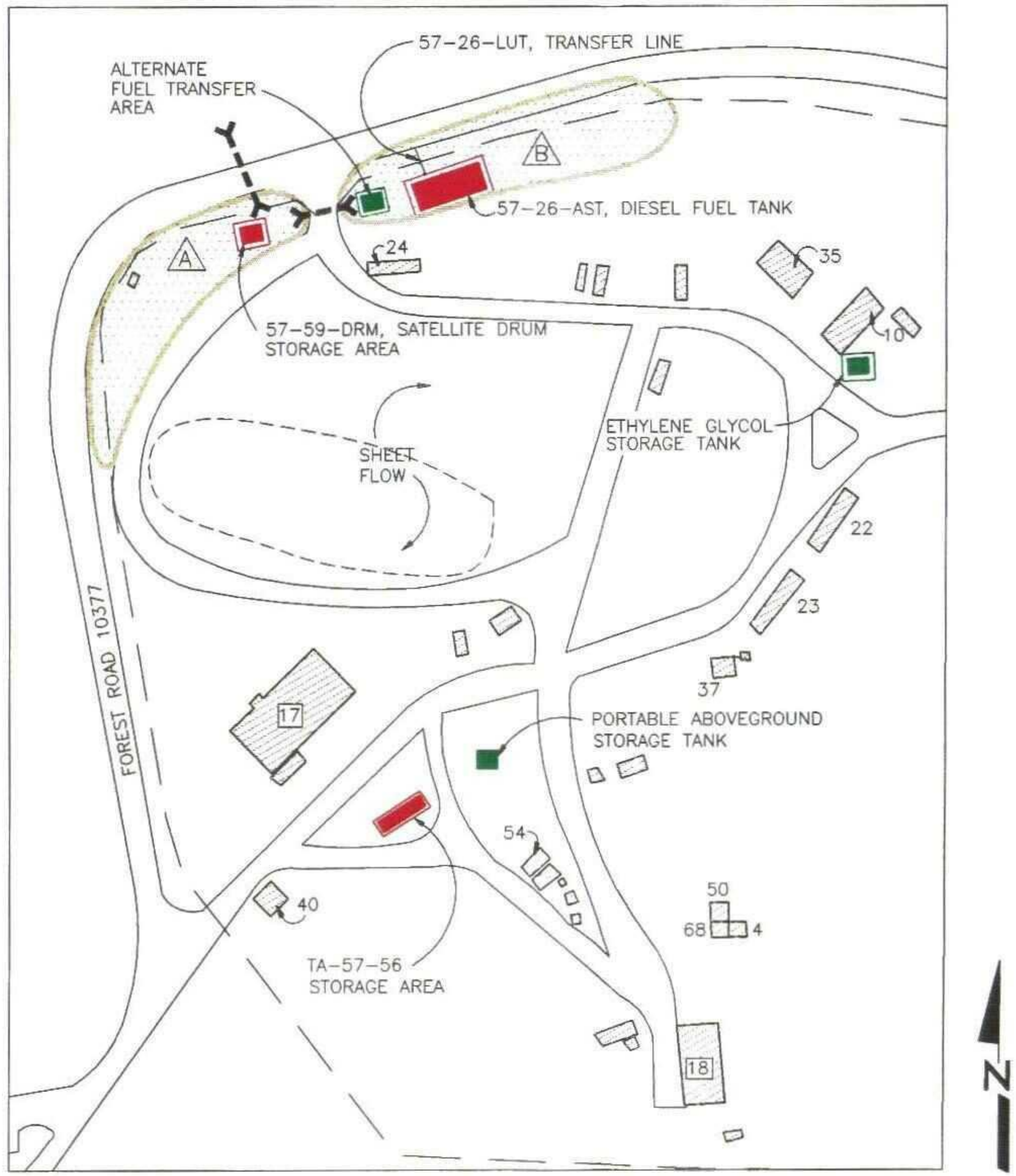
Description

This aboveground storage tank is located on the southeast corner of the heat exchanger (57-10). It is a polyethylene tank, with an approximate capacity of 500-gallons, used to store antifreeze solution for winter protection of the heat exchanger. The secondary containment is a skid-mounted metal circular structure that surrrounds the tank.

Deficiencies

The tank should have an appropriate label indicating what is being stored within the tank. Accumulated stormwater within the secondary containment structure should be periodically pumped out.

TA-57 FENTON HILL SITE



NOTES:

1. HATCHING DESIGNATES DRAINAGE AREAS ASSOCIATED WITH INDUSTRIAL ACTIVITY.

AREA OF DESIGNATED DRAINAGE BOUNDARY	
A	9,253.0 ± SQ. FT.
B	11,122.0 ± SQ. FT.

SYMBOLS LEGEND

- DIRECTION OF STORM WATER FLOW
- DIRT ROAD
- PAVED ROAD
- EXISTING BUILDING
- DRAINAGE BOUNDARY
- CULVERT
- –x–x–x– FENCE
- CENTER LINE OF DRAINAGE
- GSIP LOCATION
- AREA OF CONCERN
- STORM WATER DISCHARGE POINT
- SECONDARY CONTAINMENT

REVISIONS			
NO.	BY	DATE	REMARKS

DRAWN PJL	SCALE: 1"=100'-0"	
DESIGNED PJL	PLOT DATE 06/05/95	
CHECKED SJV	CREATION DATE 04/11/95	
APPROVED	DRAWING FILE NAME GS57FENT.DDWG	

Santa Fe Engineering Limited

2204 Brothers Rd. Santa Fe, NM 87505
(505) 988-7438 fax: (505)983-5608

Los Alamos
Los Alamos National Laboratory
Los Alamos, New Mexico 87545

REQUESTING GROUP ESH-18
LAB JOB NO.

TA-57
SPCC FACILITY SITE MAP
FENTON HILL SITE

DRAWING NUMBER

SHEET 1 OF 1
REV 0

R:\SPCC\TA-MAPS\TA-57\GS57FENT.DWG

3. SPILL IMPACT

Where experience indicates a reasonable potential for equipment failure (such as tank overflow, rupture, or leakage), the plan should include a prediction of the direction, rate of flow, and total quantity of liquid that could be discharged from the facility as a result of each major type of failure.

3.1. DIRECTION AND QUANTITY OF FLOW

The following table and the GSIP Site Map illustrate the predicted direction of flow, receiving canyon, total potential quantity and potential flow rates for a spill at TA-57, Fenton Hill Site GSIP locations.

GSIP Location	Predicted Direction of Flow	Receiving Canyon	Total Quantity	Potential Flow Rate
57-56A-AST	Sheet flow	N/A	500 gallons	Max of 500 gpm
57-56C-AST	Sheet flow	N/A	400 gallons	Max of 400 gpm
57-56B-AST	Sheet flow	N/A	500 gallons	Max of 500 gpm
57-56-DRM	Sheet flow	N/A	55 gallons (x 8)	N/A
57-59-DRM	Northwest	N/A	55 gallons (x10)	N/A
57-26-AST 57-26-LUT	Northwest	N/A	10,000 gallons	Max of 10,000 gpm

3.2. SPILL HISTORY

Review of spill history is an essential part of the GSIP because the history will indicate repetitive spill problems or any incident that indicates spill potential. The review of the GSIP Location spill history indicated that there have been no recorded spills at TA-57, Fenton Hill Site.

Table for Tracking Future Spills

Date	Spill Location	What Spilled	Quantity Spilled	Corrective Action Taken	Plans to Prevent Recurrence

GSIP LOCATIONS

4. GSIP LOCATIONS

This chapter includes a brief but concise description of each GSIP location at TA-57, Fenton Hill Site. The description of each GSIP location includes a discussion of the following items:

- Location Description and Photograph,
- Location Schematic,
- Secondary Containment,
- Spill Controls & Spill Removal,
- Storm Water Considerations (Facility Drainage),
- Other Administrative Controls, and
- Field Data Sheets

The description details adequacies and deficiencies of each of the listed items. Deficiencies are documented on the Field Data Sheets and scheduled for future corrective action.

The GSIP locations at TA-57, Fenton Hill Site are listed below:

4.1 57-56- Drum & Tank Storage Area

4.2 57-59 - Drum Storage Area

4.3 57-26 - Diesel Fuel Tank & Transfer Area

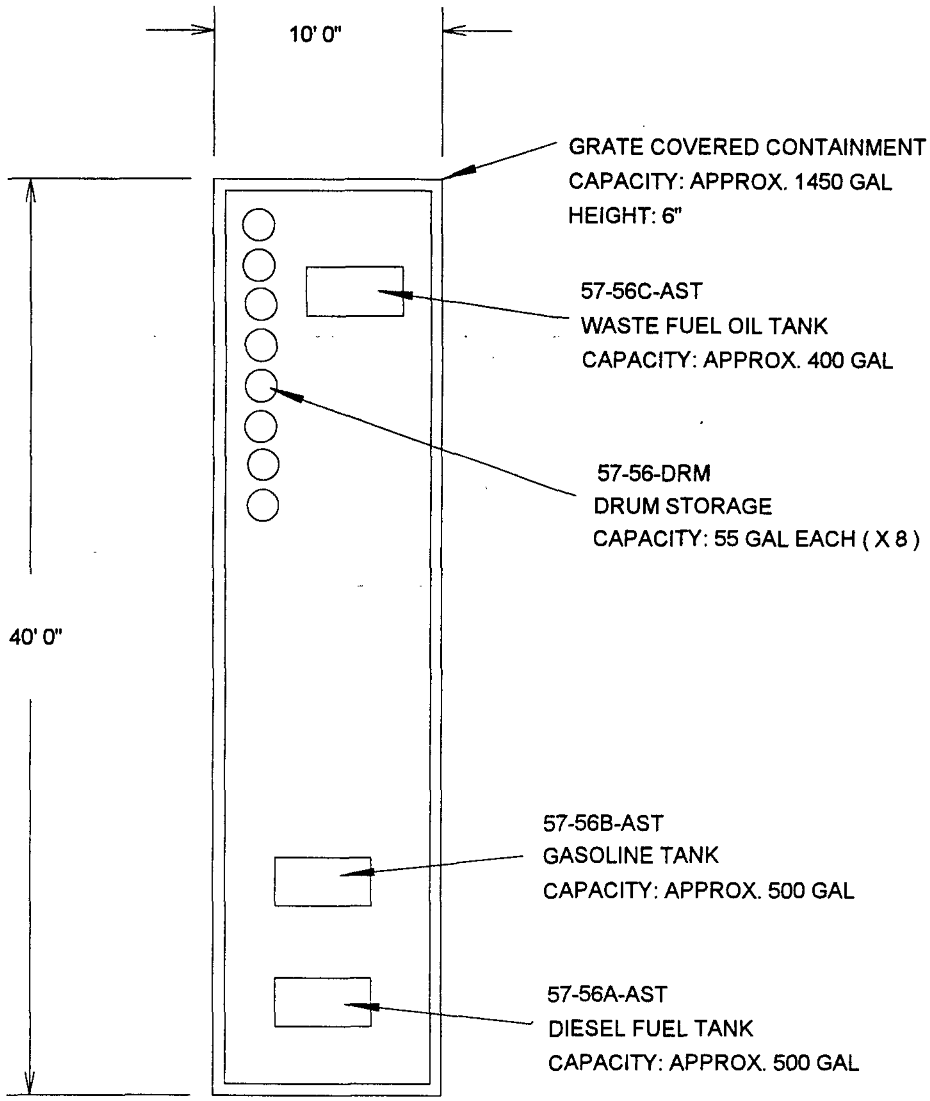
4.1. TA-57-56 DRUM & TANK STORAGE AREA

Description:

The Diesel,Waste Fuel Oil, and Gasoline Tanks are stored under covered structure 57-56 along with eight drums. The diesel fuel is used for various equipment at the site. The waste fuel oil is collected from around the site and is periodically transferred off site. The gasoline is used for various vehicles and equipment at the site. The drums contain miscellaneous fuels and oils including No. 2 Diesel Fuel, gear lubricating oil, and kerosene.

4.1.1. Location Schematic

The location schematic shows the Diesel,Waste Fuel Oil, and Gasoline Tanks, Drum Storage Area, tank and drum capacities, and secondary containment capacity.



57-56

DRUM & TANK STORAGE AREA

4.1.2. Drum & Storage Tank Requirements

40 CFR 112.7 (e)(2) defines the requirements for developing and implementing SPCC Plans related to onshore bulk storage containers. These requirements are listed below and are followed by a detailed discussion of each:

4.1.2.1. SECONDARY CONTAINMENT

Description

The secondary containment for the tanks is a concrete curbed structure that is walled on three sides. The bottom is covered by a grate. The volume of the secondary containment system is sufficient to contain the spill volume of the largest tank (500 gallons) plus 10% of the volume of the drum storage (44 gallons). Storm water is minimized by the walls and by the roof.

The containment is designed with impervious materials to prevent leaking or contamination of storm water, surface, and groundwater supplies for a minimum of 72 hours.

The Diesel, Waste Fuel Oil, and Gasoline Tanks are made from commonly accepted metal and steel alloys used for manufacturing fuel storage tanks.

Deficiencies

FOR THE STORAGE TANKS:

None.

FOR THE DRUM STORAGE AREA:

None

4.1.2.2. SPILL CONTROL & SPILL REMOVAL

<u>Integrity Testing:</u>

Description

Integrity testing of these Fuel Tanks has not been performed. Integrity testing is not required for storage drums.

Deficiencies

FOR THE STORAGE TANKS:

- 40 CFR 112.7 (e)(2)(vi) requires and describes integrity testing of ASTs.
- API Standard 653 requires ultrasonic thickness measurements of the AST shell be performed at a minimum of once every 5 years. No ultrasonic measurements have been taken for the Diesel Fuel Tank.
- See Section 4.6.1.5. of the SPCC Revision 3 for Integrity Testing description, inspector qualifications and inspection frequency considerations. Appendix A has an Integrity Test Checklist for future use. See Action Item #2 on page 2 of the Field Data Sheets.

FOR THE DRUM STORAGE AREA:

None

Monitoring:

Description

The diesel tank and gasoline tank are equipped with a visual level gauge. Monitoring devices are not required for storage drums.

Deficiencies

FOR THE STORAGE TANKS:

Some type of visual level gauge should be installed for the waste fuel oil tank. See Action Item #6 on page 3 of the Field Data Sheets.

FOR THE DRUM STORAGE AREA:

None

Spill Control

Description

Sorbent containers are located in the covered storage area. The containers are currently empty.

Deficiencies

FOR THE STORAGE TANKS:

Adequate spill control equipment should be kept on site. See Action Item #4 on page 2 of the Field Data Sheets.

FOR THE DRUM STORAGE AREA:

Adequate spill control equipment should be kept on site. See Action Item #4 on page 2 of the Field Data Sheets.

4.1.2.3. STORM WATER CONSIDERATIONS (FACILITY DRAINAGE)

Description

The storage area is covered and protected on three sides. Although some storm water accumulates in the containment area, the amount of water is minimal and generally evaporates quickly.

Deficiencies

There is no discharge valve for the secondary containment structure. See action item # 5 on page 3 of the Field Data Sheets.

4.1.2.4. OTHER ADMINISTRATIVE CONTROLS

Inspections and Maintenance:

Description

General operator observations are made by all personnel involved in handling materials and operation of TA-57, Fenton Hill Site. No records exist of any problems occurring at this facility.

A walk-around inspection was performed by Santa Fe Engineering in May 1994. The results of the inspection are included in Appendix B of this GSIP.

Accurate and up-to-date drawings of the tanks, drums and secondary containment are maintained and have been incorporated into this plan. See Location Schematic in Section 4.1.1.

Deficiencies

FOR THE STORAGE TANKS:

Three levels of inspection for ASTs are required that include general operator observations, walk-around inspections and integrity inspections. These inspections must be signed by the area supervisor or Spill Coordinator. There are no records of any past walk-around or integrity testing at this site. See Appendix A of this GSIP for blank Walk-around Inspection forms for future use.

See Action Item #6 on page 3 of the Field Data Sheets.

FOR THE DRUM STORAGE AREA:

Two levels of inspection for drum storage areas are required that include general operator observations and walk-around inspections. These inspections must be signed by the area supervisor or Spill Coordinator. There are no records of any past walk-around inspections at this site. See Appendix A of this GSIP for blank Walk-around Inspection forms for future use.

See Action Item #6 on page 3 of the Field Data Sheets.

Labeling:

Description

The tanks and drums have proper labeling and MSDSs available at the Control Office.

Deficiencies

None.

Inventory Control:

Description

Inventory control of the Diesel, Waste Fuel Oil, and Gasoline Tanks is accomplished through visual inspection of the gauge and tracking of delivery volumes. Inventory control is not required for drum storage areas.

Deficiencies

None.

Recordkeeping:

Description

This GSIP pulls together the necessary documents related to TA-57, Fenton Hill Site. These documents will be maintained as part of the GSIP for a period of three years.

Deficiencies

Future recordkeeping guidelines should apply to the entire AST system, including the tank, foundation, secondary containment, instrumentation, and piping. These guidelines also apply to the drum storage system, including new MSDS information and site maps. This documentation should be incorporated into this plan.

All inspections should be documented and include the following:

- When inspections were done,
- Who conducted inspection,
- What areas were inspected,
- What problems were found,
- Appropriate supervisor signatures,
- What steps were taken to correct problems, and
- Who was notified about any problems found.

See Action Item #6 on page 3 of the Field Data Sheets.

Security:

Description

The Fenton Hill Site is fully fenced and the main entrance gate is always controlled by a guard. Lighting is adequate for this facility.

Deficiencies

None.

4.1.2.5. LOCATION FIELD DATA SHEETS

The GSIP Field Data Sheets were used to record pertinent information and to document any action items that may be required. These sheets were used to organize information pertaining to storage capacities, types of materials stored, types of containment, and provide a record of all issues related to this GSIP location.

The following information is included:

- Storage Unit Descriptions,
- Secondary Containment Descriptions,
- Spill Controls and Spill Removal,
- Storm Water Considerations,
- Other Administrative Controls,
- Action Items, and
- GSIP Prioritization Estimate.

Los Alamos
Los Alamos National Laboratory
Los Alamos, New Mexico 87545

GROUP SPCC IMPLEMENTATION PLAN
FIELD - DATA SHEET
-GSIP-

Date: 06/01/94 SC Name and Signature:

Superscripts refer to SPCC DS-1 Page-5, GSIP Abbreviation List

1	Technical Area (T) =	57
2	Structure # (S) =	56A
3	Location Type (L) =	AST
4	GSIP Location Identification # (T+S+L) =	57-56A-AST

Storage Unit Descriptions

5	List type of storage unit:[1]	Aboveground Storage Tank (AST)
6	List material stored in unit:[2]	Diesel Fuel Oil No. 2-D
7	List associated Reportable Quantity (RQ):	13,646 gallons for a .01% concentration of Benzene
8	List the CAS #:	068 476 346
9	List Capacity in gallons of Storage Unit **(CSU)**:	500 gallons (56A)
10	Describe piping associated with this location:	Aboveground ☐ Belowground ☐ No piping ✓

Secondary Containment Descriptions

11	What type of secondary containment?[3]	Grate covered concrete containment (OTR)
12	List capacity in gallons of secondary containment: **(SCC)**	1450 gallons
13	What is the drainage area (ft^2) that can contribute to run-on into the secondary containment **(DA)**?	0 ft^2
14	Is the (SCC) > (CSU) + 1.875 x (DA)? Note: 1.875 is the storm water conversion factor for a 25-yr/24-hr rainfall:	YES ✓ NO ☐

Action Item #1 *(Secondary Containment) If answer on line 14 is* ***No****, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements.*

None.

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 1

Spill Controls & Spill Removal

15	Has the system been integrity tested?	YES ❑ NO ✓ If yes, when:

Action Item #2 *(Integrity Testing)* *If answer on line 15 is **No**, describe as a deficiency refer to Chapter 4 of the SPCC Plan for requirements.*

Integrity testing of the Fuel Tank and piping system must be completed as required by 40 CFR 112.7 and API Standard 653.

Date Deficiency Noted:5/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

16	Is there a method of level indication for the AST?	YES ✓ NO ❑ N/A ❑
17	Is there a liquid level alarm system for the AST?	YES ❑ NO ✓ N/A ❑

Action Item #3 *(Monitoring)* *If answer on line 16 or 17 is **No**, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements. Check N/A if location is not an aboveground storage tank.*

None. The level gauge is an adequate monitoring device for this tank.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

18	Is spill control equipment available at this location?[4] 1) 2) 3)	YES ❑ NO ✓ If yes, identify which types by using the GSIP Abbreviation List on Page 5.

Action Item #4 *(Spill Control)* *If answer on line 18 is **No**, describe as a deficiency.*

Adequate spill controls including sorbents and a spill control kit should be available on site.

Date Deficiency Noted:05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 2

Storm Water Considerations

19	Are methods for removing storm water or spills from secondary containment areas available?[5] 1) Evaporation (EVP) 2) 3)	YES ✓ NO ❑ If yes, identify which methods by using the GSIP Abbreviation List on Page 5.
20	Is there a storm water discharge valve and lock?	Locked ❑ Unlocked ❑ No discharge valve ✓
21	Are best management practices such as covering, run-on diversion, etc. being used?	YES ✓ NO ❑
22	What is the distance to closest storm water culverts or catch basins (in feet)?	~ 50 feet
23	Would a spill be isolated from these storm water culverts or catch basins?	YES ✓ NO ❑
24	Name of canyon eventually receiving storm water or spill run-off:	N/A

Action Item #5 *(Storm Water) If answer on lines 19 or 23 is* ***No****, describe as a deficiency. If line 20 is answered "unlocked" or "no discharge valve", describe as a deficiency. If answer on line 21 is* ***No****, explain why.*

Although there is no stormwater discharge valve, the storage area is covered and protected on three sides. The amount of stormwater that accumulates in the containment area is minimal and generally evaporates quickly.

Date Deficiency Noted:05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

Other Administrative Controls

25	Is there an Inspection & Maintenance Program in place at this GSIP Location?	YES ❑ NO ✓
26	Are aboveground storage tanks, transfer areas, drums or other ancillary sources properly labeled?	YES ✓ NO ❑
27	Is there a system of inventory control at this site?	YES ✓ NO ❑
28	Has an appropriate recordkeeping system documenting inventory controls, past inspections, testing, etc., been implemented at this GSIP Location?	YES ❑ NO ✓
29	Is security at this location adequate? (e.g., lighting, fencing, locked gates and valves)	YES ✓ NO ❑

Action Item #6 *(Administrative Controls) If answer on lines 25 through 29 is* ***No****, describe as a deficiency. Refer to Chapter 4 of SPCC Plan for requirements.*

1) Three levels of inspections are required for these aboveground storage tanks including general operator observations, walk-around inspections and integrity inspections.

2) A comprehensive recordkeeping system should be implemented for these tanks.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 3

GSIP PRIORITIZATION and IMPACT ESTIMATE

FIRST PRIORITY:	
Is this an oil storage location with a capacity greater than 660 gallons?	YES ☐ NO ✓
Is this a chemical or waste storage location with a capacity greater than 220 gallons?	YES ☐ NO ✓
Is this a chemical or waste storage location in which any individual hazardous chemical RQ is exceeded?	YES ☐ NO ✓
Is this a storage location in close proximity to a canyon rim, a storm water discharge point, floor drains, etc.?	YES ☐ NO ✓
Could an oil or chemical spill at this location enter a collection system for an NPDES permitted outfall?	YES ☐ NO ✓
If YES on any question above, the area should be considered first priority. Action items listed above should be accomplished immediately. Skip next two sections.	

SECOND PRIORITY:	
Is this an oil storage location with a capacity greater than 220 gallons?	YES ✓ NO ☐
Is this a chemical or waste storage location with a capacity greater than 55 gallons?	YES ☐ NO ☐
If YES on either question above, the area should be considered second priority. Action items listed above should be accomplished within 6 months or as soon a practicable. Skip the next section.	

THIRD PRIORITY:	
Is this an oil storage location with a capacity between zero and 220 gallons?	YES ☐ NO ☐
Is this a chemical or waste storage area with a capacity between zero and 55 gallons?	YES ☐ NO ☐
If YES on either question above, the area should be considered third priority. Action items listed above should be accomplished as soon a practicable.	

Comments: In the space provided below, discuss any additional concerns related to the description of the Storage Unit, Secondary Containment, Spill Controls & Removal, Storm Water Considerations, Administrative Controls and GSIP Prioritization.

The capacity of the secondary containment (~ 1450 gallons) is large enough to contain a complete spill from the largest tank plus 10% of the volume of the drum storage area (500 gallons + 44 gallons = 544 gallons). The storage area is covered so the tanks are subject only to minimal volumes of storm water.

SPCC Form DS-1 Page 4

Los Alamos
Los Alamos National Laboratory
Los Alamos, New Mexico 87545

GROUP SPCC IMPLEMENTATION PLAN
FIELD - DATA SHEET
-GSIP-

Date: 05/24/94 SC Name and Signature:

Superscripts refer to SPCC DS-1 Page-5, GSIP Abbreviation List

1	Technical Area (T) =	57
2	Structure # (S) =	56B
3	Location Type (L) =	Aboveground Storage Tank (AST)
4	GSIP Location Identification # (T+S+L) =	57-56B-AST

Storage Unit Descriptions

5	List type of storage unit:[1]	Aboveground Storage Tank (AST)
6	List material stored in unit:[2]	Gasoline
7	List associated Reportable Quantity (RQ):	55 gallons for a 2.5% concentration of Benzene
8	List the CAS #:	86290-81-5
9	List Capacity in gallons of Storage Unit **(CSU)**:	500 gallons
10	Describe piping associated with this location:	Aboveground ☐ Belowground ☐ No piping ✓

Secondary Containment Descriptions

11	What type of secondary containment?[3]	Grate covered concrete containment (OTR)
12	List capacity in gallons of secondary containment: **(SCC)**	500 gallons
13	What is the drainage area (ft^2) that can contribute to run-on into the secondary containment **(DA)**?	0 ft^2
14	Is the (SCC) > (CSU) + 1.875 x (DA)? Note: 1.875 is the storm water conversion factor for a 25-yr/24-hr rainfall:	YES ✓ NO ☐

Action Item #1 *(Secondary Containment) If answer on line 14 is **No**, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements.*

None.

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 1

Spill Controls & Spill Removal

15	Has the system been integrity tested?	YES ❑ NO ✓ If yes, when:

Action Item #2 *(Integrity Testing) If answer on line 15 is **No**, describe as a deficiency refer to Chapter 4 of the SPCC Plan for requirements.*

Integrity testing of the Fuel Tank and piping system must be completed as required by 40 CFR 112.7 and API Standard 653.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

16	Is there a method of level indication for the AST?	YES ✓ NO ❑ N/A ❑
17	Is there a liquid level alarm system for the AST?	YES ❑ NO ✓ N/A ❑

Action Item #3 *(Monitoring) If answer on line 16 or 17 is **No**, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements. Check N/A if location is not an aboveground storage tank.*

None. The level gauge is an adequate monitoring device for this tank.

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

18	Is spill control equipment available at this location?[4] 1) 2) 3)	YES ❑ NO ✓ If yes, identify which types by using the GSIP Abbreviation List on Page 5.

Action Item #4 *(Spill Control) If answer on line 18 is **No**, describe as a deficiency.*

Adequate spill controls including sorbents and a spill control kit should be available on site.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 2

Storm Water Considerations

19	Are methods for removing storm water or spills from secondary containment areas available?[5] 1) Evaporation (EVP) 2) 3)	YES ✓ NO ☐ If yes, identify which methods by using the GSIP Abbreviation List on Page 5.
20	Is there a storm water discharge valve and lock?	Locked ☐ Unlocked ☐ No discharge valve ✓
21	Are best management practices such as covering, run-on diversion, etc. being used?	YES ✓ NO ☐
22	What is the distance to closest storm water culverts or catch basins (in feet)?	~ 50 feet
23	Would a spill be isolated from these storm water culverts or catch basins?	YES ✓ NO ☐
24	Name of canyon eventually receiving storm water or spill run-off:	N/A

Action Item #5 *(Storm Water) If answer on lines 19 or 23 is **No**, describe as a deficiency. If line 20 is answered "unlocked" or "no discharge valve", describe as a deficiency. If answer on line 21 is **No**, explain why.*

Although there is no stormwater discharge valve, the storage area is covered and protected on three sides. The amount of stormwater that accumulates in the containment area is minimal and generally evaporates quickly.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

Other Administrative Controls

25	Is there an Inspection & Maintenance Program in place at this GSIP Location?	YES ☐ NO ✓
26	Are aboveground storage tanks, transfer areas, drums or other ancillary sources properly labeled?	YES ✓ NO ☐
27	Is there a system of inventory control at this site?	YES ✓ NO ☐
28	Has an appropriate recordkeeping system documenting inventory controls, past inspections, testing, etc., been implemented at this GSIP Location?	YES ☐ NO ✓
29	Is security at this location adequate? (e.g., lighting, fencing, locked gates and valves)	YES ✓ NO ☐

Action Item #6 *(Administrative Controls) If answer on lines 25 through 29 is **No**, describe as a deficiency. Refer to Chapter 4 of SPCC Plan for requirements.*

1) Three levels of inspections are required for these aboveground storage tanks including general operator observations, walk-around inspections and integrity inspections.

2) A comprehensive recordkeeping system should be implemented for these tanks.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 3

GSIP PRIORITIZATION and IMPACT ESTIMATE

FIRST PRIORITY:	
Is this an oil storage location with a capacity greater than 660 gallons?	YES ❑ NO ✓
Is this a chemical or waste storage location with a capacity greater than 220 gallons?	YES ❑ NO ✓
Is this a chemical or waste storage location in which any individual hazardous chemical RQ is exceeded?	YES ✓ NO ❑
Is this a storage location in close proximity to a canyon rim, a storm water discharge point, floor drains, etc.?	YES ❑ NO ✓
Could an oil or chemical spill at this location enter a collection system for an NPDES permitted outfall?	YES ❑ NO ✓
If YES on any question above, the area should be considered first priority. Action items listed above should be accomplished immediately. Skip next two sections.	

SECOND PRIORITY:	
Is this an oil storage location with a capacity greater than 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage location with a capacity greater than 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered second priority. Action items listed above should be accomplished within 6 months or as soon a practicable. Skip the next section.	

THIRD PRIORITY:	
Is this an oil storage location with a capacity between zero and 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage area with a capacity between zero and 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered third priority. Action items listed above should be accomplished as soon a practicable.	

Comments: In the space provided below, discuss any additional concerns related to the description of the Storage Unit, Secondary Containment, Spill Controls & Removal, Storm Water Considerations, Administrative Controls and GSIP Prioritization.

The capacity of the secondary containment (~ 1450 gallons) is large enough to contain a complete spill from the largest tank plus 10% of the volume of the drum storage area (500 gallons + 44 gallons = 544 gallons). The storage area is covered so the tanks are subject only to minimal volumes of storm water.

SPCC Form DS-1 Page 4

Los Alamos
Los Alamos National Laboratory
Los Alamos, New Mexico 87545

GROUP SPCC IMPLEMENTATION PLAN
FIELD - DATA SHEET
-GSIP-

Date: 06/01/94 SC Name and Signature:

Superscripts refer to SPCC DS-1 Page-5, GSIP Abbreviation List

1	Technical Area (T) =	57
2	Structure # (S) =	56C
3	Location Type (L) =	AST
4	GSIP Location Identification # (T+S+L) =	57-56C-AST

Storage Unit Descriptions

5	List type of storage unit:[1]	Aboveground Storage Tank (AST)
6	List material stored in unit:[2]	Waste Fuel Oil
7	List associated Reportable Quantity (RQ):	N/A
8	List the CAS #:	N/A
9	List Capacity in gallons of Storage Unit **(CSU)**:	400 gallons
10	Describe piping associated with this location:	Aboveground ☐ Belowground ☐ No piping ✓

Secondary Containment Descriptions

11	What type of secondary containment?[3]	Grate covered concrete containment (OTR)
12	List capacity in gallons of secondary containment: **(SCC)**	1450 gallons
13	What is the drainage area (ft^2) that can contribute to run-on into the secondary containment **(DA)**?	0 ft^2
14	Is the (SCC) > (CSU) + 1.875 x (DA)? Note: 1.875 is the storm water conversion factor for a 25-yr/24-hr rainfall:	YES ✓ NO ☐

Action Item #1 *(Secondary Containment) If answer on line 14 is **No**, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements.*

None.

Date Deficiency Noted: SC Name and Signature:

Date Action Item Completed: SC Name and Signature:

SPCC Form DS-1 Page 1

Spill Controls & Spill Removal

15	Has the system been integrity tested?	YES ☐ NO ✓ If yes, when:

Action Item #2 *(Integrity Testing) If answer on line 15 is **No**, describe as a deficiency refer to Chapter 4 of the SPCC Plan for requirements.*

Integrity testing of the Fuel Tank and piping system must be completed as required by 40 CFR 112.7 and API Standard 653.

Date Deficiency Noted:5/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

16	Is there a method of level indication for the AST?	YES ☐ NO ✓ N/A ☐
17	Is there a liquid level alarm system for the AST?	YES ☐ NO ✓ N/A ☐

Action Item #3 *(Monitoring) If answer on line 16 or 17 is **No**, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements. Check N/A if location is not an aboveground storage tank.*

Some type of liquid level monitoring device should be installed for the waste fuel oil tank.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

18	Is spill control equipment available at this location?[4] 1) 2) 3)	YES ☐ NO ✓ If yes, identify which types by using the GSIP Abbreviation List on Page 5.

Action Item #4 *(Spill Control) If answer on line 18 is **No**, describe as a deficiency.*

Adequate spill controls including sorbents and a spill control kit should be available on site.

Date Deficiency Noted:05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 2

Storm Water Considerations

19	Are methods for removing storm water or spills from secondary containment areas available?[5] 1) Evaporation (EVP) 2) 3)	YES ✓ NO ☐ If yes, identify which methods by using the GSIP Abbreviation List on Page 5.
20	Is there a storm water discharge valve and lock?	Locked ☐ Unlocked ☐ No discharge valve ✓
21	Are best management practices such as covering, run-on diversion, etc. being used?	YES ✓ NO ☐
22	What is the distance to closest storm water culverts or catch basins (in feet)?	~ 50 feet
23	Would a spill be isolated from these storm water culverts or catch basins?	YES ✓ NO ☐
24	Name of canyon eventually receiving storm water or spill run-off:	N/A

Action Item #5 *(Storm Water) If answer on lines 19 or 23 is* ***No****, describe as a deficiency. If line 20 is answered "unlocked" or "no discharge valve", describe as a deficiency. If answer on line 21 is* ***No****, explain why.*

Although there is no stormwater discharge valve, the storage area is covered and protected on three sides. The amount of stormwater that accumulates in the containment area is minimal and generally evaporates quickly.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

Other Administrative Controls

25	Is there an Inspection & Maintenance Program in place at this GSIP Location?	YES ☐ NO ✓
26	Are aboveground storage tanks, transfer areas, drums or other ancillary sources properly labeled?	YES ✓ NO ☐
27	Is there a system of inventory control at this site?	YES ✓ NO ☐
28	Has an appropriate recordkeeping system documenting inventory controls, past inspections, testing, etc., been implemented at this GSIP Location?	YES ☐ NO ✓
29	Is security at this location adequate? (e.g., lighting, fencing, locked gates and valves)	YES ✓ NO ☐

Action Item #6 *(Administrative Controls) If answer on lines 25 through 29 is* ***No****, describe as a deficiency. Refer to Chapter 4 of SPCC Plan for requirements.*

1) Three levels of inspections are required for these aboveground storage tanks including general operator observations, walk-around inspections and integrity inspections.

2) A comprehensive recordkeeping system should be implemented for these tanks.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 3

GSIP PRIORITIZATION and IMPACT ESTIMATE

FIRST PRIORITY:	
Is this an oil storage location with a capacity greater than 660 gallons?	YES ❑ NO ✓
Is this a chemical or waste storage location with a capacity greater than 220 gallons?	YES ❑ NO ✓
Is this a chemical or waste storage location in which any individual hazardous chemical RQ is exceeded?	YES ❑ NO ✓
Is this a storage location in close proximity to a canyon rim, a storm water discharge point, floor drains, etc.?	YES ❑ NO ✓
Could an oil or chemical spill at this location enter a collection system for an NPDES permitted outfall?	YES ❑ NO ✓
If YES on any question above, the area should be considered first priority. Action items listed above should be accomplished immediately. Skip next two sections.	

SECOND PRIORITY:	
Is this an oil storage location with a capacity greater than 220 gallons?	YES ✓ NO ❑
Is this a chemical or waste storage location with a capacity greater than 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered second priority. Action items listed above should be accomplished within 6 months or as soon a practicable. Skip the next section.	

THIRD PRIORITY:	
Is this an oil storage location with a capacity between zero and 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage area with a capacity between zero and 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered third priority. Action items listed above should be accomplished as soon a practicable.	

Comments: In the space provided below, discuss any additional concerns related to the description of the Storage Unit, Secondary Containment, Spill Controls & Removal, Storm Water Considerations, Administrative Controls and GSIP Prioritization.

The capacity of the secondary containment (~ 1450 gallons) is large enough to contain a complete spill from the largest tank plus 10% of the volume of the drum storage area (500 gallons + 44 gallons = 544 gallons). The storage area is covered so the tanks are subject only to minimal volumes of storm water.

SPCC Form DS-1 Page 4

Los Alamos
Los Alamos National Laboratory
Los Alamos, New Mexico 87545

GROUP SPCC IMPLEMENTATION PLAN
FIELD - DATA SHEET
-GSIP-

Date: 06/01/94 SC Name and Signature:

Superscripts refer to SPCC DS-1 Page-5, GSIP Abbreviation List

1	Technical Area (T) =	57
2	Structure # (S) =	56
3	Location Type (L) =	DRM
4	GSIP Location Identification # (T+S+L) =	57-56-DRM

Storage Unit Descriptions

5	List type of storage unit:[1]	Drum Storage Area (DRM)
6	List material stored in unit:[2]	Various Fuels and lubricants
7	List associated Reportable Quantity (RQ):	N/A
8	List the CAS #:	N/A
9	List Capacity in gallons of Storage Unit **(CSU)**:	440 gallons (55 gal x 8)
10	Describe piping associated with this location:	Aboveground ☐ Belowground ☐ No piping ✓

Secondary Containment Descriptions

11	What type of secondary containment?[3]	Grate covered concrete containment (OTR)
12	List capacity in gallons of secondary containment: **(SCC)**	1450 gallons
13	What is the drainage area (ft^2) that can contribute to run-on into the secondary containment **(DA)**?	0 ft^2
14	Is the (SCC) > (CSU) + 1.875 x (DA)? Note: 1.875 is the storm water conversion factor for a 25-yr/24-hr rainfall:	YES ✓ NO ☐

Action Item #1 *(Secondary Containment) If answer on line 14 is **No**, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements.*

None.

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 1

Spill Controls & Spill Removal

15	Has the system been integrity tested?	YES ☐ NO ✓ If yes, when:

Action Item #2 *(Integrity Testing) If answer on line 15 is* ***No****, describe as a deficiency refer to Chapter 4 of the SPCC Plan for requirements.*

None. Not applicable for drum storage area.

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

16	Is there a method of level indication for the AST?	YES ☐ NO ☐ N/A ☐✓
17	Is there a liquid level alarm system for the AST?	YES ☐ NO ☐ N/A ☐✓

Action Item #3 *(Monitoring) If answer on line 16 or 17 is* ***No****, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements. Check N/A if location is not an aboveground storage tank.*

None.

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

18	Is spill control equipment available at this location?[4] 1) 2) 3)	YES ☐ NO ✓ If yes, identify which types by using the GSIP Abbreviation List on Page 5.

Action Item #4 *(Spill Control) If answer on line 18 is* ***No****, describe as a deficiency.*

Adequate spill controls including sorbents and a spill control kit should be available on site.

Date Deficiency Noted:05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 2

Storm Water Considerations

19	Are methods for removing storm water or spills from secondary containment areas available?[5] 1) Evaporation (EVP) 2) 3)	YES ✓ NO ❑ If yes, identify which methods by using the GSIP Abbreviation List on Page 5.
20	Is there a storm water discharge valve and lock?	Locked ❑ Unlocked ❑ No discharge valve ✓
21	Are best management practices such as covering, run-on diversion, etc. being used?	YES ✓ NO ❑
22	What is the distance to closest storm water culverts or catch basins (in feet)?	~ 50 feet
23	Would a spill be isolated from these storm water culverts or catch basins?	YES ✓ NO ❑
24	Name of canyon eventually receiving storm water or spill run-off:	N/A

Action Item #5 *(Storm Water) If answer on lines 19 or 23 is* ***No****, describe as a deficiency. If line 20 is answered "unlocked" or "no discharge valve", describe as a deficiency. If answer on line 21 is* ***No****, explain why.*

Although there is no stormwater discharge valve, the storage area is covered and protected on three sides. The amount of stormwater that accumulates in the containment area is minimal and generally evaporates quickly.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

Other Administrative Controls

25	Is there an Inspection & Maintenance Program in place at this GSIP Location?	YES ❑ NO ✓
26	Are aboveground storage tanks, transfer areas, drums or other ancillary sources properly labeled?	YES ✓ NO ❑
27	Is there a system of inventory control at this site?	YES ✓ NO ❑
28	Has an appropriate recordkeeping system documenting inventory controls, past inspections, testing, etc., been implemented at this GSIP Location?	YES ❑ NO ✓
29	Is security at this location adequate? (e.g., lighting, fencing, locked gates and valves)	YES ✓ NO ❑

Action Item #6 *(Administrative Controls) If answer on lines 25 through 29 is* ***No****, describe as a deficiency. Refer to Chapter 4 of SPCC Plan for requirements.*

1) Two levels of inspections are required for the drum storage area.

2) A comprehensive recordkeeping system should be implemented.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 3

GSIP PRIORITIZATION and IMPACT ESTIMATE

FIRST PRIORITY:	
Is this an oil storage location with a capacity greater than 660 gallons?	YES ❑ NO ✓
Is this a chemical or waste storage location with a capacity greater than 220 gallons?	YES ❑ NO ✓
Is this a chemical or waste storage location in which any individual hazardous chemical RQ is exceeded?	YES ❑ NO ✓
Is this a storage location in close proximity to a canyon rim, a storm water discharge point, floor drains, etc.?	YES ❑ NO ✓
Could an oil or chemical spill at this location enter a collection system for an NPDES permitted outfall?	YES ❑ NO ✓
If YES on any question above, the area should be considered first priority. Action items listed above should be accomplished immediately. Skip next two sections.	

SECOND PRIORITY:	
Is this an oil storage location with a capacity greater than 220 gallons?	YES ✓ NO ❑
Is this a chemical or waste storage location with a capacity greater than 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered second priority. Action items listed above should be accomplished within 6 months or as soon a practicable. Skip the next section.	

THIRD PRIORITY:	
Is this an oil storage location with a capacity between zero and 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage area with a capacity between zero and 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered third priority. Action items listed above should be accomplished as soon a practicable.	

Comments: In the space provided below, discuss any additional concerns related to the description of the Storage Unit, Secondary Containment, Spill Controls & Removal, Storm Water Considerations, Administrative Controls and GSIP Prioritization.

The capacity of the secondary containment (~ 1450 gallons) is large enough to contain a complete spill from the largest tank plus 10% of the volume of the drum storage area (500 gallons + 44 gallons = 544 gallons). The storage area is covered so the tanks are subject only to minimal volumes of storm water.

SPCC Form DS-1 Page 4

GSIP ABBREVIATION LIST

NOTES: CHOICES INCLUDE:

1. Types of Storage Units

   AST - Aboveground Storage Tank
   CHM - Aboveground Chemical Storage Tank
   PCT - Portable Containers (such as TUFF tank)
   DRM - Drum Storage
   LUT - Loading, Unloading and Transfer
   TRN - Transformers
   HYD - Hydraulic and Oil Containing Equipment
   BAT - Battery Packs

2. Types of Materials Stored

   If oil, grease or fuel indicate as such. If chemicals in drums, use common chemical name with CAS#. Use separate sheet if list of chemicals is long. If in small containers, list as general chemical storage.

3. Types of Secondary Containment

   EDB - Earthen Diking or Berms
   ERC - Earthen Redirection to other containment
   ADB - Asphaltic Diking or Berms
   ACU - Asphaltic Curbing
   ASU - Asphaltic Sump (or drainage to sump)
   ARC - Asphaltic Redirection to other containment
   CDB - Concrete Diking or Berms
   CCU - Concrete Curbing
   CSU - Concrete Sump (or drainage to sump)
   CRC - Concrete Redirection to other containment
   MOD - Modular Secondary Containment Systems
   PAL - Palletized Secondary Containment
   OTR - Other Types of Secondary Containment (specify)

4. Types of Spill Control Equipment

   SRB - Sorbents (granular, fibrous, powders, etc.)
   GEL - Gel Type Immobilization Agents
   BMM - Booms
   DCV - Drain Covers
   NUT - Neutralization (pH adjust for acids or bases)
   SPC - Specialized Control Kits (Hg, HF, Strong Oxidizers, etc.)
   DPN - Drip Pans
   CPP - Cathodic Pipe Protection
   OTR - Other Types (specify)

5. Methods of Storm Water Removal or Spill Removal

   EVP - Evaporation (storm water)
   VAC - Vacuum Truck Removal (off-site treatment)
   SRB - Sorbents (oils and chemicals)
   REC - Recovery for Reuse Methods
   TRT - Treatment (on-site storm water treatment)
   OTR - Other Types of Removal (specify)
   OVD - Open Valve Discharge

SPCC FORM DS-1 Page 5

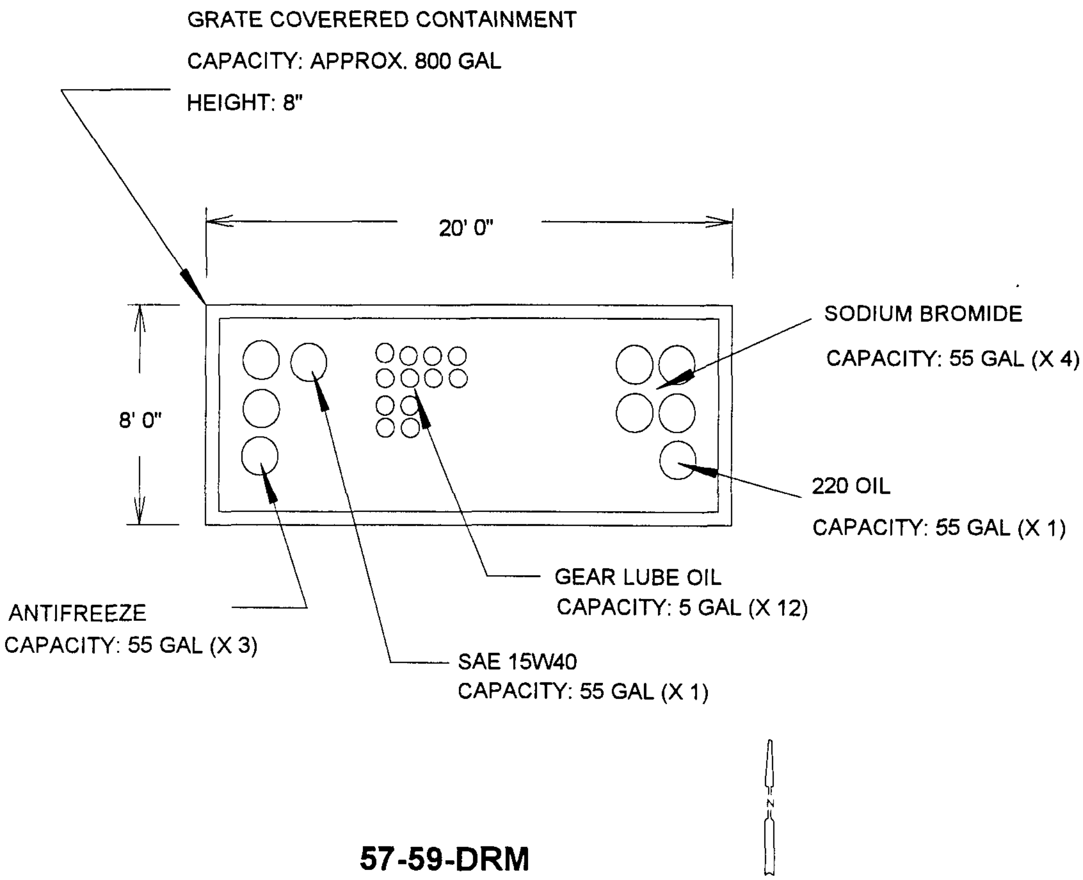
4.2. TA-57-59 - DRUM STORAGE AREA

Description:

Nine 55-gallon drums and twelve 5-gallon containers are stored in structure 57-59. Materials stored in the unit include Ethylene Glycol (antifreeze), Sodium Bromide, and various oils. Walls on three sides and a roof protect the drums from exposure to the elements. A spill would be contained by a grate-covered pit with approximately an 800 gallon capacity.

4.2.1. Location Schematic

The location schematic shows the Drum Storage Area, materials stored, and secondary containment capacity.



57-59-DRM

DRUM STORAGE

4.2.2. Drum Storage Area Requirements

40 CFR 112.7 (e)(2) defines the requirements for developing and implementing SPCC Plans related to onshore bulk storage containers. 40 CFR 125 - Subpart K describes the requirements for a Best Management Practices (BMP) program to prevent the discharge of significant amounts of hazardous or toxic pollutants to surface waters. These requirements are listed below and are followed by a detailed discussion of each:

4.2.2.1. SECONDARY CONTAINMENT

Description

The secondary containment structure for the storage area is a grate covered pit six inches deep. The volume of the secondary containment system is large enough to contain the volume of the largest drum or 10% of the total volume stored whichever is larger.

Deficiencies

None.

4.2.2.2. SPILL CONTROL & SPILL REMOVAL

<u>Integrity Testing:</u>

Description

Integrity testing is not applicable to drum storage areas.

Deficiencies

None.

<u>Monitoring:</u>

Description

Monitoring devices are not required for storage drums.

Deficiencies

None.

<u>Spill Control</u>

Description

Sorbent containers are located in the covered storage area. The containers are currently empty.

Deficiencies

Adequate spill control inventories should be kept on site. See Action Item #4 on page 2 of the Field Data Sheets.

4.2.2.3. STORM WATER CONSIDERATIONS (FACILITY DRAINAGE)

Description

The storage area is covered and protected on three sides. Although some storm water accumulates in the containment area, the amount of water is minimal and generally evaporates quickly.

Deficiencies

There is no discharge valve for the secondary containment structure. See action item # 5 on page 3 of the Field Data Sheets.

4.2.2.4. OTHER ADMINISTRATIVE CONTROLS

Inspections and Maintenance:

Description

General operator observations are made by all personnel involved in handling materials and operation of the Satellite Drum Storage Area. No records exist of any problems occurring at this facility.

A walk-around inspection was performed by Santa Fe Engineering in May, 1994. The results of the inspection are included in Appendix B of this GSIP.

Accurate and up-to-date drawings of these tanks and secondary containment are maintained and have been incorporated into this plan. See Location Schematic in Section 4.4.1.

Deficiencies

Two levels of inspection for drum storage areas are required that include general operator observations and walk-around inspections. These inspections must be signed by the area supervisor or Spill Coordinator. There are no records of any past walk-around inspections at this site. See Appendix A of this GSIP for blank Walk-around Inspection forms for future use.

See Action Item #6 on page 3 of the Field Data Sheets.

Labeling:

Description

The Drum Storage Area has proper labeling and MSDSs available at the Control Office.

Deficiencies

None.

Inventory Control:

Description

Inventory control is not required for drum storage areas.

Deficiencies

None.

Recordkeeping:

Description

This GSIP pulls together the necessary documents related to the Drum Storage Area. These documents will be maintained as part of the GSIP for a period of three years.

Deficiencies

Future recordkeeping guidelines should apply to the entire Drum Storage system, including the secondary containment, new MSDS information and site maps. This documentation should be incorporated into this plan. See Action Item #6 on page 3 of the Field Data Sheets.

All inspections should be documented and include the following:

- When inspections were done,
- Who conducted inspection,
- What areas were inspected,
- What problems were found,
- What steps were taken to correct problems, and
- Who was notified about any problems found?

See Action Item #6 on page 3 of the Field Data Sheets.

Security:

Description

The Fenton Hill Site is fully fenced and the main entrance gate is always controlled by a guard. Lighting is adequate for this facility.

Deficiencies

None.

4.2.2.5. LOCATION FIELD DATA SHEETS

The GSIP Field Data Sheets were used to record pertinent information and to document any action items that may be required. These sheets were used to organize information pertaining to storage capacities, types of materials stored, types of containment, and provide a record of all issues related to this GSIP location.

The following information is included:

- Storage Unit Descriptions,
- Secondary Containment Descriptions,
- Spill Controls and Spill Removal,
- Storm Water Considerations,
- Other Administrative Controls,
- Action Items, and
- GSIP Prioritization Estimate.

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GROUP SPCC IMPLEMENTATION PLAN
FIELD - DATA SHEET
-GSIP-

Date: 05/24/94 SC Name and Signature:

Superscripts refer to SPCC DS-1 Page-5, GSIP Abbreviation List

1	Technical Area (T) =	57
2	Structure # (S) =	59
3	Location Type (L) =	DRM
4	GSIP Location Identification # (T+S+L) =	57-59-DRM

Storage Unit Descriptions

5	List type of storage unit:[1]	Drum Storage (DRM)
6	List material stored in unit:[2]	Sodium Bromide, Ethylene Glycol, Lubricating oil
7	List associated Reportable Quantity (RQ):	900 gallons (Sodium Bromide)
8	List the CAS #:	108054 (Sodium Bromide) 107211 (Ethylene Glycol)
9	List Capacity in gallons of Storage Unit **(CSU)**:	~ 500 gallons total -- 55 gal (x9) + 5 gal (x12)
10	Describe piping associated with this location:	Aboveground ☐ Belowground ☐ No piping ✓

Secondary Containment Descriptions

11	What type of secondary containment?[3]	Grate-covered pit (OTH)
12	List capacity in gallons of secondary containment: **(SCC)**	800 gallons
13	What is the drainage area (ft^2) that can contribute to run-on into the secondary containment **(DA)**?	0 ft^2
14	Is the (SCC) > (CSU) + 1.875 x (DA)? Note: 1.875 is the storm water conversion factor for a 25-yr/24-hr rainfall:	YES ✓ NO ☐

Action Item #1 *(Secondary Containment) If answer on line 14 is* ***No****, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements.*

None.

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 1

Spill Controls & Spill Removal

15	Has the system been integrity tested?	YES ❑ NO ✓ If yes, when:

Action Item #2 *(Integrity Testing) If answer on line 15 is **No**, describe as a deficiency refer to Chapter 4 of the SPCC Plan for requirements.*

None. Integrity testing is not applicable to drum storage areas.

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

16	Is there a method of level indication for the AST?	YES ❑ NO ❑ N/A ✓
17	Is there a liquid level alarm system for the AST?	YES ❑ NO ❑ N/A ✓

Action Item #3 *(Monitoring) If answer on line 16 or 17 is **No**, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements. Check N/A if location is not an aboveground storage tank.*

None.

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

18	Is spill control equipment available at this location?[4] 1) 2) 3)	YES ❑ NO ✓ If yes, identify which types by using the GSIP Abbreviation List on Page 5.

Action Item #4 *(Spill Control) If answer on line 18 is **No**, describe as a deficiency.*

Adequate spill control equipment should be kept on site.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 2

Storm Water Considerations

19	Are methods for removing storm water or spills from secondary containment areas available?[5] 1) Evaporation (EVP) 2) 3)	YES ✓ NO ☐ If yes, identify which methods by using the GSIP Abbreviation List on Page 5.
20	Is there a storm water discharge valve and lock?	Locked ☐ Unlocked ☐ No discharge valve ✓
21	Are best management practices such as covering, run-on diversion, etc. being used?	YES ✓ NO ☐
22	What is the distance to closest storm water culverts or catch basins (in feet)?	~ 100 feet
23	Would a spill be isolated from these storm water culverts or catch basins?	YES ✓ NO ☐
24	Name of canyon eventually receiving storm water or spill run-off:	N/A

Action Item #5 *(Storm Water) If answer on lines 19 or 23 is* ***No****, describe as a deficiency. If line 20 is answered "unlocked" or "no discharge valve", describe as a deficiency. If answer on line 21 is* ***No****, explain why.*

Although there is no stormwater discharge valve, the storage area is covered and protected on three sides. The amount of stormwater that accumulates in the containment area is minimal and generally evaporates quickly.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

Other Administrative Controls

25	Is there an Inspection & Maintenance Program in place at this GSIP Location?	YES ☐ NO ✓
26	Are aboveground storage tanks, transfer areas, drums or other ancillary sources properly labeled?	YES ✓ NO ☐
27	Is there a system of inventory control at this site?	YES ☐ NO ☐ Not Applicable ✓
28	Has an appropriate recordkeeping system documenting inventory controls, past inspections, testing, etc., been implemented at this GSIP Location?	YES ☐ NO ✓
29	Is security at this location adequate? (e.g., lighting, fencing, locked gates and valves)	YES ✓ NO ☐

Action Item #6 *(Administrative Controls) If answer on lines 25 through 29 is* ***No****, describe as a deficiency. Refer to Chapter 4 of SPCC Plan for requirements.*

1) Two levels of inspections are required for drum storage areas.

2) An appropriate recordkeeping system must be implemented.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 3

GSIP PRIORITIZATION and IMPACT ESTIMATE

FIRST PRIORITY:	
Is this an oil storage location with a capacity greater than 660 gallons?	YES ❑ NO ✓
Is this a chemical or waste storage location with a capacity greater than 220 gallons?	YES ✓ NO ❑
Is this a chemical or waste storage location in which any individual hazardous chemical RQ is exceeded?	YES ❑ NO ✓
Is this a storage location in close proximity to a canyon rim, a storm water discharge point, floor drains, etc.?	YES ❑ NO ✓
Could an oil or chemical spill at this location enter a collection system for an NPDES permitted outfall?	YES ❑ NO ✓
If YES on any question above, the area should be considered first priority. Action items listed above should be accomplished immediately. Skip next two sections.	

SECOND PRIORITY:	
Is this an oil storage location with a capacity greater than 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage location with a capacity greater than 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered second priority. Action items listed above should be accomplished within 6 months or as soon a practicable. Skip the next section.	

THIRD PRIORITY:	
Is this an oil storage location with a capacity between zero and 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage area with a capacity between zero and 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered third priority. Action items listed above should be accomplished as soon a practicable.	

Comments: In the space provided below, discuss any additional concerns related to the description of the Storage Unit, Secondary Containment, Spill Controls & Removal, Storm Water Considerations, Administrative Controls and GSIP Prioritization.

The secondary containment is large enough (800 gallons) to contain the total volume stored of the largest container (55 gallons) or 10% of the total volume of drum storage, whichever is greater. Storm water volumes are minimized by the walls and by the roof.

SPCC Form DS-1 Page 4

GSIP ABBREVIATION LIST

NOTES: CHOICES INCLUDE:

1. Types of Storage Units

   AST - Aboveground Storage Tank
   CHM - Aboveground Chemical Storage Tank
   PCT - Portable Containers (such as TUFF tank)
   DRM - Drum Storage
   LUT - Loading, Unloading and Transfer
   TRN - Transformers
   HYD - Hydraulic and Oil Containing Equipment
   BAT - Battery Packs

2. Types of Materials Stored

   If oil, grease or fuel indicate as such. If chemicals in drums, use common chemical name with CAS#. Use separate sheet if list of chemicals is long. If in small containers, list as general chemical storage.

3. Types of Secondary Containment

   EDB - Earthen Diking or Berms
   ERC - Earthen Redirection to other containment
   ADB - Asphaltic Diking or Berms
   ACU - Asphaltic Curbing
   ASU - Asphaltic Sump (or drainage to sump)
   ARC - Asphaltic Redirection to other containment
   CDB - Concrete Diking or Berms
   CCU - Concrete Curbing
   CSU - Concrete Sump (or drainage to sump)
   CRC - Concrete Redirection to other containment
   MOD - Modular Secondary Containment Systems
   PAL - Palletized Secondary Containment
   OTR - Other Types of Secondary Containment (specify)

4. Types of Spill Control Equipment

   SRB - Sorbents (granular, fibrous, powders, etc.)
   GEL - Gel Type Immobilization Agents
   BMM - Booms
   DCV - Drain Covers
   NUT - Neutralization (pH adjust for acids or bases)
   SPC - Specialized Control Kits (Hg, HF, Strong Oxidizers, etc.)
   DPN - Drip Pans
   CPP - Cathodic Pipe Protection
   OTR - Other Types (specify)

5. Methods of Storm Water Removal or Spill Removal

   EVP - Evaporation (storm water)
   VAC - Vacuum Truck Removal (off-site treatment)
   SRB - Sorbents (oils and chemicals)
   REC - Recovery for Reuse Methods
   TRT - Treatment (on-site storm water treatment)
   OTR - Other Types of Removal (specify)
   OVD - Open Valve Discharge

SPCC FORM DS-1 Page 5

4.3. TA-57-26 - DIESEL FUEL TANK & TRANSFER AREA

Description:

This tank is located in the northwest section of the Fenton Hill Site. The tank contains No. 2 Diesel Fuel and has a capacity of 10,000 gallons. A failure of the tank would be contained by a lined earthen berm with a capacity of approximately 25,500 gallons. The tank has an associated transfer area which extends north to the opposite side of the fence.

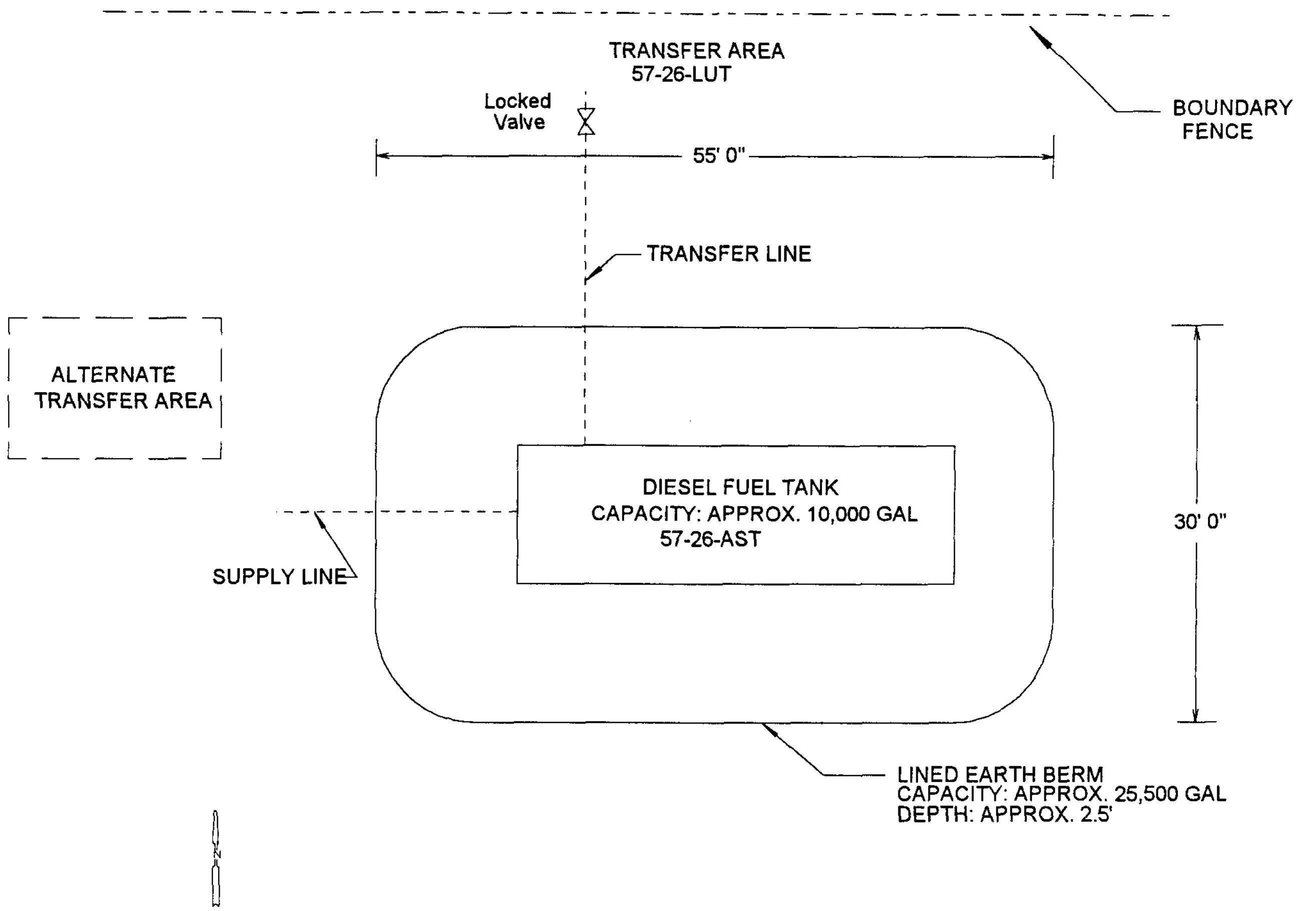
Description:

This photograph is a view of the fuel transfer area (57-26-LUT) that is located north of the Diesel Fuel tank. Access to the transfer area is through a locked gate. Potential spills would be discharged from the transfer area to the drainage ditch adjacent to the road.

An alternate transfer area to the west of the tank is currently being used. The fuel truck backs up to the west end of the tank and fuel is transfered by hoses into the top of the tank. The area where the truck parks during the transfer should be bermed to contain any spillage during the transfer.

4.3.1. Location Schematic

The location schematic shows the Diesel Fuel Tank and Transfer Area, Alternate Transfer Area, the tank capacity and the secondary containment capacity.



57-26

DIESEL FUEL TANK & TRANSFER AREA

4.3.2. Aboveground Storage Tank Requirements

40 CFR 112.7 (e)(2) defines the requirements for developing and implementing SPCC Plans related to onshore bulk storage containers. These requirements are listed below and are followed by a detailed discussion of each:

4.3.2.1. SECONDARY CONTAINMENT

Description

The secondary containment structure for the tank is a plastic lined earthen berm. The volume of the secondary containment system is large enough to contain the volume of the tank plus the volume of storm water produced by a 3-inch rainfall. The Diesel Fuel Tank is made from commonly accepted metal and steel alloys used for manufacturing diesel fuel storage tanks.

There is no secondary containment structure for either the transfer area or the alternate transfer area.

Deficiencies

FOR THE STORAGE TANK:

None.

FOR THE TRANSFER AREAS:

Some type of secondary containment structure, such as an asphalt or soil berm, should be installed at these areas.

4.3.2.2. SPILL CONTROL & SPILL REMOVAL

<u>Integrity Testing:</u>

Description

The Diesel Fuel Tank, Transfer Area, and the associated piping have never been integrity tested.

Deficiencies

- 40 CFR 112.7 (e)(2)(vi) requires and describes integrity testing of ASTs.
- API Standard 653 requires ultrasonic thickness measurements of the AST shell be performed at a minimum of once every 5 years. No ultrasonic measurements have been taken for the Diesel Fuel Tank.
- See Section 4.6.1.5. of the SPCC Revision 3 for Integrity Testing description, inspector qualifications and inspection frequency considerations. Appendix A has an Integrity Test Checklist for future use. See Action Item #2 on page 2 of the Field Data Sheets.

See Action Item #2 on page 2 of the Field Data Sheets.

Monitoring:

Description

The Diesel Fuel Tank and the Transfer Area do not have monitoring devices.

Deficiencies

New and old AST installations should, as far as practical, be fail-safe engineered to avoid spills. Consideration should be given to providing one or more of the following monitor devices.

FOR THE STORAGE TANK:

A) A fast response system for determining the liquid level in AST's such as digital computers, telepulse, direct vision gauges or equivalent,

B) Modified filling necks, couplings or vents which prevent overfilling, and

C) Rapid level loss monitors with audible or visual signals.

Monitoring systems can also include liquid-level sensors, pressure and temperature gauges, and pressure-relief devices for bulk storage tanks.

FOR THE TRANSFER AREAS:

A) High liquid level alarm with audible or visual signal at a constantly manned operation or surveillance station; in smaller installations, an audible air vent may suffice,

B) Considering size and complexity of the system, high liquid level pump cutoff devices set to stop flow at a predetermined tank content level,

C) Direct audible or code signal communication between tank gauge and the pumping station,

See Action Item #3 on page 2 of the Field Data Sheets.

Spill Control

Description

Sorbent containers are located in the covered storage area. The containers are currently empty.

Deficiencies

Adequate spill control equipment should be kept on site. See Action Item #4 on page 2 of the Field Data Sheets.

4.3.2.3. STORM WATER CONSIDERATIONS (FACILITY DRAINAGE)

Description

Storm water and snow melt occasionally accumulate in the earthen berm containment area around the tank. The containment does not have a valve, although site personnel indicate that storm water can be removed by pumping. Stormwater runoff from the Transfer Area discharges to a drainage swale adjacent to Forest Road 10377. This drainage swale leads to a culvert that discharges near 57-59-DRM.

Deficiencies

FOR THE STORAGE TANK:

There is no discharge valve. See action item #5 on page 3 of the Field Data Sheets

FOR THE TRANSFER AREAS:

Installation of a secondary containment structure such as a berm to eliminate stormwater run-on and runoff.

4.3.2.4. OTHER ADMINISTRATIVE CONTROLS

Inspections and Maintenance:

Description

General operator observations are made by all personnel involved in handling materials and operation of the Diesel Fuel Tank. No records exist of any problems occurring at this facility.

A walk-around inspection was performed by Santa Fe Engineering in May, 1994. The results of the inspection are included in Appendix B of this GSIP.

Accurate and up-to-date drawings of these tanks and secondary containment are maintained and have been incorporated into this plan. See Location Schematic in Section 4.5.1.

Deficiencies

Three levels of inspection for ASTs are required that include general operator observations, walk-around inspections and integrity inspections. These inspections must be signed by the area supervisor or Spill Coordinator. There are no records of any past walk-around or integrity testing at this site. See Section 4.5.2.2. regarding Integrity Testing at this location and Appendix A of this GSIP for blank Walk-around Inspection forms for future use.

See Action Item #6 on page 3 of the Field Data Sheets.

Labeling:

Description

The Diesel Fuel Tank has proper labeling and MSDSs available at the Control Office.

Deficiencies

None.

Inventory Control:

Description

Inventory control of the Diesel Fuel Tank is accomplished through monthly measurement of the liquid level inside the tank. If a consistent loss is indicated, an investigation should be conducted to determine if the loss is due to accounting errors or tank leakage.

Inventory reconciliation is also performed as a method of leak detection. Inventory reconciliation includes accurate measurement of the deliveries into the tank, use from the tank, and the remaining inventory. The inventory of the tanks takes into account fluid expansion or contraction from fluid temperature changes.

Deficiencies

None.

Recordkeeping:

Description

This GSIP pulls together the necessary documents related to the Diesel Fuel Tank and Transfer Area. These documents will be maintained as part of the GSIP for a period of three years.

Deficiencies

Future recordkeeping guidelines should apply to the entire AST system, including the tank, foundation, secondary containment, instrumentation, and piping. This documentation should be incorporated into this plan.

All inspections should be documented and include the following:

- When inspections were done,
- Who conducted inspection,
- What areas were inspected,
- What problems were found,
- Appropriate supervisor signatures,
- What steps were taken to correct problems, and
- Who was notified about any problems found.

See Action Item #6 on page 3 of the Field Data Sheets.

Security:

Description

TA 57 Fenton Hill Site is fully fenced and the main entrance gate is locked during non-working hours. Control pumps are locked and are accessible only to authorized personnel at all times. The transfer lines are capped and locked. Lighting is adequate for this facility

Deficiencies

FOR THE STORAGE TANK:

None.

FOR THE TRANSFER AREAS:

None.

4.3.2.5. LOCATION FIELD DATA SHEETS

The GSIP Field Data Sheets were used to record pertinent information and to document any action items that may by required. These sheets were used to organize information pertaining to storage capacities, types of materials stored, types of containment, and provide a record of all issues related to this GSIP location.

The following information is included:

- Storage Unit Descriptions,
- Secondary Containment Descriptions,
- Spill Controls and Spill Removal,
- Storm Water Considerations,
- Other Administrative Controls,
- Action Items, and
- GSIP Prioritization Estimate.

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GROUP SPCC IMPLEMENTATION PLAN
FIELD - DATA SHEET
-GSIP-

Date: 05/24/94	SC Name and Signature:

Superscripts refer to SPCC DS-1 Page-5, GSIP Abbreviation List

1	Technical Area (T) =	57
2	Structure # (S) =	26
3	Location Type (L) =	AST
4	GSIP Location Identification # (T+S+L) =	57-26-AST

Storage Unit Descriptions

5	List type of storage unit:[1]	Aboveground Storage Tank (AST)
6	List material stored in unit:[2]	Diesel Fuel Oil No. 2-D
7	List associated Reportable Quantity (RQ):	13,646 gallons for a .01% concentration of Benzene
8	List the CAS #:	068 476 346
9	List Capacity in gallons of Storage Unit **(CSU)**:	10,000 gallons
10	Describe piping associated with this location:	Aboveground ✓ Belowground ☐ No piping ☐

Secondary Containment Descriptions

11	What type of secondary containment?[3]	Lined Earthen Berm (EDB)
12	List capacity in gallons of secondary containment: **(SCC)**	25,500 gallons
13	What is the drainage area (ft^2) that can contribute to run-on into the secondary containment **(DA)**?	1650 ft^2
14	Is the (SCC) > (CSU) + 1.875 x (DA)? Note: 1.875 is the storm water conversion factor for a 25-yr/24-hr rainfall:	YES ✓ NO ☐

Action Item #1 *(Secondary Containment) If answer on line 14 is **No**, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements.*

None.

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 1

Spill Controls & Spill Removal

15	Has the system been integrity tested?	YES ❑ NO ✓ If yes, when:

Action Item #2 *(Integrity Testing) If answer on line 15 is* ***No****, describe as a deficiency refer to Chapter 4 of the SPCC Plan for requirements.*

Integrity testing of the Fuel Tank and piping system must be completed as required by 40 CFR 112.7 and API Standard 653.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

16	Is there a method of level indication for the AST?	YES ❑ NO ✓ N/A ❑
17	Is there a liquid level alarm system for the AST?	YES ❑ NO ✓ N/A ❑

Action Item #3 *(Monitoring) If answer on line 16 or 17 is* ***No****, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements. Check N/A if location is not an aboveground storage tank.*

Some type of monitoring device is required for the Diesel Fuel Tank.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

18	Is spill control equipment available at this location?[4] 1) 2) 3)	YES ❑ NO ✓ If yes, identify which types by using the GSIP Abbreviation List on Page 5.

Action Item #4 *(Spill Control) If answer on line 18 is* ***No****, describe as a deficiency.*

Adequate spill control equipment should be kept on site.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 2

Storm Water Considerations

19	Are methods for removing storm water or spills from secondary containment areas available?[5] 1) Evaporation (EVP) 2) Pumping (OTR) 3)	YES ✓ NO ☐ *If yes, identify which methods by using the GSIP Abbreviation List on Page 5.*
20	Is there a storm water discharge valve and lock?	Locked ☐ Unlocked ☐ No discharge valve ✓
21	Are best management practices such as covering, run-on diversion, etc. being used?	YES ✓ NO ☐
22	What is the distance to closest storm water culverts or catch basins (in feet)?	~ 75 feet
23	Would a spill be isolated from these storm water culverts or catch basins?	YES ✓ NO ☐
24	Name of canyon eventually receiving storm water or spill run-off:	N/A

Action Item #5 *(Storm Water) If answer on lines 19 or 23 is* ***No****, describe as a deficiency. If line 20 is answered "unlocked" or "no discharge valve", describe as a deficiency. If answer on line 21 is* ***No****, explain why.*

A mannual discharge valve should be installed to allow discharge of accumulated stormwater in the secondary containment area. BMPs inlcude the secondary containment berm.

Date Deficiency Noted:05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

Other Administrative Controls

25	Is there an Inspection & Maintenance Program in place at this GSIP Location?	YES ☐ NO ✓
26	Are aboveground storage tanks, transfer areas, drums or other ancillary sources properly labeled?	YES ✓ NO ☐
27	Is there a system of inventory control at this site?	YES ✓ NO ☐
28	Has an appropriate recordkeeping system documenting inventory controls, past inspections, testing, etc., been implemented at this GSIP Location?	YES ☐ NO ✓
29	Is security at this location adequate? (e.g., lighting, fencing, locked gates and valves)	YES ✓ NO ☐

Action Item #6 *(Administrative Controls) If answer on lines 25 through 29 is* ***No****, describe as a deficiency. Refer to Chapter 4 of SPCC Plan for requirements.*

1) Three levels of inspections are required for these aboveground storage tanks including general operator observations, walk-around inspections and integrity inspections.

2) A comprehensive recordkeeping system should be implemented for these tanks.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 3

GSIP PRIORITIZATION and IMPACT ESTIMATE

FIRST PRIORITY:	
Is this an oil storage location with a capacity greater than 660 gallons?	YES ✓ NO ❑
Is this a chemical or waste storage location with a capacity greater than 220 gallons?	YES ❑ NO ✓
Is this a chemical or waste storage location in which any individual hazardous chemical RQ is exceeded?	YES ❑ NO ✓
Is this a storage location in close proximity to a canyon rim, a storm water discharge point, floor drains, etc.?	YES ❑ NO ✓
Could an oil or chemical spill at this location enter a collection system for an NPDES permitted outfall?	YES ❑ NO ✓
If YES on any question above, the area should be considered first priority. Action items listed above should be accomplished immediately. Skip next two sections.	

SECOND PRIORITY:	
Is this an oil storage location with a capacity greater than 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage location with a capacity greater than 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered second priority. Action items listed above should be accomplished within 6 months or as soon a practicable. Skip the next section.	

THIRD PRIORITY:	
Is this an oil storage location with a capacity between zero and 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage area with a capacity between zero and 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered third priority. Action items listed above should be accomplished as soon a practicable.	

Comments: In the space provided below, discuss any additional concerns related to the description of the Storage Unit, Secondary Containment, Spill Controls & Removal, Storm Water Considerations, Administrative Controls and GSIP Prioritization.

The secondary containment (25,500 gallons) is large enough to simultaneously contain a complete failure of the tank (10,000 gallons) and a 3 inch storm event (the storm event would produce: 1650 sq ft x 3 inches x 1/12 feet/inch x 7.48 gallons/cubic foot = 3086 gallons). 25,500 > 10,000 + 3086 = 13086

SPCC Form DS-1 Page 4

Los Alamos
Los Alamos National Laboratory
Los Alamos, New Mexico 87545

GROUP SPCC IMPLEMENTATION PLAN
FIELD - DATA SHEET
-GSIP-

Date: 05/24/94 SC Name and Signature:

Superscripts refer to SPCC DS-1 Page-5, GSIP Abbreviation List

1	Technical Area (T) =	57
2	Structure # (S) =	26
3	Location Type (L) =	LUT
4	GSIP Location Identification # (T+S+L) =	57-26-LUT

Storage Unit Descriptions

5	List type of storage unit:[1]	Aboveground Storage Tank (AST)
6	List material stored in unit:[2]	Diesel Fuel Oil No. 2-D
7	List associated Reportable Quantity (RQ):	13,646 gallons for a .01% concentration of Benzene
8	List the CAS #:	068 476 346
9	List Capacity in gallons of Storage Unit **(CSU)**:	N/A (tanker trucks have a 3,000 gallon capacity)
10	Describe piping associated with this location:	Aboveground ✓ Belowground ☐ No piping ☐

Secondary Containment Descriptions

11	What type of secondary containment?[3]	None
12	List capacity in gallons of secondary containment: **(SCC)**	0
13	What is the drainage area (ft^2) that can contribute to run-on into the secondary containment **(DA)**?	
14	Is the (SCC) > (CSU) + 1.875 x (DA)? Note: 1.875 is the storm water conversion factor for a 25-yr/24-hr rainfall:	YES ☐ NO ✓

Action Item #1 *(Secondary Containment) If answer on line 14 is **No**, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements.*

Some type of secondary containment is required for the Transfer Area and the Alternate Transfer Area. Secondary containment could consist of an earthen or asphalt berm around the pipe transfer area.

Date Deficiency Noted:5/24/94 SC Name and Signature:

Date Action Item Completed: SC Name and Signature:

SPCC Form DS-1 Page 1

Spill Controls & Spill Removal

15	Has the system been integrity tested?	YES ☐ NO ✓ If yes, when:

Action Item #2 *(Integrity Testing) If answer on line 15 is **No**, describe as a deficiency refer to Chapter 4 of the SPCC Plan for requirements.*

Integrity testing of the Fuel Tank and piping system must be completed as required by 40 CFR 112.7 and API Standard 653.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

16	Is there a method of level indication for the AST?	YES ☐ NO ✓ N/A ☐
17	Is there a liquid level alarm system for the AST?	YES ☐ NO ✓ N/A ☐

Action Item #3 *(Monitoring) If answer on line 16 or 17 is **No**, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements. Check N/A if location is not an aboveground storage tank.*

Some type of monitoring device and level alarm is required for the Transfer Areas.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

18	Is spill control equipment available at this location?[4] 1) 2) 3)	YES ☐ NO ✓ If yes, identify which types by using the GSIP Abbreviation List on Page 5.

Action Item #4 *(Spill Control) If answer on line 18 is **No**, describe as a deficiency.*

Adequate spill control equipment should be kept on site.

Date Deficiency Noted: 05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 2

Storm Water Considerations

19	Are methods for removing storm water or spills from secondary containment areas available?[5] 1) 2) 3)	YES ❑ NO ✓ *If yes, identify which methods by using the GSIP Abbreviation List on Page 5.*
20	Is there a storm water discharge valve and lock?	Locked ❑ Unlocked ❑ No discharge valve ✓
21	Are best management practices such as covering, run-on diversion, etc. being used?	YES ❑ NO ✓
22	What is the distance to closest storm water culverts or catch basins (in feet)?	~ 75 feet
23	Would a spill be isolated from these storm water culverts or catch basins?	YES ❑ NO ✓
24	Name of canyon eventually receiving storm water or spill run-off:	N/A

Action Item #5 *(Storm Water) If answer on lines 19 or 23 is* ***No****, describe as a deficiency. If line 20 is answered "unlocked" or "no discharge valve", describe as a deficiency. If answer on line 21 is* ***No****, explain why.*

Some type of secondary containment structure is required for either Transfer Area. A secondary containment berm would also serve to control stormwater run-on and runoff.

Date Deficiency Noted:5/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

Other Administrative Controls

25	Is there an Inspection & Maintenance Program in place at this GSIP Location?	YES ❑ NO ✓
26	Are aboveground storage tanks, transfer areas, drums or other ancillary sources properly labeled?	YES ✓ NO ❑
27	Is there a system of inventory control at this site?	YES ✓ NO ❑
28	Has an appropriate recordkeeping system documenting inventory controls, past inspections, testing, etc., been implemented at this GSIP Location?	YES ❑ NO ✓
29	Is security at this location adequate? (e.g., lighting, fencing, locked gates and valves)	YES ❑ NO ✓

Action Item #6 *(Administrative Controls) If answer on lines 25 through 29 is* ***No****, describe as a deficiency. Refer to Chapter 4 of SPCC Plan for requirements.*

1) Three levels of inspections are required for this aboveground storage tank including general operator observations, walk-around inspections and integrity inspections.

2) A comprehensive recordkeeping system should be implemented.

3) The transfer area has a gate which is locked to prevent access to the piping. An additional lock should be provided on the transfer line valve when not in use.

Date Deficiency Noted:05/24/94	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

SPCC Form DS-1 Page 3

GSIP PRIORITIZATION and IMPACT ESTIMATE

FIRST PRIORITY:	
Is this an oil storage location with a capacity greater than 660 gallons?	YES ❑ NO ✓
Is this a chemical or waste storage location with a capacity greater than 220 gallons?	YES ❑ NO ✓
Is this a chemical or waste storage location in which any individual hazardous chemical RQ is exceeded?	YES ❑ NO ✓
Is this a storage location in close proximity to a canyon rim, a storm water discharge point, floor drains, etc.?	YES ✓ NO ❑
Could an oil or chemical spill at this location enter a collection system for an NPDES permitted outfall?	YES ❑ NO ✓
If YES on any question above, the area should be considered first priority. Action items listed above should be accomplished immediately. Skip next two sections.	

SECOND PRIORITY:	
Is this an oil storage location with a capacity greater than 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage location with a capacity greater than 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered second priority. Action items listed above should be accomplished within 6 months or as soon a practicable. Skip the next section.	

THIRD PRIORITY:	
Is this an oil storage location with a capacity between zero and 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage area with a capacity between zero and 55 gallons?	YES ❑ NO ❑
If YES on either question above, the area should be considered third priority. Action items listed above should be accomplished as soon a practicable.	

Comments: In the space provided below, discuss any additional concerns related to the description of the Storage Unit, Secondary Containment, Spill Controls & Removal, Storm Water Considerations, Administrative Controls and GSIP Prioritization.

Fuel tanker truck volumes are typically 3,000 gallons. Spills from leaking or disconnected hoses from tank trucks could be potentially discharged to the stormwater system.

A secondary containment berm should be installed at both fuel transfer areas. The berm would also serve to prevent stormwater from running on to the transfer area.

The transfer area has a gate which is locked to prevent access to the piping. An additional lock is provided on the transfer line valve when not in use.

SPCC Form DS-1 Page 4

GSIP ABBREVIATION LIST

NOTES: CHOICES INCLUDE:

1. Types of Storage Units

    AST - Aboveground Storage Tank
    CHM - Aboveground Chemical Storage Tank
    PCT - Portable Containers (such as TUFF tank)
    DRM - Drum Storage
    LUT - Loading, Unloading and Transfer
    TRN - Transformers
    HYD - Hydraulic and Oil Containing Equipment
    BAT - Battery Packs

2. Types of Materials Stored

    If oil, grease or fuel indicate as such. If chemicals in drums, use common chemical name with CAS#. Use separate sheet if list of chemicals is long. If in small containers, list as general chemical storage.

3. Types of Secondary Containment

    EDB - Earthen Diking or Berms
    ERC - Earthen Redirection to other containment
    ADB - Asphaltic Diking or Berms
    ACU - Asphaltic Curbing
    ASU - Asphaltic Sump (or drainage to sump)
    ARC - Asphaltic Redirection to other containment
    CDB - Concrete Diking or Berms
    CCU - Concrete Curbing
    CSU - Concrete Sump (or drainage to sump)
    CRC - Concrete Redirection to other containment
    MOD - Modular Secondary Containment Systems
    PAL - Palletized Secondary Containment
    OTR - Other Types of Secondary Containment (specify)

4. Types of Spill Control Equipment

    SRB - Sorbents (granular, fibrous, powders, etc.)
    GEL - Gel Type Immobilization Agents
    BMM - Booms
    DCV - Drain Covers
    NUT - Neutralization (pH adjust for acids or bases)
    SPC - Specialized Control Kits (Hg, HF, Strong Oxidizers, etc.)
    DPN - Drip Pans
    CPP - Cathodic Pipe Protection
    OTR - Other Types (specify)

5. Methods of Storm Water Removal or Spill Removal

    EVP - Evaporation (storm water)
    VAC - Vacuum Truck Removal (off-site treatment)
    SRB - Sorbents (oils and chemicals)
    REC - Recovery for Reuse Methods
    TRT - Treatment (on-site storm water treatment)
    OTR - Other Types of Removal (specify)
    OVD - Open Valve Discharge

SPCC FORM DS-1 Page 5

A. BLANK FORMS

Checklists for Detailed Aboveground Storage Tank Inspections Based on API Standard 653	
SPCC FORM CHK-1 is a checklist for tank components and auxiliary items that are considered for internal and external inspection of tanks. The checklist facilitates the recording of inspection findings.	
SPCC FORM CHK-1	AST In-Service Integrity Inspection Checklist

Checklist Forms for Walk-Around Inspections	
SPCC FORM CHK-3	Aboveground Tank and Associated Piping
SPCC FORM CHK-4	Oil or Chemical Drum Storage Area
SPCC FORM CHK-5	Oil or Chemical Drum Dispensing Station
SPCC FORM CHK-6	Transformers and Associated Secondary Containment

Secondary Containment Drains and Drainage Activity	
SPCC FORM Drain-1	Record of Drainage from Secondary Containment Structures
SPCC FORM Drain-2	Decision Diagram for Secondary Containment Requirements for Indoor Storage or Use of Oil, Chemicals or Hazardous Materials

Spill Reporting Forms	
HS Form Number 9-4A	Spill report
SPCC FORM Spill-1	Spill Coordinator's Spill Information Form

GSIP Field Data Sheets	
SPCC FORM DS-1 Page 1	GSIP Description and Action Items
SPCC FORM DS-1 Page 2	GSIP Action Items
SPCC FORM DS-1 Page 3	GSIP Action Items
SPCC FORM DS-1 Page 4	GSIP Prioritization and Impact Estimate
SPCC FORM DS-1 Page 5	GSIP Abbreviation List

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Los Alamos, New Mexico 87545

TANK IN-SERVICE INTEGRITY INSPECTION CHECKLIST

Based on API Standard 653

INSPECTOR SIGNATURE: ______________________ **DATE:** __________

1.1 FOUNDATION

- ☐ Measure foundation bottom elevation and check to see if level.

1.1.1 Concrete Ring

- ☐ Inspect for broken concrete, spalling and cracks, particularly under backup bars used in welding butt welded annular rings under the shell.
- ☐ Inspect drain openings in ring, back of water draw basins and top surface of ring for indications of bottom leakage.
- ☐ Inspect for cavities under foundation and vegetation against bottom of tank.
- ☐ Check that runoff rainwater from the shell drains away from tank.
- ☐ Check for settlement around perimeter of tank.

1.1.2 Asphalt

- ☐ Check for settling of tank into asphalt base that would direct runoff rain water under the tank instead of away from it.
- ☐ Look for area where leaching of oil has left rock filler exposed, which indicates hydrocarbon leakage.

1.1.3 Oiled Dirt or Sand

- ☐ Check for settlement into the base that would direct runoff rain water under the tank rather than away from it.

1.1.4 Rock

- ☐ Presence of crushed rock under the steel bottom usually results in severe underside corrosion. Make a note to do additional bottom plate examination (ultrasonic, hammer testing or turning of coupons) when the tank is out of service.

1.1.5 Site Drainage

- ☐ Check site for drainage away from the tank and associated piping and manifolds.
- ☐ Check operating condition of dike drains.

1.1.6 Housekeeping

- ☐ Inspect the area for buildup of trash, vegetation, and other inflammables buildup.

Foundation Inspection Notes:

1.2 SHELLS

1.2.1 External Visual Inspection

- ❑ Visually inspect for paint failures, pitting, and corrosion.
- ❑ Clean off the bottom angle area and inspect for corrosion and thinning on plate and weld.
- ❑ Inspect the bottom-to-foundation seal, if any.

Shell Inspection Notes:

1.3 SHELL APPURTENANCES

1.3.1 Manways and Nozzles

- ❑ Inspect for cracks or signs of leakage, on weld joints at nozzles, manways, and reinforcing plates. Inspect for shell plate dimpling around nozzles, caused by excessive pipe deflection. Inspect for flange leaks and leaks around bolts. Inspect sealing of insulation around manways and nozzles. Check for inadequate manway flange and cover thickness on mixer manways.

1.3.2 Tank Piping

- ❑ Inspect manifold piping, flanges, and valves for leaks. Inspect fire fighting system components. Check for anchored piping that would be hazardous to the tank shell or bottom connections during earth movement. Check for adequate thermal pressure relief of piping to the tank. Check operation of regulators for tanks with purge gas systems. Check sample connections for leaks and for proper valve operation. Check for damage and test the accuracy of temperature indicators. Check welds on shell-mounted davit clips above valves 6 inches and larger.

1.3.3 Auto Gauge System

- ❑ Inspect autogauge tape guide and lower sheave of housing (floating swings) for leaks.
- ❑ Inspect auto gauge head for damage.
- ❑ Bump the checker on auto gauge head for proper movement of tap.
- ❑ Identify size and construction material of auto gauge tape guide (floating roof tanks).
- ❑ Compare actual product level to the reading on the auto gauge (maximum variation is 2 inches).
- ❑ Inspect condition of board and legibility of board-type auto gauges.
- ❑ Test freedom of movement of marker and float.

1.3.4 Shell-Mounted Sample Station

- ❑ Inspect sample lines for function of valves and plugging of lines, including drain or return to tank line.
- ❑ Check circulation pump for leaks and operating problems.
- ❑ Test bracing and supports of sample system lines and equipment.

1.3.5 Heater (Shell Manway Mounted)

- ❑ Inspect condensate drain for presence of oil indicating leakage.

1.3.6 Mixer

- ❑ Inspect for proper mounting flange and support.
- ❑ Inspect for leakage.
- ❑ Inspect condition of power lines and connections to mixer.

1.3.7 Swing Line: Winch Operation

- ❑ Raise, then lower the swing line with the winch, and check for cable tightness to confirm that swing line lowered properly.
- ❑ Check that the indicator moves in the proper direction: Floating swing line indicators show a lower level as cable is wound up on the winch. Non-floating swings line indicators show the opposite.

1.3.8 Swing Line: External Guide System

- ❑ Check for leaks at threaded and flanged joints.

1.3.9 Swing Line: Identify Ballast Varying Need

- ❑ Check for significant difference in stock specific gravity.

1.3.10 Swing Lines: Cable Material and Condition

- ❑ For non-stainless steel cable, check for corrosion over entire length.
- ❑ All cable: check for wear or fraying.

1.3.11 Swing Line: Product Sample Comparison

- ❑ Check for water or gravity differences that would indicate a leaking swing joint.

1.3.12 Swing Line: Target

- ❑ Target should indicate direction of swing opening (up or down) and height above bottom where suction will be lost with swing on bottom support.

Shell Appurtenances Inspection Notes:

1.4 ROOFS

1.4.1 Deck Plate Internal Corrosion

- ❑ For safety, before accessing the roof, check with ultrasonic instrument or lightly use a ball peen hammer to test the deck plate near the edge of the roof for thinning (Corrosion normally attacks the deck plate at the edge of a fixed roof and at the rafters in the center of the roof first.)

1.4.2 Deck Plate External Corrosion

- ❑ Visually inspect for paint failure, holes, pitting, and corrosion product on the roof deck.

1.4.3 Roof Deck Drainage

- ❑ Look for indication of standing water. (Significant sagging of roof deck indicates potential rafter failure.)

1.4.5 Gas Test Internal Floating Roof

- ❑ Test for explosive gas on top of the internal floating roof. Readings could indicate a leaking roof, leaking seal system, or inadequate ventilation of the area above the internal floating roof.

1.4.6 Roof Insulation

- ❑ Visually inspect for cracks or leaks in the insulation weather coat where runoff rain water could penetrate the insulation.
- ❑ Inspect for wet insulation under the weather coat.
- ❑ Remove small test sections of insulation and check roof deck for corrosion and holes near the edge of the insulated area.

Roof Inspection Notes:

1.5 ROOF APPURTENANCES

1.5.1 Sample Hatch

- ❑ Inspect condition and functioning of sample hatch cover.
- ❑ On tanks governed by Air Quality Monitoring District rules, check for the condition of seal inside hatch cover.
- ❑ Check for corrosion and plugging on thief and gauge hatch cover.
- ❑ Where sample hatch is used to reel gauge stock level, check for marker and tab stating hold off distance.
- ❑ Check for reinforcing pad where sample hatch pipe penetrates the roof deck.
- ❑ Test operation of system.
- ❑ On ultra clean stocks such as JP4, check for presence and condition of protective coating or liner inside sample hatch (preventing rust from pipe getting into sample).

1.5.2 Gauge Well

- ❑ Inspect visible portion of the gauge well for thinning, size of slots, and cover condition.
- ❑ Check for a hold off distance marker and tab with hold off distance (legible).
- ❑ If accessible, check the distance from the gauge well pipe to the tank shell at different levels.
- ❑ If tank has a gauge well washer, check valve for leakage and for presence of a bull plug or blind flange.

1.5.3 Fixed Roof Scaffold Support

- ❑ Inspect scaffold support for corrosion, wear, and structural soundness.

1.5.4 Auto Gauge: Inspection Hatch and Guides (Fixed Roof)

- ❑ Check the hatch for corrosion and missing bolts.
- ❑ Look for corrosion on the tape guide's and float guide's wire anchors.

1.5.5 Autogauge: Float Well Cover

- ❑ Inspect for corrosion.
- ❑ Check tape cable for wear or fraying caused by rubbing on the cover.

1.5.6 Sample Hatch (Internal Floating Roof)

- ❑ Check overall conditions.
- ❑ When equipped with a fabric seal, check for automatic sealing after sampling.
- ❑ When equipped with a recoil reel opening device, check for proper operation.

1.5.7 Roof-Mounted Vents (Internal Floating Roof)

- ❑ Check condition of screens, locking and pivot pins.

1.5.8 Gauging Platform Drip Ring

- ❑ On fixed roof tanks with drip rings under the gauging platform or sampling area, inspect for plugged drain return to the tank.

1.5.9 Emergency Roof Drains

- ❑ Inspect vapor plugs for emergency drain: that seal fabric discs are slightly smaller than the pipe ID and that fabric seal are above the liquid level.

1.5.10 Removable Roof Leg Racks

- ❑ Check for leg racks on roof.

1.5.11 Vacuum Breakers

- ❑ Report size, numbers and type of vacuum breakers. Inspect vacuum breakers. If high legs are set, check for setting of mechanical vacuum breaker in high leg position.

1.5.12 Rim Vents

- ❑ Check condition of the screen on the rim vent cover.
- ❑ Check for plating off or removal of rim vents where jurisdictional rules do not permit removal.

1.5.13 Pontoon Inspection Hatches

- ❑ Open pontoon inspection hatch covers and visually check inside for pontoon leakage..
- ❑ Test for explosive gas (an indicator of vapor space leaks).
- ❑ If pontoon hatches are equipped with locked down covers, check for vent tubes. Check that vent tubes are not plugged up. Inspect lock down devices for condition and operation.

Roof Appurtenances Inspection Notes:

1.6 ACCESSWAYS

1.6.1 Handrails

- ❑ Identify and report type (steel pipe, galvanized pipe square tube, angle) and size of handrails. Inspect for pitting and holes, paint failure.
- ❑ Inspect attachment welds.
- ❑ Identify cold joints and sharp edges. Inspect the handrails and midrails.
- ❑ Inspect safety drop bar (or safety chain) for corrosion, functioning, and length.
- ❑ Inspect the handrail between the rolling ladder and the gauging platform for a hazardous opening when the floating roof is at its lowest level.

1.6.2 Platform Frame

- ❑ Inspect frame for corrosion and paint failure.
- ❑ Inspect the attachment of frame to supports and supports to tank: for corrosion and weld failure.
- ❑ Check reinforcing pads where supports are attached to shell or roof.
- ❑ Inspect the surface that deck plate or grating rests on, for thinning and holes.
- ❑ Check that flat-surface to flat-surface junctures are seal welded.

1.6.3 Deck Plate and Grating

- ❑ Inspect deck plate for corrosion-caused thinning or holes (not drain holes) and paint failure.
- ❑ Inspect plate-to-frame weld for rust scale buildup.
- ❑ Inspect grating for corrosion-caused thinning of bars and failure of welds.
- ❑ Check grating tie down clips. Where grating has been retrofitted to replace plate, measure the rise of the step below and above the grating surface and compare with other risers on the stairway.

1.6.4 Stairway Stringers

- ❑ Inspect spiral stairway stringers for corrosion, paint failure, and weld failure. Inspect attachment of stairway treads to stringer.
- ❑ Inspect stairway supports to shell welds and reinforcing pads.
- ❑ Inspect steel support attachment to concrete base for corrosion.

1.6.5 Rolling Ladder

- ❑ Inspect rolling ladder stringers for corrosion.
- ❑ Identify and inspect ladder fixed rungs (square bar, round bar. angles) for weld attachment to stringers and corrosion, particularly where angle rungs are welded to stringers.
- ❑ Check for wear and corrosion where rolling ladder attaches to gauging platform.
- ❑ Inspect pivot bar for wear and secureness.
- ❑ Inspect operation of self-leveling stairway treads.
- ❑ Inspect for corrosion and wear on moving parts.
- ❑ Inspect rolling ladder wheels for freedom of movement, flat spots, and wear on axle.
- ❑ Inspect alignment of rolling ladder with roof rack.
- ❑ Inspect top surface of rolling ladder track for wear by wheels to assure at least 18 inches of unworn track (track long enough).
- ❑ Inspect rolling ladder track welds for corrosion.
- ❑ Inspect track supports on roof for reinforcing pads seal welded to deck plate.
- ❑ Check by dimensioning, the maximum angle of the rolling ladder when the roof is on low legs. Maximum angle: ________
- ❑ If rolling ladder track extends to within five feet of the edge of the roof on the far side, check for a handrail on the top of the shell.

Accessways Inspection Notes:

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WALK-AROUND INSPECTION FORM

OIL OR CHEMICAL DRUM DISPENSING STATION

General Site Information

Technical Area (T) =		Inspection date:	
Structure # (S) =		Inspector:	
Location Type (L) =		Room number if indoors:	
GSIP location identification # (T+S+L) =		Area description:	
Adequate lighting:	Yes ❑ No ❑	Is facility fenced?	Yes ❑ No ❑

Inventory:

DRUMS TAPPED FOR DISPENSING:		DRUMS STORED:	
Contents:	No. of Drums:	Contents:	No. of Drums:
No. of Empty Drums:			

Site Condition

Describe general condition (cleanliness, signs of leaks, condition of drums, condition of secondary containment):	
Access around drums:	Adequate ❑ Inadequate ❑
Leaking drums:	Yes ❑ No ❑
Rusting drums:	Yes ❑ No ❑
Bulging drums:	Yes ❑ No ❑
Proper labeling:	Yes ❑ No ❑
Condition of labels:	Good ❑ Poor ❑ N/A ❑
Water accumulation (around or on drums):	Yes ❑ No ❑
Rack grounding:	Yes ❑ No ❑
Drum grounding:	Yes ❑ No ❑
Bond wire available:	Yes ❑ No ❑
Drum flame arrestors/vents:	Yes ❑ No ❑
Describe spigot condition (leaks, etc.):	
Hand pump condition:	Good ❑ Poor ❑ N/A ❑
Drip pans (in place, clean, accumulation of liquids):	
Spill kit or sorbents on hand (inventory, condition):	
Spill booms (inventory, condition):	
Fire extinguishers:	Yes ❑ No ❑
Support rack condition (horizontal storage):	Good ❑ Poor ❑ N/A ❑
Describe weather protection:	
Room ventilation:	Good ❑ Poor ❑ N/A ❑

Are there any paths for spills to reach the environment (open drains, sewers, etc.):
Items requiring corrective action:
Corrective action taken (give dates):
Inspectors Signature:

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WALK-AROUND INSPECTION FORM
TRANSFORMERS AND ASSOCIATED SECONDARY CONTAINMENT

General Site Information

Technical Area (T) =		Inspection date:	
Structure # (S) =		Inspector:	
Location Type (L) =		Transformer temperature:	
GSIP Location Identification # (T+S+L) =		Inventory volume (gauge or gallons):	
Adequate lighting:	Yes ☐ No ☐	Is facility fenced?	Yes ☐ No ☐
Transformer contents:			

Storage Unit Condition

Describe general condition (signs of rust, leaking or deterioration):	
Describe condition of content labels:	
Grounding wires:	Adequate ☐ Inadequate ☐
Level gauge:	Adequate ☐ Inadequate ☐
Other items of concern:	

Secondary Containment Condition

Describe general condition (storm water accumulation, presence of oil, signs of erosion, crack,. leaks, gopher holes, weed growth, etc.):	
Storm water discharge valve:	Locked ☐ Unlocked ☐ No valve ☐
Is there a Sump? (if yes, describe in comments section below)	Yes ☐ No ☐
Oil accumulation in dike or collection sump:	Yes ☐ No ☐

Comments:

Items requiring corrective actions:

Corrective actions taken (give dates):

Inspectors signature:

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Los Alamos National Laboratory

Los Alamos, New Mexico 87545

Record of Drainage from Secondary Containment Structures

Complete a separate form each time a secondary containment area is drained.
See back of form for Information.

SPCC Location

Technical Area # = _______ (T)	(Use 99 for non-TA assigned areas)
Structure # = _______ (S)	(Use unique number associated with structure)
Location Type ID = _______ (L)	(Use GSIP location type from Facility Site Map)
Identification # = T_____S_____L_____	

Facility Type:

Type of Storage Used:

- Aboveground storage tank ☐
- Transformer ☐
- Belowground storage tank ☐
- Oil Containing Equipment ☐
- Drum Storage Area ☐
- Other: ____________________ ☐

Materials Stored in Area: ______________________________

Storage Equipment Condition Inspection:

Does Storage Equipment Show any Signs of Leaks, Seepage, Incipient Failure, Deterioration, etc.?

Valves?	YES ☐	NO ☐	NA ☐
Connections?	YES ☐	NO ☐	NA ☐
Tanks, Drums...?	YES ☐	NO ☐	NA ☐
Piping, Hoses...?	YES ☐	NO ☐	NA ☐

Does Secondary Containment Show any Signs of Leaks, Deterioration, etc.? YES ☐ NO ☐

Secondary Containment Contents Description:

Does Liquid in Secondary Containment have any of these Characteristics? (Elaborate below)

Any reason to believe that liquid contains any contaminant?	YES ☐	NO ☐
Does liquid surface appear to have a sheen or film?	YES ☐	NO ☐
Are there any odors associated with liquid?	YES ☐	NO ☐
Any reason to believe that liquid contains anything other than storm water or melted snow?	YES ☐	NO ☐

If YES to any above question, please explain: ______________________________

____

____

Secondary Containment Contents Disposal Description:

Describe Where the Accumulated Liquid is to be Disposed: ______________________________

____

____

Describe Method to be used to Dispose or Drain Accumulated Liquid: ______________________________

____

____

Itemize any Analyses of Liquid: ______________________________

____

____

Operator In Charge: ______________________________	Date: ________
Responsible Spill Coordinator: ______________________________	Date: ________
EM-8 Representative Approval: ______________________________	Date: ________

Statement of SPCC Secondary Containment Drainage Form Usage Intent:
Organizations and individuals should recognize that they own their storage equipment and the contents of that equipment. Any non-permitted discharge to the environment is not legal since it might exceed the terms of the Laboratory's NPDES Permit or other applicable regulation. **Contact ESH-8 for inspection and direction for any contemplated discharge action.** The person conducting the drainage is responsible for insuring that it is done in an environmentally and personally safe manner. The operator must remain at the site and observe the process until completion. After the operation is completed, they should verify that any outlets from the secondary containment are closed and locked if so provided. Submittal of this form to ESH-8 (Mike Alexander, MS-K490) should be as soon as practicable.

For any questions about the completion of this form, call the Environmental Protection Group (ESH-8) @ 665-0453.

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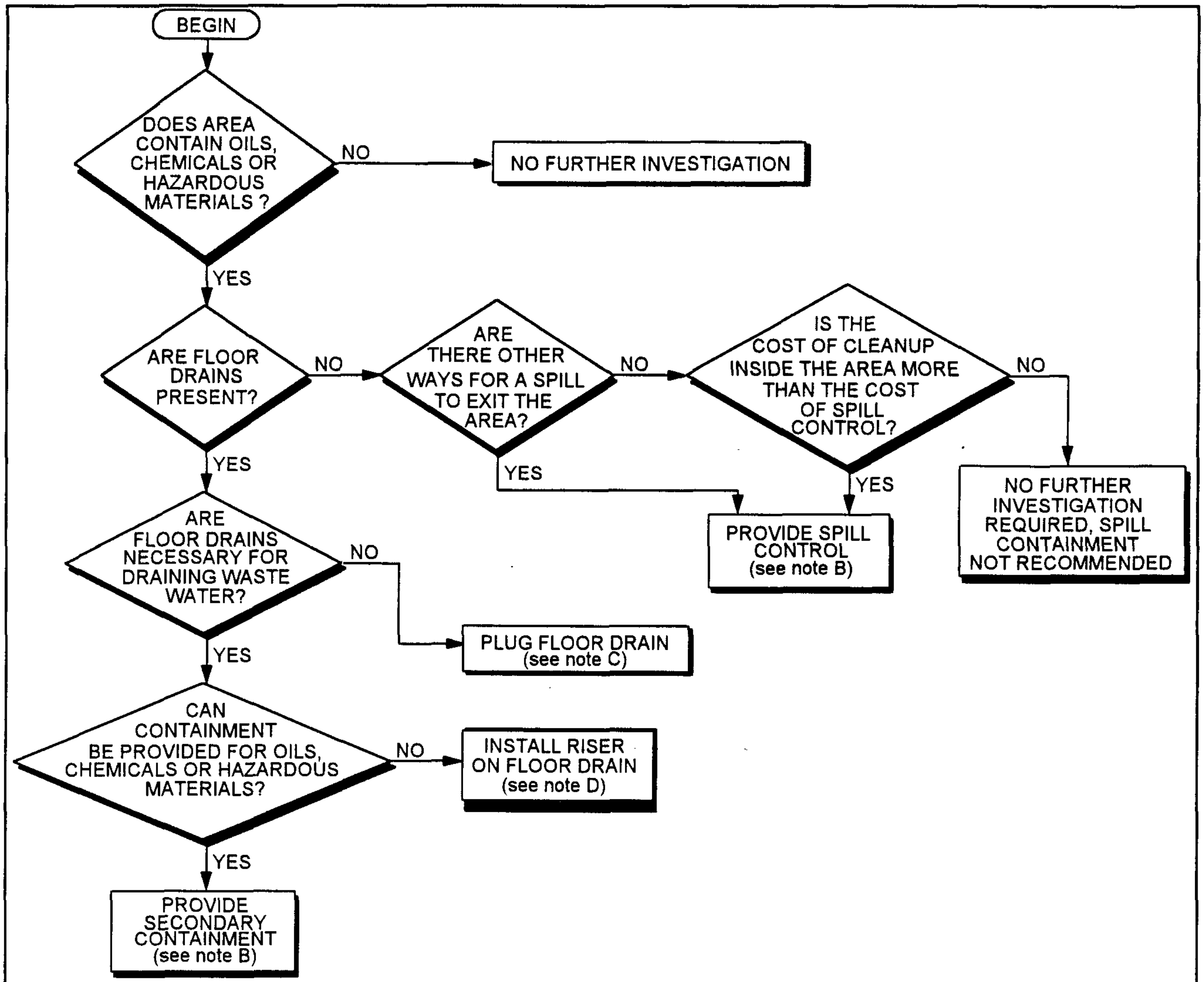
Decision Diagram for Secondary Containment Requirements for Indoor Storage or Use of Oil, Chemicals or Hazardous Materials



TA= _______ Building= _______ Location= _______ Room=_______

INSPECTOR: ____

Complete this decision diagram for each area or drain encountered by circling action taken, retain a copy of GSIP records section and forward a copy to ESH-8, MS K490

NOTE A: Hazardous Chemicals are EPA Regulated Chemicals (see Appendix D).
NOTE B: Containment can consist of Secondary Containment Cabinets, Pallets or Containment Structures such as Curbing that will Prevent Migration of Spillage.
NOTE C: Floor Drains should be Plugged Permanently.
NOTE D: Install Riser in Floor Drain to Allow Waste Water to Drain and Still Provide Containment in Case of Spill.

SPCC FORM Drain-2

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SPILL REPORT

Spill Coordinator	Telephone	Mail Stop	Division	Group

SPILL INFORMATION

Date of Spill	Time of Spill	Location
Amount of Spilled Material		**Type of Spilled Material**

Basis of Estimate ❑ Inventory ❑ Visual Estimate ❑ Recovered Volume ❑ Other

Cause *(Describe events leading up to the spill, if applicable.)*

Injuries or Exposure? ❑ Yes ❑ No *(If yes, please describe.)*

Did evacuation occur? ❑ Yes ❑ No	**Were facilities or equipment damaged?** ❑ Yes ❑ No
Did fire/explosion occur? ❑ Yes ❑ No	**Was there a potential for fire/explosion?** ❑ Yes ❑ No

Did the spill enter sewer drains, streams, or stream beds? ❑ Yes ❑ No *(If yes, give location and ultimate drainage.)*

Who discovered the Spill?

SPILL INFORMATION

Describe the spill response, in chronological order. Include a call-out of response personnel, steps taken to contain the spill, and steps taken to clean it up. Also describe spill control equipment used.

HS Form Number 9-4A (3/93)

Send original to ES&H-8, MS K490

Estimate the quantity of waste generated by the spill cleanup procedures, how that waste is packaged, and the current disposition of wastes.
Describe any sampling performed during spill cleanup and attach analytical results to this form.
Describe current status of the spill site and the need for further cleanup or monitoring activities.

	Cost Center
	Program Code

Describe actions taken to prevent recurrence of such a spill.

ADDITIONAL INFORMATION

Spill Coordinator *(Signature)*	Date

REGULATORY CONCERNS

(To Be Completed BY ESH-8)	
ESH-8 *(Signature)*	Date

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SPILL COORDINATOR'S SPILL INFORMATION FORM

Spill Coordinator	Telephone	Mail Stop	Division	Group
Responsible Facility/User Group				
Contact Person	Telephone	Mail Stop	Pager#	

Spill Location		Date of Spill	Time of Spill	Date Discovered	Time Discovered
Date Spill Stopped	Time Spill Stopped	Method used to Stop Spill			

Actions taken to Mitigate Damage

Nearest Water Course Affected? ❑ Yes ❑ No ❑ NA *(If yes, please describe.)*

Source and Cause of Spill *(pipeline, tank, truck, overflow, etc.)*

Materials Spilled

Estimated Amount of Material Spilled

Cleanup Started? ❑ Yes ❑ No	Date Started	Time Started	
Cleanup Finished? ❑ Yes ❑ No	Date Finished	Time Finished	

Cleanup Method

Weather Conditions

Comments

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WALK-AROUND INSPECTION FORM

ABOVEGROUND TANK AND ASSOCIATED PIPING

General Site Information

Technical Area (T) =		Inspection date:	
Structure # (S) =		Inspector:	
Location Type (L) =		Tank temperature:	
GSIP Location Identification # (T+S+L) =		Tank contents:	
Water content (for oil tanks):		Tank inventory (gauge or gallons):	
Adequate lighting:	Yes ❑ No ❑	Is facility fenced?	Yes ❑ No ❑

Storage Unit Condition

Describe general condition (signs of rust, leaking or deterioration):	
Tank contents labels:	Adequate ❑ Inadequate ❑
Grounding wires:	Adequate ❑ Inadequate ❑
Level gauge:	Adequate ❑ Inadequate ❑
Liquid level alarm system:	Adequate ❑ Inadequate ❑
Foundation seal:	Good ❑ Poor ❑ N/A ❑
Flanges, nozzles and piping:	Good ❑ Poor ❑ N/A ❑
Ladders or stairs:	Good ❑ Poor ❑ N/A ❑
Transfer pump:	Good ❑ Poor ❑ N/A ❑

Secondary Containment Condition

Describe general condition (storm water accumulation, presence of oil, signs of erosion, cracks, leaks, gopher holes, weed growth, etc.):	
Storm water discharge valve:	Locked ❑ Unlocked ❑ No valve ❑
Is there a Sump? (if yes, describe in comments section below):	Yes ❑ No ❑
Containment liner (for earthen berms):	Good ❑ Poor ❑ No liner ❑
Oil accumulation in dike or collection sump:	Yes ❑ No ❑

Comments:

Items requiring corrective actions:

Corrective actions taken (give dates):

Inspectors signature:

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WALK-AROUND INSPECTION FORM

OIL OR CHEMICAL DRUM STORAGE AREA

General Site Information

Technical Area (T) =		Inspection date:	
Structure # (S) =		Inspector:	
Location Type (L) =		Room number if indoors:	
GSIP Location Identification # (T+S+L) =		Area description:	
Adequate lighting:	Yes ☐ No ☐	Is facility fenced?	Yes ☐ No ☐

Inventory

Contents:	No. of Drums:	Contents:	No. of Drums:

Site condition

Describe general condition (cleanliness, signs of leaks, condition of drums, condition of secondary containment):	
Access around drums:	Adequate ☐ Inadequate ☐
Leaking drums:	Yes ☐ No ☐
Rusting drums:	Yes ☐ No ☐
Bulging drums:	Yes ☐ No ☐
Proper labeling:	Yes ☐ No ☐
Water accumulation (around or on drums):	Yes ☐ No ☐
Spill kit or sorbents on hand (inventory, condition):	
Spill booms (inventory, condition):	
Fire extinguishers:	Yes ☐ No ☐
Support rack condition (horizontal storage):	Good ☐ Poor ☐ N/A ☐
Describe weather protection:	

Comments:

Items requiring corrective action:

Corrective action taken (give dates):

Inspectors signature:

SPCC Form CHK-4 (Rev. 3)

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GROUP SPCC IMPLEMENTATION PLAN
FIELD - DATA SHEET
-GSIP-

Date:	SC Name and Signature:

Superscripts refer to SPCC DS-1 Page-5, GSIP Abbreviation List

1	Technical Area (T) =	
2	Structure # (S) =	
3	Location Type (L) =	
4	GSIP Location Identification # (T+S+L) =	

Storage Unit Descriptions

5	List type of storage unit:[1]	
6	List material stored in unit:[2]	
7	List associated Reportable Quantity (RQ):	
8	List the CAS #:	
9	List Capacity in gallons of Storage Unit **(CSU)**:	
10	Describe piping associated with this location:	Aboveground ☐ Belowground ☐ No piping ☐

Secondary Containment Descriptions

11	What type of secondary containment?[3]	
12	List capacity in gallons of secondary containment: **(SCC)**	
13	What is the drainage area (ft^2) that can contribute to run-on into the secondary containment **(DA)**?	
14	Is the (SCC) > (CSU) + 1.875 x (DA)? Note: 1.875 is the storm water conversion factor for a 25-yr/24-hr rainfall:	YES ☐ NO ☐

Action Item #1 *(Secondary Containment) If answer on line 14 is* ***No****, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements.*

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

Spill Controls & Spill Removal

15	Has the system been integrity tested?	YES ❑ NO ❑ If yes, when:

Action Item #2 *(Integrity Testing) If answer on line 15 is **No**, describe as a deficiency refer to Chapter 4 of the SPCC Plan for requirements.*

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

16	Is there a method of level indication for the AST?	YES ❑ NO ❑ N/A ❑
17	Is there a liquid level alarm system for the AST?	YES ❑ NO ❑ N/A ❑

Action Item #3 *(Monitoring) If answer on line 16 or 17 is **No**, describe as a deficiency and refer to Chapter 4 of the SPCC Plan for requirements. Check N/A if location is not an aboveground storage tank.*

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

18	Is spill control equipment available at this location?[4] 1) 2) 3)	YES ❑ NO ❑ If yes, identify which types by using the GSIP Abbreviation List on Page 5.

Action Item #4 *(Spill Control) If answer on line 18 is **No**, describe as a deficiency.*

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

Storm Water Considerations

19	Are methods for removing storm water or spills from secondary containment areas available?[5] 1) 2) 3)	YES ❑ NO ❑ If yes, identify which methods by using the GSIP Abbreviation List on Page 5.
20	Is there a storm water discharge valve and lock?	Locked ❑ Unlocked ❑ No discharge valve ❑
21	Are best management practices such as covering, run-on diversion, etc. being used?	YES ❑ NO ❑
22	What is the distance to closest storm water culverts or catch basins (in feet)?	
23	Would a spill be isolated from these storm water culverts or catch basins?	YES ❑ NO ❑
24	Name of canyon eventually receiving storm water or spill run-off:	

Action Item #5 *(Storm Water) If answer on lines 19 or 23 is **No**, describe as a deficiency. If line 20 is answered "unlocked" or "no discharge valve", describe as a deficiency. If answer on line 21 is **No**, explain why.*

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

Other Administrative Controls

25	Is there an Inspection & Maintenance Program in place at this GSIP Location?	YES ❑ NO ❑
26	Are aboveground storage tanks, transfer areas, drums or other ancillary sources properly labeled?	YES ❑ NO ❑
27	Is there a system of inventory control at this site?	YES ❑ NO ❑
28	Has an appropriate recordkeeping system (documenting inventory controls, past inspections, testing, etc., been implemented at this GSIP Location?	YES ❑ NO ❑
29	Is security at this location adequate? (e.g., lighting, fencing, locked gates and valves)	YES ❑ NO ❑

Action Item #6 *(Administrative Controls) If answer on lines 25 through 29 is **No**, describe as a deficiency. Refer to Chapter 4 of SPCC Plan for requirements.*

Date Deficiency Noted:	SC Name and Signature:
Date Action Item Completed:	SC Name and Signature:

GSIP PRIORITIZATION and IMPACT ESTIMATE

FIRST PRIORITY:

Is this an oil storage location with a capacity greater than 660 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage location with a capacity greater than 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage location in which any individual hazardous chemical RQ is exceeded?	YES ❑ NO ❑
Is this a storage location in close proximity to a canyon rim, a storm water discharge point, floor drains, etc.?	YES ❑ NO ❑
Could an oil or chemical spill at this location enter a collection system for an NPDES permitted outfall?	YES ❑ NO ❑

If YES on any question above, the area should be considered first priority. Action items listed above should be accomplished immediately. Skip next two sections.

SECOND PRIORITY:

Is this an oil storage location with a capacity greater than 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage location with a capacity greater than 55 gallons?	YES ❑ NO ❑

If YES on either question above, the area should be considered second priority. Action items listed above should be accomplished within 6 months or as soon a practicable. Skip the next section.

THIRD PRIORITY:

Is this an oil storage location with a capacity between zero and 220 gallons?	YES ❑ NO ❑
Is this a chemical or waste storage area with a capacity between zero and 55 gallons?	YES ❑ NO ❑

If YES on either question above, the area should be considered third priority. Action items listed above should be accomplished as soon a practicable.

Comments: In the space provided below, discuss any additional concerns related to the description of the Storage Unit, Secondary Containment, Spill Controls & Removal, Storm Water Considerations, Administrative Controls and GSIP Prioritization.

GSIP ABBREVIATION LIST

NOTES: CHOICES INCLUDE:

1. Types of Storage Units

   AST - Aboveground Storage Tank
   CHM - Aboveground Chemical Storage Tank
   PCT - Portable Containers (such as TUFF tank)
   DRM - Drum Storage
   LUT - Loading, Unloading and Transfer
   TRN - Transformers
   HYD - Hydraulic and Oil Containing Equipment
   BAT - Battery Packs

2. Types of Materials Stored

   If oil, grease or fuel indicate as such. If chemicals in drums, use common chemical name with CAS#. Use separate sheet if list of chemicals is long. If in small containers, list as general chemical storage.

3. Types of Secondary Containment

   EDB - Earthen Diking or Berms
   ERC - Earthen Redirection to other containment
   ADB - Asphaltic Diking or Berms
   ACU - Asphaltic Curbing
   ASU - Asphaltic Sump (or drainage to sump)
   ARC - Asphaltic Redirection to other containment
   CDB - Concrete Diking or Berms
   CCU - Concrete Curbing
   CSU - Concrete Sump (or drainage to sump)
   CRC - Concrete Redirection to other containment
   MOD - Modular Secondary Containment Systems
   PAL - Palletized Secondary Containment
   OTR - Other Types of Secondary Containment (specify)

4. Types of Spill Control Equipment

   SRB - Sorbents (granular, fibrous, powders, etc.)
   GEL - Gel Type Immobilization Agents
   BMM - Booms
   DCV - Drain Covers
   NUT - Neutralization (pH adjust for acids or bases)
   SPC - Specialized Control Kits (Hg, HF, Strong Oxidizers, etc.)
   DPN - Drip Pans
   CPP - Cathodic Pipe Protection
   OTR - Other Types (specify)

5. Methods of Storm Water Removal or Spill Removal

   EVP - Evaporation (storm water)
   VAC - Vacuum Truck Removal (off-site treatment)
   SRB - Sorbents (oils and chemicals)
   REC - Recovery for Reuse Methods
   TRT - Treatment (on-site storm water treatment)
   OTR - Other Types of Removal (specify)
   OVD - Open Valve Discharge

B. PAST INSPECTION FORMS

Type of Inspection	Date of Inspection	Who performed Inspection	GSIP Location	Deficiencies Noted
Walk-around Inspection	5/24/94	Santa Fe Engineering	57-56A-AST	No liquid level alarm system
Walk-around Inspection	5/24/94	Santa Fe Engineering	57-56B-AST	No liquid level alarm system
Walk-around Inspection	5/24/94	Santa Fe Engineering	57-56C-AST	No liquid level alarm system and or gauge
Walk-around Inspection	5/24/94	Santa Fe Engineering	57-56-DRM	Spill kits or sorbents should be made available
Walk-around Inspection	5/24/94	Santa Fe Engineering	57-59-DRM	Spill kits or sorbents should be made available
Walk-around Inspection	5/24/94	Santa Fe Engineering	57-26-AST	No liquid level alarm system
Walk-around Inspection	5/24/94	Santa Fe Engineering	57-26-LUT	No liquid level alarm system. Requires some type of secondary containment structure
Walk-around Inspection	6/1/95	Santa Fe Engineering	57-10A-AST	No labeling

Type of Inspection	Date of Inspection	Who performed Inspection	GSIP Location	Deficiencies Noted

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WALK-AROUND INSPECTION FORM

ABOVEGROUND TANK AND ASSOCIATED PIPING

General Site Information

Technical Area (T) =	57	Inspection date:	5/24/94
Structure # (S) =	56A	Inspector:	DK
Location Type (L) =	AST	Tank temperature:	N/A
GSIP Location Identification # (T+S+L) =	57-56A-AST	Tank contents:	Diesel Fuel
Water content (for oil tanks):	N/A	Tank inventory (gauge or gallons):	Gauge 3/4 full
Adequate lighting:	Yes ✓ No ❑	Is facility fenced?	Yes ❑ No ✓

Storage Unit Condition

Describe general condition (signs of rust, leaking or deterioration):	Tank in good condition
Tank contents labels:	Adequate ✓ Inadequate ❑
Grounding wires:	Adequate ✓ Inadequate ❑
Level gauge:	Adequate ✓ Inadequate ❑
Liquid level alarm system:	Adequate ❑ Inadequate ✓
Foundation seal:	Good ❑ Poor ❑ N/A ✓
Flanges, nozzles and piping:	Good ✓ Poor ❑ N/A ❑
Ladders or stairs:	Good ❑ Poor ❑ N/A ✓
Transfer pump:	Good ❑ Poor ❑ N/A ✓

Secondary Containment Condition

Describe general condition (storm water accumulation, presence of oil, signs of erosion, crack,. leaks, gopher holes, weed growth, etc.):	Grate covered pit in good condition Minor oil sheen
Storm water discharge valve:	Locked ❑ Unlocked ❑ No valve ✓
Is there a Sump? (if yes, describe in comments section below):	Yes ❑ No ✓
Containment liner (for earthen berms):	Good ❑ Poor ❑ No liner ❑ N/A
Oil accumulation in dike or collection sump:	Yes ❑ No ❑ N/A

Comments:
Facility is covered.

Items requiring corrective actions:
Some type of liquid level alarm system

Corrective actions taken (give dates):

Inspectors signature: Dk

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WALK-AROUND INSPECTION FORM

ABOVEGROUND TANK AND ASSOCIATED PIPING

General Site Information

Technical Area (T) =	57	Inspection date:	5/24/94
Structure # (S) =	56C	Inspector:	DK
Location Type (L) =	AST	Tank temperature:	N/A
GSIP Location Identification # (T+S+L) =	57-56C-AST	Tank contents:	Waste Fuel Oil
Water content (for oil tanks):	N/A	Tank inventory (gauge or gallons):	No gauge
Adequate lighting:	Yes ✓ No ☐	Is facility fenced?	Yes ☐ No ✓

Storage Unit Condition

Describe general condition (signs of rust, leaking or deterioration):	Tank in good condition
Tank contents labels:	Adequate ✓ Inadequate ☐
Grounding wires:	Adequate ☐ Inadequate ✓
Level gauge:	Adequate ☐ Inadequate ✓
Liquid level alarm system:	Adequate ☐ Inadequate ✓
Foundation seal:	Good ☐ Poor ☐ N/A ✓
Flanges, nozzles and piping:	Good ✓ Poor ☐ N/A ☐
Ladders or stairs:	Good ☐ Poor ☐ N/A ✓
Transfer pump:	Good ☐ Poor ☐ N/A ✓

Secondary Containment Condition

Describe general condition (storm water accumulation, presence of oil, signs of erosion, crack,. leaks, gopher holes, weed growth, etc.):	Grate covered pit in good condition Minor oil sheen
Storm water discharge valve:	Locked ☐ Unlocked ☐ No valve ✓
Is there a Sump? (if yes, describe in comments section below):	Yes ☐ No ✓
Containment liner (for earthen berms):	Good ☐ Poor ☐ No liner ☐ N/A
Oil accumulation in dike or collection sump:	Yes ☐ No ☐ N/A

Comments:
Facility is covered.

Items requiring corrective actions:
Some type of liquid level gauge should be installed.

Corrective actions taken (give dates):

Inspectors signature: DK

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WALK-AROUND INSPECTION FORM

OIL OR CHEMICAL DRUM STORAGE AREA

General Site Information

Technical Area (T) =	57	Inspection date:	5/24/94
Structure # (S) =	59	Inspector:	DK
Location Type (L) =	DRM	Room number if indoors:	
GSIP Location Identification # (T+S+L) =	57-59-DRM	Area description:	Covered storage area
Adequate lighting:	Yes ✓ No ☐	Is facility fenced?	Yes ☐ No ✓

Inventory

Contents:	No. of Drums:	Contents:	No. of Drums:
Eth;ylene Glycol	3		
SAE 15W-40	1		
Sodium Bromide	4		
220 Oil	1		
Mobile Gear Oil	12 (5 gallon)		

Site condition

Describe general condition (cleanliness, signs of leaks, condition of drums, condition of secondary containment):	Clean area. Drums in good condition.
Access around drums:	Adequate ✓ Inadequate ☐
Leaking drums:	Yes ☐ No ✓
Rusting drums:	Yes ☐ No ✓
Bulging drums:	Yes ☐ No ✓
Proper labeling:	Yes ✓ No ☐
Water accumulation (around or on drums):	Yes ☐ No ✓
Spill kit or sorbents on hand (inventory, condition):	none
Spill booms (inventory, condition):	none
Fire extinguishers:	Yes ✓ No ☐
Support rack condition (horizontal storage):	Good ☐ Poor ☐ N/A ✓☐
Describe weather protection:	Covered on three sides

Comments:
Drums are stored in a covered area, walled in on three sides.

Items requiring corrective action:
Spill kit or sorbents should be made available.

Corrective action taken (give dates):

Inspectors signature: DK

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WALK-AROUND INSPECTION FORM

ABOVEGROUND TANK AND ASSOCIATED PIPING

General Site Information

Technical Area (T) =	57	Inspection date:	5/24/94
Structure # (S) =	26	Inspector:	DK
Location Type (L) =	AST	Tank temperature:	N/A
GSIP Location Identification # (T+S+L) =	57-26-AST	Tank contents:	Diesel Fuel
Water content (for oil tanks):	minor	Tank inventory (gauge or gallons):	none
Adequate lighting:	Yes ✓ No ☐	Is facility fenced?	Yes ✓ No ☐

Storage Unit Condition

Describe general condition (signs of rust, leaking or deterioration):	Tank in good condition
Tank contents labels:	Adequate ✓ Inadequate ☐
Grounding wires:	Adequate ✓ Inadequate ☐
Level gauge:	Adequate ☐ Inadequate ✓
Liquid level alarm system:	Adequate ☐ Inadequate ✓
Foundation seal:	Good ✓ Poor ☐ N/A ☐
Flanges, nozzles and piping:	Good ✓ Poor ☐ N/A ☐
Ladders or stairs:	Good ✓ Poor ☐ N/A ☐
Transfer pump:	Good ☐ Poor ☐ N/A ✓

Secondary Containment Condition

Describe general condition (storm water accumulation, presence of oil, signs of erosion, crack,. leaks, gopher holes, weed growth, etc.):	Berm containment in good condition Stormwater accumulation of 1 foot
Storm water discharge valve:	Locked ☐ Unlocked ☐ No valve ✓
Is there a Sump? (if yes, describe in comments section below):	Yes ☐ No ✓
Containment liner (for earthen berms):	Good ✓ Poor ☐ No liner ☐
Oil accumulation in dike or collection sump:	Yes ☐ No ☐ N/A

Comments:
Secondary containment is in good condition. Recommend installation of a manual discharge valve to remove accumulated stormwater in containment berm.

Items requiring corrective actions:
Some type of liquid level alarm system.

Corrective actions taken (give dates):

Inspectors signature: DK

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WALK-AROUND INSPECTION FORM

ABOVEGROUND TANK AND ASSOCIATED PIPING

General Site Information

Technical Area (T) =	57	Inspection date:	5/24/94
Structure # (S) =	26	Inspector:	DK
Location Type (L) =	LUT	Tank temperature:	N/A
GSIP Location Identification # (T+S+L) =	57-26-LUT	Tank contents:	Diesel Fuel
Water content (for oil tanks):	N/A	Tank inventory (gauge or gallons):	N/A
Adequate lighting:	Yes ✓ No ☐	Is facility fenced?	Yes ✓ No ☐

Storage Unit Condition

Describe general condition (signs of rust, leaking or deterioration):	Transfer area piping in good condition
Tank contents labels:	Adequate ✓ Inadequate ☐ N/A
Grounding wires:	Adequate ✓ Inadequate ☐ N/A
Level gauge:	Adequate ☐ Inadequate ✓
Liquid level alarm system:	Adequate ☐ Inadequate ✓
Foundation seal:	Good ✓ Poor ☐ N/A ☐
Flanges, nozzles and piping:	Good ✓ Poor ☐ N/A ☐
Ladders or stairs:	Good ☐ Poor ☐ N/A ✓
Transfer pump:	Good ☐ Poor ☐ N/A ✓

Secondary Containment Condition

Describe general condition (storm water accumulation, presence of oil, signs of erosion, crack,. leaks, gopher holes, weed growth, etc.):	No secondary containment.
Storm water discharge valve:	Locked ☐ Unlocked ☐ No valve ✓
Is there a Sump? (if yes, describe in comments section below):	Yes ☐ No ✓
Containment liner (for earthen berms):	Good ☐ Poor ☐ No liner ☐ N/A
Oil accumulation in dike or collection sump:	Yes ☐ No ☐ N/A

Comments:
Transfer valve unlocked and easily turned on.

Items requiring corrective actions:
Fuel transfer area should be bermed. A level alarm or gauge should be installed.

Corrective actions taken (give dates):

Inspectors signature: DK

SPCC Form CHK-4 (Rev. 3)

Los Alamos
Los Alamos National Laboratory
Los Alamos, New Mexico 87545

WALK-AROUND INSPECTION FORM
ABOVEGROUND TANK AND ASSOCIATED PIPING

General Site Information

Technical Area (T) =	57	Inspection date:	5/24/94
Structure # (S) =	56B	Inspector:	DK
Location Type (L) =	AST	Tank temperature:	N/A
GSIP Location Identification # (T+S+L) =	57-56B-AST	Tank contents:	Gasoline
Water content (for oil tanks):	N/A	Tank inventory (gauge or gallons):	Gauge 2/3 full
Adequate lighting:	Yes ✓ No ❑	Is facility fenced?	Yes ❑ No ✓

Storage Unit Condition

Describe general condition (signs of rust, leaking or deterioration):	Tank in good condition
Tank contents labels:	Adequate ✓ Inadequate ❑
Grounding wires:	Adequate ✓ Inadequate ❑
Level gauge:	Adequate ✓ Inadequate ❑
Liquid level alarm system:	Adequate ❑ Inadequate ✓
Foundation seal:	Good ❑ Poor ❑ N/A ✓
Flanges, nozzles and piping:	Good ✓ Poor ❑ N/A ❑
Ladders or stairs:	Good ❑ Poor ❑ N/A ✓
Transfer pump:	Good ❑ Poor ❑ N/A ✓

Secondary Containment Condition

Describe general condition (storm water accumulation, presence of oil, signs of erosion, crack,. leaks, gopher holes, weed growth, etc.):	Grate covered pit in good condition Minor oil sheen
Storm water discharge valve:	Locked ❑ Unlocked ❑ No valve ✓
Is there a Sump? (if yes, describe in comments section below):	Yes ❑ No ✓
Containment liner (for earthen berms):	Good ❑ Poor ❑ No liner ❑ N/A
Oil accumulation in dike or collection sump:	Yes ❑ No ❑ N/A

Comments:
Facility is covered.

Items requiring corrective actions:
Some type of liquid level alarm system

Corrective actions taken (give dates):

Inspectors signature: DK

SPCC Form CHK-4 (Rev. 3)

Los Alamos

Los Alamos National Laboratory

Los Alamos, New Mexico 87545

WALK-AROUND INSPECTION FORM

ABOVEGROUND TANK AND ASSOCIATED PIPING

General Site Information

Technical Area (T) =	57	Inspection date:	6/1/95
Structure # (S) =	10A	Inspector:	SFE/S. Veenis
Location Type (L) =	AST	Tank temperature:	N/A
GSIP Location Identification # (T+S+L) =	57-10A-AST	Tank contents:	Ethylene Glycol
Water content (for oil tanks):	N/A	Tank inventory (gauge or gallons):	60% full or 300 gallons
Adequate lighting:	Yes ❑ No ✓	Is facility fenced?	Yes ✓ No ❑

Storage Unit Condition

Describe general condition (signs of rust, leaking or deterioration):	polyethylene tank in good condition
Tank contents labels:	Adequate ❑ Inadequate ✓
Grounding wires:	Adequate ✓ Inadequate ❑ N/A ❑
Level gauge:	Adequate ✓ Inadequate ❑ visual
Liquid level alarm system:	Adequate ❑ Inadequate ✓
Foundation seal:	Good ✓ Poor ❑ N/A ❑
Flanges, nozzles and piping:	Good ✓ Poor ❑ N/A ❑
Ladders or stairs:	Good ✓ Poor ❑ N/A ❑
Transfer pump:	Good ✓ Poor ❑ N/A ❑

Secondary Containment Condition

Describe general condition (storm water accumulation, presence of oil, signs of erosion, crack,. leaks, gopher holes, weed growth, etc.):	Containment in good condition Stormwater accumulation of 6-inches
Storm water discharge valve:	Locked ❑ Unlocked ❑ No valve ✓
Is there a Sump? (if yes, describe in comments section below):	Yes ✓ No ❑
Containment liner (for earthen berms):	Good ✓ Poor ❑ No liner ✓
Oil accumulation in dike or collection sump:	Yes ❑ No ✓

Comments:
Secondary containment is in good condition. Sump pump appears to be in good condition, should be used to periodically empty containment of accumulated storm water.

Items requiring corrective actions:
Appropriate labeling of tank is required.

Corrective actions taken (give dates):

Inspectors signature:

SPCC Form CHK-4 (Rev. 3)

NEW MEXICO
HEALTH AND ENVIRONMENT
DEPARTMENT

Post Office Box 968
Santa Fe, New Mexico 87504-0968

ENVIRONMENTAL IMPROVEMENT DIVISION

Michael J. Burkhart
Director

GARREY CARRUTHERS
Governor

LARRY GORDON
Secretary

CARLA L. MUTH
Deputy Secretary

Certified Mail-Return Receipt Requested

January 8, 1988

Mr. Myron Knudson
U.S. Environmental Protection Agency
Allied Bank Tower
1445 Ross Avenue
Dallas, Texas 75202-2733

Re: State Certification

Dear Mr. Knudson:

Enclosed please find the state certification for the following minor industrial permit.

Department of Energy (Fenton Hill), Permit Number NM0028576

Comments are enclosed on separate sheets. The original Public Notice deadline was October 27,1987 but it was extended until February 8, 1988 at the request of the New Mexico Environmental Improvement Division.

Sincerely,

Kathleen M. Sisneros

Kathleen M. Sisneros
Bureau Chief
Surface Water Quality Bureau

MS/ms

Enclosures

cc: NMEID Espanola Field Office
NMEID District II Office
NMOCD, Dave Boyer
DOE LANL, Charles Nylander
DOE LANL, Harold Valencia

Mr. Robert Layton Jr., Regional Administrator
Environmental Protection Agency
1445 Ross Avenue
Dallas, TX 75202-2733

January 8, 1988

STATE CERTIFICATION

Re: Department of Energy (Fenton Hill)
Los Alamos Area Office
Los Alamos, New Mexico 87544
NM0028576, September 26, 1987

Dear Mr. Layton:

The New Mexico Environmental Improvement Division has examined the application for and the proposed NPDES permit NM0028576 above. The following conditions are necessary to assure compliance with the applicable provisions of the Clean Water Act Sections 208(e), 301, 302, 303, 306, and 307 and with appropriate requirements of State law. Compliance with the terms and conditions of the permit and this certification will provide reasonable assurance that the permitted activities will be conducted in a manner which will not violate applicable water quality standards.

The State of New Mexico

( ) includes the following more stringent conditions and citation to the State or Federal requirements upon which those conditions are based (see attachments).

(x) certifies that the discharge will comply with the applicable provisions of Sections 208(e), 301, 302, 303, 306 and 307 of the Clean Water Act and with appropriate requirements of State law.

( ) waives its right to certify

( ) denies certification for the reasons stated in the attachment

In order to meet the requirements of State law, including water quality standards and appropriate basin plan, each of the conditions cited in the draft permit and the State certification shall not be made less stringent.

Please contact Mike Saladen if you have any questions concerning this certification. Comments pertaining to this Draft Permit are included on a separate page.

Sincerely,

Kathleen M. Sisneros

Kathleen M. Sisneros
Bureau Chief
Surface Water Quality Bureau

Department of Energy
Fenton Hill
NM0028576

Comments That Are Not Conditions Of State Certification

The discharge is incorrectly cited on the Public Notice, Statement of Basis and on page 1, Part I of the permit. The correct discharge is into Lake Fork Canyon, thence the Rio Cebolla, thence the Rio Guadalupe in stream segment 2-106 of the Rio Grande Basin.

The designated uses of stream segment 2-106 are as follows: domestic water supply, fish culture, high quality coldwater fishery, irrigation, livestock and wildlife watering and secondary contact recreation.

The State ground water standard for boron is 0.75 mg/l (Section 3-103.C., NM Water Quality Control Commission (WQCC) Regulations). The current NPDES permit requires monitoring of boron. Review of the permittee's DMR data indicates discharges of boron as high as 122 mg/l (December 1986). The EID hereby requests that EPA retain the monitoring and reporting requirement for boron.

The federal Safe Drinking Water Act standard for fluoride in drinking water is 4.0 mg/l. The State ground water standard for fluoride is 1.6 mg/l (Section 3-103.A., WQCC Regulations). Designated uses of the receiving waters include domestic water supply. The current NPDES permit requires monitoring of fluoride. Review of the permittee's Discharge Monitoring Report (DMR) data indicates discharge as high as 8.5 mg/l fluoride (September 1986). The EID hereby requests that EPA retain the monitoring and reporting requirements for fluoride.

The State ground water standard for total dissolved solids or filterable residue (TDS) is 1000 mg/l (Section 3-103.B., WQCC Regulations). On June 24,1987, the Oil Conservation Division (OCD) visited the site and collected a sample for TDS which indicated it to be 5278 ppm. The EID hereby requests the EPA to include monitoring and reporting of TDS in the permit.

A review of DMRs submitted by the permittee document arsenic and cadmium levels as high as 7.5 mg/l and 2.0 mg/l respectively. Based on DMR data submitted by the permittee, the EID requests that EPA retain the monitoring and reporting requirements for arsenic and cadmium.

A review of flow schematics submitted by the permittee document potential unpermitted outfalls at the Fenton Hill Geothermal site. The permittee stated their belief that these outlets would be used in emergency situations only and that a discharge from any of these outlets would be covered by their permit, Part II.5. Bypassing. EID would like to bring to the attention of EPA these potential outfalls, (see enclosed attachments). EID would also like to explain that these bypass outfalls discharge to a different watercourse than outfall 001. The State believes that the bypassing of treatment units is unacceptable and prohibited by the NPDES permit. If a bypass does occur, the permittee must immediately notify both the EPA and EID, sample the discharge and meet all requirements for bypassing stated in the NPDES permit. The DOE will also be responsible for complying with all applicable provisions of the WQCC regulations (e.g. Section 1-203, Notification of Discharge-Removal) with regard to any bypass.

Department of Energy
Fenton Hill
NM0028576

Conditions Of State Certification

NONE.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VI
ALLIED BANK TOWER AT FOUNTAIN PLACE
1445 ROSS AVENUE
DALLAS, TEXAS 75202

RECEIVED
JAN 12 1988
OIL CONSERVATION DIVISION
SANTA FE

JAN 05 1988

REPLY TO: 6W-PI

Ms. Kathleen M. Sisneros
Bureau Chief
Surface Water Quality Bureau
Environmental Improvement Division
New Mexico Department of Health and Environment
P.O. Box 968
Santa Fe, New Mexico 87504-0968

Re: NPDES Permit No. NM0028576

Dear Ms. Sisneros:

This is in response to your December 23, 1987, request for an extension of the certification period for the Fenton Hill LANL permit. An extension until February 26, 1988, is hereby approved.

Sincerely yours,

Kenneth Huffman, Ph.D.
Chief
Industrial Permits Section (6W-PI)

cc: Mr. Charles Nylander
Department of Energy
Los Alamos Area Office
Los Alamos, New Mexico 87544

Mr. David G. Boyer
Environmental Bureau Chief
Oil Conservation Division
Energy, Minerals and Natural Resources Department
State of New Mexico
P.O. Box 2088
Santa Fe, New Mexico 87504

January 5, 1987

Mr. Mike Saladen
New Mexico Environmental Improvement Division
Surface Water Quality Bureau
P.O. Box 968
Santa Fe, New Mexico 87504

Dear ~~Mr. Saladen~~ Mike:

Per our telephone conversation today, I am expediting to you the attached copies of the analytical reports for the water samples collected at the Fenton Hill Geothermal Site on November 9, 1987. Sample number 87.02641 was collected from the 5 million gallon hypalon-lined sump, and sample number 87.02642 was collected from the 5 million gallon hypalon-lined pond access hatch. The quality assurance reports are also attached.

As we discussed, we had both recently received the Oil Conservation Division's analytical reports for the Fenton Hill split samples collected simultaneously and analyzed by the N.M. Scientific Laboratory Division. As you will notice by comparing the two laboratory's analytical data, the analytical results are very similar. It would appear that the trace of toluene previously detected in samples last Fall has for all practical purposes disappeared. Also, the quantitative presence of the various trihalomethanes detected by both laboratories and other volatile organic compounds is well below the Safe Drinking Water Act standards. At this point, I believe more fervently that the presence of trace organic compounds is the result of field-seaming and repair of the hypalon liner, as hypothesized last November.

I hope the timely transmittal of these analytical data will assist you in completing your review and certification of the proposed permit for Fenton Hill. Please call me at 665-0453 should you wish to discuss the attachments or the proposed permit.

Sincerely,

Charlie

Charles Nylander
Environmental Surveillance
Group (HSE-8)

Attachments: a/s

Cy: David Boyer, N.M. Oil Conservation Division

HSE-9 ORGANIC ANALYSIS RESULT
VOLATILE ORGANICS

REQUEST SHEET NUMBER: 6462
SAMPLE NUMBERS: 87.02641-02642
SUBMITTER: ROY BOHN, HSE-8
DATE: DECEMBER 15, 1987

On November 9, 1987 the above two water samples were delivered to me for analysis of volatile organics. The analysis was performed using purge and trap gas chromatography/mass spectroscopy. Analysis was begun on November 12, 1987 and was completed on November 22, 1987. Qualitative analysis was accomplished using library searching, retention time confirmation, and analyst interpretation. Quantitative analysis was performed using the internal standard method. Surrogate standards were added to each sample. The % recovery of the surrogates is used as a measure of the efficacy of the analytical technique. A matrix spike was also analyzed, and the % recovery of these compounds is useful in detecting any unusual matrix effects that might be attributable the actual sample matrix. The results of the individual analyses and quality control analyses are attached. Please call if you have any questions.

Suzanne C. Bell

Suzanne C. Bell
HSE-9 Organic Analysis Section

Carol R Sutcliffe

Carol Sutcliffe
HSE-9 Organic Analysis Section Leader

HSE-9 ORGANIC ANALYSIS SECTION
VOLATILE ORGANICS RESULT SHEET

SAMPLE NUMBER: 87.02641
MATRIX: Water
NUMBER OF REPLICATE RUNS: Total of 5

SURROGATE SPIKE RECOVERIES: (% RECOVERY)

1,2-DICHLOROETHANE d4 101.5
TOLUENE d8 101.8
p-BROMOFLUOROBENZENE 93.1
one run

CAS #	COMPOUND	RESULT +/- (ppb)		MDL (ppb)
74873	CHLOROMETHANE	<MDL		40.0
73839	BROMOMETHANE			40.0
75014	VINYL CHLORIDE			40.0
75003	CHLOROETHANE			40.0
75092	METHYLENE CHLORIDE			5.0
67641	ACETONE			5.0
75150	CARBON DISULFIDE			5.0
75354	1,1-DICHLOROETHENE			10.0
75343	1,1-DICHLOROETHANE			5.0
540590	1,2-DICHLOROETHENE		(TOTAL)	10.0
67663	CHLOROFORM	11.6 ± 7.1		5.0
107062	1,2-DICHLOROETHANE	<MDL		5.0
78933	2-BUTANONE	<MDL		5.0
71556	1,1,1-TRICHLOROETHANE	56.4 ± 21.4		5.0
56235	CARBON TETRACHLORIDE	<MDL		5.0
108054	VINYL ACETATE	<MDL		10.0
75274	BROMODICHLOROMETHANE	8.9 ± 0.9		5.0
78875	1,2-DICHLOROPROPANE	<MDL		5.0
10061015	cis-1,3-DICHLOROPROPENE	<MDL		5.0
79016	TRICHLOROETHENE	<MDL		5.0
124481	DIBROMOCHLOROMETHANE	11.6 ± 0.5		5.0
79005	1,1,2-TRICHLOROETHANE	<MDL		5.0
71432	BENZENE	<MDL		5.0
10061026	trans-1,3-DICHLOROPROPENE	<MDL		5.0
75252	BROMOFORM	11.4 ± 1.1		5.0
108101	4-METHYL-2-PENTANONE	<MDL		5.0
591786	2-HEXANONE			5.0
127184	TETRACHLOROETHENE			5.0
79345	1,1,2,2-TETRACHLOROETHANE			5.0
108883	TOLUENE			5.0
108907	CHLOROBENZENE			5.0
100414	ETHYLBENZENE			5.0
100425	STYRENE			5.0
133027	XYLENES		(TOTAL)	5.0
75694	TRICHLOROFLUOROMETHANE			5.0
95501	1,2-DICHLOROBENZENE			5.0
541731	1,3-DICHLOROBENZENE			5.0

106467	1,4-DICHLOROBENZENE	<MDL	5.0
91023	NAPHTHALENE		20.0*
104518	n-BUTYLBENZENE		5.0*
108861	BROMOBENZENE		5.0*
95498	2-CHLOROTOLUENE		5.0*
106434	4-CHLOROTOLUENE		5.0*
74953	DIBROMOMETHANE		5.0*
142289	1,3-DICHLOROPROPANE		5.0*
590207	2,2-DICHLOROPROPANE		5.0*
87683	HEXACHLOROBUTADIENE		5.0*
103651	n-PROPYLBENZENE		5.0*
630206	1,1,1,2-TETRACHLOROETHANE		5.0*
120821	1,2,4-TRICHLOROBENZENE		5.0*
96184	1,2,3-TRICHLOROPROPANE		5.0*
95636	1,2,4-TRIMETHYLBENZENE		5.0*

MDL : Minimum detection limit (* is estimated)

The system has been shown to be capable of detecting all of the above listed compounds. In some cases, not all of these compounds are included in the standard calibration runs.

The linear range of the detector is 20-200 ppb. In those samples with analyte concentrations greater than 200 ppb, dilutions are made. In those samples with analyte concentrations between 5 and 20 ppb, a second calibration curve is made for that range. As a calculated value approaches the limit of detection, the uncertainty associated with that value increases. In general, uncertainties are assigned as follows:

CALCULATED CONCENTRATION (ppb)	UNCERTAINTY (%)
5-10	100.0
10-20 (SEPARATE CURVE)	10.0
10-20 (STANDARD CURVE)	50.0
20-200	10.0

If a sample is run in triplicate and its concentration falls within the range of the curves, uncertainty is reported as the standard deviation of the replicates. Normally, samples are run in duplicate.

The results of matrix spike and matrix spike duplicate runs if applicable are attached.

Results are ± 2 std. deviations, except BOCM.

HSE-9 ORGANIC ANALYSIS SECTION
VOLATILE ORGANICS RESULT SHEET

SAMPLE NUMBER: 87.02642
MATRIX: Water
NUMBER OF REPLICATE RUNS: Total of 6

SURROGATE SPIKE RECOVERIES: (% RECOVERY)

1,2-DICHLOROETHANE d4	94.5	mean of 2
TOLUENE d8	101.2	
p-BROMOFLUOROBENZENE	119.6	

CAS #	COMPOUND	RESULT +/- (ppb)		MDL (ppb)
74873	CHLOROMETHANE	<MDL		40.0
73839	BROMOMETHANE			40.0
75014	VINYL CHLORIDE			40.0
75003	CHLOROETHANE			40.0
75092	METHYLENE CHLORIDE			5.0
67641	ACETONE			5.0
75150	CARBON DISULFIDE			5.0
75354	1,1-DICHLOROETHENE			10.0
75343	1,1-DICHLOROETHANE			5.0
540590	1,2-DICHLOROETHENE		(TOTAL)	10.0
67663	CHLOROFORM	11.0 ± 4.9		5.0
107062	1,2-DICHLOROETHANE	<MDL		5.0
78933	2-BUTANONE	<MDL		5.0
71556	1,1,1-TRICHLOROETHANE	53.0 ± 12.1		5.0
56235	CARBON TETRACHLORIDE	<MDL		5.0
108054	VINYL ACETATE	<MDL		10.0
75274	BROMODICHLOROMETHANE	11.7 ± 0.2		5.0
78875	1,2-DICHLOROPROPANE	<MDL		5.0
10061015	cis-1,3-DICHLOROPROPENE			5.0
79016	TRICHLOROETHENE			5.0
124481	DIBROMOCHLOROMETHANE	10.6 ± 0.7		5.0
79005	1,1,2-TRICHLOROETHANE	<MDL		5.0
71432	BENZENE			5.0
10061026	trans-1,3-DICHLOROPROPENE			5.0
75252	BROMOFORM	13.2 ± 0.8		5.0
108101	4-METHYL-2-PENTANONE	<MDL		5.0
591786	2-HEXANONE			5.0
127184	TETRACHLOROETHENE			5.0
79345	1,1,2,2-TETRACHLOROETHANE			5.0
108883	TOLUENE	detected, too low to quantitate		5.0
108907	CHLOROBENZENE	<MDL		5.0
100414	ETHYLBENZENE			5.0
100425	STYRENE			5.0
133027	XYLENES		(TOTAL)	5.0
75694	TRICHLOROFLUOROMETHANE			5.0
95501	1,2-DICHLOROBENZENE			5.0
541731	1,3-DICHLOROBENZENE			5.0

106467	1,4-DICHLOROBENZENE	<MDL	5.0
91023	NAPHTHALENE		20.0*
104518	n-BUTYLBENZENE		5.0*
108861	BROMOBENZENE		5.0*
95498	2-CHLOROTOLUENE		5.0*
106434	4-CHLOROTOLUENE		5.0*
74953	DIBROMOMETHANE		5.0*
142289	1,3-DICHLOROPROPANE		5.0*
590207	2,2-DICHLOROPROPANE		5.0*
87683	HEXACHLOROBUTADIENE		5.0*
103651	n-PROPYLBENZENE		5.0*
630206	1,1,1,2-TETRACHLOROETHANE		5.0*
120821	1,2,4-TRICHLOROBENZENE		5.0*
96184	1,2,3-TRICHLOROPROPANE		5.0*
95636	1,2,4-TRIMETHYLBENZENE		5.0*

MDL : Minimum detection limit (* is estimated)

The system has been shown to be capable of detecting all of the above listed compounds. In some cases, not all of these compounds are included in the standard calibration runs.

The linear range of the detector is 20-200 ppb. In those samples with analyte concentrations greater than 200 ppb, dilutions are made. In those samples with analyte concentrations between 5 and 20 ppb, a second calibration curve is made for that range. As a calculated value approaches the limit of detection, the uncertainty associated with that value increases. In general, uncertainties are assigned as follows:

CALCULATED CONCENTRATION (ppb)	UNCERTAINTY (%)
5-10	100.0
10-20 (SEPARATE CURVE)	10.0
10-20 (STANDARD CURVE)	50.0
20-200	10.0

If a sample is run in triplicate and its concentration falls within the range of the curves, uncertainty is reported as the standard deviation of the replicates. Normally, samples are run in duplicate.

The results of matrix spike and matrix spike duplicate runs if applicable are attached.

Results are all ± 2 standard deviations
since multiple runs were made.

Calibrations : 1-200 ppb. Estimated
MDL for the calibrated compounds : 0.5 ppb

HSE-9 ORGANIC ANALYSIS SECTION
VOLATILE ORGANICS RESULT SHEET

SAMPLE NUMBER: 87.02641
MATRIX: Water
NUMBER OF REPLICATE RUNS: 2

MATRIX SPIKE

SURROGATE SPIKE RECOVERIES: (% RECOVERY)

1,2-DICHLOROETHANE d4 NA
TOLUENE d8 ↓
p-BROMOFLUOROBENZENE ↓

CAS #	COMPOUND	RESULT +/- (ppb) Added	Calculated	%recovery		MDL (ppb)
74873	CHLOROMETHANE					40.0
73839	BROMOMETHANE					40.0
75014	VINYL CHLORIDE					40.0
75003	CHLOROETHANE					40.0
75092	METHYLENE CHLORIDE					5.0
67641	ACETONE					5.0
75150	CARBON DISULFIDE					5.0
75354	1,1-DICHLOROETHENE	See note				10.0
75343	1,1-DICHLOROETHANE					5.0
540590	1,2-DICHLOROETHENE				(TOTAL)	10.0
67663	CHLOROFORM					5.0
107062	1,2-DICHLOROETHANE					5.0
78933	2-BUTANONE					5.0
71556	1,1,1-TRICHLOROETHANE					5.0
56235	CARBON TETRACHLORIDE					5.0
108054	VINYL ACETATE					10.0
75274	BROMODICHLOROMETHANE					5.0
78875	1,2-DICHLOROPROPANE					5.0
10061015	cis-1,3-DICHLOROPROPENE					5.0
79016	TRICHLOROETHENE	43.8	44.6	101.8%		5.0
124481	DIBROMOCHLOROMETHANE					5.0
79005	1,1,2-TRICHLOROETHANE					5.0
71432	BENZENE	44.8	46.2	103.1%		5.0
10061026	trans-1,3-DICHLOROPROPENE					5.0
75252	BROMOFORM					5.0
108101	4-METHYL-2-PENTANONE					5.0
591786	2-HEXANONE					5.0
127184	TETRACHLOROETHENE					5.0
79345	1,1,2,2-TETRACHLOROETHANE					5.0
108883	TOLUENE	41.0	42.6	103.1%		5.0
108907	CHLOROBENZENE	40.0	40.3	100.7%		5.0
100414	ETHYLBENZENE					5.0
100425	STYRENE					5.0
133027	XYLENES				(TOTAL)	5.0
75694	TRICHLOROFLUOROMETHANE					5.0
95501	1,2-DICHLOROBENZENE					5.0
541731	1,3-DICHLOROBENZENE					5.0

106467	1,4-DICHLOROBENZENE	______	5.0
91023	NAPHTHALENE	______	20.0*
104518	n-BUTYLBENZENE	______	5.0*
108861	BROMOBENZENE	______	5.0*
95498	2-CHLOROTOLUENE	______	5.0*
106434	4-CHLOROTOLUENE	______	5.0*
74953	DIBROMOMETHANE	______	5.0*
142289	1,3-DICHLOROPROPANE	______	5.0*
590207	2,2-DICHLOROPROPANE	______	5.0*
87683	HEXACHLOROBUTADIENE	______	5.0*
103651	n-PROPYLBENZENE	______	5.0*
630206	1,1,1,2-TETRACHLOROETHANE	______	5.0*
120821	1,2,4-TRICHLOROBENZENE	______	5.0*
96184	1,2,3-TRICHLOROPROPANE	______	5.0*
95636	1,2,4-TRIMETHYLBENZENE	______	5.0*

MDL : Minimum detection limit (* is estimated)

The system has been shown to be capable of detecting all of the above listed compounds. In some cases, not all of these compounds are included in the standard calibration runs.

The linear range of the detector is 20-200 ppb. In those samples with analyte concentrations greater than 200 ppb, dilutions are made. In those samples with analyte concentrations between 5 and 20 ppb, a second calibration curve is made for that range. As a calculated value approaches the limit of detection, the uncertainty associated with that value increases. In general, uncertainties are assigned as follows:

CALCULATED CONCENTRATION (ppb)	UNCERTAINTY (%)
5-10	100.0
10-20 (SEPARATE CURVE)	10.0
10-20 (STANDARD CURVE)	50.0
20-200	10.0

If a sample is run in triplicate and its concentration falls within the range of the curves, uncertainty is reported as the standard deviation of the replicates. Normally, samples are run in duplicate.

The results of matrix spike and matrix spike duplicate runs if applicable are attached.

Older matrix spike - 1,1-Dichloroethene
loss is not unexpected.

HSE-9 ORGANIC ANALYSIS SECTION
VOLATILE ORGANICS RESULT SHEET

SAMPLE NUMBER: 00.97651
MATRIX: Water
NUMBER OF REPLICATE RUNS: 2

Quality Assurance Sample

SURROGATE SPIKE RECOVERIES: (% RECOVERY)

1,2-DICHLOROETHANE d4 100.2
TOLUENE d8 100.2
p-BROMOFLUOROBENZENE 118.7

} mean of 2

CAS #	COMPOUND	RESULT +/- (ppb)		MDL (ppb)
74873	CHLOROMETHANE	<MDL		40.0
73839	BROMOMETHANE			40.0
75014	VINYL CHLORIDE			40.0
75003	CHLOROETHANE			40.0
75092	METHYLENE CHLORIDE			5.0
67641	ACETONE			5.0
75150	CARBON DISULFIDE			5.0
75354	1,1-DICHLOROETHENE			10.0
75343	1,1-DICHLOROETHANE			5.0
540590	1,2-DICHLOROETHENE		(TOTAL)	10.0
67663	CHLOROFORM			5.0
107062	1,2-DICHLOROETHANE			5.0
78933	2-BUTANONE			5.0
71556	1,1,1-TRICHLOROETHANE	49.7 ± 5.0		5.0
56235	CARBON TETRACHLORIDE	<MDL		5.0
108054	VINYL ACETATE			10.0
75274	BROMODICHLOROMETHANE			5.0
78875	1,2-DICHLOROPROPANE			5.0
10061015	cis-1,3-DICHLOROPROPENE			5.0
79016	TRICHLOROETHENE			5.0
124481	DIBROMOCHLOROMETHANE			5.0
79005	1,1,2-TRICHLOROETHANE			5.0
71432	BENZENE			5.0
10061026	trans-1,3-DICHLOROPROPENE			5.0
75252	BROMOFORM			5.0
108101	4-METHYL-2-PENTANONE			5.0
591786	2-HEXANONE			5.0
127184	TETRACHLOROETHENE			5.0
79345	1,1,2,2-TETRACHLOROETHANE			5.0
108883	TOLUENE			5.0
108907	CHLOROBENZENE			5.0
100414	ETHYLBENZENE			5.0
100425	STYRENE			5.0
133027	XYLENES		(TOTAL)	5.0
75694	TRICHLOROFLUOROMETHANE			5.0
95501	1,2-DICHLOROBENZENE			5.0
541731	1,3-DICHLOROBENZENE			5.0

Added 75±20 % Rec 66%

106467	1,4-DICHLOROBENZENE	<MDL	5.0
91023	NAPHTHALENE		20.0*
104518	n-BUTYLBENZENE		5.0*
108861	BROMOBENZENE		5.0*
95498	2-CHLOROTOLUENE		5.0*
106434	4-CHLOROTOLUENE		5.0*
74953	DIBROMOMETHANE		5.0*
142289	1,3-DICHLOROPROPANE		5.0*
590207	2,2-DICHLOROPROPANE		5.0*
87683	HEXACHLOROBUTADIENE		5.0*
103651	n-PROPYLBENZENE		5.0*
630206	1,1,1,2-TETRACHLOROETHANE		5.0*
120821	1,2,4-TRICHLOROBENZENE		5.0*
96184	1,2,3-TRICHLOROPROPANE		5.0*
95636	1,2,4-TRIMETHYLBENZENE		5.0*

MDL : Minimum detection limit (* is estimated)

The system has been shown to be capable of detecting all of the above listed compounds. In some cases, not all of these compounds are included in the standard calibration runs.

The linear range of the detector is 20-200 ppb. In those samples with analyte concentrations greater than 200 ppb, dilutions are made. In those samples with analyte concentrations between 5 and 20 ppb, a second calibration curve is made for that range. As a calculated value approaches the limit of detection, the uncertainty associated with that value increases. In general, uncertainties are assigned as follows:

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10-20 (STANDARD CURVE)	50.0
20-200	10.0

If a sample is run in triplicate and its concentration falls within the range of the curves, uncertainty is reported as the standard deviation of the replicates. Normally, samples are run in duplicate.

The results of matrix spike and matrix spike duplicate runs if applicable are attached.

Department of Energy
Albuquerque Operations
Los Alamos Area Office
Los Alamos, New Mexico 87544

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

DEC 29 1987

Mr. Mike Saladen
Environmental Scientist, Surface Water Section
New Mexico Health and Environment Department
Environmental Improvement Division
P. O. Box 968
Santa Fe, NM 87504-0968

Dear Mr. Saladen:

RE: FENTON HILL STATE CERTIFICATION, PERMIT NO. NM0028576

In response to your November 13, 1987 request for additional information about potential discharge, water lines and experimental procedures at the Fenton Hill Geothermal Facility, I have prepared the enclosed process description, topographic map and schematics of piping and valving.

PROCESS DESCRIPTION

Introduction: The Fenton Hill Geothermal Facility is a technical site at Los Alamos National Laboratory developed for geothermal experimentation. A typical experiment conducted at Fenton Hill would inject water into very deep boreholes where heat is transferred from hot rocks beneath the earth's surface into the injected water. The heated water and steam is then recovered for evaluation. Planned activities include treating this recovered water and reusing it.

Process: The Fenton Hill site was designed and developed with the necessary water handling flexibility required for this kind of experimentation. The following description is of a waterflow pattern for a typical experiment; however, by opening or closing gate valves in the distribution system, very large volumes of water can be quickly delivered to various locations about the site.

For an understanding of water distribution and collection at the site it is convenient to focus on three locations within the facility: the valve pit on the west side of the 5 million gallon reservoir; the pump house north of the reservoir; and, the EE 1 pond.

The Valve Pit: On the west side of the 5 million gallon reservoir is a vertical, buried, 8 ft diameter corrugated culvert pipe. This section of culvert has a cover made of steel plate with 2 ft square access manhole. Please refer to Figure 2. Three water lines (the reservoir overflow, the emergency drain, and the underdrain or seepage drain) pass through the pit approximately parallel to each other in a northeast to southwest direction. One line, the recirculation line, enters the pit on the north side and is tied into the emergency drain. A 2-inch galvanized iron (G.I.) recovery line enters the pit on the southwest side and is tied into the emergency drain line.

The overflow line is a 6-inch cast iron (C.I.) pipeline on the southeast side of the pit that contains no gate valves. It would discharge to the recovery tank if the water level in the reservoir were excessive.

The emergency drain is a 12-inch C.I. pipeline through the center of the pit with a normally closed gate valve which prevents discharge to the recovery tank. A second gate valve, normally open, is in the emergency drain line east of the valve pit between the reservoir and the fence. Were an emergency to arise requiring the reservoir to be emptied, emergency drain flow would overfill the collection box at the inlet to the recovery tank then flow down the arroyo to the southeast. (See topographic map in Figure 1).

The underdrain or seepage drain is an 8-inch C.I. pipeline on the northwest side of the pit. This line has no gate valves. This pipeline conducts any seepage that collects in a sump under the Hypalon lining of the reservoir to the recovery tank.

Water collected in the recovery tank is lifted by alternating submersible pumps through the 2-inch G.I. pipeline, injected into the emergency drain line, and is returned to the reservoir. The 2-inch G.I. pipeline contains a check valve preventing flow from the reservoir to the recovery tank.

The recirculating line is an 8-inch C.I. pipeline that enters the pit on the north side and is tied into the emergency drain through a gate valve. This pipeline conducts water from the pumphouse to the emergency drain where it then returns to the reservoir. Recirculation is to ensure that the water in the reservoir is uniformly mixed.

The recovery tank to the southwest of the valve pit is a steel tank approximately 8 ft in a diameter and 16 ft long. Capacity of the tank is about 6000 gal.

Southeast of the valve pit and recovery tank is an abandoned eight inch C.I. pipeline with concrete thrust blocks for each section. An earlier experiment required pumping water from this location up to the boreholes through the recirculation line. After completion of the experiment the line was cut and the recirculation line was connected to the emergency drain. The abandoned line is not connected to existing pipelines at the facility.

The Pumphouse: The pumphouse contains piping, numerous gate valves and one 1000 gpm vertical turbine pump and one 400 gpm vertical turbine pump. (Please see Figures 1 and 3.) The primary purpose of the pumping facility is to provide firefighting water and water for experimental use. Normally valves and pipelines are configured to permit pumping water from the reservoir to the two 16,000 gallon process water tanks and subsequently to the boreholes or, as stated previously, to the recirculation line for return to the reservoir. Because of the demand for large volumes of water during an experiment, the system is configured to allow water addition to the reservoir by trucking it in and discharging through the three hose connects on the northeast side of the pumphouse and by filling the reservoir through a 6-inch C.I. water line from the site potable water well.

Pond EE 1: This pond contains water recovered from the boreholes during experiments and water collected during the drilling of the boreholes. (Please see Figure 1.) There are three potential discharge pipelines through the southern embankment of EE 1, all approximately parallel and lying along a north south line: a 10-inch steel overflow line, a 4-inch G.I. drain line and a 6-inch G.I. auxiliary drain line.

The overflow line is on the west side of the 4-inch drain line. It would discharge if the water depth of EE 1 were in excess of approximately 12 feet. Discharge from this line would flow almost directly west as surface drainage to a canyon to the west. (See topography shown in Figure 1.)

Normally any discharge from the pond is through the 4-inch G.I. drain line. This line contains a gate valve which remains closed except for discharge. The Fenton Hill site is planning the construction of the totalizing meter, gate valve and discharge flume shown in Figure 1. Materials for construction have arrived and the flume has been encased in a concrete form.

A 6-inch auxiliary pipeline is placed to the east of the drain line. This pipeline is not connected to the pond. If it were necessary to discharge through this pipeline, a portable pump or a siphon would be required.

Discharges from the facility: As stated in our National Pollutant Discharge Elimination System (NPDES) permit application, the only planned discharge from the Fenton Hill Geothermal Facility is from the existing Outfall 001 permitted in NPDES permit number NM 0028576. Any other discharge would be treated as required in Part II of the NPDES permit, either as an an anticipated or as an unanticipated bypass arising from an emergency situation or as an accident.

In your letter you expressed interest in a possible discharge from the hypalon-lined reservoir. Please be aware that water in the reservoir is from the site's potable water well that has been chlorinated and will be injected into the deep boreholes. If an emergency should occur that required emptying the five million gallon reservoir, the quality of the contained water usually approaches drinking water standards. A discharge from this reservoir poses minimal threat to ground water quality.

While there is potential for a bypass in the existing piping system, we believe that it is necessary to continue to operate with the existing system because of it's required safety features (emergency drains and overflows) and it's inherent flexibility required for experimentation. Any anticipated or unanticipated discharge from any "Outfall" would be monitored and reported pursuant to the requirements of NPDES permit number NM0028576. Other than Outfall 001, we do not believe that it is necessary to file an application for other "potential Outfalls" which may discharge during an accident or emergency, as such discharges are already addressed by Part 2 of the NPDES permit.

Your letter stated that during the November 9th visit a substance with characteristics of drilling mud was observed flowing off the Fenton Hill site, and you requested that this discharge be addressed. The material that was observed during the visit was not flowing, but rather was observed on the ground down-slope from Outfall 001, as there was no active discharge from the Fenton Hill site the day of the visit. The observed material resulted from the deposition of settleable and suspended solids from the discharge from Outfall 001, either historical or from the discharge events that occurred on November 7 and 8, 1987.

As you are aware, the water in the EE-1 pond that is discharged from Outfall 001 contains settleable and suspended solids derived from drilling mud, well cuttings, and sediment from site runoff into the pond. The drilling mud used at the site is a standard Baroid-type mud and is considered inert and nontoxic. Whenever a discharge occurs from the EE-1 pond, a certain solids content will settle out on the normally-dry drainage channel down-slope from Outfall 001. Certainly, any solids contained in the discharge will settle out in the sediment trap located approximately 900 feet down-slope from Outfall 001. There was and is no deliberate discharge of drilling mud or other solids that would constitute a sludge or solids as defined by Part 2.A.6. of the NPDES permit.

Sludges and solids that are deposited in the EE-1 pond are periodically sampled and analyzed according to the Extraction Procedure for Toxicity (EP Tox) test prior to their removal and disposal. The analytical results have never exceeded the EP Tox levels, and thus the materials have never been considered a hazardous waste. When the solid materials are removed from the EE-1 pond, they are disposed of in a drying area southwest of Fenton Hill site. This disposal site is located on U.S. Forest Service property, has their approval, and is constructed in such a manner that there is no discharge of solids into "navigable waters." The most recent EP Tox analyses of the solids in the EE-1 pond (October 22, 1987) are listed below for your information.

Arsenic	0.05	mg/l
Silver	0.05	ng/l
Cadmium	0.01	mg/l
Barium	2.0	mg/l
Mercury	0.005	mg/l
Chromium	0.05	mg/l
Selenium	0.01	mg/l
Lead	0.17	mg/l

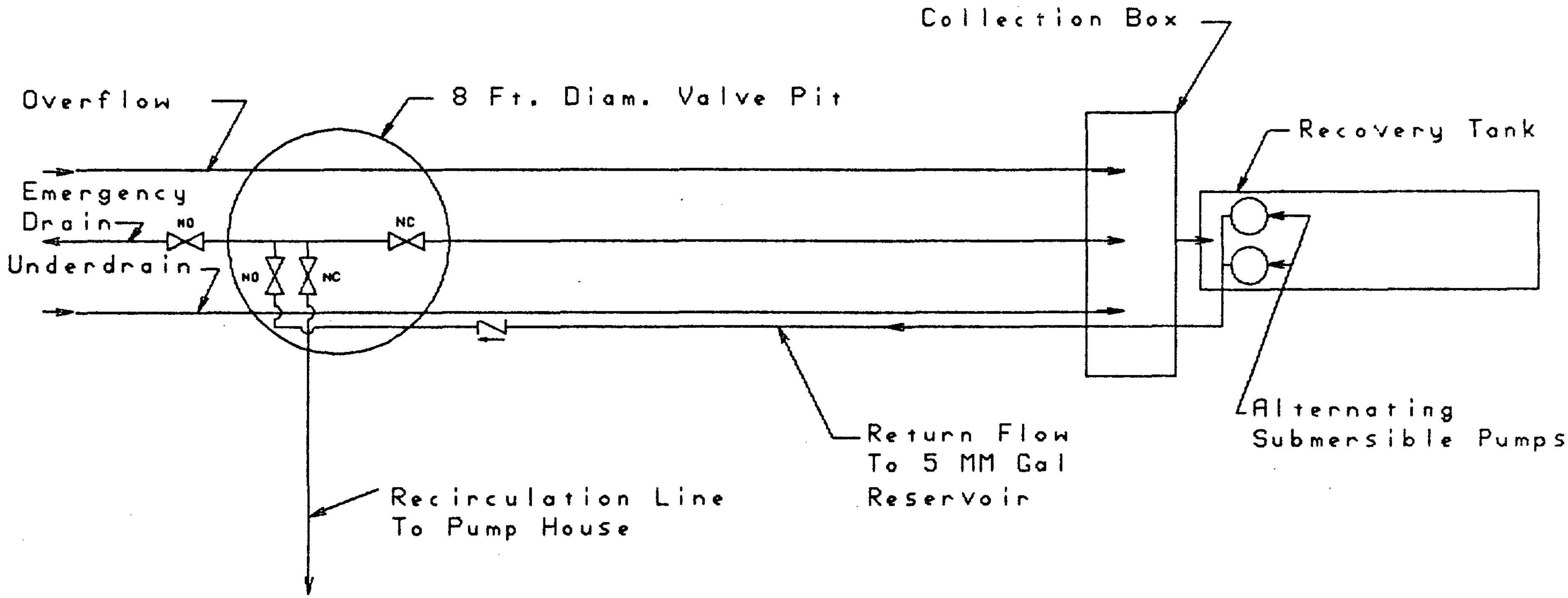
I trust that the information contained in this letter addresses your information request of November 23, 1987. Should you have any questions concerning this information, please call James Phoenix (667-5288) of my staff.

Sincerely,

Harold E. Valencia
Area Manager

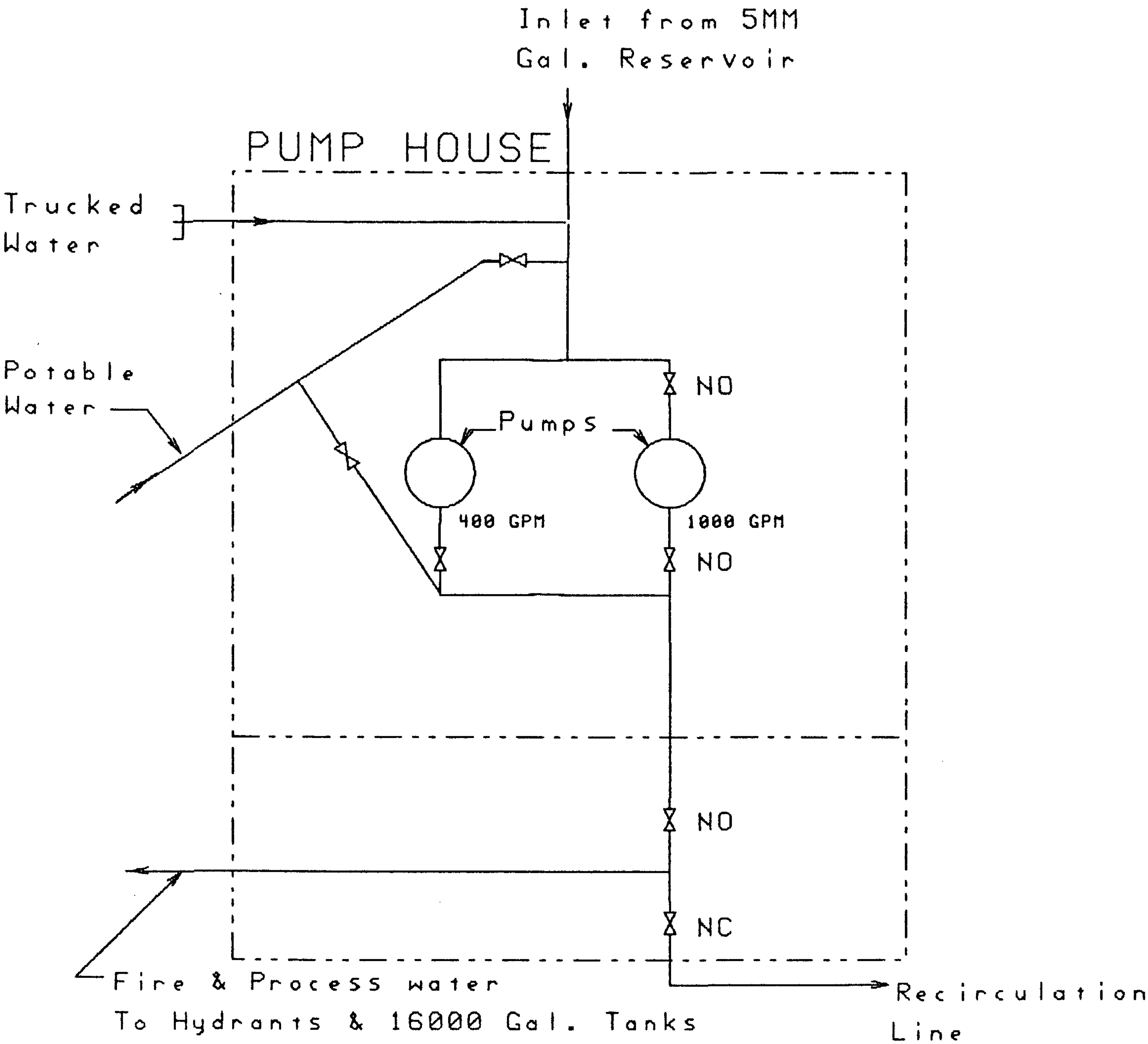
Enclosure:
As Stated

cc:
Kathleen Sisneros, NMEID, Santa Fe, NM, w/encl.
David Boyer, NMOCD, Santa Fe, NM, w/encl.



KEY
= Gate Valve
= Check Valve
NC = Normally closed
NO = Normally opened

SANTA FE ENGINEERING, LTD. 1900 CHAMISA ST. SANTA FE NM (505) 988-7438			Line and Valve Schematic
DESIGN BY: BK	DATE Dec 87	SCALE NTS	Valve Pit and Recovery Tank
DRAWN BY: BK	DATE Dec 87	DRAWING NUMBER FIG. 2	West of 5 MM Gal. Reservoir
CHECKED BY: LBA	DATE Dec 87		



KEY

= Gate valve
NC = Normally closed
NO = Normally opened

SANTA FE ENGINEERING, LTD. 1900 CHAMISA ST. SANTA FE, NM (505) 988-7438			Line and Valve Schematic
DESIGN BY: BK	DATE Dec 87	SCALE NTS	Pump House
DRAWN BY: BK	DATE Dec 87	DRAWING NUMBER	North of 5 MM Gal. Reservoir
CHECKED BY: LBA	DATE Dec 87	FIG. 3	

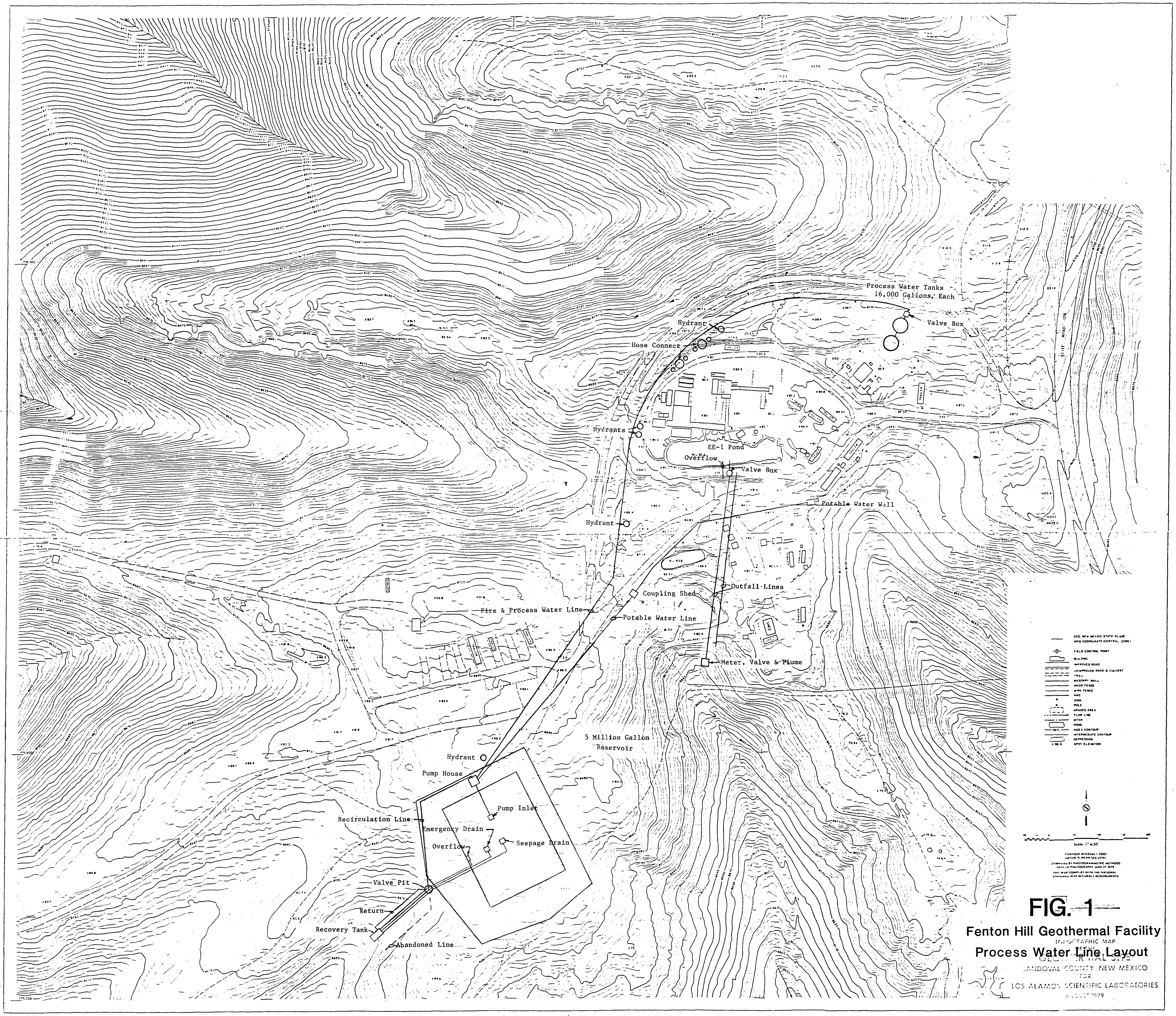


FIG. 1
Fenton Hill Geothermal Facility
Process Water Line Layout

NEW MEXICO
HEALTH AND ENVIRONMENT
DEPARTMENT

Post Office Box 968
Santa Fe, New Mexico 87504-0968

ENVIRONMENTAL IMPROVEMENT DIVISION

Michael J. Burkhart
Director

GARREY CARRUTHERS
Governor

LARRY GORDON
Secretary

CARLA L. MUTH
Deputy Secretary

December 22, 1987

Certified Mail
Return Receipt Requested

Mr. Myron Knudson
U.S. Environmental Protection Agency
Allied Bank Tower, 12th Floor
1445 Ross Avenue
Dallas, Texas 75202-2733

Re: State Certification of Proposed NPDES Permit NM0028576 (Department of Energy, Fenton Hill)

Dear Mr. Knudson:

The State of New Mexico Environmental Improvement Division (NMEID) hereby requests an extension to provide certification pursuant to Section 401 of the federal Clean Water Act for the referenced draft permit. The proposed permit is currently in the public notice period. This public notice period has been extended once from the original due date of October 27, 1987. The NMEID expects an extension of thirty (30) days beyond the current January 8, 1988 deadline will be sufficient to address this matter. Since the first extension, NMEID personnel have visited the Fenton Hill site and have requested additional information from the permittee. The permittee has agreed to submit flow schematics for the geothermal site and send in sampling results which they collected and split with the Oil Conservation Division (OCD), who also accompanied us on the inspection. The NMEID requests this additional time to evaluate sampling results collected by OCD and the permittee, plus time to review the treatment process schematics for potential unpermitted outfalls located at the Fenton Hill Geothermal site. To date, NMEID has not received the sampling results or the schematics.

If you have any questions please contact Mike Saladen at (505) 827-2798.

Sincerely,

Kathleen M. Sisneros

Kathleen M. Sisneros
Bureau Chief
Surface Water Quality Bureau

MS/ms

cc: Charles Nylander, LANL
Ellen Caldwell, USEPA (6W-PS)
David Boyer, OCD
Harold Valencia, DOE

Department of Energy
Albuquerque Operations
Los Alamos Area Office
Los Alamos, New Mexico 87544

OCT 26 1987

RECEIVED
OCT 28 1987
OIL CONSERVATION DIVISION
SANTA FE

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Myron Knudson, Director
Water Management Division, 6W
U. S. Environmental Protection Agency, Region VI
Allied Bank Tower at Fountain Place
1445 Ross Avenue
Dallas, Texas 75202-2733

Dear Mr. Knudson:

Proposed Permit NM0028576

The Department of Energy (DOE) Los Alamos Area Office (LAAO) has reviewed the public notice, "Statement of Basis", and proposed National Pollutant Discharge Elimination System (NPDES) permit (NM0028576) drafted by the U. S. Environmental Protection Agency (EPA) for the discharge from the Fenton Hill Geothermal Site. Although we have no objections regarding the proposed permit, as drafted, it is our understanding that the New Mexico Environmental Improvement Division (EID) and the New Mexico Oil Conservation Division (OCD) may desire additional effluent limitations and monitoring requirements be placed in the permit pursuant to Section 401 State Certification.

In order to meet with the EID and OCD and discuss their concerns prior to their initiation of Section 401 State Certification, I hereby request an extension of time sixty (60) days beyond the current October 27, 1987, deadline. This extension of time to comment on the proposed permit will be adequate to allow all parties ample opportunity to discuss their concerns regarding surface water quality impacts.

Thank you for your consideration of this request. Should you have any questions, please contact Jim Phoenix (667-5288) of my staff.

Sincerely,

Harold E. Valencia
Area Manager

cc:
K. Sisneros, NMEID, Santa Fe, NM
David Boyer, OCD, Santa Fe, NM

ETP:JAP00029

Celebrating the U.S. Constitution Bicentennial — 1787-1987

Mr. Robert Layton Jr., Regional Administrator
Environmental Protection Agency
1445 Ross Avenue
Dallas, TX 75202-2733

October 20, 1987

STATE CERTIFICATION

Re: Department of Energy (Fenton Hill)
Los Alamos Area Office
Los Alamos, New Mexico 87544
NM0028576, September 26, 1987

Dear Mr. Layton:

The New Mexico Environmental Improvement Division has examined the application for and the proposed NPDES permit NM0029157 above. The following conditions are necessary to assure compliance with the applicable provisions of the Clean Water Act Sections 208(e), 301, 302, 303, 306, and 307 and with appropriate requirements of State law. Compliance with the terms and conditions of the permit and this certification will provide reasonable assurance that the permitted activities will be conducted in a manner which will not violate applicable water quality standards.

The State of New Mexico

(x) includes the following more stringent conditions and citation to the State or Federal requirements upon which those conditions are based (see attachments).

(x) certifies that the discharge will comply with the applicable provisions of Sections 208(e), 301, 302, 303, 306 and 307 of the Clean Water Act and with appropriate requirements of State law.

( ) waives its right to certify

( ) denies certification for the reasons stated in the attachment

In order to meet the requirements of State law, including water quality standards and appropriate basin plan, each of the conditions cited in the draft permit and the State certification shall not be made less stringent.

Please contact Mike Saladen if you have any questions concerning this certification. Comments pertaining to this Draft Permit are included on a separate page.

Sincerely,

DRAFT

Kathleen M. Sisneros
Bureau Chief
Surface Water Quality Bureau

Department of Energy
Fenton Hill
NM0028576

Conditions Of State Certification

Listed below are effluent limitations, monitoring requirements and their basis as required for State Certification.

Page 2 of PART I

Section A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

OUTFALL 001

Effluent Characteristic	Discharge Limitations			
	Mass (lbs/day)		Other Units (mg/l)	
	Daily Avg	Daily Max	Daily Avg	Daily Max
Flow (MGD)	N/A	N/A	N/A	N/A
Phenols	1.75	1.75	0.5	0.5
Arsenic	0.18	0.18	0.05	0.05
Cadmium	0.35	0.35	0.01	0.01

Effluent Characteristic	Monitoring Requirements	
	Measurement Frequency	Sample Type
Flow (MGD)	Daily*	Totalized
Phenols	Daily*	Grab
Arsenic	Daily*	Grab
Cadmium	Daily*	Grab

* During discharge.

These water quality based effluent limitations are needed to maintain use for domestic water supply, as required by Section 1-102. F of the "Water Quality Standards for Interstate and Intrastate Streams in New Mexico", WQCC 85-1, dated February 15, 1985. See attached comments regarding the designated uses of the receiving water.

Loading values for Phenols, Arsenic and Cadmium are derived using the flow value of 0.42 MGD. This flow value comes from the maximum daily value for flow in the permittee's permit application.

$0.42 \times 10^6 \frac{g}{day} \times \frac{1 day}{1440 min} = 292 gpm$

DRAFT

Department of Energy
~~Fenton Hill~~
NM002856 002857

Comments That Are Not Conditions Of State Certification

The discharge is incorrectly cited on the Public Notice, Statement of Basis and on page 1, Part I of the permit. The correct discharge is into Lake Fork Canyon, thence the Rio Cebolla and thence the Rio Guadalupe in stream segment 2-106 of the Rio Grande Basin.

The designated uses of stream segment 2-106 are as follows: domestic water supply, fish culture, high quality coldwater fishery, irrigation, livestock and wildlife watering and secondary contact recreation.

The state ground water standard for boron is 0.75 mg/l (Section 3-103.C., NM Water Quality Control Commission (WQCC) Regulations). The current NPDES permit requires monitoring of boron. Review of the permittee's DMR data indicates discharges of boron as high as 122 mg/l (December 1986). The EID hereby requests that EPA retain the monitoring and reporting requirement for boron.

The federal Safe Drinking Water Act standard for fluoride in drinking water is 4.0 mg/l. The state ground water standard for fluoride is 1.6 mg/l (Section 3-103.A., WQCC Regulations). Designated uses of the receiving waters include domestic water supply. The current NPDES permit requires monitoring of fluoride. Review of the permittee's DMR data indicates discharge as high as 8.5 mg/l fluoride (September 1986). The EID hereby requests that EPA retain the monitoring and reporting requirements for fluoride and suggests the EPA consider a limitation for fluoride as appropriate.

The state ground water standard for total dissolved solids or filterable residue (TDS) is 1000 mg/l (Section 3-103.B., WQCC Regulations). On June 24,1987 the Oil Conservation Division (OCD) visited the site and collected a sample for TDS which indicated it to be 5278 ppm. The EID hereby requests the EPA to include monitoring and reporting of TDS in the permit.

David Boyer, Bureau Chief, New Mexico Oil Conservation Division, has written under separate cover, a letter to Mike Saladen, EID Surface Water Section, addressing the fluoride problem. A copy of this letter has been sent to Ellen Caldwell, USEPA (6W-PS). The EID concurs with OCD in their analysis.

DRAFT

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

GARREY CARRUTHERS
GOVERNOR

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87504
(505) 827-5800

October 12, 1987

Mr. Mike Saladen
Environmental Scientist
Surface Water Section
NM Environmental Improvement Division
P.O. Box 968
Santa Fe, NM 87504-0968

RE: Draft NPDES Permit #NM0028576
Fenton Hill Geothermal Site,
Los Alamos National Laboratory

Dear Mr. Saladen:

The Oil Conservation Division (OCD) has received and reviewed your letter of September 29, 1987 which included the above draft EPA NPDES permit for discharges to Lake Fork Canyon. We have also reviewed the permittee's discharge monitoring reports for the previous 12 calendar months ending this past August. There have been 47 discharges during this time period ranging from 24.0 to 295 gallons per minute. The average and maximum value ranges for arsenic, cadmium, and fluoride during the past twelve months are shown below along with the US EPA Federal drinking water limit (all values milligrams per liter):

	AVERAGE	MAXIMUM	USEPA MCL
Arsenic	0.056 to 6.67	0.056 to 7.50	0.05
Cadmuim	0.0001 to 0.41	0.0001 to 2.00	0.01
Fluoride	0.662 to 7.30	0.690 to 8.50	4.00

In addition values of boron discharged were up to 122 mg/l, which greatly exceeded the state ground water standard of 0.75 mg/l. All discharges were within the required pH range of 6 to 9 standard units.

On June 24, 1987 the OCD visited the site to sample effluents in conjunction with modification of their approved geothermal ground water discharge plan. The sampling results are enclosed.

The current NPDES permit requires monitoring of all the above constitutes plus lithum. Only pH is subject to an effluent limitation. The draft permit retains the pH requirement and requires monitoring only flow and phenols. No monitoring or effluent limitations were required for any other constituents. Based on the NPDES monitoring results, OCD sampling, and the corrected characteristics of the receiving waters (including use as a domestic water supply, and high quality coldwater fishery), the OCD requests that in addition to be above, monitoring and effluent limitations be placed on the discharge of Arsenic, Cadmium and Flouride; and that the permit monitoring be required for Boron and Total Dissolved Solids (TDS).

If you have any questions or need further information, please contact me at 827-5812.

Sincerely,

David G. Boyer
Hydrogeologist/Environmental
Bureau Chief

ENC: OCD Sampling Results

cc: Kathleen Sisneros, EID
David Tqgue, EID
Harold Valencia, DOE
Ellen Caldwell, USEPA (GW-PS)

Department of Energy
Albuquerque Operations
Los Alamos Area Office
Los Alamos, New Mexico 87544

MAY 20 1987

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Kenneth Huffman, Ph.D.
Industrial Permits Section (6W-PI)
U.S. Environmental Protection Agency
Region VI
Allied Bank Tower at Fountain Place
1445 Ross Avenue
Dallas, TX 75202-2733

Dear Mr. Huffman:

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES) PERMIT NO. NM0028576

Your letter of April 15, 1987, requested that I review our NPDES permit reapplication, originally submitted to the U.S. Environmental Protection Agency (EPA) on January 10, 1983, to assure that the application represents present conditions at the Fenton Hill Geothermal Facility. Because the original reapplication package is more than 4 years old, I have elected to enclose an updated EPA Form 3510-2C for your use in preparing a permit for reissuance. In addition, I am enclosing the following information that may be useful in developing the permit.

Fenton Hill Site is located about 35 miles west of Los Alamos on the western flank of the Valles Caldera. Research and Development (R&D) studies at the site are based on the concept of extracting heat from dry geothermal reservoirs by developing artificial hydrothermal systems. The site includes two deep holes (each approximately 10,000 ft.) completed in dry Precambrian granitic rock. The holes are connected by a large fracture, which was induced by hydraulic pressurization. Water is circulated under pressure through this system to recover heat from fracture areas. The system is complete and initial tests have been completed.

A second system has now been developed to depth of about 14,000 ft. to test the system at a higher temperature and develop a commercial-sized reservoir. The drilling operations to complete the second system used chemical additives (drilling mud). As the wells are worked over, drilling mud and drilling byproducts are used and produced. Water from the geothermal circulation loop contains moderate concentrations of silica, sodium, sulfates, arsenic, and lithium with moderate to high amounts of flouride. These chemicals can be from drilling mud or dissolved from the geothermal reservoir by the circulating waters encountering rock formations with temperatures at or near 250 degrees Celsius.

Although the Federal Government began funding the Hot Dry Rock (HDR) geothermal energy development project as a possible method of meeting some of the future energy needs of this country, the R&D funding of alternative energy sources such as this has been severely curtailed these past few years. Therefore, future R&D at the Fenton Hill Site is becoming more uncertain as other R&D geothermal sites in the U.S. The NPDES permit requirements that are proposed for the Fenton Hill discharge may not only establish a precedent for geothermal activities nation-wide, but may also pose a severe economic impact on R&D activities that have already suffered severe funding cuts.

In developing the permit for a discharge from the Fenton Hill Site, I believe the R&D nature of the operation should be taken into account. As water is circulated through the rock formations during experiments, many naturally occurring elements are dissolved in the water due to the high temperature and pressure. Because this operation is experimental, many wastewater treatment problems occur that would have been solved if the hot dry rock energy extraction process was already a proven technology and available for commercial use.

In the commercial mode, little if any, discharge would occur on a routine basis. A large volume discharge occurs when the energy extraction process is stopped—a rare occurrence in the commercial mode, but more frequent in the R&D mode. Experiments are carried out which require the closed loop energy extraction process to be stopped so that measurements can be taken, equipment tested or replaced, different or new experiments set up, etc. During the energy extraction process, water is forced into the fissures of the deep subterranean hot rock strata. When the system is shutdown, the subsurface pressure forces water back out of the well, much in the same manner as a person squeezing a wet sponge. The nature of the current reservoir testing at Fenton Hill requires that the experimental systems be started and stopped several times a year. This process causes additional quantities of unsaturated water to be injected which in turn dissolves additional quantities of materials from the hot subsurface rock. The random nature of the discharge greatly complicated the wastewater treatment process.

The Fenton Hill discharge is to a dry arroyo, does not reach a perennial stream, and causes no measurable deterioration of the environment. The enclosed report "Water Quality in the Vicinity of Fenton Hill-1983 and 1984" includes information concerning the quality of the discharge, the ambient quality of surface and ground water, and the results of biomonitoring studies on riparian vegetation and soils. This report further confirms that the discharge causes no measurable deterioration of the environment.

During the time period from January 1983 to December 1986, there have been discharges during 7 of the 48 months. Thus, on a daily basis, a discharge from Fenton Hill occurred on 71 out of 1,460 days. These discharges flowed approximtely 700 feet down the ephemeral channel before they were lost to infiltration and evaporation. The discharge outfall is approximately 3.5

miles upstream from the first perennial water source which is spring water inflow from saturated alluvium and water issuing from the intercepted Bandelier tuff. This natural water which may amount to a natural flow of 1 cubic foot per second (cfs) becomes intermittent as it flows down the channel. Thus the most procimal perennial surface water is located some 7.5 miles downstream from the outfall.

On August 7, 1979, the New Mexico Environmental Improvement Division (EID) requested EPA insert certain language in the NPDES permit, assumably pursuant to Section 401 of the Clean Water Act, which addresses State Certification. That language was inserted in the present NPDES permit, as follows:

> "Quantity of discharge from the outfall point shall be controlled such that no effluent flow, whether alone or co-mingled with natural runoff, travels beyond the point where the Lake Fork Canyon Road crosses the watercourse receiving the effluent; this point is approximately one mile downstream from the outfall."

As previously described above, a perennial source of naturally occurring water proximal to the discharge outfall is located some 3.5 miles downstream. Thus, the restrictive language inserted in the present NPDES permit at the request of EID, is unnecessary and may also have no basis in law for inclusion in the permit. I request that the permit be developed in such a manner that no restriction be included on the distance the discharge may move downstream. Should mixing zones or dilution represent a concern with regard to the effluent discharged, seasonal flow limitations may represent a reasonable compromise viz a viz the present flow limitation.

The New Mexico Oil Conservation Division (OCD) regulates discharges onto or below the surface of the ground at the Fenton Hill Site pursuant to the New Mexico Water Quality Control Commission (NMWQCC) Regulations. A request to modify the Ground Water Discharge Plan (GW-31) for the Fenton Hill Site was recently made to OCD and a copy is enclosed for your information and use in developing the NPDES permit.

In summary, the Fenton Hill Geothermal Site is continuing its R&D experiments albeit under austere funding levels. Because of the R&D nature of the facility, infrequency of discharge, small volume of discharge, insignificant impact on the ephemeral channel and environmental resources, and the added regulatory controls by the OCD via the Ground Water Discharge Plan, I request that in developing a permit for reissuance that EPA adopt the same effluent limitations and monitoring requirements listed on Page 2 of Part I in the existing NPDES permit No. NM0028576.

By copy of this letter to the EID, the provisions of Section 1-201 and 3-106.B of the NMWQCC regulations are met.

Thank you for the opportunity to update the EPA Form 3510-2C and supply the enclosed information for purposes of developing the NPDES permit. Should you or your staff desire a site visit in order to better understand the operations at Fenton Hill, I would be pleased to make the necessary arrangements. Because of his long-standing familiarity with Los Alamos National Laboratory and the Fenton Hill Site, I recommend that Mr. Fred Humpke, EPA, be involved in the development of this permit. Should you have any questions concerning the application or enclosed information, please feel free to contact James Phoenix (FTS 843-5288) of my staff.

Sincerely,

Original signed by
Harold E. Valencia

Harold E. Valencia
Area Manager

6887A

Enclosures:
As stated

cc w/enclosures:
Michael Burkhart, Director, NMEID, Santa Fe, NM
Kathleen Sisneros, NMEID, Santa Fe, NM
David Boyer, NMOCD, Santa Fe, NM

TABLE OF CONTENTS

I. INTRODUCTION

II. CONSOLIDATED PERMIT APPLICATION

III. ATTACHMENT I

INTRODUCTION

This consolidated permit appliation was prepared after a telephone consultation with Mr. Fred Humke, Enforcement Division, Region VI, Dallas, Texas, which resulted in the following interpretations and clarification of the instruction accompanying the applications.

A. EPA ID Number [Item 1 EPA form 3510-1 (6-80)]. This number (NM 0890010515) was assigned to the Los Alamos National Laboratory by EPA in response to the submission of "notification of Waste Activity," dated 13 August 1980.

B. Item V. A.B.C.D. Page 3 of 4 [EPA Form 3510-2C (6-80)]. Constituents listed in Table 2C-3 are not routinely in the Laboratory's discharge.

C. Item V, A and B. Page V-1 through V-9 [EPA form 3510-2C (6-80)]. Mr. Humke authorized reporting only those constituents analyzed as a result of the self monitoring program contained in the current NPDES permit or other monitoring associated with the geothermal operations. The data is summarized in Attachment I to the permit application per discussions with Mr. Humke. Therefore, Parts A and B have not been completed.

Please print or type in the unshaded areas only
(fill–in areas are spaced for elite type, i.e., 12 characters/inch).

Form Approved OMB No. 158-R0175

FORM 1 GENERAL — EPA

U.S. ENVIRONMENTAL PROTECTION AGENCY
GENERAL INFORMATION
Consolidated Permits Program
(Read the "General Instructions" before starting.)

I. EPA I.D. NUMBER

F | T/A C | D

LABEL ITEMS

I. EPA I.D. NUMBER

III. FACILITY NAME

V. FACILITY MAILING ADDRESS

VI. FACILITY LOCATION

DEPARTMENT OF ENERGY
ATTN: MR. WILLIAM CRISMON
LOS ALAMOS AREA OFFICE
LOS ALAMOS, NM 87544

GENERAL INSTRUCTIONS

If a preprinted label has been provided, affix it in the designated space. Review the information carefully; if any of it is incorrect, cross through it and enter the correct data in the appropriate fill–in area below. Also, if any of the preprinted data is absent *(the area to the left of the label space lists the information that should appear)*, please provide it in the proper fill–in area(s) below. If the label is complete and correct, you need not complete Items I, III, V, and VI *(except VI-B which must be completed regardless)*. Complete all items if no label has been provided. Refer to the instructions for detailed item descriptions and for the legal authorizations under which this data is collected.

II. POLLUTANT CHARACTERISTICS

INSTRUCTIONS: Complete A through J to determine whether you need to submit any permit application forms to the EPA. If you answer "yes" to any questions, you must submit this form and the supplemental form listed in the parenthesis following the question. Mark "X" in the box in the third column if the supplemental form is attached. If you answer "no" to each question, you need not submit any of these forms. You may answer "no" if your activity is excluded from permit requirements; see Section C of the instructions. See also, Section D of the instructions for definitions of bold–faced terms.

SPECIFIC QUESTIONS	YES	NO	FORM ATTACHED
A. Is this facility a publicly owned treatment works which results in a discharge to waters of the U.S.? (FORM 2A)	X		NO
B. Does or will this facility *(either existing or proposed)* include a concentrated animal feeding operation or aquatic animal production facility which results in a discharge to waters of the U.S.? (FORM 2B)		X	
C. Is this a facility which currently results in discharges to waters of the U.S. other than those described in A or B above? (FORM 2C)	X		NO
D. Is this a proposed facility *(other than those described in A or B above)* which will result in a discharge to waters of the U.S.? (FORM 2D)		X	
E. Does or will this facility treat, store, or dispose of hazardous wastes? (FORM 3)	X		NO
F. Do you or will you inject at this facility industrial or municipal effluent below the lowermost stratum containing, within one quarter mile of the well bore, underground sources of drinking water? (FORM 4)		X	
G. Do you or will you inject at this facility any produced water or other fluids which are brought to the surface in connection with conventional oil or natural gas production, inject fluids used for enhanced recovery of oil or natural gas, or inject fluids for storage of liquid hydrocarbons? (FORM 4)		X	
H. Do you or will you inject at this facility fluids for special processes such as mining of sulfur by the Frasch process, solution mining of minerals, in situ combustion of fossil fuel, or recovery of geothermal energy? (FORM 4)	X		YES
I. Is this facility a proposed stationary source which is one of the 28 industrial categories listed in the instructions and which will potentially emit 100 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an attainment area? (FORM 5)		X	
J. Is this facility a proposed stationary source which is NOT one of the 28 industrial categories listed in the instructions and which will potentially emit 250 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an attainment area? (FORM 5)		X	

III. NAME OF FACILITY

1 SKIP LOS ALAMOS NATIONAL LABORATORY

IV. FACILITY CONTACT

A. NAME & TITLE (last, first, & title)	B. PHONE (area code & no.)
2 WILLIAM CRISMON	505 667 5288

V. FACILITY MAILING ADDRESS

A. STREET OR P.O. BOX

3 LOS ALAMOS

B. CITY OR TOWN	C. STATE	D. ZIP CODE
4 TA-57 FENTON HILL	NM	87544

VI. FACILITY LOCATION

A. STREET, ROUTE NO. OR OTHER SPECIFIC IDENTIFIER

5 SANDOVAL COUNTY

B. COUNTY NAME

C. CITY OR TOWN	D. STATE	E. ZIP CODE	F. COUNTY CODE (if known)
6	NM		

EPA Form 3510-1 (6-80)

CONTINUE ON REVERSE

CONTINUED FROM THE FRONT

VII. SIC CODES (4-digit, in order of priority)

A. FIRST: 7 9711 (specify) NATIONAL SECURITY	B. SECOND: 7 (specify)
C. THIRD: 7 (specify)	D. FOURTH: 7 (specify)

VIII. OPERATOR INFORMATION

A. NAME: 8 LOS ALAMOS NATIONAL LABORATORY

B. Is the name listed in Item VIII-A also the owner? [X] YES [ ] NO

C. STATUS OF OPERATOR (Enter the appropriate letter into the answer box; if "Other", specify.)
F = FEDERAL; M = PUBLIC (other than federal or state); S = STATE; O = OTHER (specify); P = PRIVATE

F (specify)

D. PHONE (area code & no.): A 505 667 4301

E. STREET OR P.O. BOX: P O BOX 1663 MS E518

F. CITY OR TOWN: 8 LOS ALAMOS

G. STATE: NM

H. ZIP CODE: 87545

IX. INDIAN LAND

Is the facility located on Indian lands? [ ] YES [X] NO

X. EXISTING ENVIRONMENTAL PERMITS

A. NPDES (Discharges to Surface Water): 9 N NM0028355	D. PSD (Air Emissions from Proposed Sources): 9 P
B. UIC (Underground Injection of Fluids): 9 U	E. OTHER (specify): 9 NM0028576 (specify) NPDES FENTON HILL
C. RCRA (Hazardous Wastes): 9 R NM0890010515	E. OTHER (specify): 9 (specify)

XI. MAP

Attach to this application a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the outline of the facility, the location of each of its existing and proposed intake and discharge structures, each of its hazardous waste treatment, storage, or disposal facilities, and each well where it injects fluids underground. Include all springs, rivers and other surface water bodies in the map area. See instructions for precise requirements.

XII. NATURE OF BUSINESS (provide a brief description)

The mission of Los Alamos National Laboratory is the application of science and technology to solve national problems including weapons development and energy supply and conservation programs, while basic science research complements and strengthens its fundamental technical capabilities. The Laboratory is owned by the US Department of Energy and operated under contract by the University of California.

XIII. CERTIFICATION (see instructions)

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe that the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

A. NAME & OFFICIAL TITLE (type or print)	B. SIGNATURE	C. DATE SIGNED
Harold Valencia Area Manager	Original signed by Harold E. Valencia	JAN 6 1983

COMMENTS FOR OFFICIAL USE ONLY

C

Please print or type in the unshaded areas only.

I.D. NUMBER (copy from Item 1 of Form 1)
NM089001515

Form Approved OMB No. 158-R0173

FORM 2C NPDES

EPA

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR PERMIT TO DISCHARGE WASTEWATER
EXISTING MANUFACTURING, COMMERCIAL, MINING AND SILVICULTURAL OPERATIONS
Consolidated Permits Program

I. OUTFALL LOCATION

For each outfall, list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

A. OUTFALL NUMBER (list)	B. LATITUDE 1. DEG.	2. MIN.	3. SEC.	C. LONGITUDE 1. DEG.	2. MIN.	3. SEC.	D. RECEIVING WATER (name)
001	35	52	50	106	50	5	Lake Fork Canyon and thence to the Rio Grande.

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined *(e.g., for certain mining activities)*, provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) The average flow contributed by each operation; and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

1. OUT-FALL NO (list)	2. OPERATION(S) CONTRIBUTING FLOW: a. OPERATION (list)	b. AVERAGE FLOW (include units)	3. TREATMENT: a. DESCRIPTION	b. LIST CODES FROM TABLE 2C-1	
001	Discharge results from excess water from hot dry rock geothermal operation		Settling ponds are used prior to discharge.	1-U	

OFFICIAL USE ONLY (effluent guidelines sub-categories)

CONTINUE ON REVERSE

CONTINUED FROM THE FRONT

C. Except for storm runoff, leaks, or spills, are any of the discharges described in Items II-A or B intermittent or seasonal?

☒ YES *(complete the following table)* ☐ NO *(go to Section III)*

1. OUTFALL NUMBER *(list)*	2. OPERATION(s) CONTRIBUTING FLOW *(list)*	3. FREQUENCY		4. FLOW				
		a. DAYS PER WEEK *(specify average)*	b. MONTHS PER YEAR *(specify average)*	a. FLOW RATE *(in mgd)* 1. LONG TERM AVERAGE	a. FLOW RATE *(in mgd)* 2. MAXIMUM DAILY	b. TOTAL VOLUME *(specify with units)* 1. LONG TERM AVERAGE	b. TOTAL VOLUME *(specify with units)* 2. MAXIMUM DAILY	c. DURATION *(in days)*
001	Overflow from geothermal operations Reported values are for calendar year 1982.	0.27	12.0	0.11	0.14	0.11 mgd	0.14 mgd	14/yr

III. MAXIMUM PRODUCTION

A. Does an effluent guideline limitation promulgated by EPA under Section 304 of the Clean Water Act apply to your facility?

☐ YES *(complete Item III-B)* ☒ NO *(to to Section IV)*

B. Are the limitations in the applicable effluent guideline expressed in terms of production *(or other measure of operation)*?

☐ YES *(complete Item III-C)* ☐ NO *(go to Section IV)*

C. If you answered "Yes" to Item III-B, list the quantity which represents an actual measurement of your maximum level of production, expressed in the terms and units used in the applicable effluent guideline, and indicate the affected outfalls.

1. MAXIMUM QUANTITY			2. AFFECTED OUTFALLS *(list outfall numbers)*
a. QUANTITY PER DAY	b. UNITS OF MEASURE	c. OPERATION, PRODUCT, MATERIAL, ETC. *(specify)*	

IV. IMPROVEMENTS

A. Are you now required by any Federal, State or local authority to meet any implementation schedule for the construction, upgrading or operation of wastewater treatment equipment or practices or any other environmental programs which may affect the discharges described in this application? This includes, but is not limited to, permit conditions, administrative or enforcement orders, enforcement compliance schedule letters, stipulations, court orders, and grant or loan conditions.

☐ YES *(complete the following table)* ☒ NO *(go to Item IV-B)*

1. IDENTIFICATION OF CONDITION, AGREEMENT, ETC.	2. AFFECTED OUTFALLS		3. BRIEF DESCRIPTION OF PROJECT	4. FINAL COMPLIANCE DATE	
	a. NO.	b. SOURCE OF DISCHARGE		a. REQUIRED	b. PROJECTED

B. OPTIONAL: You may attach additional sheets describing any additional water pollution control programs *(or other environmental projects which may affect your discharges)* you now have underway or which you plan. Indicate whether each program is now underway or planned, and indicate your actual or planned schedules for construction. ☐ MARK "X" IF DESCRIPTION OF ADDITIONAL CONTROL PROGRAMS IS ATTACHED

CONTINUED FROM THE FRONT

VII. BIOLOGICAL TOXICITY TESTING DATA

Do you have any knowledge or reason to believe that any biological test for acute or chronic toxicity has been made on any of your discharges or on a receiving water in relation to your discharge within the last 3 years?

☐ YES *(identify the test(s) and describe their purposes below)* ☒ NO *(go to Section VIII)*

VIII. CONTRACT ANALYSIS INFORMATION

Were any of the analyses reported in Item V performed by a contract laboratory or consulting firm?

☐ YES *(list the name, address, and telephone number of, and pollutants analyzed by, each such laboratory or firm below)* ☒ NO *(go to Section IX)*

A. NAME	B. ADDRESS	C. TELEPHONE *(area code & no.)*	D. POLLUTANTS ANALYZED *(list)*

IX. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

A. NAME & OFFICIAL TITLE *(type or print)*	B. PHONE NO. *(area code & no.)*
Harold E. Valencia, Area Manager Los Alamos Area Office, Department of Energy	505-667-5288
C. SIGNATURE	D. DATE SIGNED

CONTINUED FROM PAGE 2

EPA I.D. NUMBER (copy from Item 1 of Form 1)
NM0890001515

Form Approved OMB No. 158-R0173

V. INTAKE AND EFFLUENT CHARACTERISTICS

A, B, & C: See instructions before proceeding — Complete one set of tables for each outfall — Annotate the outfall number in the space provided.
NOTE: Tables V-A, V-B, and V-C are included on separate sheets numbered V-1 through V-9.

D. Use the space below to list any of the pollutants listed in Table 2c-3 of the instructions, which you know or have reason to believe is discharged or may be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it to be present and report any analytical data in your possession.

1. POLLUTANT	2. SOURCE	1. POLLUTANT	2. SOURCE
DO NOT BELIEVE	ANY OF THE POLLUTANTS IN TA	BLE 2c-3 TO BE PRESE	NT.

VI. POTENTIAL DISCHARGES NOT COVERED BY ANALYSIS

A. *Is any pollutant listed in Item V-C a substance or a component of a substance which you do or expect that you will over the next 5 years use or manufacture as an intermediate or final product or byproduct?*

☐ YES *(list all such pollutants below)* ☒ NO *(go to Item VI-B)*

B. Are your operations such that your raw materials, processes, or products can reasonably be expected to vary so that your discharges of pollutants may during the next 5 years exceed two times the maximum values reported in Item V?

☐ YES *(complete Item VI-C below)* ☒ NO *(go to Section VII)*

C. If you answered "Yes" to Item VI-B, explain below and describe in detail the sources and expected levels of such pollutants which you anticipate will be discharged from each outfall over the next 5 years, to the best of your ability at this time. Continue on additional sheets if you need more space.

PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets *(use the same format)* instead of completing these pages.
SEE INSTRUCTIONS.

EPA I.D. NUMBER *(copy from Item 1 of Form 1)*
NM 0890010515

Form Approved OMB No. 158-R0173

V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO. 001

PART A - You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT							3. UNITS *(specify if blank)*		4. INTAKE *(optional)*		
	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE *(if available)*		c. LONG TERM AVRG. VALUE *(if available)*		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Biochemical Oxygen Demand *(BOD)*												
b. Chemical Oxygen Demand *(COD)*			FOR DATA REQUIRED FOR PAGE V-1 THROUGH V-9 PLEASE SEE ATTACHMENT I									
c. Total Organic Carbon *(TOC)*			TO THIS APPLICATION.									
d. Total Suspended Solids *(TSS)*												
e. Ammonia *(as N)*												
f. Flow	VALUE		VALUE		VALUE					VALUE		
g. Temperature *(winter)*	VALUE		VALUE		VALUE			°C		VALUE		
h. Temperature *(summer)*	VALUE		VALUE		VALUE			°C		VALUE		
i. pH	MINIMUM	MAXIMUM	MINIMUM	MAXIMUM				STANDARD UNITS				

PART B - Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2-a for any pollutant, you must provide the results of at least one analysis for that pollutant. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. *(if available)*	2. MARK 'X'		3. EFFLUENT							4. UNITS		5. INTAKE *(optional)*		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE *(if available)*		c. LONG TERM AVRG. VALUE *(if available)*		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Bromide (24959-67-9)														
b. Chlorine, Total Residual														
c. Color														
d. Fecal Coliform														
e. Fluoride (16984-48-8) X														
f. Nitrate—Nitrite *(as N)* X														

ITEM V-B CONTINUED FROM FRONT

1. POLLUTANT AND CAS NO. *(if available)*	2. MARK 'X'		3. EFFLUENT							4. UNITS		5. INTAKE *(optional)*		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE *(if available)*		c. LONG TERM AVRG. VALUE *(if available)*		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic *(as N)*														
h. Oil and Grease														
i. Phosphorus *(as P)*, Total (7723-14-0) X														
j. Radioactivity														
(1) Alpha, Total														
(2) Beta, Total														
(3) Radium, Total														
(4) Radium 226, Total														
k. Sulfate *(as SO_4)* (14808-79-8) X														
l. Sulfide *(as S)*														
m. Sulfite *(as SO_3)* (14265-45-3)														
n. Surfactants														
o. Aluminum, Total (7429-90-5) X														
p. Barium, Total (7440-39-3) X														
q. Boron, Total (7440-42-8) X														
r. Cobalt, Total (7440-48-4)														
s. Iron, Total (7439-89-6) X														
t. Magnesium, Total (7439-95-4) X														
u. Molybdenum, Total (7439-98-7)														
v. Manganese, Total (7439-96-5) X														
w. Tin, Total (7440-31-5)														
x. Titanium, Total (7440-32-6)														

CONTINUE ON PAGE V-3

CONTINUED FROM PAGE 3 OF FORM 2-C

EPA I.D. NUMBER *(copy from Item 1 of Form 1)*	OUTFALL NUMBER
NM0890010515	001

Form Approved OMB No. 158-R0173

PART C : If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a *(secondary industries, non–process wastewater outfalls, and non–required GC/MS fractions)*, mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe to be absent. If you mark either columns 2-a or 2-b for any pollutant, you must provide the results of at least one analysis for that pollutant. Note that there are seven pages to this part; please review each carefully. Complete one table *(all seven pages)* for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER *(if available)*	2. MARK 'X'			3. EFFLUENT							4. UNITS		5. INTAKE *(optional)*		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE *(if available)*		c. LONG TERM AVRG. VALUE *(if available)*		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)															
2M. Arsenic, Total (7440-38-2) X															
3M. Beryllium, Total, 7440-41-7)															
4M. Cadmium, Total (7440-43-9) X															
5M. Chromium, Total (7440-47-3) X															
6M. Copper, Total (7550-50-8)															
7M. Lead, Total (7439-97-6) X															
8M. Mercury, Total (7439-97-6) X															
9M. Nickel, Total (7440-02-0)															
10M. Selenium, Total (7782-49-2) X															
11M. Silver, Total (7440-22-4) X															
12M. Thallium, Total (7440-28-0)															
13M. Zinc, Total (7440-66-6) X															
14M. Cyanide, Total (57-12-5) X															
15M. Phenols, Total X															
DIOXIN															
2,3,7,8-Tetrachlorodibenzo-P-Dioxin (1764-01-6)				DESCRIBE RESULTS											

CONTINUED FROM THE FRONT

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK 'X'			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION — VOLATILE COMPOUNDS															
1V. Acrolein (107-02-8)															
2V. Acrylonitrile (107-13-1)															
3V. Benzene (71-43-2)															
4V. Bis (*Chloromethyl*) Ether (542-88-1)															
5V. Bromoform (75-25-2)															
6V. Carbon Tetrachloride (56-23-5)															
7V. Chlorobenzene (108-90-7)															
8V. Chlorodibromomethane (124-48-1)															
9V. Chloroethane (75-00-3)															
10V. 2-Chloroethylvinyl Ether (110-75-8)															
11V. Chloroform (67-66-3)															
12V. Dichlorobromomethane (75-27-4)															
13V. Dichlorodifluoromethane (75-71-8)															
14V. 1,1-Dichloroethane (75-34-3)															
15V. 1,2-Dichloroethane (107-06-2)															
16V. 1,1-Dichloroethylene (75-35-4)															
17V. 1,2-Dichloropropane (78-87-5)															
18V. 1,2-Dichloropropylene (542-75-6)															
19V. Ethylbenzene (100-41-4)															
20V. Methyl Bromide (74-83-9)															
21V. Methyl Chloride (74-87-3)															

CONTINUE ON PAC

CONTINUED FROM PAGE V-4

EPA I.D. NUMBER *(copy from Item 1 of Form 1)* NM 0890010515 | OUTFALL NUMBER 001

Form Approved OMB No. 158-R0173

1. POLLUTANT AND CAS NUMBER *(if available)*	2. MARK 'X'			3. EFFLUENT							4. UNITS		5. INTAKE *(optional)*		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE *(if available)*		c. LONG TERM AVRG. VALUE *(if available)*		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS *(continued)*															
22V. Methylene Chloride (75-09-2)															
23V. 1,1,2,2-Tetrachloroethane (79-34-5)															
24V. Tetrachloroethylene (127-18-4)															
25V. Toluene (108-88-3)															
26V. 1,2-Trans-Dichloroethylene (156-60-5)															
27V. 1,1,1-Trichloroethane (71-55-6)															
28V. 1,1,2-Trichloroethane (79-00-5)															
29V. Trichloroethylene (79-01-6)															
30V. Trichlorofluoromethane (75-69-4)															
31V. Vinyl Chloride (75-01-4)															
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)															
2A. 2,4-Dichlorophenol (120-83-2)															
3A. 2,4-Dimethylphenol (105-67-9)															
4A. 4,6-Dinitro-O-Cresol (534-52-1)															
5A. 2,4-Dinitrophenol (51-28-5)															
6A. 2-Nitrophenol (88-75-5)															
7A. 4-Nitrophenol (100-02-7)															
8A. P-Chloro-M-Cresol (59-50-7)															
9A. Pentachlorophenol (87-86-5)															
10A. Phenol (108-95-2)															
11A. 2,4,6-Trichlorophenol (88-06-2)															

CONTINUE ON REVERSE

CONTINUED FROM THE FRONT

1. POLLUTANT AND CAS NUMBER (if available)	2. MARK 'X'			3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (if available)		c. LONG TERM AVRG. VALUE (if available)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION — BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)															
2B. Acenaphtylene (208-96-8)															
3B. Anthracene (120-12-7)															
4B. Benzidine (92-87-5)															
5B. Benzo *(a)* Anthracene (56-55-3)															
6B. Benzo *(a)* Pyrene (50-32-8)															
7B. 3,4-Benzofluoranthene (205-99-2)															
8B. Benzo *(ghi)* Perylene (191-24-2)															
9B. Benzo *(k)* Fluoranthene (207-08-9)															
10B. Bis *(2-Chloroethoxy)* Methane (111-91-1)															
11B. Bis *(2-Chloroethyl)* Ether (111-44-4)															
12B. Bis *(2-Chloroisopropyl)* Ether (39638-32-9)															
13B. Bis *(2-Ethylhexyl)* Phthalate (117-81-7)															
14B. 4-Bromophenyl Phenyl Ether (101-55-3)															
15B. Butyl Benzyl Phthalate (85-68-7)															
16B. 2-Chloronaphthalene (91-58-7)															
17B. 4-Chlorophenyl Phenyl Ether (7005-72-3)															
18B. Chrysene (218-01-9)															
19B. Dibenzo *(a,h)* Anthracene (53-70-3)															
20B. 1,2-Dichlorobenzene (95-50-1)															
21B. 1,3-Dichlorobenzene (541-73-1)															

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EPA I.D. NUMBER *(copy from Item 1 of Form 1)*: NM 0890010515

OUTFALL NUMBER: 001

Form Approved OMB No. 158-R0173

1. POLLUTANT AND CAS NUMBER *(if available)*	2. MARK 'X'			3. EFFLUENT							4. UNITS		5. INTAKE *(optional)*		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE *(if available)*		c. LONG TERM AVRG. VALUE *(if available)*		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS *(continued)*															
22B. 1,4-Dichlorobenzene (106-46-7)															
23B. 3,3'-Dichlorobenzidine (91-94-1)															
24B. Diethyl Phthalate (84-66-2)															
25B. Dimethyl Phthalate (131-11-3)															
26B. Di-N-Butyl Phthalate (84-74-2)															
27B. 2,4-Dinitrotoluene (121-14-2)															
28B. 2,6-Dinitrotoluene (606-20-2)															
29B. Di-N-Octyl Phthalate (117-84-0)															
30B. 1,2-Diphenylhydrazine *(as Azobenzene)* (122-66-7)															
31B. Fluoranthene (206-44-0)															
32B. Fluorene (86-73-7)															
33B. Hexachlorobenzene (118-71-1)															
34B. Hexachlorobutadiene (87-68-3)															
35B. Hexachlorocyclopentadiene (77-47-4)															
36B. Hexachloroethane (67-72-1)															
37B. Indeno *(1,2,3-cd)* Pyrene (193-39-5)															
38B. Isophorone (78-59-1)															
39B. Naphthalene (91-20-3)															
40B. Nitrobenzene (98-95-3)															
41B. N-Nitrosodimethylamine (62-75-9)															
42B. N-Nitrosodi-N-Propylamine (621-64-7)															

CONTINUE ON REVERSE

CONTINUED FROM THE FRONT

1. POLLUTANT AND CAS NUMBER (if available)	2. MARK 'X'			3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (if available)		c. LONG TERM AVRG. VALUE (if available)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION — BASE/NEUTRAL COMPOUNDS *(continued)*															
43B. N-Nitrosodiphenylamine (86-30-6)															
44B. Phenanthrene (85-01-8)															
45B. Pyrene (129-00-0)															
46B. 1,2,4 - Trichlorobenzene (120-82-1)															
GC/MS FRACTION — PESTICIDES															
1P. Aldrin (309-00-2)															
2P. α-BHC (319-84-6)															
3P. β-BHC (319-85-7)															
4P. γ-BHC (58-89-9)															
5P. δ-BHC (319-86-8)															
6P. Chlordane (57-74-9)															
7P. 4,4'-DDT (50-29-3)															
8P. 4,4'-DDE (72-55-9)															
9P. 4,4'-DDD (72-54-8)															
10P. Dieldrin (60-57-1)															
11P. α-Endosulfan (115-29-7)															
12P. β-Endosulfan (115-29-7)															
13P. Endosulfan Sulfate (1031-07-8)															
14P. Endrin (72-20-8)															
15P. Endrin Aldehyde (7421-93-4)															
16P. Heptachlor (76-44-8)															

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EPA I.D. NUMBER (copy from Item 1 of Form 1)	OUTFALL NUMBER
NM 0890010515	001

Form Approved OMB No. 158-R0173

1. POLLUTANT AND CAS NUMBER (if available)	2. MARK 'X'			3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (if available)		c. LONG TERM AVRG. VALUE (if available)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION — PESTICIDES (continued)															
17P. Heptachlor Epoxide (1024-57-3)															
18P. PCB-1242 (53469-21-9)															
19P. PCB-1254 (11097-69-1)															
20P. PCB-1221 (11104-28-2)															
21P. PCB-1232 (11141-16-5)															
22P. PCB-1248 (12672-29-6)															
23P. PCB-1260 (11096-82-5)															
24P. PCB-1016 (12674-11-2)															
25P. Toxaphene (8001-35-2)															

ATTACHMENT I

EPA I.D. NUMBER NM0890010515 OUTFALL NUMBER 001

		1979				1980			
	Units	Ave	Min	Max	# Values	Ave	Min	Max	# Values
Flow	gpm	95.28	85.0	100.0	7	47.8	22.0	90.0	17
pH	SU		6.25	8.20	8		6.0	10.3	17
TSS	mg/L	244.0	77.0	950.0	8	27.4	1.0	280.0	17
SiO_2	mg/L	132.9	109.0	208.0	8	191.9	70.0	240.0	17
Na	mg/L	826.0	370.0	1900.0	8	446.6	12.5	770.0	17
K	mg/L	33.7	18.8	89.2	8	34.0	9.3	77.2	17
TDS	mg/L	2630.8	1812.0	4860.0	8	1782.8	230.0	2731.0	17
TS	mg/L	2874.8	1894.0	5096.0	8	1810.2	231.0	3011.0	17
Mg	mg/L	3.04	0.27	10.0	8	12.70	.049	35.80	17
Fe	mg/L	5.84	1.24	26.50	8	5.34	0.028	9.42	17
Cl	mg/L	441.0	110.0	2200.0	8	428.8	14.0	777.0	17
Ca	mg/L	61.54	48.0	97.0	8	47.0	17.3	69.0	17
Al	mg/L	4.27	0.37	16.33	8	0.47	0.02	1.91	17
HCO_3	mg/L	231.1	130.0	460.0	8	401.2	104.0	1140.0	17
P	mg/L	1.95	0.67	3.39	8	0.228	0.011	2.75	17
Li	mg/L	3.65	1.95	10.73	8	6.31	0.013	10.61	17
F	mg/L	5.6	4.7	7.3	8	6.98	0.285	11.30	17
SO_4	mg/L	721.8	707.0	739.0	8	189.0	7.2	580.0	17
CO_3	mg/L	0	0	0	8	0	0	0	17
B	mg/L	12.37	1.75	63.0	8	5.6	0.1	9.5	17
Cd	mg/L	0.0012	0.0004	0.002	8	0.0036	0.0001	0.032	17
As	mg/L	0.018	0.013	0.03	7	0.19	0.00001	3.25	17

EPA I.D. NUMBER NM0890010515 OUTFALL NUMBER 001

		1981				1982			
	Units	Ave	Min	Max	# Values	Ave	Min	Max	# Values
Flow	gpm	24.5	5.0	125.0	59	79.0	25.0	100.0	14
pH	SU		6.0	8.5	60		8.0	8.8	14
TSS	mg/L	61.0	4.0	876.0	60	161.1	45.0	388.0	14
SiO_2	mg/L	188.1	98.0	244.0	60	88.1	58.1	156.0	14
Na	mg/L	872.0	385.0	1425.0	60	696.6	490.0	850.0	14
K	mg/L	63.8	19.0	92.9	60	45.4	15.0	108.0	14
TDS	mg/L	3500.4	1575.0	6298.0	60	3205.2	2275.0	3670.0	14
TS	mg/L	3561.5	1658.0	6450.0	60	3366.4	2486.0	3722.0	14
Mg	mg/L	6.5	2.2	26.8	60	4.5	20	10.0	14
Fe	mg/L	33.9	1.9	75.5	60	5.1	1.3	13.4	14
Cl	mg/L	947.8	55.0	1332.0	60	393.9	90.0	905.0	14
Ca	mg/L	246.0	39.7	2030.0	60	37.1	31.7	44.0	14
Al	mg/L	1.36	0.04	31.7	60	8.4	2.4	25.3	14
HCO_3	mg/L	55.9	256.0	700.0	60	845.7	560.0	1000.0	14
P	mg/L	0.37	0	2.93	60	1.6	0.3	2.4	14
Li	mg/L	11.18	0.12	16.0	60	3.4	0.3	9.3	14
F	mg/L	7.27	1.14	10.0	60	2.3	1.2	4.5	14
SO_4	mg/L	480.2	173.0	2563.0	60	161.3	71.0	211.0	14
CO_3	mg/L	9.3	0	200.0	60	42.9	0	160.0	14
B	mg/L	11.2	2.6	14.6	60	10.3	2.3	25.0	14
Cd	mg/L	0.0009	0.00002	0.013	60	1.7	0.0002	23.3	14
As	mg/L	0.05	0.002	0.23	60	0.88	0.012	2.5	14
NO_3	mg/L	2.32	0.20	4.44	60	0.31	0.08	0.90	14
Cr	mg/L	1.3	1.25	1.35	2	0.26	0.005	0.06	14
Se	mg/L	0.073	0.072	0.074	2	0.003	0.000002	0.011	14
CN	mg/L	0.008	0.008	0.008	2	0.01	0.007	0.016	14
Ag	mg/L	0.01	0.005	0.015	2	0.008	0	0.027	14
Hg	mg/L	0.0001	0.0001	0.0001	2	0.0005	0.0001	0.0017	14
Cu	mg/L	0.344	0.256	0.432	2	0.08	0.02	0.27	14
Pb	mg/L	0.04	0.03	0.05	2	0.04	0.002	0.08	14
Phenols	mg/L	0	0	0	2	81.5	0.24	343.0	14
Ba	mg/L	0.50	0.47	0.53	2	0.91	0.10	2.33	14
U	mg/L	0.01	0.01	0.01	2	0	0	0	14
Mn	mg/L	0.44	0.44	0.44	2	0.29	0.14	0.52	14
Zn	mg/L	0.78	0.53	1.03	2	0.24	0.11	0.45	14
Ra_{226}	pCi/L					0.20 ± 0.20	0.05 ± 0.01	0.75 ± 1.00	6

"corrected copy"

SCIENTIFIC LABORATORY DIVISION

700 Camino de Salud NE
Albuquerque, NM 87106 841-2570

754 nfu

87- 1823 -C

ENVIRONMENT

REPORT TO: David Boyer
N.M. Oil Conservation Division
P. O. Box 2088
Santa Fe, N.M. 87504-2088

S.L.D. No. OR- 1823 A & B
DATE REC. 11-16-87
PRIORITY ______

PHONE(S): 327-5812
USER CODE: 8 2 2 3 5
SUBMITTER: David Boyer
CODE: 2 6 0

SAMPLE COLLECTION CODE: (YYMMDDHHMMIII) 8711091155 A & B

SAMPLE TYPE: WATER [X], SOIL [ ], FOOD [ ], OTHER: ______ CODE: ______

COUNTY: Los Alamos ; CITY: Fenton Hill CODE: ______

LOCATION CODE: (Township-Range-Section-Tracts) ___ + ___ + ___ + ___ (10N06E24342)

ANALYSES REQUESTED: Please check the appropriate box(es) below to indicate the type of analytical screens required. Whenever possible list specific compounds suspected or required.

PURGEABLE SCREENS

- [X] (753) Aliphatic Purgeables (1-3 Carbons)
- [X] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

Remarks: ______

FIELD DATA:

pH= 7 ; Conductivity= ______ umho/cm at ______ °C; Chlorine Residual= ______ mg/l

Dissolved Oxygen= ______ mg/l; Alkalinity= ______ mg/l; Flow Rate ______ ______/______

Depth to water ______ ft.; Depth of well ______ ft.; Perforation Interval ______ - ______ ft.; Casing: ______

Sampling Location, Methods and Remarks (i.e. odors, etc.)
LANL Fenton Hill - From Hypalon Lined Pond, NW Access Hatch

I certify that the results in this block accurately reflect the results of my field analyses, observations and activities.(signature collector): D L Boyer Method of Shipment to the Lab: Car

This form accompanies 2 Septum Vials, 1 Glass Jugs, and/or ______ ______

Samples were preserved as follows:

- [ ] NP: No Preservation; Sample stored at room temperature.
- [X] P-Ice Sample stored in an ice bath (Not Frozen).
- [ ] P-$Na_2S_2O_3$ Sample Preserved with Sodium Thiosulfate to remove chlorine residual.

CHAIN OF CUSTODY

I certify that this sample was transferred from D. Boyer to R Meyerhein at (location) SLD on 11/16/87 - 13 : 12 and that the statements in this block are correct. Evidentiary Seals: Not Sealed [ ] Seals Intact: Yes [X] No [ ]

Signatures ______ R Meyerhein

For OCD Use: Date Owner Notified ______ Phone or Letter? ______ Initials ______

ANALYSES PERFORMED

LAB. No.: OR- 1823

THIS PAGE FOR LABORATORY RESULTS ONLY

This sample was tested using the analytical screening method(s) checked below:

PURGEABLE SCREENS

- [ ] (753) Aliphatic Purgeables (1-3 Carbons)
- [x] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

ANALYTICAL RESULTS

COMPOUND(S) DETECTED	CONC. [PPB]	COMPOUND(S) DETECTED	CONC. [PPB]
aromatic purgeables		halogenated purgeables	
benzene	T.R.	chloroform	41
toluene	1	dichlorobromomethane	9
ethylbenzene	T.R.	dibromochloromethane	13
p-xylene	T.R.	bromoform	13
m-xylene	T.R.	~~tetrachloromethane~~	~~48~~
o-xylene	T.R.	1,1,1-Trichloroethane	18 K.E.
		corrected	
~~halogenated~~			
* DETECTION LIMIT *	1 μg/L	+ DETECTION LIMIT +	1 μg/L

ABBREVIATIONS USED:

N D = NONE DETECTED AT OR ABOVE THE STATED DETECTION LIMIT

T R = DETECTED AT A LEVEL BELOW THE STATED DETECTION LIMIT (NOT CONFIRMED)

[RESULTS IN BRACKETS] ARE UNCONFIRMED AND/OR WITH APPROXIMATE QUANTITATION

LABORATORY REMARKS: 1,1,1-Trichloroethane K.E. ~~tetrachloromethane~~ confirmed by mass spectrometry

CERTIFICATE OF ANALYTICAL PERSONNEL

Seal(s) Intact: Yes [x] No [ ]. Seal(s) broken by: Mary C. Eden date: 11/17/87

I certify that I followed standard laboratory procedures on handling and analysis of this sample unless otherwise noted and that the statements on this page accurately reflect the analytical results for this sample.

Date(s) of analysis: 11/17/87 . Analyst's signature: Mary C. Eden

I certify that I have reviewed and concur with the analytical results for this sample and with the statements in this block.

Reviewers signature: L Meyerhein

corrected copy

SCIENTIFIC LABORATORY DIVISION

700 Camino de Salud NE
Albuquerque, NM 87106 841-2570

754

87-1822-C

REPORT TO: David Boyer
N.M. Oil Conservation Division
P. O. Box 2088
Santa Fe, N.M. 87504-2088

S.L.D. No. OR- 1822 A+B
DATE REC. 11-16-87
PRIORITY ______

PHONE(S): 327-5812
USER CODE: 8 2 2 3 5

SUBMITTER: David Boyer
CODE: 2 6 0

SAMPLE COLLECTION CODE: (YYMMDDHHMMIII) 871109113520B

SAMPLE TYPE: WATER [X], SOIL [ ], FOOD [ ], OTHER: ______ CODE: ______

COUNTY: Los Alamos; CITY: Fenton Hill CODE: ______

LOCATION CODE: (Township-Range-Section-Tracts) ___+___+___+___ (10N06E24342)

ANALYSES REQUESTED: Please check the appropriate box(es) below to indicate the type of analytical screens required. Whenever possible list specific compounds suspected or required.

PURGEABLE SCREENS

- [ ] (753) Aliphatic Purgeables (1-3 Carbons)
- [X] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

Remarks: ______

FIELD DATA:

pH= 6.5; Conductivity= ______ umho/cm at ______ °C; Chlorine Residual= ______ mg/l

Dissolved Oxygen= ______ mg/l; Alkalinity= ______ mg/l; Flow Rate ______ ______/______

Depth to water ______ ft.; Depth of well ______ ft.; Perforation Interval ______-______ ft.; Casing: ______

Sampling Location, Methods and Remarks (i.e. odors, etc.)
LANL Fenton Hill - Hypalon Pond Sump

I certify that the results in this block accurately reflect the results of my field analyses, observations and activities.(signature collector): D. Boyer Method of Shipment to the Lab: Car

This form accompanies 2 Septum Vials, ______ Glass Jugs, and/or ______ ______

Samples were preserved as follows:

- [ ] NP: No Preservation; Sample stored at room temperature.
- [X] P-Ice Sample stored in an ice bath (Not Frozen).
- [ ] P-$Na_2S_2O_3$ Sample Preserved with Sodium Thiosulfate to remove chlorine residual.

CHAIN OF CUSTODY

I certify that this sample was transferred from D Boyer to R Meyerhein

at (location) SLD on 11/16/87 - 13:12 and that

the statements in this block are correct. Evidentiary Seals: Not Sealed [ ] Seals Intact: Yes [X] No [ ]

Signatures ______ R Meyerhein

For OCD Use: Date Owner Notified ______ Phone or Letter? ______ Initials ______

ANALYSES PERFORMED

LAB. No.: OR- 1822

THIS PAGE FOR LABORATORY RESULTS ONLY

This sample was tested using the analytical screening method(s) checked below:

PURGEABLE SCREENS

- [ ] (753) Aliphatic Purgeables (1-3 Carbons)
- [x] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

ANALYTICAL RESULTS

COMPOUND(S) DETECTED	CONC. [PPB]	COMPOUND(S) DETECTED	CONC. [PPB]
aromatic purgeables		halogenated purgeables	
toluene	1	chloroform	13
ethylbenzene	T.R	dichlorobromomethane	10
p-xylene	T.R.	dibromochloromethane	13
m-xylene	T.R.	bromoform	8
o-xylene	T.R.	~~tetrachloromethane~~	~~40~~
benzene	N.D.	1,1,1-Trichloroethane corrected	53 K.E.
* DETECTION LIMIT *	1 ug/L	+ DETECTION LIMIT +	1 ug/L

ABBREVIATIONS USED:

N D = NONE DETECTED AT OR ABOVE THE STATED DETECTION LIMIT
T R = DETECTED AT A LEVEL BELOW THE STATED DETECTION LIMIT (NOT CONFIRMED)
[RESULTS IN BRACKETS] ARE UNCONFIRMED AND/OR WITH APPROXIMATE QUANTITATION

LABORATORY REMARKS: 1,1,1-Trichloroethane K.E. ~~tetrachloromethane~~ confirmed by mass spectrometry.

CERTIFICATE OF ANALYTICAL PERSONNEL

Seal(s) Intact: Yes [x] No [ ]. Seal(s) broken by: Gary C. Eden date: 11/17/87

I certify that I followed standard laboratory procedures on handling and analysis of this sample unless otherwise noted and that the statements on this page accurately reflect the analytical results for this sample.

Date(s) of analysis: 11/17/87. Analyst's signature: Gary C. Eden

I certify that I have reviewed and concur with the analytical results for this sample and with the statements in this block.

Reviewers signature: L Meyerhen

SCIENTIFIC LABORATORY DIVISION

700 Camino de Salud NE
Albuquerque, NM 87106 841-2570

754 wpw

HEALTH ENVIRO... EXICO

87-1822-C

REPORT TO: David Boyer
N.M. Oil Conservation Division
P. O. Box 2088
Santa Fe, N.M. 87504-2088

S.L.D. No. OR- 1822 A+B

DATE REC. 11-16-87

PRIORITY ______

PHONE(S): 827-5812 USER CODE: | 8 | 2 | 2 | 3 | 5 |

SUBMITTER: David Boyer CODE: | 2 | 6 | 0 |

SAMPLE COLLECTION CODE: (YYMMDDHHMMIII) | 8 | 7 | 1 | 1 | 0 | 9 | 1 | 1 | 3 | 5 | 2 A+B |

SAMPLE TYPE: WATER [X], SOIL [ ], FOOD [ ], OTHER: ______ CODE: |__|__|__|

COUNTY: Los Alamos ; CITY: Fenton Hill CODE: |__|__|__|__|__|

LOCATION CODE: (Township-Range-Section-Tracts) |__|__|__+__|__|__+__|__+__|__|__|(10N06E24342)

ANALYSES REQUESTED: Please check the appropriate box(es) below to indicate the type of analytical screens required. Whenever possible list specific compounds suspected or required.

PURGEABLE SCREENS

- [ ] (753) Aliphatic Purgeables (1-3 Carbons)
- [X] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

Remarks: ______

FIELD DATA:

pH= 6.5 ; Conductivity= ______ umho/cm at ______ °C; Chlorine Residual= ______ mg/l

Dissolved Oxygen= ______ mg/l; Alkalinity= ______ mg/l; Flow Rate ______ ______/______

Depth to water ______ ft.; Depth of well ______ ft.; Perforation Interval ______-______ ft.; Casing: ______

Sampling Location, Methods and Remarks (i.e. odors, etc.)

LANL Fenton Hill - Hypalon Pond Sump.

I certify that the results in this block accurately reflect the results of my field analyses, observations and activities.(signature collector): D W Boyer Method of Shipment to the Lab: Car

This form accompanies 2 Septum Vials, ______ Glass Jugs, and/or ______ ______

Samples were preserved as follows:

- [ ] NP: No Preservation; Sample stored at room temperature.
- [X] P-Ice Sample stored in an ice bath (Not Frozen).
- [ ] P-$Na_2S_2O_3$ Sample Preserved with Sodium Thiosulfate to remove chlorine residual.

CHAIN OF CUSTODY

I certify that this sample was transferred from D Boyer to R Meyerhein

at (location) SLD on 11/16/87 - 13 : 12 and that

the statements in this block are correct. Evidentiary Seals: Not Sealed [ ] Seals Intact: Yes [X] No [ ]

Signatures ______ R Meyerhein

For OCD Use: Date Owner Notified ______ Phone or Letter? ______ Initials ______

ANALYSES PERFO[redacted]ED

LAB. [redacted]: OR- 1822

THIS PAGE FOR LABORATORY RESULTS ONLY

This sample was tested using the analytical screening method(s) checked below:

PURGEABLE SCREENS

- ☐ (753) Aliphatic Purgeables (1-3 Carbons)
- ☒ (754) Aromatic & Halogenated Purgeables
- ☐ (765) Mass Spectrometer Purgeables
- ☐ (766) Trihalomethanes

Other Specific Compounds or Classes

- ☐ ______
- ☐ ______
- ☐ ______
- ☐ ______
- ☐ ______

EXTRACTABLE SCREENS

- ☐ (751) Aliphatic Hydrocarbons
- ☐ (760) Organochlorine Pesticides
- ☐ (755) Base/Neutral Extractables
- ☐ (758) Herbicides, Chlorophenoxy acid
- ☐ (759) Herbicides, Triazines
- ☐ (760) Organochlorine Pesticides
- ☐ (761) Organophosphate Pesticides
- ☐ (767) Polychlorinated Biphenyls (PCB's)
- ☐ (764) Polynuclear Aromatic Hydrocarbons
- ☐ (762) SDWA Pesticides & Herbicides

ANALYTICAL RESULTS

COMPOUND(S) DETECTED	CONC. [PPB]	COMPOUND(S) DETECTED	CONC. [PPB]
aromatic purgeables		halogenated purgeables	
toluene	1	chloroform	13
ethylbenzene	T.R.	dichlorobromomethane	10
p-xylene	T.R.	dibromochloromethane	13
m-xylene	T.R.	bromoform	8
o-xylene	T.R.	tetrachloromethane	40
benzene	N.D.		
* DETECTION LIMIT * *	1 µg/L	+ DETECTION LIMIT + +	1 µg/L

ABBREVIATIONS USED:

N D = NONE DETECTED AT OR ABOVE THE STATED DETECTION LIMIT

T R = DETECTED AT A LEVEL BELOW THE STATED DETECTION LIMIT (NOT CONFIRMED)

[RESULTS IN BRACKETS] ARE UNCONFIRMED AND/OR WITH APPROXIMATE QUANTITATION

LABORATORY REMARKS: tetrachloromethane confirmed by mass spectrometry.

CERTIFICATE OF ANALYTICAL PERSONNEL

Seal(s) Intact: Yes ☑ No ☐. Seal(s) broken by: Mary C. Eden date: 11/17/87

I certify that I followed standard laboratory procedures on handling and analysis of this sample unless otherwise noted and that the statements on this page accurately reflect the analytical results for this sample.

Date(s) of analysis: 11/17/87. Analyst's signature: Mary C. Eden

I certify that I have reviewed and concur with the analytical results for this sample and with the statements in this block.

Reviewers signature: K Meyerhein

87- 1823 -C

SCIENTIFIC LABORATORY DIVISION

700 Camino de Salud NE
Albuquerque, NM 87106 841-2570

HEALTH ENVIRONMENT ... EXICO

754 wpw

REPORT TO: David Boyer
N.M. Oil Conservation Division
P. O. Box 2088
Santa Fe, N.M. 87504-2088

S.L.D. No. OR- 1823 A+B
DATE REC. 11-16-87
PRIORITY ______

PHONE(S): 827-5812 USER CODE: 8 2 2 3 5
SUBMITTER: David Boyer CODE: 2 6 0
SAMPLE COLLECTION CODE: (YYMMDDHHMMIII) 871109111155 A+B
SAMPLE TYPE: WATER [X], SOIL [ ], FOOD [ ], OTHER: ______ CODE: ______
COUNTY: Los Alamos; CITY: Fenton Hill CODE: ______
LOCATION CODE: (Township-Range-Section-Tracts) ___ + ___ + ___ + ___ (10N06E24342)

ANALYSES REQUESTED: Please check the appropriate box(es) below to indicate the type of analytical screens required. Whenever possible list specific compounds suspected or required.

PURGEABLE SCREENS

- [X] (753) Aliphatic Purgeables (1-3 Carbons)
- [X] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

Remarks: ______

FIELD DATA:

pH= 7; Conductivity= ______ umho/cm at ______ °C; Chlorine Residual= ______ mg/l

Dissolved Oxygen= ______ mg/l; Alkalinity= ______ mg/l; Flow Rate ______ ___/___

Depth to water ______ ft.; Depth of well ______ ft.; Perforation Interval ___-___ ft.; Casing: ______

Sampling Location, Methods and Remarks (i.e. odors, etc.)
LANL Fenton Hill - From Hypalon Lined Pond, NW Access Hatch

I certify that the results in this block accurately reflect the results of my field analyses, observations and activities.(signature collector): D.G. Boyer Method of Shipment to the Lab: Car

This form accompanies 2 Septum Vials, / Glass Jugs, and/or ______ ______

Samples were preserved as follows:

- [ ] NP: No Preservation; Sample stored at room temperature.
- [X] P-Ice Sample stored in an ice bath (Not Frozen).
- [ ] P-$Na_2S_2O_3$ Sample Preserved with Sodium Thiosulfate to remove chlorine residual.

CHAIN OF CUSTODY

I certify that this sample was transferred from D. Boyer to R Meyerhein at (location) SLD on 11/16/87 - 13:12 and that the statements in this block are correct. Evidentiary Seals: Not Sealed [ ] Seals Intact: Yes [X] No [ ]

Signatures ______ R Meyerhein

For OCD Use: Date Owner Notified ______ Phone or Letter? ______ Initials ______

ANALYSES PERFORMED

LAB. No.: OR- 1823

THIS PAGE FOR LABORATORY RESULTS ONLY

This sample was tested using the analytical screening method(s) checked below:

PURGEABLE SCREENS

- [ ] (753) Aliphatic Purgeables (1-3 Carbons)
- [X] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

ANALYTICAL RESULTS

COMPOUND(S) DETECTED	CONC. [PPB]	COMPOUND(S) DETECTED	CONC. [PPB]
aromatic purgeables		halogenated purgeables	
benzene	T.R.	chloroform	11
toluene	1	dichlorobromomethane	9
ethylbenzene	T.R.	dibromochloromethane	13
p-xylene	T.R.	bromoform	13
m-xylene	T.R.	tetrachloromethane	48
o-xylene	T.R.		
~~halogenates~~			
* DETECTION LIMIT *	1 µg/L	+ DETECTION LIMIT +	1 µg/L

ABBREVIATIONS USED:

N D = NONE DETECTED AT OR ABOVE THE STATED DETECTION LIMIT
T R = DETECTED AT A LEVEL BELOW THE STATED DETECTION LIMIT (NOT CONFIRMED)
[RESULTS IN BRACKETS] ARE UNCONFIRMED AND/OR WITH APPROXIMATE QUANTITATION

LABORATORY REMARKS: tetrachloromethane confirmed by mass spectrometry

CERTIFICATE OF ANALYTICAL PERSONNEL

Seal(s) Intact: Yes [X] No [ ]. Seal(s) broken by: Gary C. Eden date: 11/17/87

I certify that I followed standard laboratory procedures on handling and analysis of this sample unless otherwise noted and that the statements on this page accurately reflect the analytical results for this sample.

Date(s) of analysis: 11/17/87. Analyst's signature: Gary C. Eden

I certify that I have reviewed and concur with the analytical results for this sample and with the statements in this block.

Reviewers signature: R Meyerhein

700 Camino de Salud NE
[illegible]uquerque, NM 87106 841-2570

754 wpw

ENV 87- 1194 -C

REPORT TO: David Boyer
N.M. Oil Conservation Division
P. O. Box 2088
Santa Fe, N.M. 87504-2088

S.L.D. No. OR- 1194 A+B
DATE REC. 6-26-87
PRIORITY 3

PHONE(S): 327-5812 USER CODE: | 8 | 2 | 2 | 3 | 5 |

SUBMITTER: David Boyer CODE: | 2 | 6 | 0 |

SAMPLE COLLECTION CODE: (YYMMDDHHMMIII) | 8 | 7 | 0 | 6 | 2 | 4 | 1 | 2 | 2 | 0 | W | C | 0 |

SAMPLE TYPE: WATER ☒, SOIL ☐, FOOD ☐, OTHER: ________ CODE: |__|__|__|

COUNTY: Sandoval ; CITY: La Cueva CODE: |__|__|__|__|

LOCATION CODE: (Township-Range-Section-Tracts) | 1 | 9 | N + 0 | 2 | E + 1 | 3 + 2 | 2 | 2 | (10N06E24342)

ANALYSES REQUESTED: Please check the appropriate box(es) below to indicate the type of analytical screens required. Whenever possible list specific compounds suspected or required.

PURGEABLE SCREENS

- ☐ (753) Aliphatic Purgeables (1-3 Carbons)
- ☒ (754) Aromatic & Halogenated Purgeables
- ☐ (765) Mass Spectrometer Purgeables
- ☐ (766) Trihalomethanes

Other Specific Compounds or Classes

- ☐ ________
- ☐ ________
- ☐ ________
- ☐ ________
- ☐ ________

EXTRACTABLE SCREENS

- ☐ (751) Aliphatic Hydrocarbons
- ☐ (760) Organochlorine Pesticides
- ☐ (755) Base/Neutral Extractables
- ☐ (758) Herbicides, Chlorophenoxy acid
- ☐ (759) Herbicides, Triazines
- ☐ (760) Organochlorine Pesticides
- ☐ (761) Organophosphate Pesticides
- ☐ (767) Polychlorinated Biphenyls (PCB's)
- ☐ (764) Polynuclear Aromatic Hydrocarbons
- ☐ (762) SDWA Pesticides & Herbicides

Remarks: ________

FIELD DATA:

pH= 8.5 ; Conductivity= 8000 umho/cm at 24.5 °C; Chlorine Residual= ____ mg/l

Dissolved Oxygen= ____ mg/l; Alkalinity= ____ mg/l; Flow Rate ____ ____/____

Depth to water ____ ft.; Depth of well ____ ft.; Perforation Interval ____-____ ft.; Casing: ________

Sampling Location, Methods and Remarks (i.e. odors, etc.)
Fenton Hill - EE1 Service Pond - rim of yellow pine pollen around pond

I certify that the results in this block accurately reflect the results of my field analyses, observations and activities.(signature collector): Willis Olsen Method of Shipment to the Lab: hand

This form accompanies 2 Septum Vials, ____ Glass Jugs, and/or ____ ________

Samples were preserved as follows:

- ☐ NP: No Preservation; Sample stored at room temperature.
- ☒ P-Ice Sample stored in an ice bath (Not Frozen).
- ☐ P-$Na_2S_2O_3$ Sample Preserved with Sodium Thiosulfate to remove chlorine residual.

CHAIN OF CUSTODY

I certify that this sample was transferred from ________ to ________

at (location) ________ on ___/___/___ - ___:___ and that

the statements in this block are correct. Evidentiary Seals: Not Sealed ☐ Seals Intact: Yes ☐ No ☐

Signatures ________ ________

For OCD Use: Date Owner Notified ________ Phone or Letter? ________ Initials ________

ANALYSES PERFORMED

LAB. No.: OR- 1194

THIS PAGE FOR LABORATORY RESULTS ONLY

This sample was tested using the analytical screening method(s) checked below:

PURGEABLE SCREENS

- [ ] (753) Aliphatic Purgeables (1-3 Carbons)
- [x] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

ANALYTICAL RESULTS

COMPOUND(S) DETECTED	CONC. [PPB]	COMPOUND(S) DETECTED	CONC. [PPB]
aromatic purgeables	N.D.		
halogenated purgeables	N.D.		
* DETECTION LIMIT * *	1 µg/L	+ DETECTION LIMIT + +	

ABBREVIATIONS USED:

N D = NONE DETECTED AT OR ABOVE THE STATED DETECTION LIMIT
T R = DETECTED AT A LEVEL BELOW THE STATED DETECTION LIMIT (NOT CONFIRMED)
[RESULTS IN BRACKETS] ARE UNCONFIRMED AND/OR WITH APPROXIMATE QUANTITATION

LABORATORY REMARKS: ______

CERTIFICATE OF ANALYTICAL PERSONNEL

Seal(s) Intact: Yes [ ] No [x] Seal(s) broken by: not sealed date: ______

I certify that I followed standard laboratory procedures on handling and analysis of this sample unless otherwise noted and that the statements on this page accurately reflect the analytical results for this sample.

Date(s) of analysis: 7/16/87 Analyst's signature: Mary C. Eden

I certify that I have reviewed and concur with the analytical results for this sample and with the statements in this block.

Reviewers signature: K Meyerhein

700 Camino de Salud NE
uquerque, NM 87106 841-2570

754 wpn

ENVIRON

87- 1193 -C

REPORT TO: David Boyer
N.M. Oil Conservation Division
P. O. Box 2088
Santa Fe, N.M. 87504-2088

S.L.D. No. OR- 1193 A4B
DATE REC. 6-26-87
PRIORITY ______

PHONE(S): 327-5812 USER CODE: | 3 | 2 | 2 | 3 | 5 |

SUBMITTER: David Boyer CODE: | 2 | 6 | 0 |

SAMPLE COLLECTION CODE: (YYMMDDHHMMIII) | 8 | 7 | 0 | 6 | 2 | 4 | 1 | 2 | 3 | 5 | W | C | O |

SAMPLE TYPE: WATER [X], SOIL [ ], FOOD [ ], OTHER: ______ CODE: | | | |

COUNTY: Sandoval ; CITY: La Cueva CODE: | | | | | |

LOCATION CODE: (Township-Range-Section-Tracts) | 1 | 9 | N + 0 | 2 | E + 1 | 3 + 2 | 2 | 2 | (10N06E24342)

ANALYSES REQUESTED: Please check the appropriate box(es) below to indicate the type of analytical screens required. Whenever possible list specific compounds suspected or required.

PURGEABLE SCREENS

- [ ] (753) Aliphatic Purgeables (1-3 Carbons)
- [X] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

Remarks: ______

FIELD DATA:

pH= ____; Conductivity= ____ umho/cm at ____ °C; Chlorine Residual= ____ mg/l

Dissolved Oxygen= ____ mg/l; Alkalinity= ____ mg/l; Flow Rate ____ ____/____

Depth to water ____ ft.; Depth of well ____ ft.; Perforation Interval ____-____ ft.; Casing: ______

Sampling Location, Methods and Remarks (i.e. odors, etc.)

Fenton Hill - Leak Drain Sump
Sampled reddish area in sump

I certify that the results in this block accurately reflect the results of my field analyses, observations and activities.(signature collector): W Olson Method of Shipment to the Lab: hand

This form accompanies 2 Septum Vials, ____ Glass Jugs, and/or ____ ______

Samples were preserved as follows:

- [ ] NP: No Preservation; Sample stored at room temperature.
- [X] P-Ice Sample stored in an ice bath (Not Frozen).
- [ ] P-$Na_2S_2O_3$ Sample Preserved with Sodium Thiosulfate to remove chlorine residual.

CHAIN OF CUSTODY

I certify that this sample was transferred from ______ to ______

at (location) ______ on ___/___/___ - ___:___ and that

the statements in this block are correct. Evidentiary Seals: Not Sealed [ ] Seals Intact: Yes [ ] No [ ]

Signatures ______ ______

For OCD Use: Date Owner Notified ______ Phone or Letter? ______ Initials ______

ANALYSES PERFORMED

LAB. No.: OR- 1193

THIS PAGE FOR LABORATORY RESULTS ONLY

This sample was tested using the analytical screening method(s) checked below:

PURGEABLE SCREENS

- [ ] (753) Aliphatic Purgeables (1-3 Carbons)
- [x] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______
- [ ] ______

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

ANALYTICAL RESULTS

COMPOUND(S) DETECTED	CONC. [PPB]	COMPOUND(S) DETECTED	CONC. [PPB]
aromatic purgeables			
toluene	~~2~~ TR		
halogenated purgeables			
chloroform	T.R.		
1,1,1-Trichloroethane	23		
	–		
* DETECTION LIMIT *	10 ug/l	+ DETECTION LIMIT +	

ABBREVIATIONS USED:

N D = NONE DETECTED AT OR ABOVE THE STATED DETECTION LIMIT
T R = DETECTED AT A LEVEL BELOW THE STATED DETECTION LIMIT (NOT CONFIRMED)
[RESULTS IN BRACKETS] ARE UNCONFIRMED AND/OR WITH APPROXIMATE QUANTITATION

LABORATORY REMARKS: 1,1,1, Trichloroethane confirmed by mass spec.

CERTIFICATE OF ANALYTICAL PERSONNEL

Seal(s) Intact: Yes [ ] No [✓] Seal(s) broken by: not sealed date: ______

I certify that I followed standard laboratory procedures on handling and analysis of this sample unless otherwise noted and that the statements on this page accurately reflect the analytical results for this sample.

Date(s) of analysis: 7/16/87 Analyst's signature: Mary C. Eden

I certify that I have reviewed and concur with the analytical results for this sample and with the statements in this block.

Reviewers signature: R Meyerhein

New Mexico Health and Environment Department
SCIENTIFIC LABORATORY DIVISION
700 Camino de Salud NE
Albuquerque, NM 87106

HEAVY METAL ANALYSIS FORM

Telephone: (505)841-2553

Date Received	Lab No.	User Code	
6/26/87	ICP-396	☒ 82235	☐ Other:

COLLECTION DATE & TIME: yy 87 mm 06 dd 24 hh 12 mm 20

COLLECTED BY: Olson, Anderson, Bailey

COLLECTION SITE DESCRIPTION sample taken from SE corner of pit

TO:

ENVIRONMENTAL BUREAU
NM OIL CONSERVATION DIVISION
State Land Office Bldg., PO Box 2088
SANTA FE, NM 87504-2088

ATTN: David Boyer
TELEPHONE: 827-5812

OWNER: Dept. of Energy

SITE LOCATION:
County: Sandoval

Township, Range, Section, Tract: (10N06E24342)
19N+02E+13+222

STATION/ WELL CODE: EE SERVICE Pond

LATITUDE, LONGITUDE:

SAMPLING CONDITIONS:

☐ Bailed ☒ Dipped	☐ Pump ☐ Tap	Water Level:	Discharge:	Sample Type: grab

pH(00400)	Conductivity(Uncorr.)	Water Temp.(00010)	Conductivity at 25°C (00094)
8.5	8000 µmho	24.5 °C	µmho

FIELD COMMENTS:

SAMPLE FIELD TREATMENT sample only pre-filtered
Check proper boxes:

☐ WPN: Water Preserved w/HNO_3 Non-Filtered

☒ WPF: Water Preserved w/HNO_3 Filtered

LAB ANALYSIS REQUESTED:

☒ ICAP Scan
Mark box next to metal if AA is required.

ANALYTICAL RESULTS (MG/L)

ELEMENT	ICAP VALUE	AA VALUE	ELEMENT	ICAP VALUE	AA VALUE
Aluminum	<0.1		Silicon	31.	
Barium	0.4		Silver	<0.1	☐
Beryllium	<0.1		Strontium	1.6	
Boron	71.		Tin	<0.1	
Cadmium	<0.1	☐	Vanadium	<0.1	
Calcium	54.		Zinc	<0.1	
Chromium	<0.1	☐	Arsenic		JHA ☒ 3.4
Cobalt	<0.05		Selenium		JHA ☒ 0.007
Copper	<0.1		Mercury		☐
Iron	3.8				☐
Lead	<0.1	☐			☐
Magnesium	6.2				☐
Manganese	0.31				☐
Molybdenum	<0.1				☐
Nickel	<0.1				☐

LAB COMMENTS: DIGESTED.
Subsequent Request (7/31/87) for As & Se by Dave Boyer. JHA

For OCD Use:
Date Owner Notified:
Phone or Letter?
Initials:

ICAP Analyst JB
Date Analyzed 7/13/87

Reviewer JHA Jim Ashley
Date Reveived 7/23/87 9/25/87

859
WMN

New Mexico Health and Environment Department
SCIENTIFIC LABORATORY DIVISION
700 Camino de Salud NE
Albuquerque, NM 87106 — (505) 841-2555

GENERAL WATER CHEMISTRY and NITROGEN ANALYSIS

DATE RECEIVED 6 26 87 | LAB NO. WC-2678 | USER CODE ☐ 59300 ☐ 59600 ☒ OTHER: 82235

Collection DATE 6 24 87
Collection TIME 1220
Collected by — Person/Agency Olson, Anderson, Bailey /OCD

SITE INFORMATION ►
Sample location 19N 02E Sec 13
Collection site description sample taken from SE corner of service pond

SEND FINAL REPORT TO ►
ENVIRONMENTAL BUREAU
NM OIL CONSERVATION DIVISION
State Land Office Bldg, PO Box 2088
Santa Fe, NM 87504-2088
Attn: David Boyer
Phone: 827-5812

Station/well code Fenton Hill - EE1 Service Pond
Owner Dept. of Energy

SAMPLING CONDITIONS

☐ Bailed ☐ Pump ☒ Dipped ☐ Tap	Water level	Discharge	Sample type grab
pH (00400) 8.5	Conductivity (Uncorrected) 8000 µmho	Water Temp. (00010) 24.5 °C	Conductivity at 25 °C (00094) µmho

Field comments: sample only prefiltered

SAMPLE FIELD TREATMENT — *Check proper boxes*

No. of samples submitted 1
☐ NF: Whole sample (Non-filtered)
☒ F: Filtered in field with 0.45 µmembrane filter
☐ A: 2 ml H_2SO_4/L added
☒ NA: No acid added
☐ Other-*specify:*
☐ A: 5ml conc. HNO_3 added
☐ A: 4ml fuming HNO_3 added

ANALYTICAL RESULTS from SAMPLES

NA		Units	Date analyzed
☒ Conductivity (Corrected) 25 °C (00095)	8755	µmho	7/9
☐ Total non-filterable residue (suspended) (00530)		mg/l	
☒ Other:	pH = 8.57		7/1
☐ Other:			
☐ Other:			

A-H_2SO_4		Units	Date analyzed
☐ Nitrate-N +, Nitrate-N total (00630)		mg/l	
☐ Ammonia-N total (00610)		mg/l	
☐ Total Kjeldahl-N ( )		mg/l	
☐ Chemical oxygen demand (00340)		mg/l	
☐ Total organic carbon ( )		mg/l	
☐ Other:			
☐ Other:			

From PF, NA Sample: prefiltered

			Date Analyzed
☒ Calcium	62	mg/l	7/17
☒ Potassium	204	mg/l	8/3
☒ Magnesium	6	mg/l	7/17
☒ Sodium	1743	mg/l	8/3
☒ Bicarbonate	445	mg/l	7/1
☒ Chloride	2230	mg/l	8/4
☒ Sulfate	97.6	mg/l	7/14
☒ Total Solids	5278	mg/l	7/16
☐			
☐			
☒ Cation/Anion Balance			

Analyst	Date Reported	Reviewed by
	8 10 87	CS

Laboratory remarks: CO_3^{-2} = 55.4 ppm

FOR OCD USE -- Date Owner Notified________ Phone or Letter?________ Initals________

CATIONS				ANIONS			
ANALYTE	MEQ.	PPM	DET. LIMIT	ANALYTE	MEQ.	PPM	DET. LIMIT
Ca	3.09	62.00	<3.0	HC03	7.29	445.00	<1.0
Mg	0.49	6.00	<0.3	SO4	2.03	97.60	<10.0
Na	75.82	1743.00	<10.0	CL	62.91	2230.00	<5.0
K	5.22	204.00	<0.3				
Mn	0.00	0.00		NO3	0.00	0.00	< 0.
Fe	0.00	0.00		C03	0.92	55.40	< 1.
				NH3	0.00	0.00	< 0.
				PO4	0.00	0.00	< 0.
SUMS	84.62	2015.00			73.15	2828.00	

Total Dissolved Solids= 5278
Ion Balance = 115.67%

WC No. = 8702678
Date out/By ____ 8/10 ____

SCIENTIFIC LABORATORY DIVISION

700 Camino de Salud NE

[redacted]querque, NM 87106 841-2570 [redacted] 55 ex

ENVIRO

87-1195-B

REPORT TO: David Boyer

N.M. Oil Conservation Division

P. O. Box 2088

Santa Fe, N.M. 87504-2088

S.L.D. No. OR- 1195 A

DATE REC. 6-26-87

PRIORITY

RECEIVED SEP - 9 1987 OIL CONSERVATION DIVISION SANTA FE

PHONE(S): 327-5812

USER CODE: | 8 | 2 | 2 | 3 | 5 |

SUBMITTER: David Boyer

CODE: | 2 | 6 | 0 |

SAMPLE COLLECTION CODE: (YYMMDDHHMMIII) | 8 | 7 | 0 | 6 | 2 | 4 | 1 | 1 | 2 | 2 | 0 | W | C | O |

SAMPLE TYPE: WATER [X], SOIL [ ], FOOD [ ], OTHER: ________ CODE: |__|__|__|

COUNTY: Sandoval ; CITY: La Cueva CODE: |__|__|__|__|

LOCATION CODE: (Township-Range-Section-Tracts) | 1 | 9 | N + 0 | 2 | E + | 1 | 3 + 2 | 2 | 2 | (10N06E24342)

ANALYSES REQUESTED: Please check the appropriate box(es) below to indicate the type of analytical screens required. Whenever possible list specific compounds suspected or required.

PURGEABLE SCREENS

- [ ] (753) Aliphatic Purgeables (1-3 Carbons)
- [ ] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [ ] ~~[illegible]~~
- [X] meta - nitrophenol
- [X] para - nitrophenol } Extractables = ?
- [X] ortho - nitrophenol
- [ ] ________

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

Remarks: ________

FIELD DATA:

pH= 8.5 ; Conductivity= 8000 umho/cm at 24.5 °C; Chlorine Residual= ____ mg/l

Dissolved Oxygen= ____ mg/l; Alkalinity= ____ mg/l; Flow Rate ____ ____/____

Depth to water ____ ft.; Depth of well ____ ft.; Perforation Interval ____ - ____ ft.; Casing: ____

Sampling Location, Methods and Remarks (i.e. odors, etc.)

Fenton Hill - EE-1 Service Pond - rim of yellow pine pollen around pond

I certify that the results in this block accurately reflect the results of my field analyses, observations and activities.(signature collector): William Olson Method of Shipment to the Lab: hand

This form accompanies 0 Septum Vials, 1 Glass Jugs, and/or ____

Samples were preserved as follows:

- [ ] NP: No Preservation; Sample stored at room temperature.
- [X] P-Ice Sample stored in an ice bath (Not Frozen).
- [ ] P-$Na_2S_2O_3$ Sample Preserved with Sodium Thiosulfate to remove chlorine residual.

CHAIN OF CUSTODY

I certify that this sample was transferred from ________ to ________

at (location) ________ on ___/___/___ - ___:___ and that the statements in this block are correct. Evidentiary Seals: Not Sealed [ ] Seals Intact: Yes [ ] No [ ]

Signatures ________ ________

For OCD Use: Date Owner Notified ________ Phone or Letter? ________ Initials ________

ANALYSES PERFORMED

LAB No.: OR- 1195

THIS PAGE FOR LABORATORY RESULTS ONLY

This sample was tested using the analytical screening method(s) checked below:

PURGEABLE SCREENS

- [ ] (753) Aliphatic Purgeables (1-3 Carbons)
- [ ] (754) Aromatic & Halogenated Purgeables
- [ ] (765) Mass Spectrometer Purgeables
- [ ] (766) Trihalomethanes

Other Specific Compounds or Classes

- [x] acid EXTRACTABLES
- [ ]
- [ ]
- [ ]
- [ ]

EXTRACTABLE SCREENS

- [ ] (751) Aliphatic Hydrocarbons
- [ ] (760) Organochlorine Pesticides
- [ ] (755) Base/Neutral Extractables
- [ ] (758) Herbicides, Chlorophenoxy acid
- [ ] (759) Herbicides, Triazines
- [ ] (760) Organochlorine Pesticides
- [ ] (761) Organophosphate Pesticides
- [ ] (767) Polychlorinated Biphenyls (PCB's)
- [ ] (764) Polynuclear Aromatic Hydrocarbons
- [ ] (762) SDWA Pesticides & Herbicides

ANALYTICAL RESULTS

COMPOUND(S) DETECTED	CONC. [PPB]	COMPOUND(S) DETECTED	CONC. [PPB]
Using gas chromatographic			
relative retention times			
this sample contains the			
following phenolic compounds:			
1. 2,4,6-TRICHLOROphenol			
2. 2,4-DINITROphenol	–		
3. p-nitrophenol			
4. Pentachlorophenol			
* DETECTION LIMIT * *		+ DETECTION LIMIT + +	

ABBREVIATIONS USED:

N D = NONE DETECTED AT OR ABOVE THE STATED DETECTION LIMIT

T R = DETECTED AT A LEVEL BELOW THE STATED DETECTION LIMIT (NOT CONFIRMED)

[RESULTS IN BRACKETS] ARE UNCONFIRMED AND/OR WITH APPROXIMATE QUANTITATION

Sple 840 ml

LABORATORY REMARKS:

NOT ABLE TO REPORT META NITROPHENOL BECAUSE NO APPROPRIATE STANDARD AVAILABLE. Not able to confirm presence or absence because extract lost before we could apply GC/MS analysis. There were a number of hydrocarbon peaks which interfered with analysis.

CERTIFICATE OF ANALYTICAL PERSONNEL

Seal(s) Intact: Yes [ ] No [ ]. Seal(s) broken by: MO Deals date:

I certify that I followed standard laboratory procedures on handling and analysis of this sample unless otherwise noted and that the statements on this page accurately reflect the analytical results for this sample.

Date(s) of analysis: 9/27/82 . Analyst's signature: CS Bussey

I certify that I have reviewed and concur with the analytical results for this sample and with the statements in this block.

Reviewers signature: K Meyerhein

New Mexico Health and Environment Department
SCIENTIFIC LABORATORY DIVISION
700 Camino de Salud NE
Albuquerque, NM 87106

HEAVY METAL ANALYSIS FORM

Telephone: (505)841-2553

Date Received	6/26/87	Lab No.	ICP-396	User Code	☒ 82235 ☐ Other:

COLLECTION DATE & TIME: yy 87 | mm 06 | dd 24 | hh 12 | mm 20

COLLECTION SITE DESCRIPTION sample taken from SE corner of pit

COLLECTED BY: Olson, Anderson, Bailey

TO:

ENVIRONMENTAL BUREAU
NM OIL CONSERVATION DIVISION
State Land Office Bldg., PO Box 2088
SANTA FE, NM 87504-2088

ATTN: David Boyer
TELEPHONE: 827-5812

OWNER: Dept. of Energy

SITE LOCATION:
County: Sandoval

Township, Range, Section, Tract: (10N06E24342)
19N+02E+13+2222

STATION/ WELL CODE: FE11 SERVICE Pond

LATITUDE, LONGITUDE:

SAMPLING CONDITIONS:

☐ Bailed ☐ Pump ☒ Dipped ☐ Tap	Water Level:	Discharge:	Sample Type: grab

pH(00400)	Conductivity(Uncorr.)	Water Temp.(00010)	Conductivity at 25°C (00094)
8.5	8000 µmho	24.5 °C	µmho

FIELD COMMENTS:

SAMPLE FIELD TREATMENT sample only prefiltered
Check proper boxes:

☐ WPN: Water Preserved w/HNO_3 Non-Filtered

☒ WPF: Water Preserved w/HNO_3 Filtered

LAB ANALYSIS REQUESTED:

☒ ICAP Scan
Mark box next to metal if AA is required.

ANALYTICAL RESULTS (MG/L)

ELEMENT	ICAP VALUE	AA VALUE	ELEMENT	ICAP VALUE	AA VALUE
Aluminum	<0.1		Silicon	31.	
Barium	0.4		Silver	<0.1	☐
Beryllium	<0.1		Strontium	1.6	
Boron	71.		Tin	<0.1	
Cadmium	<0.1	☐	Vanadium	<0.1	
Calcium	54.		Zinc	<0.1	
Chromium	<0.1	☐	Arsenic		☐
Cobalt	<0.1		Selenium		☐
Copper	<0.1		Mercury		☐
Iron	3.8				☐
Lead	~~0.14~~ <0.1	☐			☐
Magnesium	62.				☐
Manganese	0.31				☐
Molybdenum	<0.1				☐
Nickel	<0.1				☐

LAB COMMENTS: DIGESTED.

For OCD Use:
Date Owner Notified:
Phone or Letter?
Initials:

ICAP Analyst JB
Date Analyzed 7/13/87

Reviewer Jim Ashby
Date Reviewed 7/23/87

NEW MEXICO
HEALTH AND ENVIRONMENT
DEPARTMENT

Post Office Box 968
Santa Fe, New Mexico 87504-0968

GARREY CARRUTHERS
Governor

LARRY GORDON
Secretary

CARLA L. MUTH
Deputy Secretary

September 29, 1987

RECEIVED
OCT - 1 1987
OIL CONSERVATION DIVISION
SANTA FE

David Boyer, Chief
Environmental Bureau
New Mexico Oil Conservation Division
State Land Office Building
P.O. Box 2088
Santa Fe, New Mexico 87501

Re: Department of Energy (Fenton Hill), application to discharge to Waters of the United States, Permit Number NM0028576

Dear Mr. Boyer:

Enclosed please find the public notice, statement of basis and a copy of the draft permit for Fenton Hill. Please submit any written comments you may have to USEPA and myself before October 19, 1987. I am in the process of certifying this permit and I would appreciate your comments. If you have any questions, please contact me at 827-2798.

Sincerely,

Mike Saladen

Mike Saladen
Environmental Scientist
Surface Water Section

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VI
ALLIED BANK TOWER AT FOUNTAIN PLACE
1445 ROSS AVENUE
DALLAS, TEXAS 75202

SEP 25 1987

CERTIFIED MAIL: RETURN RECEIPT REQUESTED (P 483 657 906)

REPLY TO: 6W-PS

RECEIVED
SEP 28 1987

Mr. Harold E. Valencia
Area Manager
Department of Energy
Los Alamos Area Office
Los Alamos, New Mexico 87544

Re: Application to Discharge to Waters of the United States
Permit No. NM0028576

Dear Mr. Valencia:

Enclosed is the public notice, statement of basis, and a copy of the permit which this Agency has drafted under the authority of the National Pollutant Discharge Elimination System. Please submit any written comments you may have to Ms. Ellen Caldwell (6W-PS) as stated in the enclosed public notice. A copy of the final permit will be mailed to you when the Agency has made a final permit decision.

Should you have any questions concerning any part of the permit, please feel free to contact the Permits Branch at the above address or telephone (214) 655-7190.

Sincerely yours,

Myron O. Knudson, P.E.
Director
Water Management Division (6W)

Enclosures

cc w/permit copy:
New Mexico Environmental Improvement Division

Advertising Order Number ____________
U.S. Environmental Protection Agency
Public Notice of Draft NPDES Permit(s)

SEPTEMBER 26, 1987

This is to give notice that the U.S. Environmental Protection Agency, Region 6, has formulated a Draft Permit for the following facility (facilities) under the National Pollutant Discharge Elimination System. Development of the draft permit(s) was based on a preliminary staff review by EPA, Region 6, and consultation with the State of NEW MEXICO. The State of NEW MEXICO is currently reviewing the draft permit(s) for the purpose of certifying or denying certification of the permit(s). The permit(s) will become effective within 30 days after the close of the comment period unless:

a. The State of NEW MEXICO denies certification, or requests an extension for certification prior to that date.

b. Comments received prior to OCTOBER 27, 1987 warrant a public notice of EPA's final permit decision.

c. A public hearing is held requiring delay of the effective date.

EPA's contact person for submitting written comments, requesting information regarding the draft permit, and/or obtaining copies of the permit and the Statement of Basis or Fact Sheet is:

Ms. Ellen Caldwell
Permits Branch (6W-PS)
U.S. Environmental Protection Agency
Allied Bank Tower
1445 Ross Avenue
Dallas, Texas 75202-2733
(214) 655-7190

EPA's comments and public hearing procedures may be found at 40 CFR 124.10 and 124.12 (48 Federal Register 14264, April 1, 1983, as amended at 49 Federal Register 38051, September 26, 1984). The comment period during which written comments on the draft permit may be submitted extends for 30 days from the date of this Notice. During the comment period, any interested person may request a Public Hearing by filing a written request which must state the issues to be raised. A public hearing will be held when EPA finds a significant degree of public interest.

EPA will notify the applicant and each person who has submitted written comments or requested notice of the final permit decision. A final permit decision means a final decision to issue, deny, modify, revoke or reissue, or terminate a permit. Any person may request an Evidentiary Hearing on the agency's final permit decision. However, the request must be submitted within 30 days of the date of the final permit decision and be in accordance with the requirements of 40 CFR 124.74. Any condition(s) contested in a request for an evidentiary hearing on an existing Source may be stayed if the request for a hearing is granted. If any condition(s) contested in a request for an evidentiary hearing are granted on a New Source, New Discharger, or Recommencing Discharger the applicant shall be without a permit.

Further information including the administrative record may be viewed at the above address between 8 a.m. and 8:30 p.m., Monday through Friday.

NPDES authorization to discharge to waters of the United States, Permit No. NM0028576.

The applicant's mailing address is: Department of Energy
Los Alamos Area Office
Los Alamos, New Mexico 87544

The discharge from this existing discharger is made into Lake Fork Canyon and thence to the Rio Grande River, a water of the United States classified for irrigation, limited warmwater fishery, livestock and wildlife watering, and secondary contact recreation. The discharge is located on that water about 15 kilometers due north of Jemez Springs in Sandoval County, New Mexico. A statement of basis is available. Under the standard industrial classification (SIC) code 9511, the applicant's activities are geothermal research and development.

The changes from the existing permit are:

The boron, cadmium, arsenic, fluoride and lithium parameters were deleted and the phenols parameter was added.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION VI

ALLIED BANK TOWER AT FOUNTAIN PLACE

1445 ROSS AVENUE

DALLAS, TEXAS 75202

September 10, 1987

STATEMENT OF BASIS

for proposed National Pollutant Discharge Elimination System (NPDES) permit No. NM0028576 to discharge to waters of the United States.

Issuing office: U.S. Environmental Protection Agency, Region VI
Allied Bank Tower
1445 Ross Avenue
Dallas, Texas 75202-2733

Applicant: Department of Energy
Los Alamos Area Office
Los Alamos, New Mexico 87544

1. The applicant currently operates a geothermal research and development facility.

2. As described in the application, the facility is located in Sandoval County, New Mexico. Discharge is to Lake Fork Canyon thence the Rio Grande in Segment No. 2-111 of the Rio Grande Basin. This segment is effluent limited.

3. On the basis of preliminary staff review, the Environmental Protection Agency, after consultation with the State of New Mexico has made a tentative determination to issue a permit for the discharge described in the application.

4. The following is an explanation of the derivation of the conditions of the draft permit and the reasons for them, or in the case of notices of intent to deny or terminate, reasons suggesting the tentative decisions as required under 40 CFR 124.7 (45 FR 33488, May 19, 1980).

The proposed permit is based on the existing permit and the re-application. The permittee has stated that the discharge is absorbed by the soil within approximately 750 feet of the outfall. The cadmium, lithium, arsenic, fluoride, and boron parameters were deleted based on the reported monitoring results and the phenols parameter was added based on the tracer study to be conducted. The NMEID requirement on quantity of discharge was continued in Part III of the permit.

5. The permit is in the process of certification by the State Agency. A draft permit and draft public notice will be sent to the District Engineer, Corps of Engineers and to the Regional Director of the U.S. Fish and Wildlife Service and the National Marine Fisheries Service prior to the publication of that notice.

6. The public notice describes the procedures for the formulation of final determinations.

Permit No. NM0028576

AUTHORIZATION TO DISCHARGE UNDER THE
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provisions of the Federal Water Pollution Control Act, as amended, (33 U.S.C... 1251 et. seq; the "Act"),

United States Department of Energy
Los Alamos Area Office
Los Alamos, New Mexico 87544

is authorized to discharge from a facility located at TA-57 Geothermal Site, Fenton Hill, Sandoval County, New Mexico

to receiving waters named Lake Fork Canyon

in accordance with effluent limitations, monitoring requirements and other conditions set forth in Parts I (4 pages), II (14 pages), and III (1 page) hereof.

This permit shall become effective on

This permit and the authorization to discharge shall expire at midnight,

Signed this day of

Myron O. Knudson, P.E.
Director
Water Management Division (6W)

PART I
REQUIREMENTS FOR NPDES PERMITS

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

OUTFALL 001

During the period beginning the effective date and lasting through the expiration date, the permittee is authorized to discharge from Outfall 001 - process discharge.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitations			
	Mass(lbs/day)		Other Units (mg/l)	
	Daily Avg	Daily Max	Daily Avg	Daily Max
Flow (MGD)	N/A	N/A	N/A	N/A
Phenols	N/A	N/A	N/A	Report

Effluent Characteristic	Monitoring Requirements	
	Measurement Frequency	Sample Type
Flow (MGD)	Daily*	Totalized
Phenols	Daily*	Grab

* During discharge.

OUTFALL 001

The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored daily when discharging by a grab sample.

There shall be no discharge of floating solids or visible foam in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): Outfall 001, at the discharge from the pond.

SECTION B. SCHEDULE OF COMPLIANCE

The permittee shall achieve compliance with the effluent limitations specified for discharges in accordance with the following schedule:

N/A

PART II
STANDARD CONDITIONS FOR NPDES PERMITS

SECTION A. GENERAL CONDITIONS

1. Duty to Comply

The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Clean Water Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

2. Penalties for Violations of Permit Conditions

The Clean Water Act provides that any person who violates a permit condition implementing Sections 301, 302, 306, 307, 308, 318, or 405 of the Clean Water Act is subject to a civil penalty not to exceed $10,000 per day of such violation. Any person who willfully or negligently violates permit conditions implementing Sections 301, 302, 306, 307, or 308 of the Clean Water Act is subject to a fine of not less than $2,500 nor more than $25,000 per day of violation, or by imprisonment for not more than 1 year, or both.

3. Permit Actions

This permit may be modified, revoked and reissued, or terminated for cause including, but not limited to, the following:

a. Violation of any terms or conditions of this permit;

b. Obtaining this permit by misrepresentation or failure to disclose fully all relevant facts;

c. A change in any condition that requires either a temporary or a permanent reduction or elimination of the authorized discharge; or,

d. A determination that the permitted activity endangers human health or the environment and can only be regulated to acceptable levels by permit modification or termination.

The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

4. Toxic Pollutants

Notwithstanding Part II.A.3, if any toxic effluent standard or prohibition (including any schedule of compliance specified in such effluent standard or prohibition) is promulgated under Section 307(a) of the Clean Water Act for a toxic pollutant which is present in the discharge and that standard or prohibition is more stringent than any limitation on the pollutant in this permit, this permit shall be modified or revoked and reissued to conform to the toxic effluent standard or prohibition and the permittee so notified.

The permittee shall comply with effluent standards or prohibitions established under Section 307(a) of the Clean Water Act for toxic pollutants within the time provided in the regulations that established those standards or prohibitions, even if the permit has not yet been modified to incorporate the requirement.

5. Civil and Criminal Liability

Except as provided in permit conditions on "Bypassing" (Part II.B.4.b) and "Upsets" (Part II.B.5.b), nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance.

6. Oil and Hazardous Substance Liability

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee is or may be subject under Section 311 of the Clean Water Act.

7. State Laws

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or regulation under authority preserved by Section 510 of the Clean Water Act.

8. Property Rights

The issuance of this permit does not convey any property rights of any sort, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of Federal, State, or local laws or regulations.

9. Severability

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

10. Definitions

The following definitions shall apply unless otherwise specified in this permit:

a. "Daily Discharge" means the discharge of a pollutant measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling. For pollutants with limitations expressed in terms of mass, the "daily discharge" is calculated as the total mass of the pollutant discharged over the sampling day. For pollutants with limitations expressed in other units of measurement, the "daily discharge" is calculated as the average measurement of the pollutant over the sampling day. "Daily discharge" determination of concentration made using a composite sample shall be the concentration of the composite sample. When grab samples are used, the "daily discharge" determination of concentration shall be the arithmetic average (weighted by flow value) of all samples collected during that sampling day.

b. "Daily Average" (also known as monthly average) discharge limitation means the highest allowable average of "daily discharges" over a calendar month, calculated as the sum of all "daily discharges" measured during a calendar month divided by the number of "daily discharges" measured during that month. When the permit establishes daily average concentration effluent limitations or conditions, the daily average concentration means the arithmetic average (weighted by flow) of all "daily discharges" of concentration determined during the calendar month.

c. "Daily Maximum" discharge limitation means the highest allowable "daily discharge" during the calendar month.

d. The term "MGD" shall mean million gallons per day.

e. The term "mg/l" shall mean milligrams per liter or parts per million (ppm).

f. The term "ug/l" shall mean micrograms per liter or parts per billion (ppb).

SECTION B. OPERATION AND MAINTENANCE OF POLLUTION CONTROLS

1. Proper Operation and Maintenance

The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance also includes adequate laboratory controls and appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems which are installed by a permittee only when the operation is necessary to achieve compliance with the conditions of the permit.

2. Need to Halt or Reduce not a Defense

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

3. Duty to Mitigate

The permittee shall take all reasonable steps to minimize or prevent any discharge in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment.

4. Bypass of Treatment Facilities

a. Definitions

(1) "Bypass" means the intentional diversion of waste streams from any portion of a treatment facility.

(2) "Severe property damage" means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

b. Bypass not exceeding limitations. The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of Part II.B.4.c and 4.d.

c. Notice

(1) Anticipated bypass. If the permittee knows in advance of the need for a bypass, it shall submit prior notice, if possible at least ten days before the date of the bypass.

(2) Unanticipated bypass. The permittee shall submit notice of an unanticipated bypass as required in Part II.D.6 (24-hour notice).

d. Prohibition of bypass

(1) Bypass is prohibited, and the Director may take enforcement action against a permittee for bypass, unless:

(a) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(b) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occured during normal periods of equipment downtime or preventive maintenance; and,

(c) The permittee submitted notices as required by Part II.B.4.c.

(2) The Director may approve an anticipated bypass, after considering its adverse effects, if the Director determines that it will meet the three conditions listed at Part II.B.4.d.(1).

5. <u>Upset Conditions</u>

a. Definition. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

b. Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with such technology-based permit effluent limitations if the requirements of Part II.B.5.c are met. No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

c. Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:

(1) An upset occurred and that the permittee can identify the cause(s) of the upset;

(2) The permitted facility was at the time being properly operated;

(3) The permittee submitted notice of the upset as required by Part II.D.6; and,

(4) The permittee complied with any remedial measures required by Part II.B.3.

d. Burden of proof. In any enforcement proceeding the permittee seeking to establish the occurrence of an upset has the burden of proof.

6. Removed Substances

Solids, sludges, filter backwash, or other pollutants removed in the course of treatment or control of wastewaters shall be disposed of in a manner such as to prevent any pollutant from such materials from entering navigable waters.

SECTION C. MONITORING AND RECORDS

1. Representative Sampling

Samples and measurements taken as required herein shall be representative of the volume and nature of the monitored discharge. All samples shall be taken at the monitoring points specified in this permit and, unless otherwise specified, before the effluent joins or is diluted by any other wastestream, body of water, or substance. Monitoring points shall not be changed without notification to and the approval of the Director.

2. Flow Measurements

Appropriate flow measurement devices and methods consistent with accepted scientific practices shall be selected and used to ensure the accuracy and reliability of measurements of the volume of monitored discharges. The devices shall be installed, calibrated, and maintained to insure that the accuracy of the measurements are consistent with the accepted capability of that type of device. Devices selected shall be capable of measuring flows with a maximum deviation of less than ± 10% from true discharge rates throughout the range of expected discharge volumes. Guidance in selection, installation, calibration, and operation of acceptable flow measurement devices can be obtained from the following references:

a. "A Guide to Methods and Standards for the Measurement of Water Flow", U.S. Department of Commerce, National Bureau of Standards, NBS Special Publication 421, May 1975, 97 pp. (Available from the U.S. Government Printing Office, Washington, D.C. 20402. Order by SD catalog No. C13.10:421).

b. "Water Measurement Manual", U.S. Department of Interior, Bureau of Reclamation, Second Edition, Revised Reprint, 1974, 327 pp. (Available from the U.S. Government Printing Office, Washington, D.C. 20402. Order by Catalog No. I27.19/2:W29/2, Stock No. S/N 24003-0027).

c. "Flow Measurement in Open Channels and Closed Conduits", U.S. Department of Commerce, National Bureau of Standards, NBS Special Publication 484, October 1977, 982 pp. (Available in paper copy or microfiche from National Technical Information Service (NTIS), Springfield, VA 22151. Order by NTIS No. PB-273 535/5ST).

d. "NPDES Compliance Sampling Manual", U.S. Environmental Protection Agency, Office of Water Enforcement, Publication MCD-51, 1977, 140 pp.

(Available from the General Services Administration [8FFS], Centralized Mailing Lists Services, Building 41, Denver Federal Center, Denver, CO 80225).

3. Monitoring Procedures

Monitoring must be conducted according to test procedures approved under 40 CFR Part 136, unless other test procedures have been specified in this permit.

4. Penalties for Tampering

The Clean Water Act provides that any person who falsifies, tampers with, or knowingly renders inaccurate, any monitoring device or method required to be maintained under this permit shall, upon conviction, be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than 6 months per violation, or by both.

5. Reporting of Monitoring Results

Monitoring results must be reported on a Discharge Monitoring Report (DMR) Form EPA No. 3320-1. Monitoring results obtained during the previous 3 months shall be summarized for each month and reported on a DMR form post-marked no later than the 28th day of the month following the completed reporting period. The first report is due on ______________. Duplicate copies of DMR's signed and certified as required by Part II.D.11 and all other reports required by Part II.D (Reporting Requirements) shall be submitted to the Director and to the State (if listed) at the following address(es):

Director
Water Management Division (6W)
U.S. Environmental Protection Agency
Region VI
Allied Bank Tower
1445 Ross Avenue
Dallas, Texas 75202-2733

Program Manager
Surface Water Section
Surface Water Quality Bureau
New Mexico Environmental
Improvement Division
P.O. Box 968
Santa Fe, New Mexico 87504-0968

6. Additional Monitoring by the Permittee

If the permittee monitors any pollutant more frequently than required by this permit, using test procedures approved under 40 CFR Part 136 or as specified in this permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR. Such increased monitoring frequency shall also be indicated on the DMR.

7. Averaging of Measurements

Calculations for all limitations which require averaging of measurements shall utilize an arithmetic mean unless otherwise specified by the Director in the permit.

8. Retention of Records

The permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least 3 years from the date of the sample, measurement, report, or application. This period may be extended by request of the Director at any time.

9. Record Contents

Records of monitoring information shall include:

a. The date, exact place, and time of sampling or measurements;

b. The individual(s) who performed the sampling or measurements;

c. The date(s) analyses were performed;

d. The individual(s) who performed the analyses;

e. The analytical techniques or methods used; and,

f. The results of such analyses.

10. Inspection and Entry

The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

a. Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and,

d. Sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the Clean Water Act, any substances or parameters at any location.

SECTION D. REPORTING REQUIREMENTS

1. Planned Changes

The permittee shall give notice to the Director as soon as possible of any planned physical alterations or additions to the permitted facility. Notice is required only when:

a. The alteration or addition to a permitted facility may meet one of the criteria for determining whether a facility is a new source in 40 CFR Part 122.29(b) [48 FR 14153, April 1, 1983, as amended at 49 FR 38046, September 26, 1984]; or,

b. The alteration or addition could significantly change the nature or increase the quantity of pollutants discharged. This notification applies to pollutants which are subject neither to effluent limitations in the permit, nor to notification requirements under 40 CFR Part 122.42(a)(1) [48 FR 14153, April 1, 1983, as amended at 49 FR 38046, September 26, 1984].

2. Anticipated Noncompliance

The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

3. Transfers

This permit is not transferable to any person except after notice to the Director. The Director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the Clean Water Act.

4. Monitoring Reports

Monitoring results shall be reported at the intervals and in the form specified at Part II.C.5 (Monitoring).

5. Compliance Schedules

Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 14 days following each schedule date. Any reports of noncompliance shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

6. Twenty-Four Hour Reporting

The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within 5 days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The Director may waive the written report on a case-by-case basis if the oral report has been received within 24 hours.

The following shall be included as information which must be reported within 24 hours:

a. Any unanticipated bypass which exceeds any effluent limitation in the permit;

b. Any upset which exceeds any effluent limitation in the permit; and,

c. Violation of a maximum daily discharge limitation for any of the pollutants listed by the Director in Part III of the permit to be reported within 24 hours.

7. Other Noncompliance

The permittee shall report all instances of noncompliance not reported under Part II.D.4, 5, and 6 at the time monitoring reports are submitted. The reports shall contain the information listed at Part II.D.6.

8. Changes in Discharges of Toxic Substances

The permittee shall notify the Director as soon as it knows or has reason to believe:

a. That any activity has occured or will occur which would result in the discharge, in a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the "notification levels" described in 40 CFR Part 122.42(a)(1) [48 FR 14153, April 1, 1983, as amended at 49 FR 38046, September 26, 1984].

b. That any activity has occured or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the "notification levels" described in 40 CFR Part 122.42(a)(2) [48 FR 14153, April 1, 1983, as amended at 49 FR 38046, September 26, 1984).

9. Duty to Provide Information

The permittee shall furnish to the Director, within a reasonable time, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit.

10. Duty to Reapply

If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must apply for and obtain a new permit. The application shall be submitted at least 180 days before the expiration date of this permit. The Director may grant permission to submit an application less than 180 days in advance but no later than the permit expiration date. Continuation of expiring permits shall be governed by regulations promulgated at 40 CFR Part 122.6 [48 FR 14153, April 1, 1983] and any subsequent amendments.

11. Signatory Requirements

All applications, reports, or information submitted to the Director shall be signed and certified.

a. All permit applications shall be signed as follows:

(1) For a corporation - by a responsible corporate officer. For the purpose of this section, a responsible corporate officer means:

(a) A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision making functions for the corporation; or,

(b) The manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second-quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

(2) For a partnership or sole proprietorship - by a general partner or the proprietor, respectively.

(3) For a municipality, State, Federal, or other public agency - by either a principal executive officer or ranking elected official. For purposes of this section, a principal executive officer of a Federal agency includes:

(a) The chief executive officer of the agency, or

(b) A senior executive officer having responsibility for the overall operations of a principal geographic unit of the agency.

b. All reports required by the permit and other information requested by the Director shall be signed by a person described above or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(1) The authorization is made in writing by a person described above;

(2) The authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company. A duly authorized representative may thus be either a named individual or any individual occupying a named position; and,

(3) The written authorization is submitted to the Director.

c. Certification. Any person signing a document under this section shall make the following certification:

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

12. Availability of Reports

Except for data determined to be confidential under 40 CFR Part 2, all reports prepared in accordance with the terms of this permit shall be available for public inspection at the office of the Director. As required by the Clean Water Act, the name and address of any permit applicant or permittee, permit applications, permits, and effluent data shall not be considered confidential.

13. Penalties for Falsification of Reports

The Clean Water Act provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance shall, upon conviction, be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than 6 months per violation, or by both.

PART III
OTHER CONDITIONS

A. Monitoring shall be conducted according to analytical, apparatus and materials, sample collection, preservation, handling, etc., procedures listed at 40 CFR Part 136 [38 FR 28758, 10/16/73, as amended at 41 FR 52781, 12/1/76; 41 FR 52785, 12/1/76; 42 FR 3306, 1/18/77; 42 FR 37205, 7/20/77; 49 FR 43250, 10/26/84; as corrected at 50 FR 690, 1/4/85]. Appendices A, B, and C to Part 136 [49 FR 43250, 10/26/84] are specifically referenced as part of this requirement. Amendments to 40 CFR Part 136 promulgated after the effective date of this permit shall supersede these requirements as applicable.

B. STORET/CAS CROSS-REFERENCE

For the proper identification of parameters being regulated in this permit, the following table lists the corresponding EPA Storet Number and the Chemical Abstract Service (CAS) Registry Number where applicable:

Parameter	Storet	CAS
Flow	50050	---
pH	00400	---
Phenols	32730	---

The above classification numbers will be helpful in identifying the appropriate analytical, apparatus and materials, sample collection, preservation, handling, etc., procedures listed at 40 CFR Part 136 and at "Methods of Chemical Analysis of Water and Wastes," EPA 600/4-79/020, 1979 (revised March 1983). The EPA Storet number is additionally used to identify parameters on the Discharge Monitoring Report described at Part II.C.5.

C. The quantity of discharge from the outfall shall be controlled such that no effluent flow, whether alone or co-mingled with natural runoff, travels beyond the point where the Lake Fork Canyon Road crosses the water course receiving the effluent. This point is approximately one mile downstream of the outfall.

NEW MEXICO
HEALTH AND ENVIRONMENT DEPARTMENT

Post Office Box 968
Santa Fe, New Mexico 87504-0968

ENVIRONMENTAL IMPROVEMENT DIVISION

Michael J. Burkhart
Director

GARREY CARRUTHERS
Governor

LARRY GORDON
Secretary

CARLA L. MUTH
Deputy Secretary

ENVIRONMENTAL IMPROVEMENT DIVISION

Michael J. Burkhart
Director

Certified Mail - Return Receipt Requested

September 11, 1987

Mr. Harold Valencia, Area Manager
Department of Energy
Los Alamos Area Office
Los Alamos, N.M. 82544

Re: Fenton Hill, TA 57, NPDES No:NM0028576

Dear Mr. Valencia:

Enclosed, please find the report on the Compliance Evaluation Inspection that Mike Saladen, Shelda Sutton-Mendoza, Michele Giese and I did at the Fenton Hill site on August 11, 1987. Copies will be sent to the Environmental Protection Agency for their review.

The problems that we found were as follows:

1. An "Unsatisfactory" rating was assigned for flow measurement. A totalized flow was not recorded or reported.
2. A new discharge pipe was installed from GT_2 pond. The discharge was not sampled and the flow was not totalized.
3. Sampling records need to be improved and records for the pH parameter need to be improved.
4. The pH result recorded on the DMR is the value obtained by the laboratory in Los Alamos. The pH is required to be analyzed immediately upon collection, on site, and not after transfer to an off-site lab.

Mr. Harold Valencia
Page 2
September 11, 1987

If you have any questions regarding this report, please call me at 827-2796. Please thank Mr. Jim Phoenix, Mr. Charles Nylander, Mr. George Cocks, Mr. Paul Franke, and Mr. Joe Skalski for their assistance during the inspection.

Sincerely,

Ann M. Young

Ann M. Young
Environmental Scientist
Surface Water Section

SSM/cv

cc: USEPA, Region 6 (2 copies)
NMEID Field Office, Santa Fe
LANL - Charles Nylander
Department of Energy - Jim Phoenix
NMOCD - David Boyer